California Independent
System Operator Corporation

January 13, 2012

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER12-____-000
Operation and Maintenance Cost Adder Tariff Amendment

Dear Secretary Bose:

The California Independent System Operator Corporation submits this tariff amendment to increase the number of default variable operations and maintenance cost values from two to ten.[1] These values are used to calculate minimum load costs and default energy bids under the ISO tariff. Increasing the number of default values captures the differentiation in operations and maintenance costs by technology as well as fuel type. The ISO requests an effective date of April 1, 2012. As discussed in more detail below, due to the implementation schedule for the spring 2012 release and full net work model update, the ISO is requesting that the Commission issue an order regarding this tariff amendment on or before March 16, 2012 so that these values can be in place in the ISO market systems for the April 1, 2012 trading date.

I. Background

The ISO tariff establishes default values for recovery of variable operations and maintenance costs. These values are intended to capture the variable non-fuel costs associated with operating a generating resource at or above its minimum operating level. Accordingly, these values are used in the cost-based calculations of default energy bids under the variable cost option set forth in ISO tariff section 39.7.1.1 and minimum load costs calculated pursuant to

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[1] The ISO submits this filing pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d. Capitalized terms not otherwise defined herein have the meanings set forth in Appendix A of the ISO tariff.

ISO tariff section 30.4.1.[2] The default operations and maintenance values are specified in ISO tariff section 39.7.1.1.2. The current default values are a $4.00 per MWh value for combustion turbines and reciprocating engines technology and a $2.00 per MWh value for all other generating resources.

Since implementation of the ISO's nodal market design on April 1, 2009, the ISO has implemented several tariff amendments to increase the options and flexibility for scheduling coordinators to recover both start-up and minimum load costs. The first tariff amendment involved reducing the minimum time period for the election of either the proxy cost option or the registered cost option from six months to 30 days. The Commission accepted this change effective as of August 1, 2009.[3]

In July of 2010, the ISO Board of Governors authorized ISO Management to further modify the ISO tariff regarding start-up and minimum load cost recovery options, and approved a proposal by ISO Management to evaluate the default variable operations and maintenance cost values every three years. On January 26, 2011, the ISO submitted tariff revisions to, among other things, allow scheduling coordinators to make independent elections of either the proxy or registered cost option for start-up and minimum load costs and to permit (non-negative) daily bidding of start-up and minimum load costs on behalf of resources subject to the proxy cost option. [4] In an order issued on March 31, 2011, the Commission accepted the proposed tariff revisions, to become effective on April 1, 2011.[5]

The purpose of this tariff amendment is to propose changes to the default variable operations and maintenance adders and to clarify that custom operations and maintenance adders pursuant to ISO tariff section 39.7.1.1.2 are used for both variable cost option default energy bids and minimum load costs pursuant to ISO tariff section 30.4.1.[6] In addition, the ISO is proposing to include

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[2] The operations and maintenance adder is used to calculate minimum load cost under the proxy cost option in ISO tariff section 30.4.1.1 and to calculate the cap applicable to the registered minimum load costs calculated pursuant to ISO tariff section 30.4.1.2.

[3] *California Independent System Operator Corp.*, 128 FERC ¶ 61,282 (2009). This tariff amendment also modified the cap applicable to resources located within defined local capacity areas from 400% of projected proxy costs down to 200% of projected proxy costs, with the result that all resources eligible for the registered cost option were subject to the same 200% cap.

[4] ISO tariff amendment, Docket No. ER11-2760-000 (Jan. 26, 2011).

[5] *California Independent System Operator Corp.,* 134 FERC ¶ 61,257 (2011).

[6] During a brief period beginning in late December 2011 and ending in early January 2012, the ISO attempted to utilize the operations and maintenance adders negotiated as part of the *negotiated* default energy bids to calculate minimum load costs. Since the ISO's practice as of April 2009 has been to use the custom operations and maintenance adder negotiated as part of

any negotiated values in the informational reports filed with the Commission pursuant to ISO tariff section 39.7.1.3.2.

II. Variable Operation and Maintenance Cost Adder Tariff Changes

To implement the Board's directive to evaluate the default operations and maintenance cost adders, the ISO engaged a consultant, Utilicast, LLC, to examine the current values and to propose any necessary changes to them. The consultant recommended a methodology to calculate and determine the adder for variable operations and maintenance costs and recommended values depending on the technology type and, alternatively, fuel type.[7] The ISO conducted a stakeholder process to provide a chance for stakeholders to review and give feedback on the proposed methodology and the recommended values. Upon completion of the stakeholder process, ISO Management presented the proposed new values to the ISO Board of Governors on December 15, 2011 and the Board approved them.[8]

The ISO, therefore, is proposing to amend ISO tariff section 39.7.1.1.2 to increase the number of operations and maintenance adder values from two to ten so that the differentiation in operations and maintenance costs by technology type is captured. These values, provided in the table below, will replace the existing default operations and maintenance cost values currently set forth in section 39.7.1.1.2.

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the negotiated default energy bid solely to calculate default energy bids, the ISO determined that it would be more appropriate to implement any such change through the business practice manual change management process.

[7] Provided in Attachment C is the "Final Methodology for Calculating Variable Operation and Maintenance Cost Under the Variable Cost Option" (Oct. 6, 2011). This document is available on the ISO website at http://www.caiso.com/Documents/FinalMethodology_UpdateISODefaultOperations-MaintenanceAdderValues.pdf. Also, materials from the stakeholder process for this tariff amendment (including the document in Attachment C) are available on the ISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/Operations_MaintenanceCostAdderReview_Update.aspx.

[8] Materials related to the ISO Governing Board's approval are provided in Attachment D to this filing and are available on the ISO's website at http://www.caiso.com/informed/Pages/BoardCommittees/Default.aspx.

Default Operations & Maintenance Cost Adder Values

Generation Technology	Recommended O&M Cost Adder ($/MWh)
Solar	$0.00
Nuclear	$1.00
Coal	$2.00
Wind	$2.00
Hydro	$2.50
Combined Cycle and Steam	$2.80
Geothermal	$3.00
Landfill Gas	$4.00
Combustion Turbine & Reciprocating Engine	$4.80
Biomass	$5.00

Because these values identify both fuel and technology types, it is possible that some resources may qualify for more than one default value. The ISO plans to utilize fuel type as the default value when a resource may be eligible for more than one category. Scheduling coordinators on behalf of resources may request an alternative default value if more than one applies. For example, a solar thermal resource might be eligible to be treated as a steam resource and, therefore, be eligible for a $2.80 adder rather than a $0 adder applicable to solar resources.

With respect to the option pursuant to section 39.7.1.1.2 to negotiate a custom operations and maintenance cost adder, the ISO is proposing to add clarifying tariff language that any such value would be used for purposes of calculating both default energy bids pursuant to the variable cost option as well as for minimum load costs. The ISO is also proposing tariff language to specify that the ISO will include any such values in the informational reports it files pursuant to ISO tariff section 39.7.1.3.2.[9]

Although stakeholders supported the changes to the default values for the variable operations and maintenance costs, some stakeholders urged the ISO to go further and to include major maintenance costs, noting that the ISO tariff does not currently expressly include recovery of major maintenance costs as part of the proxy cost calculation of either start-up or minimum load costs. Major maintenance costs are incurred by performing maintenance activities and are periodic rather than costs that are incurred on a continual basis as the resource

[9] Although the option to negotiate a custom operations and maintenance adder pursuant to ISO tariff section 39.7.1.1.2 has been available since April 1, 2009, no scheduling coordinator requested a custom operations and maintenance adder until fall 2011.

is operating. Major maintenance costs may include expenses for scheduled major overhauls that cannot be accomplished as part of routine maintenance or while the unit is in commercial operation.

In response to these concerns, the ISO explained that major maintenance costs are not within the scope of the triennial reassessment of variable operations and maintenance costs. ISO Management made a commitment, which the Board approved, to make a triennial reassessment of the *variable* operations and maintenance costs. Therefore, only such costs can be included within the scope of the triennial assessment performed by Utilicast, the contractor utilized by the ISO for that purpose. Utilicast benchmarked other independent system operators and regional transmission organizations and drew upon major studies to discern what should appropriately be included in variable operations and maintenance costs, and the changes proposed in this tariff amendment are based on those conclusions. Major maintenance costs, on the other hand, are periodic undertakings rather than costs incurred on a continual basis. Accordingly, variable operations and maintenance cost values should not include major maintenance costs.

In this regard, although the scope of the tariff changes is limited to updating the variable operations and maintenance adder, the ISO agrees that major maintenance costs are legitimate costs. The ISO will be addressing this issue in a new stakeholder process on commitment costs. That stakeholder process will commence in the early part of the first quarter of 2012. In the meantime, scheduling coordinators continue to have the option to elect the registered cost option for minimum load cost compensation pursuant to ISO tariff section 30.4.1.2. Under the registered cost option, a scheduling coordinator can elect to recover up to 200% of the projected proxy cost calculation of start up and/or minimum load costs calculated pursuant to ISO tariff section 39.6.1.6. Thus, scheduling coordinators can elect the registered cost option if they believe that the proxy cost option is not adequately compensatory. Alternatively, scheduling coordinators also have the option to negotiate custom operations and maintenance adders pursuant to ISO tariff section 39.7.1.1.2, in which case the custom values will be used for the variable cost option default energy bids, the minimum load costs under the proxy cost option, or the calculation of the cap on registered minimum load costs.[10]

The proposal to update the default variable operations and maintenance costs constitutes the most recent enhancement to improve the ISO tariff provisions concerning cost recovery. The fact that the ISO has not gone as far as some stakeholders would like does not render the ISO's filing unjust or unreasonable. The ISO's amendments *increase* the options available to

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[10] Custom operations and maintenance cost adders can also be negotiated as part of the default negotiated energy bids pursuant to ISO tariff section 39.7.1.3.

scheduling coordinators and improve upon the existing just and reasonable approach. The fact that other approaches might also be just and reasonable or even superior is irrelevant.[11]

III. Effective Date

The ISO requests that the Commission accept the proposed tariff revisions effective as of April 1, 2012. In order to permit the ISO to implement revised variable operations and maintenance values by April 1, 2012, the ISO requests that the Commission issue an order by March 16, 2012. The default operations and maintenance adders are maintained in the master file. The normal master file change process requires seven to ten business days to complete. There is a planned master file freeze from March 22-29, 2012 for the full network model update prior to the spring 2012 release. Thus, issuance of an order on or before March 16 is required to provide the regulatory certainty and time needed for making the system changes and data updates prior to the master field freeze period and to allow the changes to be implemented effective as of April 1, 2012.

