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September 26, 2019

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY,
Advice No. 19-02 (ADV 919) New Load Direct Access Program
Docket No. UE 358

Dear Filing Center:

Please find enclosed the Cross-Examination Exhibits (AWEC/300 – AWEC/307) of the Alliance of Western Energy Consumers in the above-referenced docket.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 358

In the Matter of	)	
	)	CROSS-EXAMINATION EXHIBITS OF
PORTLAND GENERAL ELECTRIC	)	THE ALLIANCE OF WESTERN ENERGY
COMPANY,	)	CONSUMERS
	)	
Advice No. 19-02, New Load Direct Access	)	
Program.	)	

Pursuant to the Chief Administrative Law Judge's September 10, 2019 Ruling, the Alliance of Western Energy Consumers ("AWEC") submits the following cross-examination exhibits in the above-referenced Docket:

Cross Examination Exhibit	Description
AWEC/300	Edison Electric Institute Master Power Purchase & Sale Agreement
AWEC/301	Portland General Electric Wholesale Renewable Power Purchase Agreement Template (Appendix A to PGE Request for Proposals filed in UM 1934)
AWEC/302	California ISO Resource Adequacy Enhancements Revised Straw Proposal (July 1, 2019)
AWEC/303	Puget Sound Energy 2017 Integrated Resource Plan Executive Summary
AWEC/304	PacifiCorp 2017 Integrated Resource Plan Executive Summary
AWEC/305	Portland General Electric Rule K

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
Telephone: (503) 241-7242

Cross Examination Exhibit	Description
AWEC/306	Portland General Electric Schedule 600
AWEC/307	Portland General Electric Schedule 489

Dated this 26th day of September, 2019.

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

/s/ Tyler C. Pepple
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Of Attorneys for the Alliance of Western Energy Consumers

Master Power Purchase & Sale Agreement

Version 2.1 (modified 4/25/00)

MASTER POWER PURCHASE AND SALES AGREEMENT

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MASTER POWER PURCHASE AND SALE AGREEMENT

COVER SHEET

This *Master Power Purchase and Sale Agreement* ("*Master Agreement*") is made as of the following date: ________________ ("Effective Date"). The *Master Agreement*, together with the exhibits, schedules and any written supplements hereto, the Party A Tariff, if any, the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any confirmations accepted in accordance with Section 2.3 hereto) shall be referred to as the "Agreement." The Parties to this *Master Agreement* are the following:

Name ("__________________" or "Party A")	Name ("Counterparty" or "Party B")
All Notices:	All Notices:
Street: ______________________	Street: ______________________
City: ______________ Zip: ________	City: ______________ Zip: ________
Attn: Contract Administration Phone: ______________________ Facsimile: ______________________ Duns: ______________________ Federal Tax ID Number: ______________	Attn: Contract Administration Phone: ______________________ Facsimile: ______________________ Duns: ______________________ Federal Tax ID Number: ______________
Invoices: Attn: ______________________ Phone: ______________________ Facsimile: ______________________	**Invoices:** Attn: ______________________ Phone: ______________________ Facsimile: ______________________
Scheduling: Attn: ______________________ Phone: ______________________ Facsimile: ______________________	**Scheduling:** Attn: ______________________ Phone: ______________________ Facsimile: ______________________
Payments: Attn: ______________________ Phone: ______________________ Facsimile: ______________________	**Payments:** Attn: ______________________ Phone: ______________________ Facsimile: ______________________
Wire Transfer: BNK: ______________________ ABA: ______________________ ACCT: ______________________	**Wire Transfer:** BNK: ______________________ ABA: ______________________ ACCT: ______________________
Credit and Collections: Attn: ______________________ Phone: ______________________ Facsimile: ______________________	**Credit and Collections:** Attn: ______________________ Phone: ______________________ Facsimile: ______________________
With additional Notices of an Event of Default or Potential Event of Default to: Attn: ______________________ Phone: ______________________ Facsimile: ______________________	With additional Notices of an Event of Default or Potential Event of Default to: Attn: ______________________ Phone: ______________________ Facsimile: ______________________

The Parties hereby agree that the General Terms and Conditions are incorporated herein, and to the following provisions as provided for in the General Terms and Conditions:

Party A Tariff Tariff ________________ Dated ________________ Docket Number ______________

Party B Tariff Tariff ________________ Dated ________________ Docket Number ______________

Article Two

Transaction Terms and Conditions [] Optional provision in Section 2.4. If not checked, inapplicable.

Article Four

Remedies for Failure to Deliver or Receive [] Accelerated Payment of Damages. If not checked, inapplicable.

Article Five

Events of Default; Remedies

[] Cross Default for Party A:

[] Party A:__________________ Cross Default Amount $_________

[] Other Entity:______________ Cross Default Amount $_________

[] Cross Default for Party B:

[] Party B:__________________ Cross Default Amount $_________

[] Other Entity:______________ Cross Default Amount $_________

5.6 Closeout Setoff

[] Option A (Applicable if no other selection is made.)

[] Option B - Affiliates shall have the meaning set forth in the Agreement unless otherwise specified as follows:______________
____

[] Option C (No Setoff)

Article 8

Credit and Collateral Requirements

8.1 Party A Credit Protection:

(a) Financial Information:

[] Option A
[] Option B Specify: ________________
[] Option C Specify: ________________

(b) Credit Assurances:

[] Not Applicable
[] Applicable

(c) Collateral Threshold:

[] Not Applicable
[] Applicable

If applicable, complete the following:

Party B Collateral Threshold: $ __________; provided, however, that Party B's Collateral Threshold shall be zero if an Event of Default or Potential Event of Default with respect to Party B has occurred and is continuing.

Party B Independent Amount: $_____________

Party B Rounding Amount: $_______________

(d) Downgrade Event:

[] Not Applicable
[] Applicable

If applicable, complete the following:

[] It shall be a Downgrade Event for Party B if Party B's Credit Rating falls below __________ from S&P or __________ from Moody's or if Party B is not rated by either S&P or Moody's

[] Other:
Specify:____

(e) Guarantor for Party B:____

Guarantee Amount:_____________________________________

8.2 Party B Credit Protection:

(a) Financial Information:

[] Option A
[] Option B Specify: _________________
[] Option C Specify: _________________

(b) Credit Assurances:

[] Not Applicable
[] Applicable

(c) Collateral Threshold:

[] Not Applicable
[] Applicable

If applicable, complete the following:

Party A Collateral Threshold: $ __________; provided, however, that Party A's Collateral Threshold shall be zero if an Event of Default or Potential Event of Default with respect to Party A has occurred and is continuing.

Party A Independent Amount: $_____________

Party A Rounding Amount: $_______________

(d) Downgrade Event:

[] Not Applicable
[] Applicable

If applicable, complete the following:

[] It shall be a Downgrade Event for Party A if Party A's Credit Rating falls below ___________ from S&P or ___________ from Moody's or if Party A is not rated by either S&P or Moody's

[] Other:
Specify:____

(e) Guarantor for Party A:____________________________________

Guarantee Amount:__________________________________

Article 10		
Confidentiality	[] Confidentiality Applicable	If not checked, inapplicable.

Schedule M

[] Party A is a Governmental Entity or Public Power System
[] Party B is a Governmental Entity or Public Power System
[] Add Section 3.6. If not checked, inapplicable
[] Add Section 8.6. If not checked, inapplicable

Other Changes Specify, if any: ____

IN WITNESS WHEREOF, the Parties have caused this Master Agreement to be duly executed as of the date first above written.

Party A Name	Party B Name
By: ______________________	By: ______________________
Name: ____________________	Name: ____________________
Title: _____________________	Title: _____________________

DISCLAIMER: This Master Power Purchase and Sale Agreement was prepared by a committee of representatives of Edison Electric Institute ("EEI") and National Energy Marketers Association ("NEM") member companies to facilitate orderly trading in and development of wholesale power markets. Neither EEI nor NEM nor any member company nor any of their agents, representatives or attorneys shall be responsible for its use, or any damages resulting therefrom. By providing this Agreement EEI and NEM do not offer legal advice and all users are urged to consult their own legal counsel to ensure that their commercial objectives will be achieved and their legal interests are adequately protected.

GENERAL TERMS AND CONDITIONS

ARTICLE ONE: GENERAL DEFINITIONS

1.1 "Affiliate" means, with respect to any person, any other person (other than an individual) that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such person. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

1.2 "Agreement" has the meaning set forth in the Cover Sheet.

1.3 "Bankrupt" means with respect to any entity, such entity (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it, (ii) makes an assignment or any general arrangement for the benefit of creditors, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (v) is generally unable to pay its debts as they fall due.

1.4 "Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

1.5 "Buyer" means the Party to a Transaction that is obligated to purchase and receive, or cause to be received, the Product, as specified in the Transaction.

1.6 "Call Option" means an Option entitling, but not obligating, the Option Buyer to purchase and receive the Product from the Option Seller at a price equal to the Strike Price for the Delivery Period for which the Option may be exercised, all as specified in the Transaction. Upon proper exercise of the Option by the Option Buyer, the Option Seller will be obligated to sell and deliver the Product for the Delivery Period for which the Option has been exercised.

1.7 "Claiming Party" has the meaning set forth in Section 3.3.

1.8 "Claims" means all third party claims or actions, threatened or filed and, whether groundless, false, fraudulent or otherwise, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorneys' fees and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement.

1.9 "Confirmation" has the meaning set forth in Section 2.3.

1.10 “Contract Price” means the price in $U.S. (unless otherwise provided for) to be paid by Buyer to Seller for the purchase of the Product, as specified in the Transaction.

1.11 “Costs” means, with respect to the Non-Defaulting Party, brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or entering into new arrangements which replace a Terminated Transaction; and all reasonable attorneys’ fees and expenses incurred by the Non-Defaulting Party in connection with the termination of a Transaction.

1.12 “Credit Rating” means, with respect to any entity, the rating then assigned to such entity’s unsecured, senior long-term debt obligations (not supported by third party credit enhancements) or if such entity does not have a rating for its senior unsecured long-term debt, then the rating then assigned to such entity as an issues rating by S&P, Moody’s or any other rating agency agreed by the Parties as set forth in the Cover Sheet.

1.13 “Cross Default Amount” means the cross default amount, if any, set forth in the Cover Sheet for a Party.

1.14 “Defaulting Party” has the meaning set forth in Section 5.1.

1.15 “Delivery Period” means the period of delivery for a Transaction, as specified in the Transaction.

1.16 “Delivery Point” means the point at which the Product will be delivered and received, as specified in the Transaction.

1.17 “Downgrade Event” has the meaning set forth on the Cover Sheet.

1.18 “Early Termination Date” has the meaning set forth in Section 5.2.

1.19 “Effective Date” has the meaning set forth on the Cover Sheet.

1.20 “Equitable Defenses” means any bankruptcy, insolvency, reorganization and other laws affecting creditors’ rights generally, and with regard to equitable remedies, the discretion of the court before which proceedings to obtain same may be pending.

1.21 “Event of Default” has the meaning set forth in Section 5.1.

1.22 “FERC” means the Federal Energy Regulatory Commission or any successor government agency.

1.23 “Force Majeure” means an event or circumstance which prevents one Party from performing its obligations under one or more Transactions, which event or circumstance was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and which, by the exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (i) the loss of Buyer’s markets; (ii) Buyer’s inability economically to use or resell the Product purchased hereunder; (iii) the loss or failure of Seller's supply; or (iv) Seller's ability to sell the Product at a price greater than the Contract Price. Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Product to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined in the first sentence hereof has occurred. The applicability of Force Majeure to the Transaction is governed by the terms of the Products and Related Definitions contained in Schedule P.

1.24 "Gains" means, with respect to any Party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of a Terminated Transaction, determined in a commercially reasonable manner.

1.25 "Guarantor" means, with respect to a Party, the guarantor, if any, specified for such Party on the Cover Sheet.

1.26 "Interest Rate" means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%) and (b) the maximum rate permitted by applicable law.

1.27 "Letter(s) of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch with such bank having a credit rating of at least A- from S&P or A3 from Moody's, in a form acceptable to the Party in whose favor the letter of credit is issued. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit.

1.28 "Losses" means, with respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from termination of a Terminated Transaction, determined in a commercially reasonable manner.

1.29 "Master Agreement" has the meaning set forth on the Cover Sheet.

1.30 "Moody's" means Moody's Investor Services, Inc. or its successor.

1.31 "NERC Business Day" means any day except a Saturday, Sunday or a holiday as defined by the North American Electric Reliability Council or any successor organization thereto. A NERC Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

1.32 “Non-Defaulting Party” has the meaning set forth in Section 5.2.

1.33 “Offsetting Transactions” mean any two or more outstanding Transactions, having the same or overlapping Delivery Period(s), Delivery Point and payment date, where under one or more of such Transactions, one Party is the Seller, and under the other such Transaction(s), the same Party is the Buyer.

1.34 “Option” means the right but not the obligation to purchase or sell a Product as specified in a Transaction.

1.35 “Option Buyer” means the Party specified in a Transaction as the purchaser of an option, as defined in Schedule P.

1.36 “Option Seller” means the Party specified in a Transaction as the seller of an option , as defined in Schedule P.

1.37 “Party A Collateral Threshold” means the collateral threshold, if any, set forth in the Cover Sheet for Party A.

1.38 “Party B Collateral Threshold” means the collateral threshold, if any, set forth in the Cover Sheet for Party B.

1.39 “Party A Independent Amount” means the amount , if any, set forth in the Cover Sheet for Party A.

1.40 “Party B Independent Amount” means the amount , if any, set forth in the Cover Sheet for Party B.

1.41 “Party A Rounding Amount” means the amount, if any, set forth in the Cover Sheet for Party A.

1.42 “Party B Rounding Amount” means the amount, if any, set forth in the Cover Sheet for Party B.

1.43 “Party A Tariff” means the tariff, if any, specified in the Cover Sheet for Party A.

1.44 “Party B Tariff” means the tariff, if any, specified in the Cover Sheet for Party B.

1.45 “Performance Assurance” means collateral in the form of either cash, Letter(s) of Credit, or other security acceptable to the Requesting Party.

1.46 “Potential Event of Default” means an event which, with notice or passage of time or both, would constitute an Event of Default.

1.47 “Product” means electric capacity, energy or other product(s) related thereto as specified in a Transaction by reference to a Product listed in Schedule P hereto or as otherwise specified by the Parties in the Transaction.

1.48 “Put Option” means an Option entitling, but not obligating, the Option Buyer to sell and deliver the Product to the Option Seller at a price equal to the Strike Price for the Delivery Period for which the option may be exercised, all as specified in a Transaction. Upon proper exercise of the Option by the Option Buyer, the Option Seller will be obligated to purchase and receive the Product.

1.49 “Quantity” means that quantity of the Product that Seller agrees to make available or sell and deliver, or cause to be delivered, to Buyer, and that Buyer agrees to purchase and receive, or cause to be received, from Seller as specified in the Transaction.

1.50 “Recording” has the meaning set forth in Section 2.4.

1.51 “Replacement Price” means the price at which Buyer, acting in a commercially reasonable manner, purchases at the Delivery Point a replacement for any Product specified in a Transaction but not delivered by Seller, plus (i) costs reasonably incurred by Buyer in purchasing such substitute Product and (ii) additional transmission charges, if any, reasonably incurred by Buyer to the Delivery Point, or at Buyer’s option, the market price at the Delivery Point for such Product not delivered as determined by Buyer in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Buyer be required to utilize or change its utilization of its owned or controlled assets or market positions to minimize Seller’s liability. For the purposes of this definition, Buyer shall be considered to have purchased replacement Product to the extent Buyer shall have entered into one or more arrangements in a commercially reasonable manner whereby Buyer repurchases its obligation to sell and deliver the Product to another party at the Delivery Point.

1.52 “S&P” means the Standard & Poor’s Rating Group (a division of McGraw-Hill, Inc.) or its successor.

1.53 “Sales Price” means the price at which Seller, acting in a commercially reasonable manner, resells at the Delivery Point any Product not received by Buyer, deducting from such proceeds any (i) costs reasonably incurred by Seller in reselling such Product and (ii) additional transmission charges, if any, reasonably incurred by Seller in delivering such Product to the third party purchasers, or at Seller’s option, the market price at the Delivery Point for such Product not received as determined by Seller in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Seller be required to utilize or change its utilization of its owned or controlled assets, including contractual assets, or market positions to minimize Buyer’s liability. For purposes of this definition, Seller shall be considered to have resold such Product to the extent Seller shall have entered into one or more arrangements in a commercially reasonable manner whereby Seller repurchases its obligation to purchase and receive the Product from another party at the Delivery Point.

1.54 “Schedule” or “Scheduling” means the actions of Seller, Buyer and/or their designated representatives, including each Party’s Transmission Providers, if applicable, of notifying, requesting and confirming to each other the quantity and type of Product to be delivered on any given day or days during the Delivery Period at a specified Delivery Point.

1.55 "Seller" means the Party to a Transaction that is obligated to sell and deliver, or cause to be delivered, the Product, as specified in the Transaction.

1.56 "Settlement Amount" means, with respect to a Transaction and the Non-Defaulting Party, the Losses or Gains, and Costs, expressed in U.S. Dollars, which such party incurs as a result of the liquidation of a Terminated Transaction pursuant to Section 5.2.

1.57 "Strike Price" means the price to be paid for the purchase of the Product pursuant to an Option.

1.58 "Terminated Transaction" has the meaning set forth in Section 5.2.

1.59 "Termination Payment" has the meaning set forth in Section 5.3.

1.60 "Transaction" means a particular transaction agreed to by the Parties relating to the sale and purchase of a Product pursuant to this Master Agreement.

1.61 "Transmission Provider" means any entity or entities transmitting or transporting the Product on behalf of Seller or Buyer to or from the Delivery Point in a particular Transaction.

ARTICLE TWO: TRANSACTION TERMS AND CONDITIONS

2.1 Transactions. A Transaction shall be entered into upon agreement of the Parties orally or, if expressly required by either Party with respect to a particular Transaction, in writing, including an electronic means of communication. Each Party agrees not to contest, or assert any defense to, the validity or enforceability of the Transaction entered into in accordance with this Master Agreement (i) based on any law requiring agreements to be in writing or to be signed by the parties, or (ii) based on any lack of authority of the Party or any lack of authority of any employee of the Party to enter into a Transaction.

2.2 Governing Terms. Unless otherwise specifically agreed, each Transaction between the Parties shall be governed by this Master Agreement. This Master Agreement (including all exhibits, schedules and any written supplements hereto), , the Party A Tariff, if any, and the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmations accepted in accordance with Section 2.3) shall form a single integrated agreement between the Parties. Any inconsistency between any terms of this Master Agreement and any terms of the Transaction shall be resolved in favor of the terms of such Transaction.

2.3 Confirmation. Seller may confirm a Transaction by forwarding to Buyer by facsimile within three (3) Business Days after the Transaction is entered into a confirmation ("Confirmation") substantially in the form of Exhibit A. If Buyer objects to any term(s) of such Confirmation, Buyer shall notify Seller in writing of such objections within two (2) Business Days of Buyer's receipt thereof, failing which Buyer shall be deemed to have accepted the terms as sent. If Seller fails to send a Confirmation within three (3) Business Days after the Transaction is entered into, a Confirmation substantially in the form of Exhibit A, may be forwarded by Buyer to Seller. If Seller objects to any term(s) of such Confirmation, Seller shall notify Buyer of such objections within two (2) Business Days of Seller's receipt thereof, failing which Seller shall be deemed to have accepted the terms as sent. If Seller and Buyer each send a Confirmation and neither Party objects to the other Party's Confirmation within two (2) Business Days of receipt, Seller's Confirmation shall be deemed to be accepted and shall be the controlling Confirmation, unless (i) Seller's Confirmation was sent more than three (3) Business Days after the Transaction was entered into and (ii) Buyer's Confirmation was sent prior to Seller's Confirmation, in which case Buyer's Confirmation shall be deemed to be accepted and shall be the controlling Confirmation. Failure by either Party to send or either Party to return an executed Confirmation or any objection by either Party shall not invalidate the Transaction agreed to by the Parties.

2.4 Additional Confirmation Terms. If the Parties have elected on the Cover Sheet to make this Section 2.4 applicable to this Master Agreement, when a Confirmation contains provisions, other than those provisions relating to the commercial terms of the Transaction (e.g., price or special transmission conditions), which modify or supplement the general terms and conditions of this Master Agreement (e.g., arbitration provisions or additional representations and warranties), such provisions shall not be deemed to be accepted pursuant to Section 2.3 unless agreed to either orally or in writing by the Parties; provided that the foregoing shall not invalidate any Transaction agreed to by the Parties.

2.5 Recording. Unless a Party expressly objects to a Recording (defined below) at the beginning of a telephone conversation, each Party consents to the creation of a tape or electronic recording ("Recording") of all telephone conversations between the Parties to this Master Agreement, and that any such Recordings will be retained in confidence, secured from improper access, and may be submitted in evidence in any proceeding or action relating to this Agreement. Each Party waives any further notice of such monitoring or recording, and agrees to notify its officers and employees of such monitoring or recording and to obtain any necessary consent of such officers and employees. The Recording, and the terms and conditions described therein, if admissible, shall be the controlling evidence for the Parties' agreement with respect to a particular Transaction in the event a Confirmation is not fully executed (or deemed accepted) by both Parties. Upon full execution (or deemed acceptance) of a Confirmation, such Confirmation shall control in the event of any conflict with the terms of a Recording, or in the event of any conflict with the terms of this Master Agreement.

ARTICLE THREE: OBLIGATIONS AND DELIVERIES

3.1 Seller's and Buyer's Obligations. With respect to each Transaction, Seller shall sell and deliver, or cause to be delivered, and Buyer shall purchase and receive, or cause to be received, the Quantity of the Product at the Delivery Point, and Buyer shall pay Seller the Contract Price; provided, however, with respect to Options, the obligations set forth in the preceding sentence shall only arise if the Option Buyer exercises its Option in accordance with its terms. Seller shall be responsible for any costs or charges imposed on or associated with the Product or its delivery of the Product up to the Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Product or its receipt at and from the Delivery Point.

3.2 Transmission and Scheduling. Seller shall arrange and be responsible for transmission service to the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers, as specified by the Parties in the Transaction, or in the absence thereof, in accordance with the practice of the Transmission Providers, to deliver the Product to the Delivery Point. Buyer shall arrange and be responsible for transmission service at and from the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers to receive the Product at the Delivery Point.

3.3 Force Majeure. To the extent either Party is prevented by Force Majeure from carrying out, in whole or part, its obligations under the Transaction and such Party (the "Claiming Party") gives notice and details of the Force Majeure to the other Party as soon as practicable, then, unless the terms of the Product specify otherwise, the Claiming Party shall be excused from the performance of its obligations with respect to such Transaction (other than the obligation to make payments then due or becoming due with respect to performance prior to the Force Majeure). The Claiming Party shall remedy the Force Majeure with all reasonable dispatch. The non-Claiming Party shall not be required to perform or resume performance of its obligations to the Claiming Party corresponding to the obligations of the Claiming Party excused by Force Majeure.

ARTICLE FOUR: REMEDIES FOR FAILURE TO DELIVER/RECEIVE

4.1 Seller Failure. If Seller fails to schedule and/or deliver all or part of the Product pursuant to a Transaction, and such failure is not excused under the terms of the Product or by Buyer's failure to perform, then Seller shall pay Buyer, on the date payment would otherwise be due in respect of the month in which the failure occurred or, if "Accelerated Payment of Damages" is specified on the Cover Sheet, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

4.2 Buyer Failure. If Buyer fails to schedule and/or receive all or part of the Product pursuant to a Transaction and such failure is not excused under the terms of the Product or by Seller's failure to perform, then Buyer shall pay Seller, on the date payment would otherwise be due in respect of the month in which the failure occurred or, if "Accelerated Payment of Damages" is specified on the Cover Sheet, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Sales Price from the Contract Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

ARTICLE FIVE: EVENTS OF DEFAULT; REMEDIES

5.1 Events of Default. An "Event of Default" shall mean, with respect to a Party (a "Defaulting Party"), the occurrence of any of the following:

(a) the failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within three (3) Business Days after written notice;

(b) any representation or warranty made by such Party herein is false or misleading in any material respect when made or when deemed made or repeated;

(c) the failure to perform any material covenant or obligation set forth in this Agreement (except to the extent constituting a separate Event of Default, and except for such Party's obligations to deliver or receive the Product, the exclusive remedy for which is provided in Article Four) if such failure is not remedied within three (3) Business Days after written notice;

(d) such Party becomes Bankrupt;

(e) the failure of such Party to satisfy the creditworthiness/collateral requirements agreed to pursuant to Article Eight hereof;

(f) such Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of such Party under this Agreement to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party;

(g) if the applicable cross default section in the Cover Sheet is indicated for such Party, the occurrence and continuation of (i) a default, event of default or other similar condition or event in respect of such Party or any other party specified in the Cover Sheet for such Party under one or more agreements or instruments, individually or collectively, relating to indebtedness for borrowed money in an aggregate amount of not less than the applicable Cross Default Amount (as specified in the Cover Sheet), which results in such indebtedness becoming, or becoming capable at such time of being declared, immediately due and payable or (ii) a default by such Party or any other party specified in the Cover Sheet for such Party in making on the due date therefor one or more payments, individually or collectively, in an aggregate amount of not less than the applicable Cross Default Amount (as specified in the Cover Sheet);

(h) with respect to such Party's Guarantor, if any:

 (i) if any representation or warranty made by a Guarantor in connection with this Agreement is false or misleading in any material respect when made or when deemed made or repeated;

 (ii) the failure of a Guarantor to make any payment required or to perform any other material covenant or obligation in any guaranty made in connection with this Agreement and such failure shall not be remedied within three (3) Business Days after written notice;

(iii) a Guarantor becomes Bankrupt;

(iv) the failure of a Guarantor's guaranty to be in full force and effect for purposes of this Agreement (other than in accordance with its terms) prior to the satisfaction of all obligations of such Party under each Transaction to which such guaranty shall relate without the written consent of the other Party; or

(v) a Guarantor shall repudiate, disaffirm, disclaim, or reject, in whole or in part, or challenge the validity of any guaranty.

5.2 Declaration of an Early Termination Date and Calculation of Settlement Amounts. If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the other Party (the "Non-Defaulting Party") shall have the right (i) to designate a day, no earlier than the day such notice is effective and no later than 20 days after such notice is effective, as an early termination date ("Early Termination Date") to accelerate all amounts owing between the Parties and to liquidate and terminate all, but not less than all, Transactions (each referred to as a "Terminated Transaction") between the Parties, (ii) withhold any payments due to the Defaulting Party under this Agreement and (iii) suspend performance. The Non-Defaulting Party shall calculate, in a commercially reasonable manner, a Settlement Amount for each such Terminated Transaction as of the Early Termination Date (or, to the extent that in the reasonable opinion of the Non-Defaulting Party certain of such Terminated Transactions are commercially impracticable to liquidate and terminate or may not be liquidated and terminated under applicable law on the Early Termination Date, as soon thereafter as is reasonably practicable).

5.3 Net Out of Settlement Amounts. The Non-Defaulting Party shall aggregate all Settlement Amounts into a single amount by: netting out (a) all Settlement Amounts that are due to the Defaulting Party, plus, at the option of the Non-Defaulting Party, any cash or other form of security then available to the Non-Defaulting Party pursuant to Article Eight, plus any or all other amounts due to the Defaulting Party under this Agreement against (b) all Settlement Amounts that are due to the Non-Defaulting Party, plus any or all other amounts due to the Non-Defaulting Party under this Agreement, so that all such amounts shall be netted out to a single liquidated amount (the "Termination Payment") payable by one Party to the other. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate.

5.4 Notice of Payment of Termination Payment. As soon as practicable after a liquidation, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to or due from the Non-Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. The Termination Payment shall be made by the Party that owes it within two (2) Business Days after such notice is effective.

5.5 Disputes With Respect to Termination Payment. If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, within two (2) Business Days of receipt of Non-Defaulting Party's calculation of the Termination Payment, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute; provided, however, that if the Termination Payment is due from the Defaulting Party, the Defaulting Party shall first transfer Performance Assurance to the Non-Defaulting Party in an amount equal to the Termination Payment.

5.6 Closeout Setoffs.

Option A: After calculation of a Termination Payment in accordance with Section 5.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to (i) set off against such Termination Payment any amounts due and owing by the Defaulting Party to the Non-Defaulting Party under any other agreements, instruments or undertakings between the Defaulting Party and the Non-Defaulting Party and/or (ii) to the extent the Transactions are not yet liquidated in accordance with Section 5.2, withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

Option B: After calculation of a Termination Payment in accordance with Section 5.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to (i) set off against such Termination Payment any amounts due and owing by the Defaulting Party or any of its Affiliates to the Non-Defaulting Party or any of its Affiliates under any other agreements, instruments or undertakings between the Defaulting Party or any of its Affiliates and the Non-Defaulting Party or any of its Affiliates and/or (ii) to the extent the Transactions are not yet liquidated in accordance with Section 5.2, withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

Option C: Neither Option A nor B shall apply.

5.7 Suspension of Performance. Notwithstanding any other provision of this Master Agreement, if (a) an Event of Default or (b) a Potential Event of Default shall have occurred and be continuing, the Non-Defaulting Party, upon written notice to the Defaulting Party, shall have the right (i) to suspend performance under any or all Transactions; provided, however, in no event shall any such suspension continue for longer than ten (10) NERC Business Days with respect to any single Transaction unless an early Termination Date shall have been declared and notice thereof pursuant to Section 5.2 given, and (ii) to the extent an Event of Default shall have occurred and be continuing to exercise any remedy available at law or in equity.

ARTICLE SIX: PAYMENT AND NETTING

6.1 Billing Period. Unless otherwise specifically agreed upon by the Parties in a Transaction, the calendar month shall be the standard period for all payments under this Agreement (other than Termination Payments and, if "Accelerated Payment of Damages" is specified by the Parties in the Cover Sheet, payments pursuant to Section 4.1 or 4.2 and Option premium payments pursuant to Section 6.7). As soon as practicable after the end of each month, each Party will render to the other Party an invoice for the payment obligations, if any, incurred hereunder during the preceding month.

6.2 Timeliness of Payment. Unless otherwise agreed by the Parties in a Transaction, all invoices under this Master Agreement shall be due and payable in accordance with each Party's invoice instructions on or before the later of the twentieth (20th) day of each month, or tenth (10th) day after receipt of the invoice or, if such day is not a Business Day, then on the next Business Day. Each Party will make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any amounts not paid by the due date will be deemed delinquent and will accrue interest at the Interest Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

6.3 Disputes and Adjustments of Invoices. A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice, rendered under this Agreement or adjust any invoice for any arithmetic or computational error within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment shall be made within two (2) Business Days of such resolution along with interest accrued at the Interest Rate from and including the due date to but excluding the date paid. Inadvertent overpayments shall be returned upon request or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Interest Rate from and including the date of such overpayment to but excluding the date repaid or deducted by the Party receiving such overpayment. Any dispute with respect to an invoice is waived unless the other Party is notified in accordance with this Section 6.3 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made. If an invoice is not rendered within twelve (12) months after the close of the month during which performance of a Transaction occurred, the right to payment for such performance is waived.

6.4 Netting of Payments. The Parties hereby agree that they shall discharge mutual debts and payment obligations due and owing to each other on the same date pursuant to all Transactions through netting, in which case all amounts owed by each Party to the other Party for the purchase and sale of Products during the monthly billing period under this Master Agreement, including any related damages calculated pursuant to Article Four (unless one of the Parties elects to accelerate payment of such amounts as permitted by Article Four), interest, and payments or credits, shall be netted so that only the excess amount remaining due shall be paid by the Party who owes it.

6.5 Payment Obligation Absent Netting. If no mutual debts or payment obligations exist and only one Party owes a debt or obligation to the other during the monthly billing period, including, but not limited to, any related damage amounts calculated pursuant to Article Four, interest, and payments or credits, that Party shall pay such sum in full when due.

6.6 Security. Unless the Party benefiting from Performance Assurance or a guaranty notifies the other Party in writing, and except in connection with a liquidation and termination in accordance with Article Five, all amounts netted pursuant to this Article Six shall not take into account or include any Performance Assurance or guaranty which may be in effect to secure a Party's performance under this Agreement.

6.7 Payment for Options. The premium amount for the purchase of an Option shall be paid within two (2) Business Days of receipt of an invoice from the Option Seller. Upon exercise of an Option, payment for the Product underlying such Option shall be due in accordance with Section 6.1.

6.8 Transaction Netting. If the Parties enter into one or more Transactions, which in conjunction with one or more other outstanding Transactions, constitute Offsetting Transactions, then all such Offsetting Transactions may by agreement of the Parties, be netted into a single Transaction under which:

(a) the Party obligated to deliver the greater amount of Energy will deliver the difference between the total amount it is obligated to deliver and the total amount to be delivered to it under the Offsetting Transactions, and

(b) the Party owing the greater aggregate payment will pay the net difference owed between the Parties.

Each single Transaction resulting under this Section shall be deemed part of the single, indivisible contractual arrangement between the parties, and once such resulting Transaction occurs, outstanding obligations under the Offsetting Transactions which are satisfied by such offset shall terminate.

ARTICLE SEVEN: LIMITATIONS

7.1 Limitation of Remedies, Liability and Damages. EXCEPT AS SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR

OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE EIGHT: CREDIT AND COLLATERAL REQUIREMENTS

8.1 Party A Credit Protection. The applicable credit and collateral requirements shall be as specified on the Cover Sheet. If no option in Section 8.1(a) is specified on the Cover Sheet, Section 8.l(a) Option C shall apply exclusively. If none of Sections 8.1(b), 8.1(c) or 8.1(d) are specified on the Cover Sheet, Section 8.1(b) shall apply exclusively.

(a) Financial Information. Option A: If requested by Party A, Party B shall deliver (i) within 120 days following the end of each fiscal year, a copy of Party B’s annual report containing audited consolidated financial statements for such fiscal year and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of Party B’s quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as Party B diligently pursues the preparation, certification and delivery of the statements.

Option B: If requested by Party A, Party B shall deliver (i) within 120 days following the end of each fiscal year, a copy of the annual report containing audited consolidated financial statements for such fiscal year for the party(s) specified on the Cover Sheet and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of quarterly report containing unaudited consolidated financial statements for such fiscal quarter for the party(s) specified on the Cover Sheet. In all cases the statements shall be for the most recent accounting period and shall be prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as the relevant entity diligently pursues the preparation, certification and delivery of the statements.

Option C: Party A may request from Party B the information specified in the Cover Sheet.

(b) Credit Assurances. If Party A has reasonable grounds to believe that Party B's creditworthiness or performance under this Agreement has become unsatisfactory, Party A will provide Party B with written notice requesting Performance Assurance in an amount determined by Party A in a commercially reasonable manner. Upon receipt of such notice Party B shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to Party A. In the event that Party B fails to provide such Performance Assurance, or a guaranty or other credit assurance acceptable to Party A within three (3) Business Days of receipt of notice, then an Event of Default under Article Five will be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

(c) Collateral Threshold. If at any time and from time to time during the term of this Agreement (and notwithstanding whether an Event of Default has occurred), the Termination Payment that would be owed to Party A plus Party B's Independent Amount, if any, exceeds the Party B Collateral Threshold, then Party A, on any Business Day, may request that Party B provide Performance Assurance in an amount equal to the amount by which the Termination Payment plus Party B's Independent Amount, if any, exceeds the Party B Collateral Threshold (rounding upwards for any fractional amount to the next Party B Rounding Amount) ("Party B Performance Assurance"), less any Party B Performance Assurance already posted with Party A. Such Party B Performance Assurance shall be delivered to Party A within three (3) Business Days of the date of such request. On any Business Day (but no more frequently than weekly with respect to Letters of Credit and daily with respect to cash), Party B, at its sole cost, may request that such Party B Performance Assurance be reduced correspondingly to the amount of such excess Termination Payment plus Party B's Independent Amount, if any, (rounding upwards for any fractional amount to the next Party B Rounding Amount). In the event that Party B fails to provide Party B Performance Assurance pursuant to the terms of this Article Eight within three (3) Business Days, then an Event of Default under Article Five shall be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

For purposes of this Section 8.1(c), the calculation of the Termination Payment shall be calculated pursuant to Section 5.3 by Party A as if all outstanding Transactions had been liquidated, and in addition thereto, shall include all amounts owed but not yet paid by Party B to Party A, whether or not such amounts are due, for performance already provided pursuant to any and all Transactions.

(d) Downgrade Event. If at any time there shall occur a Downgrade Event in respect of Party B, then Party A may require Party B to provide Performance Assurance in an amount determined by Party A in a commercially reasonable manner. In the event Party B shall fail to provide such Performance Assurance or a guaranty or other credit assurance acceptable to Party A within three (3) Business Days of receipt of notice, then an Event of Default shall be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

(e) If specified on the Cover Sheet, Party B shall deliver to Party A, prior to or concurrently with the execution and delivery of this Master Agreement a guarantee in an amount not less than the Guarantee Amount specified on the Cover Sheet and in a form reasonably acceptable to Party A.

8.2 Party B Credit Protection. The applicable credit and collateral requirements shall be as specified on the Cover Sheet. If no option in Section 8.2(a) is specified on the Cover Sheet, Section 8.2(a) Option C shall apply exclusively. If none of Sections 8.2(b), 8.2(c) or 8.2(d) are specified on the Cover Sheet, Section 8.2(b) shall apply exclusively.

(a) Financial Information. Option A: If requested by Party B, Party A shall deliver (i) within 120 days following the end of each fiscal year, a copy of Party A's annual report containing audited consolidated financial statements for such fiscal year and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of such Party's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as such Party diligently pursues the preparation, certification and delivery of the statements.

Option B: If requested by Party B, Party A shall deliver (i) within 120 days following the end of each fiscal year, a copy of the annual report containing audited consolidated financial statements for such fiscal year for the party(s) specified on the Cover Sheet and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of quarterly report containing unaudited consolidated financial statements for such fiscal quarter for the party(s) specified on the Cover Sheet. In all cases the statements shall be for the most recent accounting period and shall be prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as the relevant entity diligently pursues the preparation, certification and delivery of the statements.

Option C: Party B may request from Party A the information specified in the Cover Sheet.

(b) Credit Assurances. If Party B has reasonable grounds to believe that Party A's creditworthiness or performance under this Agreement has become unsatisfactory, Party B will provide Party A with written notice requesting Performance Assurance in an amount determined by Party B in a commercially reasonable manner. Upon receipt of such notice Party A shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to Party B. In the event that Party A fails to provide such Performance Assurance, or a guaranty or other credit assurance acceptable to Party B within three (3) Business Days of receipt of notice, then an Event of Default under Article Five will be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

(c) Collateral Threshold. If at any time and from time to time during the term of this Agreement (and notwithstanding whether an Event of Default has occurred), the Termination Payment that would be owed to Party B plus Party A's Independent Amount, if any, exceeds the Party A Collateral Threshold, then Party B, on any Business Day, may request that Party A provide Performance Assurance in an amount equal to the amount by which the Termination Payment plus Party A's Independent Amount, if any, exceeds the Party A Collateral

Threshold (rounding upwards for any fractional amount to the next Party A Rounding Amount) ("Party A Performance Assurance"), less any Party A Performance Assurance already posted with Party B. Such Party A Performance Assurance shall be delivered to Party B within three (3) Business Days of the date of such request. On any Business Day (but no more frequently than weekly with respect to Letters of Credit and daily with respect to cash), Party A, at its sole cost, may request that such Party A Performance Assurance be reduced correspondingly to the amount of such excess Termination Payment plus Party A's Independent Amount, if any, (rounding upwards for any fractional amount to the next Party A Rounding Amount). In the event that Party A fails to provide Party A Performance Assurance pursuant to the terms of this Article Eight within three (3) Business Days, then an Event of Default under Article Five shall be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

For purposes of this Section 8.2(c), the calculation of the Termination Payment shall be calculated pursuant to Section 5.3 by Party B as if all outstanding Transactions had been liquidated, and in addition thereto, shall include all amounts owed but not yet paid by Party A to Party B, whether or not such amounts are due, for performance already provided pursuant to any and all Transactions.

(d) Downgrade Event. If at any time there shall occur a Downgrade Event in respect of Party A, then Party B may require Party A to provide Performance Assurance in an amount determined by Party B in a commercially reasonable manner. In the event Party A shall fail to provide such Performance Assurance or a guaranty or other credit assurance acceptable to Party B within three (3) Business Days of receipt of notice, then an Event of Default shall be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

(e) If specified on the Cover Sheet, Party A shall deliver to Party B, prior to or concurrently with the execution and delivery of this Master Agreement a guarantee in an amount not less than the Guarantee Amount specified on the Cover Sheet and in a form reasonably acceptable to Party B.

8.3 Grant of Security Interest/Remedies. To secure its obligations under this Agreement and to the extent either or both Parties deliver Performance Assurance hereunder, each Party (a "Pledgor") hereby grants to the other Party (the "Secured Party") a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, such Secured Party, and each Party agrees to take such action as the other Party reasonably requires in order to perfect the Secured Party's first-priority security interest in, and lien on (and right of setoff against), such collateral and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default or an Early Termination Date, the Non-Defaulting Party may do any one or more of the following: (i) exercise any of the rights and remedies of a Secured Party with respect to all Performance Assurance, including any such rights and remedies under law then in effect; (ii) exercise its rights of setoff against any and all property of the Defaulting Party in the possession of the Non-Defaulting Party or its agent; (iii) draw on any outstanding

Letter of Credit issued for its benefit; and (iv) liquidate all Performance Assurance then held by or for the benefit of the Secured Party free from any claim or right of any nature whatsoever of the Defaulting Party, including any equity or right of purchase or redemption by the Defaulting Party. The Secured Party shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Pledgor's obligations under the Agreement (the Pledgor remaining liable for any amounts owing to the Secured Party after such application), subject to the Secured Party's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

ARTICLE NINE: GOVERNMENTAL CHARGES

9.1 Cooperation. Each Party shall use reasonable efforts to implement the provisions of and to administer this Master Agreement in accordance with the intent of the parties to minimize all taxes , so long as neither Party is materially adversely affected by such efforts.

9.2 Governmental Charges. Seller shall pay or cause to be paid all taxes imposed by any government authority("Governmental Charges") on or with respect to the Product or a Transaction arising prior to the Delivery Point. Buyer shall pay or cause to be paid all Governmental Charges on or with respect to the Product or a Transaction at and from the Delivery Point (other than ad valorem, franchise or income taxes which are related to the sale of the Product and are, therefore, the responsibility of the Seller). In the event Seller is required by law or regulation to remit or pay Governmental Charges which are Buyer's responsibility hereunder, Buyer shall promptly reimburse Seller for such Governmental Charges. If Buyer is required by law or regulation to remit or pay Governmental Charges which are Seller's responsibility hereunder, Buyer may deduct the amount of any such Governmental Charges from the sums due to Seller under Article 6 of this Agreement. Nothing shall obligate or cause a Party to pay or be liable to pay any Governmental Charges for which it is exempt under the law.

ARTICLE TEN: MISCELLANEOUS

10.1 Term of Master Agreement. The term of this Master Agreement shall commence on the Effective Date and shall remain in effect until terminated by either Party upon (thirty) 30 days' prior written notice; provided, however, that such termination shall not affect or excuse the performance of either Party under any provision of this Master Agreement that by its terms survives any such termination and, provided further, that this Master Agreement and any other documents executed and delivered hereunder shall remain in effect with respect to the Transaction(s) entered into prior to the effective date of such termination until both Parties have fulfilled all of their obligations with respect to such Transaction(s), or such Transaction(s) that have been terminated under Section 5.2 of this Agreement.

10.2 Representations and Warranties. On the Effective Date and the date of entering into each Transaction, each Party represents and warrants to the other Party that:

(i) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(ii) it has all regulatory authorizations necessary for it to legally perform its obligations under this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(iii) the execution, delivery and performance of this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

(iv) this Master Agreement, each Transaction (including any Confirmation accepted in accordance with Section 2.3), and each other document executed and delivered in accordance with this Master Agreement constitutes its legally valid and binding obligation enforceable against it in accordance with its terms; subject to any Equitable Defenses.

(v) it is not Bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming Bankrupt;

(vi) there is not pending or, to its knowledge, threatened against it or any of its Affiliates any legal proceedings that could materially adversely affect its ability to perform its obligations under this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(vii) no Event of Default or Potential Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(viii) it is acting for its own account, has made its own independent decision to enter into this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) and as to whether this Master Agreement and each such Transaction (including any Confirmation accepted in accordance with Section 2.3) is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(ix) it is a “forward contract merchant” within the meaning of the United States Bankruptcy Code;

(x) it has entered into this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) in connection with the conduct of its business and it has the capacity or ability to make or take delivery of all Products referred to in the Transaction to which it is a Party;

(xi) with respect to each Transaction (including any Confirmation accepted in accordance with Section 2.3) involving the purchase or sale of a Product or an Option, it is a producer, processor, commercial user or merchant handling the Product, and it is entering into such Transaction for purposes related to its business as such; and

(xii) the material economic terms of each Transaction are subject to individual negotiation by the Parties.

10.3 Title and Risk of Loss. Title to and risk of loss related to the Product shall transfer from Seller to Buyer at the Delivery Point. Seller warrants that it will deliver to Buyer the Quantity of the Product free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any person arising prior to the Delivery Point.

10.4 Indemnity. Each Party shall indemnify, defend and hold harmless the other Party from and against any Claims arising from or out of any event, circumstance, act or incident first occurring or existing during the period when control and title to Product is vested in such Party as provided in Section 10.3. Each Party shall indemnify, defend and hold harmless the other Party against any Governmental Charges for which such Party is responsible under Article Nine.

10.5 Assignment. Neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent may be withheld in the exercise of its sole discretion; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), (i) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, (ii) transfer or assign this Agreement to an affiliate of such Party which affiliate's creditworthiness is equal to or higher than that of such Party, or (iii) transfer or assign this Agreement to any person or entity succeeding to all or substantially all of the assets whose creditworthiness is equal to or higher than that of such Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

10.6 Governing Law. THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW. EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AGREEMENT.

10.7 Notices. All notices, requests, statements or payments shall be made as specified in the Cover Sheet. Notices (other than scheduling requests) shall, unless otherwise specified herein, be in writing and may be delivered by hand delivery, United States mail, overnight courier service or facsimile. Notice by facsimile or hand delivery shall be effective at the close of business on the day actually received, if received during business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. Notice by overnight United States mail or courier shall be effective on the next Business Day after it was sent. A Party may change its addresses by providing notice of same in accordance herewith.

10.8 General. This Master Agreement (including the exhibits, schedules and any written supplements hereto), the Party A Tariff, if any, the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmation accepted in accordance with Section 2.3) constitute the entire agreement between the Parties relating to the subject matter. Notwithstanding the foregoing, any collateral, credit support or margin agreement or similar arrangement between the Parties shall, upon designation by the Parties, be deemed part of this Agreement and shall be incorporated herein by reference. This Agreement shall be considered for all purposes as prepared through the joint efforts of the parties and shall not be construed against one party or the other as a result of the preparation, substitution, submission or other event of negotiation, drafting or execution hereof. Except to the extent herein provided for, no amendment or modification to this Master Agreement shall be enforceable unless reduced to writing and executed by both Parties. Each Party agrees if it seeks to amend any applicable wholesale power sales tariff during the term of this Agreement, such amendment will not in any way affect outstanding Transactions under this Agreement without the prior written consent of the other Party. Each Party further agrees that it will not assert, or defend itself, on the basis that any applicable tariff is inconsistent with this Agreement. This Agreement shall not impart any rights enforceable by any third party (other than a permitted successor or assignee bound to this Agreement). Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. Any provision declared or rendered unlawful by any applicable court of law or regulatory agency or deemed unlawful because of a statutory change (individually or collectively, such events referred to as “Regulatory Event”) will not otherwise affect the remaining lawful obligations that arise under this Agreement; and provided, further, that if a Regulatory Event occurs, the Parties shall use their best efforts to reform this Agreement in order to give effect to the original intention of the Parties. The term “including” when used in this Agreement shall be by way of example only and shall not be considered in any way to be in limitation. The headings used herein are for convenience and reference purposes only. All indemnity and audit rights shall survive the termination of this Agreement for twelve (12) months. This Agreement shall be binding on each Party’s successors and permitted assigns.

10.9 Audit. Each Party has the right, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Master Agreement. If requested, a Party shall provide to the other Party statements evidencing the Quantity delivered at the Delivery Point. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly and shall bear interest calculated at the Interest Rate from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of twelve (12) months from the rendition thereof, and thereafter any objection shall be deemed waived.

10.10 Forward Contract. The Parties acknowledge and agree that all Transactions constitute "forward contracts" within the meaning of the United States Bankruptcy Code.

10.11 Confidentiality. If the Parties have elected on the Cover Sheet to make this Section 10.11 applicable to this Master Agreement, neither Party shall disclose the terms or conditions of a Transaction under this Master Agreement to a third party (other than the Party's employees, lenders, counsel, accountants or advisors who have a need to know such information and have agreed to keep such terms confidential) except in order to comply with any applicable law, regulation, or any exchange, control area or independent system operator rule or in connection with any court or regulatory proceeding; provided, however, each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with, this confidentiality obligation.

SCHEDULE M

(THIS SCHEDULE IS INCLUDED IF THE APPROPRIATE BOX ON THE COVER SHEET IS MARKED INDICATING A PARTY IS A GOVERNMENTAL ENTITY OR PUBLIC POWER SYSTEM)

A. The Parties agree to add the following definitions in Article One.

"Act" means ______________________________.[1]

"Governmental Entity or Public Power System" means a municipality, county, governmental board, public power authority, public utility district, joint action agency, or other similar political subdivision or public entity of the United States, one or more States or territories or any combination thereof.

"Special Fund" means a fund or account of the Governmental Entity or Public Power System set aside and or pledged to satisfy the Public Power System's obligations hereunder out of which amounts shall be paid to satisfy all of the Public Power System's obligations under this Master Agreement for the entire Delivery Period.

B. The following sentence shall be added to the end of the definition of "Force Majeure" in Article One.

If the Claiming Party is a Governmental Entity or Public Power System, Force Majeure does not include any action taken by the Governmental Entity or Public Power System in its governmental capacity.

C. The Parties agree to add the following representations and warranties to Section 10.2:

Further and with respect to a Party that is a Governmental Entity or Public Power System, such Governmental Entity or Public Power System represents and warrants to the other Party continuing throughout the term of this Master Agreement, with respect to this Master Agreement and each Transaction, as follows: (i) all acts necessary to the valid execution, delivery and performance of this Master Agreement, including without limitation, competitive bidding, public notice, election, referendum, prior appropriation or other required procedures has or will be taken and performed as required under the Act and the Public Power System's ordinances, bylaws or other regulations, (ii) all persons making up the governing body of Governmental Entity or Public Power System are the duly elected or appointed incumbents in their positions and hold such

[1] Cite the state enabling and other relevant statutes applicable to Governmental Entity or Public Power System.

positions in good standing in accordance with the Act and other applicable law, (iii) entry into and performance of this Master Agreement by Governmental Entity or Public Power System are for a proper public purpose within the meaning of the Act and all other relevant constitutional, organic or other governing documents and applicable law, (iv) the term of this Master Agreement does not extend beyond any applicable limitation imposed by the Act or other relevant constitutional, organic or other governing documents and applicable law, (v) the Public Power System's obligations to make payments hereunder are unsubordinated obligations and such payments are (a) operating and maintenance costs (or similar designation) which enjoy first priority of payment at all times under any and all bond ordinances or indentures to which it is a party, the Act and all other relevant constitutional, organic or other governing documents and applicable law or (b) otherwise not subject to any prior claim under any and all bond ordinances or indentures to which it is a party, the Act and all other relevant constitutional, organic or other governing documents and applicable law and are available without limitation or deduction to satisfy all Governmental Entity or Public Power System' obligations hereunder and under each Transaction or (c) are to be made solely from a Special Fund, (vi) entry into and performance of this Master Agreement and each Transaction by the Governmental Entity or Public Power System will not adversely affect the exclusion from gross income for federal income tax purposes of interest on any obligation of Governmental Entity or Public Power System otherwise entitled to such exclusion, and (vii) obligations to make payments hereunder do not constitute any kind of indebtedness of Governmental Entity or Public Power System or create any kind of lien on, or security interest in, any property or revenues of Governmental Entity or Public Power System which, in either case, is proscribed by any provision of the Act or any other relevant constitutional, organic or other governing documents and applicable law, any order or judgment of any court or other agency of government applicable to it or its assets, or any contractual restriction binding on or affecting it or any of its assets.

D. The Parties agree to add the following sections to Article Three:

Section 3.4 Public Power System's Deliveries. On the Effective Date and as a condition to the obligations of the other Party under this Agreement, Governmental Entity or Public Power System shall provide the other Party hereto (i) certified copies of all ordinances, resolutions, public notices and other documents evidencing the necessary authorizations with respect to the execution, delivery and performance by Governmental Entity or Public Power System of this Master Agreement and (ii) an opinion of counsel for Governmental Entity or Public Power System, in form and substance reasonably satisfactory to the Other Party, regarding the validity, binding effect and enforceability of this Master Agreement against Governmental Entity or Public Power System in respect of the Act and all other relevant constitutional organic or other governing documents and applicable law.

Section 3.5 No Immunity Claim. Governmental Entity or Public Power System warrants and covenants that with respect to its contractual obligations hereunder and performance thereof, it will not claim immunity on the grounds of sovereignty or similar grounds with respect to itself or its revenues or assets from (a) suit, (b) jurisdiction of court (including a court located outside the jurisdiction of its organization), (c) relief by way of injunction, order for specific performance or recovery of property, (d) attachment of assets, or (e) execution or enforcement of any judgment.

E. If the appropriate box is checked on the Cover Sheet, as an alternative to selecting one of the options under Section 8.3, the Parties agree to add the following section to Article Three:

Section 3.6 Governmental Entity or Public Power System Security. With respect to each Transaction, Governmental Entity or Public Power System shall either (i) have created and set aside a Special Fund or (ii) upon execution of this Master Agreement and prior to the commencement of each subsequent fiscal year of Governmental Entity or Public Power System during any Delivery Period, have obtained all necessary budgetary approvals and certifications for payment of all of its obligations under this Master Agreement for such fiscal year; any breach of this provision shall be deemed to have arisen during a fiscal period of Governmental Entity or Public Power System for which budgetary approval or certification of its obligations under this Master Agreement is in effect and, notwithstanding anything to the contrary in Article Four, an Early Termination Date shall automatically and without further notice occur hereunder as of such date wherein Governmental Entity or Public Power System shall be treated as the Defaulting Party. Governmental Entity or Public Power System shall have allocated to the Special Fund or its general funds a revenue base that is adequate to cover Public Power System's payment obligations hereunder throughout the entire Delivery Period.

F. If the appropriate box is checked on the Cover Sheet, the Parties agree to add the following section to Article Eight:

Section 8.4 Governmental Security. As security for payment and performance of Public Power System's obligations hereunder, Public Power System hereby pledges, sets over, assigns and grants to the other Party a security interest in all of Public Power System's right, title and interest in and to [specify collateral].

G. The Parties agree to add the following sentence at the end of Section 10.6 - Governing Law:

> NOTWITHSTANDING THE FOREGOING, IN RESPECT OF THE APPLICABILITY OF THE ACT AS HEREIN PROVIDED, THE LAWS OF THE STATE OF _____________[2] SHALL APPLY.

[2] Insert relevant state for Governmental Entity or Public Power System.

SCHEDULE P: PRODUCTS AND RELATED DEFINITIONS

"Ancillary Services" means any of the services identified by a Transmission Provider in its transmission tariff as "ancillary services" including, but not limited to, regulation and frequency response, energy imbalance, operating reserve-spinning and operating reserve-supplemental, as may be specified in the Transaction.

"Capacity" has the meaning specified in the Transaction.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in megawatt hours.

"Firm (LD)" means, with respect to a Transaction, that either Party shall be relieved of its obligations to sell and deliver or purchase and receive without liability only to the extent that, and for the period during which, such performance is prevented by Force Majeure. In the absence of Force Majeure, the Party to which performance is owed shall be entitled to receive from the Party which failed to deliver/receive an amount determined pursuant to Article Four.

"Firm Transmission Contingent - Contract Path" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the transmission provider(s) for the Product in the case of the Seller from the generation source to the Delivery Point or in the case of the Buyer from the Delivery Point to the ultimate sink, and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable transmission provider's tariff. This contingency shall excuse performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Section 1.23 to the contrary.

"Firm Transmission Contingent - Delivery Point" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission to the Delivery Point (in the case of Seller) or from the Delivery Point (in the case of Buyer) for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the transmission provider(s) for the Product, in the case of the Seller, to be delivered to the Delivery Point or, in the case of Buyer, to be received at the Delivery Point and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable transmission provider's tariff. This transmission contingency excuses performance for the duration of the interruption or curtailment, notwithstanding the provisions of the definition of "Force Majeure" in Section 1.23 to the contrary. Interruptions or curtailments of transmission other than the transmission either immediately to or from the Delivery Point shall not excuse performance

"Firm (No Force Majeure)" means, with respect to a Transaction, that if either Party fails to perform its obligation to sell and deliver or purchase and receive the Product, the Party to which performance is owed shall be entitled to receive from the Party which failed to perform an amount determined pursuant to Article Four. Force Majeure shall not excuse performance of a Firm (No Force Majeure) Transaction.

"Into ______________ (the "Receiving Transmission Provider"), Seller's Daily Choice" means that, in accordance with the provisions set forth below, (1) the Product shall be scheduled and delivered to an interconnection or interface ("Interface") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which Interface, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area; and (2) Seller has the right on a daily prescheduled basis to designate the Interface where the Product shall be delivered. An "Into" Product shall be subject to the following provisions:

1. Prescheduling and Notification. Subject to the provisions of Section 6, not later than the prescheduling deadline of 11:00 a.m. CPT on the Business Day before the next delivery day or as otherwise agreed to by Buyer and Seller, Seller shall notify Buyer ("Seller's Notification") of Seller's immediate upstream counterparty and the Interface (the "Designated Interface") where Seller shall deliver the Product for the next delivery day, and Buyer shall notify Seller of Buyer's immediate downstream counterparty.

2. Availability of "Firm Transmission" to Buyer at Designated Interface; "Timely Request for Transmission," "ADI" and "Available Transmission." In determining availability to Buyer of next-day firm transmission ("Firm Transmission") from the Designated Interface, a "Timely Request for Transmission" shall mean a properly completed request for Firm Transmission made by Buyer in accordance with the controlling tariff procedures, which request shall be submitted to the Receiving Transmission Provider no later than 30 minutes after delivery of Seller's Notification, provided, however, if the Receiving Transmission Provider is not accepting requests for Firm Transmission at the time of Seller's Notification, then such request by Buyer shall be made within 30 minutes of the time when the Receiving Transmission Provider first opens thereafter for purposes of accepting requests for Firm Transmission.

Pursuant to the terms hereof, delivery of the Product may under certain circumstances be redesignated to occur at an Interface other than the Designated Interface (any such alternate designated interface, an "ADI") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which ADI, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area using either firm or non-firm transmission, as available on a day-ahead or hourly basis (individually or collectively referred to as "Available Transmission") within the Receiving Transmission Provider's transmission system.

3. Rights of Buyer and Seller Depending Upon Availability of/Timely Request for Firm Transmission.

A. Timely Request for Firm Transmission made by Buyer, Accepted by the Receiving Transmission Provider and Purchased by Buyer. If a Timely Request for Firm Transmission is made by Buyer and is accepted by the Receiving Transmission Provider and Buyer purchases such Firm Transmission, then Seller shall deliver and Buyer shall receive the Product at the Designated Interface.

i. If the Firm Transmission purchased by Buyer within the Receiving Transmission Provider's transmission system from the Designated Interface ceases to be available to Buyer for any reason, or if Seller is unable to deliver the Product at the Designated Interface for any reason except Buyer's non-performance, then at Seller's choice from among the following, Seller shall: (a) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, require Buyer to purchase such Firm Transmission from such ADI, and schedule and deliver the affected portion of the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, or (b) require Buyer to purchase non-firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by Seller, or (c) to the extent firm transmission is available on an hourly basis, require Buyer to purchase firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of such hourly firm transmission from the Designated Interface or an ADI designated by Seller.

ii. If the Available Transmission utilized by Buyer as required by Seller pursuant to Section 3A(i) ceases to be available to Buyer for any reason, then Seller shall again have those alternatives stated in Section 3A(i) in order to satisfy its obligations.

iii. Seller's obligation to schedule and deliver the Product at an ADI is subject to Buyer's obligation referenced in Section 4B to cooperate reasonably therewith. If Buyer and Seller cannot complete the scheduling and/or delivery at an ADI, then Buyer shall be deemed to have satisfied its receipt obligations to Seller and Seller shall be deemed to have failed its delivery obligations to Buyer, and Seller shall be liable to Buyer for amounts determined pursuant to Article Four.

iv. In each instance in which Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI pursuant to Sections 3A(i) or (ii), and Firm Transmission had been purchased by both Seller and Buyer into and within the Receiving Transmission Provider's transmission system as to the scheduled delivery which could not be completed as a result of the interruption or curtailment of such Firm Transmission, Buyer and Seller shall bear their respective transmission expenses and/or associated congestion charges incurred in connection with efforts to complete delivery by such alternative scheduling and delivery arrangements. In any instance except as set forth in the immediately preceding sentence, Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI under Sections 3A(i) or (ii), Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with such alternative scheduling arrangements.

B. Timely Request for Firm Transmission Made by Buyer but Rejected by the Receiving Transmission Provider. If Buyer's Timely Request for Firm Transmission is rejected by the Receiving Transmission Provider because of unavailability of Firm Transmission from the Designated Interface, then Buyer shall notify Seller within 15 minutes after receipt of the Receiving Transmission Provider's notice of rejection ("Buyer's Rejection Notice"). If Buyer timely notifies Seller of such unavailability of Firm Transmission from the Designated Interface, then Seller shall be obligated either (1) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, to require Buyer to purchase (at Buyer's own expense) such Firm Transmission from such ADI and schedule and deliver the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, and thereafter the provisions in Section 3A shall apply, or (2) to require Buyer to purchase (at Buyer's own expense) non-firm transmission, and schedule and deliver the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by the Seller, in which case Seller shall bear the risk of interruption or curtailment of the non-firm transmission; provided, however, that if the non-firm transmission is interrupted or curtailed or if Seller is unable to deliver the Product for any reason, Seller shall have the right to schedule and deliver the Product to another ADI in order to satisfy its delivery obligations, in which case Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with Seller's inability to deliver the Product as originally prescheduled. If Buyer fails to timely notify Seller of the unavailability of Firm Transmission, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface, and the provisions of Section 3D shall apply.

C. Timely Request for Firm Transmission Made by Buyer, Accepted by the Receiving Transmission Provider and not Purchased by Buyer. If Buyer's Timely Request for Firm Transmission is accepted by the Receiving Transmission Provider but Buyer elects to purchase non-firm transmission rather than Firm Transmission to take delivery of the Product, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Four.

D. No Timely Request for Firm Transmission Made by Buyer, or Buyer Fails to Timely Send Buyer's Rejection Notice. If Buyer fails to make a Timely Request for Firm Transmission or Buyer fails to timely deliver Buyer's Rejection Notice, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Four.

4. Transmission.

A. Seller's Responsibilities. Seller shall be responsible for transmission required to deliver the Product to the Designated Interface or ADI, as the case may be. It is expressly agreed that Seller is not required to utilize Firm Transmission for its delivery obligations hereunder, and Seller shall bear the risk of utilizing non-firm transmission. If Seller's scheduled delivery to Buyer is interrupted as a result of Buyer's attempted transmission of the Product beyond the Receiving Transmission Provider's system border, then Seller will be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for damages pursuant to Article Four.

B. Buyer's Responsibilities. Buyer shall be responsible for transmission required to receive and transmit the Product at and from the Designated Interface or ADI, as the case may be, and except as specifically provided in Section 3A and 3B, shall be responsible for any costs associated with transmission therefrom. If Seller is attempting to complete the designation of an ADI as a result of Seller's rights and obligations hereunder, Buyer shall co-operate reasonably with Seller in order to effect such alternate designation.

5. Force Majeure. An "Into" Product shall be subject to the "Force Majeure" provisions in Section 1.23.

6. Multiple Parties in Delivery Chain Involving a Designated Interface. Seller and Buyer recognize that there may be multiple parties involved in the delivery and receipt of the Product at the Designated Interface or ADI to the extent that (1) Seller may be purchasing the Product from a succession of other sellers ("Other Sellers"), the first of which Other Sellers shall be causing the Product to be generated from a source ("Source Seller") and/or (2) Buyer may be selling the Product to a succession of other buyers ("Other Buyers"), the last of which Other Buyers shall be using the Product to serve its energy needs ("Sink Buyer"). Seller and Buyer further recognize that in certain Transactions neither Seller nor Buyer may originate the decision as to either (a) the original identification of the Designated Interface or ADI (which designation may be made by the Source Seller) or (b) the Timely Request for Firm Transmission or the purchase of other Available Transmission (which request may be made by the Sink Buyer). Accordingly, Seller and Buyer agree as follows:

A. If Seller is not the Source Seller, then Seller shall notify Buyer of the Designated Interface promptly after Seller is notified thereof by the Other Seller with whom Seller has a contractual relationship, but in no event may such designation of the Designated Interface be later than the prescheduling deadline pertaining to the Transaction between Buyer and Seller pursuant to Section 1.

B. If Buyer is not the Sink Buyer, then Buyer shall notify the Other Buyer with whom Buyer has a contractual relationship of the Designated Interface promptly after Seller notifies Buyer thereof, with the intent being that the party bearing actual responsibility to secure transmission shall have up to 30 minutes after receipt of the Designated Interface to submit its Timely Request for Firm Transmission.

C. Seller and Buyer each agree that any other communications or actions required to be given or made in connection with this "Into Product" (including without limitation, information relating to an ADI) shall be made or taken promptly after receipt of the relevant information from the Other Sellers and Other Buyers, as the case may be.

D. Seller and Buyer each agree that in certain Transactions time is of the essence and it may be desirable to provide necessary information to Other Sellers and Other Buyers in order to complete the scheduling and delivery of the Product. Accordingly, Seller and Buyer agree that each has the right, but not the obligation, to provide information at its own risk to Other Sellers and Other Buyers, as the case may be, in order to effect the prescheduling, scheduling and delivery of the Product

"Native Load" means the demand imposed on an electric utility or an entity by the requirements of retail customers located within a franchised service territory that the electric utility or entity has statutory obligation to serve.

"Non-Firm" means, with respect to a Transaction, that delivery or receipt of the Product may be interrupted for any reason or for no reason, without liability on the part of either Party.

"System Firm" means that the Product will be supplied from the owned or controlled generation or pre-existing purchased power assets of the system specified in the Transaction (the "System") with non-firm transmission to and from the Delivery Point, unless a different Transmission Contingency is specified in a Transaction. Seller's failure to deliver shall be excused: (i) by an event or circumstance which prevents Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Seller; (ii) by Buyer's failure to perform; (iii) to the extent necessary to preserve the integrity of, or prevent or limit any instability on, the System; (iv) to the extent the System or the control area or reliability council within which the System operates declares an emergency condition, as determined in the system's, or the control area's, or reliability council's reasonable judgment; or (v) by the interruption or curtailment of transmission to the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Seller's performance. Buyer's failure to receive shall be excused (i) by Force Majeure; (ii) by Seller's failure to perform, or (iii) by the interruption or curtailment of transmission from the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Buyer's performance. In any of such events, neither party shall be liable to the other for any damages, including any amounts determined pursuant to Article Four.

"Transmission Contingent" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission for such Transaction is unavailable or interrupted or curtailed for any reason, at any time, anywhere from the Seller's proposed generating source to the Buyer's proposed ultimate sink, regardless of whether transmission, if any, that such Party is attempting to secure and/or has purchased for the Product is firm or non-firm. If the transmission (whether firm or non-firm) that Seller or Buyer is attempting to secure is from source to sink is unavailable, this contingency excuses performance for the entire Transaction. If the transmission (whether firm or non-firm) that Seller or Buyer has secured from source to sink is interrupted or curtailed for any reason, this contingency excuses performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of “Force Majeure” in Article 1.23 to the contrary.

“Unit Firm” means, with respect to a Transaction, that the Product subject to the Transaction is intended to be supplied from a generation asset or assets specified in the Transaction. Seller’s failure to deliver under a “Unit Firm” Transaction shall be excused: (i) if the specified generation asset(s) are unavailable as a result of a Forced Outage (as defined in the NERC Generating Unit Availability Data System (GADS) Forced Outage reporting guidelines) or (ii) by an event or circumstance that affects the specified generation asset(s) so as to prevent Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, and which is not within the reasonable control of, or the result of the negligence of, the Seller or (iii) by Buyer’s failure to perform. In any of such events, Seller shall not be liable to Buyer for any damages, including any amounts determined pursuant to Article Four.

EXHIBIT A

MASTER POWER PURCHASE AND SALE AGREEMENT
CONFIRMATION LETTER

This confirmation letter shall confirm the Transaction agreed to on ___________, ___ between __________________________ ("Party A") and _____________________ ("Party B") regarding the sale/purchase of the Product under the terms and conditions as follows:

Seller: ____

Buyer: ____

Product:

[] Into _________________, Seller's Daily Choice

[] Firm (LD)

[] Firm (No Force Majeure)

[] System Firm

(Specify System: ____)

[] Unit Firm

(Specify Unit(s): ____)

[] Other ____

[] Transmission Contingency (If not marked, no transmission contingency)

[]	FT-Contract Path Contingency	[]	Seller	[]	Buyer
[]	FT-Delivery Point Contingency	[]	Seller	[]	Buyer
[]	Transmission Contingent	[]	Seller	[]	Buyer
[]	Other transmission contingency				

(Specify: ____)

Contract Quantity: ____

Delivery Point: ____

Contract Price:

Energy Price: ____

Other Charges: ____

Confirmation Letter
Page 2

Delivery Period: ____

Special Conditions: ____

Scheduling: ____

Option Buyer: ____

Option Seller: ____

Type of Option: ______________________________________

Strike Price: ____

Premium: ____

Exercise Period: ______________________________________

This confirmation letter is being provided pursuant to and in accordance with the Master Power Purchase and Sale Agreement dated _______________ (the "Master Agreement") between Party A and Party B, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

[Party A]	[Party B]
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________
Phone No: ___________________	Phone No: ___________________
Fax: _______________________	Fax: _______________________

APPENDIX A

WHOLESALE RENEWABLE POWER PURCHASE AGREEMENT

Between

Portland General Electric Company

And

[*Seller*]

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This WHOLESALE RENEWABLE POWER PURCHASE AGREEMENT ("Agreement") is entered into effective as of the _______ day of _______, 201_ ("Effective Date"), by and between [*Seller*], a [*STATE*] limited liability company ("Seller"), and Portland General Electric Company, an Oregon corporation ("PGE"). PGE and Seller are also referred to in this Agreement individually as a "Party" and collectively as the "Parties."