IV. Communications

Communications regarding this filing should be addressed to the following individuals, whose names should be put on the official service list established by the Commission with respect to this submittal:

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[11] *Calpine Corp. v. California Independent System Operator Corp.*, 128 FERC ¶ 61,271, at P 41 (2009) (citations omitted). *See also New England Power Co.,* 52 FERC ¶ 61,090, at 61,336 (1990), *aff'd, Town of Norwood v. FERC,* 962 F.2d 20 (D.C. Cir. 1992) (rate design proposed need not be perfect, it merely needs to be just and reasonable), *citing Cities of Bethany*, *et al. v. FERC,* 727 F.2d 1131, 1136 (D.C. Cir.), *cert. denied*, 469 U.S. 917 (1984) (utility needs to establish that its proposed rate design is reasonable, not that it is superior to all alternatives).

V. Service

The ISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, and all parties with effective scheduling coordinator service agreements in accordance with the ISO tariff. In addition, the ISO is posting this transmittal letter and all attachments on the ISO website.

VI. Attachments

The following attachments, in addition to this transmittal letter, support the instant filing:

Attachment A	Revised ISO tariff sheets that incorporate the proposed changes described above
Attachment B	The proposed changes to the ISO tariff shown in black-line format
Attachment C	Final Methodology for Calculating Variable Operation and Maintenance Cost Under the Variable Cost Option
Attachment D	ISO Board of Governors Memorandum and Decision

VII. Conclusion

For the foregoing reasons, the Commission should accept the proposed tariff changes contained in this filing to become effective as of April 1, 2012. Please contact the undersigned if you have any questions regarding this matter.

Respectfully submitted,

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Attachment A – Clean Tariff

Operations and Maintenance Cost Adder Tariff Amendment

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

* * *

39.7.1.1.2 Variable Operation and Maintenance Cost Under the Variable Cost Option

The default value for the variable operation and maintenance cost portion will vary by fuel source or technology as follows: (1) solar $0.00/MWh; (2) nuclear $1.00/MWh; (3) coal $2.00/MWh; (4) wind $2.00/MWh; (5) hydro $2.50/MWh; (6) natural gas-fired combined cycle and steam units $2.80/MWh; (7) geothermal $3.00 WMh; (8) landfill gas $4.00/MWh; (9) combustion turbines and reciprocating engines $4.80/MWh; and (10) biomass $5.00/MWh. Resource specific values may be negotiated with the CAISO or the Independent Entity charged with calculating the Default Energy Bid. Default operation and maintenance values as well as any negotiated values will also be used to calculate Minimum Load Costs pursuant to Section 30.4.

* * *

39.7.1.3.2 Informational Filings With FERC

The CAISO shall make an informational filing with FERC of any Default Energy Bids negotiated pursuant to this section, or any temporary Default Energy Bids established pursuant to Section 39.7.1.5, or any custom operations and maintenance adders negotiated pursuant to Section 39.7.1.1.2, no later than seven (7) days after the end of the month in which the Default Energy or operations and maintenance values were established.

* * *

Attachment B – Marked Tariff

Operations and Maintenance Cost Adder Tariff Amendment

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

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39.7.1.1.2 Variable Operation and Maintenance Cost Under the Variable Cost Option

The default value for the variable operation and maintenance cost portion will vary by fuel source or technology as follows: (1) solar $0.00~~be $2~~/MWh; (2) nuclear $1.00/MWh; (3) coal $2.00/MWh; (4) wind $2.00/MWh; (5) hydro $2.50/MWh; (6) natural gas-fired combined cycle and steam units $2.80/MWh; (7) geothermal $3.00 WMh; (8) landfill gas $4.00/MWh; (9) ~~. Generating Units that are of the~~ combustion turbines and ~~turbine or~~ reciprocating engines $4.80/MWh; and (10) biomass $5.00/MWh.~~engine technology will be eligible for a default variable operation and maintenance cost of $4/MWh.~~ Resource specific values may be negotiated with the CAISO or the Independent Entity charged with calculating the Default Energy Bid. Default operation and maintenance values as well as any negotiated values will also be used to calculate Minimum Load Costs pursuant to Section 30.4.

* * *

39.7.1.3.2 Informational Filings With FERC

The CAISO shall make an informational filing with FERC of any Default Energy Bids negotiated pursuant to this section, or any temporary Default Energy Bids established pursuant to Section 39.7.1.5, or any custom operations and maintenance adders negotiated pursuant to Section 39.7.1.1.2, no later than seven (7) days after the end of the month in which the Default Energy ~~Bids~~ or operations and maintenance values were established.

* * *

Attachment C

Final Methodology

for

Calculating Variable Operation and Maintenance Cost

Under the Variable Cost Option

The purpose of this cover sheet is to provide attribution and background information for documents posted to the California ISO website that were not authored by ISO.

Project Name	**Operation and maintenance cost adder review and update**
Author Company	UTILICAST LLC
Author Name	Ronald R. McNamara
Author Title	
Title of document	Final Methodology for Calculating Variable Operation and Maintenance Cost Under the Variable Cost Option
Date submitted	October 6, 2011
Other Comments	
Notes	

This document was submitted to the California Independent System Operator for posting to the ISO website in conjunction with a Stakeholder-involved initiative or similar activity.

The document was not produced by the ISO and therefore does not necessarily reflect its views or opinion.

Final Methodology for Calculating Variable Operation and Maintenance Cost Under the Variable Cost Option

1. Introduction

At its core, the electricity market designed, implemented and operated by the California ISO is based on a series of integrated processes that take place before and during real time. These processes are described in Sections 31-34 of the FERC–approved CAISO Tariff. The overarching intent of these processes including the Day Ahead, Intra Day and Real Time Markets is to minimize the production cost of balancing supply and demand given the offers from generation resources and constraints imposed by reliable operation of the grid and network topology.

The purpose of this paper is to derive the appropriate methodology for determining a portion of the costs that are included in the Variable Cost Option. More specifically, the objective of this paper is to recommend (1) the methodology used to calculate/determine the adder for Variable O&M (VOM[1]) costs and (2) the appropriate values for this specific cost adder.

Figure 1: Disaggregation of Total Generation Costs

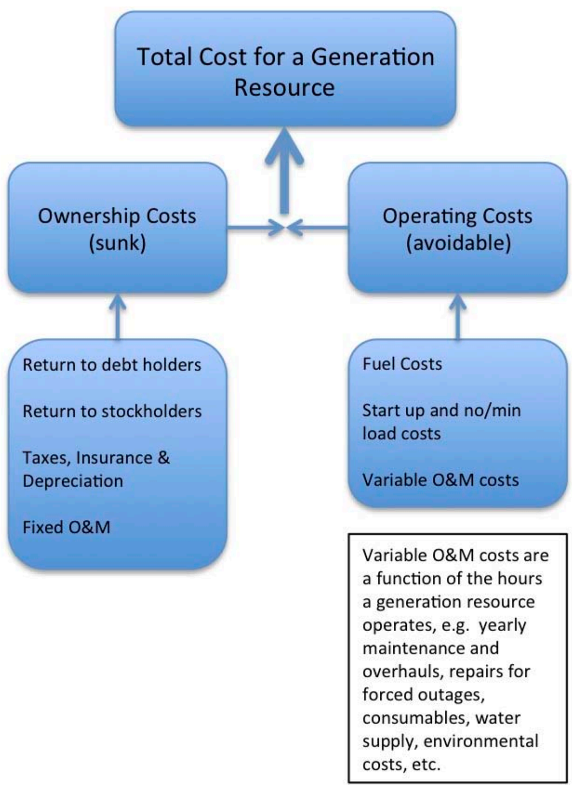

Figure 1, provides a disaggregation of the total costs for a generation resource into (1) Ownership or "sunk" costs and (2) Operating or "avoidable" costs. A generator will only operate if the latter costs are covered, since they incur the former expenditures regardless of the level of production.

It is important to note that with respect to many operational activities, accepted accounting standards allow generators to allocate the respective costs in different ways. Thus costs that one generator allocates to running at minimum load, another generator may allocate to the costs associated with start-up. As is discussed in Section 5, the recognition that not all costs must be defined similarly by all generators, underpins the differences found in the methodologies currently used by the RTO/ISO markets in the US.

Finally, the scope and direction of this paper and, therefore, the resulting recommendations are based Board approval[2] following the commitment cost

[1]The acronyms O&M and VOM are used interchangeably.

[2]See the following links: http://www.caiso.com/Documents/Board%206)%20Decision%20on%20Modifications%20to%20Bidding%20Provisions%20for%20Commitment%20Costs and http://www.caiso.com/informed/Pages/StakeholderProcesses/BiddingMitigationCommitmentCosts.aspx.

initiative, to specifically update the default variable operations and maintenance adder and not change the existing market design with respect to the cost items the adder was meant to include. In particular, the analysis in this paper reflects the language of Section 30.4 of the approved Tariff (and in particular Section 30.4.1 which specifies the appropriate start-up and minimum load costs for the proxy cost option) and Section 4.1 of the BPM for Market Instruments of including only actual variable costs in the VOM adder in the minimum load costs. [3]

2. Tariff Language and Requirements Regarding the Use of the O&M Cost Adder

In most cases, competition between generators, through their offers, will ensure that production costs are minimized and the market will yield the maximum level of consumer and producer surplus. However, in situations where effective competition is not possible, the Tariff allows the CAISO to substitute a default energy bid in place of an offer from a generator that is designed to reflect competitive outcomes.

In order to ensure the CAISO-run energy markets approximate a competitive solution, Section 39.7.1 of the CAISO Tariff[4]requires the CAISO to calculate a Default Energy Bid (DEB). Specifically, The Tariff allows for the choice of one of three methodologies to be used in determining these Default Energy Bids, the:

1. Variable Cost Option,
2. Negotiated Rate Option, or the
3. LMP Option.

The Variable Cost Option includes a component intended to capture the variable (that is, per MWh) cost for a particular generating unit to operate.

> **39.7.1.1.2 Variable Operation and Maintenance Cost Under the Variable Cost Option**
>
> The default value for the variable operation and maintenance cost portion will be $2/MWh. Generating Units that are of the combustion turbine or reciprocating engine technology will be eligible for a default variable operation and maintenance cost of $4/MWh. Resource specific values may be negotiated with the Independent Entity charged with calculating the Default Energy Bid.

Thus the approved Tariff mandates the calculation by the CAISO of a Default Energy Bid and identifies three acceptable methodologies along with their specific requirements. With respect to the VOM adder, the current tariff specifies the values for the adder but does not define or describe the methodology by which those values were determined.

3. Business Practice Manual (BPM) Language and the Calculation of the Variable O&M Adder

[3] We note that several Market Participants provided comments on the Draft of this paper that pertained to this issue, see: http://www.caiso.com/informed/Pages/StakeholderProcesses/Operations_MaintenanceCostAdderReview_Update.aspx.

[4] As of February 1, 2011.

Appendix D of the Business Practice Manual for Market Instruments mirrors the Tariff in providing the values for the Variable O&M adder but does not describe the methodology by which the values were derived:

> **D.5.4 Operations and Maintenance Adder**
>
> The Operation and Maintenance cost adder is an amount in terms of $/MW. The exact amount is dependent on resource type. The default value for the O&M adder is $2/MW for all types of resources except Combustion Turbines and Reciprocating Engines, for which it is $4/MW, regardless of fuel type. RMR Units use the FERC Filed RMR Variable O&M cost.

With respect to the methodology used to determine the VOM adder, neither the Tariff nor Business Practice Manuals constrain or limit choices to a specific approach.

4. Description of the Methodology Used to Develop the Current Values for the Variable Operations and Maintenance Cost Adder

As given in Tariff Section 39.7.1.1.2 (see above), the current value used by the CAISO for the variable operations and maintenance cost adder is $2/MWH. However, combustion turbine or reciprocating engine technology generation resources are eligible to receive a $4/MWh cost adder.

The basis for the cost adder can be traced to comments made by LECG, LLC (Scott Harvey and Susan Pope) in conjunction with Prof. William Hogan in 2005, regarding the California nodal market design.[5] The Executive Summary of the review notes:

> The failure to attempt to accurately reflect all costs (NOx allowances, current gas prices) in the calculation of start-up and minimum-load costs for the purpose both of clearing the day-ahead financial market and the reliability unit commitment (RUC) (Section VII.B) could lead to inefficiency, inflated resource adequacy costs and potentially compromise both gas and power system reliability.

The CAISO operationalized this recommendation and the rationale and methodology is found in the "California ISO White Paper for Default Energy Bids".[6]The CAISO, in collaboration with their Stakeholders, incorporated data from several sources to arrive at the initial values for the adder, i.e. $2 and $4:

> The ISO has made an effort to find empirical evidence of Operations and Maintenance Costs of generators using different generation technologies and particularly those located in California. In terms of publicly available documentation the Energy Information Administration's Assumptions to the Annual Energy Outlook 2005, Table 38: Cost and Performance Characteristics of New Central Station Electricity Generating Technologies is the most accessible…The CAISO currently has access to data supplied by Henwood which provides the Variable Operations and Maintenance Costs of a number of units in California…Whilst this data source is not definitive it does give an indication of the approximate values of variable O&M costs for California generating stations.
>
> Data from both the EIA source and from Henwood indicate that for the California resource profile there is a natural break between CCGTs and peakers, of about $2 and $4 respectively.

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[5]Harvey, Scott M, Susan L. Pope and William W. Hogan, "Comments on the California MRTU LMP Market Design." February 23, 2005. Prepared for the California Independent System Operator.
[6]Isemonger, Alan G. "California ISO White Paper for Default Energy Bids." August 16, 2005.

> According to the Henwood data steam units appear to fall around $2 as well.[7]

Thus the two initial values - $2 and $4 per MWh – for the VOM cost components were based on information from the EIA and from Henwood that was vetted and approved by the Stakeholder process.

The CAISO confirmed this methodological approach in 2010:

> The proxy cost option for start-up costs is comprised of two elements: an indexed value that changes daily depending on the natural gas price (or, for units for which that is not applicable, on the energy price), and a fixed natural gas transport adder. The proxy cost option for minimum load costs is based on the same natural gas and gas transport component as is the proxy start-up calculation, and also includes a *per* MWh operations and maintenance (O&M) adder.
>
> The VOM adder is a fixed $/MWh value that is added to the proxy cost value for Minimum Load. That value is $4/MWh for combustion turbine or reciprocating engine technology, and $2/MWh for all others. There is also the option to negotiate a *per* MWh value for minimum load with the Independent Entity.[8]

As will be discussed in the following section, other RTOs have adopted a more precise methodology and, to a greater or lesser extent have created a VOM cost adder that varies not only by generation technology but also by individual facilities.

In summary, the rationale for the inclusion of an adder for VOM stems originally from comments made by LECG, which were then operationalized by the CAISO and the Stakeholders through information primarily from EIA and Henwood. The importance of paying generation resources all of the variable costs associated with productionas well as the aggregated methodology was re-affirmed by the CAISO in 2010.

5. Methodology Used by Other RTOs and ISOs

All other RTO/ISO markets[9] include in their design something equivalent to what is termed the "Default Energy Bid" in the CAISO Tariff. Although the exact terminology varies across markets, the concept is similar: to create a generator offer that can be used during times when the generator has market power. The fundamental principle of the methodology used to create these administered offers is exactly as it is in the CAISO market design – that the offer should reflect what would take place in a competitive market.

With respect to the methodology used to determine the Variable O&M costs, PJM and ERCOT are the most specific – both have created explicit publicly available documentation as to how costs are determined.[10] Alternatively, neither the approved Tariff nor the appropriate Business Practice Manuals for the Midwest ISO and the New York ISO provide specific documentation for the calculation of the Variable O&M costs. Rather they allow the Independent Market Monitor (IMM)[11] the discretion to develop the methodology.

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[7] See Isemonger p. 14.

[8] CAISO, "Changes to Bidding and Mitigation of Commitment Costs," June 14, 2010.

[9] ISO-NE, NYISO, PJM, Midwest ISO, and ERCOT.

[10] PJM Manual 15: Cost Development Guidelines while ERCOT has the Verifiable Cost Manual.

[11] In both markets Potomac Economics currently serves as the IMM.

Regarding the actual value of the cost adder itself, the CAISO is far and away the most transparent of all the markets. In no other market is the actual dollar value of the adder publicly available. In PJM and ERCOT the methodology leads most likely to the creation of a unique adder for every generation resource. [12] In the Midwest ISO and NYISO we can presume that there are multiple cost adders but we cannot know for sure. In every market other than the CAISO, the adder is proprietary and confidential.

5.1 PJM

The approach that a generation resource owner uses to develop their cost-based offer in PJM is explained in PJM Manual 15: Cost Development Guidelines.[13]

> **1.6 Purpose of this Manual**
>
> This document details the standards recognized by PJM for determining cost components for markets where products or services are provided to PJM at cost-based rates, as referenced in Schedule 1, Section 6 of the Operating Agreement of PJM Interconnection, L.L.C.
>
> **1.6.1 Reason for Cost Based Offers: Market Power Mitigation**
>
> The following material is provided for background and should be used for information only. Structural market power is the ability of seller, or a group of sellers, to alter the market price of a good or service for a sustained period. To mitigate the potential exercise of market power, market rules can offer cap units in various markets. The Three Pivotal Supplier (TPS) test is used to determine if structural market power exists in a given market. If structural market power is found to exist, some Unit Owner may be mitigated to cost-based offers to prevent any exercise of that market power.
>
> The TPS test is a test for structural market power. The test examines the concentration of ownership of the supply compared to the level of demand. The test does not examine the competitiveness of offers or other factors.
>
> The general concept of the TPS test is to control a constraint; a certain amount of MW of relief is needed. If there are not enough MWs to satisfy the constraint without using the top two suppliers' output plus the output of the supplier being tested, then those three suppliers are jointly pivotal. According to the criteria utilized by the TPS test, because the supply can be constrained by those three owners and the demand could potentially not be satisfied, they are considered to have structural market power. If any one supplier fails, then the top two suppliers also fail.
>
> A test failure means that the ownership of the supply needed to meet is concentrated among few suppliers and therefore those suppliers have the potential to exercise market power or structural market power. It does not mean those suppliers are attempting to exercise market power.
>
> A test failure triggers mitigation as a preventative step in the event of a concentration of ownership. If a generator is brought on for constraint control and Unit Owner fails a TPS test, then unit is dispatched at the lower of the cost or price offer. The purpose of this Manual is to outline the development of the cost-based offer to ensure that PJM Members who own or control a generating unit(s) with structural market power cannot exercise it.
>
> **1.7 Components of Cost**

[12] While it is theoretically possible that two separate generation resources could – under the two methodologies – have the same adder, it would only be by coincidence.
[13] http://www.pjm.com/~/media/documents/manuals/m15.ashx

This Manual is designed to instruct Unit Owners on how to develop their cost based offers. These cost based offers are used by PJM to schedule generation in cases in which structural market power is found to exist. PJM uses the information provided from PJM Members to determine each unit's production costs.

Production costs are the costs to operate a unit for a particular period. Several different cost components are needed to determine a generating unit's total production cost. The total production cost includes:

☐ Start-up cost

☐ No-load cost

☐ Incremental costs (energy cost per segment of output range)

Production costs have a direct impact on which units are scheduled by PJM. In general, generation will be scheduled to achieve the lowest possible overall costs to the system.

The following material is provided for background and should be used for information only.

1.7.1 Generator offer curves

Generator Offer curves are representations of a generator's willingness to provide energy. Offer curves are used in determining incremental and total production costs. An offer curve can have up to ten points defined. The first point describes the lowest MW amount offered for a unit. The offer curve may be a smooth line or a block curve depending on how the points between each segment are calculated. The participant can determine how the slope of the offer curve is defined; however, the slope must be monotonically increasing.

1.7.2 Start Cost

Start costs - are defined as the costs to bring the boiler, turbine and generator from shutdown conditions to a state ready to connect to the transmission system. Start costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold. Start cost is a dollar cost and is incurred once each time the unit operates regardless of the period of operation. See Start Cost in Section 2.4 and in each Generator Section under Start.

1.7.3 No Load Cost

N**o-load cost** – is the calculated cost per hour to run at zero net output.

1.7.4 Incremental Cost

Hourly production costs -are calculated for a period. It is the cost per hour to operate a unit assuming a start has already occurred. It is calculated by summing all costs, which are incurred during one hour of operation including the hourly no-load cost and the incremental energy cost per output segment.

The incremental energy cost is the cost per MWh to produce all of the energy segments above the economic minimum level (minimum generation level with the unit available for economic dispatch). No-load costs are not included in the incremental costs. It is calculated by summing the cost of each segment of energy in the unit's incremental cost curve up to the generation level. This cost is a dollar per hour ($/MWh) rate.