ARTICLE 1
DEFINITIONS AND INTERPRETATION

1.1 Definitions.

As used in this Agreement, the following terms, when initially capitalized, shall have the meanings specified in this Section 1.1.

1.1.1 "AAA Procedures" has the meaning set forth in Section 18.2.

1.1.2 "Affiliate" means, with respect to a Party, any Person that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such Party. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

1.1.3 "Agreement" means this Wholesale Renewable Power Purchase Agreement entered into between Seller and PGE and all incorporated appendices, exhibits, schedules and attachments to this Agreement, as the same may be amended by the Parties from time to time.

1.1.4 "Ancillary Services" means any of the services identified by a Transmission Provider in its transmission tariff as "ancillary services" including, but not limited to, energy imbalance services, generation imbalance services, regulation and frequency response services, reactive supply services, voltage control services, inadvertent energy flow services, control area services, system integration services, operating spinning reserve services, and operating supplemental reserve services.

1.1.5 "As-Available Energy" means any Firm Energy, measured in MWh, scheduled and delivered from the Facility to the Delivery Point during a month that exceeds the Specified Amounts for such month.

1.1.6 "Balancing Authority Area" means an electric power system or combination of electric power systems under the control of an operator who acts to (i) match, at all times, the power output of the electric generators within the electric power system(s) and the capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s), (ii) maintain scheduled interchange with other control areas, within the limits of Prudent Electric Industry Practice, (iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Prudent Electric Utility Practice and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Prudent Electric Industry Practice.

1.1.7 "Bankrupt" means with respect to any entity, such entity (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it and such petition filed or commenced against it is not dismissed after one hundred and eighty (180) days, (ii) makes an assignment or any general arrangement for the benefit of creditors, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (v) is generally unable to pay its debts as they fall due.

1.1.8 "Bundled REC" means a REC that, subject to the terms and conditions of this Agreement, is generated by the Facility and delivered simultaneously and directly to PGE together with the equivalent quantity of Energy generated by the Facility as a single bundled Product, as represented by the lesser of the final e-Tag or the actual Facility Output on an hourly basis.

1.1.9 "Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party by whom the notice or payment or delivery is to be received.

1.1.10 "Capacity Attributes" means any current or future attribute, as may be currently defined or otherwise defined in the future, including but not limited to a characteristic, certificate, tag, credit, ancillary service or attribute thereof, or accounting construct, associated with the electric generation capability and capacity of the Facility or the Facility's capability and ability to produce or curtail energy, including any attribute counted towards any current or future resource adequacy or reserve requirements. Capacity Attributes are measured in MW. Notwithstanding any other provision of this Agreement, "Capacity Attributes" do not include: (i) any PTCs, ITCs, or any other tax credits, deductions, or tax benefits associated with the Facility, or (ii) any state, federal, local, or private cash payments or grants relating in any way to the Facility or the electric power output of the Facility.

1.1.11 "Claiming Party" has the meaning set forth in Section 4.2.

1.1.12 "Commercial Operation" means that not less than the Nameplate Capacity is fully operational and reliable and the Facility is fully interconnected, fully integrated, and synchronized with the Transmission System, all of which shall be Seller's responsibility to receive or obtain. Without limiting Seller's other obligations under this Agreement, Commercial Operation occurs when all of the following events (a) have occurred, and (b) remain simultaneously true and accurate as of the time at which Seller gives PGE notice that Commercial Operation has occurred:

(i) PGE has received a certificate addressed to PGE from a Licensed Professional Engineer stating that the Nameplate Capacity of the Facility is able to generate electric power reliably in amounts and quality expected by this Agreement and in accordance with all other terms and conditions hereof;

(ii) Start-Up Testing of the Facility shall have been completed;

(iii) PGE has received a certificate addressed to PGE from a Licensed Professional Engineer stating that, in accordance with the Interconnection Agreement, all required Interconnection Facilities have been constructed, all required interconnection tests have been completed and the Facility is physically interconnected with the applicable Transmission System in conformance with the Interconnection Agreement and is able to deliver energy at no less than the Nameplate Capacity.

(iv) PGE has received confirmation from the Transmission Provider(s) that (a) the Facility has successfully achieved interconnected operations, and (b) Seller has paid all amounts due under the interconnection agreement, including, but not limited to required network upgrades.

(v) PGE has received confirmation from Seller and the applicable Transmission Provider(s) that Seller has obtained for the Facility long-term, firm, point-to-point transmission service agreement with roll over rights, sufficient to enable Energy to be transmitted from the Facility and delivered to the Delivery Point at no less than the Nameplate Capacity. ***[Note to bidders:* Bidders may propose alternative transmission service arrangements. The quality of the proposed transmission service will be considered in PGE's evaluation of the bid.]**

(vi) PGE has received (1) a certificate addressed to PGE from an authorized officer of Seller stating that Seller has obtained or entered into all Facility Documents, and (2) copies of any Facility Documents requested by PGE; provided, however¸ that Seller may redact or omit confidential or commercial terms from non-public Facility Documents.

(vii) PGE has received an opinion from a Licensed Professional Engineer, or an attorney, licensed to practice in the state in which the Site is situated stating that Seller has all Permits and all other rights and agreements required to operate the Facility as contemplated by this Agreement in accordance with Law.

(viii) PGE shall have received all Performance Assurance required by this Agreement.

Seller shall provide written notice to PGE stating when Seller believes that the Facility has achieved Commercial Operation accompanied by the certificates described above. PGE shall have ten (10) days after receipt of Seller's notice either to confirm to Seller that all of the conditions to Commercial Operation have been satisfied or have occurred, or to state with specificity what PGE reasonably believes has not been satisfied. If, within such ten (10) day period, PGE does not respond or notifies Seller confirming that the Facility has achieved Commercial Operation, the original date of receipt of Seller's notice shall be the Commercial Operation Date. If PGE notifies Seller within such ten (10) day period that PGE reasonably believes the Facility has not achieved Commercial Operation, the Commercial Operation Date shall not occur until Seller has addressed the concerns stated in PGE's notice to the mutual satisfaction of both Parties.

1.1.13 "Commercial Operation Date" means the date on which the Facility achieves Commercial Operation.

1.1.14 "Contract Termination Damages" has the meaning set forth in Section 3.1.12.

1.1.15 "Contract Year" means any consecutive twelve (12) month period during the Term, commencing at 00:00:00 hours on the Commercial Operation Date or any of its anniversaries and ending at 24:00:00 hours on the last day of such twelve (12) month period.

1.1.16 "Costs" means, with respect to a Party, brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party in entering into new arrangements which replace this Agreement and all reasonable attorneys' fees and expenses incurred by a Party in connection with enforcing its rights under this Agreement. Costs shall not include any expenses incurred by such Party in either entering into or terminating any arrangement pursuant to which it has hedged its obligations.

1.1.17 "Credit Rating" means (i) with respect to any entity other than a financial institution, the (a) current ratings issued or maintained by S&P or Moody's with respect to such entity's long-term senior, unsecured, unsubordinated debt obligations (not supported by third party credit enhancements) or (b) corporate credit rating or long-term issuer rating issued or maintained with respect to such entity by S&P or Moody's, or (ii) if such entity is a financial institution, the ratings issued or maintained by S&P or Moody's with respect to such entity's long-term, unsecured, unsubordinated deposits.

1.1.18 "Credit Requirements" means a senior, unsecured long term debt rating (or corporate rating if such debt rating is unavailable) of (a) BBB or greater from S&P, or (b) Baa2 or greater from Moody's, and if such ratings are split, the lower of the two ratings must be at least 'BBB' or 'Baa2' from S&P or Moody's, respectively.

1.1.19 "Critical Milestone" has the meaning set forth in Section 3.1.9.

1.1.20 "Daily" means any 24-Hour period commencing at 00:00:00 Hours.

1.1.21 "Delay Damages" for any given day are equal to (a) the Nameplate Capacity, expressed in kWs, multiplied by (b) $200 per kW divided by 365, but in no event less than [$___] per day.

1.1.22 "Delivered Energy Quantity" means the sum of the Specified Energy, Un-Specified Energy and As-Available Energy delivered to PGE by or on behalf of Seller to the Delivery Point each hour as represented on the final e-Tag. The Delivered Energy Quantity shall not exceed Net Available Capacity in any given hour.

1.1.23 "Delivery Period" has the meaning set forth in Section 2.3.

1.1.24 "Delivery Period Security" has the meaning set forth in Section 9.2.1.

1.1.25 "Delivery Point" means the BPAT.PGE point of delivery on the BPA side of the BPA-PGE interface.

1.1.26 "Dispute" has the meaning set forth in 18.1.

1.1.27 "Early Termination Date" has the meaning set forth in Section 5.2.1.

1.1.28 "Effective Date" has the meaning set forth in the first paragraph of this Agreement.

1.1.29 "EIM" means the western Energy Imbalance Market, of which PGE is a participating entity.

1.1.30 "Emissions Reduction Credit" is any credit, allowance or instrument issued or issuable pursuant to a state implementation plan under the Clean Power Plan promulgated by the Environmental Protection Agency under the Clean Air Act.

1.1.31 "Energy" means all electric energy, expressed in MWh, generated by the Facility and scheduled to PGE at the Delivery Point as required by this Agreement.

1.1.32 "Environmental Attributes" means any and all claims, credits, benefits, emissions reductions, offsets and allowances, however named, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water or otherwise arising as a result of the generation of electricity from the Facility, regardless of whether or not (i) such environmental attributes have been verified or certified, (ii) such environmental attributes are creditable under any applicable legislative or regulatory program, or (iii) such environmental attributes are recognized as of the Effective Date or at any time during the Term. Environmental Attributes include but are not limited to: (a) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; (b) all Emissions Reduction Credits; and (c) any avoided emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere; and (3) the reporting rights to these avoided emissions, such as the carbon content of the Energy generated by the Facility and REC Reporting Rights. Environmental Attributes do not include (i) production tax credits associated with the construction or operation of the Facility and other financial incentives in the form of credits, reductions, or allowances associated with the Facility that are applicable to a state or federal income taxation obligation, (ii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iii) emission reduction credits encumbered or used by the Facility for compliance with local, state, or federal operating and/or air quality permits.

1.1.33 "Equitable Defenses" means any bankruptcy, insolvency, reorganization and other laws affecting creditors' rights generally, and with regard to equitable remedies, the discretion of the court before which proceedings to obtain same may be pending.

1.1.34 "EWG" means an "exempt wholesale generator," as defined under Public Utility Holding Company Act of 1935.

1.1.35 "Event of Default" has the meaning set forth in Section 5.1.

1.1.36 "Facility" means the ***[describe renewable energy technology]*** facility more fully described in Exhibit D, and includes all generators, equipment, devices and associated appurtenances owned, controlled, operated and managed by Seller in connection with, or to facilitate, the production, generation, transmission, delivery, or furnishing of Product to PGE in accordance with this Agreement (including the Interconnection Facilities).

1.1.37 "Facility Documents" means the Permits and other written authorizations, rights and agreements now or hereafter necessary for (i) construction, ownership, operation, and maintenance of the Facility in accordance with Prudent Electric Industry Practices, and (ii) transmission of Energy from the Facility to the Balancing Authority Area (including documents with respect to Balancing Authority Area services). Facility Documents include the Permits and other written authorizations, rights and agreements listed in Exhibit E; provided, however, that nothing set forth in Exhibit E limits the obligations of Seller to obtain all Facility Documents required to enable Seller to perform its obligations under this Agreement in accordance with its terms.

1.1.38 "Facility Meter" means the metering equipment designed, furnished, installed, owned, inspected, tested, maintained and replaced as provided in the Interconnection Agreement.

1.1.39 "Facility Output" means all electric energy, produced by the Facility, less station service (parasitic power and electrical losses), if any, all as measured at the Facility Meter.

1.1.40 "FERC" means the Federal Energy Regulatory Commission or any successor government agency.

1.1.41 "FIN 46" has the meaning set forth in Section 19.11.

1.1.42 "Firm Energy" means Energy that is to be scheduled, delivered, sold, received and purchased on an uninterruptible basis. Firm Energy shall be scheduled in hourly increments and delivered on long-term firm transmission from the Facility to the Delivery Point, in accordance with the provisions in Article Three. Neither Party shall be relieved of its obligations to sell and deliver or to receive and purchase Firm Energy except for any period during which such performance is prevented or delayed by Force Majeure or as otherwise expressly allowed herein.

1.1.43 "Fixed Price" means the respective monthly On-Peak and Off-Peak prices per MWh to be paid by PGE to Seller for Specified Energy scheduled and delivered during each month of the Delivery Period as set forth in the price schedule attached to this Agreement as Exhibit B.

1.1.44 "Forecasting Agent" shall have the meaning set forth in Section 3.8.3.

1.1.45 "Force Majeure" is defined in Section 4.1.

1.1.46 "Gains" means, with respect to a Party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of its obligations with respect to this Agreement determined in a commercially reasonable manner.

1.1.47 "Generation Forecast" shall have the meaning given to that term in Section 3.4.1.

1.1.48 "Governmental Authority" means any and all foreign, national, federal, state, county, city, municipal, local or regional authorities, departments, bodies, commissions, corporations, branches, directorates, agencies, ministries, courts, tribunals, judicial authorities, legislative bodies, administrative bodies, regulatory bodies, autonomous or quasi-autonomous entities or taxing authorities or any department, municipality or other political subdivision thereof; provided, however, that "Governmental Authority" shall not in any event include either Party.

1.1.49 "Governmental Charges" means any charges or costs that are assessed or levied by any entity, including local, state or federal regulatory or taxing authorities that would affect the sale and purchase of the Product contemplated by this Agreement, or any component of the Product, either directly or indirectly.

1.1.50 "Guaranteed Commercial Operation Date" means the date that is ninety (90) days after the Scheduled Commercial Operation Date.

1.1.51 "Guarantor" means, with respect to Seller, [__________].

1.1.52 "Guaranty" means an instrument or agreement pursuant to which the Guarantor guarantees the performance of each and all of the obligations of Seller, which instrument or agreement is reasonably acceptable in form and substance to PGE.

1.1.53 "Guaranty Default" means with respect to a Guaranty or the Guarantor thereunder, the occurrence of any of the following events: (i) any representation or warranty made or deemed to be made or repeated by such Guarantor in connection with such Guaranty shall be false or misleading in any material respect when made or when deemed made or repeated; (ii) such Guarantor fails to pay, when due, any amount required pursuant to such Guaranty; (iii) the failure of such Guarantor to comply with or timely perform any other material covenant or obligation set forth in such Guaranty if such failure is not capable of remedy or shall not be remedied in accordance with the terms and conditions of such Guaranty; (iv) a Merger Event occurs with respect to such Guarantor; (v) such Guaranty shall expire or terminate, or shall fail or cease to be in full force and effect and enforceable in accordance with its terms against such Guarantor, prior to the satisfaction of all obligations of the guaranteed Party under this Agreement, in any such case without replacement; (vi) such Guarantor shall repudiate, disaffirm, disclaim, or reject, in whole or in part, or challenge the validity of, its Guaranty, or (vii) such Guarantor becomes Bankrupt; provided, however, that no Guaranty Default shall occur or be continuing in any event with respect to a Guaranty after the time such Guaranty is required to be canceled or returned to Seller in accordance with the terms of this Agreement.

1.1.54 "Indemnitee" has the meaning set forth in Section 12.2.

1.1.55 "Indemnitor" has the meaning set forth in Section 12.2.

1.1.56 "Indemnity Claims" means all third party claims or actions, threatened or filed, whether groundless, false, fraudulent or otherwise, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorneys' fees and court costs, whether resulting from a settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement.

1.1.57 "Initial Specified Amounts" means the Specified Amounts set forth on Exhibit C as of the Effective Date.

1.1.58 "Interconnection Agreement" means the generator interconnection agreement between Seller and ***[identify applicable Transmission Provider*]** [***if already executed:*** dated [_____, 20__].***]***

1.1.59 "Interest Rate" means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in The Wall Street Journal under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), or (b) the maximum rate permitted by applicable law. Notwithstanding the foregoing, in no case shall the Interest Rate be less than zero (0).

1.1.60 "Interconnection Facilities" means all the facilities installed, or to be installed, for the purpose of interconnecting the Facility to the Transmission System, including electrical transmission lines, upgrades, transformers and associated equipment, substations, relay and switching equipment, and safety equipment.

1.1.61 "ITCs" means the investment tax credits established pursuant to Section 48 of the Internal Revenue Code, as such law may be amended or superseded.

1.1.62 "Law" means any act, statute, law, regulation, permit (including applicable Permits), ordinance, rule, judgment, order, decree, directive, guideline or policy (to the extent mandatory) or any similar form of decision or determination by, or any interpretation or administration of, any of the foregoing by any Governmental Authority with jurisdiction over Seller, PGE, the Site, the Facility, or the performance of the obligations under the Agreement, and includes any of the same as they may be amended or imposed from time to time.

1.1.63 "Letter(s) of Credit" means one or more irrevocable, transferable, standby letters of credit issued by a major U.S. commercial bank or a U.S. branch office of a major foreign commercial bank with such bank having shareholders' equity of at least $10 billion USD and a Credit Rating of at least A1 from Moody's or A+ from S&P, in a form and substance reasonably acceptable to PGE. The costs of a Letter of Credit shall be borne by Seller.

1.1.64 "Letter of Credit Default" means with respect to a Letter of Credit, the occurrence of any of the following events: (i) the issuer of such Letter of Credit shall fail to be a major U.S. commercial bank or a U.S. branch office of a major foreign commercial bank with such bank having shareholders' equity of at least $10 billion USD and a Credit Rating of at least A1 from Moody's or A+ from S&P; (ii) the issuer of the Letter of Credit shall fail to comply with or perform its obligations under such Letter of Credit; (iii) the issuer of such Letter of Credit shall disaffirm, disclaim, repudiate or reject, in whole or in part, or challenge the validity of, such Letter of Credit; (iv) such Letter of Credit shall be within fifteen (15) Business Days of expiration or termination, or shall fail or cease to be in full force and effect at any time during the Term, in any such case without replacement; (v) the issuer of such Letter of Credit shall become Bankrupt; or (vi) a Merger Event occurs with respect to the issuer of such Letter of Credit; provided, however, that no Letter of Credit Default shall occur or be continuing in any event with respect to a Letter of Credit after the time such Letter of Credit is required to be canceled or returned in accordance with the terms of this Agreement.

1.1.65 "Licensed Professional Engineer" means a Person proposed by Seller and acceptable to PGE in its reasonable judgment who (a) to the extent mandated by Law is licensed to practice engineering in the appropriate engineering discipline for the required certification being made, in the United States, and in all states for which the person is providing a certification, evaluation or opinion with respect to matters or Law specific to such state, (b) has training and experience in the engineering disciplines relevant to the matters with respect to which such person is called upon to provide a certification, evaluation or opinion, (c) has no economic relationship, association, or nexus with Seller or its members or Affiliates, other than with the prior written consent of PGE, services previously or currently being rendered to Seller or its members or

Affiliates, and (d) is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or seller of any equipment installed in the Facility.

1.1.66 "Losses" means, with respect to a Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from termination of its obligations with respect to this Agreement determined in a commercially reasonable manner.

1.1.67 "Market Index Settlement Prices" means the production-weighted sum of the Market Index Price for each hour during the delivery month. In the event of PGE's participation in a different market design (e.g., full ISO participation), the respective five (5) minute pricing interval for the Delivery Point will be used to calculate the Market Index Settlement Prices. Exhibit I sets forth an accurate and indicative example of a Market Index Settlement Price calculation under certain stated assumptions.

1.1.68 "Market Price Index" means the EIM Locational Marginal Price associated with the Pricing Node or Aggregate Pricing Node for the Delivery Point.

1.1.69 "Material Adverse Change" means (i) with respect to PGE, PGE shall have a Credit Rating below BBB- by S&P and below Baa3 by Moody's or both ratings are withdrawn or terminated on a voluntary basis by the rating agencies, (ii) with respect to Seller, Seller or Seller's Guarantor, if applicable, shall have a Credit Rating below BBB- by S&P and below Baa3 by Moody's or both ratings are withdrawn or terminated on a voluntary basis by the rating agencies, if rated by both services. If Seller or Seller's Guarantor is rated by only one service, a Material Adverse Change shall occur if the rating falls below the pertinent level specified above or if such rating is withdrawn or terminated on a voluntary basis by the rating agency.

1.1.70 "Maximum Annual Volume" means the maximum annual production of Specified Energy equal to [___] MWh (the annual total of the Initial Specified Amounts) for each calendar year during the Delivery Period, prorated for any partial calendar years during the Term.

1.1.71 "Merger Event" means, with respect to a Party or an Affiliate of a Party that such Party or Affiliate consolidates or amalgamates with, or merges into or with, or transfers all or substantially all of its assets to another entity, and (i) the resulting, surviving or transferee entity fails, at the time of such consolidation, amalgamation, merger or transfer, to assume each and all of the obligations of such Party or Affiliate under this Agreement or under any Guaranty, Letter of Credit or other Performance Assurance, either by operation of law or pursuant to an agreement reasonably satisfactory to the other Party, or (ii) the benefits of any Guaranty, Letter of Credit, or other Performance Assurance or credit support provided pursuant to this Agreement fail, at any time following such consolidation, amalgamation, merger or transfer, to extend to the performance by such Party or such resulting, surviving or transferee entity of its obligations under this Agreement, or (iii) the Credit Rating (from any of S&P or Moody's) of the resulting, surviving or transferee entity is not equal to or higher than that of such Party or Affiliate immediately prior to such consolidation, amalgamation, merger, or transfer.

1.1.72 "Mid-Columbia" means an area which includes points at any of the switchyards associated with the following four hydro projects: Rocky Reach, Rock Island, Wanapum and Priest Rapids. These switchyards include: Rocky Reach, Rock Island, Wanapum, McKenzie, Valhalla, Columbia, Midway and Vantage.

1.1.73 "Milestone" and "Milestones" have the meaning assigned to those terms in Section 3.1.9(a)(i).

1.1.74 "Minimum Annual Volume" means an annual production of Specified Energy equal to [___] MWh (85% of the Initial Specified Amounts) for all calendar years during the Delivery Period, prorated for partial calendar years. ***[Note to bidders: For use with baseload facilities.]***

1.1.75 "Month" means a calendar month commencing at hour ending 01:00:00 PPT on the first day of such month through hour ending 24:00:00 PPT on the last day of such month.

1.1.76 "Moody's" means Moody's Investor Services, Inc. or its successor.

1.1.77 "MW" means megawatt.

1.1.78 "MWh" means megawatt hour.

1.1.79 "Nameplate Capacity" means [__] ***[solar: MW_{DC}.] [other resources: MW_{AC}]***, which is the full (maximum) gross power capability of the Facility's electric power production equipment under optimal conditions designated by the manufacturer and described on Exhibit M. ***[Note to bidders: the optimal conditions based on manufacturer designation and the equipment used by the Facility to be agreed upon and included in Exhibit M]***

1.1.80 "Negative Price Event" shall have the meaning given to that term in Section 3.4.7.

1.1.81 "NERC" means the North American Electric Reliability Corporation.

1.1.82 "Net Available Capacity" means the full (maximum) net Energy the Facility is capable of delivering to the interconnecting Balancing Authority Area continuously for at least sixty (60) minutes; which is equivalent to the Nameplate Capacity Rating of the Facility's generating unit less station service (parasitic power and electrical losses) and inverter limitations, expressed in MW_{AC}.

1.1.83 "Non-Defaulting Party" has the meaning set forth in Section 5.2.1.

1.1.84 "Off-Peak" shall mean all hours ending 01:00:00 through 06:00:00 and hours ending 23:00:00 through 24:00:00, PPT, Monday through Saturday and hours ending 01:00:00 through 24:00:00, PPT, on Sundays and NERC designated holidays.

1.1.85 "On-Peak" shall mean all hours ending 07:00:00 through 22:00:00 PPT, Monday through Saturday, excluding NERC designated holidays.

1.1.86 "Oregon Renewable Portfolio Standard" means the renewable portfolio standard contemplated by ORS Chapter 469A, and its implementing regulations, in each case as amended from time to time.

1.1.87 "Party" or "Parties" are defined in the preamble of this Agreement.

1.1.88 "Performance Assurance" means collateral in the form of cash, Letter(s) of Credit, or a Guaranty.

1.1.89 "Permits" shall mean permits, licenses, approvals, consents, orders, registrations, privileges, franchises, memberships, certificates, entitlements variances, waivers, certificates of occupancy and other authorizations issued by any Governmental Authorities, and any siting, zoning and land use approvals required under Law in connection with the development, construction, operation, occupancy, use and/or maintenance of the Site or Facility, including those specified in Exhibit E, and all amendments, modifications, supplements, general conditions and addenda thereto.

1.1.90 "Person" means an individual, partnership, corporation, limited liability company, joint venture, association, trust, unincorporated organization, Governmental Authority, or other form of entity.

1.1.91 "PGE Representatives" has the meaning set forth in Section 3.10.

1.1.92 "PPT" means Pacific Prevailing Time (i.e., prevailing Standard Time or Daylight Savings Time in the Pacific Time Zone).

1.1.93 "Pre-COD Security" has the meaning set forth in Section 9.1.1.

1.1.94 "Pre-Scheduled Energy" has the meaning set forth in Section 3.8.4(a).

1.1.95 "Product" means, each and together, Specified Energy, Un-Specified Energy, and As-Available Energy to be scheduled, delivered and sold by Seller and to be received and purchased by PGE pursuant to this Agreement, together with all associated Environmental Attributes (including Bundled RECs) and Capacity Attributes.

1.1.96 "Prudent Electric Industry Practice" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power generation industry in the Western Interconnection that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by the Facility's equipment sellers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electric Industry Practice is not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the Western Interconnection, during the relevant period, as described in the immediately preceding sentence.

1.1.97 "PURPA" means the Public Utility Regulatory Policies Act of 1978.

1.1.98 "QF" means "Qualifying Facility," as that term is defined in the FERC regulations (codified at 18 CFR Part 292) in effect on the Effective Date.

1.1.99 "PTCs" means production tax credits under Section 45 of the Internal Revenue Code, as such law may be amended or superseded.

1.1.100 "Qualifying Replacement RECs" means environmental attributes (including renewable energy credits and renewable energy credit reporting rights) that are (i) delivered to PGE bundled with energy produced simultaneously by a generating source that (A) is an Oregon Renewable Portfolio Standard eligible renewable energy resource, (B) produces environmental attributes (including renewable energy credits and renewable energy credit reporting rights) of the same type and quality as Environmental Attributes (including Bundled RECs and REC Reporting Rights), (C) is located in [________], and (D) achieves commercial operation after the Commercial Operation Date, or (ii) RECs from As-Available Energy that were not conveyed by Seller to PGE under this Agreement, if any, or (iii) a combination thereof.

1.1.101 "Qualifying Replacement REC Price" means the price for Qualifying Replacement RECs as determined by taking the lower of two dealer quotes representing a live offer to sell Qualifying Replacement RECs for the entire quantity of Bundled RECs that are being replaced and subtracting the value of the energy component of such quantity (as specified in the applicable dealer quote) of such Qualifying Replacement RECs.

1.1.102 "REC" means the Environmental Attributes and the REC Reporting Rights associated with Facility Output, however commercially transferred or traded under any or other product names, such as "green tags," "Green-e Certified," or otherwise. RECs are accumulated on a MWh basis and one REC represents the Environmental Attributes made available by the generation of one MWh of Facility Output, as represented by the lesser of the final e-Tag or the actual Facility Output on an hourly basis. All RECs delivered to PGE under this Agreement must comply with the Oregon Renewable Portfolio Standard.

1.1.103 "REC Reporting Rights" are the right of a buyer to report the ownership of accumulated RECs in compliance with federal or state law, if applicable, and to a federal or state agency or any other party at such buyer's discretion, and include without limitation those REC Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present federal, state, or local law, regulation or bill, and international or foreign emissions trading program.

1.1.104 "Regulatory Event" has the meaning given to that term in Section 19.6.

1.1.105 "Reliability Entity" may include, without limitation, NERC, WECC, the Balancing Authority, Transmission Provider, regional transmission organization, independent system operator, reliability coordinator or any other entity that has, or that may have in the future, (i) responsibility over the reliability of the bulk power system and (ii) by virtue of such responsibility the legal authority to affect the operations of the Facility or delivery of the Product.

1.1.106 "Remedial Action Scheme" means an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows.

1.1.107 "S&P" means the Standard & Poor's, a division of McGraw-Hill Companies, Inc., or any successor thereto.

1.1.108 "Sales Price" means the price at which Seller, acting in a commercially reasonable manner, resells any Product not accepted by PGE in breach of PGE's obligations under this Agreement, deducting from such proceeds any (i) Costs reasonably incurred by Seller in reselling such Product and (ii) additional transmission charges, if any, reasonably incurred by Seller in delivering such Product to the third party purchasers. "Costs" shall not include any negative price amounts for the Product, penalties, ratcheted demand or similar charges. In no event shall the Sales Price be less than zero dollars ($0.00).

1.1.109 "Schedule," "Scheduled" or "Scheduling" means the actions of Seller, PGE, a Transmission Provider and all other impacted entities, or their representatives, of notifying, requesting, and confirming/implementing the quantity and type of Product, transmission arrangements, and timing of delivery, subject to the prevailing Western EIM, NAESB, WECC and NERC scheduling requirements.

1.1.110 "Scheduled Commercial Operation Date" means [____, 20__].

1.1.111 "Scheduling Agent" has the meaning set forth in Section 3.8.3.

1.1.112 "Scheduling Period" means the hourly scheduling period during which Energy is Scheduled to the Delivery Point in accordance with the tariff and business practices of the EIM.

1.1.113 "Seller" is defined in the Preamble of this Agreement.

1.1.114 "Settlement Amount" means, with respect to this Agreement and the Non-Defaulting Party, the Losses or Gains, and Costs, expressed in USD, which such Party incurs as a result of the termination and liquidation of this Agreement pursuant to Article 5. If the Non-Defaulting Party's Costs and Losses exceed its Gains, then the Settlement Amount shall be an amount owing to the Non-Defaulting Party. If the Non-Defaulting Party's Gains exceed its Costs and Losses, then the Settlement Amount shall be zero dollars ($0). The Settlement Amount shall not include consequential, punitive, exemplary or indirect or business interruption damages.

1.1.115 "Settlement Period" has the meaning set forth in Section 5.2.2.

1.1.116 "Settlement Energy" has the meaning set forth in Section 5.2.2.

1.1.117 "Site" means the real property on which the Facility is or will be located, as more fully described on Exhibit F.

1.1.118 "Specified Amount(s)" means the amount of Firm Energy generated by the Facility that Seller is required to deliver to PGE at the Delivery Point for each monthly On-Peak period and for each monthly Off-Peak period during the Delivery Period. The Specified Amounts for each month during the following calendar year shall be established by Seller pursuant to Section 3.3. ***[Note to bidders: For baseload facilities, the Specified Amount(s) will be based on daily On/Off Peak Hours.]***

1.1.119 "Specified Energy" means Firm Energy simultaneously bundled with the Facility's associated Environmental Attributes, including Bundled RECs, as generated and metered net of all Facility losses and station service at the Facility Meter, scheduled in hourly blocks, and delivered to the Delivery Point, up to the Specified Amount according the Scheduling Procedure in Section 3.8. Each MWh of Specified Energy delivered shall include one (1) Bundled REC.

1.1.120 "Start-Up Testing" means the start-up tests for the Facility as set forth in Exhibit G.

1.1.121 "Taxes" means all taxes, rates, levies, adders, assessments, surcharges, duties and other fees and charges of any nature, including but not limited to ad valorem, consumption, excise, franchise, gross receipts (including any [*State Name*] business and occupation tax and [*State Name*] public utility tax and any successor tax thereto), import, export, license, property, sales, stamp, storage, transfer, turnover, use, or value-added taxes, and any and all items of withholding, deficiency, penalty, addition to tax, interest, or assessment related thereto.

1.1.122 "Term" means the period of time referenced in Section 2.1.

1.1.123 "Test Energy" means electric energy generated by the Facility during periods before the Commercial Operation Date, and all RECs and Capacity Rights associated with such electric energy.

1.1.124 "Termination Payment" has the meaning set forth in Section 5.3.

1.1.125 "Transmission Provider(s)" means any entity (including any FERC-authorized regional transmission organization) transmitting Energy on behalf of Seller to and at the Delivery Point; or on behalf of PGE at and from the Delivery Point.

1.1.126 "Transmission Services" means any and all services (including but not limited to Ancillary Services and control area services) required for the transmission and delivery of Energy to the Delivery Point or at and from the Energy Delivery Point.

1.1.127 "Transmission System(s)" means the transmission system(s) of the Transmission Provider(s) to be used by Seller for the purpose of transmitting Energy to and at, the Delivery Point; or by PGE for the purpose of transmitting Energy at and from, the Delivery Point.

1.1.128 "Transmission Upgrade Cost Cap' has the meaning set forth in Section 3.8.1.

1.1.129 "Un-Specified Energy" means that portion of Firm Energy, measured in MWh, scheduled and delivered to Seller that was not generated by the Facility but is delivered to PGE as a result of Ancillary Services provided by a Balancing Authority Area or Transmission Provider, or other entity, as applicable.

1.1.130 "USD" means United States Dollars.

1.1.131 "WECC" means the Western Electricity Coordinating Council or any successor thereto.

1.1.132 "Western Interconnection" means the network of subsystems of generators, transmission lines, transformers, switching stations, and substations owned or operated by members of the WECC, to the extent located in the continental United States.

1.1.133 "WREGIS" means the Western Renewable Energy Generation Information System.

1.2 Rules of Interpretation.

Unless the context otherwise requires:

1.2.1 Words singular and plural in number shall be deemed to include the other and pronouns having masculine or feminine gender shall be deemed to include the other.

1.2.2 Subject to ARTICLE 15, any reference in this Agreement to any Person includes its successors and assigns and, in the case of any Governmental Authority, any Person succeeding to its functions and capacities.

1.2.3 Any reference in this Agreement to any Section, Exhibit or Appendix means and refers to the Section contained in, or Exhibit or Appendix attached to, this Agreement.

1.2.4 A reference to writing includes typewriting, printing, lithography, photography, email and any other mode of representing or reproducing words, figures or symbols in a lasting and visible form.

1.2.5 Unless otherwise expressly provided in this Agreement, a reference to a specific time for the performance of an obligation is a reference to that time in the place where that obligation is to be performed.

1.2.6 A reference to a Party to this Agreement includes that Party's successors and permitted assigns.

1.2.7 Unless otherwise expressly provided in this Agreement, a reference to a document or agreement, including this Agreement, includes a reference to that document or agreement as modified, amended, supplemented or restated from time to time.

1.2.8 References in this Agreement to "or" shall be deemed to be disjunctive but not necessarily exclusive (i.e., unless the context dictates otherwise, "or" shall be interpreted to mean "and/or" rather than "either/or").

1.2.9 If any payment, act, matter or thing hereunder would occur on a day that is not a Business Day, then such payment, act, matter or thing shall, unless otherwise expressly provided for herein, occur on the next Business Day.

1.3 Technical Meanings.

Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used in this Agreement in accordance with such recognized meanings.

ARTICLE 2
CONTRACT TERM; DELIVERY PERIOD; PRICE; SALE OF FACILITY

2.1 Term; [Conditions Precedent].

2.1.1 Term. The term of this Agreement shall begin on the Effective Date and shall continue through [***existing facility:*** ________[*Date*]] [***facility to be built:*** the [__] anniversary of the Commercial Operation Date] (the "Term"), unless earlier terminated in accordance with its terms; provided, however, that (a) such termination shall not affect or excuse the performance of either Party under any provision of this Agreement that by its terms survives any such termination, and (b) the terms and conditions of this Agreement and any other documents executed and delivered under this Agreement shall continue to govern with respect to obligations arising before termination until such obligations are fully discharged.

2.1.2 PGE's Conditions Precedent. PGE's obligations under this Agreement are subject to the following conditions precedent, each of which may be waived by PGE in its sole discretion:

(a) [Project Specific Conditions: TBD]; and

(b) All authorizations, approvals and consents of all Persons, including PGE's Board of Directors, that are required in connection with the execution, delivery, and performance of this Agreement have been received by PGE; and

(c) All required regulatory approvals have been made and obtained.

If these conditions precedent have not been satisfied or waived by PGE on or before [_______, 20__], either Party shall have the right to terminate this Agreement by giving five (5) Business Days' prior notice of termination to the other Party. Neither Party shall have any liability for such a termination.

2.1.3 <u>Seller's Conditions Precedent</u>. Seller's obligations under this Agreement are subject to the following conditions precedent, each of which may be waived by Seller in its sole discretion: ***[<u>Note to bidders</u>: conditions precedent, if any, to Seller's obligations under the PPA should be set out here]***

If these conditions precedent have not been satisfied or waived by Seller on or before [_____, 20__], either Party shall have the right to terminate this Agreement by giving five (5) Business Days' prior notice of termination to the other Party. Neither Party shall have any liability for such a termination.

2.2 <u>Test Energy</u>. Seller shall use its best efforts to schedule and deliver Facility Test Energy to its Transmission Provider, to a third-party or to an organized market (to the extent PGE has consented to Seller participating in such organized market pursuant to Section 3.14) via its Transmission Provider's system. Seller shall be entitled to any and all compensation received from its Transmission Provider or any third-party or organized market for such Test Energy. Notwithstanding the forgoing, in the event that it is necessary for Seller to schedule and deliver Facility Test Energy to PGE in order to complete start-up testing, Seller shall be entitled to do so pursuant to the Scheduling Procedure set forth in Section 3.8 (to the extent applicable). In such case, the Parties shall coordinate in good faith to schedule deliveries of Test Energy to PGE that minimizes the burden to each of the Parties, and PGE shall receive the Test Energy. The price for such Test Energy received by PGE shall be zero dollars ($0.00) and Seller shall pay any costs or additional expenses that are required for PGE to receive the Test Energy, including but not limited to reimbursement for negative pricing and procurement of any necessary capacity costs or reserves.

2.3 <u>Delivery Period; Price and Adjustments</u>.

2.3.1 <u>Delivery Period</u>. Starting on [***for a completed Facility:***________[*Date*]] [***for a Facility under development:*** the Commercial Operation Date], Seller shall Schedule all of the Facility Output to PGE as Energy at the Delivery Point and shall continue such deliveries for the Term (the "Delivery Period").

2.3.2 <u>Price</u>. For each calendar month during the Delivery Period, and except as otherwise provided herein, PGE shall pay Seller the sum of the following:

(a) Subject to subpart (d) below, the Specified Energy delivered during the calendar month, up to the Specified Amount for such month, multiplied by the applicable Fixed Price for On-Peak hours and for Off-Peak hours; and

(b) The As-Available Energy delivered during the calendar month multiplied by the Market Index Settlement Price for the calendar month; and

(c) The Un-Specified Energy delivered during the calendar month multiplied by the Market Index Price for each hour that the Un-Specified Energy was delivered.

(d) For each hour that the Market Index Price is negative, the sum of the Delivered Energy Quantity less Un-Specified Energy, for each applicable hour, multiplied by the Market Index Price.

An indicative example illustrating the determination of payment due under this Section 2.3.2 is set forth in Exhibit I.

2.4 Notice of Sale of Facility.

If Seller or an Affiliate of Seller desire to sell the Facility during the Term, either by a sale of the Facility's assets or by a direct or indirect transfer of the membership interest(s) in Seller, Seller shall first, before it or its Affiliate enters into any substantive discussions with other parties, notify PGE of its desire to sell the Facility. PGE agrees to notify Seller if it is interested in acquiring the Facility within twenty (20) days following receipt of Seller's notice. If PGE so notifies Seller, the Parties shall engage in exclusive good faith negotiations to reach agreement with respect to such a transaction for a period of ninety (90) days thereafter. If during this period the Parties execute a letter of intent, or other document similarly confirming the Parties' intent to enter into a transaction for the purchase and sale of the Facility, then such exclusive negotiation period shall be automatically extended for an additional ninety (90) day period, during which time the Parties may execute a purchase and sale agreement for the Facility. Any purchase and sale agreement executed within the time frame stated in this Section 2.4 shall remain subject to regulatory approval beyond such time frame, as applicable. Seller may pursue any transaction for the sale of the Facility with one or more third parties at any time and from time to time and shall have no obligation to PGE under this Section 2.4 following an occurrence of any of the following: (i) PGE expressly declines interest in acquiring the Facility after receipt of Seller's notice provided pursuant to the first sentence of this Section 2.4, (ii) PGE fails to respond to Seller's notice pursuant to the first sentence of this Section 2.4, within twenty (20) days after receipt thereof; (iii) PGE and Seller fail to execute a letter of intent or other similar document with respect to the sale of the Facility within ninety (90) days after PGE's receipt of notice from Seller provided pursuant to the first sentence of this Section 2.4; or (iv) PGE and Seller fail to execute a purchase and sale agreement for the Facility within one hundred eighty (180) days after PGE's receipt of notice from Seller provided pursuant to the first sentence of this Section 2.4; provided, however, that with respect to clause (iv), if Seller rejects a firm price delivered by PGE in the course of such negotiations, any sale of the Facility to a third party during the subsequent two (2)-year period must be at a price higher than such rejected price or Seller shall be required to re-engage in negotiations with PGE as otherwise set forth in this Section 2.4 for the sale of the Facility.

2.5 [Option to Purchase/Option to Extend Term]

***[Note to bidders*: if a Bidder wishes to propose an end of Term or during Term option for PGE to purchase the Facility, or an option for PGE to extend the Term of the PPA, it should include its proposal here in its mark up of the Agreement.**

ARTICLE 3
FACILITY DEVELOPMENT, CONSTRUCTION AND OPERATION

3.1 Development and Construction of Facility. ***[Note to bidders*: Section 3.1 will be "intentionally omitted" for a Facility that has already been built.]**

3.1.1 Facility Documents. Seller shall provide PGE with the documents listed below. To the extent they are available on the Effective Date, such documents have been attached to this Agreement as Exhibit E. With respect to any of the listed Facility Documents that become available or are reasonably required to be modified after the Effective Date, Seller shall provide such documents to PGE within ten (10) days after receiving them. Seller may not materially modify such documents or amend Exhibit E after the Effective Date without PGE's prior written consent, which PGE may not unreasonably withhold, condition or delay.

(a) Seller's proposed Level 1 schedule, including significant Facility activities, milestones and deliverables.

(b) A list of permits and approvals required for the construction and operation of the Facility.

(c) Facility layout drawings, including all major equipment and balance of plant equipment.

(d) An electrical single-line diagram for the Facility.

(e) 12x24 net energy profile and, if available, 8760 net energy production estimate.

3.1.2 Intentionally Left Blank.

3.1.3 Permitting. Seller shall obtain all Permits necessary to construct, own and operate the Facility in accordance with this Agreement.

3.1.4 Financing. Seller shall obtain any and all financing necessary to construct and operate the Facility during the Delivery Period and the Term on a schedule consistent with the requirements of this Agreement.

3.1.5 Facility Design. Seller shall be responsible for designing and building the Facility in compliance with all Permits and according to Prudent Electric Industry Practice with respect to project design, engineering and selection and installation of equipment to be used at or installed in the Facility. At PGE's request, Seller shall provide PGE with copies of the site plan for the Facility and descriptions, for the project design of the Facility. Any review by PGE of the design, construction, operation or maintenance of the Facility is solely for PGE's information, and PGE shall have no responsibility to Seller or any third party in connection with such review. Seller is solely responsible for the economic and technical feasibility, operational capability and reliability of the Facility.

3.1.6 Construction and Testing; Interconnection. Seller shall, at its cost, construct and test the Facility and obtain all necessary transmission and interconnection rights, all in compliance with the Permits, the Interconnection Agreement, any other agreements with any Transmission Provider, and Prudent Electric Industry Practice.

3.1.7 Monthly Reports. After the Effective Date, Seller shall provide PGE with monthly written reports regarding Seller's progress in completing the construction, testing and interconnection of the Facility and shall, at PGE's request, meet with PGE's representatives to discuss such progress.

3.1.8 Equipment Supply. Not later than [____] Seller shall provide PGE with written evidence of Seller's commitment from the parties identified on Exhibit E for the supply of all of the equipment required to construct and interconnect the Facility in a timeframe that reasonably would allow Seller to achieve the Commercial Operation Date of the Facility on or before the Scheduled Commercial Operation Date.

3.1.9 Milestones.

(a) Seller shall design, construct, own, operate, repair, and maintain the Facility in accordance and consistent with the Facility Documents and Prudent Electric Industry Practice so as to ensure the continuous ability of the Facility to meet Seller's obligations to PGE under this Agreement. Seller shall exercise its best efforts, consistent with Prudent Electric Industry Practice, to complete development of the Facility in accordance with the dates for each Milestones set forth in this Section 3.1.9 (each, a "Milestone" and collectively "Milestones"). If Seller fails to meet a Milestone in any material respect by the date on which this Section 3.1.9 requires such Milestone to be achieved, Seller shall deliver to PGE the following no more than ten (10) Business Days after receiving notice from PGE: (i) further information concerning the status of Facility development; (ii) a written report containing Seller's analysis of the reasons behind the failure to meet the original Milestone(s), including a description of the remedial actions that Seller agrees to undertake to complete the Facility by the Commercial Operation Date; and (iii) further assurances that the Facility will be completed consistent with the terms of this Agreement.

(i) Site Control. Seller shall demonstrate site control as of the Effective Date of this Agreement by ownership or lease of real property sufficient to enable Seller to finance, construct and operate the Facility, with any such lease having a term equal to or greater than the Term of this Agreement.

(ii) Pre-COD Security. On or before the 30th day following the Effective Date, Seller shall post the Pre-COD Security in the amount described in Section 9.1;

(iii) Interconnection Agreement. On or before the ninetieth (90th) day after the Effective Date, Seller shall provide to PGE a fully executed copy of the Interconnection Agreement confirming that the Facility will receive [Network Resource Interconnection Service] [Energy Resource Interconnection Service];

(iv) Permits. On or before the [__] day after the Effective Date, Seller shall provide to PGE copies of all Permits in final, nonappealable form;

(v) Transmission Service Agreements. At least three hundred sixty five (365) days prior to Commercial Operation Date, Seller shall present PGE with copies of the transmission service agreement(s) contemplated by Section 1.1.12(v) and Section 3.8.2 (together with associated service tables).

(vi) [***For biomass facilities:*** Within thirty (30) days after the Effective Date, Seller shall have executed a delivered fixed-price fuel supply contract, that is acceptable to PGE (such acceptance not to be unreasonably withheld), for a term equal to or greater than the Term of this Agreement for the supply and delivery of not less than seventy-five percent (75%) of the maximum annual fuel requirements for the Facility, with an annual escalation rate not to exceed one and nine tenths percent (1.9%) per year.

(vii) [***For biomass facilities:*** No later than sixty (60) days prior to the Commercial Operation Date, Seller shall have executed a delivered fixed-price fuel supply contract, that is acceptable to PGE (such acceptance not to be unreasonably withheld), for a term equal to or greater than the Term of this Agreement for the supply and delivery of not less than one hundred percent (100%) of the maximum annual fuel requirements for the Facility, with an annual escalation rate not to exceed one and nine tenths percent (1.9%) per year.]

(viii) Delivery Period Security. By the Commercial Operation Date, Seller shall provide Delivery Period Security required under Section 9.2;

(ix) Commercial Operation Date. Seller shall cause the Facility to achieve Commercial Operation on or before the Guaranteed Commercial Operation Date;

provided, however, that the date for achieving each Milestone (other than the dates for posting Pre-COD Security and Delivery Security) shall be extended on a day for day basis for any delay due solely to (i) PGE's delay in taking, or failure to take, any action required of it hereunder in breach of this Agreement, or (ii) an event of Force Majeure.

(b) When Seller achieves a Milestone, Seller shall provide to PGE documentation reasonably satisfactory to PGE demonstrating completion of the Milestone. Seller shall provide such documentation to PGE within thirty (30) days of such completion but not later than the date specified above for such Milestone. PGE shall acknowledge receipt of the documentation provided under this Section 3.1.9 and shall provide Seller with written acceptance or denial of each Milestone within fifteen (15) Business Days of receipt of the documentation.

(c) Seller shall notify PGE promptly (and in any event within ten (10) Business Days) after Seller becomes aware of information that leads to a reasonable conclusion that a Milestone will not be met. Seller shall convene a meeting with PGE to discuss the situation not later than fifteen (15) Business Days after becoming aware of this information.

(d) If any Milestone (other than a Critical Milestone identified in Section 3.1.9(e)) is not completed on or before the deadline specified for that Milestone in this Section 3.1.9, Seller shall (i) inform PGE of a revised projected date for the achievement of the Milestone, (ii) inform PGE of any impact on the timing of the Commercial Operation Date and on each other Milestone, and (iii) provide PGE with a written report containing Seller's analysis of the reasons behind the failure to meet the original Milestone deadline and describing the remedial actions that the Seller agrees to undertake to ensure the achievement of the Commercial Operation Date by the Scheduled Commercial Operation Date and in any event no later than the Guaranteed Commercial Operation Date. If (1) Seller fails to submit such a report and remedial action plan within 30 days after a Milestone deadline is missed, or (2) Seller timely submits the required report and remedial action plan but thereafter fails to implement the remedial action plan with diligence, or (3) PGE reasonably concludes based on the report and proposed remedial action plan that the Facility is unlikely to achieve Commercial Operation on or before the Guaranteed Commercial Operation Date, a Seller Event of Default shall be deemed to have occurred.

(e) The Milestones described in Sections 3.1.9(a)(i), 3.1.9(a)(v), and 3.1.9(a)(ix) are "Critical Milestones" that are separately addressed in Section 5.1 (Events of Default) and Section 3.1.12 (failure to achieve the Guaranteed Commercial Operation Date).

3.1.10 Notice of Commercial Operation. Seller shall notify PGE not less than five (5) Business Days in advance of the anticipated date of Commercial Operation and shall confirm to PGE in writing when Commercial Operation has been achieved.

3.1.11 Delay Damages. If Commercial Operation is not achieved on or before the Scheduled Commercial Operation Date, Seller shall pay Delay Damages to PGE from and after the Scheduled Commercial Operation Date up to, but not including, the date that the Facility achieves Commercial Operation.

3.1.12 Contract Termination Damages. If Seller does not achieve Commercial Operation on or before the Guaranteed Commercial Operation Date, PGE shall have the right to terminate this Agreement upon ten (10) Days notice to Seller, and Seller shall pay to PGE, as liquidated damages, Contract Termination Damages equal to $200 per kW of Nameplate Capacity (the "Contract Termination Damages") in addition to all Delay Damages paid or payable pursuant to Section 3.1.11.

3.1.13 Damages Invoicing. By the tenth (10th) day following the end of the calendar month in which Delay Damages begin to accrue, as applicable, and continuing on the tenth (10th) day of each calendar month during the period in which Delay Damages accrue (and the following months, if applicable), PGE shall deliver to Seller an invoice showing PGE's computation of such damages and any amount due PGE in respect thereof for the preceding calendar month. No later than ten (10) days after receiving such an invoice and subject to Section 7.2 and Section 7.3, Seller shall pay to PGE, by wire transfer of immediately available funds to an account specified in writing by PGE or by any other means agreed to by the Parties in writing from time to time, the amount set forth as due in such invoice.

3.1.14 PGE's Exclusive Remedies. PGE's exclusive remedies for the Facility's failure to achieve Commercial Operation by the Scheduled Commercial Operation Date or by the Guaranteed Commercial Operation Date, as applicable, shall be (i) the payment by Seller of Delay Damages and, if applicable, Contract Termination Damages, as provided in Sections 3.1.11 and Section 3.1.12, (ii) the right of first offer set forth in Section 3.1.15, and/or (iii) the exercise of step in rights under 9.4.

3.1.15 Right of First Offer.

(a) If PGE terminates this Agreement under Section 3.1.12 or this Agreement is otherwise terminated before the Commercial Operation Date, neither Seller nor Seller's Affiliates may sell, market or deliver any quantity of the Product associated with or attributable to the Facility to a party other than PGE for a period of two (2) years following the termination date of this Agreement, unless before selling, marketing or delivering such Product, or entering into an agreement to sell, market or deliver such Product, Seller or Seller's Affiliates provide PGE with a written offer to sell the Product on terms and conditions materially similar to the terms and conditions contained in this Agreement (including price), and PGE fails to accept such offer within forty-five (45) days of PGE's receipt thereof.

(b) Neither Seller nor Seller's Affiliates may sell or transfer the Facility, or any part thereof, or land rights or interests in the Site so long as the limitations contained in this Section 3.1.15 apply, unless the transferee agrees to be bound by the terms set forth in this Section 3.1.15 pursuant to a written agreement approved by PGE.

(c) Seller shall indemnify and hold PGE harmless from all benefits lost and other damages sustained by PGE as a result of any breach by Seller of its covenants contained within this Section 3.1.15.

3.1.16 Tax Credits. Seller shall bear all risks, financial and otherwise throughout the Term, associated with Seller's or the Facility's eligibility to receive PTCs, ITCs or other tax credits, or to qualify for accelerated depreciation for Seller's accounting, reporting or tax purposes. Seller's obligations under this Agreement shall be effective regardless of whether the sale of Facility Output from the Facility, or the Facility itself, is eligible for, or receives, PTCs, ITCs or other tax credits during the Term.

3.2 Facility Operations.

3.2.1 Commitment. Seller hereby commits one hundred percent (100%) of the Facility Output to PGE as provided under this Agreement, except only in the limited cases where Seller is required to deliver Facility Output to the provider of integration services.

3.2.2 Site Control. At all times during the Term, Seller shall control the Site through ownership or lease and shall provide PGE with prompt notice of any change in control of the Site.

3.2.3 Operation and Maintenance. Seller shall operate and maintain the Facility, the Facility Meter and that portion of the Interconnection Facilities and related equipment and systems owned by Seller in accordance with Prudent Electric Industry Practice in a manner that is reasonably likely to: (i) maximize the Facility Output, and (ii) result in an expected useful life for such facilities of not less than thirty (30) years.

3.2.4 Facility Meter Inspection and Correction. PGE shall have the right to periodically inspect, test, repair and replace the Facility Meter, without PGE assuming any obligations under the Interconnection Agreement. If any of the inspections or tests disclose an error exceeding 0.5 percent, either fast or slow, proper correction, based upon the inaccuracy found, shall be made of previous readings for the actual period during which the Facility Meter rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction shall be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) months, in the amount the Facility Meter shall have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records shall be made in the next monthly billing or payment rendered. Such correction, when made, shall constitute full adjustment of any claim between Seller and PGE arising out of such inaccuracy of metering equipment.

3.2.5 Inspection and Records. During the Term, Seller shall inspect, maintain and repair the Facility and the components thereof in order to maintain such equipment in accordance with Prudent Electric Industry Practice and shall keep records with respect to inspections, maintenance and repairs thereto consistent with Seller's reasonable business judgment. The records of such activities shall be available for inspection by PGE during Seller's regular business hours upon reasonable notice.

3.2.6 Scheduled Maintenance. Seller shall notify PGE, on or before September 1 preceding the Commercial Operation Date and on or before September 1 of each subsequent calendar year, of the Facility's scheduled maintenance for the next calendar year, and shall use commercially reasonable efforts to plan scheduled maintenance (i) to maximize the productive output of the Facility and (ii) not to occur between July and September or between December and February.

3.3 Specified Amounts. On or before September 1 following the Commercial Operation Date and on or before September 1 of each subsequent year during the Delivery Period, Seller shall provide PGE with an updated version of Exhibit C establishing the Specified Amounts for each month during the following calendar year (except for any months outside the Delivery Period).

3.3.1 For the first three (3) years of the Delivery Period, Seller's designated Specified Amounts for each month shall be consistent with [***for solar facilities: a 50% probability of exceedance of forecasted value for such month (based on PV-Syst or equivalent)] [for wind facilities: generation profile associated with a 50% probability of exceedance forecast created by an independent third party based on 5 years of meteorological tower data]***.

3.3.2 Beginning with Specified Amounts updated on September 1, 20[___] for the ***[for solar facilities: fourth (4th)] [for wind facilities: sixth (6th)]*** year of the Delivery Period, and for each year thereafter, the Specified Amounts for each month shall be consistent with ***[for solar facilities: the Project's demonstrated 3-year rolling average generating output for such month] [for wind facilities: the Project's demonstrated 5-year rolling average generating output for such month].*** In the event that the Parties mutually agree that the generating output in any particular month or months during the rolling [3-year] [5-year] period was caused by materially unusual circumstances, the Parties may agree to exclude such month or months from the rolling [three (3) year] [five (5) year] calculation of generating output. The Parties agree that the intent of using the [three (3) year] [five (5) year] rolling output is to develop generation forecasts that accurately reflect the actual generating characteristics of the Facility.

3.4 Energy Delivery. Seller shall schedule and deliver the Product to PGE at the Delivery Point, commencing on ***[specify date for existing Facility] [for new Facility:*** the Commercial Operation Date***]*** and continuing through the end of the Delivery Period, subject to the terms and conditions herein.

3.4.1 Seller shall provide PGE with (i) a rolling generation forecast, updated hourly, for the next fourteen (14) days, (ii) ***[within PGE's Balancing Authority Area:*** a rolling generation forecast for five (5) minute and fifteen (15) minute intervals, updated every five (5) and fifteen (15) minutes respectively, for the next 24 hours*/*, and (iii) an updated hourly generation forecast ninety (90) minutes prior to each delivery hour for the balance of the delivery day ("Generation Forecast"). Each Generation Forecast shall be performed by the Forecasting Agent. The Forecasting Agent shall utilize methodology consistent that the requirements set forth in Exhibit L. At PGE's request, Seller will cause the Forecasting Agent to provide PGE with an Application Program Interface from which PGE can access raw forecasting files. The Forecasting Agent and PGE shall have real time access to information and forecasts concerning the Facility's availability status.

3.4.2 Seller shall schedule the Product in accordance with Section 3.8.4 for delivery to PGE at the Delivery Point in the amount of Energy expected to be generated by the Facility consistent with the Generation Forecast. Seller's Energy delivery Schedule may not intentionally exceed the Generation Forecast in any hour. Seller and PGE agree that the intent of this Section 3.4.2 is for Seller to schedule and deliver Energy resembling actual production for each hour.

3.4.3 Seller shall make reasonable efforts to minimize the delivery of Un-Specified Energy to PGE.

3.4.4 Seller shall provide PGE with a real-time ICCP and EIDE communications link to the Facility metered output.

3.4.5 Seller shall deliver to PGE a quantity of Specified Energy for each monthly On-Peak and Off-Peak period during the Delivery Period in an amount equal to Specified Amounts.

3.4.6 Seller shall be responsible for any costs or charges imposed on or associated with the Product or its receipt provided such costs or charges are either (a) imposed on the Seller's side of the Delivery Point, (b) as a result of the schedule changes, or (c) Seller's actions.

3.4.7 If Seller or its agent reasonably anticipates that Market Index Prices will be less than zero, and Seller expects to receive little or no net payment for its output ("Negative Price Event"), Seller shall have the right, but not the obligation, to suspend part or all of its deliveries, via a reduction in Facility Output, for the anticipated duration of the Negative Price Event. In the event the Market Index Price is less than zero during the Negative Price Event, Seller's obligation to deliver Specified Amount shall be reduced by one (1) MWh and Seller's Minimum Annual Volume shall be reduced by one (1) MWh.

3.5 Environmental Attributes Delivery. Unless excused by Force Majeure, Seller shall convey to PGE all Environmental Attributes, including Bundled RECs, associated with all Specified Energy. Seller represents and warrants that Seller will hold good title, free and clear of any liens or encumbrances, to all Environmental Attributes from the Facility, including all Bundled RECs, conveyed to PGE.

3.5.1 Title to RECs transferred by Seller to PGE pursuant to this Agreement shall be settled through WREGIS.

3.5.2 Unless otherwise specified herein or by written notification by PGE, for each month of the Delivery Period after the Commercial Operation Date, Seller shall deliver and convey the Bundled RECs associated with the Specified Energy delivered to PGE within ten (10) Business Days after the end of the month in which the WREGIS certificates for such Bundled RECs are created. Seller shall be responsible for attaching, in accordance with all current WREGIS operating rules, all available and applicable NERC e-tags pertaining to the corresponding Bundled REC before such Bundled REC is transferred to PGE in WREGIS.

3.5.3 PGE and Seller may mutually agree during the Delivery Period for the purchase and conveyance of Environmental Attributes, including Bundled RECs, associated with any As-Available Energy delivered by Seller to PGE.

3.5.4 Seller shall, by written notice to PGE, offer to sell to PGE any RECs generated by the Facility that are not purchased by or conveyed to PGE pursuant to this Agreement. PGE shall have thirty (30) days in which to accept or decline the offer by notice to Seller. If PGE does not respond within the thirty (30) day period, it shall be deemed to have declined the offer. If PGE declines the offer, Seller may then sell such REC's to a third-party under terms and conditions (including price) no more favorable to the third party than those offered to PGE.

3.6 Carbon Emissions. Seller is responsible for and shall pay for all future costs, if any, whether incurred by Seller or PGE, resulting from any carbon emissions generated by or associated with the Delivered Energy Quantity delivered by Seller to the Delivery Point in accordance with this Agreement. Seller may provide PGE with carbon emissions offsets that are reasonably satisfactory to PGE in lieu of a monetary settlement. Within ten (10) Business Days after PGE's request, Seller shall provide PGE with the carbon emissions data for the Product that is delivered during the Delivery Period.

3.7 PGE's Purchase Obligations. PGE shall purchase and receive the Product delivered by Seller to the Delivery Point in an amount not to exceed the Net Available Capacity for each hour during the Delivery Period in accordance with and subject to the terms of this Agreement. PGE shall pay Seller the applicable price for all Specified Energy, Un-Specified Energy and As-Available Energy delivered to the Delivery Point as set forth in Article 6. PGE shall be responsible for any costs or charges imposed on or associated with the Product or its receipt, provided such costs or charges are imposed at or on PGE's side of the Delivery Point and not the result of Seller's actions, except any EIM charges resulting from Seller's scheduling adjustments described in Sections 3.4.7 and 3.9.4(c).

3.8 Transmission and Scheduling of Energy.

3.8.1 Transmission Capability to PGE's Sink Point. Within sixty (60) Business Days after the Effective Date, PGE will submit a request to designate the Facility as a Network Resource, as defined in Section 1.59 of PGE's Open Access

Transmission Tariff (OATT), following the procedures set forth in Section 30 of PGE's OATT and any associated business practices. Seller shall be responsible for performing all actions necessary for PGE to designate the facility as a Network Resource. Such actions may include, but are not limited to, reimbursing PGE for any necessary studies, funding of any necessary transmission upgrades, additions to or upgrades of Facility equipment, sharing of technical or operational data. If the costs of such actions is reasonably projected to exceed [$_______] (the "Transmission Upgrade Cost Cap"), Seller may terminate this Agreement by providing notice to PGE; provided, however, that such termination shall be void if, within thirty (30) days after PGE receives notice of termination, PGE agrees in its sole discretion to bear costs in excess of the Transmission Upgrade Cost Cap. Once the Facility is successfully designated as a Network Resource, PGE will arrange, be responsible for, and make available transmission service from the Delivery Point to the designated sink point. If PGE, as a Transmission Provider, determines that due to insufficient transfer capability, consistent with PGE's OATT requirements, the requested Network Resource designation cannot be achieved, regardless of any proposed upgrades, by the Guaranteed Commercial Operation Date for the Net Available Capacity then PGE may terminate this Agreement by providing notice to Seller.

3.8.2 Transmission Service Agreement. No later than [__] days after Effective Date, Seller shall deliver to PGE copies of transmission service agreements with associated service tables between Seller and its Transmission Provider for transmission service between the Facility's point of interconnection and the Delivery Point for the entire Net Available Capacity during the entire Delivery Period in the form of either: i) a fully executed Precedent Transmission Service Agreement for Long-Term Firm Point-To-Point Service, or ii) a fully executed copy of a Long-Term Firm Point-To-Point Service Transmission Service Agreement, in each case commencing no later than the Commercial Operation Date. Seller may not satisfy the requirements of this Section 3.8.2 by acquiring transmission rights currently held by a third party, or its affiliates, engaged in the development of a Qualifying Facility if such party or its affiliates has contractual obligations to PGE for the delivery of energy under PGE's Tariff Schedule 201 or Schedule 202, unless it can be reasonably determined that the transmission rights are in excess of such third party's contractual obligations to PGE.

Seller shall pay for and maintain Long-Term Firm Point-to-Point Transmission Service (as such term is defined in its Transmission Provider's Open Access Transmission Tariff that is posted on OASIS) for delivery of Energy from the Facility's point of interconnection to the Delivery Point for the entire Net Available Capacity during the entire Delivery Period, commencing on the Commercial Operation Date. Seller shall be responsible for all transmission costs for delivery of the Product to the Delivery Point, including but not limited to all Ancillary Services costs and integration service costs required by the Transmission Provider(s). Seller's transmission agreement shall have a term of no less than five (5) years. In the event Seller's transmission agreement expires prior to the end of the Delivery Period and is not eligible for reservation priority rights, Seller shall acquire replacement transmission agreement(s) consistent with the requirements set forth in this Section 3.8.2. A copy of Seller's long-term transmission plan, as of the Effective Date, is attached to this Agreement as Exhibit J. Within five (5) days of execution of any new or replacement Transmission Service Agreement(s), Seller shall provide PGE with a copy of Seller's transmission agreement and generation interconnection agreements, and the Parties shall amend Exhibit J to include copies of such agreements.

3.8.3 Seller to Designate Forecasting and Scheduling Agents. At least ten (10) days before it begins to Schedule Test Energy under this Agreement, Seller shall engage at its expense a third-party Scheduling Agent (the "Scheduling Agent") and a third-party forecasting agent (the "Forecasting Agent"), subject in each case to PGE's prior approval. The Scheduling Agent shall perform Seller's pre-scheduling and Scheduling obligations under this Section 3.8.3 based exclusively on forecasts supplied by the Forecasting Agent.

3.8.4 Scheduling Procedure. Seller shall comply with the following "Scheduling Procedure" during the Delivery Period:

(a) "Pre-Scheduled Energy" means Product scheduled under the following conditions for each day during the Delivery Period:

(i) Seller shall communicate to PGE's Pre-schedule Desk, as directed by PGE, the Facility's Generation Forecast to be delivered at the Delivery Point for the Pre-Scheduling Day(s) by 5:00 a.m. PPT of the customary WECC Pre-Scheduling Day for each day during the Delivery Period;

(ii) Seller shall schedule the Energy by submitting a NERC e-Tag ("e-Tags") prior to 1:00 p.m. PPT of the applicable WECC Pre-Scheduling Day for all hours of the applicable delivery day(s); and

(iii) Seller shall schedule the Energy with e-Tags according to prevailing WECC Pre-scheduling provisions and protocols and the terms of this Agreement. Seller shall schedule the Facility as the identified e-Tag source. Seller may not net or otherwise combine schedules from resources other than the Facility, except as necessary for Ancillary Services, subject to the terms of this Agreement.

(b) Seller shall not schedule any Energy to be delivered to PGE pursuant to this Agreement using a Dynamic or Pseudo-Tie e-Tag as such terms are defined and used by NERC.

(c) Seller may make adjustments to the Pre-Scheduled Energy scheduled from the Facility each hour in Real-Time ("Real-time Adjustments"). If Seller elects to make Real-time Adjustments, Seller will:

(i) communicate to PGE's Real-time Desk, as directed by PGE, its intent to adjust the Pre-Scheduled Energy no later than 120 minutes prior to the flow hour; and

(ii) submit and receive approval of e-Tag adjustment no later than sixty (60) minutes prior to the flow hour. Seller will make all NERC e-Tag adjustments. Seller's e-tag shall match the adjustment communicated to PGE pursuant to Section 3.8.4(c)(i). Seller shall be responsible for any costs, charges, or fees associated with deviations to the e-tag after sixty (60) minutes prior to the flow hour.

(d) In the event that the regional market design, Balancing Authority, Area,Reliability Entity or Regulatory Entity (e.g. PGE Transmission, BPA Transmission, WECC, NERC, Peak RC, FERC) causes PGE's scheduling practices to change after the Effective Date, PGE shall have the right but not the obligation to update the Scheduling Procedure by giving [__ (__)] days prior written notice to Seller of such update.

3.8.5 Authorized Scheduling Representatives. Each Party shall designate by notice to the other Party its authorized representatives responsible for Scheduling. The initial authorized representatives responsible for Scheduling are set forth on Exhibit A.

3.8.6 Maximum Delivery Amounts. Seller shall sell and deliver, and PGE shall buy and receive, the Delivered Energy Quantity delivered pursuant to this Agreement, up to the Net Available Capacity. Seller shall not increase (i) the Facility's ability to deliver Facility Output, (ii) Nameplate Capacity, or (iii) Net Available Capacity through any means, including but not limited to replacement or modification of equipment or related infrastructure.

3.8.7 Title to Energy. Title to Energy shall pass to PGE at the Delivery Point.

3.8.8 Reliability Entity Curtailment. PGE shall not be liable to Seller if curtailment of Scheduled or unscheduled Energy is due to the action of a Reliability Entity. Seller shall pay PGE the replacement cost for such Energy. The replacement cost during a Reliability Entity curtailment shall be the greater of zero or the amount calculated as: ((Market Index Price – Fixed Price) multiplied by curtailed Energy based on the Facility's potential generation for periods of the Reliability Entity curtailment. The Forecasting Agent shall calculate the potential generation during periods of the Reliability Entity curtailment.

3.8.9 Approval for Seller to Join Organized Markets. During the Term of this Agreement, Seller shall not register as a participating resource in any energy imbalance market, independent system operator market or other organized market without prior written consent from PGE, which consent may be granted in PGE's sole discretion.

3.9 Measurement and Transfer of RECs.

Bundled RECs shall be deemed sold and delivered to PGE under this Agreement as they are produced and measured by the Facility Meter. Title to such Bundled RECs shall pass to PGE when generated. PGE shall own or be entitled to claim all Bundled RECs during the Term (including any value in the ownership, use or allocation of Bundled RECs created by legislation or regulation after the Effective Date). The Facility Meter shall serve as the record source for purposes of calculating, certifying, and auditing Bundled RECs. Seller shall cause the Facility to implement all necessary generation information communications in WREGIS, and report generation information to WREGIS pursuant to a WREGIS-approved meter that is dedicated to the Facility and only the Facility. Seller shall cause delivery and transfer of the Bundled RECs to PGE's WREGIS account to be perfected in accordance with WREGIS rules. Seller shall hold the Bundled RECs in trust for PGE until such delivery and transfer is perfected. Each Party shall take such steps and further actions as may be required by WREGIS or applicable Law in order to effect and confirm the sale and delivery of the Bundled RECs to PGE for all purposes.