1.7.5 Total Production Cost

Total production cost -is calculated by adding all of the costs associated with starting a unit and operating it over a period. Total production costs include two categories of costs: start costs and hourly production costs.

To determine the total production cost of a unit, the following formula is used:

Total Production Cost=Start up Costs+

Where x= number of hours a unit is run at a certain MW level.

It is important to remember that PJM will schedule generation day-ahead based on the above but dispatch using the incremental (marginal) cost, as represented by its Generation Offer. The incremental (marginal) cost will represent the cost to generate the next MW from the unit. See Heat Rate in Section 2.1, Performance Factor in Section 2.2, Performance Factors in Section 2.2, and Fuel Cost in Section 2.3, No-Load Cost in Section 2.5 and 2.6 Maintenance Cost.

Section 2 of Manual 15 describes the policies for all types, i.e. all available generation technologies, with respect to developing a cost-based offer. Of specific interest is Section 2.6 where the methodology for determining the VOM cost adder is described:

2.6 Variable Maintenance Cost[14]

Variable Maintenance cost is the parts and labor expenses of maintaining equipment and facilities in satisfactory operating condition.

The PJM MMU will review the Maintenance Adders for all units pursuant to the Cost and Methodology Approval Process which Schedule 1, Section 6 of the Operating Agreement of PJM Interconnection, L.L.C. applies.

The Maintenance Adder is based on all available maintenance expense history for the defined Maintenance Period (See 2.6.3) regardless of unit ownership. Only expenses incurred as a result of electric production qualify for inclusion. The Maintenance Adder should be reviewed (and updated if changed) at least annually.

[14]As stated, Section 2.6 provides the base methodology for calculating the Variable O&M adder for all generation units. Sections 3.6 (nuclear), 4.6 fossil steam), 5.6 (combined cycle), 6.6 (combustion turbines and diesel units), and 7.6 (hydro), provides additional requirements for these specific generation technologies.

If a Unit Owner feels that a unit modification or required change in operating procedures will affect the unit's Maintenance Adder, the revised Maintenance Adder must be submitted to the PJM MMU for consideration pursuant to the Cost and Methodology Approval Process.

2.6. 1 Escalation Index

Escalation Index is the annual escalation index is derived from the July 1 Handy - Whitman Index Table E-1, line 6, “construction cost electrical plant”.

YEAR	INDEX	ESCALATION FACTOR
1990	308	2.036
1991	315	1.990
1992	322	1.947
1993	334	1.877
1994	346	1.812
1995	358	1.751
1996	363	1.727
1997	375	1.672
1998	383	1.637
1999	389	1.612
2000	415	1.511
2001	425	1.475
2002	438	1.432
2003	441	1.422
2004	465	1.348
2005	493	1.272
2006	515	1.217
2007	546	1.148
2008	596	1.052
2009	578	1.085
2010	604	1.038
2011	627 (est.)	1.000

Exhibit 1: Handy Whitman Index

2.6.2 Maintenance Period

A unit must choose a rolling historical period based on calendar year. A unit may choose a 10-year or 20-year period for maintenance cost. Once a unit has chosen the historical period length, the unit must stay with that period until a significant unit configuration change. Significant unit configuration change is defined any change to the physical unit‘s system that significantly affects the maintenance cost for a period greater than 10 years. Examples of a significant unit configuration may include but are not limited to:

☐ Flue Gas Desulfurization (FGD or scrubber)

☐ Activated Carbon Injection (ACI)

☐ Selective Catalytic NOx Reduction (SCR)

☐ Selective Non-Catalytic NOx Reduction (SNCR)

☐ Low-NOx burners

☐ Bag House Addition

☐ Longterm Fuel change (greater than 10 years)

☐ Water injection for NOx control

☐ Turbine Inlet Air Cooling

A maintenance period choice may also be given in circumstances of change in ownership necessitating a new Interconnection Service Agreement (ISA). Change of ownership within the same holding company is not eligible to change the historical maintenance period.

Note: Total Maintenance Dollars must be calculated for the same historical period as Equivalent Service Hours.

2.6.3 Incremental Adjustment Parameter

Any variable cost incurred in the production of energy for PJM dispatch, not included in the CDS guidelines for Total Fuel Related Costs or Maintenance Adder. This includes water injection costs, Title 5 emission fees, and any other variable cost that has been previously approved pursuant to the Cost and Methodology Approval Process for inclusion.

2.6.4 Equivalent Hourly Maintenance Cost

The hourly Maintenance Cost in dollars per hour. This is defined as total maintenance dollars divided by equivalent service hours or total fuel, depending on unit type.

Equivalent Hourly Maintenance Cost ($/Hour) =

Or

Equivalent Hourly Maintenance Cost ($/mmbtu) =

Estimated Year 2011 Total Maintenance Example for a Combustion Turbine:

Estimated Year 2011 Equivalent Service Hours

*Equivalent Service Hours= (Cyclic Starting Factor * Number of Starts) + Total Operating Hours+(Cyclic Peaking Factor *Number of Hours above Baseload)*

See cyclic starting factor and cyclic peaking factor in section 5.6.3

Equivalent Hourly Maintenance Cost ($/Hour) =

Exhibit 2: Example Calculation of Maintenance Adder for a CT using a 10 year Maintenance Period

Relative to the CAISO market, PJM and its market participants have chosen and agreed upon a much more precise and granular methodology, not only for calculating the cost-based offer, but also for determining the VOM component of the cost-based offer. A necessary result of this methodology is that ***every*** generation resource in PJM has their own unique VOM cost adder and as a result, these values are proprietary and confidential.[15]

5.2 ERCOT

With respect to the ERCOT market, language relating to the Mitigated Offer Cap can be found in Section 4 – 6 of the approved ERCOT Protocols.

4.4.9.4 Mitigated Offer Cap and Mitigated Offer Floor

4.4.9.4.1 Mitigated Offer Cap

Energy Offer Curves may be subject to mitigation in Real-Time operations under Section 6.5.7.3, Security Constrained Economic Dispatch, using a Mitigated Offer Cap. The "Mitigated Offer Cap" is:

(a) For a Generation Resource that commences commercial operation after January 1, 2004, ERCOT shall construct an incremental Mitigated Offer Cap curve (Section 6.5.7.3) such that each point on the Mitigated Offer Cap curve (cap vs. output level) is the greater of:

(i) 14.5 MMBtu/MWh times the FIP[16]; or

(ii) The Resource's verifiable incremental heat rate (MMBtu/MWh) for the output level multiplied by ((Percentage of FIP* FIP) + (Percentage of FOP[17]* FOP))/100, as specified in the Energy Offer Curve, plus verifiable variable O&M cost ($/MWh) times a multiplier described in paragraph (d) below.

(b) For all other Generation Resources, each point on the Mitigated Offer Cap curve (cap vs. output level) is the greater of:

(i) 10.5 MMBtu/MWh times the FIP; or

(ii) The Resource's verifiable incremental heat rate (MMBtu/MWh) for the output level multiplied by ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified

[15]Verified through personal conversation with Joe Bowring of Monitoring Analytics – the Market Monitor for PJM.

[16]Fuel Index Price.

[17]Fuel Oil Price.

in the Energy Offer Curve, plus verifiable variable O&M cost ($/MWh) times a multiplier described in paragraph (d) below.

(c) Notwithstanding paragraphs (a)(ii) and (b)(ii) above, the Mitigated Offer Cap verifiable variable O&M cost ($/MWh) for Quick Start Generation Resources (QSGRs) shall incorporate the generic or verifiable O&M cost to start the Resource from first fire to LSL as described in the Verifiable Cost Manual.

For our purposes the most important thing to note from the ERCOT rules is that in calculating the (default) Mitigated Offer Cap, ERCOT, per the approved Protocols does not build the offer from individual cost components, i.e. there is no attempt to establish a Variable O&M cost adder. However, the Protocols do allow, and in some cases mandate, that a generation resource seek approval by ERCOT of their Verifiable Costs, in which case the approved Verifiable Costs would replace the Mitigated Offer Cap. It is mandatory for every generation resource that receives 5 or more Reliability Unit Commitment instructions in a year to have approved Verifiable Costs. To date only 220 of ERCOT's 550 specific generation resources have approved Verifiable Costs.[18] While specific guidelines[19] are provided, the ERCOT process for approving Verifiable Costs, explicitly recognizes that generation resource owner/operators may have different accounting methodologies for assigning costs between various categories. Thus there is no single value for the Variable O&M adder across generation resources or generation technologies.

5.3 MISO and NYISO[20]

The Midwest ISO and the NYISO have similar if not identical approaches. In both markets, there is Tariff and Business Practice Manual language that mandates the creation of a Default Offer that can be substituted for an actual offer when a generation resource is found to have market power.

Using the Midwest ISO as an example of the two markets, Section 65.2.1 of Module D of the current Midwest ISO Tariff requires that a Default Offer from generation resources be determined:

65.2.1 Purpose Version: 0.0.0 Effective: 7/28/2010

A Default Offer shall be designed to cause a Market Participant to Offer as if it faced workable competition during a period when the Market Participant: (i) does not face workable competition; and, (ii) has responded to such condition by engaging in the physical or economic withholding of, or uneconomic production, from a Generation or Stored Energy, or Planning Resource. In designing Default Offers, the IMM and the Transmission Provider shall seek to avoid causing a Resource to Offer below its marginal cost.

Other than the requirement that the Default Offer should not be below marginal cost, the Tariff provides no other information on how it is to be determined.

MISO Business Practice Manual 009 – Market Monitoring and Mitigation has additional language that provides some guidance with respect to the overall methodology to be used but primarily just reinforces the Tariff language:

8.1 Default Offers

A Default Offer is a modified Offer for a Generation Resource determined by the IMM to replacethe portions of the unit's Offer that exceed the Conduct and Impact Tests with the applicableReference Levels. A Default Offer may replace any component(s) of a Generation or

[18]Direct communication with ERCOT staff.

[19]http://www.ercot.com/committees/board/tac/wms/vcwg/

[20]The description of the MISO and NYISO methodology was validated through personal communication with Potomac Economics.