3.10 Access. Upon reasonable prior notice and subject to the prudent safety requirements of Seller, and Law relating to workplace health and safety, Seller shall provide PGE and its authorized agents, employees and inspectors ("PGE Representatives") with reasonable access to the Facility: (a) for the purpose of reading or testing metering equipment, (b) as necessary to witness any acceptance tests, (c) to provide tours of the Facility to customers and other guests of PGE (not more than twelve (12) times per year), (d) for purposes of implementing Section 17.2 (Audit Rights), and (e) for other reasonable purposes at the reasonable request of PGE. PGE shall release Seller against and from any and all Liabilities resulting from actions or omissions by any of the PGE Representatives in connection with their access to the Facility, except to the extent that such damages are caused by the intentional or negligent act or omission of Seller.

3.11 Facility Remedial Action Scheme. To the extent the Facility is not otherwise subject to Seller's Transmission Provider's Remedial Action Scheme, PGE shall have the right to utilize the Facility for PGE's Transmission Provider's Remedial Action Scheme. Before the Commercial Operation Date, Seller shall at its expense make necessary arrangements, including installing any required equipment and entering into any applicable agreements, to enable the Facility to participate in a Remedial Action Scheme for PGE's benefit.

ARTICLE 4
FORCE MAJEURE

4.1 Definition.

"Force Majeure" means any event or circumstance, or combination of events or circumstances, that meets all of the following criteria:

(a) arises after the Effective Date,

(b) was not caused by and is unforeseeable and beyond the reasonable control of the Party claiming the Force Majeure Event,

(c) is unavoidable or could not be prevented or overcome by the reasonable efforts and due diligence of the Party claiming the Force Majeure Event, and

(d) either (i) as with respect to PGE as the impacted Party, has an impact which will actually, demonstrably and adversely affect PGE's ability to perform its obligations (other than payment obligations) in accordance with the terms of the Agreement or (ii) as with respect to Seller as the impacted Party, has an impact which will actually, demonstrably and adversely affect Seller's ability to perform its obligations in accordance with the terms of the Agreement.

4.2 Provided they meet all of the criteria described above, Force Majeure Events may include the following: acts of God, natural disasters, wildfires, earthquakes, tornadoes, lightning, floods, civil disturbances, riots, war and military invasion, physical damage to the Facility caused by third parties who are not subcontractors or representatives, employees or agents of the impacted Party; acts of the public enemy; blockade; acts of terrorism; insurrection, riot or revolution; sabotage or vandalism; embargoes, and actions of a Governmental Authority (other than in respect of or in relation to or resulting from Seller's non-compliance with Laws). Notwithstanding anything in the foregoing to the contrary, in no event shall any of the following constitute a Force Majeure Event: (i) strikes, and other labor disputes (including collective bargaining disputes and lockouts) of the labor force under the control of the Party claiming the Force Majeure Event or its Affiliates or with respect to the work completed by a subcontractor of Seller on the Site unless the strike is part of a more widespread or general strike extending beyond the Party, Affiliate or subcontractor; (ii) cost or shortages of labor or manpower; (iii) unavailability, late delivery, failure, breakage or malfunction of equipment or materials unless there is an independent, identifiable Force Majeure Event causing such condition; (iv) events that affect the cost of equipment or materials; (v) economic hardship (including lack of money) of any entity or its Affiliates or their respective subcontractors or suppliers; (vi) delays in transportation (including delays in clearing customs) other than delays in transportation resulting from accidents or closure of roads or other transportation route by Governmental Authorities; (vii) any weather conditions which are not defined above as Force Majeure Events; (viii) actions of a Governmental Authority in respect of or in relation to or resulting from Seller's compliance or non-compliance with Laws; (ix) any failure by Seller to obtain and maintain any Permit it is required to obtain or maintain hereunder; (x) any other act, omission, delay, default or failure (financial or otherwise) of a subcontractor of Seller or other personnel of Seller; (xi) loss of PGE's markets; (xii) PGE's inability economically to use or resell the Product purchased under this Agreement; (xiii) the loss or failure of Seller's fuel supply or equipment; (xiv) either Party's inability to pay when due any amounts owed under this Agreement; or (xv) Seller's ability to sell the Product at a price greater than the Fixed Price. Seller may not raise a claim of Force Majeure with respect to the unavailability of Energy or Bundled RECs from the Facility based on any of the following: (i) routine or scheduled maintenance of the Facility; (ii) any unscheduled outage undertaken to address normal wear and tear of the Facility during the Term; (iii) any outage caused by Seller's failure to design, construct, operate or maintain the Facility consistent with Prudent Electric Industry Practice; (iv) changes in climactic conditions; (v) environmental obstructions caused by events or circumstances that may impact the Facility's generation output but without causing a Facility outage (e.g., forest fire or volcanic eruption located outside of the Facility site); (vi) financial inability to perform; (vii) changes in cost or availability of materials, equipment, or services; or (ix) strikes or labor disturbances involving the employees of Seller or any of its subcontractors unless such strike or labor disturbance has a national impact making it impossible for Seller to perform its obligations with respect to the Facility. .Occurrence and Notice.

To the extent either Party is prevented by Force Majeure from carrying out, in whole or part, its obligations under this Agreement and such Party (the "Claiming Party") gives notice and details of the Force Majeure to the other Party as soon as practicable, then, unless the terms of this Agreement specify otherwise, the Claiming Party shall be excused from the performance of its obligations related thereto. The Claiming Party shall remedy the Force Majeure with all reasonable dispatch. The non-Claiming Party shall not be required to perform its obligations to the Claiming Party that correspond to the obligations of the Claiming Party that are excused by Force Majeure.

4.3 Obligations.

No Party shall be relieved by operation of this Article 4 of any liability to pay for Products delivered hereunder or to make payments then due or which the Party is obligated to make with respect to performance which occurred prior to the Force Majeure.

4.4 Right to Terminate.

If a Force Majeure event prevents a Party from performing its material obligations under this Agreement for a period exceeding 180 consecutive days before the Commercial Operation Date or, after the Commercial Operation Date, for a period exceeding 240 consecutive days (despite the affected Party's effort to take all reasonable steps to remedy the effects of the Force Majeure with all reasonable dispatch), then the Party not affected by the Force Majeure event, with respect to its obligations under this Agreement, may terminate this Agreement by giving 10 days' prior notice to the other Party. Upon such termination, neither Party will have any liability to the other with respect to periods following the effective date of such termination, except for the right of first offer set forth in Section 3.1.15 and as otherwise expressly provided in this Agreement; provided, however, that this Agreement will remain in effect to the extent necessary to facilitate the settlement of all liabilities and obligations arising under this Agreement before the effective date of such termination.

ARTICLE 5
EVENTS OF DEFAULT; REMEDIES

5.1 Events of Default.

An “Event of Default” shall mean, with respect to a Party (a “Defaulting Party”), the occurrence of any of the following:

5.1.1 in the case of the Seller, the occurrence of a Material Adverse Change with respect to Seller or its Guarantor; provided, such Material Adverse Change shall not be considered an Event of Default if Seller establishes, delivers to PGE and maintains for so long as the Material Adverse Change is continuing, Performance Assurance in an amount equivalent to the Termination Payment as determined under Section 5.3;

5.1.2 the failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within ten (10) Business Days after written notice;

5.1.3 any representation or warranty made by such Party in this Agreement is false or misleading in any material respect when made or when deemed made or repeated if such inaccuracy is not cured within thirty (30) days after the non-defaulting Party gives the defaulting Party a notice of default;

5.1.4 if a Party fails to deliver or receive Product as required by this Agreement, and such failure occurs for (i) more than five (5) consecutive Days, or (ii) ten (10) Days out of any Contract Year (it being the intent of the Parties that other failures to deliver or receive Product in any Contract Year will be governed by Article 6);

5.1.5 such Party becomes Bankrupt;

5.1.6 the occurrence of a Merger Event with respect to such Party or its Guarantor that is not cured within ten (10) Business Days of notice by the other Party;

5.1.7 in the case of Seller, Seller's failure to establish, maintain, extend or increase Performance Assurance when required pursuant to this Agreement;

5.1.8 ***[Note to bidders: Applicable to baseload facilities.]*** commencing on the Commercial Operation Date, Seller's failure to deliver the Minimum Annual Volume to Buyer during two (2) out of three (3) calendar years during the Delivery Period;

5.1.9 ***[Note to bidders: Applicable to intermittent facilities.]*** beginning with the second full calendar year following the calendar year in which the Commercial Operation Date has occurred, Seller's failure to maintain a minimum Mechanical Availability Percentage for the Facility of [ninety-seven percent (97%)] for any two (2) out of three (3) calendar years on a rolling basis. The Mechanical Available Percentage of the Facility shall be determined by Seller by dividing the total Operational Hours for such calendar year ***[non-solar resources:*** by the total number of hours in the calendar year***] [solar resources:*** by the total number of daylight hours in the calendar year.***]*** On or before January 31st of each year, Seller shall provide PGE written documentation, which shall be subject to audit by PGE, to verify or otherwise substantiate Seller's calculation of the Mechanical Available Percentage of the Facility for the prior calendar year. The operational hours for the Facility shall be the hours that the Facility is potentially capable of producing power at Nameplate Capacity regardless of actual weather conditions or season, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the point of interconnection with the Transmission Provider. The methodology for calculating Operational Hours and the resulting Mechanical Availability Percentage is set forth in Exhibit N ***[Note to bidders: the Parties would agree to a more detailed methodology consistent with this Section 6.1.9 and attached it as Exhibit N]***;

5.1.10 in the case of Seller, the occurrence of a Letter of Credit Default;

5.1.11 with respect to Seller's Guarantor, if any, the occurrence of a Guaranty Default;

5.1.12 in the case of Seller, the occurrence of an Event of Default under Section 3.1.9(d);

5.1.13 the failure to perform any material covenant or obligation set forth in this Agreement for which an exclusive remedy is not provided in this Agreement and which is not addressed in any other Event of Default, if the failure is not cured within thirty (30) days after the Non-Defaulting Party gives the Defaulting Party notice of the default; provided that if such default is not reasonably capable of being cured within the thirty (30) day cure period but is reasonably capable of being cured within a sixty (60) day cure period, the Defaulting Party will have such additional time (not exceeding an additional thirty (30) days) as is reasonably necessary to cure, if, prior to the end of the thirty (30) day cure period the Defaulting Party provides the Non-Defaulting Party a remediation plan, the Non-Defaulting party approves such remediation plan, and the Defaulting Party promptly commences and diligently pursues the remediation plan.

5.2 Declaration of an Early Termination Date and Calculation of Settlement Amounts.

5.2.1 Early Termination Date. If an Event of Default with respect to a Defaulting Party shall have occurred at any time during the Term and be continuing, the other Party (the "Non-Defaulting Party") shall have the right to (i) designate a day, no earlier than the day such notice is effective and no later than twenty (20) days after such notice is effective, as an early termination date ("Early Termination Date") on which to liquidate, terminate, and accelerate all amounts owing between the Parties, (ii) withhold any payments due to the Defaulting Party under this Agreement, and (iii) suspend performance. If an Early Termination Date has been designated, the Non-Defaulting Party shall calculate, in a commercially reasonable manner, its Gains or Losses and Costs resulting from the termination of this Agreement as of the Early Termination Date. The Non-Defaulting Party shall calculate the Termination Payment payable hereunder in accordance with Section 5.2.2 below.

5.2.2 Calculation of Settlement Amounts. The Gains or Losses resulting from the termination of this Agreement shall be determined by calculating the amount that would be incurred or realized to replace or to provide the economic equivalent of the remaining payments or deliveries in respect of this Agreement. The Gains or Losses shall be calculated for a period equal to the remaining Term ("Settlement Period"). The quantity of Energy in each month of the Settlement Period shall be equal to the Initial Specified Amount for such month ("Settlement Energy"). The Non-Defaulting Party (or its agent) may determine its Gains and Losses by reference to information either available to it internally or supplied by one or more third parties including, without limitation, quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets. Third parties supplying such information may include, without limitation, dealers in the relevant markets, end-users of the relevant product, information vendors and other sources of market information. However, it is expressly agreed that (a) a Party shall not be required to enter into a replacement agreement in order to determine the Termination Payment and (b) a Party's Gains, Losses or Costs will in no event include any penalties, ratcheted demand or similar charges.

5.3 Termination Payment.

The "Termination Payment" shall equal the sum of all amounts owed by the Defaulting Party to the Non-Defaulting Party under this Agreement, including a Settlement

Amount (if any), less any amounts owed by the Non-Defaulting Party to the Defaulting Party determined as of the Early Termination Date.

5.4 Notice of Payment of Termination Payment.

As soon as practicable after calculating the Termination Payment, the Non-Defaulting Party shall give notice to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to or due from the Non-Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. If the Termination Payment is due from the Defaulting Party, the Termination Payment shall be made by the Defaulting Party within two (2) Business Days after such notice is effective. Notwithstanding any provision to the contrary contained in this Agreement, the Non-Defaulting Party shall not be required to pay to the Defaulting Party any amount under this Article 5 until the earlier of (i) the date the Non-Defaulting Party receives confirmation satisfactory to it in its reasonable discretion (which may include an opinion of its counsel) that all other obligations of any kind whatsoever of the Defaulting Party to make any payments to the Non-Defaulting Party under this Agreement or otherwise which are due and payable as of the Early Termination Date have been fully and finally performed, or (ii) 180 days after the Early Termination Date.

5.5 Disputes with Respect to Termination Payment.

If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment in whole or in part, the Defaulting Party shall, within ten (10) Business Days of receipt of Non-Defaulting Party's calculation of the Termination Payment provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute; provided, however, that if the Termination Payment is due from the Defaulting Party, the Defaulting Party shall pay the non-disputed amount of the Termination Payment as provided in Section 5.4 and transfer, within two (2) Business Days, Performance Assurance to the Non-Defaulting Party in an amount equal to the disputed amount of the Termination Payment.

5.6 Closeout Setoffs.

After calculation of a Termination Payment in accordance with Section 5.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to set off against such Termination Payment any amounts due and owing by the Defaulting Party to the Non-Defaulting Party under any other agreements, instruments or undertakings between the Defaulting Party and the Non-Defaulting Party. The remedy provided for in this Section 5.6 shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which the Non-Defaulting Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

5.7 Suspension of Performance.

Notwithstanding any other provision of this Agreement, if an Event of Default shall have occurred and be continuing, the Non-Defaulting Party, upon written notice to the Defaulting Party, shall have the right (i) to suspend performance under this Agreement; provided, however, in no event shall any such suspension continue for longer than ten (10)

Business Days with respect to any single Scheduled Product unless an early Termination Date shall have been declared and notice thereof pursuant to Section 5.2 given, and (ii) to the extent an Event of Default shall have occurred and be continuing to exercise any remedy available at law or in equity.

5.8 Post-Termination PURPA Status. If this Agreement is terminated because of a default by Seller, and Seller has subsequently remedied the default after such termination, neither Seller nor any Affiliate of Seller, nor any successor to Seller with respect to the ownership of the Facility or Site, on whose behalf Seller acts herein as agent, may thereafter require or seek to require PGE to make any purchases from the Facility or any electric generation facility constructed on the Site under PURPA, or any other Law, under terms and conditions different from those set forth in this Agreement (including rates higher than those set forth in this Agreement) for any periods that would have been within the Term had this Agreement remained in effect. Seller, on behalf of itself and on behalf of any other entity on whose behalf it may act, hereby waives its rights to require PGE to do so. On or before the Effective Date, the Parties shall execute and record, in the appropriate real property records of the counties in which the Facility or Site is situated, and any federal agency as applicable, a memorandum in form acceptable to PGE to provide constructive notice to third parties of Seller's agreements under this Section 5.8. In no event will PGE be require to make any purchases from the Facility or any electric generation facility constructed on the Site in the event the default that caused the termination is still in effect.

ARTICLE 6
REMEDIES FOR FAILURE TO DELIVER/RECEIVE

6.1 Seller Failure to Deliver Specified Energy. If Seller fails to deliver Specified Energy and the associated Environmental Attributes, including Bundled RECs, in an amount equal to the Specified Amount for any monthly On-Peak and Off-peak period, and such failure is not excused by Force Majeure, or by PGE's breach of this Agreement, Seller shall owe PGE an amount as calculated below:

6.1.1 Seller shall owe PGE an amount for such deficiency equal to the positive difference (if any) of the applicable Market Index Settlement Price minus the Fixed Price multiplied by the positive difference (if any) of the Specified Amount for the applicable monthly On-Peak and Off-peak period minus the Specified Energy delivered during that monthly On-Peak and Off-peak period; and

6.1.2 Seller shall owe PGE an amount for such deficiency should the replacement energy procured by PGE as a result of Seller's failure to deliver the Specified Amount result in incremental Carbon Emissions costs to PGE, consistent with Section 3.6,

6.1.3 Seller shall owe PGE an amount for such deficiency should the replacement energy procured by PGE as a result of Seller's failure to deliver the Specified Amount result in incremental ancillary services and transmission costs; and

6.1.4 Seller shall be obligated to settle any shortfall in the delivery of Environmental Attributes (including Bundled RECs) as follows:

(a) Seller shall, within 120 days after the end of the shortfall month, deliver an equivalent amount of Qualifying Replacement RECs that are generated in the same calendar year; or

(b) If Seller elects not to deliver an equivalent amount of Qualifying Replacement RECs under Section 6.1.4(a) and PGE elects in its sole discretion to purchase Qualifying Replacement RECs, Seller shall owe PGE the price that PGE actually pays for Qualifying Replacement RECs; or

(c) If Seller elects not to deliver an equivalent amount of Qualifying Replacement RECs under Section 6.1.4(a) and PGE does not elect, in its sole discretion, to purchase replacement bundled RECs under subpart (b), Seller shall owe PGE the Qualifying Replacement REC Price identified by PGE multiplied by the number of Bundled RECs Seller failed to deliver. PGE shall use commercially reasonable efforts to mitigate the amount owed by Seller under this Section 6.1.4(c).

6.1.5 Any amount owed by the Seller to PGE under this Section 6.1shall be netted against PGE's payment obligation for the month pursuant to Section 6.5 below.

6.1.6 An example illustrating the calculation of amounts due to PGE under this Section 6.1 under certain stated assumptions is set forth in Exhibit I.

6.2 PGE's Failure to Accept. If PGE fails to accept any part of the Product that is scheduled in accordance with Section 3.8, and Seller is ready willing and able to deliver to the Delivery Point, and such failure is not excused by a reliability or transmission constraint, Force Majeure or by Seller's failure to perform, then PGE shall owe Seller an amount for such deficiency equal to the positive difference between the applicable purchase price as set forth in Section 7.1 for the amount of Product PGE fails to accept minus the Sales Price associated with the amount of Product PGE fails to accept. Any such amount owed by PGE to Seller shall be added to the calculation of PGE's payment obligation for the month pursuant to Section 7.1. For each MWh of Product not accepted by PGE pursuant to this Section 6.2, Seller's obligation to deliver the Specified Amount shall be reduced by one (1) MWh, and Seller's Minimum Annual Volume shall be reduced by one (1) MWh. An example illustrating the calculation of amounts due to Seller under this Section 6.2 under certain stated assumptions is set forth in Exhibit I.

6.3 Duty to Mitigate.

Each Party agrees that it has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this Agreement.

6.4 Acknowledgement of the Parties.

The Parties stipulate that the payment obligations set forth in this Article 6 are reasonable in light of the anticipated harm and the difficulty of estimation or calculation of actual damages and waive the right to contest such payments as an unreasonable penalty. If either Party fails to pay undisputed amounts in accordance with this Article 6 when due, the other Party shall have the right to: (i) suspend performance until such amounts plus interest at the Interest Rate have been paid, and/or (ii) exercise any remedy available at Law or in equity to enforce payment of such amount plus interest at the Interest Rate. With respect to the amount of such damages only, the remedy set forth in this Article 6 shall be the sole and exclusive remedy of the Parties for the failure of Seller to sell and deliver, and PGE to purchase and receive the Product and all other damages and remedies are hereby waived. Disagreements with respect to the calculation of damages pursuant to this Article 6 may be submitted by either Party for resolution in accordance with ARTICLE 18 and with applicable Law.

6.5 Survival.

The provisions of this Article 6 shall survive the expiration or termination of this Agreement for any reason.

ARTICLE 7
PAYMENT AND NETTING

7.1 Billing Period.

Unless otherwise specifically agreed upon by the Parties, the Month shall be the standard period for all payments under this Agreement (other than for Seller or PGE failure under Sections 6.1 and 6.2 respectively and for termination under Section 5.4). On or before the tenth (10th) day of each Month, each Party shall render to the other Party an invoice for the payment obligations, if any, incurred hereunder during the preceding Month.

7.2 Timeliness of Payment.

Unless otherwise agreed by the Parties, all invoices under this Agreement shall be due and payable in accordance with each Party's invoice instructions on or before the later of the twentieth (20th) day of each Month, or the tenth (10th) day after receipt of the invoice or, if such day is not a Business Day, then on the next Business Day. Each Party will make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any amounts not paid by the due date will be deemed delinquent and will accrue interest at the Interest Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

7.3 Disputes and Adjustments of Invoices.

A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice, rendered under this Agreement or adjust any invoice for any arithmetic or computational error within twenty-four (24) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment shall be made within ten (10) Business Days of such resolution along with interest accrued at the Interest Rate from and including the due date to but excluding the date paid. Inadvertent overpayments shall be returned upon request or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Interest Rate from and including the date of such overpayment to but excluding the date repaid or deducted by the Party receiving such overpayment. Any dispute with respect to an invoice is waived unless the other Party is notified in accordance with this Section 7.3 within twenty-four (24) months after the invoice is rendered or any specific adjustment to the invoice is made. If an invoice is not rendered within twelve (12) months after the close of the Month during which performance of this Agreement occurred, the right to payment for such performance is waived.

7.4 Netting of Payments.

The Parties hereby agree that they shall discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts owed by one Party to the other Party during the monthly billing period under this Agreement, including any related damages calculated pursuant to ARTICLE 5 (unless one of the Parties elects to accelerate payment of such amounts as permitted by Section 5.2.1), interest, and payments or credits, shall be netted so that only the excess amount remaining due shall be paid by the Party who owes it.

7.5 Payment Obligation Absent Netting.

If no mutual debts or payment obligations exist and only one Party owes a debt or obligation to the other during the monthly billing period, including, but not limited to, any related damage amounts calculated pursuant to Article 5, interest, and payments or credits, that Party shall pay such sum in full when due.

ARTICLE 8
LIMITATIONS

8.1 Essential Purposes. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES OF THIS AGREEMENT.

8.2 Exclusive Remedies. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED.

8.3 Direct Damages. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED.

8.4 No Consequential Damages. EXCEPT AS EXPRESSLY PROVIDED IN THIS AGREEMENT, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE.

8.5 Causes Disregarded. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS IMPOSED IN THIS AGREEMENT ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

8.6 Liquidated Damages. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID UNDER THIS AGREEMENT ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT, AND THE DAMAGES CALCULATED UNDER THIS AGREEMENT CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE 9
CREDIT AND COLLATERAL REQUIREMENTS

9.1 Pre-COD Security.

9.1.1 Amount of Pre-COD Security. On or before the date specified in Section 3.1.9(a)(i), Seller shall post and maintain Performance Assurance in favor of PGE, equal in each case to $200 per kW of Nameplate Capacity (the "Pre-COD Security"). Seller shall ensure that any Person providing a guaranty for Seller shall provide within five (5) Business Days from receipt of a written request from PGE all reasonable financial records necessary for PGE to confirm Seller and/or the guarantor satisfies the Credit Requirements.

9.1.2 Use of Pre-COD Security to Pay Delay Damages. If the Commercial Operation Date occurs after the Expected Commercial Operation Date and Seller has failed to pay any Delay Damages when due under Section 3.1.13, PGE shall be entitled to and shall draw upon the Pre-COD Security an amount equal to the Delay Damages until such time as the Pre-COD Security is exhausted. PGE shall also be entitled to draw upon the Pre-COD Security for Contract Termination Damages.

9.1.3 Termination of Pre-COD Security. Seller shall no longer be required to maintain the Pre-COD Security (or the remaining balance thereof) after the Commercial Operation Date, if at such time no damages are owed to PGE under this

Agreement. PGE shall release the Pre-COD Security to Seller upon PGE's receipt of the Delivery Period Security under Section 9.2. However, as of the Commercial Operation Date, Seller may elect to apply the Pre-COD Security toward the Delivery Period Security required by Section 9.2, including by the automatic continuation (as opposed to the replacement) thereof.

9.2 Delivery Period Security.

9.2.1 Duty to Post Delivery Period Security. Beginning on the Commercial Operation Date, at any time during the Term when Seller does not satisfy the Credit Requirements, Seller shall post and maintain Performance Assurance in favor of PGE as provided in this Section 9.2 (the "Delivery Period Security"). Seller and any party providing a guaranty for Seller shall provide within five (5) Business Days from receipt of a written request from PGE all reasonable financial records necessary for PGE to confirm Seller and/or the guarantor satisfies the Credit Requirements.

9.2.2 Amount of Delivery Period Security. The amount of the Delivery Period Security required by Section 9.2.1 shall be sufficient to provide replacement power and Qualifying Replacement RECs under this Agreement for the next 60 calendar months. This amount shall be deemed equal to the positive difference between (a) the forward power prices at Mid-Columbia as determined by PGE in good faith using information from a commercially reasonable independent source (e.g., indicative of the most relevant ICE forward price curve for the Mid-Columbia) for the next 60 calendar months (or, if the remaining Term is less than 60 calendar months, then for the remainder of the Term), multiplied by [__] percent ([__]%), plus the Qualifying Replacement REC Price, plus the costs of transmitting such replacement energy from Mid-Columbia to the Delivery Point, minus (b) the Fixed Price, multiplied by the MWhs that would be delivered for such period under this Agreement (based on the Specified Amount set forth on Exhibit C for that period); provided, however, that the Delivery Period Security shall in no event be less than an amount equal to the Bundled RECs that would be delivered for the next 18 months (based on the Specified Amount set forth on Exhibit C for that period) multiplied by the Qualifying Replacement REC Price.

9.2.3 Adjustments to Delivery Period Security. On or before January 31st of each year during the Term, Seller shall (a) adjust the Delivery Period Security by increasing or decreasing the Delivery Period Security to correspond to the amount reasonably determined by PGE under Section 9.2.2, and (b) deliver such adjusted Delivery Period Security to PGE. PGE shall notify Seller of the determination of such amount on or before the preceding December 1 of each calendar year.

9.3 Grant of Security Interest/Remedies.

To secure its obligations under this Agreement and to the extent Seller delivers Performance Assurance, Seller hereby grants to PGE a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, PGE, and Seller agrees to take such action as PGE reasonably requires in order to perfect PGE's first-priority security interest in, and lien on (and right of setoff against), such collateral and any and all proceeds resulting therefrom or from the liquidation thereof.

Upon or at any time after the occurrence and during the continuation of an Event of Default or an Early Termination Date affecting the Seller, PGE may do any one or more of the following: (i) exercise any of the rights and remedies of a secured party with respect to all Performance Assurance, including any such rights and remedies under Law then in effect; (ii) exercise its rights of setoff against any and all property of the Seller in the possession of PGE or its agent; (iii) draw on any outstanding Letter of Credit issued for its benefit; and (iv) liquidate all Performance Assurance then held by or for the benefit of PGE free from any claim or right of any nature whatsoever of Seller, including any equity or right of purchase or redemption by Seller. PGE shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Seller's obligations under this Agreement (the Seller remaining liable for any amounts owing to PGE after such application), subject to PGE's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

9.4 Step-In Rights.

9.4.1 Notice. At any time after the Facility has achieved Commercial Operation, and if at such time PGE has the right to terminate this Agreement due to an Event of Default, then prior to and in lieu of exercising the termination right related to such Event of Default, PGE shall have the right, but not the obligation, to assume control of and operate the Facility as agent for Seller under the terms and conditions set forth herein ("Step-In Rights"). If PGE contemplates exercising its Step-In Rights under this Section 9.4, PGE shall give Seller at least ten (10) Days' advance notice thereof.

9.4.2 Books and Records. After notice is given and during the relevant notice period, Seller shall collect and have available at a convenient central location at the Facility and shall make available to PGE, at PGE's request, all documents, contracts, books, manuals, reports, records, plans, tools, equipment, inventories and supplies necessary or convenient to construct, operate and maintain the Facility in accordance with Prudent Electric Industry Practice.

9.4.3 Application of Proceeds. During any period that PGE is in control of and operating the Facility pursuant to exercise of its Step-In Rights, PGE shall perform and comply with all of the obligations of Seller under this Agreement and shall apply the Fixed Price that Seller would otherwise be entitled to receive hereunder in respect of the sale of Product and any other revenues of the Facility received by PGE from any source attributable to the Facility operation as follows:

(a) first, to reimburse PGE for any and all out-of-pocket expenses reasonably incurred by PGE in taking possession of and operating the Facility, including PGE's personnel time and expenses, such operation to be subject to the operating budget and any operating agreement if such agreements are applicable;

(b) second, to pay any unpaid amounts owed to PGE under this Agreement;

(c) third, to satisfy any payments due and owing to any Lenders, arising after PGE's exercise of its Step-In Rights, and

(d) fourth, to Seller.

9.4.1 Title and Possession. During any period that PGE is in control of and operating the Facility pursuant to the exercise of its Step-In Rights, Seller shall retain legal title to and ownership of the Facility and PGE shall assume possession, operation and control solely as agent for Seller, provided that PGE shall operate the Facility in conformance with Prudent Electric Industry Practice (including operation and maintenance of the Facility in accordance with manufacturer's recommendations), the provisions and covenants set forth herein and in the interconnection agreement between Seller and the Transmission Provider, all leases, subleases, rights-of-way, easements and rights of ingress and egress used in connection with the Facility and Law (including all material permits, consents, licenses, approvals or authorizations from any Governmental Authority pertaining to the Facility). PGE's exercise of its Step-In Rights shall not be deemed an assumption by PGE of any liability of, or attributable to, Seller; provided, however, during the time PGE is operating the Facility, PGE shall indemnify and hold Seller harmless for any third party claims against Seller arising out of PGE's negligence or willful misconduct.

9.4.2 Seller's Resumption of Operations. If PGE is in control of the Facility pursuant to the exercise of its Step-In Rights, Seller may resume operation and PGE shall relinquish its right to control and operate the Facility under this Section 9.4 at such time as Seller has demonstrated to PGE's reasonable satisfaction that it possesses the resources to perform its duties under this Agreement.

9.4.3 PGE's Return of Control. If at any time after exercising its Step-In Rights and taking control of and operating the Facility, PGE elects to return control and operation to Seller, PGE shall give Seller thirty (30) Business Days' advance notice of the date that PGE intends to return such control to Seller. Upon receipt of such notice, Seller shall take all actions necessary or appropriate to resume control and operation of the Facility on such date in accordance with the terms of this Agreement.

9.4.4 Purpose. PGE and Seller agree that (i) the Step-In Rights are intended solely to provide further assurance that the terms of this Agreement will be achieved, and accordingly that the purpose of the Step-In Rights is the same as the purpose of this Agreement; (ii) there is no separate or additional consideration for the Step-In Rights; and (iii) Seller's obligations in respect of the Step-In Rights are inextricably interrelated to PGE's obligations under the terms of this Agreement.

9.6 Holding Performance Assurance.

PGE will be entitled to hold Performance Assurance in the form of cash provided that the following conditions are satisfied: (i) PGE is not a Defaulting Party and a Material

Adverse Change has not occurred and is continuing with respect to PGE and (ii) Performance Assurance is held only in a jurisdiction within the United States.

9.7 Interest Rate on Cash Collateral.

Performance Assurance in the form of cash shall bear interest at the Interest Rate on Cash Collateral and shall be paid to the Seller on the third Business Day of each Month. "Interest Rate on Cash Collateral" means the lesser of (i) the maximum amount allowed by applicable Law and (ii) the Federal Funds Rate for the holding period. The "Federal Funds Rate" means the effective Federal Funds Rate as published daily by the Federal Reserves Bank H.15 Statistical Release website for each day of the holding period. Such interest shall be calculated on the basis of the actual number of days elapsed over a year of 360 days.

9.8 Performance Assurance is Not a Limit on Seller's Liability.

The Performance Assurance contemplated by this ARTICLE 9: (a) constitutes security for, but is not a limitation of, Seller's obligations under this Agreement, and (b) shall not be PGE's exclusive remedy for Seller's failure to perform in accordance with this Agreement. To the extent that PGE draws on any Pre-COD Security or Delivery Period Security, Seller shall replenish or reinstate the Pre-COD Security or Delivery Period Security to the full amount then required under this ARTICLE 9.

9.9 Waiver.

This Agreement sets forth the entire agreement of the Parties regarding credit, collateral, financial assurances and adequate assurances. Except as expressly set forth in this Agreement, including this ARTICLE 9, neither Party:

(a) has or will have any obligation to post margin, provide letters of credit, pay deposits, make any other prepayments or provide any other financial assurances, in any form whatsoever, or

(b) will have reasonable grounds for insecurity with respect to the creditworthiness of a Party that is complying with the relevant provisions of Article 9 of this Agreement; and all implied rights relating to financial assurances arising from Section 2-609 of the Uniform Commercial Code or case law applying similar doctrines, are hereby waived.

ARTICLE 10
GOVERNMENTAL CHARGES

10.1 Cooperation.

Each Party shall use reasonable efforts to implement the provisions of and to administer this Agreement in accordance with the intent of the Parties to minimize all taxes, so long as neither Party is materially adversely affected by such efforts.

10.2 Non-Sale Related Governmental Charges and Taxes.

Seller shall pay or cause to be paid all charges or taxes imposed by any government authority ("Governmental Charges") on or with respect to the Product arising prior to the Delivery Point. PGE shall pay or cause to be paid all Governmental Charges on or with respect to the Product at and from the Delivery Point (other than those related to the sale of the Product, which are the responsibility of Seller). In the event Seller is required by Law or regulation to remit or pay Governmental Charges which are PGE's responsibility hereunder, PGE shall promptly reimburse Seller for such Governmental Charges. If PGE is required by Law or regulation to remit or pay Governmental Charges which are Seller's responsibility hereunder, PGE may invoice Seller for the amount of any such Governmental Charges or, in its sole discretion, deduct the amount of any such Governmental Charges from the sums due to Seller under ARTICLE 7 of this Agreement. Nothing in this Agreement shall obligate or cause a Party to pay or be liable to pay any Governmental Charges for which it is exempt under the Law.

10.3 Sale-related Governmental Charges and Taxes.

In addition to all other payments required under this Agreement, Seller shall be solely responsible for all existing and any new sales, use, excise, ad valorem, and any other similar taxes imposed or levied by any federal, state or local governmental agency on the Product sold and delivered hereunder (including any taxes imposed or levied with respect to the transmission of such energy) up to the delivery of such Product to the Delivery Point.

10.4 Indemnification.

Each Party shall indemnify, release, defend and hold harmless the other Party from and against any and all liability for taxes imposed or assessed by any taxing authority with respect to the Product sold, delivered and received hereunder that are the responsibility of such Party pursuant to this ARTICLE 10.

ARTICLE 11
RATES AND TERMS BINDING;
FERC STANDARD OF REVIEW

11.1 Mobile-Sierra Doctrine.

11.1.1 Standard of Review. Absent the agreement of all Parties to the proposed change, the standard of review for changes to any rate, charge, classification, term or condition of this Agreement, proposed by a Party (to the extent that any waiver in subsection 11.2 below is unenforceable or ineffective as to such Party), or FERC acting *sua sponte*, shall solely be the "public interest" application of the "just and reasonable" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) and clarified by Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish, 554 U.S. 527 (2008), and NRG Power Marketing LLC v. Maine Public Utility Commission, 558 U.S. 527 (2010).

11.1.2 Waiver of FERC Rights. In addition, and notwithstanding Section 11.1.1, to the fullest extent permitted by applicable Law, each Party, for itself and its successors and assigns, hereby expressly and irrevocably waives any rights it can or may have, now or in the future, whether under §§ 205 and/or 206 of the Federal Power Act or otherwise, to seek to obtain from FERC by any means, directly or indirectly (through complaint, investigation or otherwise), and each hereby covenants and agrees not at any time to seek to so obtain, an order from FERC changing any Section of this Agreement specifying the rate, charge, classification, or other term or condition agreed to by the Parties, it being the express intent of the Parties that, to the fullest extent permitted by applicable Law, neither Party shall unilaterally seek to obtain from FERC any relief changing the rate, charge, classification, or other term or condition of this Agreement, notwithstanding any subsequent changes in applicable Law or market conditions that may occur. If it were to be determined that applicable Law precludes the Parties from waiving their rights to seek changes from FERC to their market-based power sales contracts (including entering into covenants not to do so) then this subsection Section 11.1.1shall not apply, provided that, consistent with Section 11.1.1, neither Party shall seek any such changes except solely under the "public interest" application of the "just and reasonable" standard of review and otherwise as set forth in Section 11.1.1.

ARTICLE 12
REPRESENTATIONS AND WARRANTIES; INDEMNITY

12.1 Representations and Warranties.

On the Effective Date and throughout the Term, each Party represents and warrants to the other Party that:

12.1.1 it is duly organized, validly existing and in good standing under the Laws of the jurisdiction of its formation;

12.1.2 it has all regulatory authorizations necessary for it to legally perform its obligations under this Agreement;

12.1.3 the execution, delivery and performance of this Agreement are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

12.1.4 this Agreement, and each other document executed and delivered in accordance with this Agreement constitutes its legally valid and binding obligation enforceable against it in accordance with its terms; subject only to any Equitable Defenses;

12.1.5 it is not Bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming Bankrupt;

12.1.6 there is not pending or, to its knowledge, threatened against it or any of its Affiliates any legal proceedings that could materially adversely affect its ability to perform its obligations under this Agreement;

12.1.7 no Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement;

12.1.8 it is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Agreement;

12.1.9 it has entered into this Agreement in connection with the conduct of its business and it has the capacity or ability to make or take delivery of all Products referred to in this Agreement;

12.1.10 the material economic terms of this Agreement were subject to individual negotiation by the Parties;

12.1.11 it, and any guarantor of its obligations under this Agreement, is an "eligible contract participant" within the meaning of the Commodity Exchange Act.

12.2 <u>Indemnity</u>.

To the fullest extent permitted by Law, each Party (the "Indemnitor") hereby indemnifies and agrees to defend and hold harmless the other Party (the "Indemnitee") from and against any Indemnity Claims caused by, resulting from, relating to or arising out of any act or incident involving or related to the Product and occurring at any time when such Product is under the Indemnitor's possession and control; provided, however, that the Indemnitor shall not have any obligation to indemnify the Indemnitee from or against any Indemnity Claims caused by, resulting from, relating to or arising out of the negligence or intentional misconduct of the Indemnitee.

12.3 <u>Additional Representations and Warranties of Seller</u>.

On the Effective Date and throughout the Term, Seller hereby further represents and warrants to PGE that:

12.3.1 Seller has the right to sell the Product to PGE free and clear of liens of encumbrances;

12.3.2 Seller has title to the Product sold under this Agreement free and clear of liens and encumbrances;

12.3.3 Seller is authorized to sell power at market-based rates pursuant to FERC Dockets Number ER [__________];

12.3.4 The Facility is either an EWG or a QF;

12.3.5 Seller has obtained, or will obtain as and when required by this Agreement, all Permits and all other rights and agreements required to construct, own, operate and maintain the Facility, and they will be in full force and effect for the Term;

12.3.6 All leases of real property and other real property rights and agreements required for the operation of the Facility or the performance of any obligations of Seller under this Agreement have been obtained and are owned by Seller, free and clear of liens and encumbrances;

12.3.7 Except as disclosed on Exhibit E, neither Seller nor any Affiliate of Seller has entered into any document, arrangement, understanding, promise or agreement or the like with any Person concerning, with respect to the Facility, (i) remediation or mitigation of environmental impacts, (ii) endangered species, (iii) migratory birds (including eagles), (iv) wildlife and species of conservation concern (state and federal), (v) environmentally, culturally or historically sensitive property or resources, (vi) a military facility, or (vii) national security. In addition, neither Seller nor any Affiliate of Seller has entered into any agreement where public disclosure of the agreement or the subject matter of the agreement could reasonably be expected to negatively affect the Facility's reputation.

12.3.8 Except as disclosed in Exhibit K, there is no litigation, legal action or administrative action pending with respect to the Facility nor, to Seller's knowledge, is any such litigation, legal action or administrative action threatened.

12.3.9 Seller has at all times been fully compliant with the requirements of the Federal Trade Commission's "Green Guides," 77 F.R. 62122, 16 C.F.R. Part 260, as amended or restated in any communication concerning Facility Output, the Facility or the Bundled RECs.

12.4 <u>No Other Representations or Warranties</u>. Each Party acknowledges that it has entered into this Agreement in reliance upon only the representations and warranties set forth in this Agreement, and that no other representations or warranties have been made by the other Party with respect to the subject matter of this Agreement.

ARTICLE 13
INSURANCE

13.1 <u>Insurance</u>. During the Term, Seller shall secure and continuously carry the following insurance coverage:

13.1.1 Commercial general liability insurance with a minimum combined single limit of $1,000,000 per occurrence and in the annual aggregate, with coverage for bodily injury, personal injury and broad form property damage, contractual liability, products and completed operations.

13.1.2 Workers' compensation insurance to cover statutory limits of the worker's compensation laws and employers liability insurance with a minimum limit of $1,000,000.

13.1.3 Business automobile liability insurance (including coverage for owned, non-owned, and hired automobiles) used in connection with the Facility in an amount not less than $1,000,000 per accident for combined bodily injury, property damage or death. To the extent that the Seller does not own automobiles, coverage for non-owned and hired automobiles may be combined with commercial general liability.

13.1.4 Umbrella/excess insurance covering claims in excess of the underlying insurance described in Sections 13.1.1, 13.1.2 (employers liability only) and 13.1.3 with a $5,000,000 minimum per occurrence and annual aggregate.

13.1.5 All-risk property insurance including boiler & machinery coverage insuring Seller's property at replacement cost value.

13.2 Seller to Provide Certificate of Insurance. All policies required, with the exception of workers' compensation employers liability and business automobile liability, shall include (i) endorsement(s) naming PGE as an additional insured but only to the extent of Indemnitee's indemnifications as stated in Section 13.1, and (ii) a cross-liability and severability of interest clause. Said policies shall also contain provisions that such insurance is primary insurance without right of contribution of any other insurance carried by or on behalf of PGE with respect to its interests as additional insured. A certificate of insurance showing that the above-required insurance is in full force and effect (on Accord or similar form) shall be furnished to PGE. All policies shall be placed with companies with a minimum A.M. Best rating of A- IX. Seller shall deliver copies of all certificates of insurance to PGE within thirty (30) days of the Effective Date.

13.3 Seller to Notify PGE of Loss of Coverage. Seller or Seller's insurers shall endeavor to provide PGE thirty (30) days notice (or ten (10) days in the case of cancellation due to non-payment of premiums) in the event of any material change to, cancellation or non-renewal of the required insurance.

ARTICLE 14
TITLE AND RISK OF LOSS

Title and risk of loss related to the Product shall transfer from Seller to PGE at the Delivery Point, except that title to Bundled RECs up to the Specified Amounts shall transfer to PGE when generated and shall be measured at the Facility Meter. Seller represents and warrants that it will deliver all Product to PGE free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any Person arising prior to the Delivery Point.

ARTICLE 15
ASSIGNMENT; BINDING EFFECT

15.1 Assignment.

Neither Party may assign this Agreement or its rights hereunder to any entity whose Credit Rating is not equal to or higher than that of such Party and is at least above BBB- by S&P and Baa3 by Moody's. No assignment may be made without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), (i) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, (ii) transfer or assign this Agreement to an Affiliate of such Party which Affiliate's Credit Rating is equal to or higher than that of such Party, or (iii) transfer or assign this Agreement to any person or entity succeeding to all or substantially all of its assets whose Credit Rating is equal to or higher than that of such Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

15.2 Change in Control.

No direct or indirect change in the control of Seller may occur without PGE's prior written consent, not to be unreasonably withheld, conditioned or delayed.

15.3 Binding Effect.

This Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns. No assignment or transfer permitted hereunder shall relieve the assigning or transferring Party of any of its obligations under this Agreement.

ARTICLE 16
GOVERNING LAW

THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF OREGON, WITHOUT REGARD TO ITS PRINCIPLES OF CONFLICTS OF LAW.

ARTICLE 17
RECORDS AND AUDIT

17.1 Records.

Each Party shall keep proper books of records and account, in which full and correct entries shall be made of all dealings in relation to this Agreement in accordance with generally accepted accounting principles, consistently applied.

17.2 Audit Rights.

Each Party has the right, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement. If requested, a Party shall provide to the other Party statements evidencing the quantity of Product delivered at the Delivery Point. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly and shall bear interest calculated at the Interest Rate from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of twenty-four (24) months from the rendition thereof, and thereafter any objection shall be deemed waived.

ARTICLE 18
DISPUTE RESOLUTION

18.1 Referral to Senior Management

In the event of any controversy, claim or dispute between the Parties arising out of or related to this Agreement ("Dispute"), either Party may notify the other of the existence of the Dispute. Upon receipt of a notice of Dispute, the Parties' representatives will first attempt to resolve the Dispute informally through negotiation and consultation. If they are unable to do so within ten (10) Business Days after the date on the notice of Dispute was given, then within a further three (3) Business Day period following an additional written request by either Party, (i) each Party shall appoint as its representative a senior officer, and (ii) such senior officers shall meet, negotiate and attempt in good faith to resolve the Dispute quickly, informally and inexpensively.

18.2 Mediation.

Any Dispute that is not resolved pursuant to Section 18.1 within thirty (30) days after the Dispute notice was given may be submitted for mediation by either Party before a single mediator in accordance with the provisions contained herein and in accordance with the Commercial Mediation Procedures of the AAA in effect at the time of the mediation ("AAA Procedures"); provided, however, that in the event of any conflict between the procedures herein and the AAA Procedures the procedures herein shall control. The mediator will be named by mutual agreement of the Parties or by obtaining a list of five (5) qualified Persons from each of the Parties and alternately striking names. All mediation shall be administered by the AAA. All mediation shall take place in the City of Portland, Oregon, unless otherwise agreed to by the Parties. Each Party shall be required to exchange documents to be used in the mediation not less than five (5) Business Days prior to the mediation. The Parties shall use all commercially reasonable efforts to conclude the mediation as soon as practicable. All aspects of the mediation shall be treated as confidential. Neither the Parties nor any mediator may disclose the content or results of the mediation, except as necessary to comply with legal, audit or regulatory requirements. Before making any such disclosure, a Party shall give written notice to the other Party and shall afford such Party a reasonable opportunity to protect its interests. Each Party shall be responsible for its own expenses and one-half of any mediation expenses incurred to resolve the dispute. The mediator will provide the Parties with a fee and expense schedule in advance of mediation. Mediation will terminate by: (a) written agreement signed by both Parties, (b) determination by the mediator that the Parties are at an unresolvable impasse, (c) two unexcused absences by either Party from the mediation sessions, or (d) failure to resolve the Dispute on or before the sixtieth (60^{th}) day after the date on which the notice of Dispute was given (unless the Parties otherwise agree in writing to extend such date). The mediator will never participate in any claim or controversy covered by this Article as a witness, collateral contract, or attorney and may not be called as a witness to testify in any proceeding involving the subject matter of mediation. O.R.S. §§ 36.100 to 36.238 will apply to the entire process of mediation.

18.3 Legal Action.

If the Parties are still unable to resolve their differences through mediation pursuant to Section 18.2 within sixty (60) days after the date on which notice of the Dispute was originally given, then each of the Parties hereby irrevocably consents and agrees that any legal action or proceedings with respect to this Agreement may be brought in any of the courts of the State of Oregon located in the City of Portland or the courts of the United States of America for the District of Oregon having subject matter jurisdiction. By execution and delivery of this Agreement and such other documents executed in connection herewith, each Party hereby (a) accepts the exclusive jurisdiction of the aforesaid courts, (b) irrevocably agrees to be bound by any final judgment (after any and all appeals) of any such court with respect to such documents, (c) irrevocably waives, to the fullest extent permitted by Law, any objection it may now or hereafter have to the laying of venue of any action or proceeding with respect to such documents brought in any such court, and further irrevocably waives, to the fullest extent permitted by Law, any claim that any such action or proceeding brought in any such court has been brought in any inconvenient forum, (d) agrees that services of process in any such action or proceeding may be effected by mailing a copy thereof by registered or certified mail (or any substantially similar form of mail), postage prepaid, to such Party at its address set forth in Exhibit A, or at such other address of which the Parties have been notified. The dispute resolution process contemplated by this Agreement shall not prevent a Party from seeking temporary or preliminary equitable relief to prevent irreparable damage to that Party or to preserve the status quo pending resolution of a Dispute, and this Section 18.3 shall apply with respect to any application for such relief.

18.4 Waiver of Jury Trial. EACH PARTY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY AND ALL RIGHTS TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.

18.5 Attorneys' Fees. If either Party institutes any legal suit, action or proceeding against the other party arising out of or relating to this Agreement, including, but not limited to, contract, equity, tort, fraud and statutory claims, the prevailing party in the suit, action or proceeding will be entitled to receive, in addition to all other remedies to which the prevailing party may be entitled, the costs and expenses incurred by the prevailing party in conducting the suit, action or proceeding, whether incurred before suit, during suit, or at the appellate level, including reasonable attorneys' fees and expenses, court costs and other legal expenses such as expert witness fees, and all fees, taxes, costs and expenses incident to appellate, bankruptcy and post-judgment proceedings.

18.6 Survival. The provisions set forth in this ARTICLE 18 shall survive the termination or expiration of this Agreement.

ARTICLE 19
GENERAL PROVISIONS

19.1 Entire Agreement.

This Agreement (including the attached exhibits and schedules), any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all transactions under this Agreement constitute the entire agreement between the Parties relating to the subject matter. There are no prior or contemporaneous agreements or representations affecting the same subject matter other than those herein expressed. Any and all Exhibits referred to in this Agreement are, by such reference, incorporated herein and made a part hereof for all purposes.

19.2 Joint Efforts.

This Agreement shall be considered for all purposes as prepared through the joint efforts of both Parties and shall not be construed against one Party or the other as a result of the preparation, substitution, submission or other event of negotiation, drafting or execution hereof.

19.3 Amendments in Writing.

No amendment or modification to this Agreement shall be enforceable unless reduced to writing and executed by both Parties.

19.4 No Third Party Beneficiaries.

This Agreement shall not impart any rights enforceable by any third party (other than a permitted successor or assignee bound to this Agreement), it being the intent of the Parties that this Agreement shall not be construed as a third party beneficiary contract.

19.5 Non-Waiver.

No waiver by any Party of any one or more defaults by the other Party in the performance of any of the provisions of this Agreement shall be construed as a waiver of any other default or defaults whether of a like kind or different nature. No failure or delay by either Party in exercising any right, power, privilege, or remedy hereunder shall operate as a waiver thereof.

19.6 Severability.

Any provision of this Agreement declared or rendered invalid, unlawful, or unenforceable by any applicable court of law or regulatory agency or deemed unlawful because of a statutory change (individually or collectively, such events referred to as "Regulatory Event") will not otherwise affect the remaining lawful obligations that arise under this Agreement; and provided, further, that if a Regulatory Event occurs, the Parties shall use their best efforts to reform this Agreement in order to give effect to the original intention of the Parties.

19.7 Survival.

All indemnity and audit rights shall survive the termination of this Agreement. All obligations provided in this Agreement shall remain in effect, after the expiration or termination for any reason of this Agreement, for the purpose of complying herewith.

19.8 Bankruptcy Matters.

The Parties acknowledge and intend that this Agreement, the transactions contemplated in this Agreement, and any instruments that may be provided by either Party under this Agreement (including any Guaranty) will each, and together, constitute one and the same "forward contract," "forward agreement" and "master netting agreement" within the meaning of the Bankruptcy Code, and that PGE and Seller are "forward contract merchants" within the meaning of the Bankruptcy Code. Each Party agrees that it will not make any assertion or claim, or otherwise take any position to the effect that this Agreement, the transactions contemplated under this Agreement, and any instrument(s) that may be provided by either Party under this Agreement (including the Guaranty) do not each, and together, constitute one and the same "forward contract," "forward agreement" and "master netting agreement" within the meaning of the Bankruptcy Code, or that PGE and Seller are not "forward contract merchants" within the meaning of the Bankruptcy Code.

19.9 Relationships of Parties.

The Parties shall not be deemed in a relationship of partners or joint venturers by virtue of this Agreement, nor shall either Party be deemed an agent, representative, trustee or fiduciary of the other. Neither Party shall have any authority to bind the other to any agreement. This Agreement is intended to secure and provide for the services of each Party as an independent contractor.

19.10 Headings.

The headings used for the Sections and Articles herein are for convenience and reference purposes only and shall not affect the meaning or interpretation of this Agreement.

19.11 Consolidation of Variable Interest Entities.

If PGE or one of its Affiliates determines that, under Accounting Standards Codification 810 ("ASC 810") Consolidation of Variable Interest Entities ("VIE's"), formerly referred to as the Financial Accounting Standards Board's revised Interpretation No. 46 ("FIN 46"), it may hold a controlling financial interest in Seller, but it lacks the information necessary to make a definitive conclusion, Seller hereby agrees to provide, upon PGE's written request, sufficient financial and ownership information so that PGE or its Affiliate may assess whether a controlling financial interest in a VIE does exist under FIN 46. If PGE or its Affiliate determines that, under FIN 46, it holds a variable interest in Seller, Seller hereby agrees to provide, upon PGE's written request, sufficient financial and other information to PGE or its Affiliates so that PGE may properly consolidate the entity in which it holds the controlling financial interest and present the required disclosures. PGE shall reimburse Seller for Seller's reasonable costs and expenses, if any, incurred in connection with PGE's requests for information under this Section 19.11.

ARTICLE 20
CONFIDENTIALITY

Neither Party shall disclose the terms or conditions of this Agreement to a third party except (i) as may become generally available to the public, (ii) as may be required or appropriate in response to any summons, subpoena, or otherwise in connection with any litigation or to comply with any applicable law, order, regulation, ruling, or accounting disclosure rule or standard, (iii) as may be obtained from a non-confidential source that disclosed such information in a manner that did not violate its obligations to the non-disclosing Party in making such disclosure, (iv) to an index publisher or rating agency who has executed a confidentiality agreement with such Party, (v) in order to comply with any applicable law, regulation, order, or directive, including an order or directive of the Oregon Public Utility Commission, or (vi) in connection with any court or regulatory proceeding, including a proceeding of the Oregon Public Utility Commission; provided, however, that in the case of a disclosure under paragraphs (ii), (v) or (vi), each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. The parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with this confidentiality obligation. Before Seller issues any news release or publicly distributed promotional material regarding the Facility that mentions the Facility or PGE, Seller shall first provide a copy thereof to PGE for its review and approval, which approval shall not be unreasonably withheld, conditioned or delayed.

ARTICLE 21
NOTICES AND COUNTERPARTS

21.1 Notices.

21.1.1 All notices, requests, statements or payments shall be made to the addresses and persons specified in Exhibit A. All notices, requests, statements or payments shall be made in writing except where this Agreement expressly provides that notice may be made orally. Notices required to be in writing shall be delivered by hand delivery, overnight delivery, facsimile, e-mail (so long as a copy of such e-mail notice is provided immediately thereafter by hand delivery, overnight delivery, or facsimile), or other documentary form. Notice by facsimile shall (where confirmation of successful transmission is received) be deemed to have been received on the day on which it was transmitted (unless transmitted after 5:00 p.m. at the place of receipt or on a day that is not a Business Day, in which case it shall be deemed received on the next Business Day); provided that Scheduling and Dispatch notifications and notifications of changes in availability of the Facility sent by facsimile shall be treated as received when confirmation of successful transmission is received. Notice by hand delivery or overnight delivery shall be deemed to have been received when delivered. Notice by e-mail shall be deemed to have been received when delivered, so long as a copy of such e-mail notice is provided immediately thereafter by hand delivery, overnight delivery, courier or facsimile. Notice by telephone shall be deemed to have been received at the time the call is received.

21.1.2 A Party may change its address by providing notice of the same in accordance with the provisions of Section 21.1.1.

21.2 Counterparts.

This Agreement may be executed in counterparts, each of which is an original and all of which constitute one and the same instrument.

IN WITNESS WHEREOF, the Parties have caused this Wholesale Renewable Energy Purchase and Sale Agreement to be duly executed as of the Effective Date. This Agreement shall not become effective as to either Party unless and until executed by both Parties.

PORTLAND GENERAL ELECTRIC COMPANY		**[*Seller*]**	
Signature:	______________________	Signature:	______________________
Name:	______________________	Name:	______________________
Title:	______________________	Title:	______________________

Resource Adequacy Enhancements

Revised Straw Proposal

July 1, 2019

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1. Executive Summary

The California Independent System Operator (CAISO) is performing a comprehensive review of CAISO's Resource Adequacy (RA) provisions and proposing enhancements that ensure effective procurement of capacity to reliably operate the grid all hours of the year. This comprehensive review has identified potential modifications to CAISO provisions for System, Local, and Flexible RA.

CAISO's revised straw proposal considers enhancements to RA counting rules and assessments. This includes considering forced outage rates for system and flexible RA requirements. It is common practice among other ISOs to include an assessment of unforced capacity value that relies on the probability a resource will experience a forced outage at some point when it has been procured for RA capacity. CAISO proposes to develop a methodology for calculating unforced capacity values and an assessment to ensure the shown RA capacity is collectively adequate to meet the CAISO's system operational needs in all hours. The proposal also considers the assessment of planned outages and substitution rules under an unforced capacity paradigm and the elimination of the substitution obligation for forced outages.

CAISO proposes modifications to the RA import provisions, including adoption of certain existing California Public Utilities Commission (CPUC) rules to ensure firm delivery of imports used to meet RA obligations. The proposal also contemplates changes to incorporate an auction mechanism into the import capability allocation process.

Regarding flexible RA, CAISO includes an initial proposal to modify the current provisions for identifying flexible RA needs, including long ramping (3 hour), fast ramping (1 hour), and uncertainty (15 minute) needs. The proposal also incorporates Effective Flexible Capacity (EFC) counting rules and allowing imports to qualify to meet flexible RA requirements. CAISO also proposes rules for allocation of identified flexible RA needs, updated showings and assessments rules, and updated Must Offer Obligations for flexible RA capacity.

CAISO is also exploring adding tariff authority to address local capacity needs that are met with availability limited resources, and seeks authority to procure additional resources through the capacity procurement mechanism in response to planned outages that reduce capacity below requirements if no substitute capacity is provided. Proposed modifications to CAISO's backstop capacity procurement provisions are included to align backstop authority with the resource adequacy counting rules and adequacy assessments outlined above. These potential modifications include additional procurement authority to use the capacity procurement mechanism as an option to fulfill load serving entities' unforced capacity deficiencies and system deficiencies as determined through a resource adequacy portfolio showing analysis.

2. Introduction and Background

The rapid transformation to a cleaner, yet more variable and energy limited resource fleet, and the migration of load to smaller and more diverse load serving entities requires re-examining all aspects of CAISO's Resource Adequacy program. In 2006, at the onset of the RA program in California, the predominant energy production technology types were gas fired, nuclear, and hydroelectric resources. While some of these resources were subject to use-limitations because of environmental regulations, start limits, or air permits, they were generally available to produce energy when and where needed given they all had fairly dependable fuel sources. However, as the fleet transitions to achieve the objectives of SB 100,[1] CAISO must rely on a very different resource portfolio to reliably operate the grid. In this stakeholder initiative, the CAISO, in collaboration with the California Public Utilities Commission (CPUC) and stakeholders, will explore reforms needed to the CAISO's resource adequacy rules, requirements, and processes to ensure continued reliability and operability under the transforming grid.

CAISO has identified certain aspects within CAISO's current RA tariff authority that, among other things, require refinement to ensure effective procurement, help simplify overly complex rules, and ensure resources are available when and where needed all hours of the year. The following issues are of growing concern to the CAISO:

- The current RA counting rules do not adequately reflect resource availability, and instead rely on complicated substitution and availability incentive mechanism rules;
- Flexible capacity counting rules may not sufficiently align with operational needs;
- The current available import capability allocation process may result in inefficient outcomes and withholding of import capabilities;
- The eligibility rules and must offer obligations for import resources may need clarification to ensure firm energy delivery from RA imports;
- Current system and flexible RA showings assessments do not consider the overall effectiveness of the RA portfolio to meet CAISO operational needs; and
- The growing reliance on availability-limited resources where these resources may not have sufficient run hours or dispatches to maintain and serve the energy needs in local capacity areas and sub-areas.

CAISO is conducting a holistic review of its existing RA tariff provisions to make necessary changes to ensure CAISO's RA tariff authority adequately supports reliable grid operations into the future. The revised straw proposal specifically presents CAISO proposals for changes to system RA regarding the following topics; system RA requirements, showings and sufficiency testing, RA capacity counting rules, Must Offer Obligations and bid insertion, the planned outage process, and RA imports and Maximum Import Capability.

CAISO also provides updates to its proposal for flexible RA capacity. CAISO's proposal addresses identifying flexible RA capacity needs and products, setting flexible RA requirements and counting rules for EFC values, as well as flexible RA allocation, showings, and sufficiency tests and flexible RA Must Offer Obligation modifications.

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[1] The objective of SB 100 is "that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045."
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

Regarding local RA modifications, CAISO proposes changes to local capacity assessments to address availability limited resources, and meeting local capacity needs with slow demand response. CAISO also presents its proposal to modify aspects of its backstop capacity procurement, including certain enhancements to the Capacity Procurement Mechanism.

The remaining stakeholder initiative schedule is detailed below.

3. Stakeholder Engagement Plan

Table 1 outlines the schedule for this stakeholder initiative below. CAISO plans to seek CAISO board approval of the elements in this RA enhancements initiatives in the second quarter of 2020.

Table 1: Stakeholder Engagement Plan

Date	Milestone
July 1	Revised straw proposal
July 8-9	Stakeholder meeting on revised straw proposal
July 24	Stakeholder comments on revised straw proposal due
Sep 9	Second revised straw proposal
Sep 16-17	Stakeholder meeting on second revised straw proposal
Oct 9	Stakeholder comments on second revised straw proposal due
Dec 17	Third revised straw proposal
Jan 7-8	Stakeholder meeting on third revised straw proposal
Jan 22	Stakeholder comments on third revised straw proposal
Feb 26	Draft final proposal
March 3-4	Stakeholder meeting on draft final proposal
March 25	Stakeholder comments on draft final proposal due
Q2 2020	**Present proposal to CAISO Board**

4. Resource Adequacy Enhancements: Principles and Objectives

Principles

The resource adequacy framework must reflect the evolving needs of the grid

As the fleet transitions to a decarbonized system where fuel backed resources are replaced with clean, variable, and/or energy-limited resources, traditional measures of resource adequacy must be revisited to include more than simply having sufficient capacity to meet peak demand. The RA products procured and the means to assess resource adequacy must be re-examined and refreshed to remain relevant. Any proposed changes must assure that RA accounting methods effectively evaluate the RA fleet's ability to meet the CAISO's operational and reliability needs all hours of the year. The evolving fleet is altering the CAISO's operational needs. As more variable supply and demand interconnects to the system, the CAISO requires resources that are more flexible and can quickly and flexibly respond to greater levels of supply and demand uncertainty. RA requirements and assessments must reflect the evolving needs of the grid and the RA framework must properly evaluate and value resources that can meet these evolving needs.

RA counting rules should promote procurement of the most dependable, reliable, and effective resources

Both RA and non-RA resources should be recognized and rewarded for being dependable and effective at supporting system reliability. If a non-RA resource has a higher availability and is more effective at relieving local constraints relative to other similar RA resources, then such information should be publicly available to enable load-serving entities to compare and contrast the best, most effective resources to meet their procurement needs. Having this information publicly available to load-serving entities will improve opportunities for the most dependable and effective resources to sell their capacity. Thus, in principle, RA counting rules should incentivize and ensure procurement of the most dependable, reliable, and effective resources.

The RA program should incentivize showing all RA resources

Modifications to the existing RA structure should encourage showing as much contracted RA capacity as possible and not create disincentives or barriers to showing excess RA capacity. Although it may be appropriate to apply additional incentive mechanisms for availability, CAISO must balance the impact that such incentives may have on an LSE's willingness to show all of its contracted RA capacity.

LSE's RA resources must be capable of meeting its load requirements all hours of the year

RA targets should be clear, easily understood and based on reasonably stable criteria applied uniformly across all LSEs. For example, to date, the CAISO has relied on a planning reserve margin that is met through a simple summation of the shown RA resources' Net Qualifying Capacity (NQC) values. Most Local Regulatory Authorities (LRAs) set a planning reserve margin at fifteen percent above forecasted monthly peak demand. However, some LRAs have set lower planning reserve margins. It is not possible to determine if those LSEs with lower planning reserve margins impair the CAISO system without comparing the attributes of the underlying resources in LSE's portfolios, relative to resources' attributes in other portfolios. In other words, the simple summation of NQC values in a LSE's portfolio does not equate to resource adequacy and does not assure an LSE can satisfy its load requirements all hours of the year. As California Public Utilities Code section 380 states, "Each load-serving entity shall maintain physical generating capacity and electrical demand response adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves" (emphasis added).[2] In other words, resource adequacy also encompasses LSEs meeting their load requirements all hours of the year, not just meeting peak demand.

Objectives

In evaluating RA enhancements, CAISO is reviewing NQC rules, forced outage rules, adequacy assessments, and availability obligations and incentive provisions. These existing rules are inextricably linked and require a holistic review and discussion. This review includes considering assessing the reliability and dependability of resources based on forced outage rates. Incorporating forced outages into the CAISO's RA assessment will help inform which resources are most effective and reliable at helping California decarbonize its grid.

Based on the CAISO's review of best practices and the diverse stakeholder support for further exploration of these matters, CAISO is proposing a new resource adequacy framework to assess the forced outage rates for resources and conduct RA adequacy assessments based on both the unforced capacity of resources and the RA portfolio's ability to ensure CAISO can serve load and meet reliability standards.

The CAISO's proposal seeks to remain aligned with the CPUC process. However, CAISO notes that solely relying on an installed-capacity-based PRM as the basis for resource adequacy, as is the case today, is not sustainable into the future given the transforming grid and the new resource mix and its operational characteristics. A more complete discussion on the need for coordination with the CPUC's RA program is included in section 5.1.2.

CAISO must consider the express intent of the original legislated RA mandate; to ensure each load-serving entity maintains physical generating capacity and electrical demand response adequate to meet its load requirements. This is essential as California transitions to greater reliance on more variable, less predictable, and energy limited resources that may have sufficient capacity to meet a planning reserve margin, but may not have sufficient energy to meet reliability needs and load requirements all hours of the year. Given this growing concern, CAISO is proposing to develop a new resource adequacy test that will ensure there is sufficient capacity to not only meet peak load needs, but, just as importantly, to ensure sufficient energy is available within the RA fleet to meet load requirements all hours of the year.

As noted above, the current RA practices rely heavily on the existing NQC counting rules. CAISO believes that resource's NQC values will continue to be an important aspect of the RA

[2] California Public Utilities Code Section 380: http://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=1.&title=&part=1.&chapter=2.3.&article=6.

program in the future. For example, the local RA assessments and studies rely heavily on NQC. CAISO also envisions Must Offer Obligations being tied to NQC values. However, CAISO is also considering how to incorporate resource forced outage rates into RA assessments. Similar to the current provisions of other ISOs, CAISO proposes calculating and publishing both installed capacity (NQC) and unforced capacity (UCAP) values and utilizing both figures in the CAISO's RA processes.

5. RA Enhancements Revised Straw Proposal

The following sections detail the CAISO's proposed modifications and provide CAISO's rationale and supporting justification. This Revised Straw Proposal is reorganized from previous versions into sections covering System, Local, and Flexible RA and related sub topics, as well as a section covering proposed modifications to the CAISO's backstop procurement provisions.

The RA Enhancements Revised Straw Proposal covers the following topics:

- System Resource Adequacy
  - Determining System RA Requirements
  - Forced Outage Rates and RA Capacity Counting
  - System RA Showings and Sufficiency Testing
  - Must Offer Obligation and Bid Insertion Modifications
  - Planned Outage Process Enhancements
  - RA Import provisions
  - Maximum Import Capability provisions
- Flexible Resource Adequacy
  - Identifying Flexible Capacity Needs and Requirements
  - Identifying Flexible RA Requirements
  - Setting Flex RA Requirements
  - Establishing Flexible RA Counting Rules: Effective Flexible Capacity Values and Eligibility
  - Flexible RA Allocations, Showings, and Sufficiency Tests
  - Must Offer Obligation modifications
- Local Resource Adequacy
  - Local Capacity Assessments with Availability Limited Resources
  - Meeting Local Capacity Needs with Slow Demand Response
- Backstop Capacity Procurement provisions
  - Capacity Procurement Mechanism modifications
  - Reliability Must-Run modifications
  - UCAP Deficiency Tool

5.1. System Resource Adequacy

Resource deliverability under stressed system conditions remains an essential and important part of a resource's ability to support reliable grid operations, and the CAISO intends to preserve the current NQC calculations for resources i.e., CAISO will continue to perform NQC calculations exactly as they are today, and will continue to derate Qualifying Capacity values (QC) based on deliverability.

For all resources with NQC values, CAISO proposes to establish UCAP values to identify the unforced capacity value (discounted for units' forced outage rates) for use in system and flexible RA showings and assessments.[3] The UCAP value speaks to the quality and dependability of the resources procured to meet RA requirements. CAISO also proposes to establish system RA requirements and associated sufficiency tests that account for unit forced outage rates. In other words, resource's RA value would be measured in terms of its UCAP value and individual LSE sufficiency tests would be measured based on meeting UCAP requirements each month. The following section provides CAISO's proposed modifications to incorporate these changes into CAISO RA processes and tariff.

5.1.1. Determining System RA Requirements

CAISO proposes that RA accounting should reflect both NQC and UCAP values. CAISO will coordinate with the CPUC and LRAs to ensure alignment with individual LRA requirements.

System UCAP Requirement

CAISO believes it is reasonable to expect that the amount of UCAP made available is sufficient to serve forecasted peak load and ancillary services requirements. This is because CAISO has observed the impacts of forced outages exceeding resource margins established through existing planning reserve margin requirements during certain periods. To address these instances, CAISO is proposing to establish a system UCAP requirement to more directly account for forced outages. CAISO must carry reserves for three percent of load and three percent of generation, or cover the Most Severe Single Contingency according to BAL-002. Additionally, CAISO must have sufficient capacity to provide regulation and flexible ramping product. Therefore, CAISO proposes to develop a minimum system UCAP requirement that all LSEs must meet and show as RA.

If CAISO had perfect foresight, then this UCAP requirement would be, for example, equal to the forecasted peak, plus all other ancillary serves and flexible ramping needs, or about 109 percent of the 1:2 year peak load forecast. However, CAISO does not have perfect foresight. Therefore, CAISO is considering an additional factor for observed year-ahead forecast error (*i.e.*, if the 1:2 year peak load forecast was 40,000 MW, but observed was 42,000).

CAISO believes this bottom-up approach to establish a minimum system RA UCAP requirement is appropriate and helps ensure minimum resource adequacy requirements are achieved, given the number of LRAs and potential variance in the LRAs' PRM targets. A system UCAP

[3] Resources without an NQC are not eligible to provide system or local RA capacity.

requirement should also help mitigate the potential for capacity leaning by LRAs and their respective LSEs.

CAISO also notes that it has received stakeholder feedback indicating a need for CAISO to consider how to coordinate these important system RA modifications with the CPUC's RA program. CAISO agrees this is an important consideration. For a detailed discussion on matters related to coordination of the proposed UCAP concepts with the CPUC's programs, please see section 5.1.2 below.

5.1.2. Forced Outage Rates and RA Capacity Counting

CAISO is proposing new RA counting rules that account for the probability of forced outages, eliminating the need for complicated replacement capacity rules. Many of the U.S. Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) with Centralized Capacity Markets operate using an Installed Capacity (ICAP) or Unforced Capacity (UCAP) market. ICAP values generally account for impacts to resources caused by ambient weather conditions and represents physical generating capacity. UCAP is a percent of the ICAP available once outages are taken into consideration. NYISO, PJM, and MISO incorporate forced outages when calculating each resource's qualifying capacity and measure capacity using UCAP in their respective markets. In contrast, ISO-NE relies on an ICAP value that incorporates historical forced outage data when establishing its Installed Capacity Requirement.

The methodological assumptions for calculating UCAP values vary somewhat among system operators and the criteria inputs are unique for each resource type. Generally, UCAP incorporates the availability of a resource using a derating factor referred to as Equivalent Forced Outage Rate on demand (EFORd), also referred to as unit's Effective Forced Outage Rate in some regions. The EFORd factor is a performance measurement that adjusts a resource's potential RA capacity value accounting for the portion of time a unit is needed but unavailable to deliver due to forced outages. XEFORd is a similar probability measurement but adjusted to exclude Outside Management Control (OMC) events.

There are several key advantages for integrating forced outages into a generator's calculated RA qualifying capacity value. Recognizing a unit's contribution to reliability enables a resource to be compared and contrasted to the reliability of other resources. Greater resource accountability should produce market signals that promote procurement of better performing resources with improved operational reliability and availability. The inclusion and accessibility of information on the forced outage rates of resources can help buyers avoid risks and make better informed decisions when making bilateral trades or when procuring replacement RA capacity.

To date, neither the CAISO nor the CPUC account for system-wide resources on forced outage beyond the margins included in the established planning reserve margin requirement. Instead, CAISO relies on substitution rules and the Resource Adequacy Availability Incentive Mechanism (RAAIM). RAAIM calculates incentive payments and resource non-availability charges based on a resource's bidding behavior. It is intended to incentivize compliance with bidding and must-offer obligations and ensure adequate availability of RA resources.

Calculating NQC, UCAP, and EFC values

CAISO proposes to calculate and publish monthly NQC and UCAP values for all resources each year. This calculation will limit UCAP at the resource's NQC value and will only consider forced outages in determining a resources UCAP value. The UCAP value will not be impacted by CAISO approved planned outages.

CAISO will calculate UCAP values for all resource types that do not rely on the CPUC's Effective Load Carrying Capability (ELCC) methodology for determining QC values. For resource's with ELCC values calculated using the CPUC's ELCC methodology, CAISO will use the ELCC value as the UCAP value. Additional discussion regarding the basis for this proposal is provided below.

As a starting point, CAISO proposes to adopt the standard UCAP calculation similar to the approach applied by PJM. Specifically, CAISO proposes to calculate UCAP as:

UCAP = (NQC) * (1 - EFOR)

Although CAISO is proposing the above UCAP calculation, it also notes that it is doing so as an initial concept simply because it is a generally accepted methodology. CAISO is still examining alternative variations of this calculation, such as the approaches used by MISO and NYISO.

CAISO is also assessing the benefits of calculating unit's forced outage rate seasonally as is done in NYISO and MISO. The forced outage rate could, for example, measure January through April and October through December as one season (winter or off-peak), and May through September as another season (summer or on-peak). Once calculated, the forced outage rate would be set for each season for the upcoming RA year. Although seasonal calculations may add some complexity, they likely better reflect resources' availability during peak and off-peak seasons. CAISO proposes to utilize three years of historic data to determine these calculations for unit forced outage rates. In other words, each forced outage will impact a resource's seasonal forced outage rate and its UCAP value for the next three years.

CAISO is considering incorporating a weighting method that places more weight on the most recent years that more historic periods would have less of an impact on resulting average forced outage rates that would be utilized in determining resource's UCAP values. An initial proposal for stakeholder consideration on this issue is to place the following weights on the proposed calculation; 50% weight for the most recent annual forced outage rate, 30% weight on the second annual forced outage rate period, and 20% weight on the third annual forced outage rate period (most historical observation included in the proposed three year calculation). CAISO also seeks stakeholder input as to whether each year should be weighted equally or if greater weigh should be applied to more recent years.

ELCC will establish UCAP values for wind and solar resources

CAISO will rely on the CPUC's ELCC methodology when applicable. Currently, the CPUC only applies this methodology to wind and solar resources, but could expand that to cover weather sensitive or variable output DR and storage technologies. The reason for the CAISO's reliance on the ELCC calculation is two-fold. First, as noted in Table 10 in the Appendix, other ISOs equate wind and solar UCAP values with a statistical assessment of resources' output. Second, the ELCC already takes into account the probability of forced outages for wind and solar resources.[4] Therefore, these technologies already have their QCs derated for expected forced outages.

The CPUC's ELCC calculation has two challenges as applied for this purpose. First, the CPUC calculates the average ELCC for the wind and solar fleet. This means that some resources will perform better than average, while others will perform worse. If all wind and solar resources are shown for RA, then there is no problem. However, if only a subset of solar and/or wind resources are shown as RA, then the average ELCC value of the RA wind and solar fleet may differ from the average ELCC value of the entire fleet.

A second, but related issue, is the CPUC calculates a diversity benefit that relies on the portfolios of wind and solar resources. If the showings have a different ratio of wind and solar resources, then the diversity benefit may not be reflected in the RA fleet. Either of these issues can result in over or under-procurement depending on what resources are shown. However, CAISO is looking to remove disincentives for LSEs to show all procured RA capacity. If CAISO is successful in this effort, then all procured wind and solar will be shown and this issue can be eliminated. If there are still incentives to not show all procured RA then additional work may be needed.

CAISO notes that there are additional resource types for which CAISO is still assessing the applicability of the above proposed forced outage accounting or what other methods may need to be applied to develop UCAP values. CAISO continues to explore options for DR, hydro, QFs, and new resources and seeks additional stakeholder feedback on how to address development of UCAP methodologies for these resource types.

Removing Forced Outage Replacement and RAAIM application to forced outage periods

As stated above, a fundamental component of the CAISO's proposal is to account for forced outages in upfront capacity valuation and assessments. CAISO proposes to assess forced outages against resources' UCAP values and will no longer include forced outage replacement as an option for addressing forced outages. This change is intended to align the process with the new proposed paradigm of assessing resources' forced outage rates to provide transparency into the reliability and dependability of individual resources.

This removal of the option to provide replacement capacity is also interrelated to the CAISO's RAAIM provisions. CAISO will no longer have to assess resources for RAAIM during periods they have submitted a forced outage.

Forced Outage Rate Data

The first and primary input needed to calculate a resource's UCAP value is an accurate and appropriate forced outage rate. The specific forced outage rate for a resource is the key information necessary to calculate the expected value (in terms of MWs) of a capacity resources

[4] Forced outages are accounted for by using actual production data to inform the wind and solar production profiles in the ELCC modeling.

unforced capacity. To determine these forced outage rates, CAISO considered two potential data sources, CAISO's Outage Management System, and the NERC Generation Availability Data System (GADS).[5]

NERC's GADS compiles resource outage data for resources across the country. While fleet wide averages across NERC regions are readily and publically available, resource specific information is more difficult to access and compile. Additionally, GADS reporting is mandatory only for resources 20 MW and above. As small distributed resource penetration increases over time, GADS may miss a large number of resources and/or resource types. CAISO could propose to establish tariff requirements for the reporting of NERC GADS data for the purposes of data development for the CAISO's proposed UCAP concept. CAISO believes this could be problematic due to the limitations on size and resource types requiring potential exclusions or caveats. Furthermore, CAISO is concerned that the more universal outage reporting for GADS purposes may not always align with all of the potential CAISO forced outage nature of work cards that CAISO believes is a good area to focus on for defining the type/nature of outages that will be assessed against resource's forced outage rates – which is a vital issue to establish an accurate and fair forced outage rate definition. CAISO believes that the nature of work cards utilized currently provide a good basis for development of resource specific forced outage data.

Currently, CAISO has established numerous outage cards in the CAISO Outage Management System (OMS) designed to describe the nature of work for resource outages. These outage cards are also used to describe whether a resource is required to provide substitute capacity to avoid RAAIM charges, or if the outage is beyond the resource's control and therefore RAAIM exempt. A list of the current forced outage nature of work cards available in OMS is provided later in this section.

Given the challenges of establishing forced outage rates for individual resources and the growing number of distributed resources that would not be subject to the GADS reporting requirements, CAISO proposes to rely on the information reported in OMS to calculate resource specific forced outage rates. Although the data is reported at the resource level in OMS, CAISO has reviewed the current OMS outage cards and determined that they may not adequately cover the different types of forced outages or reflect the types of forced outages that would be exempt from forced outage calculations. This proposal requires that CAISO determine if there are any necessary modifications to the forced outage cards nature of work definitions. CAISO also needs to modify the requirements for what information is provided through CAISO OMS to provide the correct information to make accurate assessments of resource specific forced outage rates. Additionally, OMS will likely require some level of system modifications to accurately and automatically track resource outage data on a comparable basis.

Proposed Forced Outage Rate Assessment Interval

CAISO proposes to apply a 16-hour window between 5:00 AM and 9:00 PM as the assessment window for assessing resource specific forced outage rates. This interval is intended to cover

[5] https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx

the periods when resources are most highly in demand to meet CAISO needs and will also simplify existing Availability Assessment Hours currently in use.

CAISO also considered a 24-hour assessment interval. However, using all hours reduces the impact of forced outages during peak needs by increasing the denominator in the forced outage calculation. The CAISO's proposed 16-hour assessment interval focuses on the hours of greatest need and, as discussed below, mirrors the convergence between the hours of system, local, and flexible capacity needs. Further, as noted below, using the same assessment intervals allows CAISO to calculate and utilize the same forced outage rate for both generic and flexible capacity.

Calculating Unit Forced Outage Rates

Forced Outage Rate Background

Conceptually, a forced outage rate performance index evaluates the total hours of full and partial forced outages for the purpose of estimating a unit's availability frequency. IEEE has established a standard methodology to calculate the generating unit's availability using GADS historical event and performance data (see standard equation below).[6]

The defined methods are commonly adjusted by system operators to accommodate for unique reliability needs, but generally the metric accounts for those hours and months of greatest demand and excludes planned or maintenance outages. Similarly, some RTOs and ISOs use the standard EFORd metric, but others such as MISO, use an adjusted calculation (referred to as XEFORd) which adjusts the EFORd metric to remove outages outside of management control. NYISO, PJM, and ISO-NE all use the net dependable capacity in lieu of the net maximum capacity. The standard EFORd availability metric formula is:

$$EFORd = \frac{FOHd + EFDGd}{FOHd + SH} \times 100\%$$

- EFORd = Equivalent demand forced outage rate: A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.
- FOH = Forced outage hours: The phrase forced outage hours represents the number of hours a unit was in an unplanned outage state.
- EFDH = Equivalent forced derated hours: EFDH is the forced derated hours converted to equivalent hours. [7]
- SH = Service hours: The phrase service hours represents the number of hours a unit was in the in-service state.

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[6] IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity, available at: https://www.nerc.com/docs/pc/gadstf/ieee762tf/762-2006.pdf

[7] The phrase equivalent hours represents the number of hours a unit was in a time category involving unit derating, expressed as equivalent hours of full outage at maximum capacity. Both unit derating and maximum capacity shall be expressed on a consistent basis, gross or net.

Initial proposal for CAISO Forced Outage Rate formulation

CAISO proposes using the standard IEEE formula as a basis for its proposed forced outage rate calculation. As noted above, the standard methodology to calculate the generating unit's availability using GADS historical event and performance data to determine unit specific equivalent demand forced outage rates. Because CAISO is proposing to asses forced outage rates during a 16 hour assessment window, the proposed approach CAISO is exploring is based upon a simplified Effective Forced Outage Rate or (EFOR). The formula proposed is a starting point to develop an EFOR determination for each unit with a NQC, which is as follows:

$$EFOR = \frac{FOH + EFDG}{FOH + SH} \times 100\%$$

CAISO proposes to apply this standard formulation to determine unit level EFOR rates as a starting point for the proposed inclusion of forced outages in RA capacity valuation and assessments. As noted above, the various other RTO/ISO regions that have incorporated these unit availability measures into their RA processes have all made various adjustments and necessary accommodations to apply this general formula to their particular market and region's needs and differences. Similarly, CAISO proposes to further develop this more general measure of forced outage rates into a CAISO specific approach.

One of the major concepts in other regions is the exclusion of outages considered "outside of management control", or OMC, from resources forced outage rates. OMC outage periods are commonly excluded in these regions and cover outage periods that are outside of a resource owner's direct control. For example, a transmission induced outage or a force majeure event such as a wildfire or flooding event that forces a unit outage should be considered outside of management control. CAISO proposes to incorporate a similar concept in the final EFOR formulation under this proposal. CAISO seeks stakeholder feedback on this concept and any input on the various types of modification or enhancements that should be considered for application to the initial IEEE standard availability metric calculation included in this proposal.

Outage Cards – Nature of Work classifications and categorization for forced outage rates

CAISO must calculate each unit's forced outage rate using clear, well defined outage definitions to establish their UCAP values. CAISO will clarify how each outage type and nature of work card will be assessed against a resource specific forced outage rate.

CAISO has also provided the following table of outage nature of work cards to develop the appropriate classification for each outage nature of work card and how it will be used in calculating resources' forced outage rates. CAISO proposes to assess outages against resource's forced outage rates for the nature of work outage cards as described in Table 2 below.

Table 2: Forced Outage Cards – Nature of Work

Outage Type	Nature of Work/Opportunity Status	Lowers resource's available UCAP?
Forced	Ambient Due to Temperature	Yes
Forced	Ambient Not Due to Temperature	No
Forced	Ambient due to Fuel insufficiency	Yes
Forced	AVR/Exciter	Yes
Forced	Environmental Restrictions	Yes
Forced	Short term use limit reached	No
Forced	Annual use limit reached	No
Forced	Monthly use limit reached	No
Forced	Other use limit reached	No
Forced	ICCP	Yes
Forced	Metering/Telemetry	Yes
Forced	New Generator Test Energy	No
Forced	Plant Maintenance	Yes
Forced	Plant Trouble	Yes
Forced	Power System Stabilizer (PSS)	Yes
Forced	Ramp Rate	Yes
Forced	RTU/RIG	Yes
Forced	Transitional Limitation	Yes
Forced	Transmission Induced	No
Forced	Technical Limitations not in Market Model	No
Forced	Unit Supporting Startup	Yes
Forced	Unit Testing	No
Forced	Off Peak Opportunity	No

Outage Type	Nature of Work/Opportunity Status	Lowers resource's available UCAP?
Forced	Short Notice Opportunity	No
Forced	RIMS testing	Yes
Forced	RIMS Outage	Yes

CAISO seeks stakeholder feedback on this initial classification of outage nature of work cards to define the outages that will included in calculating resource specific forced outage rates.

Unit Outage Rate Analysis Examples

CAISO has received feedback requesting analysis supporting the proposed inclusion of unit's forced outage rates for capacity valuation. CAISO has conducted some preliminary analysis to assess the proposal's potential impacts. However, at this time, CAISO has not identified a generally applicable method for converting OMS data into forced outage rates. As a result, CAISO has not conducted a fleet-wide forced outage analysis for the purposes of this proposal. However, based in CAISO's review of NERC GADS data for WECC provides a WECC-wide average approximately 8% forced outage rate for all resource types providing outage data. As an alternative, CAISO has analyzed a subset of unit outage data and provides some examples of the resulting analysis in the following figures.

CAISO made the assumptions and utilized the formulas below for determining the following example outage analyses.

Assumptions:

- For any Forced Outages lasting over 7 days, change to planned outage
- For overlapping forced outages, sum of all outages are accounted for in calculations

Calculation formulas:

$$Forced\ Outage\ Rate = \frac{\sum_{area} Pmax - \sum_{area} Forced\ Avail\ MW}{\sum_{area} Pmax}$$

$$Planned\ Outage\ Rate = \frac{\sum_{area} Pmax - \sum_{area} Planned\ Avail\ MW}{\sum_{area} Pmax}$$

$$Total\ Outage\ Rate = \frac{\sum_{area} Pmax - \sum_{area} Total\ Avail\ MW}{\sum_{area} Pmax}$$

Example Outage Analysis Results

The following figures provide the results of CAISO's outage analysis for two example resources to illustrate the magnitude of outages for these example resources over 2018 annual and summer periods. The two example resources were selected in order to provide a viable illustrative example for discussion purposes. CAISO's analysis shows that resource availability related to forced outages varies over seasons and between resources. Significant variance among forced outage rates of resources is precisely the issue that CAISO's proposed UCAP modifications are intended to capture.

Figure 1: Example Unit #1 – Seasonal outage rate analysis: summer 2018

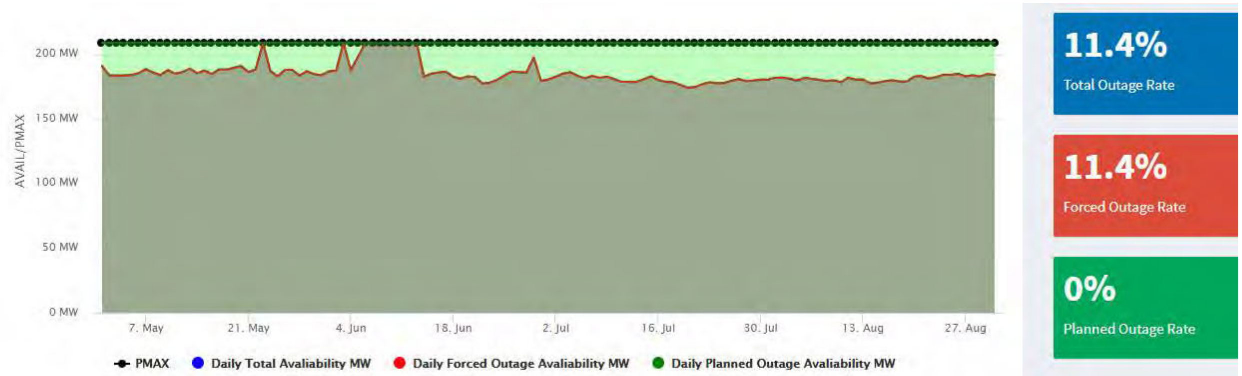


Figure 2: Example Unit #1 – Annual outage rate analysis: 2018

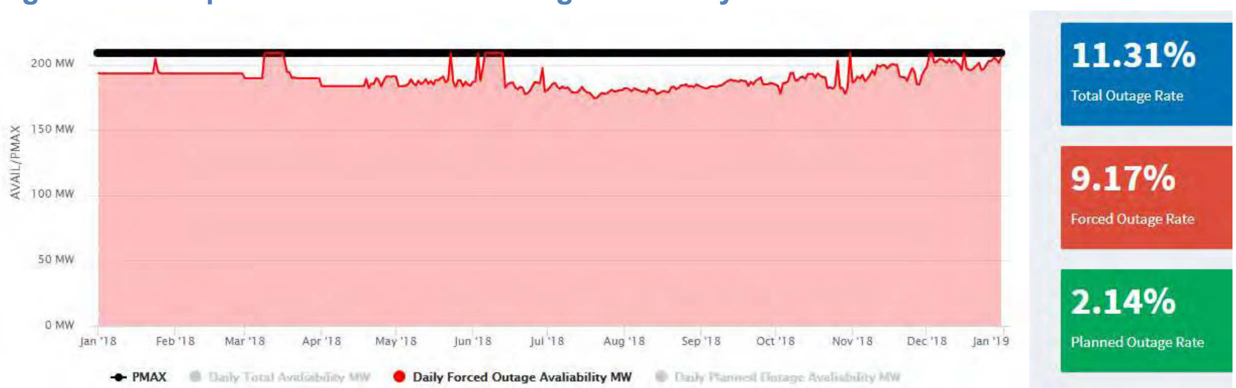


Figure 3: Example Unit #2 – Seasonal outage rate analysis: summer 2018

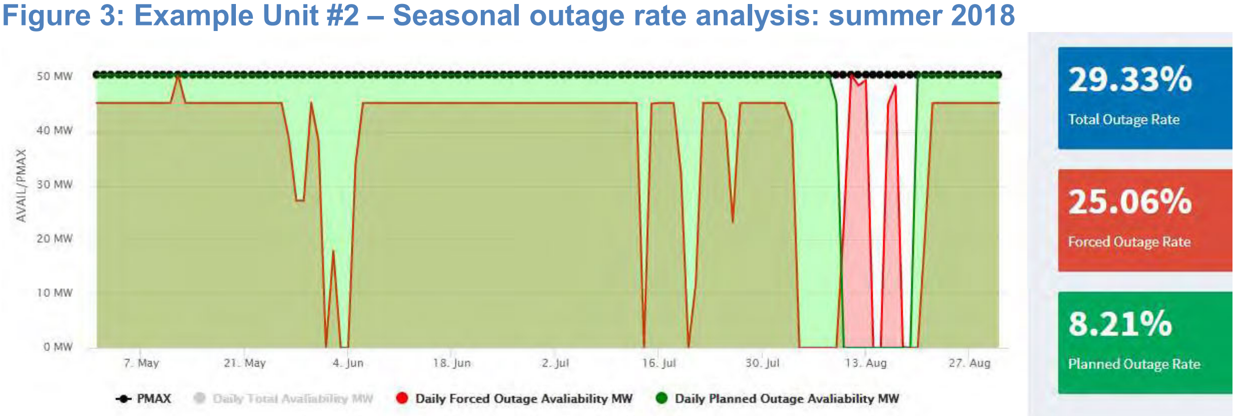
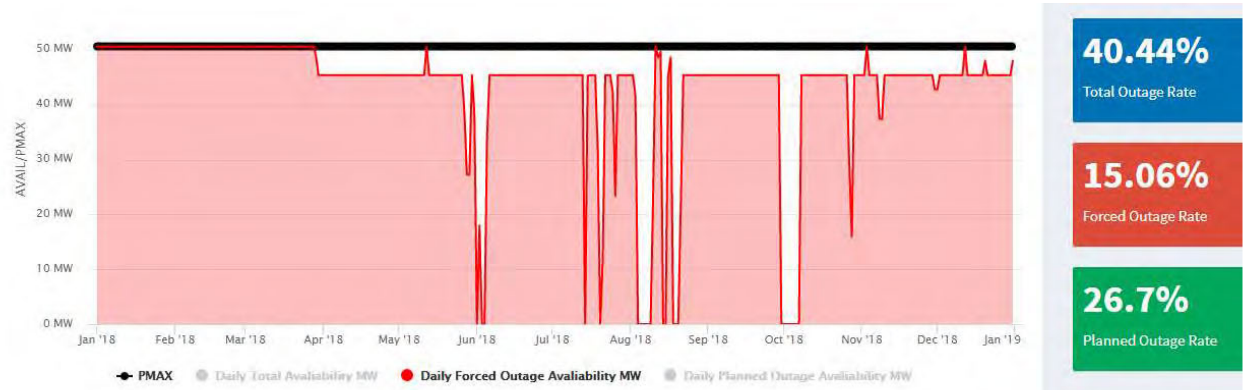


Figure 4: Example Unit #2 – Annual outage rate analysis: 2018



The example resource forced outage analysis included in the proposal is for illustrative purposes only and any final proposal will provide detailed calculation parameters and inputs. CAISO intends to further develop these aspects of the proposed forced outage rate calculations with stakeholder input.

Coordination of Proposed UCAP Concept with CPUC RA Program

CAISO has received stakeholder feedback that it must closely consider how its proposed UCAP concept will be coordinated with the current CPUC RA program. Some of the feedback received expressed concern that the CAISO proposal could create conflicting RA requirements, or otherwise undermine the System RA Planning Reserve Margin (PRM) established by LRAs. CAISO understands these valid concerns and commits to providing the coordination necessary to align with LRAs' RA programs. Ideally, LRAs would adopt similar counting rules and requirements to minimize administrative complexity. However, system RA requirements and PRMs based on installed capacity are not necessarily inconsistent with CAISO's proposal. Regardless, CAISO will work with LRAs to align RA programs with the current proposal. This collaborative effort includes proposing similar counting rules in the upcoming CPUC RA proceeding.

Some stakeholders expressed concerns that CAISO's proposal can result in over-procurement. CAISO's proposal for UCAP requirements recognizes that forced outages are accounted for in the counting methodology, therefore, a margin for forced outages is not included in the proposed system UCAP requirement. In other words, CAISO's proposed UCAP PRM would be lower than an installed-capacity-based PRM to avoid double counting of forced outages. CAISO believes that LRAs could maintain an installed capacity PRM. In fact, the CAISO will continue to post resource NQC values as it does today.

CAISO believes the proposal offers improved transparency with respect to the forced outage rates that could improve procurement and retirement decisions. Existing installed capacity measures reflect an expected fleet average outage rate. This can result in efficient procurement of resources on the low end of the forced outage distribution and more overall procurement than might be seen using UCAP values. CAISO believes that the UCAP requirement basis will provide an appropriate target to guide forward procurement of resources with better forced outage rates and better reliability, compared to other resources of lower reliability quality.

As noted above, some stakeholders expressed concern that the CAISO's proposed UCAP concept could create two different system RA procurement targets. CAISO does not believe that the proposed UCAP requirement and UCAP counting rule concepts will create incompatible procurement targets for system RA. Rather, CAISO views the two concepts as interrelated, not problematic or incompatible. The proposed CAISO UCAP requirement will simply be a subset (or lower bound) of the LRA's established system RA PRM target. In other regions utilizing UCAP and PRM concepts, there are two established targets; one system PRM target, and one UCAP requirement that is also a subset of the system PRM target that simply removes the additional margin established to cover the forced outage component of the system PRM target.

CAISO seeks stakeholder input to identify any additional CPUC/LRA RA program issues or UCAP related concepts that should be included for consideration and coordination.

Availability Assessment Hours and RAAIM background

The current CAISO Resource Adequacy Availability Incentive Mechanism (RAAIM) provisions rely on different Availability Assessment Hours (AAHs) for determining the hours of greatest need for each capacity product, which adds significant complexity. The AAH for generic capacity is for the five peak load hours on non-holiday weekdays. The AAHs for flexible capacity differ in both hours and duration. Category 1 flexible capacity has a 17 hour assessment interval for all days designed to cover both the morning and evening ramps. Flexible capacity categories 2 and 3 have 5 hour assessment windows designed to cover the maximum net load ramp. Flexible capacity category 2 assessment hours covers all days and category 3 covers only non-holiday weekdays. The AAHs can change annually for both generic and flexible capacity.

The difference between the AAHs across generic and flexible capacity constructs has created confusion for market participants. Additionally, it complicates availability calculations since generic and flexible capacity products have different offer obligations. Finally, having different AAHs implies that flexible capacity and generic capacity needs differ significantly by day of the week or hours of the day. Although the needs differed at the onset of the flexible capacity program, this is simply not the case anymore. The peak load and the largest net load ramps are now occurring during the same hours. Additionally, the amount of uncertainty CAISO must address between day-ahead and real-time markets with flexible capacity does not appear to differ dramatically across day-light hours.[8]

The RA program is designed to ensure CAISO has sufficient capacity available to serve load reliably. Any resource providing RA capacity to CAISO has an obligation to offer that capacity into CAISO's markets. The Must Offer Obligations (MOO) for various RA and technology types are listed in the CAISO's Reliability Requirements BPM.[9] CAISO also relies on outage reporting

[8] See http://www.caiso.com/Documents/RevisedStrawProposal-DayAheadMarketEnhancments.pdf at p.37-38.
[9] See the Reliability Requirements BPM, pp. 77-82 for System and Local RA obligations and pp. 93-96 for flexible RA obligations.

to track whether or not resources are available at any given time. If there is sufficient notice given and capacity available, CAISO can grant outages without requiring replacement capacity. However, not all outages occur under those conditions, and CAISO developed RAAIM to address these instances in particular.

RAAIM is designed to provide an incentive for resources on outage to minimize the duration of the outage or to provide substitute capacity. Additionally, RAAIM provides an additional incentive payment to generation that is available over a predetermined measurement. RAAIM does not apply to all hours; it only applies during the Availability Assessment Hours. These hours and days differ depending on the RA product the resource is providing to CAISO. While RAAIM provides an incentive to provide substitute capacity, it also provides an incentive to only show the bare minimum RA capacity needed for each capacity type, because showing additional capacity exposes that capacity to RAAIM non-availability charges without providing any corresponding benefit to the LSE to which that resource is contracted.

The discussion above is a brief summary of the relationship between MOOs, RA substitution rules, and RAAIM. The reality of these relationships is that they combine to create a complex system of processes that differ vastly from other ISOs/RTOs. However, in light of CAISO's UCAP proposal, it is possible to eliminate these complex relationships in favor of a process that simply relies on upfront accounting for forced outages. Therefore, CAISO continues to explore modifications to remove or limit the application of RAAIM. CAISO also proposes to remove the current allowance for forced outage replacement, and instead will rely on the UCAP and EFOR concepts to the extent possible.

CAISO seeks stakeholder feedback on the need for any continued utilization of RAAIM beyond limited applications, and feedback on the proposed removal of allowance for forced outage replacement.

5.1.3. System RA Showings and Sufficiency Testing

CAISO will conduct two sufficiency tests for system capacity: An individual deficiency test and a portfolio deficiency test. These tests are designed to ensure there is both adequate UCAP to maintain reliability for peak load and that the portfolio of resources, when combined, work together to provide reliable operations during all hours. CAISO will also conduct tests for flexible and local capacity needs; those assessments are discussed in Sections 5.2**Error! Reference source not found.** and 5.3, respectively.

Individual Deficiency Assessments

CAISO will conduct an assessment of LSE RA showings and resource supply plans to ensure there is sufficient UCAP shown to meet the identified reliability need described above. Although CAISO will be assessing system capacity showings based on UCAP values, CAISO proposes that, as done today, LSEs and resource SCs need only submit and show resources' NQC. Once shown, CAISO will consider each resource's UCAP value to conduct its UCAP assessment.

Additionally, LSEs may not procure the "good part" of a resource (*i.e.*, LSEs cannot simply procure only the unforced capacity part of a resource and any amount shown for RA will be assessed considering the resource's forced outage rate). For example, an LSE could not claim to buy 90 MW of both NQC and UCAP from a 100 MW resource with a 10 percent forced outage rate. In comments to the straw proposal – part 2, several parties requested CAISO allow resources to sell and show only the UCAP value of the resource. There are two reasons CAISO cannot allow this. First, the UCAP accounting method relies on the probability that some resources will be out at various times. Allowing some resources to do so would likely require CAISO to maintain the same complicated substitution rules it is seeking to eliminate to maintain the desired level of reliability. Second, in CAISO's review of best practices in other ISO's such practices are not permitted.

Partial RA resources (shown for RA for only a portion of its capacity) will receive a proportional UCAP value reflecting the proportion shown for RA purposes (*i.e.*, A 100 MW resource with a 10 percent forced outage rate shown for 50 MW of NQC will be assessed as being shown for 45 MW of UCAP RA).

LSEs that fail to meet the UCAP requirement will be notified of the deficiency and provided an opportunity to cure. LSEs that fail to cure may be subject to backstop procurement cost allocation. Specific backstop procurement authority for this deficiency and cost allocation are discussed in greater detail in Section 5.4.

Individual RA Showing Incentive

CAISO also proposes to develop an individual LSE RA showing incentive. CAISO proposes to develop a new tool called the UCAP deficiency tool, which is intended to provide an incentive for LSEs to show above their UCAP obligations and to also prevent or discourage LSEs from failing to show RA at least equal to their UCAP requirement. The concept of the UCAP deficiency tool is to apply a penalty to LSEs that show less than (below) their UCAP requirement, and distribute those collected penalties to LSEs showing over (above) their UCAP requirements. This proposed tool and incentive is included in detail in Section 5.4, below. Examples and further discussion of this proposed concept are also provided in Section 5.4.3.

Portfolio Assessment

CAISO will also conduct a portfolio deficiency test of only the resources shown for RA to determine if the portfolio is adequate to serve load under various load and net load conditions during all hours of the day. The portfolio deficiency test will use only the shown RA fleet in a production simulation to determine if CAISO is likely to serve forecasted gross and net-load peaks, and maintain adequate reserves and load following. The need for this assessment is similar in concept to the collective deficiency test CAISO conducts for local RA. However, CAISO will only conduct this assessments on monthly RA showings because they are the only showing that provides 100 percent of the system, local, and flexible RA capacity requirements. The increased penetration of energy and availability-limited resources and the reliance on these resources to meet RA needs means that some resource mixes provided to meet RA requirements may not be able to ensure the reliable operation of the grid during all hours of the day across the entire month. Similar to the local assessments, CAISO is looking to maintain a consistent definition for capacity to facilitate transacting a homogeneous product. However, CAISO must assess how the shown RA fleet works collectively to meet system needs.

The objective of a portfolio analysis is to assess if CAISO can serve load with the shown RA fleet. Because year ahead system RA showing requirements are currently only 90 percent for the five summer months for CPUC jurisdictional entities, CAISO will only conduct this assessment for monthly RA showings.

CAISO has considered three general approaches to conducting this model. These options are included in the following table.

Table 3: Portfolio Assessment Modeling Options

Modeling Approach Option	Iteration[10]	Load	Wind/solar	Other Generators
Net Load Deterministic	One	Known	Known	a) A generator forced outage schedule determined randomly prior to the assessment, or b) Model all resources at UCAP value
Generator Stochastic	One or several	Known	Randomly determined for each iteration with fixed installed capacity	A generator forced outage schedule determined randomly prior to each iteration
Full stochastic	Several	Random draws	Randomly determined for each iteration with fixed installed capacity	A generator forced outage schedule determined randomly prior to each iteration

There are relative pros and cons with respect to each of the above testing options. For example, the net load deterministic model can run relatively quickly when compared with the other options. However, this speed comes at the expense of performing numerous draws and the robust statistical results that can be derived from a full stochastic production simulation. The net load deterministic and the full stochastic models basically have inverse pros and cons (*i.e.*, one runs fast but does not provide the same volume of information, the other takes longer but produces more information), while the generator stochastic model falls somewhere in between.

[10] One iteration is defined a predetermined interval. This is interval can be a single day, a week, or a full month.

Additionally, CAISO must determine the best platform for conducting this test. CAISO believes that any platform used to conduct this assessment should reasonably reflect that actual CAISO system. Therefore, CAISO explored three primary platforms:

- Market Optimization based model – An offline version of CAISO market optimization software
- Integrated Optimal Outage Coordination (IOOC) tool – A tool used by CAISO's Operations Engineering group to test planned transmission and generation outages, similar to the market optimization tool in terms of resource commitment and optimization
- Summer Assessment Plexos model – A Plexos model used to conduct CAISO summer assessment. Models many constraints, but not all.

All of the above options are complex, time-consuming simulations. The Summer Assessment model is capable of running more quickly than the other two, but lacks the detail offered by the other two.

In balance, having assessed the time constraints, complexity, and data output, CAISO favors the net load deterministic model using the IOOC at this time. CAISO will be required to conduct this assessment and provide feedback to market participants within 10 days of receiving RA showings; therefore, processing time is critical. CAISO will be the first ISO or RTO to conduct such an assessment, regardless of turnaround time, making it reasonable to start with the less complicated option and learn to walk before we run. Additionally, although the Summer Assessment Plexos model runs faster, it does not model all CAISO constraints and warrants relying on one of the other two models. Given the IOOC offers the ability to include planned outages, CAISO believes it will yield the most reliable results.

Finally, CAISO must establish the proper metric to determine the adequacy of the portfolio. Each of the above approaches may provide different metrics. These different metrics can be interpreted differently in evaluating whether the RA portfolio meets CAISO's operational needs. CAISO has explored two primary metrics for the portfolio deficiency test: Serving load and loss-of-load expectation. Given that CAISO will initially conduct a production simulation that is largely deterministic, there is insufficient information to generate a meaningful LOLE. Therefore, CAISO proposes to use the portfolio's ability to serve forecasted load for the upcoming month. The portfolio must ensure CAISO can maintain load, Ancillary Services, and load following [11] requirements for all days and all hours in the portfolio deficiency test. If any of these requirements is not met, CAISO will identify a portfolio deficiency.

CAISO will model <u>only</u> RA resources in this portfolio analysis. Any additional energy provided in CAISO's day-ahead or real-time markets represent energy substitutes in those markets, but are not needed in the portfolio assessment to determine if the RA fleet is adequate. Additionally, CAISO must establish baseline inputs into the portfolio assessment. CAISO will rely on CEC 1-in-2 hourly load forecast. Because the analysis is run on hourly blocks, CAISO will also include load following requirements. The wind and solar production profiles will be generated prior to

[11] Load following is needed because the production simulation is run at an hourly granularity and does not fully capture intra-hour ramping needs.

running the production simulation. These profiles represent maximum potential output from these resources. These profiles will not be considered must take capacity and actual use of wind and solar resources in the production simulation may be lower than the profile. Generator availability will be determined through Monte Carlo draw using resource forced outage rates.

If the portfolio is adequate then no additional actions will be taken. If the portfolio is unable to serve load under given load or net load conditions, then CAISO will declare a collective deficiency, provide a cure period, and will conduct backstop procurement using the CPM competitive solicitation process to find the least cost solutions to resolve the deficiency if left uncured. The specific details regarding CPM designations and cost allocation is provided in Section 5.4.1.

CAISO considered additional assessments of individual RA showings, however, CAISO believes it is not feasible to adequately develop individual LSE load profiles and determine that a specific LSE's RA portfolio contributed to the collective deficiency and, therefore, subject to LSE specific cost allocation.

5.1.4. Must Offer Obligation and Bid Insertion Modifications

Must Offer Obligations

The RA program is designed to ensure CAISO has sufficient capacity available to serve load reliably all hours of the year. Any resource providing RA capacity to the CAISO has an obligation to offer that capacity into the CAISO market. Currently, CAISO tariff contains provisions regarding must offer obligations, bidding, and bid insertion rules. Resources providing RA capacity will continue to have a must offer obligation for that capacity under RA Enhancements. Additionally, at this time, CAISO is developing the imbalance reserve product in the Day-Ahead Market Enhancements initiative. As these two stakeholder processes evolve, the CAISO continues to assess the need for a real-time RA must offer obligation or if there is sufficient commitments and capacity reservations made in the day-ahead markets. At this time, the specific details of the imbalance reserves are not sufficiently developed to make a determination on these issues at this time. At this juncture, CAISO is preserving the real-time RA must offer obligation, until and if a change is warranted. Regardless, CAISO will align any RA must-offer obligations with the policies and needs identified in the Day-Ahead Market Enhancements.

CAISO proposes, consistent with the practice in certain other ISOs, that a resource's must offer obligation must be consistent with the resource's NQC value.[12] More specifically, if a resource is shown for 100 MW of NQC, it must bid 100 MW of capacity into CAISO's markets. This bidding rule is required to ensure the underlying UCAP availability is met. As an example, the UCAP requirement is set with the expectation that some portion of the RA fleet is on forced

[12] See https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf at p. 22. "In all the reviewed markets except California and ISO-NE, the capacity of these facilities is procured and settled as UCAP. In California and ISO-NE, the capacity obligation is denominated as installed capacity (ICAP). Notwithstanding that, in most markets, capacity is procured and settled as UCAP, the resulting performance obligation on conventional controllable generation is to offer all of the ICAP except on recognized outages."

outage. Assume that unit with 100 MW of NQC had a UCAP value of 80 MW, reflecting that it is available 80% of the time. If that unit were only required to bid its UCAP value of 80 MW, then during the showing period, on average, CAISO would only receive 64 MWs of dependable capacity from that unit.

Setting must offer obligations at the UCAP means that all forced outages would require substitute capacity to ensure reliability. Alternatively, and as proposed here, setting the must offer obligation at the shown NQC value allows CAISO to dramatically simplify forced outage substitution. By establishing a UCAP-based RA construct with an associated must offer obligation at the NQC value, the RA fleet effectively provides its substitute capacity upfront, eliminating the need for complex resource substitution rules. For this reason, CAISO is exploring eliminating the existing RA forced outage substitution rules in favor of UCAP-based resource RA counting and NQC-based resource bidding. This concept is addressed in greater detail below.

CAISO has performed a comprehensive review of must offer obligations for all resource types in the tariff and Reliability Requirements BPM and believes the current must offer obligations can be simplified to provide market participants more clarity when determining the must offer obligations for different resources. As a way to simplify the must offer obligations, CAISO proposes a standard must offer obligation that would apply to all resources unless specified by CAISO under an exemption by resource type.

As outlined in Table 4, the standard must offer obligation would require 24 by 7 bidding into the day-ahead market for all resources and 24 by 7 bidding into the real-time market for all resources committed in the day-ahead or that can be committed in the Short-Term Unit Commitment (STUC) horizon.[13] STUC is the most forward looking real-time market process and can commit resources available to CAISO in real-time. Any unit with a startup time greater than the STUC horizon is unable to be committed in the real-time market; therefore, it would not be required to bid into the real-time market if they have not already been committed in the day-ahead market.

[13] Tariff Definition of STUC, p. 175: http://www.caiso.com/Documents/AppendixA-MasterDefinitionSupplement-asof-Apr1-2019.pdf

Table 4: Standard Must Offer Obligation for System and Local RA Capacity

DA MOO	RUC MOO[14]	RT MOO
Economic bids or self-schedules for all RA capacity for all hours of the month resource is not on outage	RUC availability bid for all RA capacity for all hours of the month the resource is not on outage	Economic bids or self-schedules for any remaining RA capacity from resources scheduled in IFM or RUC. Economic Bids or Self-Schedules for all RA capacity that can be committed within the STUC horizon

Bid Insertion

As part of this RA enhancements initiative, CAISO is proposing revisions to the bid insertion rules. Although CAISO currently requires RA resources to economically bid or self-schedule into the market, it also supplements those bidding obligations with bid insertion provisions for non-use limited resources. CAISO has considered two potential options for revising bid insertion rules:

1. Apply bid insertion to all non-use-limited resources and resources registered as use-limited under Commitment Cost Enhancements – Phase 3 (CCE3) policy, or;
2. No bid insertion for any resource but either apply RAAIM to RA resources or treat all intervals without bids as forced outages for the purposes of the UCAP calculation.

At this time, CAISO proposes to pursue adoption of option 1. CAISO has recently implemented the CCE3 policy that allows resources with certain use limitations to include approved opportunity costs in their market bids. The policy is designed to ensure the more effective and efficient use of resources in the market and to facilitate regular and consistent market participation from resources with certain use limitations.

Applying bid-insertion to non-use-limited resources and resources registered as use-limited under CCE3 policy would ensure that resources have bids in the market and would need to report outages to avoid the market dispatching the resource, enhancing the CAISO's ability to identify forced outages. Additionally, this option would not create a disincentive to show RA capacity, unlike option 2.

[14] CAISO currently requires a $0 RUC availability bid for all RA capacity. This policy is being changed as a part of the Extension of the Day-Ahead Market (EDAM) initiative. With the implementation of EDAM, all energy imbalance market (EIM) entities can voluntarily bid into the CAISO's day-ahead market. Under that paradigm, maintaining $0 RUC availability bids would result in the commitment of California RA resources to serve load outside of the California area. Considering this is not the purpose of the California resource adequacy program, CAISO is proposing to remove the $0 requirement for RUC availability bids in EDAM. The correlation between RA Enhancements, Day-Ahead Market Enhancements (DAME), and EDAM will be discussed in the CAISO's Day-Ahead Vision document, which will be published in the late summer of 2019.

CAISO is seeking stakeholder input regarding this proposed modification to bid insertion rules.

Exemptions to Standard Must Offer Obligation

CAISO recognizes that not all resource types are physically capable of adhering to the proposed standard must offer obligation, and therefore proposes a list of exemptions to the standard must offer obligation outlined in Table 5. Resource types that are defined by CAISO as having an exemption will still be subject to must offer obligations. These must offer obligations will be defined by CAISO based on the characteristics of the resource type.

CAISO also recognizes the need to define specifically the bid insertion rules for resources that fall outside the categories of non-use-limited or registered use-limited. For example, it may not be appropriate to apply bid insertion to resources with variable output or limitations that cannot be modeled through an opportunity cost. Therefore, CAISO also includes bid insertion exemptions listed in Table 5. If a resource is exempt from bid insertion, CAISO would not insert bids for these resources in the event that required amounts of RA capacity are not offered into the respective markets unless there is a RUC Availability Bid or RUC Schedule for a resource without a corresponding Economic Bid or Self-Schedule.

CAISO initially proposes to generally define the following exemptions based on resources type and seeks stakeholder feedback on this list, including modifications or additions.

Table 5: Exemptions to Standard Must Offer Obligation and Bid Insertion Proposal

Exemption Type	DA MOO	RUC MOO[15]	RT MOO	Bid Insertion
Eligible Intermittent Resource	May, but not required to, submit Bids in the Day-Ahead Market	No requirement to submit RUC Availability Bids	Must be available consistent with the resources forecast for RA Capacity	No
NGR (Non-REM)	Standard DA MOO plus MOO should reflect charge and discharge capabilities	RUC Availability Bids are to be submitted for all RA Capacity for all hours of the month the resource is not on outage. MOO should reflect charge and discharge capabilities	Standard RT MOO plus MOO should reflect charge and discharge capabilities	No

[15] *Id.*

NGR (REM)	Economic Bids or Self-Schedules are to be submitted for regulation for all hours of the month resource is not on outage. MOO should reflect charge and discharge capabilities	RUC Availability Bids are to be submitted for all RA Capacity for all hours of the month the resource is not on outage. MOO should reflect charge and discharge capabilities	Economic bids or self-schedules for any remaining RA capacity from resources scheduled in IFM or RUC. Economic Bids or Self-Schedules for all RA capacity that can be committed within the STUC horizon. MOO should reflect charge and discharge capabilities	No
Non-Dynamic Resource Specific Imports	Standard DA MOO	Standard RUC MOO	Economic Bids or Self-Schedules for any remaining RA Capacity from resources scheduled in IFM or RUC. No RTM Bids or Self-Schedules are required for resources not scheduled in IFM or RUC	DA-Yes RT- Yes, up to RA amount if any portion of the resources is scheduled in IFM or RUC
Non-Dynamic, Non-Resource Specific Imports	Economic Bids or Self-Schedules are to be submitted for all RA Capacity consistent with inter-temporal constraints such as multi-hour run blocks or contractual	Standard RUC MOO	Economic Bids or Self-Schedules for any remaining RA Capacity from resources scheduled in IFM or RUC. No RTM Bids or Self-Schedules are required for resources not	DA-Yes RT- Yes, up to RA amount if any portion of the resources is scheduled in IFM or RUC

	limitations (e.g. 6 X 16)		scheduled in IFM or RUC	
PDR[16]	Economic Bids are to be submitted for RA Capacity that the market participant expects to be available per supply plan[17]	Standard RUC MOO	Standard RT MOO	No
Pumping load	Economic Bids or Self-Schedules are to be submitted for all available energy up to RA Capacity quantity	No requirement to submit RUC Availability Bids	Economic Bids or Self-Schedules are to be submitted for all available energy up to remaining RA Capacity	No
RDRR	May, but not required to, submit Bids in the Day-Ahead Market	N/A	Bid 95 -100% of the bid cap in real-time for all available energy up to RA capacity quantity	Real-time only
Regulatory Must Take (RMT)	Must be available consistent with the resource's availability plan for all RA capacity up to the RMT amount, standard DA MOO for any RA capacity above the RMT amount	No requirement to submit RUC Availability Bids	Must be available consistent with the resource's availability plan for all RA capacity up to the RMT amount, standard RT MOO for any RA capacity above the RMT amount	No

[16] CAISO is considering potential modifications to must offer obligations for variable-output DR in the ESDER 4 stakeholder process. ESDER Stakeholder Initiative Webpage: http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx
[17] PDR bidding requirements are specified in CAISO tariff Section 30.6.1 – Bidding and Scheduling of PDRs

This proposal includes several modifications to the current must offer and bid insertion rules. Namely, CAISO proposes that for resources participating under the NGR, the must offer obligation should reflect both the charge and discharge capabilities of the resource such that CAISO can fully optimize the resource. To do so, the CASIO must have bids available for the unit's full capability. Bidding full charge and discharge capability would allow CAISO to ensure fuel sufficiency for the resource. At this time, the CASIO sees this proposal applying well for battery storage resources participating under the NGR model and is considering how it would apply to other technology types that may participate under NGR in the future.

Additionally, CAISO proposes to apply bid insertion for RDRR resources in the real-time. RDRR resources only have an obligation to bid into the real-time market and are only utilized after the CASIO declares a warning or emergency. These bids must be 95-100% of the bid cap.

CAISO proposes that for Regulatory Must-Take (RMT) resources, the must offer obligation for the portion of the resource that is RMT should be consistent with availability. CAISO initially proposes that RMT resources submit an availability plan 45 days prior to the RA month for the portion of the resource that is RMT. The corresponding must offer obligation would be for the MW amount specified on the availability plan. If a portion of the resource is not RMT and provides RA, that portion of the resource would fall under the standard must offer obligation.

CAISO believes the proposed must offer obligations and bidding rules provide clearer requirements for market participants to follow when determining when they must bid into CAISO market. CAISO welcomes stakeholder feedback on the proposals for the standard must offer obligations and list of exemptions.

5.1.5. Planned Outage Process Enhancements

CAISO considered modifications to its current planned outage provisions that will be needed to correspond with the proposed modifications to its RA counting rules and assessments. CAISO's proposed changes to its planned outage provisions are provided in the following section, as well as relevant background on the current provisions.

Background

CAISO currently uses the Planned Outage Substitution Process Obligation (POSO) for planned outages. The POSO provisions are provided in CAISO tariff at sections 9.3.1.3 and 40.9.3.6. RA resources currently enter planned outages into CAISO Outage Management System (OMS). CAISO's Customer Interface for Resource Adequacy (CIRA) system runs a daily POSO report with determination for a planned outage need for substitution. The POSO process is currently conducted on a first-in-last-out basis,[18] therefore resources submitting planned outages earliest will have the greatest likelihood of being approved to take their planned outages without

[18] CAISO will first request the resource providing RA Capacity with the most-recently-requested outage for that day to provide RA Substitute Capacity and then will continue to assign substitution opportunities until the ISO has sufficient operational RA Capacity to meet the system RA requirement for that particular day.

substitution requirements. The POSO process compares the total amount of operational RA capacity to the total system RA requirement.

As noted previously, system RA requirements are established by LRAs based upon CEC monthly peak forecasts and are updated 60 days prior to the start of each delivery month. If, after removing all planned outages, available capacity is less than the RA requirement, CAISO assigns substitution obligations for resources seeking to take planned outages during those short timeframes.

Objectives and Principles

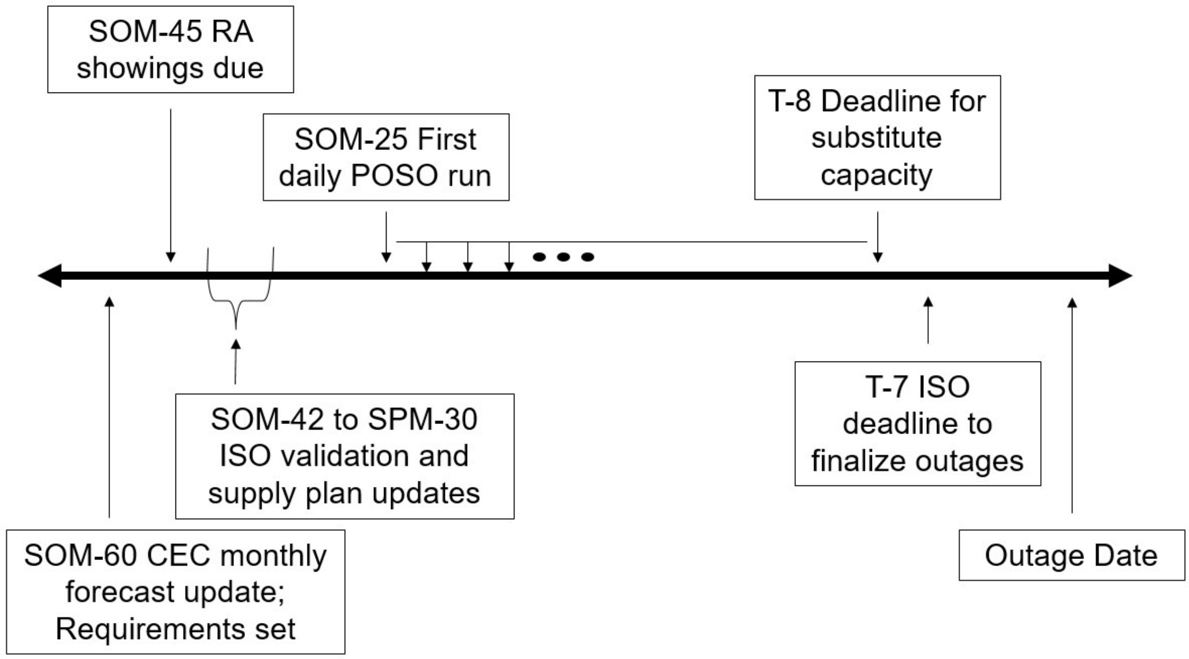
CAISO provides the following objectives and principles to guide the development of modifications to the planned outage provisions. Modifications to CAISO planned outage provisions should:

- Encourage resource owners to enter outages as early as possible,
- Generally avoid cancellation of any approved planned outages to the extent possible,
- Identify specific replacement requirements for resources requiring replacement,
- Allow owners to self-select, or self-provide, replacement capacity, and;
- Include development of a CAISO system for procuring replacement capacity.

Current Planned Outage Substitution Obligation Timeline

The current POSO timeline is provided in **Figure 5** below. The current timeline provides the first POSO assessment at T-22, or 22 days prior to the start of the RA delivery month, for all outages submitted prior to T-25. This is the first instance when resource owners are provided with indication of any POSO replacement obligations. Resource owners are allowed to provide replacement capacity through the T-8 timeframe and CAISO finalizes replacements and outages at T-7.

Figure 5: Current POSO timeline



Proposed Modifications to the Planned Outage Substitution Obligations Tool

CAISO is proposing several changes to the existing planned outage provisions and Planned Outage Substitution Obligation (POSO) tool. CAISO proposes to redesign the POSO tool to base substitution requirements on system UCAP targets rather than traditional NQC targets. This proposed change is intended to align with the counting rules and RA assessments proposal to incorporate forced outage rates in capacity valuation and assess resource adequacy on a UCAP basis, as detailed in Section 5.1. The proposed modifications include:

- Development of a planned outage calendar
- Requiring comparable substitute capacity
- Development of a substitute capacity bulletin board
- Revisions to CAISO planned outage substitution process

Each of these elements are described below and in greater detail with examples and justification in the subsequent sections.

Planned Outage Outlook transparency

CAISO proposes to offer greater visibility into available resource adequacy compared to requirements. The goal is to provide resources greater transparency regarding available capacity well in advance of planning outages. Specifically, CAISO proposes to develop a calendar that shows, on a daily basis, the potential availability of additional system RA headroom in advance. This RA headroom should allow resources to identify potential calendar dates with RA headroom in advance to request planned outages to mitigate replacement obligations while helping the CAISO maintain adequate available capacity. If the calendar shows no available headroom, then any RA resource requesting a planned outage will be required to show substitute capacity.

Outages will continue to be approved and denied through the outage tool. Outages and substitute capacity will continue to be evaluated, accepted, the outage calendar adjusted on a first-in-last-out basis. This means that resources submitting first will be assessed first and less likely to have their outage denied or require substitute capacity than later requesting resources. Resource owners with resources taking outages requiring replacement will continue to be allowed to self-select (self-provide) substitute capacity for any outages requiring replacement. Resources requesting planned outages during periods when CAISO does not have excess capacity above the RA requirements will be required to procure sufficient UCAP substitute capacity, or have their outage period assessed against their forced outage rate.

Figure 6 demonstrates the conceptual planned outage outlook calendar. CAISO proposes to publish this type of calendar including daily MW values for UCAP headroom in excess of system RA requirements.

Figure 6: Example substitution availability calendar

2 Headroom: 25 MW	3 Headroom: 205 MW	4 Headroom: - MW	5 Headroom: - MW	6 Headroom: - MW	7 Headroom: 350 MW	8 Headroom: 7 MW
9 Headroom: 30 MW	10 Headroom: 712 MW	11 Headroom: 145 MW	12 Headroom: 320 MW	13 Headroom: 200 MW	14 Headroom: - MW	15 Headroom: - MW

Requirements for Comparable Resource Substitution for Planned Outages

CAISO proposed to assess the shown RA fleet through the portfolio analysis discussed in Section 5.1, because the CAISO system is transitioning to a decarbonized fleet with greater reliance on variable, and availability and use-limited resources. Due to this new reality, CAISO believes that it is important to reflect these new operational constraints in related RA topics, including the planned outage substitution obligation requirements.

CAISO believes it may be necessary to place additional constraints on the type of replacement resources that will qualify for meeting the planned outage substation obligation requirements of particular resource types. In other words, CAISO believes it is necessary to propose that POSO requirements ensure like for like replacement obligations, for example – a resource that is available during all hours of the day, with no use or availability limitations, that faces a replacement obligation would be required to replace with a similar resource that was not use or availability limited.

Only certain resources will be acceptable substitution for other resources seeking to take planned outages with replacement obligations. CAISO proposes to adopt an approach to ensure comparable resources are provided for planned outage substitution. CAISO is focused on availability and capabilities, not technology or fuel types. Specifically, CAISO proposing to explore requirements to provide comparability related similarities such as location, use limitations, availability limitations, run time duration limits, and Ancillary Services certification/capabilities.

Table 6: Comparability Categories

Comparability Categories	Issues Considered in CAISO Review
Location	TAC area, Local area
Use Limitations	ULR status
Availability Limitations	Availability Limitations: # of starts per day, # of consecutive days of operation
Ancillary Services certification/capabilities	AS categories: Spin, Non-Spin, Regulation Up, Regulation Down
Run time duration limits	Equal or greater run time duration (at Pmax or full NQC output)

CAISO has identified these categories of comparability for the planned outage substitution obligation as an initial proposal for stakeholder consideration. CAISO will review all planned outages requiring substitution to ensure they are comparable and reliability can be maintained with the substituted resource offered. An example planned outage substitution obligation bulletin board concept is provided below. This example substitution bulletin board includes the potential comparability categories proposed to illustrate how this requirement would be effectuated.

CAISO seeks feedback on the proposed categories (location, use limitations, availability limitations, run time duration limits, and Ancillary Services certification/capabilities). CAISO will explore the implementation feasibility of this proposal for further development in future straw proposal iterations.

Additional issues related to planned outage provisions

Local constraints will continue to be enforced in CAISO's outage planning, and CAISO may deny outages if local reliability issues arise. Self-selected substitute resources (within the same local area) may reduce instances of CAISO denying outages for local reliability issues.

CAISO will retain its authority to deny any outage for reliability reasons, even those that have provided substitute capacity. CAISO will also retain its ability to procure additional capacity through backstop tools for reliability after the planned outage timeframe, as necessary.

Planned Outage Substitution Capacity Bulletin Board

CAISO proposes to develop a bulletin board for resources to match planned outages requiring substitution with substitute capacity resource sellers. The intent of this planned outage substitution bulletin board is to make it easier for resources to connect with potential substitute supply. Resources not shown as RA resources or with additional available UCAP may voluntarily offer that capacity to provide substitute capacity. The resource SC will be able to list resources and a specified price for use of that substitute capacity. Resources looking for substitute capacity can use this bulletin board to find the comparable capacity needed to take the planned outage.

CAISO will provide daily granularity. Resource owners looking for substitute capacity will have visibility into resources offering substitute capacity. Results will be filtered to only substitute capacity suitable for substitution (per replacement comparability requirements). Accepting capacity through this tool will automatically match resources on outage with substitute capacity.

Table 7: Example for a substitution bulletin board

Resource	Use-Limited or Availability - Limited	Run-time duration limit at NQC	A/S Certified	Fuel Type	MWs (NQC UCAP)	Offer ($/kW-Month)
A	Yes (avail-limit)	4 hours	Yes – Reg Up / Down	Battery Storage	20 NQC 18.0 UCAP	$8
B	No	None	Yes – Spin	Gas	50 NQC 44.3 UCAP	$6
C	Yes (starts per day)	24 hours	Yes – Spin	Gas	50 NQC 36.6 UCAP	$5
D	Yes (avail-limit)	2 hours	Yes – Reg Up / Down	Battery Storage	10 NQC 9.2 UCAP	$5
E	No	N/A	Yes – Spin + Reg Up	Gas	100 NQC 94.9 UCAP	$4.5
F	Yes (VER)	N/A	No	Solar	10 NQC 10 UCAP	$2
G	Yes (VER)	N/A	No	Wind	10 NQC 10 UCAP	$2
H	No	16 hours	Yes – Spin	Gas	30 NQC 17.5 UCAP	$2

New planned outage process will be similar to the current process with timing changes

CAISO provides the following figures to show the intended modifications to the planned outage process. The modified process with continue to look and feel similar to the current process, but will include the changes proposed above and the new timeline is described below ("SOM" – start of month).

Figure 7: Planned outage process illustrated

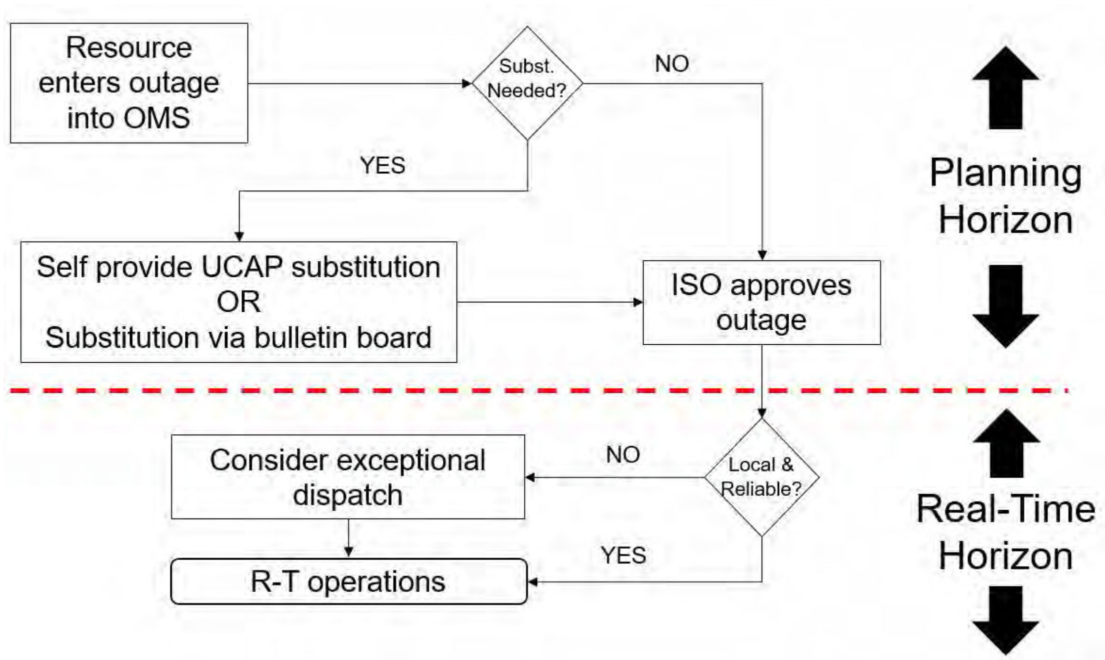
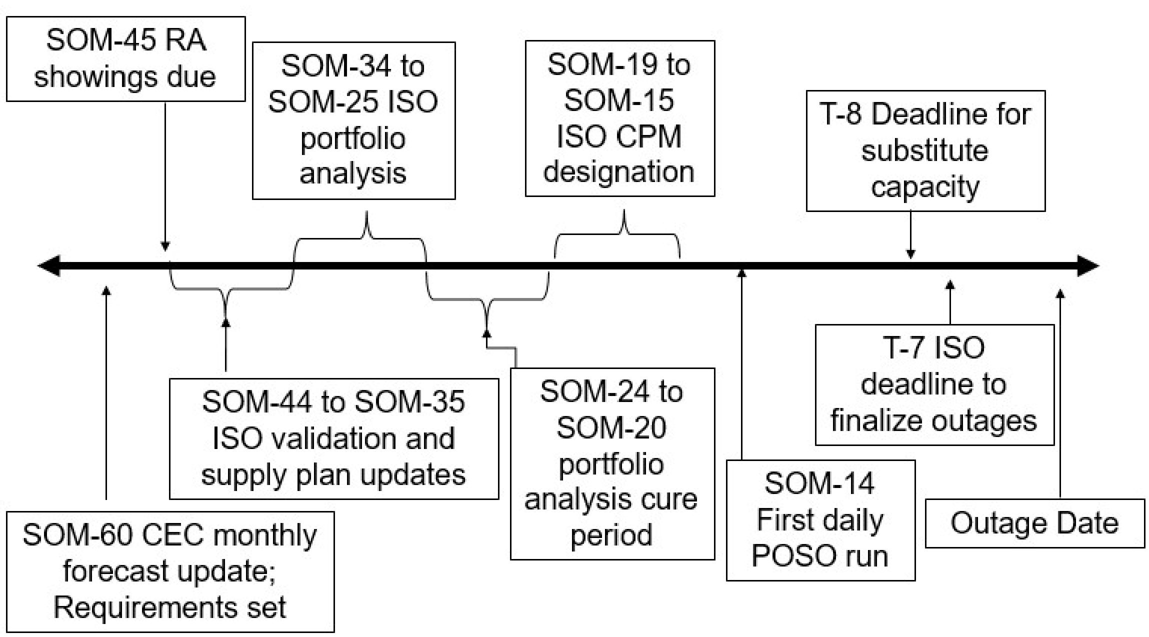


Figure 8: Proposed planned outage obligation process timeline



5.1.6. RA Import Provisions

CAISO has reviewed import RA rules and provisions in this initiative. This review includes an assessment of the requirements and rules for the sources behind RA imports. CAISO provides analysis and an initial proposal for modifications to the RA imports provisions in the following section. Please note that price caps for RA import bid submissions are out of scope of this initiative.

Background

LSEs can meet system RA requirements with a mix of RA resources, which can include imports from outside the CAISO balancing authority area. Import RA resources were used to meet an average of around 3,600 MW (or around 7 percent) of system RA requirements during the peak summer hours of 2017. In the summer of 2018, this increased to an average of around 4,000 MW (or around 8 percent) of system resource adequacy requirements. [19] Thus, the quantities are not insignificant and impact the RA program and its ability to ensure reliability.

Today, RA import resources are not required to be resource specific or to represent supply from a specific balancing area. RA import resources are only required to be shown, and make offers as shown, at a specific intertie point into the CAISO's system. Import RA can be bid at any price below the offer cap and does not have any further obligation to bid into the real-time market if not scheduled in the day-ahead integrated forward market or residual unit commitment process.

Some stakeholders previously expressed concerns with current RA import provisions potentially undermining the integrity of the RA program and threatening system reliability. Additionally, CAISO's Department of Marking Monitoring (DMM) expressed similar concerns in their September 2018 DMM special report on import RA. In that report, DMM explained that the existing rules could allow for some portion of resource adequacy requirements to be met by import RA that may have limited availability and value during critical system and market conditions. For example, import RA could satisfy their RA must offer obligation by routinely bidding significantly above projected prices in the day-ahead market to help ensure they do not clear the market, relieving them of any further offer obligations in real-time. [20]

Clarification of concerns and issues under review

CAISO agrees it is important to consider concerns related to the current import RA provisions. CAISO believes it is useful to clarify the problem statement and objectives for this issue in this revised straw proposal. CAISO is primarily concerned with understanding if the current RA import provisions could cause reliability concerns and determining how any potential concerns can be mitigated. CAISO has previously identified two areas of potential concern related to the current RA import provisions that are explained below.

[19] 2017 CAISO DMM Annual Report, p. 259:
http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf
[20] DMM Special Report: Import Resource Adequacy, September 10, 2018:
http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

Potential concerns related to current RA import provisions:

1. Double counting of RA import resources:

CAISO's RA import provisions should ensure the CAISO can certify that import resources shown for RA are not also being used by the resource's native BA to serve native load, sold to a third party, or being used to meet capacity needs of other areas in addition to CAISO load. CAISO cannot be sure whether RA imports are being double counted or not under current provisions.

2. Speculative RA import supply being used on RA showings:

CAISO's RA import provisions should foreclose (or at a minimum, discourage) the potential for speculative RA import supply. Speculative RA import supply occurs when RA imports shown on RA supply plans have no physical resource backing the showing or no firm contractual delivery obligation secured at time of the showing.

CAISO has described this speculative RA import supply concern previously, and has noted DMM's similar concerns above. Previously CAISO indicated this may be a significant concern due to initial evidence of relatively high priced DA bidding by Non-Resource Specific RA imports, which could be a potential bidding strategy to avoid a subsequent RT MOO or actual RT energy award and resulting delivery obligation. CAISO also notes that this initial analysis was not conclusive and has undertaken further analysis efforts in attempt to better define this issue's possible magnitude and validity.