OperatingReserve Offer, including one or more of the Energy prices in a Generation Offer (Energy Offersinclude up to ten MW/Price pairs), No-Load Offer (minimum generation cost is derived from theNo-Load Offer and the Energy Offer at Dispatch Minimum), Start-up Offer (Cold, Intermediate,and Hot), Operating Reserve Offers, time-based parameters, or other Offer parameters. ForEnergy prices, the Default Offer's substitute values are set equal to or as close to the ReferenceLevel values as possible, taking into account the requirement that Energy Offer prices must bemonotonically increasing.Substituting a Default Offer for a supplier's as-bid Generation or Operating Reserve Offercauses an MP to bid as if it faced workable competition during a period when both of thefollowing apply:

1) The MP does not face workable competition, and
2) The MP has engaged in either:
    a) Economic withholding (typically determined day-ahead or in real-time and permitting prospective substitution of Default Offers), or
    b) Uneconomic production from an Electric Facility involving Energy generated at allocation where the LMP is less than 50% of the applicable Reference Level (typically determined day-ahead or in real-time and permitting prospective substitution of Default Offers)

In determining and implementing Default Offers, the IMM will avoid causing a Generation Resource to bid below its marginal cost. When the conditions for substituting a Default Offer have been satisfied, the as-bid component of the Generation Offer is replaced by the Reference Level value. Any of the following Generation Offer components may be substituted:

1) Energy Offer ($/MWh)
2) Minimum Generation Offer ($/Hr) – Default Offers are substituted either for the No-LoadOffer, for the Energy Offer at Dispatch Minimum or both
3) Start-Up Offer ($)
4) Operating Reserve Offers, including:
    a) Spinning Reserve Offer
    b) Supplemental Reserve Offer
    c) Regulation Offer
5) Time-based Offer Parameter (e.g., Start-Up Time, Minimum Run Time, Minimum Down Time, Cold Startup Time and Hot Notification Time)
6) Offer Parameter in Units Other Than Time or Dollars (e.g., Ramp Rate, Maximum Number of Daily Starts and Maximum Weekly Energy).

Only the component or components that meet the conditions for substituting a Default Offer are substituted; all other Offer prices and Offer components remain as bid.

While requiring the creation of a Cost-Based Default Offer, the Midwest ISO market design does not institutionalize a methodology nor a value for the Variable Cost O&M adder, however, the adder is determined on the basis of the reported and verified actual costs of the generation facilities.

5.4 ISO-NE[21]

In the design, ISO-New England is similar to both the Midwest ISO and the NYISO. Section III.A.5.6.1. Methods for Determining Reference Levels in Appendix A of the approved Transmission, Markets and Services Tariff describe the procedures that must be followed:

III.A.5.6.1. Methods for Determining Reference Levels.

The Internal Market Monitor will calculate a reference price or, where an element of a bid or offer is not in dollars, the time-based or quantity level (any of which being referred to as a "Reference Level") for each component of a generator's bid on the basis of the following procedures:

(a) The Internal Market Monitor will calculate Reference Levels using the first of the following three procedures for which adequate information is available, with the understanding that, for dollar-based Supply Offer parameters, Reference Levels will be calculated using the third of the three procedures if the Reference Levels calculated using the third procedure are greater than the Reference Levels calculated using either of the first two procedures.

(i) The lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation (excluding negative values) or bid components (hereinafter, a "Submitted Offer") in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource;

(ii) If that procedure is not applicable due to lack of data, then the mean of the LMP at the Resource's location during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90days for similar hours or load levels, adjusted for changes in fuel prices; or

(iii) A level negotiated with the Market Participant submitting the bid or bids at issue, and intended to reflect the Resource's marginal costs, provided such a level has been negotiated prior to the occurrence of the conduct being examined by the Internal Market Monitor, and provided that the Market Participant has provided data on the Resource's operating costs in accordance with specifications provided by the Internal Market Monitor. The Internal Market Monitor's determination of a generating unit's marginal costs shall include an assessment of the unit's incremental operating costs in accordance with the following formula, and such other factors or adjustments as the Internal Market Monitor shall reasonably determine to be appropriate based on such data supplied by the Market Participant or otherwise available to the Internal Market Monitor:

(heat rate * fuel costs) + (emissions rate * emissions allowance price) + other variable and operating maintenance costs.

While requiring the creation of a Cost-Based Default Offer, the ISO-NE market design does not institutionalize a specific methodology nor a value for the Variable Cost O&M adder. The eventual adder is based on the actual and verified costs of the generation facilities.

[21] The description of the ISO-NE methodology was validated through personal communication with the ISO-NE Internal Market Monitor.

5.5 Summary

Table 1 below summarizes the current methodologies used by each of six RTOs/ISOs in the US in terms of three characteristics: the level of granularity or the number of potential adders, whether the adder is based on actual verified costs or on an average cost level, and whether the numerical value of the adder itself can change over time without a Tariff change.

Table 1: Summary of Default Energy Bid Variable O&M Cost Adder Attributes by RTO/ISO.

RTO/ISO	Methodological Characteristics of Calculating VOM for DEB		
	Level of Granularity	**Based on Actual Costs of Generator or Average Cost**	**Is the VOM Adder Static/Dynamic?**
PJM	High	Generator	Dynamic
ERCOT	High	Generator	Dynamic
MISO	High	Generator	Dynamic
NYISO	High	Generator	Dynamic
ISO-NE	High	Generator	Dynamic
CAISO	Low	Average	Static (until Tariff change)

Table 1 validates the comment that was made at the end of Section 1, i.e. that the current methodology for calculating the VOM adder, and hence the actual numerical values, used by the CAISO is unique among the six (full[22]) RTOs/ISOs.

6. Methodological Considerations

The methodology used by the other RTOs/ISOs is simple in description but data intensive in application. In essence every other RTO/ISO calculates the VOM adder by using actual cost data from every generation facility. As a result there are potentially as many adders are there are generation facilities. Furthermore, as the actual VOM costs change, the generator can file the new costs with the internal/external market monitor and have their specific adder(s) adjusted accordingly without changing the tariff.

The current methodology used by the CAISO is quite different in that it relies on periodically determining an "average" VOM that is applied across a class of generators. Initially the CAISO established two VOM adders – $2 for all units other than peakers and $4 for peaking units.

The current CAISO methodology raises three specific methodological considerations that are not relevant for the other markets. Variable O&M costs differ across, (1) generation technology, (2) the vintage or age of the generator, and, as was discussed in Section 1 above, (3) the accounting protocols used. By using the actual verified generation costs, the other RTOs/ISOs largely eliminate the relevance of these considerations in arriving at a VOM adder. Moreover, because their methodology allows for potentially as many VOM adders as there are generators, there is no need to find a suitable average.

On the other hand, once the numbers are decided upon, the CAISO methodology is simpler to both implement and operate under and provides more transparency.

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[22]By "full" we mean performing centralized commitment and dispatch. The Southwest Power Pool (SPP) does not yet perform centralized commitment and the dispatch is (at least theoretically) limited.

However, any recommendations for the VOM adder(s) must address the issues caused by having different generation technologies of different ages. Individual generators can presumably solve the accounting issue once they know the CAISO Tariff VOM rate, i.e. they can seek to allocate actual costs not recovered by the VOM adder through other cost categories.

7. Relevant Research and Analysis on the Calculation of Variable O&M Costs.

In the 2005 White Paper, the CAISO referenced the Energy Information Administration's Assumptions to the Annual Energy Outlook 2005, Table 38: Cost and Performance Characteristics of New Central Station Electricity Generating Technologies[23].

7.1 Energy Information Administration (EIA)

Table 2 provides the Variable O&M costs for the years 2003 – 2009 from the Assumptions to the Annual Energy Outlook 2005 – 2011.

The Table highlights several important facts that warrant explicit discussion[24]:

- The Variable O&M cost data used in the 2011 Annual Energy Outlook stems from analysis performed by the EIA in conjunction with engineering consultants R.W. Beck – Updated Capital Cost Estimates for Electricity Generation Plants (November 2010).[25]Thus the data reflects current technology and updated actual costs.

- Studies of the kind prepared by the EIA in2010 are expensive and time consuming. As such, the methodology for obtaining data for electricity generation Variable O&M costs prior to 2010 can best be described as ad hoc and inconsistent across technologies.

- The prior estimates were developed in the early 2000's and then largely adjusted for inflation from one year to the next, which was problematic for renewable technologies that were either relatively scarce or just emerging at the time.[26]

- For virtually every generation technology, the 2009 Variable O&M costs are significantly different than the prior years. The exception being electricity generation from biomass where the structural shift occurred in 2006.

[23]See Appendix 2 of Isemonger.

[24]Information in this paragraph reflects email exchanges and telephone discussions with EIA staff.

[25]http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf

[26]According to the EIA "there is much more information on the costs of these technologies today than in the early 2000's, when the initial estimates were developed. The R.W. Beck study represents real time estimates based off of either current projects or current labor and material costs. Over the past 10 years there has been a much more realistic assessment of the true costs of many non-traditional power technologies, as more commercial projects have been developed. Therefore, expenses that encompass VOM such as wastewater treatment and chemicals become more apparent as projects move from high level estimates to detailed engineering and operation…this is what we are seeing here…the AEO 2011 is the first year we caught up with a lot of these changes."

Table 2: Estimates of Variable O&M Cost from the Annual Energy Outlook (2005 – 2011)[27]

Technology	2005 AEO - Variable O&M ($2003 mills/kWh)	2006 AEO - Variable O&M ($2004 mills/kWh)	2007 AEO - Variable O&M ($2005 mills/kWh)	2008 AEO - Variable O&M ($2006 mills/kWh)	2009 AEO - Variable O&M ($2007 mills/kWh)	2010 AEO - Variable O&M ($2008 mills/kWh)	2011 AEO - Variable O&M (2009 $/MWh)
Scrubbed Coal – New	4.06	4.18	4.32	4.46	4.59	4.69	4.20
Integrated Coal-Gasification Combined Cycle (IGCC)	2.58	2.65	2.75	2.84	2.92	2.99	6.79
IGCC with Carbon Sequestration	3.93	4.04	4.18	4.32	4.44	4.54	8.83
Combined Cycle – Conv. Gas/Oil CC Combustion Turbine	1.83	1.88	1.94	2.01	2.07	2.11	3.37
Combined Cycle – Advanced Gas/Oil CC Combustion Turbine	1.77	1.82	1.88	1.95	2.00	2.04	3.07
Advanced Combined Cycle with Carbon Sequestration	2.60	2.68	2.77	2.86	2.94	3.01	6.37
Conventional Combustion Turbine	3.16	3.25	3.36	3.47	3.57	3.65	8.15
Advanced Combustion Turbine – Steam Injected Gas Turbine	2.80	2.89	2.98	3.08	3.17	3.24	6.90
Fuel Cells	42.40	43.64	45.09	46.62	47.92	49.00	0.00
Advanced Nuclear – Advanced Light Water Reactor	0.44	0.45	0.47	0.48	0.49	0.51	2.00
Distributed Generation - Base	6.30	6.49	6.70	6.93	7.12	7.28	7.37
Distributed Generation - Peak	6.30	6.49	6.70	6.93	7.12	7.28	7.37
Biomass	2.96	3.13	2.96	6.53	6.71	6.86	6.94
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	9.52
MSW – Landfill Gas	0.01	0.01	0.01	0.01	0.01	0.01	8.23
Conventional Hydro	4.60	3.20	3.30	3.41	2.43	2.49	2.42
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind - Offshore				0.00	0.00	0.00	0.00
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00

[27] U.S. Energy Information Administration, Assumptions to the Annual Energy Outlook 2005 - 2011, Table 38 (2005, 2006, and 2008), Table 39 (2007) and Table 8.2 (2009 – 2011). Cost and Performance Characteristics of New Central Electricity Generating Technologies.