Objectives

CAISO provides the following objectives that are intended to help guide any potential RA import rule modifications.

- Create more comparable treatment to internal RA resources for RA imports. The current provisions provide less rigorous requirements for RA imports.
  - There is currently no RT MOO for RA import MWs that have not been awarded in the CAISO's IFM.
  - CAISO has no emergency recall ability for non-resource specific RA imports and there is no assurance that external non-resource specific RA imports will respond to CAISO operator's Exceptional Dispatches.

- Consider other aspects of RA Enhancements proposals for incorporating forced outage rates.
  - Ensure fair and comparable treatment to the extent possible for RA imports and specifically non-resource specific RA imports as related to the proposed Unforced Capacity counting and assessment modifications proposed above.

- Ensure coordination with any related modifications being proposed through CAISO's extended EIM and DAME initiatives. Correlation between the RA Enhancements initiative, the Day-Ahead Market Enhancements (DAME) initiative, and the Extension of the Day-Ahead Market to the EIM (EDAM) will be discussed in CAISO's Policy Vision document. CAISO anticipates posting this document in late summer 2019.

RA imports analysis

CAISO completed related import analysis in the summer of 2018 as a part of the Intertie Deviation Settlement initiative.[21] The Intertie Deviation Settlement initiative investigated why awarded import resources are not delivered, the magnitude of non-delivery that occurs, and a proposal to mitigate non-delivery of import resources. The RA Enhancements effort leverages the Intertie Deviation Settlement analysis to determine if there is a problem with non-delivery of import RA when awarded in the CAISO real-time market. The description below describes this analysis effort.

To determine delivery patterns and behavior for import RA resources, CAISO has analyzed three data sets: import RA showing, HASP schedule for import RA resources, and RA delivered quantity. This enables CAISO to identify if the resource was awarded in the real-time market but failed to deliver, did not deliver because the scheduling coordinator failed to bid, or actually delivered a MWh quantity greater than the RA showing.

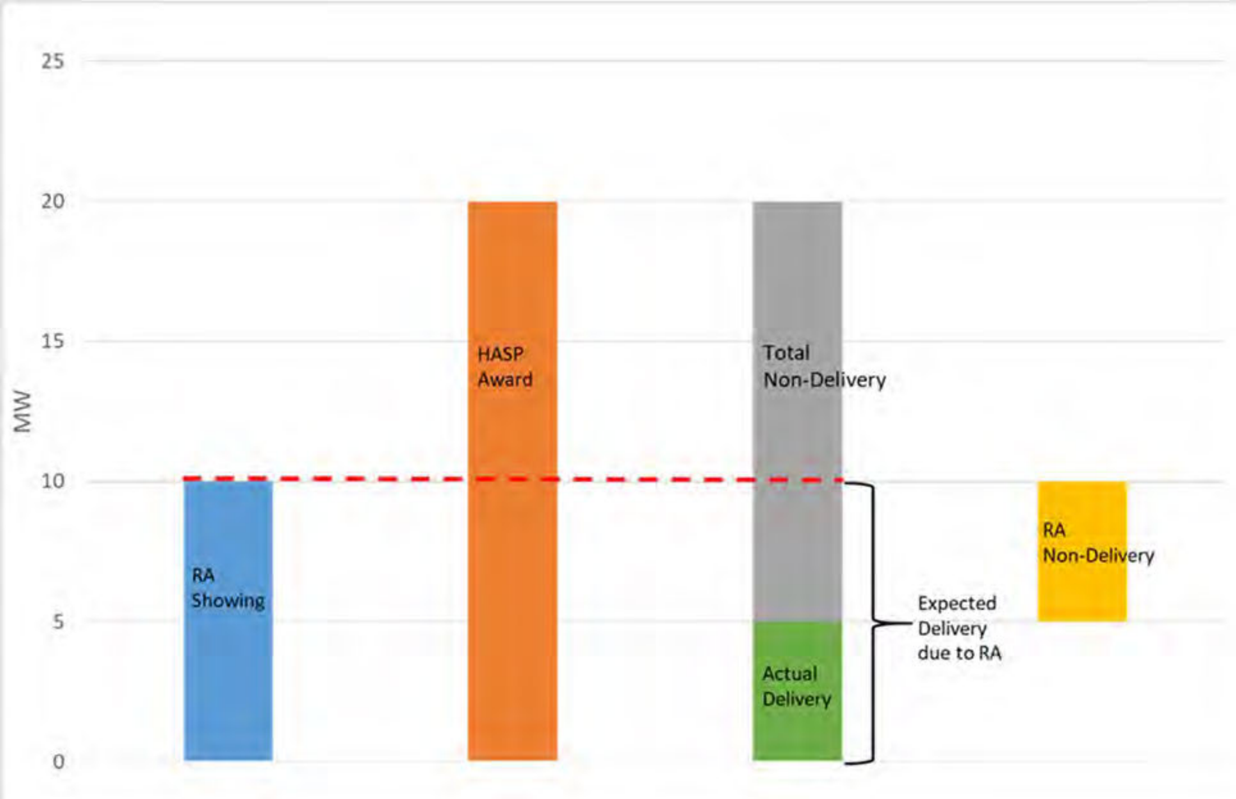
CAISO defines "non-delivery" as the MWh quantity that did not meet the real-time schedule. Because RA imports are scheduled hourly, the non-delivery quantity is determined by comparing the HASP schedule to the RA delivery quantity. It is important to compare these values to the RA showing. Specifically, an RA import resource's Resource ID is not limited to bidding only the amount of MWs that have been shown for RA, and CAISO has observed many instances when bidding and awards for RA import Resource IDs exceed the amount of MWs shown for RA. CAISO attempts to illustrate this issue with a hypothetical example below. Additional analysis to better quantify the potential for any reliability concerns related to RA import non-delivery is also included in the hypothetical example below.

Illustrated in the chart below, 10 MW was shown for import RA and the HASP schedule was for 20 MW during a specific hour. When comparing the HASP schedule to the market dispatch we determine that only 5 MW was delivered. Therefore, 15 MW can be classified as not delivered. This quantity is depicted in the grey colored bar.

To determine how much of this non-delivery can be attributed to import RA, CAISO has assumed the total amount of RA that was expected to be delivered would be the same as the import RA showing. In this example, the non-delivery due to RA imports can be assumed to be 5 MW. While the total amount of non-delivery can be considered a reliability concern, it is particularly concerning that 5 MW of RA was not delivered. This may indicate a potential of speculative RA. This 5 MW that is not delivered is a potential reliability concern.

[21] Information on the Intertie Deviation Settlement initiative can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/IntertieDeviationSettlement.aspx

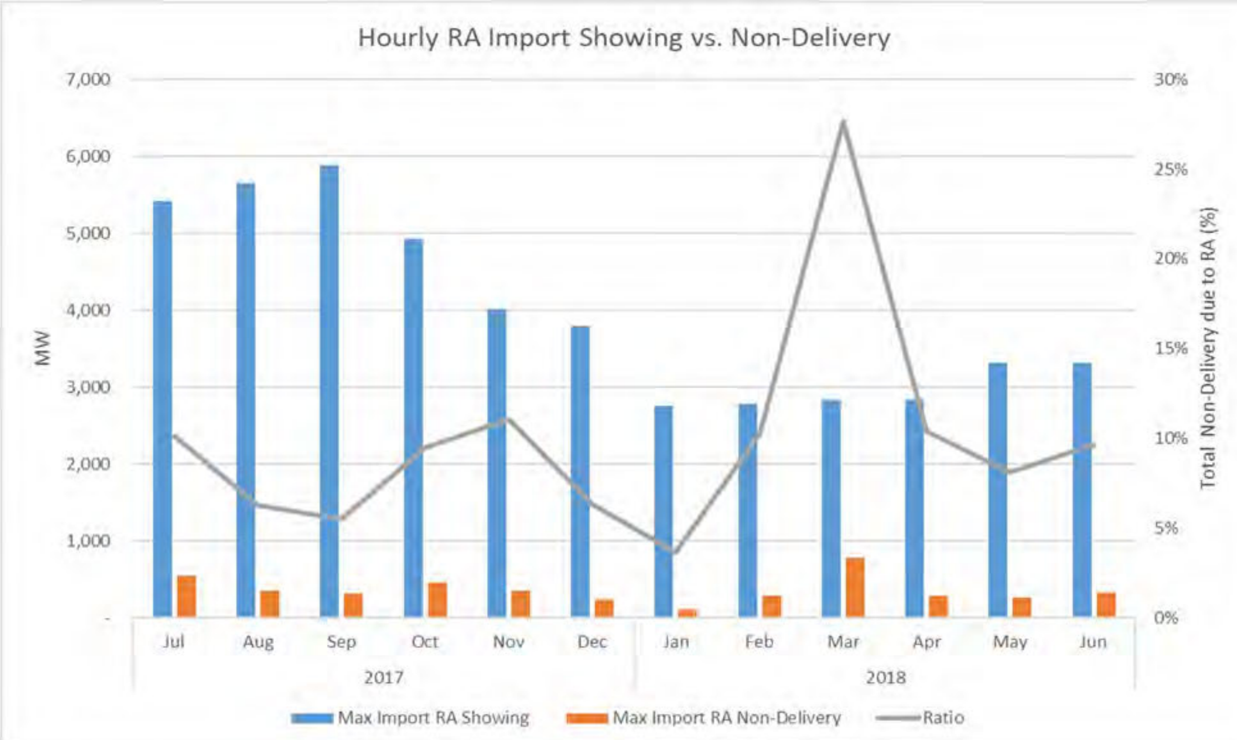
Figure 9: Clarifying potential concerns related to RA import delivery



CAISO has applied the approach described in the hypothetical example above to the initial RA enhancements analysis, previously presented in the CAISO straw proposal on this issue, to ensure that the actual stated magnitude of non-delivery of RA imports provided through this analysis is more accurate and appropriate.

Looking at actual data from July 2017 to June 2018, CAISO observed that in any given hour the maximum amount of import RA classified as RA import non-deliveries does not exceed more than 1,000 MW. When comparing this value to the maximum hourly import RA showings, the amount of non-delivery is a relatively small fraction of the RA imports the CAISO anticipated. The data shows that the worst case scenario for every month (the one hour of the month with the most non-delivery of RA imports), is approximately 10% of the RA showing (*i.e.*, maximum monthly non-delivery observed in a single hour averages approximately 10%). This analysis is shown in the figure below.

Figure 10: Observed undelivered RA import resources accounts for less than 10% on average of hourly RA showings



CAISO notes that the actual non-delivery results after considering the modification to its analysis described above shows a maximum monthly non-delivery of RA imports to be around 10% on average over the study period. Observations of around 10% average non-delivery of RA imports is comparable to WECC-wide average forced outage rates. For this reason, CAISO believes the potential reliability impact of RA import non-delivery may be less a concern than previously thought.

The analysis indicates that non-delivery of RA is not a significantly large or overly concerning magnitude, and therefore may not represent as substantial a reliability concern as CAISO's initial analysis had suggested. The updated analysis is more accurate in this assessment. Saying this, CAISO believes internal RA resources are held to a higher standard than RA imports and CAISO intends to pursue modifications to the current import RA provisions to bring the treatment of RA imports in-line and comparable with internal system RA resource provisions to the extent possible and appropriate. The speculative supply concerns may have some market impacts that could be important, and CAISO is currently undertaking the intertie bidding cost justification initiative to address these related issues.

Additionally, it is important to note CAISO is addressing all non-delivery (regular imports and RA imports) with the Intertie Deviation Settlement proposal. The proposal is scheduled for fall 2020 implementation, and will impose an additional charge on intertie resources that are scheduled in the HASP process but are not delivered. This new charge will incentivize delivery of awarded intertie resources. When comparing the Intertie Deviation Settlement proposal to the RA rules, CAISO believes Intertie Deviation Settlement proposal provides an incentive for RA import delivery and therefore CAISO does not believe it is necessary to impose to the UCAP concept for non-resource specific RA imports.

Proposed RA Import Rule Modifications

CAISO proposes to require specification of the Source BA for all RA imports on RA and Supply Plans for monthly showings. CAISO also proposes to adopt and codify provisions similar to current CPUC RA program rules and regulations for RA imports to provide firm monthly delivery in CAISO's tariff to ensure similar treatment among all LSEs. These modifications are described in further detail below.

Specification of RA Import Resource Balancing Area Source

The CAISO's current RA provisions allow for Non-Resource Specific Resources to qualify to provide System RA. As noted above, RA import resources are not required to be resource specific or to provide any greater certainty they represent supply from a specific Balancing Area. Instead they are only required to be shown as sourced on a specific intertie into CAISO's system.

Because of tighter supply in the West, CAISO has expressed increasing concerns about the potential for Non-Resource Specific RA import resources to be double counted for reliability. This may occur when a resource is shown to the CAISO as RA while also being concurrently relied upon by other regions or Balancing Areas (BA) to meet capacity or energy needs. CAISO is proposing modifications to specify the source of RA imports to ensure all RA import resources are fully available and dedicated to CAISO for reliability. This is an increasingly important matter as CAISO considers extending the day-ahead market to EIM entities, ensuring that resources outside of CAISO's BA are not double counted for meeting resource sufficiency requirements.

CAISO proposes to require specification of the Source BA for all RA imports on RA and Supply Plans for monthly showings. With the extension of the day-ahead market to EIM entities, CAISO believes that, at minimum, RA import resources must specify the source Balancing Area. The proposed modification would allow CAISO to ensure that RA imports are not double counted for EIM entities' resource sufficiency tests. CAISO believes that requiring a designation of the source Balancing Area ("Source BA") will be sufficient to assist in ensuring that RA imports are not being double counted for EIM resource sufficiency tests.

CAISO has also discussed a potential modification to require "resource-specific" designations as a qualification to provide RA imports with stakeholders. As noted above, CAISO believes that the additional analysis provided supports a determination that it is not necessary to propose a resource-specific requirement for RA imports at this time.

Incorporating CPUC RA program RA imports rules and regulations in CAISO's tariff

CAISO has had ongoing discussions with CPUC staff regarding current CPUC RA provisions for RA imports. An area of mutual concern is the potential for unspecified imports being used to meet Resource Adequacy (RA) requirements that may not be firm and supported by spinning reserves.

Prior CPUC decisions have specified the CPUC's qualifying capacity rules require that there are sufficient physical resources – both energy and operating reserves – behind imports used to meet RA requirements. Specifically, D.04-10-035, adopted the following methodology:

> *"The qualifying capacity for import contracts is the contract amount if the contract (1) is an Import Energy Product with operating reserves, (2) cannot be curtailed for economic reasons, and either (a) is delivered on transmission that cannot be curtailed in operating hours for economic reasons or bumped by higher priority transmission or (b) specifies firm delivery point (i.e., is not seller's choice)."* [22]

The CPUC's RA program allows for non-unit specific imports to qualify to meet RA requirements as long as they meet import deliverability requirements and have sufficient physical resources associated with them (i.e., spinning reserve and firm energy delivery to a certain point). The CPUC's Decision D.05-10-042 specifically states that:

> *"Firm import LD contracts do not raise issues of double counting and deliverability that led us to conclude that other LD contracts should be phased out for purposes of RAR. We note that firm import contracts are backed by spinning reserves. Accordingly, we approve the exemption of firm import LD contracts from the sunset/phase-out provisions applicable to other LD contracts as adopted in Section 7.4."* [23]

To ensure that import rules are followed both in form and substance, the CPUC requires that LSEs provide documentation in their current RA compliance filing that reflects that the unspecified imports being submitted to meet RA requirements have firm energy delivery and operating reserves behind them. The CPUC has specified that this documentation can be in the form of contract language or an attestation from the import provider that confirms the import is supported by firm energy and operating reserves.

CAISO believes it is appropriate to incorporate similar provisions for RA imports in its tariff. Therefore, CAISO proposes that all LSEs must submit supporting documentation that any non-specified RA import resource being shown on annual and monthly RA and Supply plans have firm energy delivery. Similarly to the CPUC requirements, the support documentation that CAISO will also require can be in the form of contract language or an attestation from the import provider that confirms the import is supported by firm energy and operating reserves.

[22] See CPUC Decision D.04-10-035 Workshop Report at 21, available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/REPORT/37456.PDF
[23] See CPUC Decision: D.05-10-042 at 68.

No Longer Proposing Real-Time Bidding Requirements for All RA Imports

Currently, RA imports have a day-ahead must offer obligation, but only have a real-time must offer obligations if they receive a day-ahead award. The real-time must offer obligation for these RA import resources is only for the amount of MWs awarded in the day-ahead market. CAISO previously proposed to extend the must offer obligations for RA imports into the real-time markets, including all shown RA capacity, not only for resources/MWs scheduled in IFM or RUC. One reason for this previous proposal was to provide CAISO access to RA imports for reliability through real-time, and also in hopes to further mitigate the potential for suppliers and LSEs to provide RA showings that may include speculative supply.

However, after reviewing stakeholder feedback and considering the related consequences of extending RA import bidding requirements into real-time, CAISO does not believe it is appropriate to pursue a full real-time bidding requirement for all RA import MWs regardless of their day-ahead awards. Therefore CAISO is proposing to maintain the current bidding rules for RA imports and only MWs that have received day-ahead awards will be required to bid in real-time.

Feedback provided by the CPUC on this issue provided its rationale for exempting non-resource specific RA imports from a real time bidding obligation:

> *"…in D.06-12-067 the Commission exempted imports, supported solely by non-dynamic system resources (non- resource specific), from the real time must offer obligation, stating that they cannot be preferentially called upon during congestion conditions to meet the CAISO's needs even if they are subject to a real-time obligation." Parties' argued that a real-time obligation is unworkable because imports do not have transmission priority under FERC's open access rules."* [24]

CAISO believes that this aspect of the RA imports proposal should continue to align with the current CPUC rules regarding bidding obligations for non-resource specific resources. This will maintain alignment of CAISO tariff provisions with current CPUC rules for RA imports on this issue as well.

Additional justification for maintaining the current rules for non-resource specific RA import bidding in real-time is to continue allowing for release and use of the transmission capability associated with these RA imports. The current provisions provide greater ability for the most efficient utilization of transmission capability because when the non-resource specific imports do not clear the day-ahead market for some or all of their shown RA capacity, the associated transmission can be released for use in the real-time market by economic energy imports. CAISO believes this impact to potential efficient utilization of the transmission system is important to consider regarding this issue.

Requiring a real-time bidding obligation for all non-resource specific RA imports could have a negative impact on the efficient utilization of the transmission, potentially increasing overall

[24] http://www.caiso.com/Documents/CPUCComments-ResourceAdequacyEnhancements-StrawProposalPart1.pdf

costs to serve load. This could occur if an RA import resource's bid in the real-time was priced at a level that would not clear the market, precluding the utilization of that reserved transmission capability. In this potential scenario a lower cost energy import that may have cleared the real-time market could be precluded from being awarded and overall costs to serve load could be increased in comparison. For these reasons, CAISO believes it is appropriate to maintain the current real-time bidding rules for non-resource specific RA imports.

No Longer Proposing Changing RA Import Must Offer Obligations to 24 by 7

CAISO has also considered expanding MOO requirements for RA imports to 24 hours, 7 days a week in prior iterations of this initiative. The potential for changing the RA import MOO to a 24 by 7 requirement was intended to ensure resource availability during all hours of the day to meet reliability needs that can occur at any time, not just during peak periods. Following CAISO review of stakeholder feedback and considering the related consequences of this change, CAISO does not believe it is appropriate to pursue a 24 by 7 bidding obligation for all RA imports at this time.

CAISO understands that such an extension of the bidding obligations would fully preclude any sub-set of hours import contracts for firm energy delivery from qualifying to meet RA requirements. While there are some benefits of the potential change, considering the updated analysis on RA imports described above, this change and resulting impact of removing qualification of some helpful resources does not appear justified at this time. Sub-set of hours contracts for firm energy delivery RA imports may also assist in meeting peak needs in future periods that could present challenges as the system begins to experience tightening supply across the west.

CAISO also intends to conduct additional analysis and explore relevant events to determine if the current proposal continues to be appropriate. CAISO seeks stakeholder feedback on the proposed RA import provisions modifications.

5.1.7. Maximum Import Capability Provisions

Each year, CAISO establishes maximum import capability (MIC) values for import paths. CAISO's tariff defines maximum import capability to mean "a quantity in MW determined by CAISO for each Intertie into CAISO Balancing Authority Area to be deliverable to the CAISO Balancing Authority Area based on CAISO study criteria." [25] Once these values are calculated, the capacity is allocated to scheduling coordinators for LSEs in the CAISO BAA for resource adequacy purposes.

CAISO received requests from stakeholders regarding the need to review both the MIC calculation and allocation provisions. Some stakeholders have indicated that CAISO should consider alternative calculation methods, and have also asserted that there are numerous challenges presented by the current 13-step Import Capability Assignment process. In response to stakeholder input and feedback, CAISO is conducting a comprehensive review of

[25] See Appendix A to CAISO tariff.

the CAISO's Import Capability provisions, including; calculation methodologies, allocation process, and reassignment/trading provisions.

Import Capability Background

CAISO assesses the deliverability for imports using the MIC calculation methodology. CAISO calculates the MIC MW amount mainly based on a historic methodology that utilizes the actual schedules into the CAISO's BAA for highest imports obtained simultaneously during peak system load hours over the last two years. CAISO examines the prior two years of historical import schedule data during high load periods. Sample hours are selected by choosing two hours in each year, and on different days within the same year, with the highest total import level when peak load was at least 90% of the annual system peak load. CAISO then calculates the historically-based MIC values based on the scheduled net import values for each intertie, plus the unused Existing Transmission Contract (ETC) rights and Transmission Ownership Rights (TOR), averaged over the four selected historical hours. This concept is an important fundamental principle of the MIC framework, intended to ensure that existing ownership rights and pre-existing RA commitments and contracts should be recognized and honored.

MIC values for each intertie are calculated annually for a one-year term and a 13-step process is used to allocate MIC to LSEs. MIC allocations are not assigned directly to external resources, rather LSEs choose the portfolio of imported resources they wish to elect for utilization of their MIC allocations. This is also an important principle underlying the MIC framework. The reason that MIC is allocated to LSEs is the fundamental concept that LSEs pay for the transmission system so they should receive the benefits from it, and this is the reason that MIC is allocated to LSEs and not all market participants. Once the allocation process is complete, LSEs can use their MIC allocations on each intertie to support their procurement of RA capacity from external resources. The 13 step import capability allocation process is detailed further below.

RA showings designating import MWs to meet RA obligations across interties using either Non-Resource-Specific System Resources, Pseudo-ties, or Dynamically Scheduled System Resources are required to be used in conjunction with a MIC allocation and are considered a firm monthly commitment to deliver those MWs to CAISO at the specified interconnection point with the CAISO system.

Maximum Import Capability Calculation Review

For most interties, CAISO calculates MIC values based on historical usage of a given intertie. This historically-based MIC methodology establishes a baseline set of values for each intertie. As noted above, this calculation is based on the maximum amount of simultaneous energy schedules into CAISO BAA, during select CAISO coincident peak system load hours over last two years. CAISO also performs a power flow study in the CAISO's TPP to test MIC values to ensure each intertie's MIC can accommodate all state and federal policy goals; if any intertie is found deficient, CAISO establishes a forward looking MIC for that intertie and plans the system to accommodate this level of MIC in the TPP and RA.

Some stakeholders provided feedback indicating they believe the MIC calculation methodology should be modified to be a forward looking approach for all MIC values, in contrast to continuing to use only the forward looking MIC approach that is currently utilized in limited circumstances along with the current historic methodology used for most interties. CAISO has observed declines in MIC values determined in recent years that are reflective of the historic import data during the selected study period. The data provided in Table 8: Historic MIC dataTable 8, below, provides relevant MIC values calculated over time using the current methodology.

Table 8: Historic MIC data

MIC RA Year	2014	2015	2016	2017	2018	2019
Maximum Import Capability (MWs)	17,486	16,228	15,755	15,221	14,852	15,208
ETC and TOR held by non-CAISO LSEs (MWs)	4,090	4,090	4,090	4,211	4,511	5,015
Available Import Capability for CAISO Resource Adequacy purposes (MWs)	13,396	12,138	11,665	11,310	10,341	10,193
Total Pre-RA Import Commitments & ETC (MWs)	6,047	5,426	5,256	4,736	4,628	4,306
Remaining Import Capability - less all ETC and TOR (MWs)	7,348	6,712	6,409	6,574	5,713	5,888

The CAISO's initial review of the MIC calculation process indicates that the current MIC calculation methodology is still appropriate. CAISO believes the calculation methodology is still working as intended without significant impact to reliability or LSEs' ability to utilize imports for RA purposes. As such, CAISO is not proposing to make any modifications to the calculation methodology at this time.

CAISO is open to additional feedback on the MIC calculation methodology position and seeks input on potential analysis or alternative calculation methodology proposals for further review.

Available Import Capability Assignment Process Background

CAISO assigns the total Available Import Capability on an annual basis for a one-year term to LSE SC serving Load in CAISO's BAA and, in limited circumstances, to Scheduling Coordinators representing Participating Generators or System Resources, through the 13 step allocation process detailed in the CAISO tariff, Section 40.4.6.2.1, Available Import Capability Assignment process.

This multi-step assignment process of import capability does not guarantee or result in any actual transmission service being assigned, and it is only used for determining the import capability that can be credited towards satisfying the Reserve Margin of a LSE under CAISO tariff Section 40. Following the 13 step Available Import Capability allocation process, LSEs have the opportunity to trade their assigned Import Capability with other entities bilaterally. This trading opportunity is detailed in the CAISO tariff Section 40.4.6.2.2, Bilateral Import Capability Transfers and Registration Process.

The following table lists the 13 steps of the Available Import Capability Assignment Process. This process is also described in further detail in the appendix.[26]

Table 9: Available Import Capability Assignment process overview

Step	Process description
Step 1	Determine Maximum Import Capability (MIC)
	- Total ETC
	- Total ETC for non-ISO BAA Loads
Step 2	Available Import Capability
	- Total Import Capability to be shared
Step 3	Existing Contract Import Capability (ETC inside loads)
Step 4	Total Pre-RA Import Commitments & ETC
	- Remaining Import Capability after Step 4
Step 5	Allocate Remaining Import Capability by Load Share Ratio
Step 6	CAISO posts Assigned and Unassigned Capability per Steps 1-5
Step 7	CAISO notifies SCs of LSE Assignments
Step 8	Transfer [Trading] of Import Capability among LSEs or Market Participants
Step 9	Initial SC requests to ISO to Assign Remaining Import Capability by Intertie
Step 10	CAISO notifies SCs of LSE Assignments & posts unassigned Available Import Capability
Step 11	Secondary SC Request to ISO to Assign Remaining Import Capability by Intertie
Step 12	CAISO Notifies SCs of LSE Assignments & posts unassigned Available Import Capability
Step 13	SCs may submit requests for Balance of Year Unassigned Available Import Capability

Available Import Capability Assignment Process issues under consideration

Considering the issues and concerns raised by some stakeholder's, CAISO is considering potential enhancements to the Import Capability Assignment process. The following concepts have been discussed with stakeholders in previous iterations of the RA enhancements initiative:

- Incorporate an auction or other market based mechanism into the Available Import Capability Assignment process

[26] Also see Section 40.4.6.2.1 of CAISO Tariff.

- Allow for the release and reallocation of unused import capability after initial monthly RA showings
- Enhance the provisions for reassignment, trading, or other forms of sales of Import Capability among LSEs

CAISO has developed two different auctions mechanism options. These options are detailed below. In regards to the second and third concepts, CAISO is not offering detailed proposals at this time because the any policy to address release/reallocation and trading/reassignment will directly depend on the viability of the proposed auction mechanism. However, CAISO offers additional thoughts on those topics as well.

Available Import Capability Assignment Process modification options

Some stakeholders asked CAISO to incorporate an auction or other market based mechanism into the Available Import Capability Assignment process. They assert that doing so will provide alternatives or additional opportunities for procurement of import capability by LSEs that may need to secure more than their pro rata load ratio share of MIC on any given branch group/intertie to support a particular RA contract. Alternative mechanisms could allow for more efficient procurement of import capability by those LSEs that place a greater value on the Import Capability for various reasons. CAISO could allocate all, or only a portion of the remaining Available Import Capability through a mechanism similar to the current process but CAISO could retain all, or a portion of the remaining Available Import Capability, to be auctioned or otherwise procured by LSEs. Additional auction revenues could potentially be used to reduce the TAC Transmission Revenue Requirement, or allocated back to LSEs on a pro rata load share basis.

CAISO proposes to develop and include an auction mechanism in the Available Import Capability Assignment Process. CAISO believes that incorporating an auction into the Available Import Capability Assignment Process is the best approach to address stakeholder concerns and efficiency issues related to the import capability assignment process.

As a starting point, CAISO presents an initial auction design concept for consideration and discussion purposes. CAISO will consider the level of stakeholder support, implementation feasibility, and economic market design principles in decisions for future proposal direction on this preliminary import capability auction design.

CAISO proposes to develop an auction mechanism to sell and allocate all Remaining Import Capability to LSEs, following current Step 4 (after CAISO has protected for all ETCs, TORs, and Pre-RA commitments in the current process through Step 4). The proposed auction mechanism would be included in the process to replace current Steps 5 through 13.

- The proposed auction mechanism will provide LSEs an opportunity to procure intertie-specific import capability rights for all of the Remaining Import Capability
- Following Step 4 of the current process, CAISO would keep all of the Remaining Import Capability unassigned and make it all available through this auction process.
- An auction allows LSEs to determine the value they place on import capability on any branch groups. LSEs can then bid for the import capability they need. Import capability will be allocated according to LSE bids.

- 100% of the Remaining Import Capability will allocated based upon bids to buy on specific interties, with each intertie becoming a specific a product.
- Any auction revenues could potentially be used to reduce the TAC Transmission Revenue Requirement or allocated back to LSEs on a pro rata load share basis. CAISO seeks feedback on these options for auction revenue allocation.

CAISO believes the proposed auction mechanism can provide the greatest responsiveness to the stakeholder concerns related to fairness, and the potential for hoarding, or underutilization of assigned import capability by some LSEs. The auction mechanism provides a more equitable solution than today by ensuring that import capability is allocated to those entities that value it most, instead of simply allocating to LSEs based on their load share ratio. This inequity driven by the comparative size of LSEs is inherent in the current process and CAISO hopes to provide some solutions to mitigate its impacts. CAISO also notes that the proposed auction mechanism may address many of the concerns raised regarding the current process; however, due to the inherent inequity caused by the relative size of LSEs, and how much each LSE's customers pay to meet their relative portion of overall TAC charges, the proposed auction mechanism may also still result in some inequitable outcomes and issues related to potential inefficient outcomes.

Current practices related to the import capability allocation process are particularly troubling given the fact that almost half of the total allocated import capability goes unused in during most months. The proposed auction mechanism also attempts to address potential hoarding or underutilization concerns by encouraging LSEs to only bid for import capability on interties that they truly need import capability on to meet their procurement plans. CAISO believes this design may be helpful to discourage LSEs from attempting to win import capability awards above their true procurement needs. CAISO seeks stakeholder feedback on this proposed auction design.

CAISO also notes that under any potential auction design, CAISO will continue to ensure that the total amount of MIC allocated to LSEs on each specific intertie branch group is within the studied value for each intertie.

Other Import Capability Allocation Process issues

As noted above, the manner in which CAISO addresses release/reallocation and trading/reassignment concerns will directly depend on the viability of an auction mechanism and the version selected. However, at this time, CAISO offers these additional thoughts on those topics:

- Modifications to allow for the release and reallocation of unused import capability after initial monthly RA showings:
    - CAISO is considering if it is appropriate to subject some or all of LSEs' unused import capability to a release mechanism. Stakeholders suggested that intertie capability not used to support an RA contract within a respective RA procurement timeframe should be released and made available to other LSEs and market participants to support RA contracts. Stakeholders expressed efficiency and fairness

concerns related to the current provisions, stating views that some LSEs may potentially hoard assigned import capability without utilizing it on RA plans and showings. These stakeholders claim this is unfair to smaller LSEs and may underutilize the available import capability, resulting in inefficiencies.

  - For any changes to this aspect it is important for CAISO to ensure that it is also able to maintain the fundamental principle that entities that fund the costs associated with intertie facilities, *i.e.*, internal LSEs that pay the Transmission Access Charge ("TAC") should have priority access to the use of import capability to support their own RA contracts, similar to the current process. In other words, the entities funding the embedded cost of CAISO interties should be given the first opportunity to use that intertie capacity to support an RA contract in each RA procurement timeframe.

CAISO did not develop this change in the current proposal. The initial concept was suggested by some stakeholders to address efficiency concerns, but CAISO has not identified a workable approach to incorporate any import capability release provisions or requirement. CAISO remains open to the possibility of this option, however, CAISO believes that the proposed auction options included below may be able to address the related concerns expressed by stakeholders.

- Enhance the provisions for reassignment, trading, or other forms of sales of Import Capability among LSEs:
  - Modification of this aspect of the process may still be needed to provide alternative approaches to bilateral transfers to better facilitate the transfer of Import Capability among LSEs and improve the efficient utilization of Import Capability if described above are not pursued.

CAISO remains open to changes that enhance the facilitation of trading import capability. However, at this time, CAISO has not proposed any specific enhancements and believes the proposed auction mechanism options discussed may address the concerns and issues with the current trading options.

5.2. Flexible Resource Adequacy

CAISO will seek to close certain gaps by developing a new flexible RA framework that more deliberately captures both CAISO's operational needs and the predictability (or unpredictability) of ramping needs. Changes to the flexible capacity product and flexible capacity needs determination should closely align with CAISO's actual operational needs for various market runs (*i.e.*, day-ahead market and fifteen-minute market).

Background

In 2014, CAISO filed, and FERC approved, tariff revisions to implement CAISO's FRACMOO proposal. CAISO developed the original FRACMOO proposal and accompanying tariff provisions through an extensive stakeholder process in collaboration with the CPUC, municipal utilities, investor-owned utilities, generators, environmental groups, and other market participants. The FRACMOO proposal was a first step toward ensuring that load serving entities procured and offered resources to CAISO that would ensure CAISO had sufficient flexible capacity to reliably operate the transforming grid that was growing more reliant on distributed and variable energy resources. The tariff provisions resulting from that effort provided CAISO with a flexible capacity framework. Specifically, the FRACMOO tariff provisions established:

- A study methodology for determining flexible capacity needs and allocating those needs to local regulatory authorities;
- Rules for assessing the system-wide adequacy of flexible capacity showings;
- Backstop procurement authority to address system-wide deficiencies of flexible capacity; and
- Must offer obligations to ensure CAISO has the authority to commit and dispatch flexible resources through its markets.

When CAISO filed the tariff revisions to implement the FRACMOO proposal with FERC, CAISO stated:

> This simplified initial approach provides a smooth transition to establishing durable flexible capacity requirements. CAISO has committed to re-evaluating the effectiveness of the flexible capacity requirements in 2016 to consider, among other matters, whether enhancements are needed to meet system flexibility needs or to allow resources that are dispatchable on a fifteen-minute basis to fulfill a portion of the flexible capacity needs.[27]

The original FRACMOO proposal was a first step toward ensuring that adequate flexible capacity was available to the CAISO to address the needs of a more dynamic and rapidly transforming grid. The FRACMOO proposal also represented the first ever flexible capacity obligation in any ISO market, recognizing that a resource adequacy program should include both the size (MW) of resource needs and the attributes of the resources providing them (*e.g.*, dispatchability and ramp rate). CAISO anticipated making enhancements to the original FRACMOO tariff provisions once it had experience with a flexible capacity paradigm and better understood the system's flexible capacity needs, especially in light of CAISO's operational needs and the transforming grid.

Subsequently, CAISO initiated the FRACMOO2 stakeholder process. The objective of that initiative was to make changes to the existing flexible capacity to address fundamental gaps between CAISO's markets and operational needs the current flexible RA product. Although the FRACMOO2 initiative was placed on hold, the objectives and work from that initiative have been integrated into the present initiative.[28]

[27] Transmittal letter at p. 19.
[28] At this time, CAISO is closing the FRACMOO stakeholder process.

5.2.1. Identifying Flexible Capacity Needs and Requirements

Flexible capacity needs

In an effort to define a flexible RA capacity requirement, CAISO reviewed the drivers of flexibility on the system. This assessment sought to identify reasons CAISO would need to move resources from a fixed schedule. The goal of this assessment was not to expand the requirement definitions for flexible RA, but to more clearly identify how CAISO can access flexibility, then determine if an identified flexibility need required forward procurement to ensure adequate capacity is available to the CAISO. Although flexibility is required in all intervals to satisfy CAISO operational needs, not all types of flexibility are required in all hours. CAISO identified multiple drivers of CAISO need for flexibility, including:

- Forecasts (i.e. load, VER, BTMs) improve between market runs
- Timing granularity differs between market runs (1 hour, 15 min, 5 min)
- Deviations from dispatch
- Shaping around prescribed delivery of interties (Hourly blocks and industry ramp blocks)
- Net-load ramps are non-linear

CAISO defines its flexible capacity needs into the following three categories based on dispatch, controllability, and the response required in certain time horizons:

- Primary – Frequency Response (Impacted by secondary and tertiary)
- Secondary – Regulation and AGC (Impacted by tertiary)
- Tertiary – Market flexibility needs

CAISO requires all three types of flexibility, but not all must be procured through a resource adequacy construct. For example, primary flexibility is a requirement embedded in the resource interconnection process. Secondary flexibility needs ensure CAISO has sufficient regulation. At this time, CAISO has sufficient regulation capability incentivized and procured through the CAISO market to address this flexibility need.

Finally, tertiary flexibility, i.e. ensuring the market has sufficient flexibility reserved to address day-to-day operational needs has numerous benefits that may not be fully realized absent express procurement in the forward planning horizon. Examples of benefits from forward planning for tertiary or market flexibility needs include:

- Realization of full EIM benefits
- Predictable and economic retirement of resources
- Facilitate state environmental policy at lowest cost
- Mitigate random price spikes
- Provide for lower cost, more reliable dispatches
- Ensures CAISO can maintain reliability during highly variable weather conditions

As a result, CAISO's flexible capacity needs are to ensure:

- Markets have sufficient economic bid range to dispatch around load and resource variability (or inflexibility), manage significant net load ramps, address uncertainty and differences in market granularity (i.e. hourly vs. fifteen minute) between market runs,
- CAISO always has sufficient flexible capacity to pass its own EIM ramp sufficiency tests
- Flexible resources have a path to economic viability relative to inflexible resources (i.e. leads to more rational retirement)

CAISO reviewed the day-to-day operational system needs pertaining to flexible capacity. CAISO observes the need for two categories of flexible capacity:

1) Predictable: known and/or reasonably forecastable ramping needs, and

2) Unpredictable: ramping needs caused by load following and forecast error.

These two types of flexible capacity needs ─ predictable and unpredictable ─ drive different forms of flexible capacity procurement needs. Predictable and reasonably forecastable ramping needs require a set of resources economically bidding into CAISO's day-ahead market to properly shape the day-ahead market to meet forecastable ramps. This allows CAISO to create a feasible market dispatch in the day-ahead market without relying on penalty parameters or exceptional dispatches. However, once CAISO produces a day-ahead dispatch solution CAISO must rely on real-time market dispatches to account for unpredictable ramps caused by uncertainty.

CAISO's flexible capacity framework is based on connecting these two ramping needs into a single framework. The remainder of this section describes each type of ramping need.

Predictable and forecastable ramping needs

The current flexible RA needs determination is based on the largest forecasted three-hour net load plus 3.5 percent expected peak load.[29] The greatest net load ramps are largely driven by the sunset during the non-summer months. Numerous stakeholders questioned the need for a specific RA requirement predicated on ramps that are largely predictable. CAISO agrees these ramps are largely forecastable on a day-to-day basis; however, this does not mean forward procurement to meet these ramps is not important for continued reliable operations. Setting up a fleet of resources with economic bids to meet day-ahead net load ramps allows CAISO to better shape day-ahead commitments. Specifically, a deeper pool of resources that are flexible in the day-ahead market through day-ahead economic bids will improve the efficiency of CAISO dispatch and management of renewable resources.

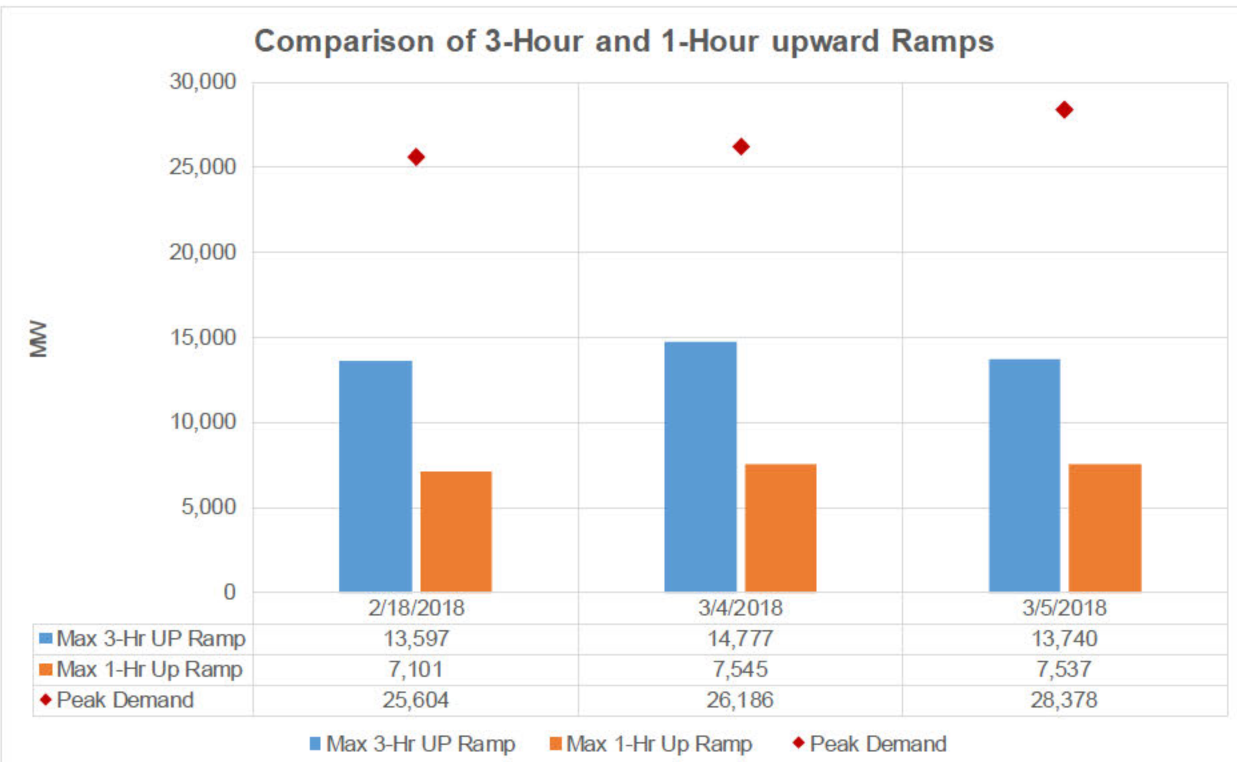
To date, CAISO manages most resource commitments through the day-ahead market process. CAISO does not expect this to change. However, CAISO expects net load ramps to grow and minimum net load to decrease over time with the growing penetration of solar resources. This

[29] The 3.5 percent portion of this equation was originally established to address overlap between flexible RA provisions and contingency reserves. However, the basis for determining the quantity of contingency reserves needed has since been revised.

will likely lead to ramp constraints within the RA fleet and require additional exceptional dispatches if not addressed through forward planning. As such, CAISO proposes to maintain a requirement for, and assessment of, flexible capacity that ensures there is sufficient bid range to cover the forecasted maximum three-hour net load ramps. CAISO envisions that this requirement will provide the resources CAISO needs to shape day-ahead market awards and commitments based on market solutions and should mitigate the need for exceptional dispatches and Capacity Procurement Mechanism (CPM) designations.

The three hour net load lamp is not a linear ramp, it is logistic. This means there is a segment within the three hour net load ramp that requires a much faster ramp rate than the rest of the net load ramp. Currently, 3-hour upward ramps are over 50% of daily peak demand. As shown Figure 11, the largest 1 hour net load ramps can be more than 50 percent of the three hour net load ramp indicating need for faster ramping resources.

Figure 11: Comparison of three hour and one hour net load ramp



CAISO will develop flexible capacity requirements to address both of these needs.

Unpredictable and uncertain ramping needs

With the continued expansion of VERs and behind-the-meter solar photovoltaic systems, both load and generation output will continue to create greater uncertainty between the day-ahead and real-time markets. Under the current ISO market rules, no additional long-start resources are committed after the day-ahead market closes and RUC awards are made. All remaining uncertainty, including both load following and forecast error, must be addressed by resources previously committed in the day-ahead market or faster starting resources available for commitment in the real-time market.

CAISO's first full market run is its day-ahead market. This market is currently run with hourly granularity using a forecast between 14 to 36 hours ahead of actual operations. Given the large time gap between the day-ahead market run and the 15 minute market, there can be significant differences between the two market iterations based on forecast error and time granularity. This is particularly true during sun rise and sun set.

CAISO is developing market rules to procure imbalance reserves as part of its Day-Ahead Market Enhancements stakeholder initiative.[30] The objective of imbalance reserves is to ensure the day-ahead market has sufficient resources awarded with upward and downward ramping capabilities to address real-time imbalances. Resources that receive an imbalance reserve award will have a must offer obligation in the real-time market. The energy bids associated with the imbalance reserve award will enable the real time market to address uncertainties that materialize between the day-ahead market and real-time market through economic bids.

CAISO proposes to develop flexible resource adequacy capacity requirements to align with the proposed imbalance reserves to address uncertainty needs between the day-ahead and fifteen minute markets. While the benefits of having sufficient ramping capabilities to address the three-hour net load ramp were addressed in great detail through the initial FRACMOO process, the challenges with uncertainty in the forward planning horizon did not receive comparable attention. Therefore, CAISO provides additional details and descriptions about the challenges and magnitude of issues to be addressed.

5.2.2. Identifying Flexible RA Requirements

The current flexible RA capacity requirements are divided into three categories, differentiated primarily by resource eligibility and the must-offer obligation for each category. Generally, eligible resources can provide flexible capacity for the amount of capacity it can produce over three hours. However, this structure fails to adequately differentiate and value the capability to move more quickly over shorter time intervals. Given the flexible capacity needs identified above, CAISO will develop new flexible capacity requirements that incorporate shorter interval ramping capabilities. CAISO will sunset the existing flexible capacity products once these new requirements are developed and implemented.

To address the above flexible capacity needs, CAISO proposes three flexible capacity requirements:

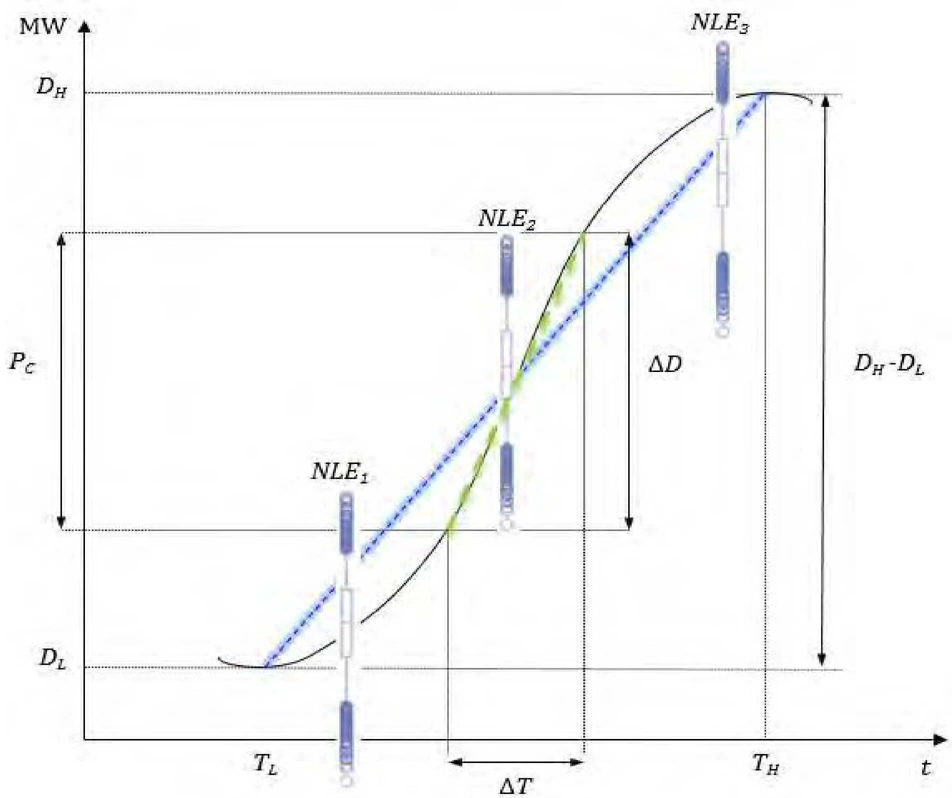
- **Uncertainty Ramp:** Historic forecasted net load error between IFM and FMM
- **Fast Ramp:** Steepest section requiring highest ramp rate ($\Delta D/\Delta T$) over typically one hour

[30] The Day-Ahead Market Enhancements straw proposal is available at: http://www.caiso.com/Documents/RevisedStrawProposal-DayAheadMarketEnhancments.pdf

- **Long ramp:** From a low net demand (D_L) to a high net demand (D_H) over a time period (T_H – T_L), typically three hours

CAISO seeks stakeholder input on these flexible RA capacity requirement definitions.

Figure 12: Graphic representation of CAISO's proposed flexible capacity requirements



As with the existing flexible capacity requirement, any new flexible RA capacity requirements should meet basic criteria. These criteria include:

- Easily procurable bilaterally
- Each requirement is clearly defined and quantified
- Resources' ability to meet each requirement is known and quantified
- Mitigates regulatory risks for procuring LSEs

The existing flexible RA capacity requirement met these objectives. However, CAISO will modify the existing flexible capacity product to simplify counting, eligibility rules, and the must offer obligations to the greatest extent possible.

5.2.3. Setting Flex RA Requirements

The current flexible capacity needs assessment provides a tested process that can be used for determining the flexible capacity needs for both the long and fast ramping flexible RA capacity needs. However, CAISO proposes to make some important changes to this study process and needs determination for the long ramping requirement. Once these changes are made, the process will also produce the data needed for the short ramping requirement.

Long ramping requirement

CAISO believes maintaining the existing flexible capacity needs determination using the maximum forecasted three-hour net load ramp plus contingency reserves should continue serving as the preliminary starting point for the long ramping requirement. The interplay between contingency reserves, which are flexible resources that must be reserved for contingency dispatch, and flexible capacity identified in the original FRACMOO process still exists. However, with the modifications to the NERC standard on calculating contingency reserve, "WECC Standard BAL-002-WECC-2a "Contingency Reserve", the means for determining the quantity of contingency reserves has changed. Contingency Reserve is determined by the greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

Based on the new requirement, the Operating Reserve – Spinning is approximately 50% of the Contingency Reserve requirement. As such, CAISO will modify the existing 3.5 percent expected peak load portion of the flexible capacity requirement to be consistent with the revised standard. Specifically, CAISO proposes to change the flexible requirement formula to the following:

Max Forecasted 3-Hour ramp + ½ Max (MSSC, 6% of the monthly expected peak load[31]) + ε

Finally, since the inception of the flexible capacity product there has been an increase in CAISO dispatches of VER resources, both through economic bidding and curtailed self-schedules. This makes forecasting the three-hour net load ramp more challenging. As a result, the CAISO will enhance its forecasting study to account for these dispatches. Therefore, CAISO will reconstruct overall available wind and solar output and include this quantity into the formulation of the three-hour net load ramp. This eliminates the concerns of double counting VERs towards meeting flexible capacity needs. This double counting would occur if the observed three hour net ramp is mitigated by the curtailment (i.e. reduced overall need) and then again by allowing the resources to provide flexible capacity. CAISO will modify how wind and solar resources are considered in meeting the flexible RA requirements. CAISO's proposed changes to the treatment of wind and solar resources for Effective Flexible Capacity (EFC) are discussed in greater detail below.

Combining all off these elements yields an overall flexible capacity needs determination of:

[31] 6% of the monthly expected peak load is approximately equivalent to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation.

Max Forecasted 3-Hour ramp (including reconstituted renewable curtailments) + ½ Max (MSSC, 6% of the monthly expected peak load) + ε

Fast ramping requirement

The current flexible capacity needs assessment produces minute by minute net load data. This data allows the CAISO to determine the largest daily forecasted one-hour net load ramps. As with the three hour net load ramp, CAISO proposes to set the fast ramping flexible RA capacity need based on the largest forecasted net-load ramp in each month. At this time, CAISO is seeking stakeholder input regarding what should be given for operating reserves when making the fast ramping needs determination. Specifically, CAISO is contemplating if it should include an additional quantity of the fast ramping requirement to account for the overlap between flexible RA capacity or is this overlap sufficiently addressed by long-ramping procurement.

Uncertainty requirement

CAISO is currently exploring different options for determining the requirements for uncertainty. At this juncture, CAISO is proposing to use three years of historic data to determine both the maximum difference between the day-ahead and fifteen-minute market forecasts and the rate that difference is changing. CAISO will combine the identified needs from the calculated forecast error with and expected growth in wind and solar (including behind the meter solar) as submitted by LSEs in the CAISO's annual flexible capacity needs assessment survey. CAISO will then use those data points to extrapolate the need for the uncertainty requirement for the upcoming RA year. Once there is sufficient data available from the imbalance reserves market, CAISO can reexamine this practice and consider establishing this need based on imbalance reserves procurements. CAISO seeks stakeholder input on this approach to determining the requirements for uncertainty.

5.2.4. Establishing Flexible RA Counting Rules: Effective Flexible Capacity Values and Eligibility

To ensure each LSE can demonstrate it has procured sufficient flexible RA capacity to meet its share of a flexible capacity requirement, CAISO, as it does today, will publish a list annually showing all resources' EFC values. Each resource will receive an EFC value for each month for each flexible RA requirement it can meet. The remainder of this section details the eligibility and counting rules for meeting each requirement. CAISO notes that the eligibility and counting rules look to remain technology agnostic. The goal is to ensure any resource contributing to a given flexible capacity requirement, regardless of technology, provides comparable attributes to any other resource providing that same service.

Internal resources

Under the existing flexible capacity eligibility rule, section 40.10.3.2 of CAISO tariff, resources are required to meet various criteria to be eligible to provide flexible capacity. Many of these criteria are proving to be extremely difficult to validate. CAISO is looking to simplify the eligibility criteria. At this time, CAISO is proposing a very basic set of eligibility criteria. However, CAISO recognizes that this list will result in numerous unresolved issues. CAISO will identify these issues and seek additional stakeholder feedback for ways to resolve them.

Eligibility criteria

For resources internal to CAISO BAA to be eligible to provide forecastable requirement (i.e. long and fast ramping flexible RA capacity) the resource must meet all of the following criteria:

- Either be a non-use limited resource or a use-limited resource with a use limitation CAISO can model in its energy market or through an opportunity cost adder
- Be a dispatchable resource
- Not be a Conditionally Available Resource
- Not be a regulation energy management resource [32]

For resources internal to CAISO BAA to be eligible to provide uncertainty flexible RA capacity, the resource must meet all of the following criteria:

- Meet the qualifications to provide the forecastable requirements
- Meet the definition of a short start resource
- Be dispatchable in at least 15 minute increments
- Must be able to reasonably control fuel source

Although these eligibility criteria provide much cleaner eligibility criteria than those originally provided under the existing flexible capacity eligibility criteria, they also leave two primary issues unresolved. The first is how the eligibility criteria accounts for energy limitations. At some level, the EFC counting rules ensure the resource is capable of producing energy for a given time period. However, these eligibility criteria do not address other concerns such as the ability of the resource to have available energy when needed. Similarly, the above eligibility do not contain requirements for starts or ramping frequency. For example, the current Base Ramping flexible RA capacity product requires two starts or two ramps per day. CAISO is not proposing minimum start or ramp requirements here, but this issue requires further discussion.

CAISO recognizes that these two unresolved issues risk having resources receiving commitments that change from day-ahead to real-time that could result the resource no longer being able to meet its day-ahead commitment. This can occur for resources with one start per day receiving a day-ahead award for an evening start and then being committed in the morning of the operating day. A similar scenario can exist for storage resources that are not able to recharge during the day. CAISO is seeking stakeholder input about how, or if, flexible RA capacity eligibility criteria should address these concerns. Additionally, CAISO seeks stakeholder feedback regarding the proposed eligibility rules as well as any additional criteria that should be considered.

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[32] As noted above, flexible capacity needs are defined by energy needs and the overlap with operating reserves. Regulation needs are not currently considered as part of the flexible RA capacity needs

EFC Counting Rules

The EFC for internal resources providing the long ramping requirement will be calculated using a resource's ability to ramp over a three hour period. However, CAISO proposes to modify the existing calculation to be more universally applicable than the existing calculation. CAISO proposes to use a similar methodology to calculate the EFC values for all resources ramping capabilities, but will change the interval of assessment. The long ramp EFC will be calculated over a three hour interval, the fast ramp interval will use a one hour interval, and the uncertainty requirement will be assessed over a 15 minute interval. EFC values will only be calculated for resources that are eligible to meet the given requirement(s).

The current EFC counting methodology includes an accounting for Pmin as well as a weighted average ramp rate for the resource. CAISO will no longer consider those elements. Instead, CAISO will calculate the EFC for the long ramping process as the largest range a resource can move over three hour interval capped at the resource's UCAP.[33] Exceptions to this rule are discussed below. This calculation will not include a minimum start time for Pmin to count towards the EFC. However, the Pmin of the resource cannot be split. This means that the Pmin for a resource is either completely included or excluded from a resources EFC. CAISO will calculate resources from cold start, and will consider the full range of the resource from its lowest operating limit to max output.

At this time, CAISO proposes to use the above counting rule for all technologies, with two exceptions: Solar and non-generator resources (NGR). For solar resources, their NQC values, particularly in non-summer months, do not reflect their ability to provide fast and long ramping. Solar resources' ability to reduce net load ramps comes from their willingness to *not* generate *prior* to net load ramping events. However, solar resources' NQC is determined by its ability to serve load, or generate. As such, CAISO proposes to calculate solar resources EFC as a function of the resource's historic output. Specifically, solar resources' EFC would be calculated as a percent of their peak output for a month or season. This calculation recognizes that solar production, or lack of production, is a significant contributor to net load ramps. When there is high solar production, there are large net load ramps. When there is lower solar production, there are smaller net load ramps. Therefore, CAISO believes solar EFC should be a high percentage of historic output. CAISO seeks stakeholder feedback on high to determine that percentage.

Consistent with current practices, CAISO recognizes that NGR resources can help balance net load ramps by lifting the net-load in some intervals by charging and providing generation output during other intervals. Therefore, CAISO proposes to count NGR resources EFC based on the resource's ability to provide generation (positive and negative) over a three hour, one hour, or fifteen minute period. This allows NGR resources to potentially receive EFC values that include their full charge and discharge ranges.

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[33] CAISO is currently exploring EFC deliverability studies as part of its transmission planning process. CAISO will also use this process to inform the current process in determining if resources can be EFC only resources (i.e. not require to have an NQC to receive an EFC).

Flexible RA from Imports

Currently, import resources are not eligible to provide flexible capacity. However, during net load ramps, CAISO has found that import capacity is capable of providing significant ramping capabilities. Therefore, CAISO will allow imports to provide flexible RA capacity.

Eligibility criteria

Import resources may not be tied to a specific resources like internal flexible RA capacity.[34] As noted above, CAISO will continue to allow for non-resource specific imports to provide RA, but has provided additional clarity about the requirements for doing so. For import resources providing flexible RA capacity, including EIM and non-EIM capacity, resources must meet the same firm energy standard applied to system capacity. The LSE must demonstrate that it has adequate MIC to use the import resource to provide flexible RA capacity.

As with system RA capacity, any LSE using an import resource for flexible capacity must demonstrate it has sufficient MIC capacity to provide flexible RA capacity from an external resource. The MIC capacity is how LSEs demonstrate that the resource's output, and therefore flexibility, is deliverable to the CAISO. While the MIC ensures the flexible capacity is deliverable, CAISO will still need to ensure the flexible capacity is credited to CAISO balancing area authority for purposes of the EIM sufficiency tests. Therefore, the resource must identify the capacities BAA of origin and the interconnection point with CAISO system. CAISO will then change all EIM sufficiency tests to credit CAISO with any flexible RA capacity from resources based in an EIM BAA shown as flexible RA capacity and remove the resources from any EIM entity's sufficiency tests.

Imports will not be eligible to provide uncertainty requirement. However, they can provide both the long and fast ramping requirements. To provide flexible RA capacity imports must:

- Demonstrate all of the above requirements
- Be 15-minute dispatchable resources

EFC Counting Rules for Imports

Imports do not have the same defined ramp rates or minimum operating levels as internal resources. Imports have no Pmin and high ramp rates in Masterfile. Given these parameters, CAISO is not able to calculate an EFC in the same way it does for internal resources. However, this simply means that the LSEs and resource owners must determine how much flexible capacity they wish to procure from imports. As such, CAISO will allow imports to provide EFC up to the UCAP of the resource.

[34] However, dynamic and pseudo-tied resources are connected to specific resources. Their counting rules will be the same as internal resources.

5.2.5. Flexible RA Allocations, Showings, and Sufficiency Tests

Each LSE must demonstrate it can meet its proportionate share of each of the requirements. CAISO will provide each LRA its jurisdictional LSEs' contribution to each of the three flexible capacity requirements. LRAs can then determine its own allocation of each of the requirements. If the LRA does not provide CAISO with an allocation, then CAISO will allocate to each LSE based on CAISO's allocation methodology.[35]

For the forecastable flexible RA capacity requirements, CAISO will use similar methods to those used today. Specifically, CAISO will assess the five largest three hour and one hour forecasted net-load ramps and determine each LRA's contribution based on changes in load wind and solar. One change CAISO proposes is to ensure that load, wind, and solar values all come from the same intervals.[36] Additionally, CAISO continues to work to assess the best metric for allocating these relative changes. In past flexible RA needs assessments, CAISO found that some days with small changes in load that have a high percentage attributed to a single LRA has caused disproportionate impacts on flexible capacity needs allocation to some LRAs. Therefore, CAISO is seeking stakeholder feedback about how to develop an appropriate weighting and allocation process for the forecastable flexible RA capacity needs. Also, consistent with current practices, Load-Following, Metered Sub-System LRAs will not receive an allocation for any forecasted flexible RA capacity needs attributable to changes in load.

CAISO is currently considering allocating the uncertainty flexible RA capacity requirements to LRAs. First, CAISO is considering an allocation based on each LRAs' proportional share of peak load, and MW of wind and solar. This allocation reflects that these factors, although not the only drivers, are the major drivers of uncertainty. However, CAISO is seeking stakeholder input on this option as well as any other options that should be considered.

Each LSE will be required to meet 100 percent of its flexible capacity requirements in both the year ahead and month ahead RA showings. Showings should be submitted in terms of EFC for each requirement. CAISO will assess the showings for each showing for each requirement independently. In other words, CAISO will assess the long-ramp showings independent of the fast-ramp showings. This means that an LSE can have a resource on one, two, or all three of its flexible RA capacity showings.

Once CAISO receives flexible RA capacity showings, it will do two things. First it will notify all LSEs if they have provided adequate flexible capacity in each category and notify the LSE if it was at risk of potential backstop procurement cost allocation. Second, CAISO will assess the adequacy of each requirement at a system level. If CAISO has received enough flexible RA in each requirement at system level, it will not undertake any additional action with respect to flexible RA capacity. If CAISO finds a deficiency in any flexible RA capacity requirement, it will assess individual showings and notify LSEs of the system deficiency. LSEs will be provided an opportunity to cure the deficiency. This cure period will align with the cure period for other RA

[35] CAISO is not looking for LRAs to provide an allocation methodology, instead, the LRA should provide CAISO with each of its jurisdictional LSE's allocation.
[36] Currently, the change in load can come from different days than the wind and solar changes.

requirements. Once the cure period closes, CAISO will proceed with the remaining validation processes. These process are provided in greater detail in Section 5.4, below.

5.2.6. Flexible RA Must Offer Obligation Modifications

The current flexible RA capacity products have different must offer obligations based on the category of flexible capacity a resource provides. These different offer obligations have created a significant amount of confusion for market participants. Therefore, CAISO is looking to simplify the must offer obligations for flexible capacity. As noted above, in Section 5.1, CAISO is clarifying must offer obligations for system and local capacity. Further, as noted in the same section, CAISO has proposed to assess resource forced outage rates over a 16-hour window between 5:00 AM and 9:00 PM. Lastly, CAISO data shows the uncertainty tends to be higher during the same 16 hour window.

CAISO's proposal aims to strike a balance between having multiple must offer obligations for flexible capacity requirements with ensuring CAISO has sufficient capacity available during the intervals of need and aligning flexible capacity and generic capacity rules.[37] This balance is particularly important because CAISO expects that many resources providing flexible RA capacity will contribute to multiple flexible RA requirements and system or local capacity. However, as noted above, CAISO is still trying to address the concern that changes between day-ahead and real-time needs may necessitate different must offer obligations for the different products.[38] Therefore, CAISO seeks stakeholder input regarding how it might balance these concerns when developing flexible RA capacity must offer obligations.

As a starting point to, CAISO proposes that any resource providing any flexible capacity must submit economic bids to the CAISO's markets from 5:00 AM to 9:00 PM for all shown flexible RA capacity. Solar and wind resources should submit economic bids for the minimum of their forecast or their shown EFC value. This bidding requirement is consistent with allowing solar resources to provide EFC greater than their NQC and differs from the current practice of allowing solar resources to bid a proportionate amount of their EFC to NQC value. NGR resources must submit economic bids to cover both the charge and discharge range of shown EFC.

[37] As noted above, all RA must offer obligations, including flexible RA capacity must offer obligations will align with the Day-Ahead Market Enhancements policy.
[38] As noted above real-time RA must offer obligations will align with the Day-Ahead Market Enhancements policy

5.3. Local Resource Adequacy

5.3.1. Local Capacity Assessments with Availability Limited Resources

As a part of California's RA program, CAISO performs studies to ensure adequate capacity is procured in local areas to mitigate potential local reliability issues in those areas. As California transitions to a decarbonized grid, CAISO will likely depend more heavily on clean, variable and distributed energy resources that have certain availability limitations, such as limitations on fuel availability, run-time duration, and or event calls. It is important CAISO enhance its processes to ensure the RA program considers these limitations when determining the amount of procurement required in local capacity areas.

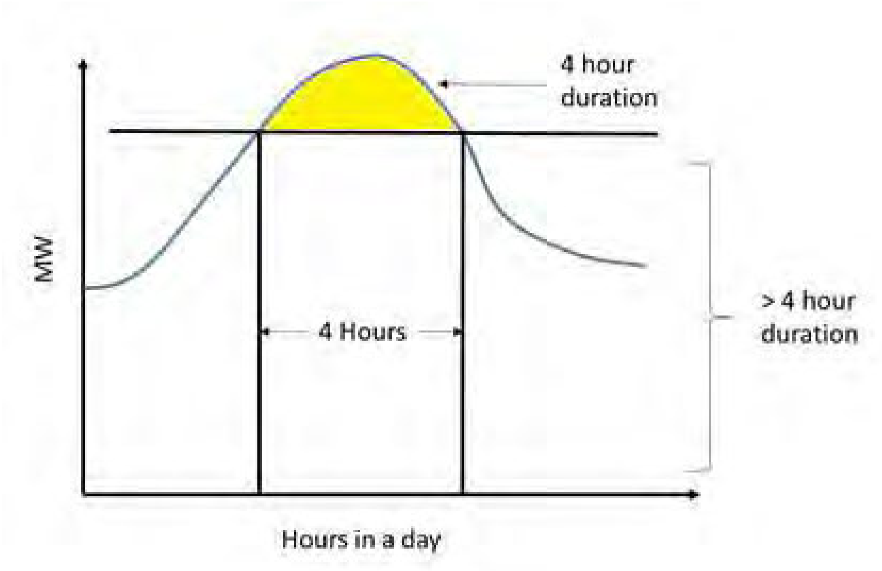
CAISO proposes to define availability-limited resources as those that have significant dispatch limitations such as limited duration hours (e.g., per year, season, month, or day) or event calls (*e.g.*, per year, season, month or consecutive days) that would limit the resources' ability to respond to a contingency event within a local capacity area. This proposed definition is limited to resources that count towards meeting a local capacity area or sub-area need.[39] As these resources make up an increasingly greater portion of CAISO's resource mix, CAISO believes it is important to evaluate local capacity needs considering these resources' availability limitations to help guide the effective procurement of local resource adequacy resources.

The Local RA program is currently based on meeting a peak capacity requirement in a locally constrained area defined in MWs without full consideration of resource availability needs, like resource duration or event calls. For example, today, availability-limited resources have a minimum duration requirement of four hours to qualify for resource adequacy. Under the current RA program, a 10 MW resource that is capable of producing for 4 hours, or 40 MWhs has the same resource adequacy capacity value as a 10 MW resource capable of producing for 8 hours, or 80 MWhs. However, if a local capacity area requires 10 MW of capacity for an eight hour period during a contingency event, only the latter is capable meeting this reliability need. Yet, from an RA perspective, these hypothetical resources are valued the same because the current RA program does not consider the availability limitations of the resources when determining RA capacity values. This has the potential for CAISO to be sufficient in MWs to meet peak demand needs in a local capacity area, but insufficient in MWhs to meet energy needs across all hours of the day and year.

Figure 13 demonstrates how CAISO can use availability-limited resources to meet the peak, but may need resources with a longer duration to meet energy needs in other hours of the day. The black vertical lines reflect a four hour minimum availability threshold. Below the black horizontal line is load that will need to be served with resources with greater than four hours of availability.

[39] See CAISO Track 2 Testimony Chapter 6: Availability Limited Resources: http://www.caiso.com/Documents/Jul10_2018_RAProceedingTrack2Testimon-Chapter6-AvailabilityLimitedResources_ProposalNo5_R17-09-020.pdf

Figure 13: Hourly Load Shape with Four Hour Minimum Availability Threshold



Each year, CAISO conducts its local capacity technical study to determine the minimum amount of local capacity area resources needed to address local area contingencies. In performing the study and setting local capacity requirements, the current process does not consider hourly load and resource analysis. However, in recent transmission planning studies, specifically the Moorpark and Santa Clara studies, CAISO developed and performed detailed hourly load and resource analyses to determine whether there were binding availability limits in the local capacity sub-areas.[40] This allowed CAISO to determine local capacity procurement needs more precisely by evaluating both the capacity and energy needs in those local areas. These studies show that availability-limited resources with a four-hour minimum duration were insufficient in meeting the energy (*i.e.*, total MWhs) required to fully address the contingency events identified in the local capacity criteria.