For most of the generation technologies in Table 2, the Variable O&M data for 2009 is non-comparable to the values reported for previous years. Prior to 2009, the methodology for estimating the Variable O&M costs, was from the early 2000s with the values for subsequent years simply increased to reflect inflation. Not only was the methodology ad hoc, but also some generation technologies have changed significantly in that time period. The latter point is significant because it highlights the important of the age of the generation facility in determining the appropriate VOM adder, i.e. new plants using new technology are likely to have significantly different cost structures.

In discussions with the EIA staff responsible for the electricity generation component of the Annual Energy Outlook they stated they were much more confident in the Variable O&M numbers derived in the 2010 study than in those used in previous years.

Table 3: Technology Performance Specifications[28]

Technology	Fuel	Nominal Capacity (kW)[29]	Nominal Heat Rate (Btu/kWh)[30]	Capital Cost (2010$/kW)[31]	Fixed O&M (2010$/kW-yr)[32]	Variable O&M (2010$/MWh)[33]
Advanced Pulverized Coal	Coal	650,000	8,800	3,167	35.97	4.25
Advanced Pulverized Coal	Coal	1,300,000	8,800	2,844	29.67	4.25
Advanced Pulverized coal with CCS	Coal	650,000	12,000	5,099	76.62	9.05
Advanced Pulverized Coal with CCS	Coal	1,300,000	12,000	4,579	63.21	9.05
Natural Gas CC	Gas	540,000	7,050	978	14.39	3.43
Adv. Gen. Natural Gas CC	Gas	400,000	6,430	1,003	14.62	3.11
Adv. Natural Gas CC with CCS	Gas	340,000	7,525	2,060	30.25	6.45
Conventional CT	Gas	85,000	10,850	974	6.98	14.70
Advanced CT	Gas	210,000	9,750	665	6.70	9.87
IGCC	Coal	600,000	8,700	6,565	59.23	6.87
IGCC	Coal	1,200,000	8,700	3,221	48.90	6.87
IGCC with CCS	Coal	520,000	10,700	5,348	69.30	8.04
Advanced Nuclear	Uranium	2,236,000	N/A	5,339	88.75	2.04
Biomass – Combined Cycle	Biomass	20,000	12,350	7,894	338.79	16.64
Biomass – Bubbling Fluidized Bed	Biomass	50,000	13,500	3,860	100.50	5.00
Fuel Cells	Gas	10,000	9,500	6,835	350.00	0
Geothermal – Dual Flash	Geothermal	50,000	N/A	5,578	84.27	9.64
Geothermal – Binary	Geothermal	50,000	N/A	4,141	84.27	9.64
MSW	MSW	50,000	18,000	8,232	373.76	8.33
Hydroelectric	Hydro	500,000	N/A	3,076	13.44	0
Pumped Storage	Hydro	250,000	N/A	5,595	13.03	0
Onshore Wind	Wind	100,000	N/A	2,438	28.07	0
Offshore Wind	Wind	400,000	N/A	5,975	53.33	0
Solar Thermal	Solar	100,000	N/A	4,692	64.00	0
Photovoltaic	Solar	7,000	N/A	6,050	26.04	0
Photovoltaic	Solar	150,000	N/A	4,755	16.70	0

[28]U.S.EIA, Office of Energy Analysis, U.S. Department of Energy, *Updated Capital Cost Estimates for Electricity Generation Plants.* November 2010. Appendix A, Table 2-5.

[29]Capacity is net of auxiliary loads.

[30]Heat Rate is on a HHV basis for British thermal units per kilowatt-hour ("Btu/kWh").

[31]Capital Cost excludes financing-related costs (e.g. fees, interest during construction).

[32]FOM expenses exclude owner's costs (e.g. insurance, property taxes, and asset management fees).

[33]VOM expenses include major maintenance.

Table 3 provides the exact data from the 2010 EIA/R.W. Beck analysis and the primary difference between the values in Tables 2 and 3 is the effect of inflation. Since the purpose of this paper is to develop recommendations for the VOM cost adder(s) that will be used in the formation of a DEB, the data in Table 3 highlights the potential costs/inefficiencies of having too few adders. For example, since the range of values presented is from $0 to $16.64, if we used the simple midpoint of $8.32 as a single adder, we would obviously be over-estimating the true VOM costs for a majority of the generation in California.

The economic inefficiency of applying this specific methodology (i.e. a single VOM adder) is greater than it would be if the range was between, say $0 and $4 in which case the VOM cost adder would be $2 under this simple methodology. Ignoring fuel cells and distributed generation for the moment and using the EIA data presented in the 2005 AEO as presented in Table 2, the range of VOM costs was between $0 and $4.60 with a midpoint of $2.30 – not too far off from the eventual VOM cost adder of $2 for non-peaking units that was included in the Tariff. The data in Table 3 suggests that since the range of VOM costs has expanded significantly it is appropriate to increase the number of cost adders beyond the two that had been used previously. Thus not only do the $2 and $4 VOM cost adders need to be changed but the number of categories needs to be increased as well.

With the understanding that the data presented in Table 3 (and hence Table 2 as well) reflects the costs and technology for ***new*** generation it appears that having only two VOM cost adders is no longer appropriate. Table 4 provides data from the California Energy Commission (CEC) regarding the use of the different in-state generating technologies for 2010. As expected there are four primary electricity generation technologies in the State: natural gas, which accounted for 53.4% of the output in 2010, followed closely by nuclear, large hydro and renewables that collectively accounted for nearly 45% of all generation, a small amount of coal generation completes the in-state generation picture.

Table 4: 2010 California Total System Power in Gigawatt Hours[34]

Fuel Type	California In-State Generation (GWh)	Percent of California In-State Generation
Coal	3,406	1.7%
Large Hydro	29,861	14.6%
Natural Gas	109,481	53.4%
Nuclear	32,214	15.7%
Oil	52	0.0%
Renewables:	30,005	14.6%
Biomass	5,745	2.8%
Geothermal	12,740	6.2%
Small Hydro	4,441	2.2%
Solar	908	0.4%
Wind	6,172	3.0%
Total	205,018	100.0%

The data in Table 4 also suggests that we should start with five technology categories and then delve deeper to see if more granularity is needed. Per Table 3, at a high level the five categories should be: (1) coal, (2) hydro, (3) natural gas, (4) nuclear and (5) renewables. Furthermore, at a first pass itappears, based on the cost characteristics, that coal, hydro and nuclear do not require any additional granularity. However the renewable category should be disaggregated into biomass (including landfill gas), geothermal, solar and wind. Likewise, the natural gas category should be broken into combined cycle and combustion turbine.

[34]California Energy Commission, http://energyalmanac.ca.gov/electricity/total_system_power.html

Based on the data in Tables 3 and 4 we can first eliminate technologies that are not found in California, e.g. carbon capture and sequestration, IGCC, and fuel cells, and then group the remaining technologies present in California from the perspective of VOM costs:

- Coal,
- Hydro,
- Combined Cycle, Steam
- Combustion turbine/reciprocating engine
- Nuclear,
- Biomass,
- Landfill Gas,
- Geothermal,
- Solar, and
- Wind

The implication of this initial grouping is that there is reason start with ten separate VOM cost adders with the understanding that some of these may have the same number.

Since the data presented by the EIA for VOM costs is based on new generation facilities, we need to better understand the age characteristics of the in-state generation. Figure 2 below breaks down the total in-state generation in 2009 according to the fuel type and vintage of the generation facilities that were used to generate the power. Thus the last column of the chart (labeled 2000 on the horizontal axis), shows that roughly 79,000 of the 205,000 MWh produced in 2009 were produced by

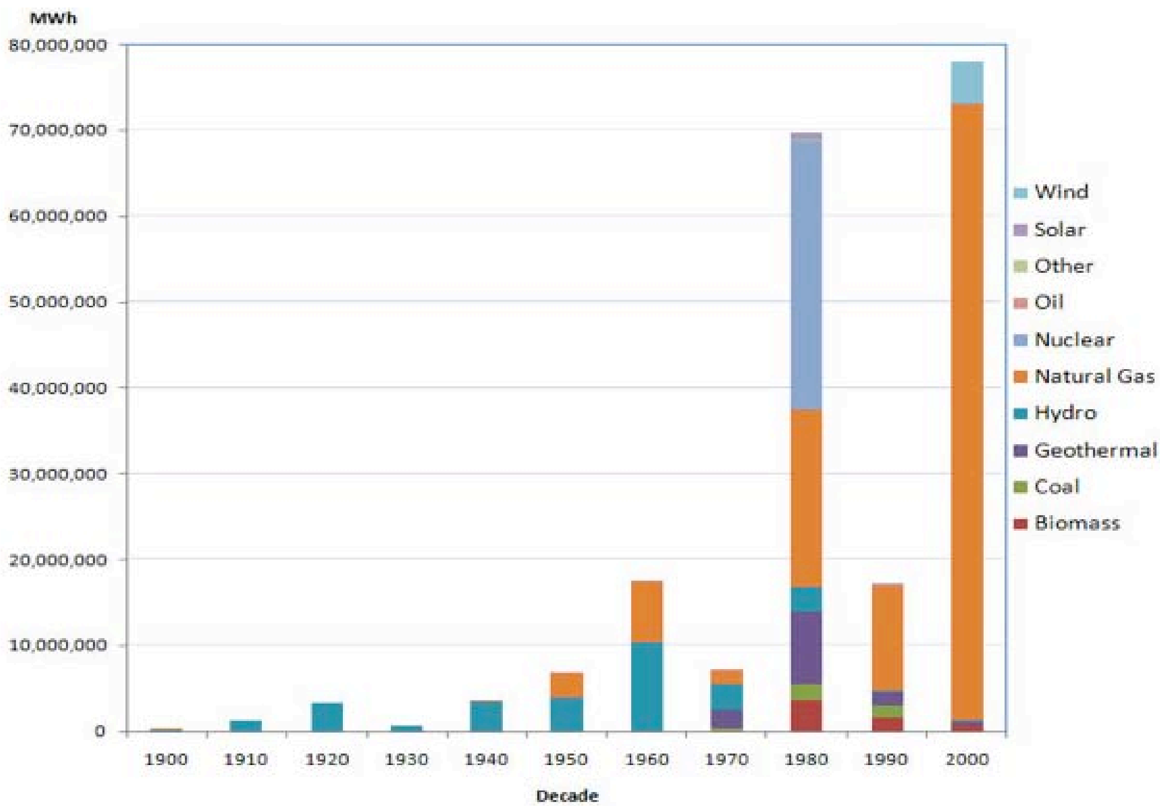

Figure 2: California In-State Electric Generation in 2009 by Generator Vintage and Fuel Type (2009 Data in MWH)[35]