Local Capacity Technical Studies

Each year, CAISO conducts its Local Capacity Technical Study (LCT Study), to determine the minimum amount of capacity needed in each local capacity area to ensure compliance with the LCT criteria. As part of this study process, CAISO reviews the study criteria, methodology, assumptions, and study results with stakeholders and receives stakeholder input. CAISO's LCT studies look out one and five years forward each year, and ten years forward every other year. The study results for year one determine the local RA requirements as required by ISO Tariff section 40.3. The long-term studies aide local regulatory authorities and LSEs in long-term procurement decisions.

[40] CAISO, Moorpark Sub-Area Local Capacity Alternative Study, August 16, 2017, http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf; and Santa Clara Sub-Area Local Capacity Technical Analysis, June 18, 2018, http://www.caiso.com/Documents/2023LocalCapacityTechnicalAnalysisfortheSantaClaraSub-Area.pdf

The current study process determines the amount of capacity in MW, based on a 1-in-10 peak load forecast, required to mitigate local reliability problems. Moving forward, CAISO plans to enhance its study process to include consideration of availability limitations such that CAISO can ensure sufficient energy (MWh) is available in addition to MW of capacity. In future years, CAISO will include hourly load and available resource data within its existing Local Capacity Technical Study reports to guide resource procurement.

After load serving entities procure local capacity resources, CAISO will validate the annual RA showings based on power flow modeling to consider reactive power and locational impacts of the procured resources. CAISO will also validate that the RA resources provided have enough energy to meet the needs for each individual area and sub-area. If provided RA resources do not have enough energy or otherwise failed to meet these needs, CAISO will use the existing process to allow load serving entities to cure any deficiencies. CAISO plans to incorporate the hourly load and available resource data into the one, five, and ten year study reports.

CAISO plans to maintain the existing LCT Study process with certain changes described below to determine availability needs in each local area and sub-area. CAISO will continue to conduct its annual LCT study to determine the capacity requirements (in MW) for each local capacity area and sub-area, but the hourly load and available resource data will provide additional information regarding energy availability needs in each local capacity area.

Additional Inputs for Hourly Load and Available Resource Data

Additional inputs that are included in the current LCT study include:

A. **Projected hourly load data** for each local capacity area and sub-area for each year of analysis. The projected load data should include the impact of behind-the-meter PV to determine the net-load shape. It should exclude the impact of supply-side demand response resources.

B. **Voltage stability or thermal area load limit** for the critical contingency for each local capacity area and sub-area, for each year of analysis. In the determination of the limit, CAISO will assume all resources that have not announced retirement will be available throughout the resource adequacy horizon. Voltage collapse or thermal overloads for contingency events are typically the most limiting condition and often set the local area requirements.

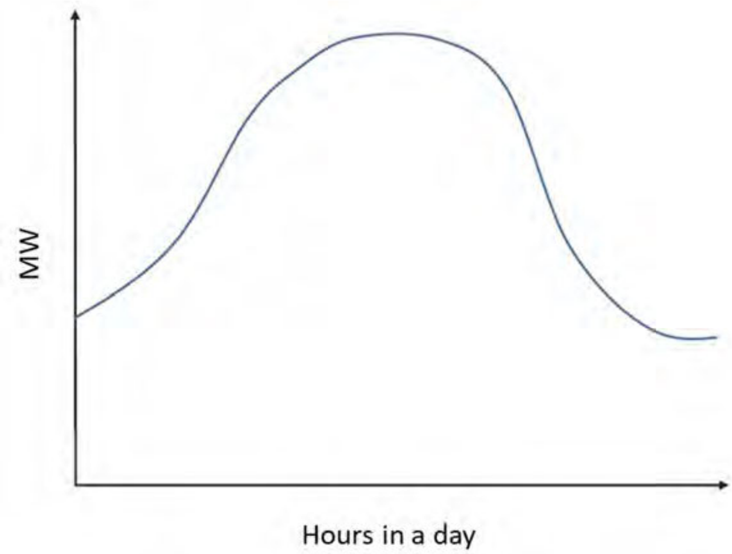
C. **Actual resource output at the time of the area or sub-area net peak** is required to evaluate if a resource is effective in mitigating the reliability needs.

Steps in Providing Hourly Load and Available Resource Data

Using the additional inputs and information available from the current LCT study (such as existing and expected online resources in each local area and sub-area), CAISO will provide hourly load and available resource data for each local capacity area and sub-area. CAISO will perform the following steps as part of the hourly load and available resource data.

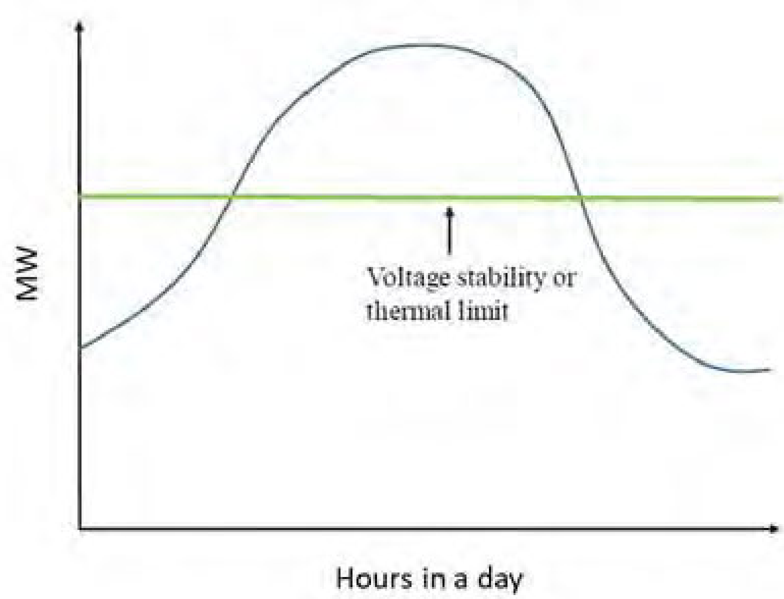
1. **Determine the hourly net load shape for each year of analysis** based on the hourly load forecast and output data from behind the meter solar PV within the local area or sub-area.

Figure 14: Illustrative Hourly Net Load Shape



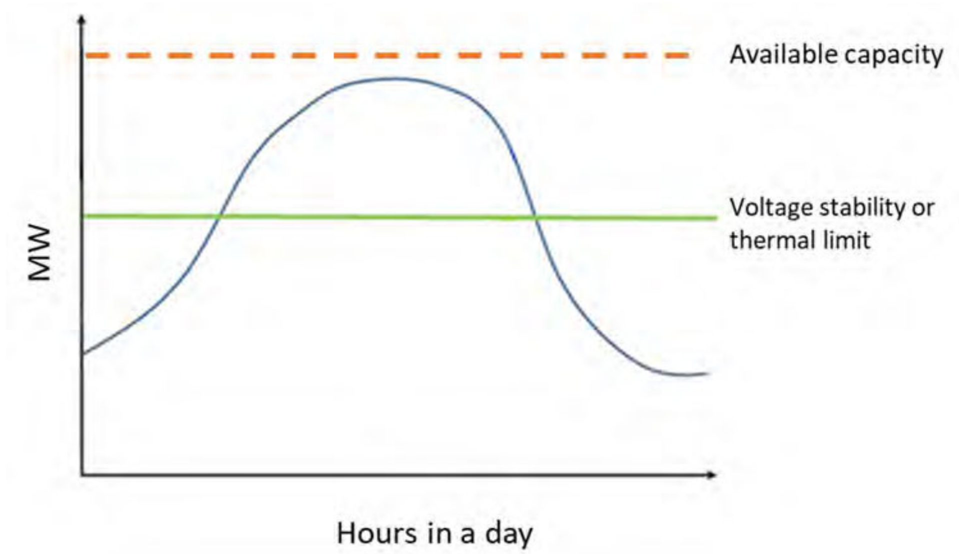
2. **Subtract the voltage stability or thermal area limit (from input analysis) to derive the remaining load that may be served by local capacity area resources.** In Figure 15, this area is bounded by the voltage stability or thermal area load limit (green horizontal line) and the hourly net load. The area below the voltage stability or thermal area load limit represents load that can be served by generation outside the local area. The area above the voltage stability or thermal area load limit represents load that must be served from resources within the local area.

Figure 15: Voltage Stability or Thermal Area Limit



3. **Determine the available MWs of capacity from all resources in the local area** using generation expected to be online during the study period.

Figure 16: Available Capacity in the Local Area



This analysis enhances the RA program by allowing load serving entities to make procurement decisions for the upcoming year based on the quantity of capacity (in MW) *and* energy (in MWhs) that will need to be served by generation located within the local capacity area. Additionally, CAISO can inform longer term procurement and investment decisions by providing greater transparency into CAISO's duration needs multiple years out. Starting this year, CAISO has incorporated this analysis into the Local Capacity Technical Study process to guide resource procurement that is aligned with operational needs.

CAISO will continue to coordinate with stakeholders when setting local RA requirements. To ensure procurement of resources with sufficient availability, CAISO will provide this data when setting local resource adequacy requirements, and will enforce them during the RA showings validation process. Additional detail is provided in Section 5.4.1 regarding actions CAISO may take if the resources procured in a local area do not meet energy needs as identified through the hourly load and resource analysis. These enhancements to the local study process will enable resource procurement that is better aligned with local capacity area needs by including the duration resources must be available to ensure local capacity area reliability. In providing this data, CAISO can ensure that sufficient resources are procured to meet operational needs in all hours of the year.

5.3.2. Meeting Local Capacity Needs with Slow Demand Response

For reliable operation of the grid, CAISO depends on adequate supply from resources in local areas to meet load. Demand response resources can help manage the system in local areas by reducing load when the local area is constrained. However, the characteristics of certain demand response resources lead to potential challenges that impact how CAISO can use them to respond to a contingency. Specifically, "slow" demand response cannot respond to dispatch instructions provided by CAISO within 20 minutes for CAISO to reposition the system within 30 minutes of the contingency occurring, due to the additional notification time required for the resource to perform after it receives a dispatch instruction from CAISO.

While many demand response resources can quickly deliver energy at a scheduled time, demand response resource operators may require longer lead times to know specifically when to deliver that energy. CAISO's market system issues instructions to each resource to operate at specific operating levels every five minutes. Resource operators must increase or decrease their resource's output to match these five minute instructions. Once online, conventional resources are prepared and ready to follow varying five-minute dispatches from the market. However, some demand response resource operators require longer notification times before they can perform and, therefore, cannot deliver energy following a varying five minute dispatch. To address this need, CAISO introduced block bidding options within the Energy Storage and Distributed Energy Resources Phase 3 (ESDER 3) initiative to provide longer notification times and extended real-time dispatch intervals, as discussed in the following sections.

CAISO and the California Public Utilities Commission (CPUC) have been working to ensure both "fast" and "slow" demand response resources are capable of meeting local reliability requirements.[41] For the purposes of this paper, CAISO defines slow demand response as demand response resources that cannot respond to an ISO dispatch instruction within 20 minutes. After a contingency occurs or when the system enters an N-1 insecure state (loss of a single critical element), CAISO must dispatch resources to return the system to an N-1 secure state within 30 minutes to minimize the risk the next contingency poses on the reliability of the system, accounting for a small amount of time for ISO operators to perform their real-time assessment and react to the contingency condition. After the contingency and real-time assessment, CAISO is left with approximately 20 minutes for resources to provide generation and load drop within the 30 minute timeframe.

Based on the need to reposition the system within 30 minutes, CAISO generally has three options:

1. Post-Contingency Dispatch: By assessing the system, issuing dispatch instructions, and having a response within 20 minutes of a contingency;
2. Pre-Contingency Dispatch: By dispatching resources pre-contingency so as to have sufficient energy (or load reduction) available before the contingency occurs to keep the system in a secure state if a potential contingency occurs;
3. Pre-Contingency and Post-Contingency Dispatch: Using a combination of pre- and post-contingency dispatch.

In 2017, CAISO performed a study to assess the availability requirements of slow-response resources, such as demand response, to count for local resource adequacy.[42] The study found that at current levels of availability limited resources on the system, most existing slow DR

[41] https://www.caiso.com/Documents/BPMChangeManagementAppealsCommitteeDecision-PRR854.pdf
[42] CAISO-CPUC Joint Workshop, Slow Response Local Capacity Resource Assessment: https://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf.

resources appear to have the required availability characteristics needed for local RA if dispatched pre-contingency as a last resort, with the exception of minimum run time duration limitations. As discussed in the prior section, CAISO will address duration limitations through the annual Local Capacity Requirements stakeholder process through hourly load and resource analysis. As the resource adequacy landscape transitions to one that relies more heavily on availability limited resources to meet its local RA needs, resources such as DR that count for local RA may be relied on more frequently than they have been historically. This concept is described in further detail in section 5.3.1.

CAISO initiated the Slow DR effort to operationalize slow demand response resources so they can be eligible to provide local resource adequacy capacity and be used by CAISO when needed for local reliability. Slow demand response resources that cannot respond within appropriate timeframes following a system event, due to the need for longer notification times, can still be useful in maintaining system reliability in local areas. In this revised straw proposal, CAISO presents a methodology for allowing slow demand response resources to be economically dispatched through the market as a preventive measure in preparing for a possible contingency using the policy frameworks proposed in the CAISO's ESDER 3 and Contingency Modeling Enhancements (CME) initiatives. ESDER 3 will provide PDRs hourly and 15-minute block bidding options. The CME proposal will introduce a preventive-corrective constraint into the market optimization such that it produces a pre-contingency dispatch that keeps the post-contingency system conditions within safe operating limits.

Under these proposals, the market will economically consider slow PDRs and dispatch them within a timeframe that will help resolve local reliability issues when the preventive-corrective constraint is enforced. The market will use these resources to provide local reliability by dispatching them pre-contingency for energy in the real-time market to prepare for potential post-contingency reliability concerns.

Additionally, this revised straw proposal includes an alternative solution for dispatching slow demand response resources on a pre-contingency basis to be used until, or as an alternative to, the market based solution. While the market based solution leverages policies planned for implementation in the future, it is important CAISO has the ability to utilize these resources for local area reliability concerns in the interim when and where needed. As detailed below, CAISO will develop a tool to dispatch slow DR post-day-ahead (either before the operating day or before the real-time market) as a way to dispatch slow demand response on a pre-contingency basis. CAISO is currently examining both the market based and post-day-ahead solution to determine the best approach for targeting local reliability needs.

Finally, this revised straw proposal introduces qualifiers for resources to qualify for local RA, such that CAISO can ensure these resources can be used to mitigate local area contingencies.

Scope of Policy Examination

CAISO is examining avenues to facilitate the dispatch of slow demand response prior to a contingency in order for these resources to qualify for local RA. CAISO is focusing on market mechanisms to operationalize this pre-contingency dispatch as a long term solution. CAISO is also considering interim solutions that allow these resources to be used in local area reliability situations, such that CAISO can re-position the system within the appropriate time constraints.

The scope of this effort will include:

- The market-based solution, including block bidding options proposed in ESDER 3 and the preventive-corrective constraint proposed in CME,
- A post-day-ahead solution to dispatch slow DR resources prior to the operating day or before the real-time market,
- Resource qualifications for local RA eligibility.

Market-based Solution

As part of CAISO's ESDER 3 initiative, CAISO introduced real-time bidding options for PDR similar to the real-time bidding options for interties, including hourly block and 15-minute bidding options. CAISO incorporated these bidding options in its ESDER 3 initiative to provide longer notification times and extended real-time dispatch intervals to proxy demand resources (PDRs). CAISO believes that by providing these bidding options, PDR that requires notification time will be able to participate more effectively in the market by leveraging the market timelines and advance dispatch notice these new bidding options provide.

With the hourly block bidding option, the SC submits a day-ahead market bid for the entire hour. In the real-time market, the resource will submit an economic bid and be scheduled during HASP. The resource will be settled at the 15-minute market prices, making the resource a "price taker" for the full hour. The binding real-time hourly block schedule is communicated at 52.5 minutes before the flow of energy.

With the 15-minute bidding option, the SC submits bids into the day-ahead market in hourly increments. In the real-time market, if the 15-minute bid is economic, it will be dispatched and receive a binding schedule at the fifteen-minute market price. The dispatch notification is communicated at 22.5 minutes prior to the flow of energy.

CAISO conducted the CME effort to explore ways the CAISO can more effectively address the need to reposition the system after a contingency within 30 minutes. These enhancements introduced the preventive-corrective market optimization model that considers post-contingency system conditions and co-optimizes both pre-contingency dispatches and post-contingency dispatches to meet reliability needs. To ensure the market has adequate resources available to reposition the system after a contingency, CME introduced a new market product, corrective capacity, so that the market can reserve capacity on resources to be used in the event of a contingency. The preventative-corrective model will reserve corrective capacity on resources with the ramping capability and the ability to respond to mitigate contingencies within the required timeframe. When a contingency occurs, corrective capacity is dispatched for energy to return the system to normal operating levels within 30 minutes.

CAISO could leverage the new real-time bidding options available to PDR to pre-contingency dispatch slow responding DR for energy above their Pmin when it is economic to do so using the preventative-corrective market optimization model. Using these tools will enable slow responding DR to qualify as local RA capacity and more effectively respond to contingencies in local capacity areas.

Post-Day-Ahead Solution

As an alternative, CAISO is also exploring a post-day-ahead solution that could be used to dispatch slow DR after the day-ahead markets runs, either before the operating day or on the operating day before the real-time market by assessing local area load and available resources in local areas that operators identify potential reliability needs.

Along with the study on slow response local capacity resources and the real-time block bidding options, CAISO introduced the Minimum Online Commitment (MOC) Constraint as a mechanism for pre-contingency dispatching slow DR.[43] MOC constraints are market mechanisms enforced in the day-ahead market used to ensure sufficient unit commitment is available that is effective in addressing specified contingencies. The MOC ensures real-time reliability by committing resources in the day-ahead market to ensure system reliability following a contingency in real-time. Currently, MOC constraints are defined by engineering analysis to identify the minimum generation capacity requirements within local areas. MOCs then commit resources to their Pmin to meet these requirements.

CAISO believes the MOC, as it currently exists, is insufficient to operationalize slow DR for two reasons. First, the MOC would commit DR resources to their Pmin, which is often zero for DR resources. Once committed, the DR resource must submit bids into the real-time market, and they may be dispatched by the market above their Pmin without the notification time they require. Second, there is currently no constraint in the real-time market to enforce the pre-contingency dispatch of slow DR. While the MOC on its own cannot operationalize slow DR for local needs, its logic can still be useful in identifying when slow DR is needed. Therefore, CAISO proposes a tool that can commit resources above their Pmin and maintain their schedule from day-ahead through real-time.

As a mechanism to dispatch slow DR for local needs, CAISO proposes to use the MOCs to define the amount of slow DR that is needed. CAISO plans to maintain existing day-ahead market processes and dispatch slow DR after the completion of these day-ahead market processes if a need is identified through the MOC. CAISO will define MOCs in local areas with slow demand response. The MOC requirement will determine when to commit long start units that cannot be committed in real-time. The MOC requirement will be determined as follows:

MOC Requirement = Local Area Load – Import Capability – Available Generation, where:

- MOC Requirement = A MW value of slow DR the needs to be dispatched prior to a contingency occurring as a preventive measure
- Local Area Load = Day-ahead load forecast of local capacity area load

[43] CAISO-CPUC Joint Workshop, Slow Response Local Capacity Resource Assessment: https://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf.

- Import Capability = Import capability into the local capacity area
- Available Generation = MWs bid into the day-ahead market from generation within the local capacity area

When the MOC requirement is greater than zero, CAISO will first meet the MOC requirement by committing long start resources. If CAISO cannot meet the entire MOC requirement with available long start resources in the local area, CAISO will dispatch slow DR to meet the MOC insufficiency. CAISO will dispatch resources for energy, rather than only committing them to Pmin, based on their bids into the day-ahead market and their ability to resolve the local area need. CAISO is also exploring the potential for performing this assessment on the operating day closer to hours of reliability need to better reflect real-time conditions, including local area load and resource availability.

Because CAISO will dispatch slow DR before a contingency occurs, as a preventive measure, the dispatches provided to slow DR must be binding through real-time to preserve the pre-contingency dispatch. This allows slow DR resources to know prior to the operating day the hours and the amount they are required to reduce load. These dispatches will not be cancelled if no contingencies occur in real-time, because CAISO does not have the ability to predict for certain whether or not a contingency will occur. As such, slow responding resources must be positioned ahead of time (i.e., dispatched on a pre-contingency basis) to prepare the system for a potential contingency.

Qualifications for Local RA Eligibility

Operationalizing Slow DR Resources through Block Bidding Options

As CAISO assesses the most appropriate tool to dispatch slow DR pre-contingency, CAISO may continue to count resources that require day-ahead notice as local RA if CAISO provides dispatches to slow demand response resources prior to the beginning of the operating day. However, CAISO believes it is important to transition such that only slow demand response resources that are dispatchable in real-time through the hourly or fifteen-minute block bidding options will be eligible for local RA. Resources that require a day-ahead notification of a binding dispatch should not be eligible for local RA once CAISO implements the ESDER 3 bidding options and has a tool in place to dispatch resources pre-contingency during the operating day. Under the existing market timelines, CAISO provides unit commitments (*i.e.*, starts) and schedules in the day-ahead but generally does not dispatch units in the day-ahead. Additionally, extending pre-contingency dispatches beyond the existing real-time market time horizons limits CAISO's the ability to adjust resource output in response to changes between day-ahead and real-time system conditions.

The block bidding options allow the market to access the resource in the day-ahead and real-time market, while also giving the resource extended notification time. Additionally, the block bidding options ensure that the resource receives a binding dispatch instruction in the fifteen minute market, and will not be re-dispatched in the five minute market. Because the market adjusts a resource's scheduled output for each market run, slow DR must use the hourly or 15-minute block bidding option to ensure it is not re-dispatched in the five-minute market intervals. Therefore, once the slow DR receives a hourly block or fifteen-minute energy award, the award is binding, the resource will not be re-dispatched in RTD, and it must perform according to its RTUC energy award in real-time.

Slow Reliability Demand Response Resources

As discussed in previous comments submitted to the CPUC's RA proceeding, slow Reliability Demand Response Resources (RDRR) are not able to be dispatched on a pre-contingency basis due to its unique dispatch limitations, and as such, should not be eligible to count as local RA.[44] While PDRs participate in CAISO market and offer their services when they are economic, RDRR resources are not eligible for dispatch in real-time unless CAISO declares a Warning or Emergency. Upon this declaration, CAISO operator may choose to activate the software flag that allows these resources to be dispatched.[45]

Because RDRR is a reliability resource and only dispatched after CAISO calls a Warning or Emergency, CAISO must exclude slow responding RDRR (*i.e.*, those resources that cannot respond to contingencies within 20 minutes) from qualifying for local RA. CAISO cannot declare Warnings or Emergencies pre-contingency in anticipation of an emergency to access RDRR. Therefore, CAISO cannot depend on the pre-contingency dispatch of slow RDRR to address local contingencies.

While slow RDRR cannot provide local RA, fast responding RDRR, or RDRR that can respond within 20 minutes post-contingency, is eligible to count towards local area capacity because it can receive a dispatch and preform in the appropriate time after a contingency occurs, given CAISO declares a warning or emergency in response to the contingency.

Resource Availability

In addition to the more concretely defined requirements outlined above, CAISO urges the Commission and other stakeholders to consider the impacts on resource availability given changing resource adequacy landscape. Eligibility for local RA is subject to requirements determined by CAISO and the CPUC for availability-limited resources. CAISO is refining local capacity assessments to include an assessment of the impact of availability-limited resources on local capacity needs within the Local Capacity Requirements stakeholder process.[46] As identified in section 5.3.1, ISO planning studies have indicated that, at current levels of availability-limited resources, slow demand response resources possess adequate availability such that they can meet our local capacity needs, given the ability to utilize them within the defined time horizons. However, given the changing landscape of the resource adequacy fleet, it is reasonable to assume slow DR will be dispatched more frequently than it has been dispatched historically for two reasons. First, because slow DR must be used to pre-position the system, not just curtail after a contingency occurs, CAISO must make certain assumptions regarding real-time conditions that may or may not materialize. Second, local capacity requirements are set based on the minimum quantity of local capacity necessary to meet the

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[44] CAISO Comments on Resource Adequacy Proposals, September 28, 2017. Page 4: http://www.caiso.com/Documents/Mar7_2018_Comments-ResourceAdequacyProposals_R17-09-020.pdf
45 CAISO BPM for Market Operations Section 7.1
[46] Local Capacity Requirements Stakeholder Initiative Webpage: http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx

LCR criteria. When slow DR is relied upon as a local capacity resource, it may need to be used more frequently, especially if other local resources go on outage or local resources without availability limitations are displaced by new resources and retire. If these resources are utilized such that their availability limitations are reached, CAISO may be required to take alternative actions to ensure system reliability in local areas.

5.4. Backstop Capacity Procurement Provisions

In this initiative CAISO is: (1) proposing new authority to make CPM designations, (2) flagging potential changes to the RMR performance mechanism if changes to RAAIM are considered, and (3) proposing a new tool to encourage load to procure resources up to full UCAP requirements and dis-incentivizing entities from leaning on other LSEs.

CAISO proposes new CPM authority to procure resources in the following three scenarios: (1) system UCAP deficiencies through the RA process, (2) inability to serve load in the portfolio deficiency test, and (3) an identified need to procure local RA after an area fails a local portfolio deficiency test. These three needs will be extensions to the existing CPM authority and are closely aligned with proposals outlined in this paper.

This proposal includes a new tool called the UCAP deficiency tool, which incentivizes entities to show at or above their UCAP requirements and will dis-incentivize leaning between entities during the RA showings. This tool will penalize entities that show UCAP below requirements and allocate these payments to entities that show above requirements.

5.4.1. Capacity Procurement Mechanism Modifications

The capacity procurement mechanism is the tool that CAISO uses to backstop the RA program. Specifically, when there is insufficient capacity shown in the RA process to reliably operate the grid, CAISO may make CPM designations to procure resources that have not been shown in the RA process so that enough capacity is available to reliably operate the system. RA is shown on a year-ahead and a month-ahead basis and CPM can be used to backstop in either timeframe or in a more granular timeframe. Resource owners with additional capacity can participate in the competitive solicitation process (CSP) for their bids to be considered when and if CAISO makes a CPM designation. Generally, in any timeframe CAISO makes a designation, all options for procurement are reviewed and the least cost option that meets the reliability need is selected. Additionally, when CAISO makes CPM designations, information about the designation and supporting documentation outlining why CAISO needs the resource is provided publicly.

Authority to make CPM designations for capacity currently includes the following designation types:

1. System annual/monthly deficiency – Addresses insufficient system RA capacity in year-ahead or month-ahead RA showings;
2. Local annual/monthly deficiency – Addresses insufficient local RA capacity in year-ahead or month-ahead RA showings for one specific entity making showings;

3. Local collective deficiency – Addresses insufficient local RA capacity in year-ahead RA showings to meet the reliability needs for one specific local area;
4. Cumulative flexible annual/monthly deficiency – Addresses insufficient flexible RA capacity in the year-ahead or month-ahead showings for system needs;
5. A "Significant Event" occurs on the grid;
6. CAISO "Exceptional Dispatches" non-RA capacity; or
7. Capacity is at risk of retirement that is needed for reliability in a future year.[47]

CAISO proposes modifications to its existing CPM authority to procure additional capacity in the following three scenarios: (1) system UCAP deficiencies through the RA process, (2) inability to serve load in the portfolio analysis test, and (3) an identified need to procure local RA after an area fails a local portfolio deficiency test. In each case, CAISO would procure to retain resources that are needed to reliably operate the system.

CAISO will seek additional CPM authority to procure capacity based on system UCAP deficiencies. CAISO will not make these designations merely because LSEs are deficient, but instead will only make such designations when there are overall system deficiencies based on RA showings. To make these designations, CAISO will compare all UCAP shown in RA showings to the total requirements for UCAP, and may make additional designations based on that difference. This authority will work similar to the CAISO's existing authority to procure for system deficiencies, which are based on total shown NQC values. This new authority will be based on shown UCAP and will apply in the year-ahead and month-ahead timeframe. Similar to other existing authority, CAISO will alert entities with shortfalls and provide these entities a chance to cure any shortfall. CAISO backstop procurement only will occur after this cure period closes.

CAISO is not seeking authority to procure additional backstop capacity if any individual entity shows less capacity than their requirement. CAISO procurement based on individual LSE shortfalls could result in CAISO procuring more capacity than was necessary for reliability if other LSEs over-procure. By procuring only for system UCAP shortfalls, CAISO will ensure that it receives enough UCAP to reliably operate the grid but will not procure excessive amounts. This approach is consistent with other categories of CPM procurement, where CAISO only procures if there is a cumulative deficiency. However, procurement in this manner could result in entities '*leaning*' on other entities that show capacity in excess of their individual UCAP requirement. Because of these incentives, CAISO also proposes to implement a UCAP incentive mechanism, discussed further below.

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[47] In the RMR-CPM enhancements initiative, CAISO proposed to remove the capability to use CPM for capacity at risk of retirement, and to effectively transfer that capability to RMR authority. Currently, FERC has not responded with a decision on this RMR-CPM enhancements initiative. http://www.caiso.com/Documents/Apr22-2019-TariffAmendment-RMR-CPMEnhancements-ER19-1641.pdf.

Section 5.1.3, above, provides details about the portfolio analysis CAISO will conduct to determine if the resources procured through the RA process will be sufficient to meet the energy needs for an entire month, in addition to the peak needs during that period. If CAISO determines it is unable to meet energy needs while performing this analysis, CAISO can designate additional capacity using the CPM tool, to pass the analysis. CAISO will use this authority at the same time it undertakes month-ahead designations for other CPM backstop designations. If CAISO identifies an issue through the portfolio analysis, CAISO will continue to allow a period for entities to cure the deficiency, before CAISO makes any backstop designation. CAISO also proposes additional CPM authority to procure capacity when it identifies a need identified from the portfolio analysis.

Finally, CAISO proposes additional backstop authority if there is a local need identified through the CAISO's local capacity technical study in the year-ahead timeframe. This authority will be similar to the authority CAISO is proposing for the portfolio analysis. It will evaluate if procured local resources can meet energy needs in the upcoming year. If CAISO identifies an energy shortfall, CAISO will provide a cure period for entities to clear any deficiencies before exercising its backstop procurement authority.

EXAMPLE: UCAP Deficiency

CAISO provides the following brief example to explain a scenario where CAISO could make a potential CPM designation for deficient UCAP procured in the RA process, after the cure period.

Assume in this example that there are three load serving entities, each with a requirement to show 100 MW of UCAP. The first entity shows 125 MW, or 25 MW above the requirement, while the second and third entities show 80 MW and 75 MW respectively, or 20 MW and 25 MW below requirements, respectively. In aggregate, at the system level the RA process procures 280 MW and does not meet the 300 MW requirement for UCAP. This indicates a 20 MW shortfall at the system level, for which CAISO could undertake backstop procurement. If CAISO procures backstop capacity, it will allocate costs for that backstop to the entities that were deficient, in this case entities 2 and 3, per the LSE's share of the overall deficiency. In this case, entity 2 will be assigned 44% (20/45) of the costs and entity 3 will be assigned 56% (25/45) of the costs to procure the additional capacity for this designation. CAISO provides additional discussion, below, about how LSE 1's showing can result in incentive payments for its 25 MW of excess capacity.

Figure 17: UCAP Deficiency CPM Backstop

LSE	Req. (MW)	Shown (MW)	Shortage (MW)
1	100	125	
2	100	80	20
3	100	75	25
TOTAL	300	280	45

Cost Allocation
20/45
25/45

BACKSTOP: 20 MW

CPM Designation Order

Today if CAISO makes multiple CPM designations for any single planning horizon, it first allocates costs and credits to individual entities that are deficient, then to all applicable LSEs that are collectively deficient. CAISO intends to maintain the similar paradigm with the new authority. Going forward, CAISO will first allocate the costs to system UCAP deficiencies, then to traditional NQC system deficiencies, then to local portfolio deficiencies, then to local NQC deficiencies, and finally to system portfolio deficiencies. This order is illustrated in Figure 18 below. As with current practice, if CAISO were to consider multiple designations in one timeframe, CAISO would make designations that meet all of the necessary reliability needs at the least cost. This Figure may be used to determine cost and credit allocation, if CAISO makes multiple CPM designations using different CPM authority.

Figure 18: CPM Designation Order

- System UCAP deficiencies
- System NQC deficiencies
- Local portfolio deficiencies
- Local NQC deficiencies
- System portfolio analysis deficiencies

5.4.2. Reliability Must-Run Modifications

This initiative is considering whether to make changes to or eliminate RAAIM. RAAIM is the primary tool used to ensure that RMR resources are bidding into the market, but any changes to RAAIM would not necessarily preclude using the RAAIM tool as the performance mechanism for RMR resources in the future. The RMR-CPM enhancements initiative, recently filed by CAISO at FERC, proposed that the RAAIM tool be used for the performance mechanism for RMR resources. CAISO is mindful that this measure was discussed at length in the RMR-CPM enhancements initiative.

5.4.3. UCAP Deficiency Tool

As noted above, CAISO is not planning new CPM authority to make designation when a specific entity shows less UCAP than individual requirements as long as the system as a whole is adequate. However, CAISO is planning to develop a new tool, called the UCAP deficiency tool that will impose penalties on entities with deficient UCAP showings. This tool would be designed to prevent entities from leaning and to incentivize entities to show above individual UCAP requirements.

The concept of the UCAP deficiency tool is to apply a penalty to resources that show less than their UCAP requirement, and distribute those collected penalties to resources showing above their requirements. Without this tool, a situation could exist where one or more entities could choose to not procure their full UCAP requirement because they suspect that showings at the system level system will be sufficient to meet aggregate requirements or that the ISO will not make a backstop designation and no additional costs will be allocated. This concept is known as *leaning*.

Ideally, these proposed rules for the UCAP deficiency tool would result in a streamlined and straightforward mechanism, where any entity that shows less than their requirements would be charged a penalty price for the amount of capacity the entity is short. This proposal includes specifications that the penalty price will be set at the CPM competitive solicitation soft offer cap, which is currently $6.31/kW-year. All revenue collected will be distributed to entities that show above their UCAP, in proportion to the total amount shown above requirements for all entities.

The examples below include several scenarios that step through the details for how the UCAP deficiency tool could work in practice.

EXAMPLES: UCAP Deficiency Tool, with no CAISO backstop

This set of examples presents three scenarios where CAISO would use the UCAP deficiency tool, but not make any CPM designation. The first scenario shows procurement above the UCAP requirements and therefore no CPM designation. In this example LSEs 1 and entity 2 show 10 MW and 15 MW above their 100 MW month-ahead requirements, respectively, and entity 3 shows 10 MW below its 100 MW requirement. Because there is no system shortfall for capacity, CAISO will not make a CPM designation, but because the showing from LSE 3 is below the requirement, the UCAP deficiency will trigger, and LSE 3 is assessed a charge for 10 MW * $6.31/kW-month, or $63,100. This charge is then allocated to LSE 1 and LSE 2, where entity 1 receives 10/25 = 40% or $25,240 and entity 2 receives 15/25 = 60% or $37,860.

Figure 19: UCAP Deficiency Tool, no Backstop

LSE	Req. (MW)	Shown (MW)	Shortage (MW)	Penalty	Payment
1	100	110			$25,240
2	100	115			$37,860
3	100	90	10	$63,100	
TOTAL	300	315	10	$63,100	$63,100

The second scenario shows a system shortfall, but CAISO does not issue a CPM designation. In this example LSE 1 and LSE 2 show UCAP below their 100 MW requirements, at 10 MW and 15 MW respectively, and LSE 3 shows 5 MW above their 100 MW requirement. In this scenario the CAISO could potentially procure backstop capacity to cure the 20 MW system UCAP deficiency, but does not make such a designation. In this case, the two LSEs that are short are assessed a charge for the capacity matching the UCAP deficiency. Because LSE 1 is 10 MW short it is assessed a penalty of $63,100 and LSE 2 is assessed a penalty of $94,650. Because LSE 3 is the only entity showing above the requirements, all of the collected charges are allocated back to that LSE, in this case the total amount allocated is $157,750.

Figure 20: UCAP Deficiency Tool, with Aggregate Shortfall

LSE	Req. (MW)	Shown (MW)	Shortage (MW)	Penalty	Payment
1	100	90	10	$63,100	
2	100	85	15	$94,650	
3	100	105			$157,750
TOTAL	300	280	25	$157,750	$157,750

In the third example LSE 2 and LSE 3 both show below their 100 MW month-ahead requirements, and LSE 1 shows exactly at its 100 MW requirement. In this scenario the aggregate amount of UCAP shown is below the aggregate amount of UCAP required for the UCAP requirements. In this case, CAISO could potentially procure backstop capacity to cure the system UCAP deficiency. Irrespective of any CPM designation, CAISO will not charge any market participants for the shortfall, as there is no entity to allocate those charges back to.

Figure 21: UCAP Deficiency Tool, no Award Recipients

LSE	Req. (MW)	Shown (MW)	Shortage (MW)	Penalty	Payment
1	100	100			
2	100	80	20		
3	100	95	5		
TOTAL	300	275	25	$0	$0

EXAMPLE: UCAP Deficiency Tool with CAISO backstop

In this example LSE 1 and LSE 2 both show below their 100 MW month-ahead requirements, and LSE 3 shows above the 100 MW requirement. In this scenario LSE 1 is again short 10 MW and LSE 2 is short 15 MW. Additionally, because LSE 3 only procures 5 MW above its requirement, there is a shortage between the aggregate amount of UCAP shown and the aggregate requirement. This shortfall triggers a CAISO CPM designation, for the 20 MW deficiency. CAISO then allocates 8 MW of the CPM procurement to LSE 1 and 12 MW to LSE 2. The shortfall persists even with the adjustment for the CPM allocation, and the shortfall equals 5 MW or exactly the capacity that that LSE 1 showed above its requirement. Therefore, the remaining shortfall, inclusive of the CPM allocation, is 2 MW for LSEs 1 and 3 MW for LSE 2, which is then subject to the UCAP deficiency tool penalty. Penalties assessed are for $12,620 for LSE 1 and $18,930 for LSE 2. The $31,550 of the collected revenues are then credited to LSE 3.

Figure 22: UCAP Deficiency Tool, with Backstop

LSE	Req. (MW)	Shown (MW)	Shortage (MW)	CPM Alloc (MW)	Adj Short (MW)	Penalty	Payment
1	100	90	10	8	2	$12,620	
2	100	85	15	12	3	$18,930	
3	100	105					$31,550
TOTAL	300	280	25	20	5	$31,550	$31,550

↓

BACKSTOP: 20 MW

6. Implementation Plan

CAISO is currently targeting a 2021 implementation for this initiative, meaning application to the 2022 RA compliance year. CAISO understands this is challenging and comprehensive initiative. CAISO seeks stakeholder feedback about how these policies must roll out and an appropriate and feasible implementation schedule once the policy details are further understood and developed.

7. EIM Governing Body Role

For this initiative, CAISO plans to seek approval from CAISO Board only. This initiative falls outside the scope of the EIM Governing Body's advisory role because the initiative does not propose changes to either real-time market rules or rules that govern all CAISO markets. This initiative is focused on CAISO RA planning, procurement, and performance obligations. This process applies only to LSEs serving load in CAISO BAA and the resources procured to serve that load, and does not apply to LSEs outside CAISO balancing authority area. CAISO did not receive any initial feedback from stakeholders regarding the initial proposed EIM classification for this initiative. CAISO continues to seek stakeholder feedback on this proposed decisional classification for the initiative.

8. Next Steps

CAISO will discuss this revised straw proposal with stakeholders during a stakeholder meeting on July 7-8, 2019. Stakeholders are asked to submit written comments by July 24, 2019 to initiativecomments@caiso.com. A comment template will be posted on the CAISO's initiative webpage here:
http://www.caiso.com/informed/Pages/StakeholderProcesses/ResourceAdequacyEnhancements.aspx

9. Appendix

9.1. Review of Counting Rules in other ISOs and RTOs

NYISO

NYISO is responsible for managing its capacity market, which is known as the Installed Capacity Market. Each year, the New York State Reliability Council determines the annual Installed Reserve Margin necessary for the NYISO to sufficiently fulfil its Resource Adequacy criteria. The NYISO then determines the Minimum Installed Capacity Requirement (ICAP) for each LSE to meet their system and local needs which is the sum of the forecasted control area peak load in addition to the reserve margin plus 1. This ICAP value is adjusted for historic availability by multiplying the Minimum Installed Capacity Requirement times one minus a rolling monthly average Effective Forced Outage Rate of Demand (EFORd)[48] value which translates to the Minimum Unforced Capacity Requirement (UCAP) for each capacity zone.

PJM

The centralized capacity market PJM relies on is called the Reliability Pricing Model (RPM). The process for estimating the Installed Capacity requirement and the use of an auction to procure capacity is similar to NYISO's ICAP market. First a Loss of Load Expectation (LOLE) study is used to determine the Installed Reserve Margin (IRM) which sets the ICAP requirement expressed as a reserve percent (*e.g.*, 15%) based on historic peak load. The EFORd ratio is then applied to the ICAP obligation to establish the Forecast Pool Requirement (FRP) measured as an UCAP value (*i.e.*, FRP = (1 + IRM)*(1 – Pool Wide Average EFORd). The FRP multiplied by the forecasted peak load for the upcoming year is used as the target in the capacity auction and is PJM's UCAP obligation known as the Reliability Requirement. Lastly, portions of the UCAP requirement are allocated to several zones served by a single utility. PJM procures resources on behalf of the LSEs unless LSEs opt out of the RPM capacity market to instead self-supply using the Fixed Resource Requirement Alternative.

PJM also has a non-performance assessment. The non-performance assessment evaluates performance of resources during emergency conditions. Resources that fail to perform are subject to non-performance charge. Resources that over-perform may be eligible for over-performance credit. The resource's expected performance is compared to actual performance for each real-time settlement interval for which an Emergency Action has been declared by PJM. "Emergency Actions" mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action. Performance is assessed for Emergency Actions.

[48] EFORd is a measure of the probability the resource will be on a forced outage and unable to serve load if needed.

MISO

MISO has a voluntary incremental central capacity market known as a Planning Resource Auction (PRA). It is the responsibility of LSEs to determine their forecasted coincident peak which MISO uses to establish the overall system Planning Reserve Margin (PRM). Each LSE is provided with a minimum ICAP responsibility and is given the choice to meet their PRM by participating in the PRA, or using bilateral contracts, similar to CAISO, which constitutes the majority of MISO's forward capacity procurement. However, there are several competitive retail zones within MISO's jurisdiction, accounting for roughly 10% of system load, that operate using the PRA process exclusively.

ISO-NE

ISO-NE uses a Forward Capacity Market which is a centralized market run every year to procure resources three years in advance for system and zonal needs. The Installed Capacity Requirement (ICR) is set based on a loss of load study accounting for the expected load forecasts and the projected installed resources necessary to meet the reliability standards. The ICR is converted to a Net Installed Capacity Requirement (NICR) which subtracts the Quebec Control Interconnection Credit. Unique to the other capacity markets, ISO-NE uses a purely financial obligation model where New England's system operator procures enough capacity and settles payments while it is LSEs that pay for their allocated share of resource needs. ISO-NE also does not consider forced outage rates, unlike the other centralized markets, when calculating a resource's qualifying capacity. Generators instead are incentivized through the use of performance payments to recognize the outages they anticipate and to only offer an ICAP quantity that they are likely to perform. The Pay-for-Performance (PFP) tool is a monthly capacity performance payment (credit or charge) based on system conditions and resource performance during scarcity condition. A scarcity condition is defined as any five-minute interval when the system cannot meet its reserve requirement. The performance payment is an exchange between suppliers (*i.e.*, money collected from those who underperform is used to pay those that over perform), similar to the CAISO's RAAIM.

Table 10: Survey of methodologies and factors determining capacity contribution for thermal, solar, wind, and hydro resources

Resource type	Attributes	NYISO	PJM	MISO	ISO-NE
Existing resources	**Capability verification test**	Capability period: summer (June 1 - Sept 15) and winter (November - April 15)	Seasonally: Summer (June - August) and winter (December - February)	Annual, 1 year prior to deliverability year	Seasonally: summer (June - September) and winter (October - May)
New or returning resources	**Capability**	DMNC is seasonal	ICAP is a summer net dependable capacity	Total Interconnection ICAP is seasonal	Seasonal claimed capacity
	Forced outage	Class average	Blend of class average and outage data	Class average	NA

Resource type	Attributes	NYISO	PJM	MISO	ISO-NE
Thermal	**Equation**	**UCAP = (DMNC) * (1 - AEFORd); UCAP = (DMNC) * (1 - AOF)**	**UCAP = (ICAP) * (1 - EFORd)**	**UCAP = (Total Interconnection ICAP) * (1 - XEFORd)**	Summer and winter Qualified Capacity
	Summary	Based on 5 year average of DMNC test data which is a generators proven ability to generate power. AEFORd factor is used if full GADS data is provided, otherwise an Average Outage Factor (AOF) from GADS average production data is used	Summer net dependable capacity	Total Interconnection ICAP is equal to the lesser of its GVTC or its Total Capacity Tested	Seasonal claimed capacity (SCC) calculated using the median value of five years of summer and winter data
Solar	**Equation**	**UCAP = (Nameplate Capacity) * (Production Factor)**	**UCAP = ICAP**	**UCAP = (Total Interconnection ICAP) * (1 - XEFORd)**	
	Summary	Uses a derating factor that averages one year of historical production during peak hours 14:00 through 18:00 in summer (June, July, August) and 16:00 through 20:00 in winter (December, January, February) of the previous season (winter, summer)	The capacity rating of three years of historical operating data during hours 13:00 through 18:00 for months June, July and August or class average capacity factor	3 year historical average output during hours 15:00 through 17:00 EST in summer (June, July, and August) Note: New or returning PV sources need 30 consecutive days of historical data during summer months for hours 15:00 through 17:00 EST	Five year median net output from 14:00 through 18:00 for summer months June - September and 18:00 through 19:00 during the winter months October - May
Wind	**Equation**	**UCAP = (Production Factor) * (Nameplate Capacity)**	**UCAP = ICAP**	**UCAP = (Total Interconnection ICAP) * (Wind Capacity Credit)**	

Resource type	Attributes	NYISO	PJM	MISO	ISO-NE
	Summary	Uses a derating factor that averages one year of historical production during peak hours 14:00-18:00 in summer (June, July, August) and 16:00-20:00 in winter (December, January, February) of the previous season (winter, summer)	The capacity rating of three years of historical operating data during hours 13:00 through 18:00 for months June, July and August or class average capacity factor	Historical wind availability is used to calculate system-wide ELCC value across all CPNodes with an 80% confidence level. This value determines a Wind Capacity Credit for each wind farm based on a maximum capacity at the highest 8 coincident peaks during summer. Ten years of averaged data is used and all hours are considered.	Five year median net output from 14:00 through 18:00 for summer months June - September and 18:00 through 19:00 during the winter months October - May
Hydro	**Equation**	**UCAP = (Production Factor) * (Nameplate Capacity)**	**UCAP = ICAP**	**UCAP = (Total Interconnection ICAP) * (1 - XEFORd)**	
	Summary	Run-of-River uses a derating factor based on a rolling average of the hourly net energy during the 20 highest load hours for the previous 5 summer and winter capability periods	Hydro summer net capability is determined using tests taken annually during summer period (June-August) based on expected head and streamflow under summer conditions	3 to 15 year historical median hourly integrated net output during hours 15:00 through 17:00 EST in summer (June, July, and August)	Five year median net output from 14:00 through 18:00 for summer months June - September and 18:00 through 19:00 during the winter months October - May

9.2. Hybrid Resources

CAISO provides this section of the appendix for hybrid resources to identify important considerations and issues that resource developers, regulators, and CAISO itself must consider carefully. Hybrid resources refers to a combination of two resource types under one generating facility, co-located behind a single point of interconnection (POI). CAISO has observed that combined hybrid resource configurations submitting interconnection requests or modifying existing facilities to this configuration are growing in number. Due to the number of interconnection requests currently in the queue and strong interest expressed by various developers and stakeholders, CAISO anticipates that hybrid resources will grow in installed capacity in future years. In 2016, CAISO developed a Technical Bulletin for the Implementation of Hybrid Energy Storage Generating Facilities that is available for review: http://www.caiso.com/Documents/TechnicalBulletin-ImplementationofHybridEnergyStorageGeneratingFacilities.pdf

Hybrid resources raise new operational and forecasting challenges that CAISO plans to address prior to the wide scale adoption of these resource configurations are operational on CAISO's system. CAISO believes that Resource Adequacy (RA) counting rules for hybrid resources are an important issue that will likely be a primary driver of future decisions by resource developers.

9.2.1. Operations and Forecasting Considerations

Combining renewable and storage resources as a single hybrid resource present significant issues and challenges that CAISO has outlined in this section. CAISO believes that grid operators, regulators, market designers, and resource developers should work together to ensure they carefully consider the primary issues related to operations and forecasting. The areas of primary concern for CAISO relate to (1) the operation and optimization of hybrid resources under separate resource IDs versus a single resource ID, and (2) forecasting concerns associated with hybrid resources under single resource IDs.

Operation and optimization of hybrid resources under a single Resource ID

There are challenges to determining how to optimize multiple resources combined as under a single resource ID. Configuring a combined hybrid resource with two separate resource IDs allows CAISO to forecast the wind or solar resource component, while also optimally dispatching the separate storage resource to the benefit of overall system reliability. In contrast, a combined hybrid resource under a single resource ID creates an operational and reliability risk and CAISO cannot ensure the same optimization and system benefits.

Current market participation and resource adequacy rules do not consider how market participants or CAISO would actually operate and optimize hybrid resources in CAISO market. For resource owners to participate in CAISO markets under this approach, the Scheduling Coordinator (resource owner) would be the entity tasked with optimizing the utilization of the resource. The variable energy resource output forecasting and storage resource state of charge would be unknown to CAISO and the optimization of the resource would need to be accomplished through the SC's bidding strategy for the resource.

CAISO could also consider developing new resource models to attempt to address this issue of operations and optimization of hybrid resources under single resource IDs. The addition of new market model capabilities to address these issues would present a large-scale project that would require stakeholder input and consideration. This potential solution is not currently included in CAISO's future market design development plans.

Forecasting issues related to hybrid resources under a single Resource ID

CAISO believes there are potential forecasting related reliability concerns related to hybrid resources. Combining storage and renewable resources under a single resource ID will have a significant effect on the CAISO's ability to accurately forecast for the wind and solar outputs for such hybrid resources. CAISO currently provides forecasts for most wind and solar resources on its system. Combining storage with wind or solar resources as a single CAISO resource will degrade the CAISO's ability to accurately forecast for the output of the combined resource. This is because the charging and discharging cycles of the storage component would not be distinguishable from the output of the underlying renewable resource. Due to this single resource ID related issue, it is currently infeasible for CAISO to generate a reliable forecast for a single resource ID combined hybrid resource. As a result, CAISO believes the potential for increased forecast error would degrade overall system reliability as opposed to improving it.

CAISO may be able to develop alternative concepts to address this concern through the addition of new telemetry requirements that may provide CAISO with accurate and transparent information into the components of hybrid resources. This additional data may be useful in developing new forecasting approaches for these hybrid resources. CAISO notes that the creation of new telemetry provisions and development of enhanced forecasting capabilities is also a large-scale project that would require stakeholder input and consideration.

9.2.2. Resource Adequacy Capacity Valuation for Hybrid Resources

CAISO believes that resolving hybrid resource RA capacity counting rules is a high priority issue for a number of reasons. CAISO is concerned with ensuring that CPUC RA counting rules for hybrid resources provide accurate capacity valuations for resource adequacy purposes. Additionally, the counting rules for these resources are important to determine because it will likely drive decisions by resource owners related to combined hybrid resources under a single resource ID or multiple resource IDs. This is vital because these decisions by resource owners will affect CAISO operations and forecasting, as noted above.

CAISO input in CPUC RA proceeding

For CAISO's latest input into the CPUC RA proceeding regarding hybrid resource counting, see CAISO comments in Rulemaking 17-09-020; Track 3 Proposal Reply Comments (March 22, 2019)[49]

9.3. Additional Details on the Available Import Capability Assignment Process[50]

MIC Allocation Step		Process Description
Step 1	Determination of Maximum Import Capability on Interties into CAISO BAA	CAISO will establish the Maximum Import Capability (MIC) for each Intertie into the BAA, and will post those values on CAISO Website in accordance with the schedule and process set forth in the BPM.
Step 2	Determination of Available Import Capability by Accounting for Existing Contracts and Transmission Ownership Rights	For each Intertie, the Available Import Capability is determined by subtracting the import capability on each Intertie associated with Existing Transmission Contracts (ETCs) and Transmission Ownership Rights (TORs) held by LSEs that do not serve Load within CAISO BAA from the MIC established in Step 1. The remaining sum of all Intertie Available Import Capability is the Total Import Capability. Total Import

49 http://www.caiso.com/Documents/Mar29-2019-ReplyComments-Track3Proposal-ELCC-ResourceAdequacyProgram-R17-09-020.pdf
50 Tariff Section 40.4.6.2.1

MIC Allocation Step		Process Description
	Held by Out-of-Balancing Authority Area LSEs	Capability is used to determine the Load Share Quantity for each LSE that serves Load within CAISO BAA.
Step 3	Determination of Existing Contract Import Capability by Accounting for ETCs and TORs Held by CAISO Balancing Authority Area LSEs	The Existing Contracts and Transmission Ownership Rights held by LSEs that serve Load within CAISO BAA will be reserved on the Available Import Capability remaining on each Intertie after Step 2 above, and will not be subject to reduction under any subsequent steps. The import capability reserved pursuant to this Step 3 is the Existing Contract Import Capability.
Step 4	Assignment of Pre-RA Import Commitments	CAISO assigns LSEs serving Load within CAISO BAA Pre-RA Import Commitment Capability on a particular Intertie based on Pre-RA Import Commitments in effect (where a supplier has an obligation to deliver the Energy or make the capacity available) at any time during the Resource Adequacy Compliance Year for which the Available Import Capability assignment is being performed. The Pre-RA Import Commitment will be assigned to the Intertie selected by the LSE during the Resource Adequacy Compliance Year 2007 import capability assignment process, which was required to be based on the Intertie upon which the Energy or capacity from the Pre-RA Import Commitment had been primarily schedule. For a Pre-RA Import Commitment without a scheduling history at the time of the Resource Adequacy Compliance Year 2007 import capability assignment process, the primary Intertie upon which the Energy or capacity was anticipated to be scheduled will be used. (2007 is the date used for Pre-RA Import Commitments for participants in the current CAISO BAA; CAISO will need to establish a new "cut-off" date for new CAISO participants.) To the extent a particular Intertie is over requested with Pre-RA Import Commitments under Step 4, due to either Pre-RA Import Commitments not included in the Resource Adequacy Compliance Year 2007 import capability assignment process or changes in system conditions that decrease the MIC of the Intertie, such that the MW represented in all Pre-RA Import Commitments utilizing the Intertie exceed the Intertie's Available Import Capability in excess of that reserved for ETCs and TORs under Steps 2 and 3, CAISO will assign Pre-RA Import Commitments Pre-RA Import Commitment Capability based on the Import Capability Load Share Ratio of each LSE submitting Pre-RA Import Commitments on the particular Intertie. To the extent this initial assignment of Pre-RA Import Commitment Capability does not fully assign the Available Import Capability of the particular over requested Intertie, the remaining Available Import Capability on the over requested Intertie will be assigned until fully exhausted based on the Import Capability Load Share Ratio of each LSE whose submitted Pre-RA Import Commitment has not been fully satisfied by the previous Import Capability Load Share Ratio assignment iteration. The Available Import

MIC Allocation Step		Process Description
		Capability assigned pursuant to this Step 4 is the Pre-RA Import Commitment Capability.
Step 5	Assignment of Remaining Import Capability Limited by Load Share Quantity	The Total Import Capability remaining after Step 4 will be assigned only to LSEs serving Load within CAISO BAA that have not received Existing Contract Import Capability and Pre-RA Import Commitment Capability under Steps 3 and 4, that exceed the Load Serving Entity's Load Share Quantity. Only the MW quantity of any Pre-RA Import Commitment Capability assigned to Existing Contract Import Capability under Step 4 that exceeds the Existing Contract Import Capability on the particular Intertie will be counted for purposes of this Step 5. This Total Import Capability will be assigned until fully exhausted to those LSEs eligible to receive an assignment under this Step based on each LSE's Import Capability Load Share Ratio up to, but not in excess of, it's Load Share Quantity. The quantity of Total Import Capability assigned to the LSE under this Step is the LSE's Remaining Import Capability. This Step 5 does not assign Remaining Import Capability on a specific Intertie.
Step 6	CAISO Posting of Assigned and Unassigned Capability	Following the completion of Step 5, CAISO will post the following information to CAISO website: (a) The Total Import Capability; (b) The quantity in MW of Existing Contracts and Transmission Ownership Rights assigned to each Intertie, distinguishing between Existing Contracts and Transmission Ownership Rights held by LSEs within CAISO BAA and those held by load serving entities outside CAISO BAA; (c) The aggregate quantity in MW, and identity of the holders, of Pre-RA Import Commitments assigned to each Intertie; and (d) The aggregate quantity in MW of Available Import Capability after Step 4, the identity of the Interties with Available Import Capability, and the MW quantity of Available Import Capability on each such Intertie.
Step 7	CAISO Notification of LSE Assignment Information	Following the completion of Step 5, the CACAISO will notify the Scheduling Coordinator for each LSE of: (a) The LSE's Import Capability Load Share; (b) The LSE's Load Share Quantity; and (c) The amount of, and Intertie on which, the LSE's Existing Contract Import Capability and Pre-RA Import Commitment Capability, as applicable, has been assigned; and (d) The LSE's Remaining Import Capability.
Step 8	Transfer of Import Capability	LSEs are then allowed to transfer some or all of their Remaining Import Capability to any other LSE or Market Participant. CAISO will accept transfers among LSEs and Market Participants only to the extent such transfers are reported to CAISO through the CAISO's Import Capability Transfer Registration Process, by the entity receiving the Remaining Import Capability who must set forth (1) the name of the counter-parties, (2) the MW quantity, (3) term of transfer, and (4) price on a per MW

MIC Allocation Step		Process Description
		basis. CAISO will post the information on transfers of Remaining Import Capability received under this Step 8 to CAISO website.
Step 9	Initial Scheduling Coordinator Request to Assign Remaining Import Capability by Intertie	The Scheduling Coordinator (SC) for each LSE or Market Participant then notifies CAISO of its request to assign its post-trading Remaining Import Capability on a MW basis per available Intertie. Total requests for assignment of Remaining Import Capability by a SC cannot exceed the sum of the post-traded Remaining Import Capability of its LSEs. CAISO will honor the requests to the extent an Intertie has not been over requested. If an Intertie is over requested, the requests for Remaining Import Capability on that Intertie will be assigned based on each LSE's Import Capability Load Share Ratio in the same manner as set forth in Step 4. A Market Participant without an Import Capability Load Share will be assigned the Import Capability Load Share equal to the average Import Capability Load Share of those LSE from which it received transfers of Remaining Import Capability.
Step 10	CAISO Notification of Initial Remaining Import Capability Assignments and Unassigned Capability	CAISO will notify the SC for each LSE or Market Participant of the accepted request(s) for assigning Remaining Import Capability under Step 9. CAISO publishes the aggregate unassigned Available Import Capability, if any, and identifies the Interties with unassigned Available Import Capability, and the MW quantity of Available Import Capability, on each such Intertie on CAISO Website. CAISO will issue a Market Notice to advise the SC for each LSE or Market Participant that Step 10 is complete and to specify the time at which CAISO will begin accepting requests for the Remaining Import Capability for Step 11.
Step 11	Secondary Scheduling Coordinator Request to Assign Remaining Import Capability by Intertie	To the extent Remaining Import Capability remains unassigned as disclosed by Step 10, SCs for LSEs or Market Participants will notify CAISO of their requests to assign any Remaining Import Capability on a MW per available Intertie basis. Step 10 must be completed before a SC may submit a request under this step for any Remaining Import Capability. Any requests received prior to the time stated in the Market Notice issued at the completion of Step 10 will not be honored by the CAISO. CAISO will honor the timely requests received to the extent an Intertie has not been over requested. If an Intertie is over requested, the requests on that Intertie will be assigned based on each LSE or Market Participant's Import Capability Load Share Ratio, as used in Steps 4 and 9.
Step 12	Notification of Secondary Remaining Import Capability Assignments and Unassigned Capability	CAISO will then notify the SC for each LSE or Market Participant of the accepted request(s) for assigning Remaining Import Capability under Step 11. CAISO will publish any unassigned aggregate Available Import Capability on CAISO website and identify the Interties with Available Remaining Import Capability, and the MW quantity of Availability Import Capability on each such Intertie. CAISO will issue a Market Notice to advise the SC for each LSE or Market Participant that Step 12 is complete and to specify the time at which CAISO will begin accepting requests for the Balance of Year Unassigned Available Import Capability for Step 13.

MIC Allocation Step		Process Description
Step 13	Requests for Balance of Year Unassigned Available Import Capability	To the extent total Available Import Capability remains unassigned as disclosed by Step 12, SCs for LSEs or Market Participants may notify CAISO of a request for unassigned Available Import Capability on a specific Intertie on a per MW basis. Step 12 must be completed before a SC may submit a request under this step for any remaining unassigned Import Capability. Any requests received prior to the time stated in the Market Notice issued at the completion of Step 12 will not be honored by the CAISO. Each request must include the identity of the LSE or Market Participant on whose behalf the request is made. CAISO will honor timely requests in priority of the time that requests from SC were received until the Intertie is fully assigned and without regard to any LSE's Load Share Quantity. Any honored request shall be for the remainder of the Resource Adequacy Compliance Year; however, any notification by CAISO of acceptance of the request in accordance with this Section after the 20th calendar day of any month shall not be permitted to be included in the LSE's Resource Adequacy Plan submitted in the same month as the acceptance. CAISO notifies the SC of the time the request was deemed received by CAISO and whether the request was honored within seven days of receipt of the request. If the request is not honored because the Intertie requested was fully assigned, the request will be deemed rejected and the SC will be required to submit a new request for unassigned Available Import Capability on a different Intertie if it still seeks to obtain unassigned Available Import Capability. CAISO will update the list of unassigned Available Import Capability by Intertie on its website.
Please note: This multi-step process for assigning Total Import Capability determines the import capability that can be credited towards satisfying the Reserve Margin of a LSE under this Section 40. Upon the request of the CAISO, SC's must provide CAISO with information on Pre-RA Import Commitments and any transfers or sales of assigned Total Import Capability.		

9.4. Additional Detail on Slow DR Market-based approach

While slow responding PDR cannot respond to dispatches post-contingency within the required timeframe, these resources can be useful for maintaining reliability by reducing load in local capacity areas. This section discusses how slow responding DR resources can be dispatched pre-contingency to lower loads in anticipation of a contingency.

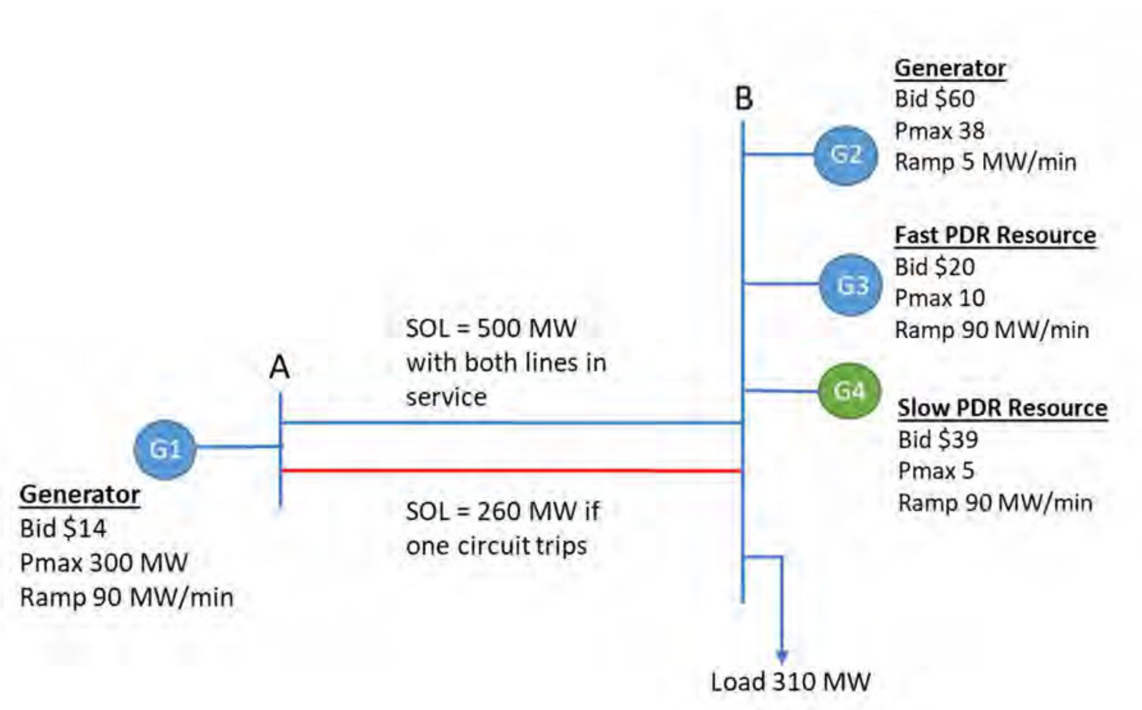
To receive longer notification times, PDR must elect either the hourly or 15-minute block bidding options proposed in ESDER 3. If the PDR resource elects these bidding options, the resource will not be eligible for corrective capacity awards under CME because the market cannot use these resources to resolve contingencies within the required timeframe if they are dispatched after the contingency occurs. However, while the market cannot reserve corrective capacity for slow response resources, the preventive-corrective constraint may find it economic to pre-dispatch slow response resources for load reduction in the Real-Time Unit Commitment (RTUC) intervals prior to a potential contingency, rather than relying on corrective capacity from other resources. This would occur when it would cost more to reserve corrective capacity from another resource than to economically drop load from the slow responding PDR prior to a contingency occurring. When economic, pre-contingency dispatch of slow responding PDR would decrease the amount of corrective capacity needed to satisfy the preventive-corrective constraint. This proposal is consistent with the proposals put forth in the Commitment Costs Enhancements Phase 3 initiative that allow PDRs to preserve their starts through the use of opportunity costs.

The following example demonstrates how slow responding DR can help lower load in anticipation of a contingency under the preventive-corrective model by receiving a dispatch in RTUC to reduce load in real-time.

Example: A Two-Node System with Two Traditional Generators and Two DR Resources

This example is a two-node system with two traditional generators and two PDRs. At node B, there are 2 PDRs, G3 and G4. G3 is not a slow response resource because can respond to 5 minute dispatches without the need for additional notification time. G4 requires a notification time of at least 50 minutes and therefore, is considered a slow response PDR. Under pre-contingency normal conditions, the limit on lines A-B is 500 MW. If a circuit trips and only one line is in service, the system would need to be repositioned to its post-contingency normal limit of 260 MW. When a contingency occurs, CAISO will have a total of 30 minutes (10 minutes for operator activities and 20 minutes for resource response) to get the system to the post-contingency normal rating of 260 MW.[51]

Figure 23: A Two-Node System with Two Traditional Generators and Two DR Resources



[51] The post-contingency emergency limit for the single line is now 500 MW.

Today, the market would dispatch G1, the cheapest generation, up to its Pmax of 300 MW on lines A-B and 10 MW from G3, the next cheapest generation, to serve the load of 310 MW at node B. This solution is demonstrated in Table 11.

Table 11: Energy Awards without CME

Energy Awards without CME		
Generator	**Energy Award (MW)**	**LMP ($/MW)**
G1	300	14
G2	0	20
G3 (PDR)	10	20
G4 (Slow PDR)	0	20

This solution is blind to the post-contingency limit of 260 MW. If a contingency occurred, the flow on lines A-B would need to reduce from 300 MW to 260 MW within 20 minutes. This solution does not set up the system to be able to respond quickly enough through market dispatches to a contingency after it occurs because G3 is already dispatched to its Pmax of 10 MW, G2 would be dispatched to its Pmax of 38 and the system would still require 2 MWs to serve all the load at node B. The slow responding DR cannot be accessed quickly enough post-contingency due to the notification time required for slow DR to be dispatched.

With CME in place, the market will consider the post-contingency limit in its solution, 260 MW in this example. If a contingency occurs, the system would need to decrease flow from A-B by 40 MW to stay within the post-contingency limit and increase generation by 40 MW at node B to serve all 310 MWs of load. This solution is demonstrated in Table 12.

Table 12: Energy and Corrective Capacity Awards with CME

Energy and Corrective Capacity Awards with CME				
Generator	**Energy Award (MW)**	**LMP ($/MW)**	**Corrective Capacity Award (MW)**	**LMCP ($/MW)**
G1	300	14	-40	0
G2	0	39	35	19
G3 (PDR)	5	39	5	19
G4 (Slow PDR)	5	39	0	19

G1 receives a 300 MW energy award and a 40 MW downward corrective capacity award. The downward corrective capacity award is not priced because it is not constrained by its ramp rate, Pmax, or Pmin. To balance the 40 MW of downward corrective capacity at node A, the system will award 40 MW of upward capacity at node B. Because the G4 is a slow PDR and cannot respond within the required timeframe, it will not receive a corrective capacity award in the real-time. Instead, the system will award G2 35 MW of corrective capacity. G3 will receive a 5 MW corrective capacity award and a 5 MW energy award. G3 is constrained by its Pmax, and so the next most economic resource, the slow DR resource, will provide the rest of the energy required to serve the load. In this example, the market positions the system so that it serves all the load pre-contingency while reserving corrective capacity so that it can return the system to its post-contingency limit should a contingency occur.

In the event of a contingency, CAISO operations will run its real-time contingency dispatch (RTCD) to dispatch corrective capacity from capacity into energy. In the example above, the market would dispatch G1 from 300 MW of energy down to 260 MW of energy to reduce flow on the line to its post-contingency rating. To replace the 40 MW from reduced from G1, the market would dispatch G2 from 0 MW to 35 MW of energy and G3 from 5 MW to 10 MW of energy.