[35]http://energyalmanac.ca.gov/electricity/generating_units.html

facilities that were built in the decade from 2000 – 2009. That column also shows that approximately 70,000 of the 79,000 MWh produced by plants of the vintage used natural gas as the input fuel. Figure 2, in combination with Table 4 also shows that roughly two-thirds of the 109,481 MWh produced by in-state natural gas fired generation was from plants that were built in the last 10 years.

Table 5: California Nameplate Generation Capacity by Technology and Vintage (Decades)[36]

Generation Technology	Pre-1980	1980-89	1990-1999	2000-2009
Coal	0%	65%	35%	0%
Hydro	82%	14%	4%	<1%
Natural Gas (non CC, CT or RE)	77%	3%	6%	14%
Combined Cycle	0%	1%	8%	91%
Combustion Turbine	6%	19%	7%	68%
Peaker[37]	58%	5%	11%	34%
Reciprocating Engine	21%	5%	<1%	74%
Nuclear	0%	100%	0%	0%
Biomass	0%	71%	17%	12%
Landfill Gas	0%	20%	26%	70%
Geothermal	18%	63%	19%	0%
Solar	0%	71%	20%	9%
Wind	0%	62%	15%	23%

Figure 2 and Table 5 both point to the conclusion that we need to look at how VOM costs have been changing over the past 20 and possibly even 30 years. While much of the combined cycle, combustion turbine and reciprocating engine facilities have been built in the last decade a majority of the rest of the generation is older. In particular a majority of the renewable generation (wind, solar and biomass) was built in the 1980's. For now however, we can state that the California generation portfolio does not reflect the technology, and hence the VOM costs, of new generation in 2009.

7.2 PJM

While the data collected by the PJM Market Monitor (Monitoring Analytics) that is used to calculate facility specific VOM costs is confidential, the 2010 Annual PJM State of the Market Report does contain some useful information. In particular:

> Variable operation and maintenance (VOM) expenses were estimated to be $7.46 per MWh for the CT plant, $3.23 per MWh for the CC plant and $3.07 per MWh for the CP plant. The VOM expenses for the CT and CC plants include accrual of anticipated, routine major overhaul expenses.[38]

The $7.46, $3.23 and $3.07 VOM costs for a new entrant advanced combustion turbine, combined cycle and coal plant respectively compare relatively favorably to the values from the EIA of $8.15, $3.43 and $4.25.

While the numbers are not identical they do provide confidence that the values derived by R.W. Beck for the EIA are "in line" with other industry analysis.

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[36]Table 5 is derived from the Generating Capability List found at http://www.caiso.com/market/Pages/NetworkandResourceModeling/Default.aspx

[37]As defined by the CAISO. See previous link. The numbers in this row represent the percentage of combustion turbines built in that time frame that have been classified as peakers, e.g. from 1980-89 5% of the combustion turbines that became operational were/are peakers.

[38]Monitoring Analytics, Independent Market Monitor for PJM, *State of the Market Report for PJM: Volume 2 Detailed Analysis.* March 10, 2011. p. 164. In actuality these values were created by Pasteris Energy, Inc. for Monitoring Analytics. Link to the PJM 2010 SOM: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml

7.3 California Energy Commission (CEC)

In January 2010 the CEC released the *Comparative Costs of California Central Station Electricity Generation Technologies*[39] in which they provided estimates of VOM costs for 2009. Table 6 provides the relevant data from that report.

Table 6: VOM Cost Adder by Technology – Merchant Plants[40]

In-Service Year = 2009 (Nominal 2009 $)	Size MW	Variable O&M
Small Simple Cycle	49.9	5.08
Conventional Simple Cycle	100	5.08
Advanced Simple Cycle	200	4.47
Conventional Combined Cycle (CC)	500	3.66
Conventional CC – Duct Fired	550	3.66
Advanced Combined Cycle	800	3.26
Coal – IGCC	300	11.98
Biomass IGCC	30	5.08
Biomass Combustion – Fluidized Bed Boiler	28	5.83
Biomass Combustion – Stoker Boiler	38	8.91
Geothermal – Binary	15	5.94
Geothermal – Flash	30	6.61
Hydro – Small Scale & Developed Sites	15	4.85
Hydro – Capacity Upgrade of Existing Site	80	3.16
Solar – Parabolic Trough	250	0.00
Solar – Photovoltaic (Single Axis)	25	0.00
Onshore Wind – Class 3 and 4	50	6.97
Onshore Wind – Class 5	100	6.97

Table 7 presents a comparison of the VOM cost adders from EIA, PJM, the CEC as well as several other recent studies. The purpose of Table 7 is to determine if there are technologies where there is agreement across a number of studies regarding the VOM costs. Before discussing the results, it is important to note again that accounting standards do not provide strict guidelines for certain cost allocations. In discussing the difference between the VOM cost estimates for wind between the CEC and EIA, Joel Klein of the CEC states:

> It is important to understand that the O&M costs are divided into fixed and variable cost components. The fixed costs are expected to occur at a fixed amount each year regardless of how much the generating unit actually operates - these costs are generally given in $/kW-Year. The variable costs are a function of how much the unit operates (its capacity factor) – these costs are generally given as $/MWh. The breakout between these two components is not well defined and knowledgeable experts will disagree. EIA elected to put all of the wind O&M costs into the fixed O&M costs - and thus you observe no variable O&M costs. KEMA, the consultant that did this work for us, divided it between the two components. I've seen cases where the entire O&M wasput in the variable component, but it is most common to put it all in the fixed component, as EIA has done, or to split it, as KEMA did.[41]

What this suggests is that when there is disagreement between studies with respect to the specific value for VOM costs it is likely – but not given – that the source of the conflict arises from how the costs were allocated between fixed and variable.

[39]Klein, Joel. 2009. *Comparative Costs of California Central Station Electricity Generation Technologies*, California Energy Commission, CEC-200-2009-017-SD. The link to the paper: http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF

[40]Klein, p. 28.

[41]Email correspondence on August 18, 2011.

Table 7: Estimates for VOM

Generation Technology	VOM Cost Estimate for New Technology/Generation per MWh							
	NREL in 2015 ($2007/MWh)[42]	Parsons Brinckerhoff ($2008)[43]	ACILTasman ($2011-12)[44]	Black & Veatch	Delmarva Power & Light Company's RFP Bid Evaluation Report ($2007)[45]	PJM (2009)	CEC ($2009)	EIA ($2009)
Coal	$1.77		$1.29		$1.90	$3.07		$4.20
Hydro			$7.69[46]	$4-$6 (2006)[47] (incremental)				$2.42
Combined Cycle	$3.13			$3.08 - $3.85[48]	$3.80	$3.23	$3.66	$3.37
Combustion Turbine/Reciprocating Engine	$2.92	$4.25 - $7.50	$8.08		$4.30	$7.46		$8.15
Nuclear	$0.52				$1.20			$2.00
Biomass	$10.42		$5.05	$10.00 (2006)[49]			$8.91	$6.94
Landfill Gas				$15.00 (2006)[50]				$8.23
Geothermal	$0.00		$2.15				$6.61	$9.52
Solar	$0.11						$0.00	$0.00
Wind	$5.21		$1.89	$8.00 (2006)[51]			$6.97	$0.00

In their study for the EIA, R.W. Beck, Inc. (see footnote 25) provided a partial description of the items included in their estimate of VOM costs, as applicable to the given power plant technology:[52]

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[42]Tidball, Rick, Joel Bluestein, Nick Rodriguez, and Stu Knoke (ICF International), Cost and Performance Assumptions for Modeling Electricity Generation Technologies. November 2010, p. 57. The report provides data from a number of studies, including the NREL-SEAC analysis performed in 2008.

[43]Parsons Brinckerhoff New Zealand Ltd, Cost Estimates for Thermal Peaking Plant – Final Report, June 2008. Values have been adjusted for the January – June US Dollar-NZ Dollar exchange but not for inflation. Link: http://large.stanford.edu/publications/coal/references/docs/thermal-peaking.pdf. Values based on parity between Australian and US dollars.

[44]ACIL Tasman, Calculation of energy costs for the 2011-2102 BCRI (Benchmark Retail Cost Index). Prepared for the Queensland Competition Authority, December 16, 2010. P. 10. Link: http://www.qca.org.au/files/ER-ACIL-NEP1011-BRCI-DraftRep-CalcEnergyCosts-1209.PDF, the numbers reflect Australia-wide costs.

[45]Docket No. 06-241 before the Public Service Commission of the State of Delaware.

[46]This reflects, in part, the unique attributes of the Snowy River Hydro Scheme which comprises over half of the hydro capacity in Australia

[47]Black & Veatch, Alternative Analysis – Brazos Electric Power Cooperative, December 2007, p. 6-19

[48]Black and Veatch, Alaska Railbelt Regional Integrated Resource Plan (RIRP) Study, December 2009. Link: http://www.akenergyauthority.org/RIRPFiles/Alaska_RIRP_Final_Report_120409/AlaskaRIRPDraftReport-Part3of6.pdf

[49]Black & Veatch, 2007, p. 6-4.

[50]Black & Veatch, 2007, p. 6-10.

[51]Black & Veatch, 2007, p. 6-12.