Slow DR resources cannot respond quickly enough within the post-contingency timeframe to mitigate local area contingencies within 30 minutes. As such, slow DR cannot receive corrective capacity awards and would not be dispatched after a contingency. Instead, they would be dispatched pre-contingency when they are economic over awarding another resource a corrective capacity and should preform based on their energy dispatch in RTUC whether or not a contingency occurs in real-time.

1

2017 PSE Integrated Resource Plan

Executive Summary

The IRP is best understood as a forecast of resource additions that appear to be cost effective given what we know today about the future. We know these forecasts will change as the future unfolds and conditions change. PSE's commitments to action are driven by what we learn through the planning exercise. These commitments are embodied in the Action Plans.

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1. OVERVIEW

The resource plan forecast presented in the 2017 IRP presents exciting changes in resource outlook and preserves a strategic agility that will allow PSE to respond to rapidly changing conditions as renewable and storage technologies mature, as the impacts of carbon regulation and climate change become clearer, and as customer behavior changes. The forecast relies on additional transmission to market to meet peak capacity need, continued strong investment in conservation, utility-scale solar to meet renewable resource need, and energy storage. While many of these changes have been on the horizon for some time and discussed extensively in the media and by advocacy groups, this is the first time that some appear to truly be part of a low-cost, low-risk resource plan for PSE's customers.

Exciting Changes in Resource Outlook

- **EMERGENCE OF SOLAR POWER**. Wind has dominated new renewable resource additions in the Pacific Northwest. This IRP finds solar power in eastern Washington appears to be a cost-effective renewable resource for the first time.
- **ENERGY STORAGE AND DEMAND RESPONSE INSTEAD OF FOSSIL FUEL GENERATION**. Energy storage and demand response resources can help push PSE's need for capacity resources out eight years, to 2025. This is a low-cost and low-risk strategy that helps avoid locking PSE's customers into a long-lived fossil fuel plant while alternative technology is evolving rapidly and greenhouse gas policies are being developed.
- **REDIRECTING TRANSMISSION TO INCREASE MARKET ACCESS**. PSE can reassign some transmission from intermittent wind resources to the Mid-C market in a way that will allow PSE to expand its access to short-term bilateral markets on a firm basis, while still allowing us to deliver that wind energy to our customers. Increasing market reliance is low cost alternative for our customers. This IRP includes a comprehensive analysis of market risk in relation to Pacific Northwest's resource adequacy outlook, built on Northwest Power and Conservation Council (NPCC), Bonneville Power Administration (BPA) and Pacific Northwest Utilities Conference Committee (PNUCC) analyses. It finds the region is nearly meeting its resource adequacy target, and with continued strong conservation programs, it may become even more reliable in the future. This is not without risk, but PSE has analyzed these risks extensively and concluded the risks are reasonable. Redirecting transmission supports the strategy to push out the need for additional fossil fuel plants to 2025, while rapidly evolving technology drives down the

costs of resource alternatives and uncertainty in greenhouse gas regulation can be resolved.

- **ENERGY EFFICIENCY.** One thing remains the same in this IRP – PSE's commitment to strong investment in encouraging customers to use energy more efficiently. Devoting significant resources to help our customers use energy more wisely is a tried and true way of reducing costs, cost risks and the environmental footprint of PSE's operations as well as our customers'.
- **NATURAL GAS UTILITY RESOURCE PLAN.** Strategic agility is also the hallmark of the natural gas utility resource plan. Continued conservation investment, completion of the Tacoma LNG peaking facility and the option to upgrade PSE's propane peaking facility (Swarr) push out the need to lock our natural gas customers into lengthy contracts to expand regional pipeline infrastructure. Again, this is a low-cost and low-risk resource strategy for our gas customers.

Impact of Uncertainty in Carbon Regulation

PSE recognizes the importance of mitigating climate change. The Base Scenario in this IRP models the impacts of Washington state's Clean Air Rule (CAR) and the federal Clean Power Plan (CPP). Even though the fate of both regulatory programs is uncertain at this time, some form of carbon regulation is likely to be enacted during the next 20 years, so it is important to reflect this possibility in the analysis. We expect these rules to evolve and for new ones to be developed. The resource plan presented here gives us the flexibility and agility to adapt to changes without having to commit our customers to long-lived fossil fuel resources at this time.

The design of carbon regulation is critically important to achieving meaningful carbon reductions and avoiding unintended consequences. For instance, the IRP analysis indicates that CPP rules may distort the value of peaking plants, making them appear more economic than energy storage. And, it is likely that the CAR will shift dispatch to less carbon-efficient plants by focusing only on Washington gas-fired plants, which are some of the most carbon-efficient in the Western Energy Coordinating Council (WECC), increasing carbon emissions in the region even though emissions in Washington state decline.

PSE is committed to working with policy makers and others to help modify and create approaches to greenhouse gas regulation that are effective at reducing carbon emissions in a way that minimizes the impact of costs on our customers. See Chapter 3, Planning Environment, for further discussion of this issue.

The Future of Colstrip

The coal-fired Colstrip plant emits a significant amount of greenhouse gasses, but it has historically been a very low cost resource, and PSE is obligated to minimize costs to customers within existing legal frameworks. The multiple ownership structure of Colstrip includes an independent power producer and utilities that serve load in six states, which creates a very complex decision-making process.

Units 1 & 2 are scheduled to retire no later than July, 2022, and the analysis indicates that retiring those plants earlier would be uneconomic. After Units 1 & 2 retire, additional conservation, demand response, energy storage batteries and firm transmission to market are expected to meet resource needs until 2025.

The continued operation of Units 3 & 4 is highly dependent on future environmental regulation. Analysis in this IRP demonstrates that a carbon regulation policy that adds to the dispatch cost of Colstrip would challenge its continued economic operation. Absent such a policy, Colstrip 3 & 4 appear to be economic to operate for the foreseeable future.

In the absence of Colstrip Units 3 & 4, the analysis currently indicates that peaking plants are the most cost-effective alternative to meeting need, but this conclusion will be revisited as the entire region continues to invest heavily in energy efficiency, emerging technologies continue to evolve, and the impacts of carbon regulation become clearer.

A Forecast, Not a Prescription

The IRP process is a legal mandate that requires PSE to identify the least cost combination of energy conservation and energy supply resources to meet the needs of our customers. Specific energy efficiency and supply-side resource decisions are not made in the context of the IRP. The primary value of the IRP is what we learn from the opportunity to do three things: develop key analytical tools to aid in making prudent decision making for long-term energy efficiency and energy supply, create and manage expectations about the near future, and think broadly about the next two decades.

The portfolio analysis presented in the IRP is best understood as a forecast of resource additions that appear to be cost effective given what we know today about the future. We know these forecasts will change as the future unfolds and conditions change. PSE's commitments to action are driven by what we learn through the planning exercise. These commitments are embodied in the Action Plans presented next.

2. ACTION PLANS

Action Plans vs. Resource Plan Forecasts

In recent years, the IRP has attracted more attention from policy makers, the public and advocacy groups. Many tend to interpret the resource plans produced in the IRP analysis as the plan that PSE intends to execute against. This is not the case. The resource plans are more accurately understood as forecasts of resource additions that look like they will be cost effective in the future, given what we know about the future today. What we learn from this forecasting exercise determines the Action Plan. The Action Plans describe the activities PSE will execute resulting from the forecasting exercise.

Electric Action Plan

1. Acquire Energy Efficiency

Develop two-year targets and implement programs that will put us on a path to achieve an additional 374 MW of energy efficiency by 2023 through program savings combined with savings from codes and standards.

2. Demand Response

Clarify the acquisition, prudence criteria and cost recovery process for demand response programs. Issue a demand response RFP based on those findings. Re-examine the peak capacity value of demand response programs in the 2019 IRP to include day-ahead demand response programs, and use the sub-hourly flexibility modeling capability developed in this IRP to value sub-hourly demand response programs.

Pursuant to the 2015 IRP action plan, PSE issued an RFP for demand response programs in 2016. That led PSE to identify policy issues that need to be resolved with regard to demand response programs.

POLICY ISSUES. Demand response is a portfolio of programs that involves relationships with customers. Some programs are pricing structures that require revised tariffs and updates to metering and billing systems. Thus, in terms of program planning, demand response is more like conservation programs than power plants. However, demand response has been excluded from the program planning design and cost recovery process used for conservation. The current processes for establishing prudence related to acquiring power plants or contracts and recovering costs through a Power Cost Only Rate Case (PCORC) do not fit for a portfolio of demand response programs that build over time. The WUTC has begun exploring these issues. PSE will be fully engaged, as this is a critical path item for being able to execute demand response to meet resource need and an essential component for postponing the need to build fossil fuel generation.

DEMAND RESPONSE RFP. Once there is line of sight on resolving policy barriers, PSE will issue a demand response RFP. This IRP applied the PSE resource adequacy modeling framework used for other kinds of resources to demand response. These findings will be included in the demand response RFP to provide better guidance to bidders on the value of duration, frequency, and the interval between demand response events.

VALUING ADDITIONAL TYPES OF DEMAND RESPONSE PROGRAMS. Fast-acting demand response is able to respond quickly, creating additional sub-hourly flexibility value in addition to potentially offsetting or delaying the need for a peaking generator. PSE will use its sub-hourly flexibility modeling capability to value sub-hourly demand response programs in the 2019 IRP. Another category of demand-response to examine in more detail is day-ahead programs. Although day-ahead demand response programs will not deliver the same benefit, they may still be a valuable resource, so PSE will also examine the peak capacity value of day-ahead demand response programs in its 2019 IRP.

3. Energy Storage

Install a small-scale flow battery to gain experience with the operation of this energy storage system in anticipation of greater reliance on flow batteries in the future.

4. Supply-side Resources: Issue an All-source RFP

Issue an all-source RFP in the first quarter of 2018 that includes updated resource needs and avoided cost information.

PSE has a need for renewable and capacity resources as early as 2022, after cost-effective conservation and demand response are accounted for.

RENEWABLE RESOURCES. Bringing on future additional renewable resources, whether in PSE's balancing authority or in BPA's, may require transmission system upgrades that will require long lead times to study, design, permit and construct. While this IRP finds eastern Washington solar power is more cost effective than wind, the results are close. Montana wind would be a "qualifying renewable resource" if it were delivered to Washington state on a real-time basis without shaping or storage. Addressing this qualification constraint will likely require a complex set of transmission studies, coordinated with Northwestern in Montana, BPA and possibly the WECC. Issuing an RFP in 2018 for delivery beginning in 2022 will provide potential respondents time to address such transmission issues.

SUPPLY-SIDE RESOURCES FOR CAPACITY. While we believe that demand response and energy storage will be a reasonable, cost-effective resource that is sufficient to meet the capacity need that appears in 2022, this assumption will be investigated further in an RFP. Issuing an RFP in 2018 for delivery in 2022 is reasonable because the regional transmission system is becoming constrained, and potential respondents may need time to address these constraints, depending on the location of the proposed resources. Furthermore, some resources, like pumped hydro storage, may have long lead times. Finally, some kinds of renewable resources can contribute to meeting peak capacity, so considering capacity resources in this RFP will help align valuation processes.

5. Develop Options to Mitigate Risk of Market Reliance

Develop strategies to mitigate the risk of redirecting transmission and increasing market reliance.

PSE relies heavily on the short-term market to meet the energy and peak capacity needs of our customers. Risk associated with this exposure to market is managed in the short term; long term, however, regional resource adequacy cannot be addressed without adding new resources. If regional resource adequacy assessments are off or unexpected demand-side or supply-side shocks happen that render the region short of resources, the burden of the resulting deficits would fall on PSE's customers. Therefore, PSE will develop strategies mitigate this risk. These strategies may include:

- maintaining options to build capacity resources quickly;
- re-examining PSE policies with regard to how much of its market reliance should be managed via short-term purchases versus long-term contracts; and
- working with others in the region on options for PSE to join or to help develop functioning wholesale markets that incorporate, energy, capacity and flexibility services.

6. Energy Imbalance Market (EIM)

Continue to participate in the California Energy Imbalance Market for the benefit of our customers.

PSE's participation in the EIM allows PSE to purchase sub-hourly flexibility at 15- and 5-minute increments from other EIM participants to meet our flexibility needs when market prices are cheaper than using our own resources. Participation also gives PSE the opportunity to sell flexibility to other EIM participants when we have surplus flexibility. The benefits of lower costs on the one hand and net revenue from EIM sales on the other reduces power costs to our customers.

7. Regional Transmission

Examine regional transmission needs in the 2019 IRP in light of efforts to reduce the region's carbon footprint.

Future progress on reducing the region's carbon footprint will necessarily involve both retirement of less carbon-efficient thermal resources and the addition of renewable resources. This will make the ability of the region's transmission resources to move power to where it is needed an increasingly important issue. This examination will include the following.

- Assess the operational risk associated with redirecting transmission from PSE's existing wind resources and address those risks if necessary.
- Coordinate with the WUTC, other utilities and stakeholders to study the alternatives for re-purposing transmission used for Colstrip 1 & 2 as these units are retired.
- Begin to coordinate with other utilities and transmission providers to understand alternatives for re-purposing transmission from Colstrip 3 & 4, so that PSE will be prepared should the plant be retired earlier than anticipated.

Natural Gas Sales Action Plan

1. Acquire Energy Efficiency

Develop two-year targets and implement programs to acquire conservation, using the IRP as a starting point for goal-setting. This includes 14 MDth per day of capacity by 2022 through program savings and savings from codes and standards.

2. LNG Peaking Plant

Complete the PSE LNG peaking project located near Tacoma.

Construction of the facility is under way and should be completed in time for the storage project to be filled for the 2019/20 heating season. This resource is essential to delaying investment in additional interstate and international year-round pipeline capacity.

3. Option to Upgrade Swarr

Maintain the ability upgrade the Swarr propane-air injection system in Renton, which the plan forecasts will be needed by the 2024/25 heating season.

Upgrading the Swarr LP-Air facility's environmental safety and reliability systems to return the facility to its maximum output of 30 MDth per year was selected as least cost in all but the low demand scenarios in the IRP analysis. This short lead time project is also within PSE's control, and the timing of the upgrade can be fine-tuned by PSE in response to load growth.

3. ELECTRIC RESOURCE PLAN FORECAST

Electric Resource Need

PSE must meet the physical needs of our customers reliably. For resource planning purposes, those physical needs are simplified and expressed in terms of peak hour capacity for resource adequacy, hourly energy and sub-hourly flexibility. Operating reserves are included in physical needs; these are required by contract with the Northwest Power Pool and by the North American Electric Reliability Corporation (NERC) to ensure total system reliability. Beyond operating reserves, sub-hourly flexibility is also required. The robust sub-hourly analytical framework implemented in this IRP determined that PSE has sufficient sub-hourly flexibility at this time, although we will continue to refine this analysis. In addition to meeting customers' physical and sub-hourly flexibility needs, Washington state law (RCW 19.285) also requires utilities to acquire specified amounts of renewable resources or equivalent renewable energy credits (RECs). There are details in the law such that complying with RCW 19.285 may not directly correspond to meeting reliability needs, so this is expressed as a separate category of resource need.

- Figure 1-1 presents electric peak hour capacity need.
- Figure 1-2 presents the electric energy need (the annual energy position for the 2017 Base Scenario).
- Figure 1-3 presents PSE's renewable energy credit need.

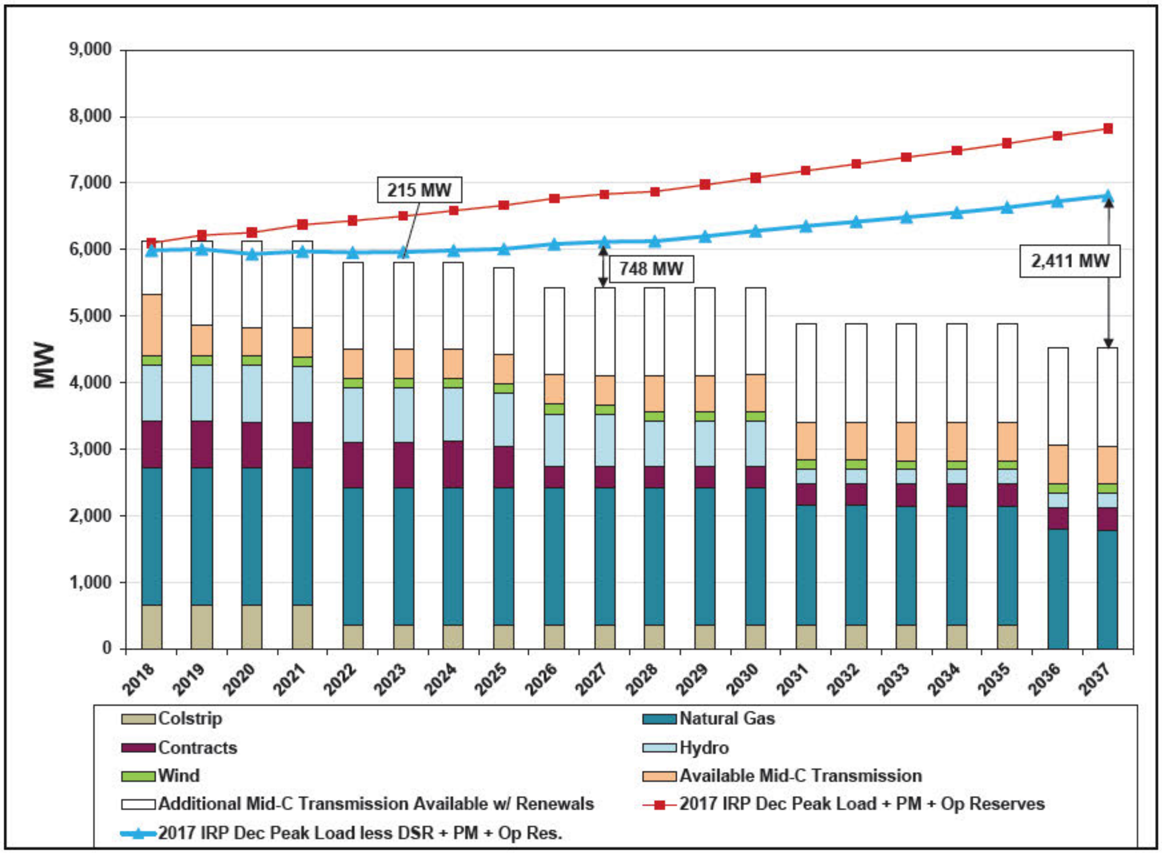
Electric Peak Hour Capacity Need

Figure 1-1 compares the existing resources available to meet peak hour capacity[1] with the projected need over the planning horizon. The electric resource outlook in the Base Scenario indicates the initial need for an additional 215 MW of peak hour capacity by 2023. This includes a 13.5 percent planning margin (a buffer above a normal peak) to achieve and maintain PSE's 5 percent loss of load probability (LOLP) planning standard. Figure 1-1 shows four noticeable drops in PSE's resource stack. The first, in 2022, is caused by retirement of Colstrip 1 & 2, approximately 300 MW of capacity. The second is at the end of 2025, when PSE's 380 MW coal-transition contract with Transalta expires upon retirement of the Centralia coal plant.[2] The third occurs in 2031, when PSE contracts with Chelan PUD for 481 MW of hydro output expire. The final significant drop is in 2035, the year that the Base Scenario assumes retirement of Colstrip Units 3 & 4, of which PSE owns 370 MW. This could occur sooner, depending on how future

1 / Resource capacities illustrated here reflect the contribution to peak, not nameplate capacity, so PSE's approximate 130 MW update with Skookumchuck of owned and contracted wind appear very small on this chart. Refer to Chapter 6, Electric Analysis, for how peak capacity contributions were assessed.
2 /PSE entered the coal transition contract with Transalta under RCW 80.80 to facilitate the retirement of the only major coal-burning power plant in Washington state.

environmental regulations affect the economics of running the plant. The important role demand-side resources play in moderating the need to add supply-side resources in the future can be seen in the peak load lines in Figure 1-1; the lower line includes the benefit of DSR while the upper line does not.

Figure 1-1: Electric Peak Hour Capacity Resource Need
(Projected peak hour need and effective capacity of existing resources)



Electric Energy Need

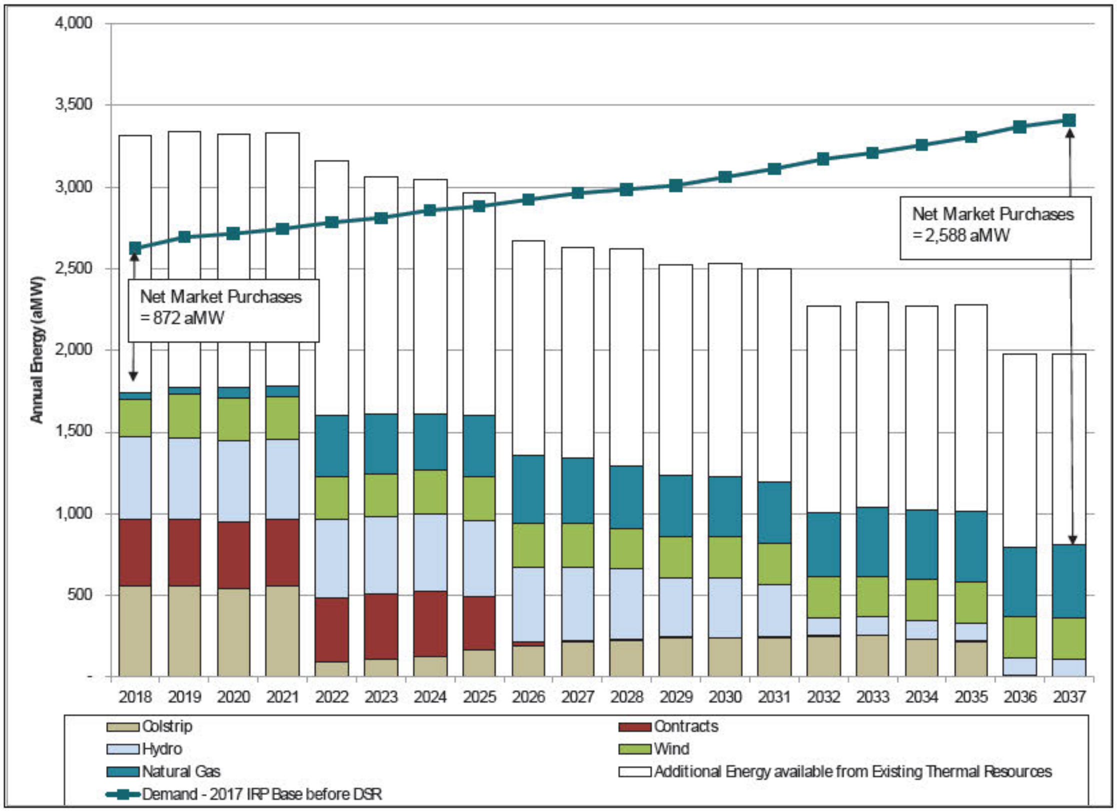
Compared to the physical planning constraints that define peak resource need, meeting customers' "energy need" for PSE is more of a financial concept that involves minimizing costs. Portfolios are required to cover the amount of energy needed to meet physical loads, but our models also examine how to do this most economically, and this includes the ability to purchase energy from the wholesale market.

Unlike utilities in the region that are heavily dependent on hydro, PSE has thermal resources that can be used to generate electricity if needed. This resource diversity is an important difference. In fact, on an average monthly or annual basis, PSE could generate significantly more energy than needed to meet our load, but it is often more cost effective to purchase wholesale market energy than to run our high-variable cost thermal resources. We do not constrain (or force) the model to dispatch resources that are not economic; if it is less expensive to buy power than to dispatch a generator, the model will choose to buy power in the market. Similarly, if a zero (or negative) marginal cost resource like wind is available, PSE's models will displace higher-cost market purchases and use wind to meet the energy need.

Figure 1-2 illustrates the company's energy position across the planning horizon, based on the energy load forecasts and economic dispatches of the 2017 IRP Base Scenario presented in Chapter 4, Key Analytical Assumptions.[3] The dashed box at the top indicates the total energy available from PSE's thermal resources if they were run without regard to economic dispatch. This chart shows that without any additional demand-side or supply-side resources, PSE could generate enough energy on an annual basis through 2025 to make wholesale market purchases unnecessary. The challenge for PSE is shaping that energy into peak hours. Should regional resource deficits in the future result in periods where market purchases were unavailable, PSE's thermal resources would be able to ramp up to minimize the number of non-peak hours that PSE customers were affected, but we would still face peak need constraints. This is why PSE has a peak capacity constraint, not an energy constraint.

3 / Wind in this chart shows more prominently in Figure 1-5 than in the peak capacity need chart, because this reflects the expected annual generation of wind, not just what can be relied upon to meet peak capacity needs.

Figure 1-2: Annual Energy Position, Economic Resource Dispatch from Base Scenario



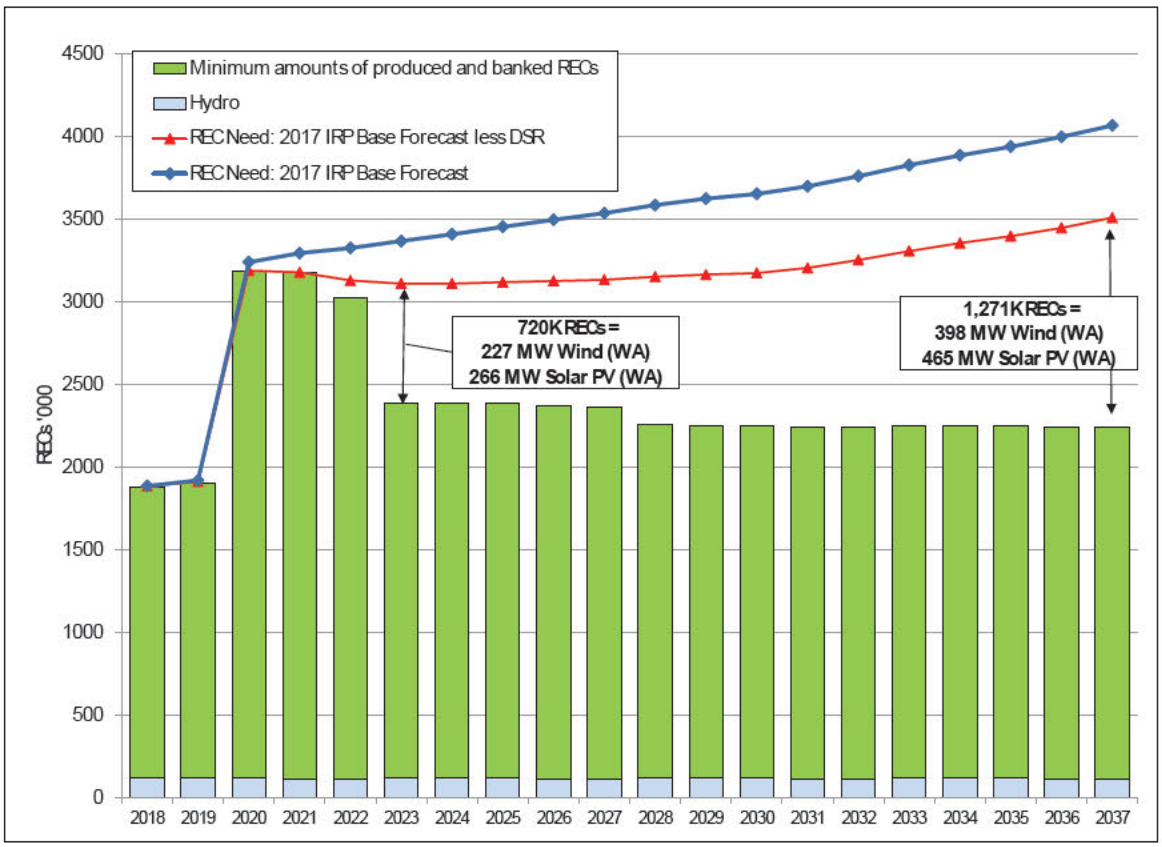
Renewable Need

In addition to reliably meeting the physical needs of our customers, RCW 19.285 – the Washington State Energy Independence Act – establishes 3 specific targets for qualifying renewable energy, commonly referred to as the state's renewable portfolio standard. Sufficient "qualifying renewable energy" must equal at least 3 percent of retail sales in 2012, 9 percent in 2016, and 15 percent in 2020. Figure 1-3 compares existing qualifying renewable resources with these targets, and shows that PSE has acquired enough eligible renewable resources and RECs to meet the requirements of the law until 2022. By 2023, PSE will need approximately 720,000 qualifying renewable energy credits. To put that need into context, it would equate to approximately 227 MW of Washington wind or 266 MW of eastern Washington solar power.[4]

4 / Slightly more MW of solar are needed because the annual output of solar in eastern Washington is slightly less than wind, so more MW of installed capacity are needed to generate the same quantity of energy in MWh.

Qualifying renewable energy is expressed in annual qualifying renewable energy credits (RECs) rather than megawatt hours, because the state law incorporates multipliers that apply in some cases. For example, generation from PSE's Lower Snake River wind project receives a 1.2 REC multiplier, because qualifying apprentice labor was used in its construction. Thus the project is expected to generate approximately 900,000 MWh per year of electricity, but contribute about 1,080,000 equivalent RECs toward meeting the renewable energy target. Note this is a long-term compliance view. PSE has sold surplus RECs to various counterparties in excess of those needed for compliance and will continue to do so as appropriate to minimize costs to customers.

Figure 1-3: Renewable Resource/REC Need



Electric Portfolio Resource Additions Forecast

As explained above, the lowest reasonable cost portfolio produced by the IRP analysis is not an action plan; rather, it is a forecast of resource additions PSE would find cost effective in the future, given what we know about resource and market trends today. It incorporates significant uncertainty in several dimensions.

Figure 1-4 summarizes the forecast for additions to the electric resource portfolio in terms of peak hour capacity over the next 20 years. This forecast is the "integrated resource planning solution."[5] It reflects the lowest reasonable cost portfolio of resources that meets the projected capacity, energy and renewable resource needs described above. Similar to prior IRPs, it accelerates acquisition of energy conservation and calls for additional demand response resources; however, it also includes significant changes. This IRP finds energy storage to be part of the lowest reasonable cost solution. It also finds that eastern Washington solar power may be more cost effective than wind. Additionally, it includes redirecting some firm transmission from existing wind resources to the Mid-C market in the resource plan forecast. Taken together, the "early" actions in this resource plan push the need to acquire additional fossil-fuel peakers out beyond 2024. This should not be interpreted to mean PSE *will* acquire new fossil fuel resources in 2025. Rather, this strategy provides a significant amount of time for technological innovations in energy efficiency, demand response, energy storage and renewable resources to develop, in the hope that additional fossil-fuel peaking generation plants will not be needed for our customers. Also, the resource plan shown here should not be interpreted as a statement of the ownership structure of resource additions; more accurately, it is a forecast of what technologies will appear cost effective in the future. For example, instead of PSE developing additional renewables or purchase power contracts, it may be lower cost and lower risk for customers to acquire unbundled RECs from independent power producers, who would then shoulder the technology and market price risk, instead of PSE's customers.

5 / Chapter 2 includes a detailed explanation of the reasoning that supports each element of the resource plan.

Figure 1-4: Electric Resource Plan Forecast,
Cumulative Nameplate Capacity of Resource Additions

	2023	2027	2037
Conservation (MW)	374	521	714
Demand Response (MW)	103	139	148
Solar (MW)	266	378	486
Energy Storage (MW)	50	75	75
Redirected Transmission (MW)	188	188	188
Baseload Gas (MW)	0	0	0
Peaker (MW)	0	717	1,912

Demand-side Resources (DSR): Energy Efficiency

This plan – like prior plans – includes aggressive, accelerated investment in helping customers use energy more efficiently. That is, significant changes in avoided cost had little impact on how much conservation could be acquired cost effectively. PSE's analysis indicates that although current market power prices are low, accelerating acquisition of DSR continues to be a least-cost strategy.

Demand-side Resources: Demand Response

In this IRP, we continue to find a ramp-up in demand response programs is part of the lowest reasonable cost portfolio. Demand response includes voluntary interruptible rate schedule programs for residential customers.

Renewable Resources

The timing of renewable resource additions is driven by requirements of RCW 19.285, as renewable resources still do not appear to be an effective or cost effective way to manage the financial risk of market exposure. This IRP found that eastern Washington solar power is expected to be more cost effective than wind from the Pacific Northwest or in Montana; however, costs between wind and solar are very close, especially in the first half of the planning horizon. As in prior IRPs, PSE's analysis shows we anticipate remaining comfortably below the four percent revenue requirement cap in RCW 19.285. PSE has acquired enough eligible renewable resources and RECs to meet the requirements of the law until 2022.

Energy Storage

This IRP finds energy storage, specifically flow batteries, to be a cost-effective part of the resource plan. While batteries are more expensive than peakers on a dollars per kW basis, batteries are more scalable, so they fit well in a portfolio with a small, flat need, as shown above in Figure 1-1 (Peak Capacity Need). Also, batteries provide more sub-hourly flexibility value than peakers, and this value is reflected in the IRP forecast.

Redirected Transmission to Market

In all future scenarios, redirecting 188 MW of BPA transmission from PSE's Hopkins Ridge and Lower Snake River wind facilities was shown to be part of the least cost solution. PSE will still be able to deliver the wind energy to our customers, but do so in a way that also helps to push the need for new generation into the future, which provides risk mitigation benefits as well. However, redirecting transmission and increasing PSE's reliance on wholesale market does entail financial and physical resource adequacy risk. Those risks were comprehensively examined in this IRP and determined to be manageable.[6]

Baseload Natural Gas Plants

The Pacific Northwest appears flush with renewable energy – hydro power, wind power and surplus solar power from California. Building additional baseload gas plants in PSE's service territory appears cost effective under only a few unlikely scenarios. Therefore, the resource plan includes no baseload gas plants.

Peakers

Beyond 2025, dual fuel peaking units appear to be the most cost-effective resource to meet larger capacity resource needs. These are units that can run off either natural gas, fuel oil or a blend of both. These peakers act as a low cost insurance policy, in case they are needed to meet loads due to extremely cold weather conditions, when another unit experiences a forced outage, or very low regional hydro conditions. A key reason why these units are so cost effective, is that backup fuel oil tanks negate the need for firm natural gas pipeline capacity. The resource adequacy implications of relying on peakers with backup fuel were examined rigorously in this IRP. The analysis shows the reliability risk of relying on backup fuel is extremely low. While PSE hopes technology innovations in energy efficiency, demand response, energy storage and renewable resources will eclipse the need for additional fossil-fuel plants of any kind in the future, dual fuel peakers appear to be the least cost resource in the later part of the planning horizon, except in unlikely scenarios where baseload natural gas plants appear cost effective.

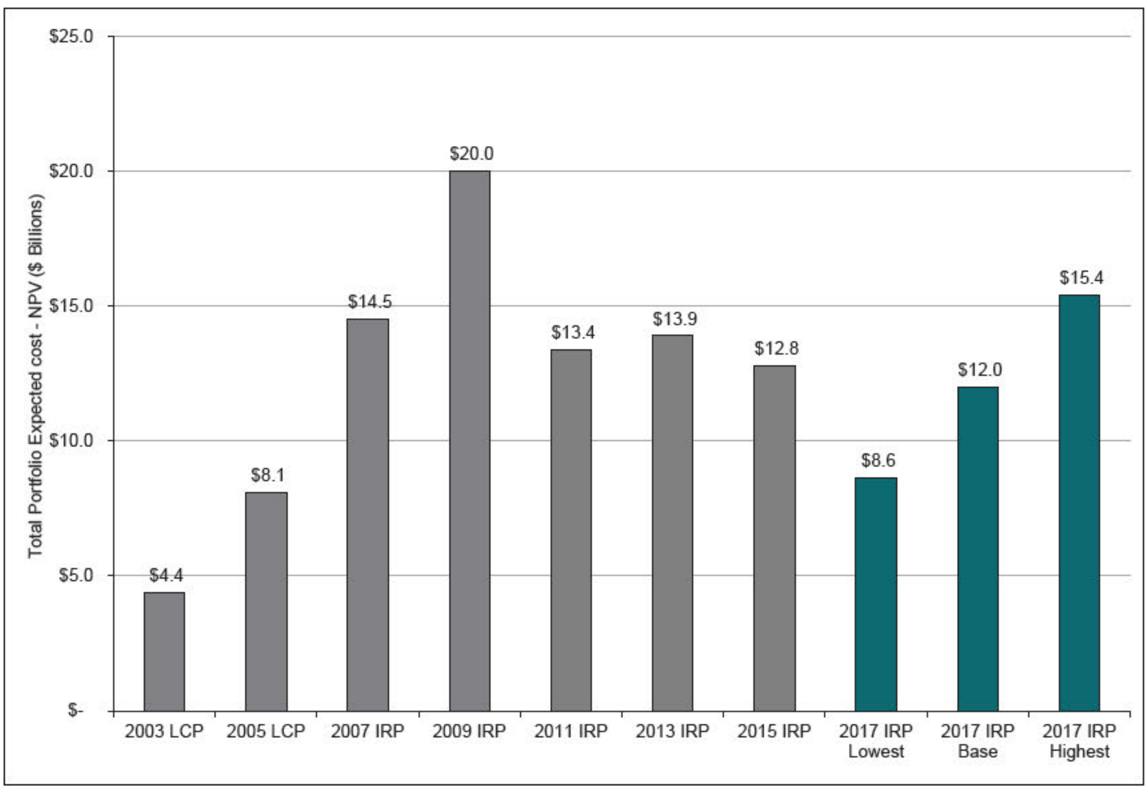
6 / *See Appendix G, Wholesale Market Risk.*

Portfolio Cost and Carbon Emissions

Portfolio Costs

The long-term outlook for incremental portfolio costs has been dynamic across IRP planning cycles since 2003, driven by changing expectations about natural gas prices and costs associated with potential carbon regulation. Figure 1-5 illustrates how incremental portfolio costs have changed over time, along with the context for the range of costs examined in this IRP. This figure shows the long-tem cost projection is down slightly from the 2015 IRP. This is primarily due to lower natural gas prices and lower capital costs for generation plants. Note that in this IRP, carbon costs on baseload natural gas and coal plants are applied across the entire WECC in the IRP Base Scenario assumptions, to simulate the effect of the Clean Power Plan if interstate carbon trading was adopted.

Figure 1-5: Incremental Portfolio Costs Over Time



Portfolio Carbon Emissions Associated with Electric Service

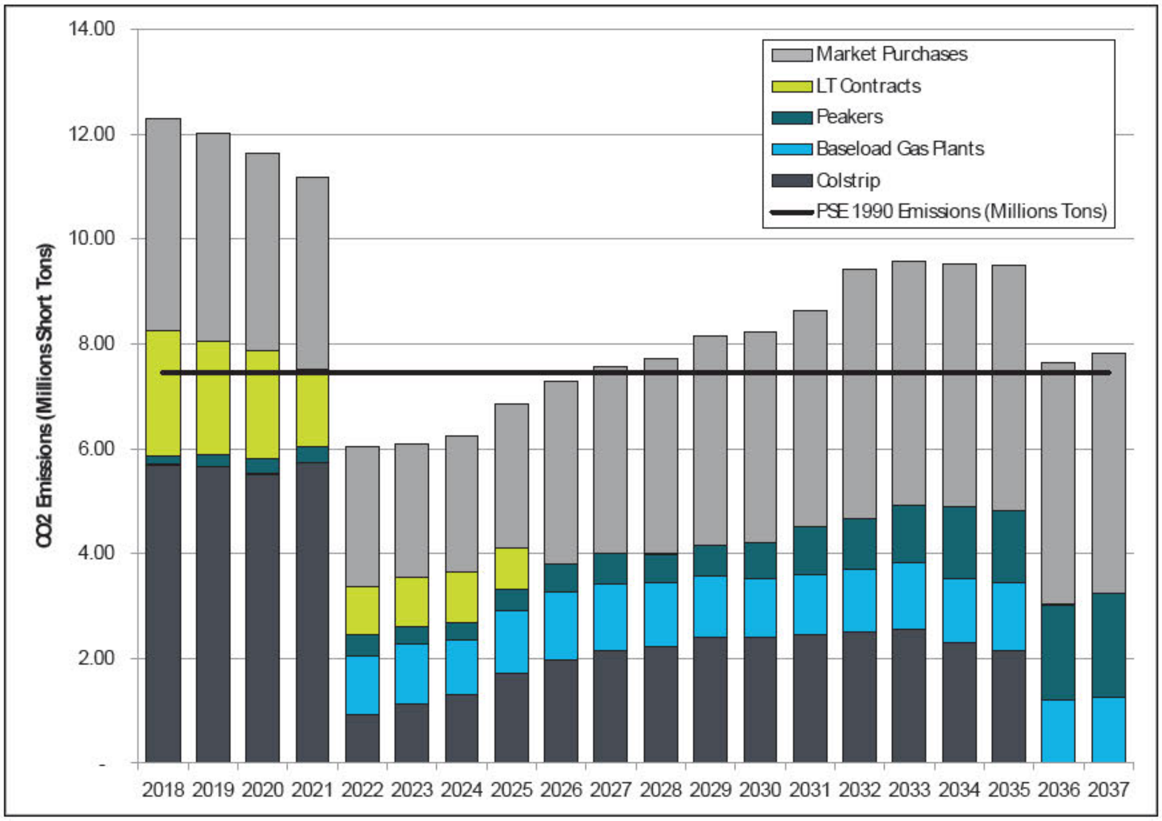
We are keenly aware of our customers' interest in reducing PSE's carbon emissions, and we share their concern and commitment to achieving meaningful carbon reduction that will mitigate climate change. Although PSE's portfolio carbon emissions can yield helpful insights, achieving the kind of results we all want will also require region-wide coordination as we continue this effort. The carbon emission profile presented in this section does not represent PSE's "preferred" outcome – we would prefer emissions to be lower. These emissions result from policies that require PSE to serve customers with the least cost combination of demand- and supply-side resources and carbon regulation policies that have been or may be enacted.

In estimating portfolio carbon emissions, PSE evaluates each of the resources in its portfolio. This is fairly straightforward when dealing with PSE-owned resources, but evaluating the wholesale market purchases that make up nearly a third of PSE's portfolio is more complicated because those purchases come from an integrated WECC-wide electric system. PSE's approach to addressing this carbon accounting issue is to calculate a WECC-wide average carbon intensity forecast in tons of CO_2 per MWh for each year in the planning horizon, and apply that average to market purchases. This is similar to the method used by the WUTC's compliance protocol, but that protocol uses the Northwest Power Pool average instead of the WECC average. Averages may satisfy reporting rules, but using an average emission rate is not appropriate for estimating how different policies or resource alternatives will affect greenhouse gas emissions. In reality, changes in emissions will be impacted by marginal resource decisions (i.e., which resources are being dispatched), not average resource dispatch. To understand how different factors will affect greenhouse gas emissions in total, one must examine impacts across the entire WECC. This kind of analysis is presented in Chapter 6 in the discussion on cost of carbon abatement.

Figure 1-6 illustrates the portfolio carbon emissions resulting from the resource plan forecast under the Base Scenario economic dispatch. The horizontal line shows PSE's estimated 1990 emissions. The stacked bars are the annual carbon emissions by resource type. The top of each stack does not represent direct PSE emissions – these are average emissions associated with market purchases. The rest of the stack relates directly to PSE resources or specific contracts. The first large drop in emissions occurs in 2022. This is caused by retirement of Colstrip 1 & 2, but also by the assumed implementation of a WECC-wide carbon price on coal and baseload gas plants, which significantly curtails the economic dispatch of Colstrip 3 & 4. From 2022 through 2034, direct emissions rise as natural gas prices increase relative to coal costs, causing the economic dispatch of Colstrip 3 & 4 to increase despite the WECC-wide carbon price. By 2037, PSE's direct emissions will be quite low, as all four units of Colstrip will have been retired – this drop would occur earlier if Colstrip 3 & 4 were retired sooner.

While this chart appears to show PSE's emissions will be in line with 1990 emissions by 2035, this is misleading. The Base Scenario assumes the most important and most difficult policy change is enacted in 2022 – the imposition of a WECC-wide carbon market. Policy makers, environmental advocates and those concerned about greenhouse gas emissions (including PSE) should not be comforted by this chart.

Figure 1-6: Projected Annual Total PSE Portfolio CO_2 Emissions and Savings from Conservation



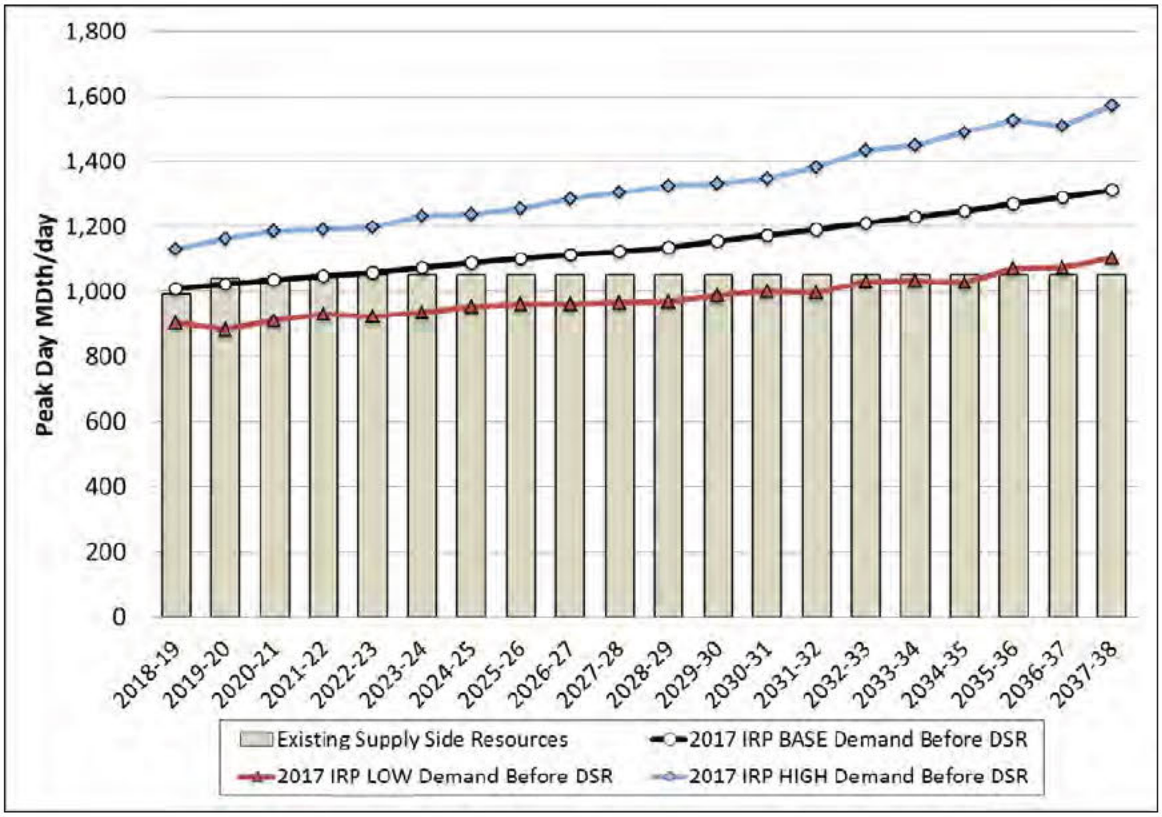
4. NATURAL GAS SALES RESOURCE PLAN FORECAST

PSE develops a separate integrated resource plan to address the needs of more than 800,000 retail natural gas sales customers. This plan is developed in accordance with WAC 480-90-238, the IRP rule for natural gas utilities. (See Chapter 7 for PSE's gas sales analysis.)

Gas Sales Resource Need – Peak Day Capacity

Gas sales resource need is driven by design peak day demand. The current design standard ensures that supply is planned to meet firm loads on a 13-degree design peak day, which corresponds to a 52 Heating Degree Day (HDD). Like electric service, gas service must be reliable every day, but design peak drives the need to acquire resources. Figure 1-7 illustrates the load-resource balance for the gas sales portfolio. The chart demonstrates PSE has a small resource need in 2018, but the LNG storage facility in Tacoma is expected to come online for the 2019/20 heating season, which will meet the peak capacity needs of our customers until the winter of 2023/24. The 2018 need can be met with a one-year capacity contract on Northwest Pipeline, rather than investing in a long-lived resource to meet need for a single year.

Figure 1-7: Gas Sales Design Peak Day Resource Need



Gas Sales Resource Additions Forecast

Figure 1-8 summarizes the gas resource plan additions PSE forecasts to be cost effective in the future in terms of peak day capacity and MDth per day. As with the electric resource plan, this is the "integrated resource planning solution." It combines the amount of demand-side resources that are cost effective with supply-side resources in order to minimize the cost of meeting projected need. Again, this is not PSE's action plan – it is a forecast of resource additions that look like they will be cost effective in the future, given what we know about resource trends and market trends today.

Figure 1-8: Gas Resource Plan Forecast, Cumulative Additions in MDth/Day of Capacity

	2025/26	2029/30	2037/38
Conservation (DSR)	27	49	84
Swarr	30	30	30
LNG Distr Upgrade	0	16	16
Additional NWP + Westcoast	0	53	133

Demand-side Resources (DSR)

Analysis in this IRP applies a 10-year ramp rate for acquisition of DSR measures. Analysis of 10- and 20-year ramp rates in prior IRPs has consistently found the 10-year rate to be more cost effective. Ten years is chosen because it aligns with the amount of savings that can practically be acquired at the program implementation level.

Swarr Upgrade

This IRP finds that upgrading the Swarr LP-Air facility's environmental safety and reliability systems and returning its production capacity to Swarr's original 30 MDth per day capability would be a cost effective resource as early as the 2024/25 heating season. Swarr is a propane-air injection facility on PSE's gas distribution system that operates as a needle-peaking facility. Propane and air are combined in a prescribed ratio to ensure the mixture injected into the distribution system maintains the same heat content as natural gas. Upgrading Swarr is a short lead time project that is totally within PSE's control (it does not require the regional coordination needed for large, mainline pipeline expansion) so the project also adds strategic agility to the resource plan. If needed sooner, PSE could move quickly to upgrade Swarr, and if need is delayed, PSE could defer the upgrade. In either circumstance, the upgrade would put off the need for large, long-lived mainline pipeline expansions.

PSE LNG Distribution Upgrade

The PSE LNG peaking facility currently under construction in Tacoma allows the company to withdraw gas from the storage tank and deliver it directly into PSE's local distribution system. This upgrade is not an expansion of the LNG facility itself, but an expansion of the distribution network's capacity east of Tacoma that will allow more gas to flow from the LNG facility into PSE's gas supply network. The analysis forecasts that this will be needed and cost effective by the 2027/28 heating season. As with Swarr, this resource provides the portfolio with the strategic agility to determine timing based customer need as it develops.

Northwest Pipeline/Westcoast Expansion

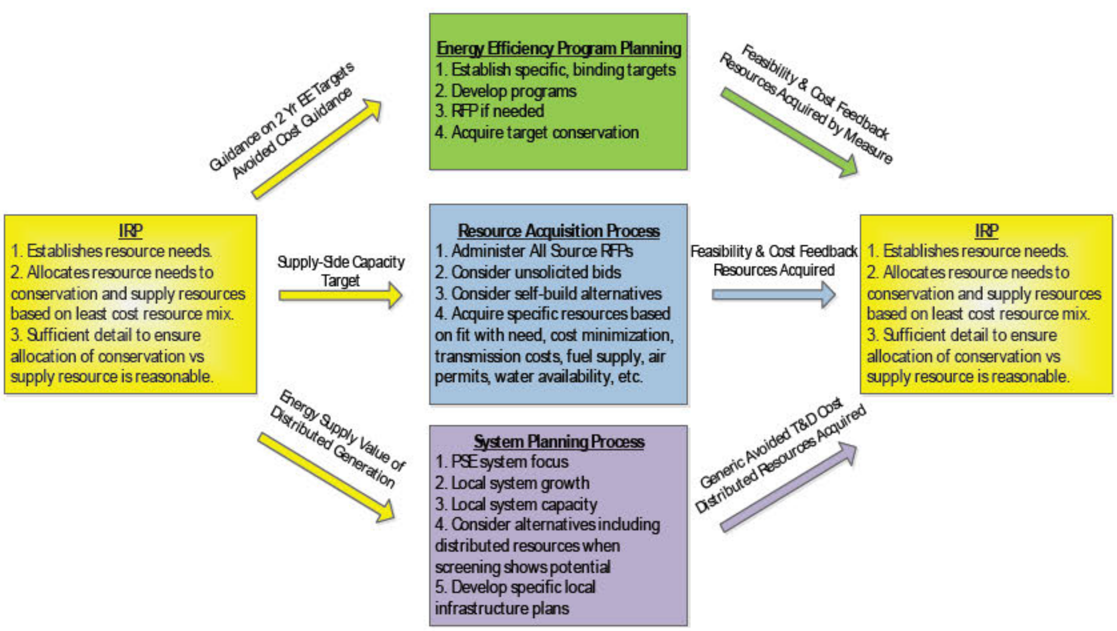
Additional transportation capacity from the gas producing regions in British Columbia at Station 2 south to PSE's system on the Westcoast pipeline is also forecast as cost effective beginning in the 2029/30 heating season.

5. THE IRP AND THE RESOURCE ACQUISITION PROCESS

The IRP is not a substitute for the resource-specific analysis done to support specific acquisitions, though one of its primary purposes is to inform the acquisition process. The action plans presented here help PSE focus on key decision-points it may face during the next 20 years so that we can be prepared to meet needs in a timely fashion.

Figure 1-9 illustrates the relationship between the IRP and activities related to resource acquisitions. Specifically, the chart shows how the IRP directly informs other acquisition and decision processes. In Washington, the formal RFP processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP and self-build (or PSE demand-side resource programs) must also be considered when making prudent resource acquisition decisions. Figure 1-9 also illustrates that information from the IRP provides information to the local infrastructure planning process.

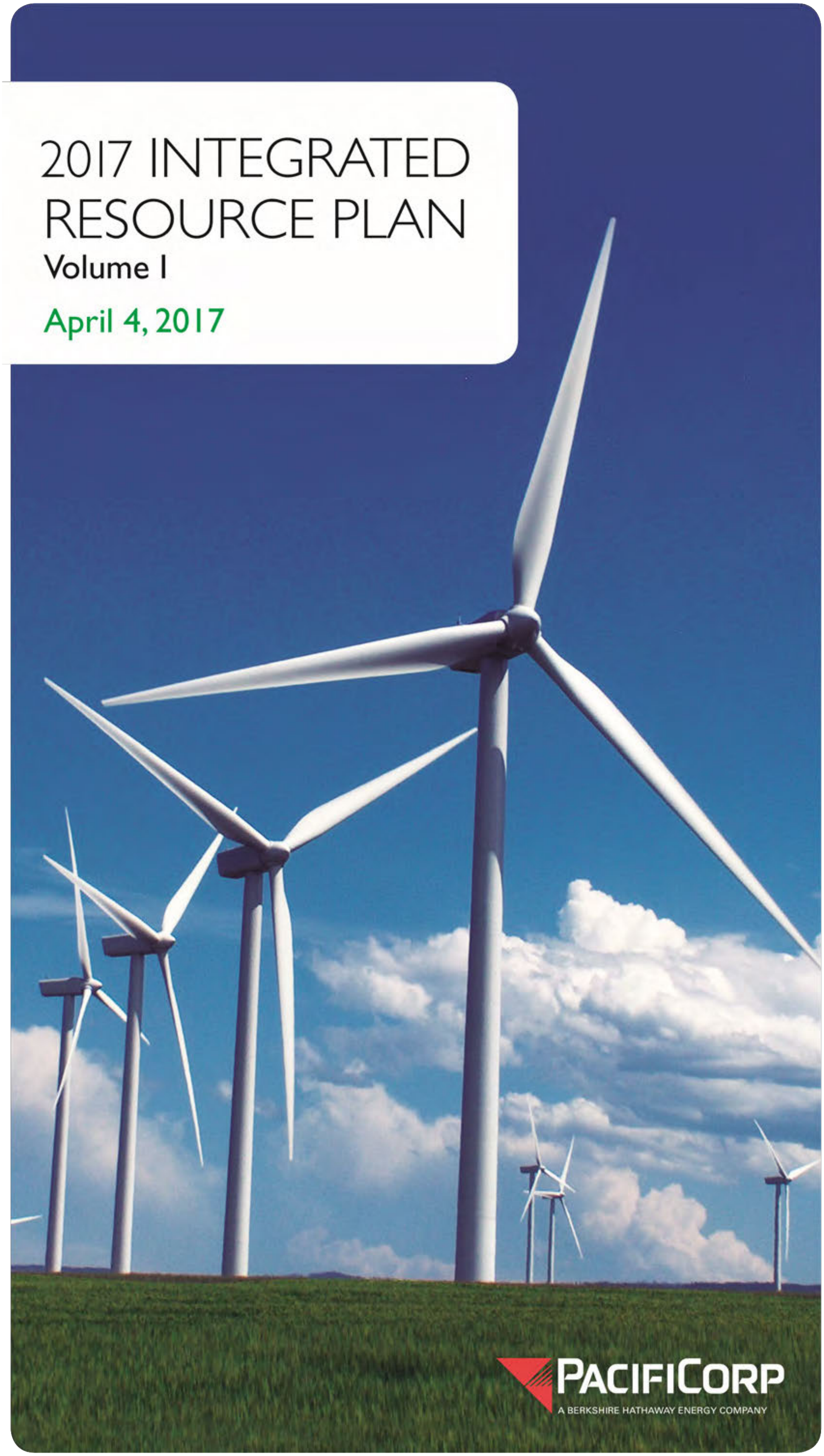
Figure 1-9: Relationship of IRP to Resource Decision Processes



2017 INTEGRATED RESOURCE PLAN

Volume I

April 4, 2017



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A BERKSHIRE HATHAWAY ENERGY COMPANY

CHAPTER 1 – EXECUTIVE SUMMARY

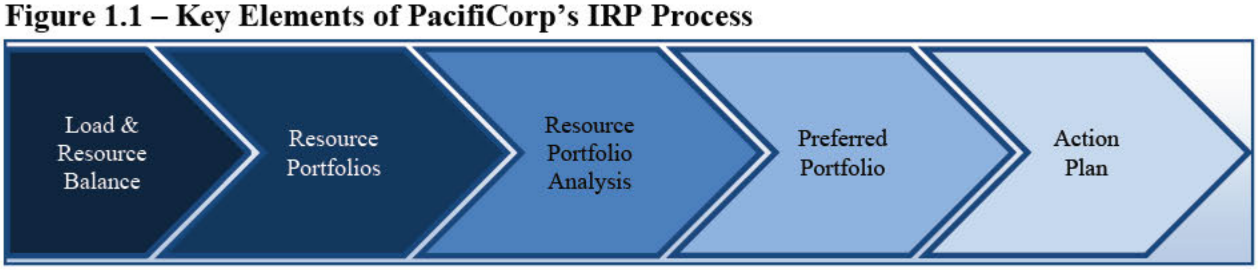
PacifiCorp's 2017 Integrated Resource Plan (IRP) presents the company's plans to provide reliable and reasonably priced service to its customers. The analysis supporting this plan helps PacifiCorp, its customers, and its regulators understand the effect of both near-term and long-term resource decisions on customer bills, the reliability of electric service PacifiCorp customers receive, and changes to emissions from the generation sources used to serve customers. In the 2017 IRP, PacifiCorp presents a cost-conscious plan to transition to a cleaner energy future with near-term investments in both existing and new renewable resources, new transmission infrastructure, and energy efficiency programs.

The primary objective of the IRP is to identify the best mix of resources to serve customers in the future. The best mix of resources is identified through analysis that measures cost and risk. The least-cost, least-risk resource portfolio—defined as the "preferred portfolio"—is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks, while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly the longer-range elements of the plans, can and do change over time. PacifiCorp's 2017 IRP was developed through an open and public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, regulatory staff, and other interested parties. The public input process began with the first public input meeting in June 2016. Over the subsequent nine months, PacifiCorp met with stakeholders in five states and hosted seven public input meetings. Through this process, PacifiCorp received valuable input from its stakeholders and presented findings from a broad range of studies and technical analyses that shaped and support the 2017 IRP.

As depicted in Figure 1.1, PacifiCorp's 2017 IRP was developed by working through five fundamental planning steps. This includes preparing a load and resource balance, which compares a forecast of load relative to existing resources. In the next planning step, PacifiCorp develops a range of different resource portfolios that meet projected deficiencies in the load and resource balance, each uniquely characterized by the type, timing, and location of new resources in PacifiCorp's system. PacifiCorp then analyzes these different resource portfolios to measure the comparative cost, risk, reliability and emission levels. This resource portfolio analysis informs selection of a preferred portfolio and the associated resource action plan. Throughout this process, PacifiCorp considers a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies are also done to produce specific modeling assumptions.

Figure 1.1 – Key Elements of PacifiCorp's IRP Process



Preferred Portfolio Highlights

The 2017 IRP preferred portfolio reflects a cost-conscious transition to a cleaner energy future. Table 1.1 shows that PacifiCorp's resource needs will be met with new renewable resources, demand side management (DSM) resources, and short-term firm market purchases (labeled as front-office transactions or FOTs) through 2028. Over the 20-year planning horizon, the preferred portfolio includes 1,959 MW of new wind resources, 905 MW of upgraded ("repowered") wind resources, 1,040 MW of new solar resources, 2,077 MW of incremental energy efficiency resources, and 365 MW of new direct load control capacity.

Notably, PacifiCorp's analysis demonstrates that—by 2020 and with all-in economic savings for customers—the company can add 905 MW of repowered wind resources, 1,100 MW of new wind resources, and a new 140-mile 500 kV transmission line in Wyoming to access the new wind resources and relieve congestion for existing capacity. The preferred portfolio also assumes existing owned coal capacity will be reduced by 3,650 MW through the end of 2036 (including assumed coal retirements at the end of 2036 not shown below). The first new natural gas resource is added in 2029, one year later when compared to PacifiCorp's 2015 IRP preferred portfolio, subject to technology and IRP reassessments over the next decade.

Table 1.1 – 2017 IRP Preferred Portfolio Summary (Nameplate MW)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
New Resources																					
Summer FOT	500	521	878	807	799	916	844	885	1,042	978	1,040	1,575	1,575	1,566	1,575	1,575	1,575	1,575	1,575	1,539	n/a
Winter FOT	281	332	273	307	319	308	306	287	348	351	297	412	551	516	490	451	437	477	479	766	n/a
DSM - Energy Efficiency	154	128	131	122	123	114	118	118	112	111	109	102	96	95	96	83	75	65	63	63	2,077
DSM - Load Control	0	0	0	0	0	0	0	0	0	0	0	193	140	5	3	3	3	4	3	12	365
Wind	0	0	0	0	1,100	0	0	0	0	0	0	0	0	0	85	0	0	0	0	774	1,959
Solar	0	0	0	0	0	0	0	0	0	0	0	11	97	0	118	237	226	48	291	13	1,040
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	30	0	0	0	0	0	0	0	30
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	200	436	0	0	677	0	0	0	1,313
Existing Resources																					
Reduced Coal Capacity	0	0	(280)	0	(387)	0	0	0	0	(82)	0	(762)	(354)	(357)	(78)	0	(359)	0	(82)	0	(2,741)
Reduced Gas Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(358)	0	0	0	(358)
Repowered Wind Capacity	0	0	794	111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	905

* Note: Energy efficiency resource capacity reflects projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource. FOTs are short-term firm market purchases delivered only in the year shown. Reductions in existing coal and natural gas capacity are shown in the year after the assumed year-end retirement date (909 MW of existing coal capacity is assumed to retire year-end 2036, which would be reflected beginning 2037). Repowered wind capacity reports the amount of existing wind capacity assumed to be repowered in the preferred portfolio.

New Renewable Resources and Transmission

The 2017 IRP preferred portfolio advances PacifiCorp's commitment to low-cost clean energy with plans to add 1,100 MW of new Wyoming wind resources by the end of 2020. These new zero-emission wind facilities will connect to a new 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This time-sensitive project requires that the new wind and transmission assets achieve commercial operation by the end of 2020 to fully achieve the benefits of federal wind production tax credits (PTCs). In addition to providing significant economic benefits for PacifiCorp's customers, the wind and transmission project will provide extraordinary economic development benefits to the state of Wyoming.

Beyond 2020, the preferred portfolio includes an additional 859 MW of new wind—85 MW of Wyoming wind coming online in 2031, and 774 MW of Idaho wind in 2036. New solar resource additions totaling 1,040 MW come on-line over the 2028 to 2036 timeframe. Approximately 77 percent of the new solar is located in Utah (beginning 2031), and the remaining 23 percent is located on the west side of PacifiCorp's system (beginning 2028).

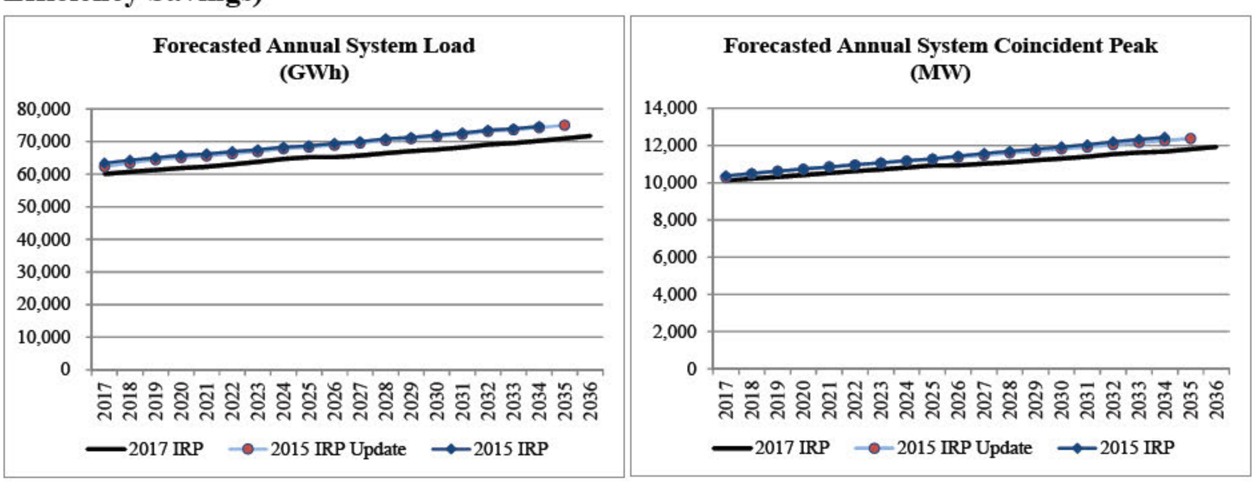
Wind Repowering

PacifiCorp executed wind-turbine-generator (WTG) equipment purchases in December 2016 to preserve the option to repower existing wind generation facilities and obtain PTC benefits for customers. Analysis performed in the 2017 IRP supports repowering 905 MW of existing wind resources by the end of 2020 and demonstrates that this exciting project will save customers hundreds of millions of dollars. The scope of the repowering project involves installing new nacelles and longer blades. With the installation of modern technology and improved control systems, the repowered wind facilities will produce more zero-emission energy for a longer period of time at reduced operating costs. Existing towers and foundations will remain in place, resulting in minimal environmental impact and permitting requirements.

Demand Side Management

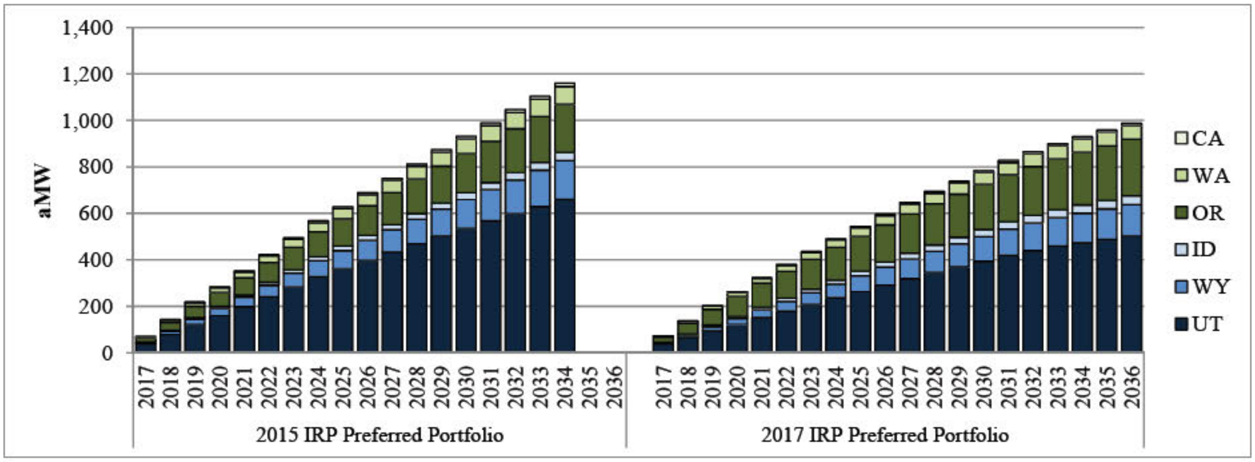
PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and direct load control programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 1.2 shows that PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2015 IRP and 2015 IRP Update. On average, forecasted system load is down 5.3 percent and forecasted coincident system peak is down 3.5 percent when compared to the 2015 IRP Update. Through the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 0.94 percent for load and 0.86 percent for peak. Changes to PacifiCorp's load forecast are driven by reduced industrial class loads, due in large part to lower commodity prices, and continued gains in energy conservation as evidenced by a drop in the average use per customer.