[52]U.S. Energy Information Administration, Office of Energy Analysis, U.S. Department of Energy, November 2010. Appendix A, p. 2-8.

- Raw water,
- Waste and wastewater disposal expenses,
- Purchase power (which is incurred inversely to operating hours), demand charges and related utilities,
- Chemicals, catalysts and gases,
- Ammonia ("NH_3") for selective catalytic reduction (SCR), as applicable,
- Lubricants, and
- Consumable materials and supplies.

Moreover, as was noted above with respect to the VOM estimates from Pasteris Energy, Inc for PJM it is typical for studies to include in VOM cost estimate, the major maintenance expenses, which include:[53]

- Scheduled major overhaul expenses for maintaining the prime mover equipment at a power plant,
- Major maintenance labor,
- Major maintenance spares parts costs,
- Balance of Plant major maintenance, which is major maintenance on the equipment at a given plant that cannot be accomplished as part of routine maintenance or while the unit is in commercial operation.

This raises two important considerations with regard to the appropriate VOM adder for the CAISO market. First, from one perspective, the VOM adders discussed above are non-comparable because the generation technologies have very different characteristics with respect to the cycling of major maintenance. Thus, comparing the expected VOM costs for say, coal and combustion turbines, is comparing two very different technology cost structures. Second, over the past few years there has been an increase in the price of replacement parts due to inflation and increased demand. This has resulted in an increase in the major maintenance component of expected VOM costs.

As discussed above, the CAISO market design and the associated language in the Tariff (Section 30.4.1.1 and 39.7.1.1.2) and Business Practice Manuals (Section 4.1 of the Market Instruments BPM), the methodology for calculating the VOM cost adder for the Proxy Cost Option is explicitly based on paying the actual variable operations and maintenance costs and not the major maintenance component. The market design recognizes that the number of starts more directly causes major maintenance expenditures and that, from an economic perspective (i.e. cost causation), it is more appropriate for these costs to be included in the start up costs than as part of the VOM costs. For base load plants like coal and nuclear, this distinction makes little difference since the cycle times are long and the number of MWs produced is great. In contrast, the major maintenance costs for a peaking plant are a much more significant component of total VOM costs.

Even with the difficulties, Table 7 suggests that there is broad agreement across several technology categories. Specifically,

- The EIA and CEC both report estimated VOM costs for solar production as $0.
- Coal plant VOM costs are in the range of $2 - $4.
- VOM costs for hydroelectric generation are in the range of $2.40 - $8.
- The NREL, Black & Veatch, PJM, the CEC and EIA all report estimated VOM costs for combined cycle production (including those using only steam) as $3 - $4
- PJM, EIA, Parsons Brinckerhoff, and ACIL Tasman all report estimated VOM costs for combustion turbine production in the $7.50 - $8.00 range.

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[53]U.S. Energy Information Administration, Office of Energy Analysis, U.S. Department of Energy, November 2010. Appendix A, p. 2-9.

- NREL and EIA report estimated VOM costs for nuclear generation in the range of $0.50 - $2.00

With respect to the new VOM cost adders for solar, nuclear and coal the estimates suggest the values should be $0, $1, and $2 per megawatt respectively. For the latter two technologies the inclusion of major maintenance costs along with the "variable" O&M component is inconsequential.

With respect to the costs for hydro, notwithstanding the value from ACIL Tasman, the VOM adder should be in line with the current EIA findings, i.e. $2.50/MWh.

In order to eliminate the dollar effect of major maintenance costs on the VOM adder, it is necessary to discount the estimated VOM cost adders by 20% for combined cycle and 40% for combustion turbines and reciprocating engines. This implies recommended cost adders of $2.80 and $4.80 per MWh for combined cycle and combustion turbines respectively.

Regarding generation from biomass, landfill gas, geothermal and wind resources we face two problems, first large variations in the estimates exist for all three exist as a result of how the fixed and variable costs are allocated and second, the inclusion of major maintenance costs drives up the VOM adder in all four. Again, given the objective of having the DEB reflect the "variable" component of the VOM costs, rather than the major maintenance component, our recommended VOM cost adders for biomass and landfill gas are $5 and $4 respectively. Geothermal and wind should receive $3 and $2 respectively.

Table 8: Recommended VOM Cost Adders by Generation Technology ($/MWh)

Generation Technology	Recommended VOM Cost Adder ($/MWh)
Solar	$0.00
Nuclear	$1.00
Coal	$2.00
Wind	$2.00
Hydro	$2.50
Combined Cycle and Steam	$2.80
Geothermal	$3.00
Landfill Gas	$4.00
Combustion Turbine & Reciprocating Engine	$4.80
Biomass	$5.00

Attachment D

ISO Board of Governors Memorandum and Decision

Memorandum

To: ISO Board of Governors

From: Keith Casey, VP of Market and Infrastructure Development

Date: December 8, 2011

Re: Decision on Default Operations and Maintenance Costs

This memorandum requires Board action.

EXECUTIVE SUMMARY

In July 2010, Management brought to the ISO Board of Governors several proposals to enhance how start-up and minimum load costs are recovered by market participants. All of the enhancements have been implemented except one, which involved a commitment to re-evaluate the default operations and maintenance cost values every three years. Management has conducted that re-evaluation and is proposing revised values to be implemented in April 2012, three years following implementation of the ISO's nodal market.

The operations and maintenance cost values are per-MWh dollar amounts that are intended to capture the variable, non-fuel costs associated with running a generating unit. Currently, the default operations and maintenance cost adder values are $4/MWh for combustion turbine and reciprocating engine resources and $2/MWh for all other resources. The operations and maintenance cost values are included in "cost-based" calculations of minimum load costs and default energy bids.

The ISO engaged a consultant to undertake a study of operations and maintenance values and to propose any necessary changes. The ISO published the draft study, and market participants were able to examine the methodology employed by the consultant and provide feedback on the results of the consultant's study.

The study recommends the ISO increase the number of operations and maintenance adder values from two to ten so that the differentiation in operations and maintenance costs by technology type is captured. Management recommends that these values, detailed in the discussion below, replace the existing default operations and maintenance cost values.

> ***Moved, that the ISO Board of Governors approves the proposed changes regarding the default operations and maintenance cost values as described in the memorandum dated December 8, 2011; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.***

DISCUSSION AND ANALYSIS

The default operations and maintenance cost values are per-MWh dollar values that are intended to capture the variable, non-fuel costs associated with running a generating unit. For example, variable non-fuel costs may include raw water, waste and wastewater disposal expenses, demand charges and related utilities, chemicals, gases, and other such consumable materials and supplies.

The operations and maintenance cost values are included in "cost-based" calculations of minimum load costs and in default energy bids.

- O&M values in minimum load costs: if a resource opts to have the ISO calculate its minimum load costs based on resource parameters and the natural gas price index, (that is, it elects the proxy minimum load cost option), the ISO includes the applicable operations and maintenance cost value in that calculation.
- O&M values in default energy bids: in the event that a resource is flagged as having locational market power, its bid is replaced with a default energy bid. A cost-based default energy bid is designed to approximate a competitive bid, i.e., one that reflects the marginal cost of production for the generator. Therefore, the applicable operations and maintenance cost value is included in the calculation of each resource's cost-based default energy bid.

In keeping with the commitment made through the commitment costs initiative to re-evaluate the default operations and maintenance cost adders every three years, the ISO engaged a consultant to conduct a study of operations and maintenance costs and to propose any necessary changes Additionally, the ISO undertook a stakeholder initiative through which market participants were able to examine the methodology employed by the consultant, and provide feedback on the results of the consultant's study.

The consultant's study included a thorough review of how variable operations and maintenance costs are accounted for by other ISOs. It also provided data from several sources of relevant cost information, and evaluated that information considering the existing generating fleet in California and the vintage of the resources by generation technology type. The study also provided some reconciliation of differences among the various data sources. This enabled the study to ultimately reflect a consistent accounting of variable operations and maintenance cost values.

After considering these factors, the study recommends increasing the number of operations and maintenance adder values from two to ten so that the differentiation in operations and maintenance costs by technology type is captured. Management recommends that these values, provided in the table below, replace the existing default operations and maintenance cost values, which are $4/MWh for combustion turbine and reciprocating engine resources, and $2/MWh for all other resources.

Recommended Default Operations & Maintenance Cost Adder Values

Generation Technology	Recommended O&M Cost Adder ($/MWh)
Solar	$0.00
Nuclear	$1.00
Coal	$2.00
Wind	$2.00
Hydro	$2.50
Combined Cycle and Steam	$2.80
Geothermal	$3.00
Landfill Gas	$4.00
Combustion Turbine & Reciprocating Engine	$4.80
Biomass	$5.00

Management recommends that the new operations and maintenance cost values commence with the spring 2012 software release, which is three years from the launch of the locational marginal price market. This timing is consistent with the commitment to review and update, as necessary, the default operations and maintenance cost values on a three-year basis.

POSITIONS OF THE PARTIES

In general, stakeholders were supportive of the values developed through the study and the stakeholder process. One point of contention that did arise, however, was whether to account for "major maintenance costs" as part of the variable operations and maintenance cost values. Major maintenance can include activities such as scheduled major overhaul expenses for maintaining the prime mover equipment at a power plant, balance of plant major maintenance (which is major maintenance on the equipment at a given plant that cannot be accomplished as part of routine maintenance or while the unit is in commercial operation), and labor and spare parts associated with these activities.

Major maintenance activities are periodic undertakings rather than costs that are incurred on a continual basis as the resource is operating. It is for this reason that the ISO's definition of operations and maintenance costs has not included major maintenance. While Management recognizes that generating resources do face major maintenance costs, we determined that including those costs in the variable operations and maintenance cost values would be a wholesale change to the ISO's definition of that cost component. Such a change was well outside the scope of this effort which was simply to update the operations and maintenance cost values as currently defined.

In response to this concern, however, an evaluation of how major maintenance costs can be best captured in "cost-based" calculations will be included in the next iteration of the commitment costs stakeholder initiative. There was receptiveness to the idea that these costs might be best accounted for in the cost-based calculation of start-up costs. Additionally, interim methodologies by which generating resources can express their major maintenance costs to the ISO were discussed. Those methodologies include (1) submission of minimum load costs directly to the ISO through use of the registered cost option rather than relying on the ISO's cost-based calculations; and (2) use of the option to negotiate a higher operations and maintenance cost adder with the Independent Entity.

CONCLUSION

Management recommends that the Board approve the revised operations and maintenance cost values authorize Management to make all necessary and appropriate filings with FERC to implement the proposed tariff change.