Figure 1.2 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



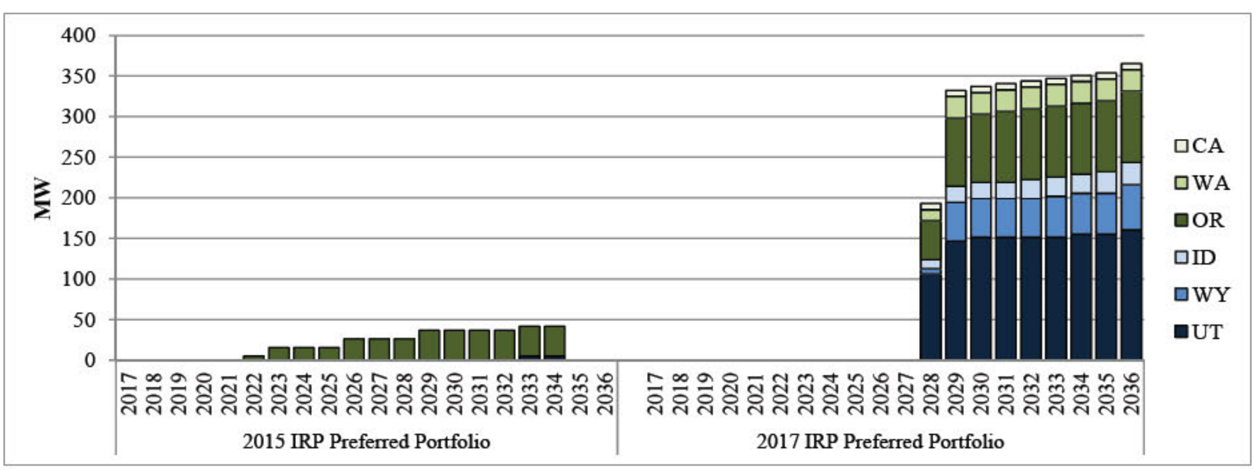
DSM resources continue to play a key role in PacifiCorp's resource mix. Over the first ten years of the planning horizon, accumulated acquisition of new incremental energy efficiency resources meets 88 percent of forecasted load growth from 2017 through 2026 (up from 86 percent in the 2015 IRP). Figure 1.3 compares total energy efficiency savings by state in the 2017 IRP preferred portfolio relative to the 2015 IRP preferred portfolio. Decreased selection of energy efficiency resources relative to the 2015 IRP is driven by reduced loads and reduced costs for wholesale market power purchases and renewable resource alternatives.

Figure 1.3 – Comparison of Total Energy Efficiency Savings between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



In addition to continued investment in energy efficiency programs, the preferred portfolio identifies an increasing role for direct load control programs with total capacity reaching 365 MW by the end of the planning period. Figure 1.4 compares total incremental capacity of direct load control program capacity by state in the 2017 IRP preferred portfolio relative to the 2015 IRP preferred portfolio. The significant increase in direct load control capacity and expansion of state programs is coincident with assumed coal unit retirements, signaling the importance of these capacity-based programs in PacifiCorp's transitioning resource mix.

Figure 1.4 – Comparison of Total Direct Load Control Capacity between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



Wholesale Power Market Purchases

Figure 1.5 shows that base case forecasted wholesale power prices and natural gas prices used in the 2017 IRP are significantly lower than the base case market prices used in the 2015 IRP and are more closely aligned with those used in PacifiCorp's 2015 IRP Update. Over the last couple of IRP cycles, growth in natural gas supplies, primarily from prolific shale plays in North America, have continued to outpace expectations. With continued declines in forward natural gas prices and on-going reductions in regional electric load growth expectations, forward power prices have also declined significantly since the 2015 IRP.

Figure 1.5 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

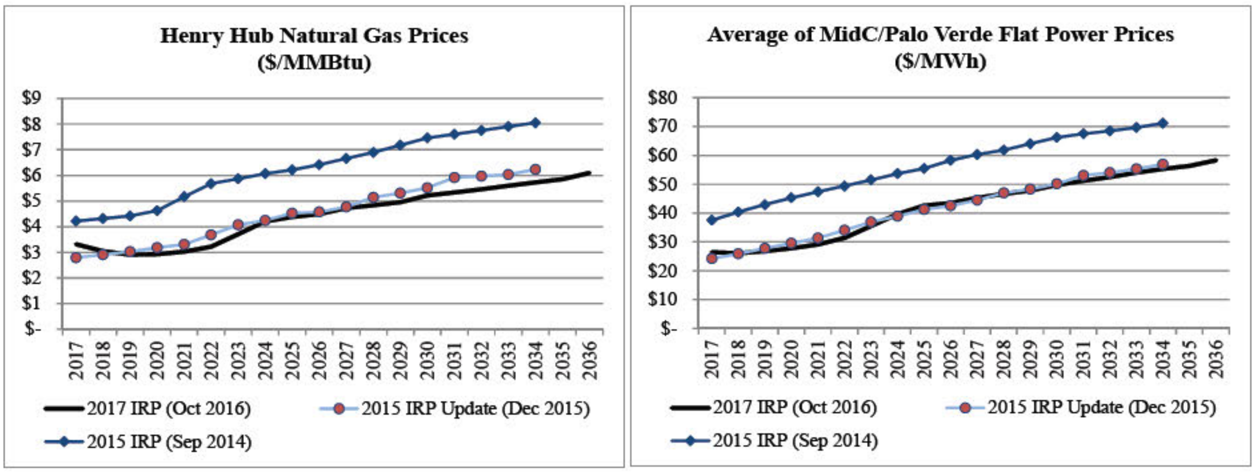
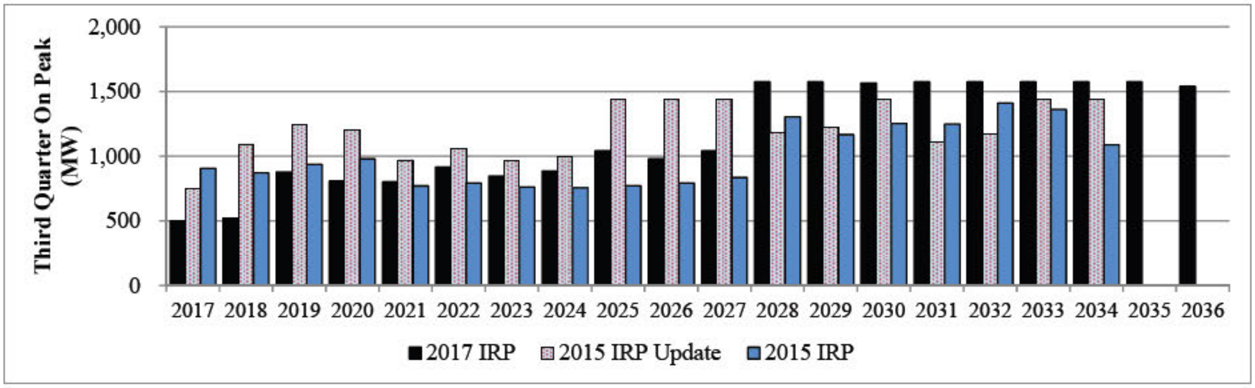


Figure 1.6 compares wholesale market firm purchases from the 2017 IRP preferred portfolio to the market purchases included in the preferred portfolio of recent IRPs. While market conditions for firm wholesale power purchases are favorable, reduced loads and continued investment in energy efficiency programs reduce the need for wholesale power purchases through 2027 relative to the 2015 IRP Update. Over this period, average annual wholesale power purchases are down by 27 percent relative to the 2015 IRP Update and are on par with wholesale power purchases projected in the 2015 IRP. Longer-term wholesale power purchases increase coincident with assumed coal unit retirements. In this 2017 IRP, PacifiCorp evaluated regional resource adequacy and determined that its wholesale power purchase limits are reasonable. PacifiCorp will, however, continue to monitor potential shortfalls in regional supply through its on-going planning process.

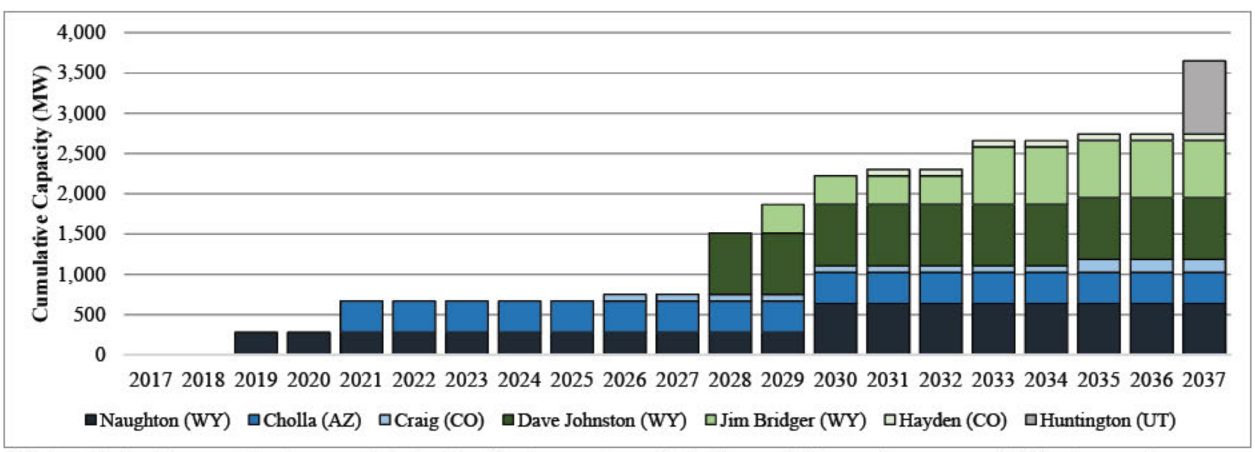
Figure 1.6 – Comparison of Summer Market Purchases in Recent IRPs



Existing Coal Resources

Supported by analysis of potential Regional Haze compliance alternatives, the 2017 IRP preferred portfolio does not include any incremental selective catalytic reduction (SCR) equipment. Avoiding installation of this equipment will save customers hundreds of millions of dollars and retain compliance-planning flexibility associated with the Clean Power Plan or other potential state and federal environmental policies. As in past IRPs, the 2017 IRP studies a range of Regional Haze compliance scenarios, reflecting potential bookend alternatives that consider early retirement outcomes as a means to avoid installation of expensive SCR equipment. The individual unit-specific outcomes assumed in the 2017 IRP preferred portfolio will ultimately be determined by on-going rulemaking; litigation results; and future negotiations with state and federal agencies, partner plant owners, and other vested stakeholders. Consequently, individual unit retirements reflected in the preferred portfolio, while reasonable for planning purposes, are not firm commitments for early unit closures. Figure 1.7 summarizes coal unit retirements assumed in the preferred portfolio. By the end of the planning horizon, PacifiCorp assumes 3,650 MW of existing coal capacity will be retired.

Figure 1.7 – 2017 IRP Preferred Portfolio Coal Unit Retirements



*Note: Retired capacity is reported in the first year in which the unit is no longer available to meet summer coincident peak load.

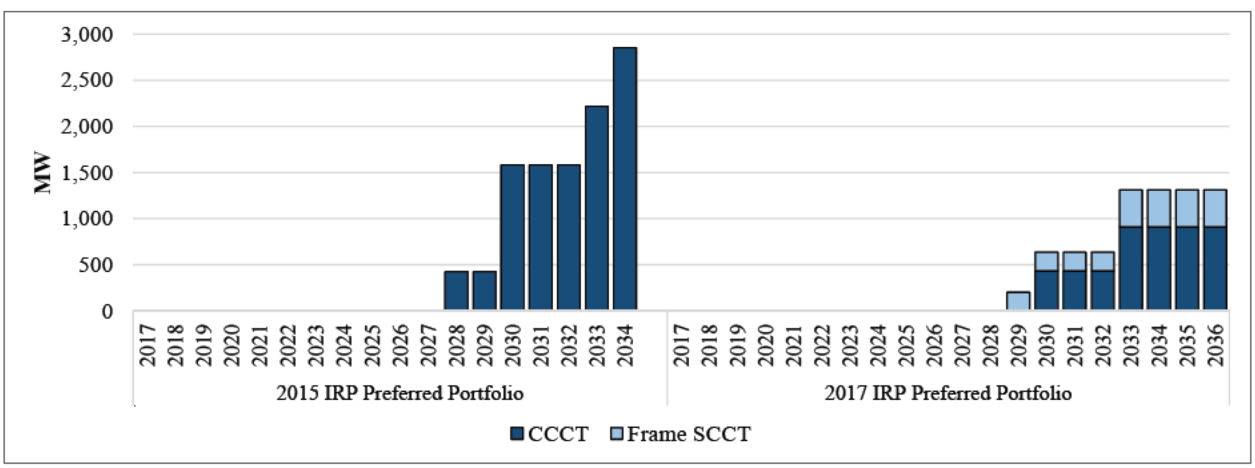
Reflecting an updated operating permit from the state of Wyoming, PacifiCorp assumes Naughton Unit 3 retires at the end of 2018—one year later than in the 2015 IRP Update.

PacifiCorp will continue to review emerging technologies, re-assess traditional gas conversion technologies and costs, and consider other potential alternatives that could be applied to Naughton Unit 3 to allow continued operation beyond year-end 2018 if proven to be cost effective for customers. PacifiCorp's analysis also assumes Cholla Unit 4 retires at the end of 2020. This early closure assumption was considered in PacifiCorp's Regional Haze compliance analysis to account for changes in market conditions, characterized by reduced loads and wholesale power prices. As with Naughton Unit 3, PacifiCorp will continue to analyze potential early-closure scenarios for Cholla Unit 4 as part of its on-going planning process. Longer term, the preferred portfolio reflects an early retirement of Craig Unit 1 at the end of 2025, Jim Bridger Unit 1 at the end of 2028, and Jim Bridger Unit 2 at the end of 2032. Assumed end-of-life retirements include four units at the Dave Johnston plant at the end of 2027, Naughton Units 1 and 2 at the end of 2029, Hayden at the end of 2030, Craig Unit 2 at the end of 2034, and two units at the Huntington plant at the end of 2036.

Natural Gas Resources

Figure 1.8 compares total new natural-gas-fired resource capacity in the 2017 IRP preferred portfolio relative to the 2015 IRP preferred portfolio. The first natural gas resource, a 200 MW frame simple cycle combustion turbine (SCCT), is added to the portfolio in 2029—one year later than the first natural gas resource in the 2015 IRP. The first combined combustion turbine (CCCT), a 436 MW G-class 1x1, is added to the system in 2030—two years later than the first CCCT in the 2015 IRP. In aggregate, the 2017 IRP preferred portfolio includes 1,313 MW of new natural-gas-fired capacity, a reduction of 1,540 MW of natural gas resources relative to the 2015 IRP preferred portfolio. Reduced loads, on-going investment in energy efficiency programs, and increased renewables reduce the need for new natural gas resources in the 2017 IRP. Recognizing the long time horizon before the first natural gas plant is added, PacifiCorp will continue to evaluate potential long-term supply alternatives, including the potential penetration of energy storage, through its on-going resource planning over the next decade.

Figure 1.8 – Comparison of Total New Natural Gas Resources between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio

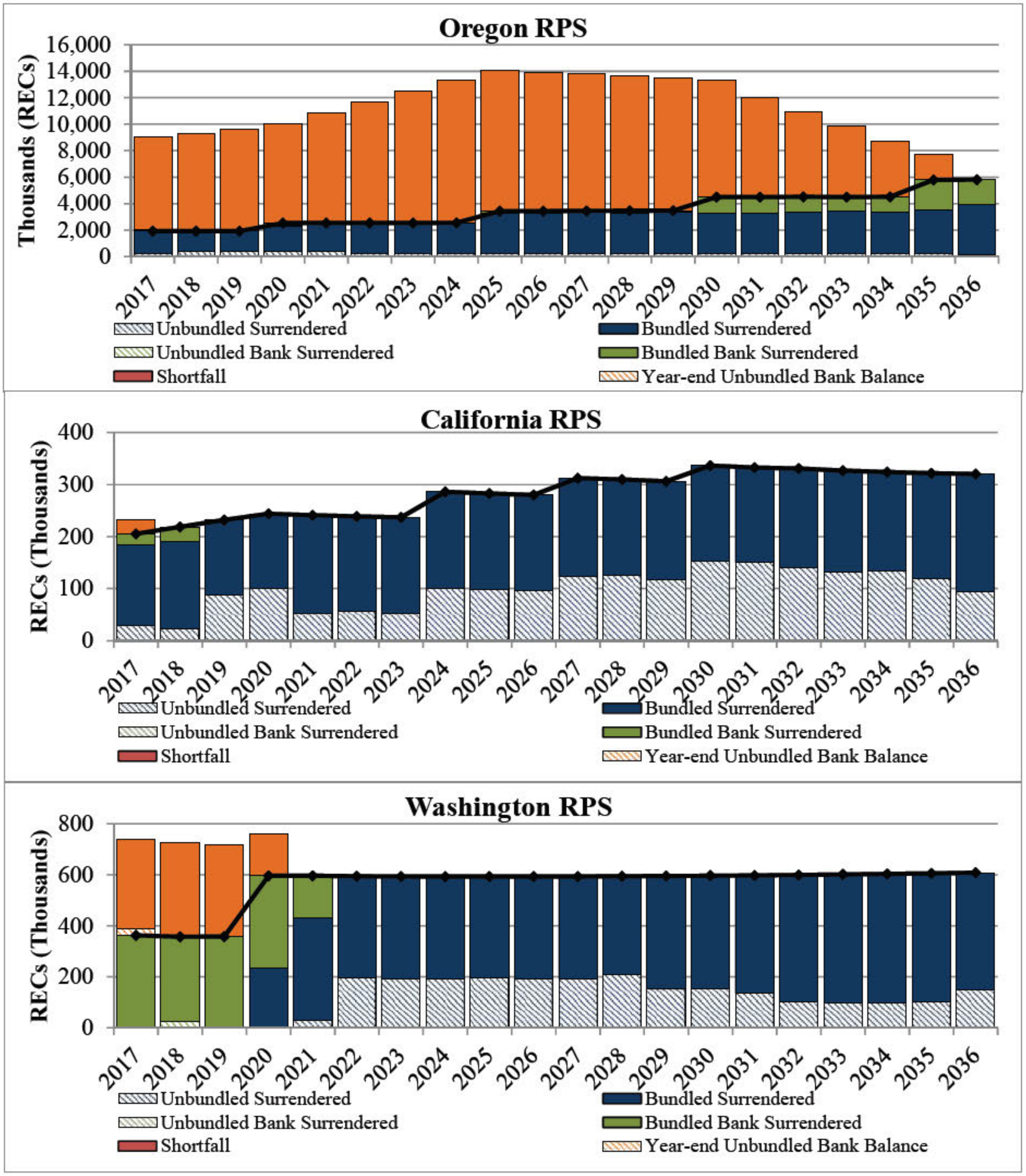


Renewable Portfolio Standards

Figure 1.9 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for the wind repowering project and new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources, they also contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2034 with the addition of repowered wind, new renewable resources and transmission in the 2017 IRP preferred portfolio. A small increment of annual purchases of unbundled renewable energy credits (REC), labeled "Unbundled Surrendered" in Figure 1.9 below, beginning at under 160 thousand RECs in 2018, is required to achieve Oregon RPS compliance through 2036. The California RPS compliance position is also improved by the addition of repowered wind, new renewable resources and transmission in the 2017 IRP preferred portfolio and similarly requires a small amount of unbundled REC purchases under 150 thousand RECs per year to achieve compliance through the planning horizon. Washington RPS compliance is achieved with the benefit of the repowered wind assets located in the west side, Marengo and Leaning Juniper, new renewable resources added to the west side beginning 2028, and unbundled REC purchases under 200 thousand RECs per year. Under current allocation mechanisms, Washington customers do not benefit from the repowered wind and new renewable resources added to the east side of PacifiCorp's system. While not shown in Figure 1.9, PacifiCorp meets the Utah 2025 state target to supply 20 percent of adjusted retail sales with eligible renewable resources with existing owned and contracted resources before considering the addition of repowered wind, new renewable resources and transmission in the 2017 IRP preferred portfolio.

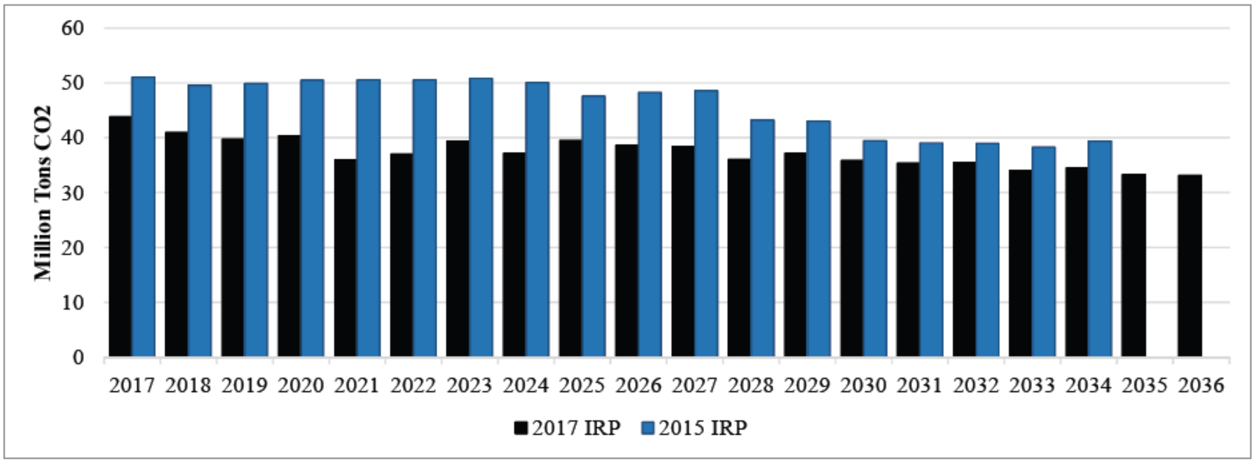
Figure 1.9 – Annual State RPS Compliance Forecast



Carbon Dioxide Emissions

The 2017 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) emissions. PacifiCorp's emissions have been declining and continue to decline as a result of a number of factors, including PacifiCorp's participation in the Energy Imbalance Market (EIM), which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going expansion of renewable resources and transmission; and Regional Haze compliance that capitalizes on flexibility. Figure 1.10 compares projected annual CO_2 emissions between the 2017 IRP and 2015 IRP preferred portfolios. Over the first 10 years of the planning horizon, average annual CO_2 emissions are down by over 10.5 million tons (21 percent) relative to the 2015 IRP. By the end of the planning horizon, system CO_2 emissions are projected to fall from 43.8 million tons in 2017 to 33.1 million tons in 2036—a 24.5 percent reduction.

Figure 1.10 – Comparison of CO_2 Emission Forecasts between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



Load and Resource Balance

A key element of PacifiCorp's IRP process is to assess its load and resource balance over the 20-year planning horizon. The load and resource balance relies on the ability for specific types of resources to meet our forecasted coincident system peak load while accounting for reserve requirements, which ensures reliable electric service for PacifiCorp customers. In developing the resource plan, PacifiCorp applies a 13 percent planning reserve margin to account for near-term and longer-term planning uncertainties.

Capacity Balance

Table 1.2 shows PacifiCorp's summer capacity position from 2017 through 2026, with coal unit retirement assumptions and incremental energy efficiency savings from the 2017 IRP preferred portfolio before adding any incremental new generating resources. With continued load growth and assumed coal unit retirements, summer margins drop over time, but remain higher than the 13 percent target planning margin throughout the first 10 years of the planning horizon.

Table 1.2 – PacifiCorp 10-Year Summer Capacity Position Forecast (MW)

System (Summer)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Existing Resource Capacity Contribution	10,493	10,494	10,109	10,194	10,069	9,980	10,062	10,043	9,920	9,912
Available FOT Capacity Contribution	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670
Total Existing Resource + FOTs	12,162	12,163	11,778	11,864	11,738	11,650	11,731	11,712	11,589	11,581
Obligation Net of Incremental DSM	9,730	9,743	9,743	9,758	9,793	9,824	9,829	9,850	9,892	9,831
13% Planning Reserve Margin	1,290	1,292	1,292	1,294	1,298	1,302	1,303	1,306	1,311	1,303
Obligation + 13% Planning Reserves	11,020	11,035	11,035	11,052	11,092	11,126	11,132	11,156	11,203	11,135
System Position with Available FOTs	1,142	1,129	743	812	647	524	599	556	386	447
Reserve Margin with Available FOTs	25.0%	24.8%	20.9%	21.6%	19.9%	18.6%	19.4%	18.9%	17.2%	17.8%

In response to stakeholder feedback from the 2015 IRP planning cycle, PacifiCorp developed a winter load and resource balance for the 2017 IRP. Table 1.3 shows PacifiCorp's annual winter capacity position from 2017 through 2026, with coal unit retirement assumptions and incremental energy efficiency savings from the 2017 IRP preferred portfolio before adding any incremental new generating resources. Accounting for available market purchases, PacifiCorp substantially exceeds its 13 percent target planning reserve margin over the winter peak through this period. With continued load growth and assumed coal unit retirements, winter margins drop over time, but remain significantly higher than the 13 percent target planning margin.

Table 1.3 – PacifiCorp 10-Year Winter Capacity Position Forecast (MW)

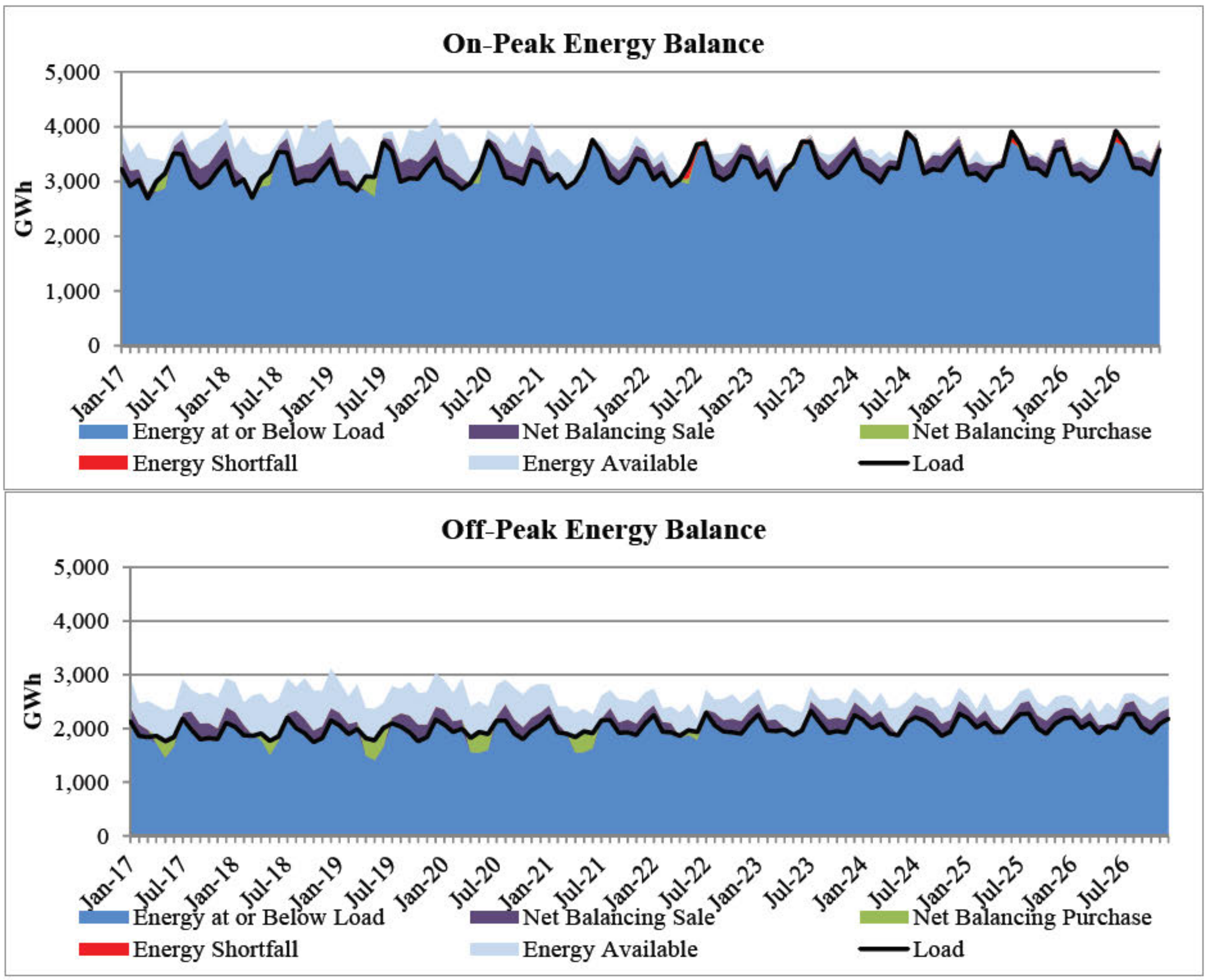
System (Winter)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Existing Resource Capacity Contribution	11,417	11,369	11,112	11,110	10,047	10,037	9,978	9,908	9,905	9,878
Available FOT Capacity Contribution	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670
Total Existing Resource + FOTs	13,087	13,038	12,781	12,779	11,717	11,707	11,647	11,577	11,574	11,548
Obligation Net of Incremental DSM	8,441	8,453	8,453	8,400	8,443	8,472	8,503	8,487	8,511	8,467
13% Planning Reserve Margin	1,123	1,124	1,124	1,117	1,123	1,127	1,131	1,129	1,132	1,126
Obligation + 13% Planning Reserves	9,564	9,578	9,578	9,518	9,566	9,599	9,634	9,616	9,643	9,593
System Position with Available FOTs	3,523	3,461	3,204	3,261	2,151	2,108	2,013	1,961	1,931	1,954
Reserve Margin with Available FOTs	55.0%	54.2%	51.2%	52.1%	38.8%	38.2%	37.0%	36.4%	36.0%	36.4%

Energy Balance

The capacity position shows how existing resources and loads balance during the coincident peak summer and winter periods, accounting for assumed coal unit retirements and incremental energy efficiency savings from the 2017 IRP preferred portfolio. Outside of these peak periods, PacifiCorp economically dispatches its resources to meet changes in load while taking into consideration prevailing market conditions. In those periods when system resource costs are less than the prevailing market price for power, PacifiCorp can dispatch resources that, in aggregate, exceed then-current PacifiCorp customer load obligations, facilitating off-system wholesale market power sales that reduce costs for PacifiCorp customers. Conversely, at times when system resource costs are greater than prevailing market prices, system balancing wholesale market power purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how PacifiCorp manages net power costs on behalf of its customers.

Figure 1.11 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given current planning assumptions and recent wholesale power and natural gas prices.[1] The figure shows expected monthly energy production from system resources during on-peak and off-peak periods in relation to load, reflecting coal unit retirement assumptions and incremental energy efficiency savings from the 2017 IRP preferred portfolio before adding any new generating resources. At times, system resources are economically dispatched above load levels facilitating net system balancing sales. This occurs more often in off-peak periods than in on-peak periods. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figure 1.11 also shows how much system energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and indicate short energy positions without addition of any new generating resources to the portfolio. During on-peak periods, the first energy shortfall appears in summer 2022. There are no energy shortfalls during off-peak periods over this timeframe.

Figure 1.11 – Economic System Dispatch of Existing Resources in Relation to Monthly Load



[1] On-peak hours are defined as hour ending 7 AM through 10 PM, Monday through Saturday. Off-peak periods are all other hours.

2017 IRP Advancements and Supplemental Studies

IRP Advancements

During each IRP planning cycle, PacifiCorp identifies and implements advancements to continuously improve the IRP for its customers, other stakeholders, and regulatory commissions. Some of the key advancements implemented in the 2017 IRP include:

- Winter Peak Analysis
  In response to stakeholder feedback received during the 2015 IRP, PacifiCorp incorporated in its 2017 IRP comprehensive analysis of how its resource plan meets winter peak load obligations. The coincident peak for PacifiCorp's system occurs during the summer, and prior IRP planning cycles have historically focused on ensuring that resource plans have sufficient capacity to cover summer coincident peak load. For the first time, the 2017 IRP enforces the target planning reserve margin on both the summer and winter coincident system peak load, allowing PacifiCorp to report a winter load and resource balance, evaluate direct load control programs targeting the winter peak, and evaluate and report market purchases used to satisfy winter peak load forecasts.

- Resource Portfolio Development Process
  PacifiCorp improved its resource portfolio development process to more efficiently produce alternative combinations of resources that could be used to serve our customers over time. This was achieved by initially evaluating a comprehensive range of Regional Haze compliance cases under different market price and environmental policy scenarios, and then using stochastic risk metrics to evaluate the relative performance of alternative compliance outcomes. Results from this analysis established coal unit retirement assumptions for subsequent core case and sensitivity case studies, addressing stakeholder feedback from the 2015 IRP requesting that portfolios considered for selection as the preferred portfolio be compared among common Regional Haze compliance assumptions. Further, PacifiCorp implemented a core case modeling framework targeting specific types of resources having operating characteristics not explicitly valued until the stochastic risk phase of portfolio analysis. This structure allowed PacifiCorp to evaluate a more diverse mix of potential resource portfolios among a broader range of market price and environmental policy scenarios to compare the relative performance of these portfolios using stochastic risk metrics.

- Stakeholder Requests
  Efficiencies gained through improvements to the resource development process better positioned PacifiCorp to develop additional studies requested by stakeholders during the public input process. PacifiCorp and stakeholders identified and requested alternative modeling scenarios that were informed by the initial and intermediate analysis that was reviewed during the public input process. This is an improvement over past IRP planning cycles, where a more rigid set of pre-defined core case and sensitivity cases limited the ability to explore alternative assumptions. This improved process in the 2017 IRP enabled PacifiCorp to develop additional Regional Haze compliance cases and alternative environmental policy cases in response to stakeholder requests. Results from some of these studies led PacifiCorp to consider additional scenarios, which directly influenced the resource mix in the preferred portfolio.

- Clean Power Plan Modeling
  In the 2015 IRP, PacifiCorp developed a modeling framework to assess the CO_2 emission rate targets identified in the Environmental Protection Agency's draft Clean Power Plan (CPP) rule. Due to modeling limitations, PacifiCorp was not able to explicitly capture the impact of the emission rate targets in stochastic risk analysis, which is used to compare the relative cost and risk performance of different resource portfolios. In the 2017 IRP, PacifiCorp identified different mass cap emission targets outlined in the final CPP, enabling us to leverage existing modeling capabilities to reflect the impact of CPP emission limits in stochastic risk analysis.

- Solar Integration Costs
  In previous IRPs, a solar integration study to define incremental operating reserve requirements and associated costs to manage the variability and uncertainty of solar resources connected to PacifiCorp's system had not been developed. In the 2017 IRP, PacifiCorp's flexible reserve study outlines incremental reserve requirements associated with solar resources and accompanying estimates for solar resource integration costs.

- Public Input Meetings
  In response to requests to improve participation in IRP public input meetings, PacifiCorp coordinated with stakeholders to include video conference connections with locations in Cheyenne, Wyoming, and Denver, Colorado, to supplement the existing video conference connection between Portland, Oregon, and Salt Lake City, Utah.

Supplemental Studies

PacifiCorp's 2017 IRP relies on numerous supplemental studies that support the derivation of specific modeling assumptions critical to its long-term resource plan. A description of these studies, discussed in more detail in appendices filed with the 2017 IRP, is provided below.

- Conservation Potential Assessment
  An updated conservation potential assessment (CPA), prepared by Applied Energy Group (commissioned by PacifiCorp) and the Energy Trust of Oregon was prepared to develop demand side management resource potential and cost assumptions specific to PacifiCorp's service territory. The CPA supports the cost and DSM savings data used during the portfolio development process.

- Private Generation Resource Assessment
  This supplemental study, prepared by Navigant Consulting, Inc., was refreshed for the 2017 IRP to produce updated private generation penetration forecasts for solar photovoltaic, small-scale wind, small-scale hydro, combined heat and power reciprocating engines, and combined heat and power micro-turbines specific to PacifiCorp's service territory. The private generation penetration forecasts from this study are applied as a reduction to forecasted load throughout the IRP modeling process.

- Western Resource Adequacy Evaluation
  PacifiCorp updated its analysis of regional resource adequacy to support its assumptions for wholesale power market purchase limits adopted for the 2017 IRP. The western resource adequacy evaluation presents data from the Western Electricity Coordinating Council's Power Supply Assessment, reviews recent resource adequacy studies performed for the Pacific Northwest region, and summarizes PacifiCorp's historical peak

period market purchase data. PacifiCorp's review of regional resource adequacy continues to support the use of wholesale power market purchases as a resource in the IRP planning process.

- Planning Reserve Margin Study
  The 2017 IRP was developed targeting a 13 percent planning reserve margin, which influences the need for new resources and is applied during the portfolio development process. In the 2017 IRP planning reserve margin study, PacifiCorp analyzes the relationship between cost and reliability among ten different planning reserve margin levels, accounting for variability and uncertainty in load and generation resources.

- Capacity Contribution Study
  PacifiCorp updated its wind and solar capacity contribution values for the 2017 IRP, which were developed using the capacity factor approximation method. Capacity contribution is defined as the availability of wind and solar resources among hours having the highest loss-of-load probability, and the resulting values are used in the 2017 IRP load and resource balance and in the portfolio development process.

- Flexible Reserve Study
  PacifiCorp expanded the scope of what has historically been titled as the wind integration study to include an overall assessment of flexible reserve demands driven by variability and uncertainty in load, wind, solar, and non-wind and non-solar generation resources. The updated study was prepared by PacifiCorp in coordination with a technical review committee and estimates flexible reserve needs and integration costs for wind and solar resources. Operating reserves estimated from the study are used in cost and risk analysis modeling and estimated wind and solar integration costs are applied during the portfolio development process.

- Stochastic Parameter Update
  PacifiCorp's preferred portfolio selection process relies, in part, on stochastic risk analysis using a Monte Carlo random sampling process. Stochastic variables include natural gas and wholesale electricity prices, load, hydro generation, and unplanned thermal outages. For its 2017 IRP, PacifiCorp updated its stochastic parameter input assumptions with more current historical data.

- Smart Grid
  PacifiCorp has included in the 2017 IRP appendix an update on its Smart Grid efforts with a focus on transmission and distribution systems and customer information.

- Energy Storage Screening Studies
  Two energy storage studies were conducted to support the 2017 IRP. The Battery Energy Storage Study prepared by DNV-GL catalogues commercially available and emerging battery energy storage technologies with forecasts and estimates for both performance and costs. The Bulk Energy Storage Study prepared by Black & Veatch is an update to the work HDR and Navigant Consulting performed for the 2015 IRP. The Bulk Energy Storage Study incorporates updated information on three pumped hydro energy storage projects and a compressed air energy storage project in PacifiCorp's service territory.

Action Plan

The 2017 IRP action plan identifies specific resource actions PacifiCorp will take over the next two to four years to deliver resources included in the preferred portfolio. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed during the development of the 2017 IRP, and other resource activities described in the 2017 IRP. Table 1.4 details specific 2017 IRP action items by category.

Table 1.4 - 2017 IRP Action Plan

Action Item	1. Renewable Resource Actions
1a	**Wind Repowering** • PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016. – Continue to refine and update the economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed. – By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills). – Pursue regulatory review and approval as necessary. – By May 2018, issue the engineering, procurement, and construction (EPC) notice to proceed to begin implementing the wind repowering for specific projects consistent with updated financial analysis. – By December 31, 2020, complete installation of wind repowering equipment on all identified projects.
1b	**Wind Request for Proposals** • PacifiCorp will issue a wind resource request for proposals (RFP) for at least 1,100 MW of Wyoming wind resources that will qualify for federal wind production tax credits and achieve commercial operation by December 31, 2020. – April 2017, notify the Utah Public Service Commission of intent to issue the Wyoming wind resource RFP. – May-June, 2017, file a draft Wyoming wind RFP with the Utah Public Service Commission and the Washington Utilities and Transportation Commission. – May-June, 2017, file to open a Wyoming wind RFP docket with the Public Utility Commission of Oregon and initiate the Independent Evaluator RFP. – June-July, 2017, file a draft Wyoming wind RFP with the Public Utility Commission of Oregon and file a Public Convenience and Necessity (CPCN) application with the Public Service Commission of Wyoming. – By August 2017, obtain approval of the Wyoming wind resource RFP from the Public Utility Commission of Oregon, the Utah Public Service Commission, and the Washington Utilities and Transportation Commission.

	– By August 2017, issue the Wyoming wind RFP to the market. – By October 2017, Wyoming wind RFP bids are due. – November-December, 2017, complete initial shortlist bid evaluation. – By January 2018, complete final shortlist bid evaluation, seek acknowledgement of the final shortlist from the Public Utility Commission of Oregon, and seek approval of winning bids from the Utah Public Service Commission. – By March 2018, receive CPCN approval from the Wyoming Public Service Commission. – Complete construction of new wind projects by December 31, 2020.
1c	**<u>Renewable Portfolio Standard Compliance</u>** • PacifiCorp will issue unbundled REC request for proposals (RFP) to meet its state RPS compliance requirements. – As needed, issue RFPs seeking then-current-year or forward-year vintage unbundled RECs that will qualify in meeting California renewable portfolio standard targets through 2020. – As needed, issue RFPs seeking low-cost then-current-year, forward-year, or older vintage unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets, deferring the currently projected 2035 initial shortfall after accounting for preferred portfolio renewable resources.
1d	**<u>Renewable Energy Credit Optimization</u>** • Before filing the 2017 IRP Update, evaluate potential opportunities to re-allocate RECs from Utah, Wyoming, and Idaho to Oregon, Washington, or California. • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.
Action Item	**2. Transmission Actions**
2a	**<u>Aeolus to Bridger/Anticline</u>** • By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary. – June-July 2017, file a CPCN application with the Public Service Commission of Wyoming. – By March 2018, receive conditional CPCN approval from the Wyoming Public Service Commission pending acquisition of rights of way. – By December 2018, obtain Wyoming Industrial Siting permit and issue EPC limited notice to proceed. – By April 2019, issue EPC final notice to proceed. – Complete construction of the transmission line by December 31, 2020.

2b	**<u>Energy Gateway Permitting</u>** • Continue permitting for the Energy Gateway transmission plan, with the following near-term targets: – For Segments D1, D3, E, and F, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits. – For Segments D, E, and F, continue to support the projects by providing information and participating in public outreach. – For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.
3c	**<u>Wallula to McNary 230 kV Transmission Line</u>** • Complete Wallula to McNary project construction per plan with a 2018 expected in-service date. Continue to support the permitting and construction process for Walla Walla to McNary.
4d	**<u>Planning Studies</u>** • Complete planning studies that include proposed coal unit retirement assumptions from the 2017 IRP preferred portfolio and two other scenarios. • Summarize studies in the 2017 IRP Update.
Action Item	**3. Firm Market Purchase Actions**
3a	**<u>Front Office Transactions</u>** • Acquire economic short-term firm market purchases for on-peak summer deliveries from 2017 through 2019 consistent with the Risk Management Policy and Commercial and Trading Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: – Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month-forward, balance-of-month, day-ahead, and hour-ahead non-brokered transactions.

Action Item	4. Demand Side Management (DSM) Actions
4a	**Class 2 DSM** • Acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2017 IRP.

Year	Annual Incremental Energy (GWh)	Annual Incremental Capacity* (MW)
2017	646	154
2018	559	128
2019	571	131
2020	527	122

*Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.

Action Item	5. Coal Resource Actions
5a	**Hunter Units 1 and 2** • The EPA's final Regional Haze Federal Implementation Plan (FIP) for Utah requires the installation of selective catalytic reduction (SCR) on Hunter Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals. • As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.
5b	**Huntington Units 1 and 2** • The EPA's final Regional Haze FIP for Utah requires the installation of SCR on Huntington Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals. • As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.
5c	**Dave Johnston Unit 3** • The EPA's final Regional Haze FIP requires the installation of SCR at Dave Johnston Unit 3 in 2019 or a commitment to shut down Dave Johnston Unit 3 by the end of 2027. PacifiCorp's commitment to the latter must be included in a permit before the 2019 compliance deadline. • PacifiCorp will update its analysis of the commitment to shut down Dave Johnston Unit 3 by the end of 2027 as part of its 2017 IRP Update.

5d	**<u>Jim Bridger Units 1 and 2</u>** • The Wyoming Regional Haze State Implementation Plan (SIP) and EPA's final Regional Haze FIP for Wyoming require the installation of SCR on Jim Bridger Units 1 and 2 in 2021 and 2022. • PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units and will provide the associated analysis in its 2017 IRP Update.
5e	**<u>Naughton Unit 3</u>** • PacifiCorp will update its economic analysis of natural gas conversion in its 2017 IRP Update.
5f	**<u>Wyodak</u>** • Continue to pursue PacifiCorp's appeal of the portion of EPA's final Regional Haze FIP that requires the installation of SCR at Wyodak, recognizing that the compliance deadline for SCR under the FIP is currently stayed by the court. • If following appeal, EPA's final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.
5g	**<u>Cholla Unit 4</u>** • EPA has approved the Arizona SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by the end of April 2025, with the option of natural gas conversion thereafter. • PacifiCorp will update its evaluation of Cholla Unit 4 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.
5h	**<u>Craig Unit 1</u>** • EPA is yet to approve the Colorado SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Craig Unit 1 as a coal-fueled resource by the end of 2025, with an option for natural gas conversion. • PacifiCorp will update its evaluation of Craig Unit 1 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update, as required.

RULE K
REQUIREMENTS RELATING TO ESSs

1. Purpose

A. **Generally**

Prior to providing Electricity Service to Customers, an Electricity Service Supplier (ESS) must be certified by the Commission, if applicable, and meet the Company's requirements for providing service. The Company may provide information to the Commission certification process, if applicable, regarding the ESS's scheduling capabilities, electronic data transmission capabilities, insurance coverage and credit. **(T)**

B. **Requirements for Providing Service**

To provide Electricity to a Customer an ESS must:

1) Be certified by the Commission, if applicable;
2) Complete the Company's business application form and submit an Application Processing Fee or Renewal Fee as listed in Schedule 600;
3) Establish creditworthiness as set forth in the ESS Credit Requirements provision of this rule;
4) Demonstrate the capability to meet the information exchange requirements of the Company.
5) Name the Company as an additional insured in the amount of at least $10 million on the ESS's general liability policy;
6) Execute an ESS Service Agreement with the Company confirming the terms and conditions of the service(s) elected and agree to abide by the terms and conditions of the Company's Tariff and the Oregon Administrative Rules;
7) If a Scheduling ESS, execute a transmission service agreement under the Company's Open Access Transmission Tariff; and
8) If a Non-Scheduling ESS, provide the name of the Scheduling ESS.

2. ESS Credit Requirements

A. **Credit Review/Applicability**

An ESS's participation in Direct Access Service is contingent upon meeting and maintaining the credit requirements set forth in this Tariff and the applicable ESS Service Agreement. The Company will determine whether the ESS meets the Company's initial creditworthiness requirements as set forth below, and advise the Commission whether the ESS has been credit approved or not. The Company will enter into an ESS Service Agreement after ESS's credit has been established, collateral has been obtained and ESS certification by the Commission is complete. The Company will continue to monitor the ESS creditworthiness to determine continuing compliance under the minimum credit requirements.

B. **Credit Exposure**

An ESS must establish and maintain creditworthiness relative to the Company's credit exposure to the ESS. Credit exposure will include, but not be limited to, the expected liabilities of the ESS.

C. **Establishment of Credit**

An ESS must establish its creditworthiness as described below.

1) **Creditworthiness Requirements**

Each ESS, or guarantor, must meet the Company's creditworthiness requirements by satisfying all of the criteria below. An ESS who cannot meet the requirements below will provide a collateral deposit as described in item (4) below.

a) **Credit Evaluation**

An ESS seeking to enter into a new ESS Service Agreement with the Company must complete a credit application to provide the financial information necessary to conduct a credit evaluation and establish the ESS's initial credit profile. The Company may require an ESS to complete a new or revised credit application if the ESS's ESS Service Agreement has been terminated, was not renewed, or in any other manner was caused to lapse; if the ESS no longer meets the minimum credit criteria; or periodically based on the Company's standard commercial practice.

The credit evaluation will be conducted by the Company. This evaluation will be completed within 10 Business Days from the Company's receipt of a completed credit application and all relevant financial statements. All information required to evaluate credit will remain strictly confidential between the ESS and the Company, except as otherwise required by law. The Company will notify the Commission of its credit decision upon completion of the Company's credit review. All credit evaluations and associated collateral deposit calculations performed by the Company will be done in a non-discriminatory and consistent manner.

b) **Required Credit Information**

Each ESS and guarantor (if applicable) will be required to provide the following information: (1) completed credit application; (2) three years of annual, audited financial statements; and (3) the latest interim financial statements along with the same interim financial statements from the prior year.

c) **Rating Agency**

An ESS and guarantor (if applicable) must demonstrate a current and maintained long-term, senior unsecured debt rating of Baa3 or higher from Moody's Investor Service (Moody's) or BBB- or higher from Standard and Poors (S&P).

d) **Tangible Net Worth**

An ESS and guarantor (if applicable) must maintain a minimum Tangible Net Worth of $750 million dollars and demonstrate a minimum Tangible Net Worth of $750 million dollars for the prior two-year period. Tangible Net Worth is defined as net worth minus intangibles such as goodwill and rights to patents or royalties.

e) **Credit History**

An ESS and guarantor (if applicable) must not be currently in default under any of its agreements with the Company or under any of its other agreements, and must be current on all of its financial obligations. An ESS and guarantor (if applicable) must pay all past due amounts owed to the Company before credit is established.

2) **Unsecured Credit**

For an ESS and guarantor (if applicable) whose creditworthiness is established by satisfying the above requirements, an unsecured credit limit may be established by the Company. **(C)**

(D)

The Company may increase or decrease the unsecured credit limit on a case by case basis using accepted commercial credit standards and based on the following criteria: (1) adequate financial statements: (2) credit payment history; and (3) business fundamentals, which includes review of (a) market position; (b) litigation and contingencies; (c) organization; and (d) strategic and financial support. The Company will monitor the established creditworthiness utilizing these factors on an on-going basis. **(C)**

3) **Collateral Requirements**

The ESS will be required to post or increase collateral under any of the following conditions:

a) The ESS does not meet the minimum creditworthiness standards established above;

b) The ESS fails to provide the Company sufficient relevant credit and financial information on an ongoing basis as required in this Tariff and the ESS Service Agreement;

c) The ESS experiences a material adverse change. A material adverse change is defined as the occurrence of any of the following events: (1) the ESS's long-term senior, unsecured debt rating is downgraded by either S&P or Moody's below BBB- and Baa3, respectively, or (2) a change in condition (financial or otherwise), net worth, assets, or properties which can reasonably be anticipated to impair the ESS's ability to fulfill its payment and credit obligations; or

d) The Company's total credit exposure to the ESS exceeds the ESS's unsecured credit limit and/or any existing Collateral Deposit.

4) **Collateral Deposits**

If collateral is required, the ESS will submit and maintain a collateral deposit as described below.

a) **Amount of Collateral Deposit**

The amount of the collateral deposit required to establish credit will be the sum of the following amounts as applicable:

(i) For ESSs billing customers for services provided by the Company, three times the estimated maximum monthly customer charges owed by the ESS to the Company, where such estimate is based on the usage and Tariff prices expected to prevail over the next 12 months;

(ii) All other charges from the Company to an ESS as estimated over a 90 day period; and

(iii) All invoiced and non-invoiced receivables due from the ESS; or

(iv) Not less than $500,000.

b) **Form of Collateral Deposit**

Collateral deposits will be in the form of (1) cash deposits, (2) Letters of Credit, defined as irrevocable and renewable issued by a major financial institution acceptable to the Company, or (3) guarantees, with guarantors who have a long-term senior, unsecured debt rating of Baa3 or higher from Moody's or BBB- or higher from S&P, unless the Company determines that a material change in the guarantor's creditworthiness has occurred, or, in other cases, through the credit evaluation process described above.

c) **Collateral Deposit Payment Timetable**

ESSs are obligated to post collateral deposits with the Company prior to entering into an ESS Service Agreement. Collateral deposit increases and/or adjustments must be received within two calendar days of a request from the Company. Collateral deposits must be established, maintained or extended within five days of expiration of a collateral deposit.

d) **Interest on Cash Deposit**

The Company will pay interest on cash collateral deposits. Interest will be calculated according to the interest rate prescribed in Schedule 300.

5) **On-going Maintenance of Credit**

a) The Company may review the ESS's creditworthiness, credit limits and the Company's credit exposure on a daily basis. The Company may request an increase in the collateral deposit by providing notice to the ESS that an increase is required as the ESS enrolls additional Customers, the ESS no longer satisfies the minimum criteria commensurate with its unsecured credit line as described above, the Company draws on the collateral deposit or a portion of the collateral deposit pursuant to this Section or the ESS Service Agreement, and/or the Company's credit exposure to the ESS increases.

b) To assure continued validity of established unsecured credit, the ESS will promptly notify the Company if the ESS (i) experiences any material adverse change; (ii) has its long-term, senior unsecured debt rating downgraded by Moody's and/or S&P; (iii) experiences a change in control as a result of merger or consolidation; (iv) sells or transfers a material portion of its assets; or (v) proposes to change its designation from Non-Scheduling to Scheduling or vice versa.

c) The ESS will provide to the Company an updated credit application reflecting current financial and business information pursuant to the terms of this Section; upon the occurrence of any event listed in Section (2)(C)(3)(c); if the ESS has been suspended pursuant to the terms of the ESS Service Agreement; to support a request for an increased credit line; or as the Company may reasonably require on a quarterly basis.

d) The ESS will review and maintain its collateral and establish, extend or increase collateral when required pursuant to this Section.

e) All collateral amounts will be adjusted up or down to the nearest integral multiple of $25,000, but never less than the required initial collateral deposit at the time the ESS enters into and signs an ESS Service Agreement. The Company will notify the ESS of any needed adjustments.

6) **Re-establishment of Credit**

An ESS whose ESS Service Agreement has been suspended due to inadequate credit may re-establish its creditworthiness in the manner prescribed in item C above.

D. **Additional Documents**

The ESS will execute and deliver all documents and instruments (including, without limitation, security agreements and Company financing statements) reasonably required from time to time to implement the provisions set forth above and to perfect any security interest granted to the Company.

3. Electronic Data Transfer Interchange (EDI)

All electronic communications between the Company and the ESS must conform to industry standard electronic data interchange protocols. The ESS must demonstrate its ability to successfully exchange test data for all transactions before the first Direct Access Service Request (DASR) is processed. The ESS will also provide a point of contact to resolve daily electronic data interchange problems. If the ESS is certified, but does not have active enrollments within a six-month period, the Company will request that the ESS retest the interchange.

The ESS must notify the Company of plans to modify its electronic data interchange systems such as the installation of new software or upgrades to software as well as any plans to change system subcontractors when such plans may affect data transfers between the Company and the ESS. The Company may require retesting of data transfers under such circumstances. Where retesting is required, the ESS will be subject to the set-up and verification charge contained in Schedule 600.

When the Company makes any changes to its interchange systems or changes subcontractors, it will promptly notify all ESSs. If the changes require retesting of systems, the Company will not charge ESSs for this testing.

4. Electricity Service Supplier Decertification

A. **Notice to ESS**

The Company may recommend to the Commission decertification of an ESS that the Commission has certified at times other than the annual renewal date. The Company will notify the ESS that it is initiating such action, if applicable.

B. **Criteria for Recommending Decertification**

The Company may recommend decertification, if applicable, of an ESS to the Commission when the ESS fails to comply with the terms and conditions under this Tariff, or fails to perform obligations under the transmission service agreement or ESS Service Agreement. The following are examples of when the Company may recommend decertification of an ESS:

1) Failure to submit an Electricity Schedule that meets the requirements of Section 11;
2) Failure to deliver Electricity according to its Electricity Schedule;
3) Submission of a DASR not authorized by a Customer;
4) Failure to conform with industry electronic data interchange protocols;
5) Failure to comply with Federal Energy Regulatory Commission (FERC), North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) operating procedures;
6) Failure to pay for services rendered by the Company;
7) The ESS makes a general assignment or arrangement for the benefit of creditors;
8) The ESS becomes bankrupt, a debtor in a bankruptcy proceeding, insolvent, however evidenced, or is unable to pay its debts as they fall due;
9) The ESS files a petition or otherwise commences a proceeding under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it;
10) The ESS has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets;
11) Evidence that indicates the ESS has violated any state or federal customer protection laws or rules, including antitrust laws, during the past three years;
12) The ESS has materially failed to meet its obligations under terms of the ESS Service Agreement so as to constitute an event of default;

13) The ESS engages in unauthorized use of Electricity or a Customer of the ESS engages in unauthorized use of Electricity and the ESS knew about it;

14) Failure to provide a complete, accurate and truthful credit application;

15) Failure to maintain credit requirements; and

16) At the general discretion of the Company.

C. **Notice to Customers**

The Company, upon consultation with the Commission, may transfer the ESS's Customers to the applicable Utility Provided Service prior to ceasing to provide service to the ESS. The Company will notify the ESS's Customers of the transfer in writing as soon as possible. The ESS will be charged a Switching Fee for each Customer transferred as listed in Schedule 600.

D. **Decertification**

Upon decertification, the ESS may no longer serve Customers, and all amounts billed or owed by the ESS are immediately due. The Company will move all Customers served by the ESS to Emergency Default Service and the ESS will be charged the Switching Fee listed in Schedule 600 for each Point of Delivery that moves to Emergency Default Service.

5. Pre-enrollment Information Provided to ESS

With the Customer's authorization, the Company may provide account-specific information, including one year of monthly usage history but excluding credit information, to an ESS. The ESS will be charged the ESS Web Portal Data Access Fee as listed in Schedule 600 for such requests.

6. Customer Enrollment

A. **ESS/Company Relationship**

The ESS may not state or in any way imply that it has been given preferential status by the Company.

B. **ESS Liability**

The ESS will defend, indemnify and hold the Company harmless against all claims of loss made by any Customer arising from claims of inappropriate switching from the Company or another ESS in violation of the solicitation or verification provisions of the Commission, regardless of whether the person or entity doing the marketing or solicitation was an independent contractor of the ESS.

C. **Enrollment DASR**

The ESS must submit to the Company an Enrollment DASR which, at a minimum, includes the Customer's name, Company account number, service address, mailing address, type of service being purchased, name of the ESS, name of Scheduling ESS if different, proposed effective date, Customer's billing preference, and Service Point Identification (SPID) for each Customer that elects **(C)**
service from the ESS.

1) Unless the Company deems otherwise, the Company will activate only one (1) Enrollment DASR per SPID per meter reading cycle. When **(C)**
multiple Enrollment DASRs for the same SPID are received during the **(C)**
same meter reading cycle, the Company will activate the first Enrollment DASR received. The Enrollment DASR must be submitted at least 13 business days prior to the effective date. The Company will notify the ESS of Enrollment DASR acceptance or rejection within three business days of its receipt. For Enrollment DASRs submitted during an enrollment window, the three business day notice period does not begin until the end of the enrollment period. The Company will notify the ESS as to the date the Customer will begin Direct Access Service once interval metering is verified.

2) The Company will charge the ESS the Switching Fee listed in Schedule 600 for each Enrollment DASR received whether accepted or rejected.

3) Upon acceptance of an Enrollment DASR the Company will provide notice within three business days to the Customer's current ESS, if any, of the pending change to a new ESS.

D. **Refusal of Enrollment DASR**

The Company may refuse to accept an Enrollment DASR when:

1) The Company has not received full payment from the Customer for past-due amounts or other obligations owed by it related to regulated charges from the Customer's prior Electricity Service account(s) unless such charges are part of a pending Customer dispute;
2) The Company has not received full payment or the Customer has not made an arrangement to pay the balance owed by the Customer on an existing Budget Payment Option or other agreements;
3) The Enrollment DASR is not accurate and/or complete;
4) The ESS has not complied with provisions of the ESS Service Agreement;
5) The Customer has not completed any term obligation under Standard Service; or
6) The ESS is not certified by the Commission.

E. **Change DASR**

A Change DASR must be submitted when the ESS is requesting a modification. The Change DASR requires up to 13 business days to process. The Change DASR may only be submitted after receipt of the assigned effective date of the information subject to modification and must be submitted at least 13 business days prior to the requested effective date of the Change DASR. There is no charge for submitting a Change DASR. However, when a Change DASR is submitted to change the assigned enrollment effective date to a date that is not a regular meter read date, a Change of Effective Date charge as listed in Schedule 600 will be imposed.

F. **Other DASRs**

The Other DASR forms are as follows:

1) **Rescind DASR**

   A Rescind DASR is a request to withdraw an Enrollment DASR and it must be submitted prior to the issuance of an Direct Access effective date. No charge is assessed for a Rescind DASR. A Rescind DASR requires three business days to process. If the Company does not have three business days to process before the effective date is issued, a Cancel DASR is required.

2) **Cancel DASR**

   A Cancel DASR is a request for cancellation of Direct Access Service that has been submitted after the Direct Access Service effective date has been issued. No charge is assessed for a Cancel DASR. A Cancel DASR requires three business days to process. Failure to provide adequate notice may require the Customer to take Direct Access Service and/or move to Emergency Default Service until processing is complete.

3) **Drop DASR**

   A Drop DASR is a request to stop Direct Access Service and return to Standard Service or to close the service account. A Drop DASR must be submitted at least 13 business days before the requested effective date. Failure to provide adequate notice may require the Customer to continue Direct Access Service and/or move to Emergency Default Service until the Drop DASR process can be completed. The Customer or ESS, whichever initiates the Drop DSAR, is charged the Switching Fee as listed in Schedule 300 or Schedule 600.

The Company may submit a Rescind, Cancel, or Drop DASR on behalf of the Customer to nullify an Enrollment DASR submitted for a Customer without their consent. The Customer will not be charged the Schedule 300 Switching Fee and the Customer's service will not be switched regardless of the required processing timeframes described above.

G. **Customer Information**

The Customer consents to the release by the Company to its ESS monthly usage data when it agrees to take Direct Access Service. Upon acceptance of an Enrollment DASR, the Company may provide to the ESS account-specific information, including one year of monthly usage history, excluding credit information.

H. **Return of Customer Deposits**

Following acceptance of an Enrollment DASR, the Company will return any Customer deposit, net of any amounts owing when the ESS is providing Consolidated Billing. When the Company is continuing to bill the Customer or the Customer has requested split billings between the ESS and the Company, the Company will retain the portion of the deposit appropriate for two months of regulated Electricity Service billings from the Company and credit the excess deposit, if any, to the Customer's account.

I. **Customer Change of Location**

When a Customer moves 100% of its operation from an existing service location enrolled under Direct Access to a [single] new service location and elects to continue Direct Access Service at such new service location ("Change of Location"), the Customer's ESS must submit a Drop DASR for the existing/old service location and an Enrollment DASR for the new service location. Customer requests for a Change of Location will not be considered should the change occur more than 12 months after the old location has been vacated, regardless of whether the service at such old location is nominal or idle or has been discontinued. **(C)**

The following additional criteria will be applicable to a Customer's Change of Location: **(T)(M)** **(T)**

1) The Customer and the ESS must provide written notice to the Company of the intended Change of Location. After processing the written request, the Company will notify the ESS when to send the Drop DASR for the existing/old location and the Enrollment DASR for the new location; **(C)** **(C)** **(C)(M)**

(M)

2) For a customer with multiple locations, the projected monthly consumption patterns of the new location will be similar to the prior location;

3) The account for the existing/old location must be: (1) closed, (2) placed on the PGE Daily Price Option prior to the new location receiving service under the terms and conditions of the applicable direct access schedule, (3) idle (i.e. no usage), or (4) placed on Cost of Service with demonstrated nominal use consistent with a vacated location. The Schedule 128 Annual Short-Term Transition Adjustment will apply to the old location if the account is placed on the PGE Daily Price Option under the second option. With respect to the third and fourth options, the Customer carries the burden to demonstrate that the old location is idle or the usage at such location is nominal and consistent with the location being vacated; (C)

4) For Schedules 485, 489, and 490, the new location must be expected to have a Facility Capacity of at least 250 kW;

5) Consistent with the terms and conditions of Customer's Long-Term Cost of Service Opt-Out Agreement, the enrollment period vintage of the existing/old location and the associated Schedule 129 Long-Term Transition Adjustments will be transferred to the Customer's new service location, as applicable; (C)

6) The new service location may be temporarily served under the provisions of the PGE Market Based Pricing Option until such time that the transfer of service location may be effectively executed; (C)

7) The ESS will pay all applicable Schedule 600 charges.

7. <u>ESS Service to Single Point of Delivery</u>

Only one ESS may serve any single Point of Delivery. If the Customer is receiving products and services from more than one ESS, the ESS that submitted the accepted Enrollment DASR is responsible for the coordination of services including, but not limited to billing, payment, delivery and scheduling.

8. Discontinuance of ESS Service **(M)**

Upon determination by an ESS that it will discontinue service to a Customer because of nonpayment of charges or other reasons provided for in the ESS/Customer Agreement, the ESS will provide the Company with ten business days' notice of such discontinuance. The Company will subsequently move the Customer to Standard Service in the absence of an accepted Enrollment DASR. The Switching Fee listed in Schedule 600 will be charged to the ESS in conjunction with moving the Customer to Standard Service.

9. Company Billings to the ESS

The ESS is responsible for payment of all charges assessed to it by the Company. All bills issued under this Tariff are due and payable through electronic payment within 15 days of presentation. Billings unpaid by the due date are subject to a late payment charge as described in Schedule 600. When the ESS disputes charges assessed to it by the Company, the ESS is still responsible to make payment of such charges within 15 days of presentation.

10. Processing of Payments

Unless otherwise specified, the Company will allocate payments from ESSs in the following order:

(1) Past due deposits or installments;

(2) Required deposits currently due;

(3) Past due regulated charges for Electricity Services;

(4) Current regulated charges for Electricity Services;

(5) Past due charges for optional services by oldest date first; and

(6) Current charges for optional services.

11. ESS Scheduling Responsibilities

At least one day prior to the Day of Flow, in accordance with the ESS Service Agreement and transmission service agreement, each Scheduling ESS will provide the Company with an Electricity Schedule of the expected aggregated hourly load requirements of the Customers for which it has scheduling responsibility subject to the following terms and conditions: **(M)**

A. **Scheduling Period: Day of Flow** (M)

Each daily scheduling period will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable, "PPT").

B. **Changes in Load**

The Company may require a Scheduling ESS to change its Electricity Schedule if the Company determines the Electricity Schedule does not adequately represent the expected ESS Customer load. If a Customer or Customers are served under an interruptible arrangement by the ESS, the ESS will notify the Company of any interruption coincident with its notification to those Customers and will adjust its Electricity Schedule accordingly.

C. **Failure to Schedule**

An ESS that fails to submit an Electricity Schedule is subject to applicable charges and immediate termination of the ESS Service Agreement. The Customers served by the ESS will be moved to Emergency Default Service.

D. **Confirmation**

The Company reserves the right to confirm with appropriate transmission service providers each Electricity Schedule provided by ESSs and to reject any Electricity Schedule that cannot be confirmed.

E. **Conformance with Regional Requirements**

The ESS will conform to FERC, NERC and WECC scheduling, operating and reporting requirements.

F. **ESS Control Information**

An ESS that chooses to self-provide ancillary services will provide the Company a real-time load and power factor signal via electronic means.

12. Company Scheduling Responsibilities

A. **Change in Load**

The Company will notify an ESS as soon as practical of a planned outage when such outage affects its Customer(s) with a load greater than one megawatt. (M)

B. **Major Outage Procedures** **(M)**

The Company will attempt to maintain system balance during a major outage using all appropriate methods available according to utility practices. The Company may require an ESS to reduce its Electricity Schedule in the event of a major loss of load due to a major outage consistent with the Company's resources. In such case, the Company will notify the ESS when it can resume normal scheduling. The Company will waive related imbalance penalty adjustment provisions during such event. The Company is responsible for responding to inquiries related to major outages. Customers who contact their ESS regarding major outages should be referred to the Company.

13. Settlement

The Company will reconcile total Electricity delivered by the ESS with the total Electricity consumed by the Customers for which the ESS has scheduling responsibility in accordance with Schedule 600 of this Tariff. Customer Electricity consumption will be measured accordingly:

A. **Interval-Metered Electricity**

Where the Customer has an interval-meter installed, Electricity consumed is equal to the metered quantity plus losses as specified in Schedule 600.

B. **Profiled Electricity**

Where interval-meter data is missing, hourly consumption will be estimated using load profiles and adjusted based on available metered data plus losses as specified in Schedule 600. For unmetered loads, consumption will be based on a test or estimated from equipment ratings, adjusted for losses, and allocated to each hour based on hours of usage and whether the equipment is operational during that hour.

14. Operational Order to Deliver Electricity

A. **General**

An "Operational Order to Deliver Electricity" may be issued by the Company upon one hour's notice for purposes of maintaining the integrity of its electrical distribution system.

(M)

B. **Action by the ESS** (M)

Upon receiving an Operational Order to Deliver Electricity, the ESS will endeavor to deliver its full capability for all its Customers served by adjusting its Electricity Schedule.

C. **Compensation**

The Company will waive all energy imbalance service charges and penalty provisions for an ESS that demonstrates substantial compliance with an Operational Order to Deliver Electricity. Compensation for excess Electricity delivered in accordance with the Company's Operational Order to Deliver Electricity will be at a rate equal to the higher of:

1) The ESS's direct cost of such Electricity; or

2) The highest incremental cost of Electricity purchased by the Company during each hour of the Operational Order to Deliver Electricity.

15. Preemption

In addition to an Operational Order to Deliver Electricity, the Company may take automatic or manual actions that, in its opinion, are necessary or prudent to protect the performance, integrity, reliability or stability of its electrical system or any electrical system with which it is interconnected. During such period, delivery of Electricity to Customers may be curtailed or interrupted by the Company even though the ESS continues to supply Electricity to the Company. The payment for such Electricity will be made at a rate equal to the higher of:

A. The ESS's direct cost of such Electricity; or

B. The highest incremental cost of Electricity purchased by the Company during each hour of the preemption.

16. Dispute Resolution

A Dispute Resolution process is contained in the ESS Service Agreement. (M)

RULE K (Concluded)

SCHEDULE 600
ELECTRICITY SERVICE SUPPLIER CHARGES (T)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To any Electricity Service Supplier (ESS), including an applicant ESS, providing service to Customers. To receive service under this schedule, the ESS must sign an ESS Service Agreement and abide by all provisions of the Company's Tariff. (T)

SERVICES

The following services are offered to an ESS providing Electricity to one or more Direct Access Service Customers.

Transmission Services (Applicable to Scheduling ESS only)

Transmission services are provided to an ESS pursuant to the Company's Open Access Transmission Tariff (OATT), Original Volume No. 8 (PGE-8). Transmission services include:

(a) Transmission as further described under Special Conditions;
(b) Scheduling, System Control and Dispatch Service;
(c) Reactive Supply and Voltage Control Service;
(d) Regulation and Frequency Response Service*;
(e) Energy Imbalance Service*;
(f) Operating Reserve - Spinning Reserve Service*; and
(g) Operating Reserve - Supplemental Reserve Service*.

* When provided by the Company.

ESS Provided Regulation and Imbalance Service

An ESS that self-provides Regulation and Frequency Response and Energy Imbalance Services must provide the Company with a real-time load and power factor signal via electronic metering from the Customer load to the location designated by the Company.

SCHEDULE 600 (Continued)

ESS SUPPORT SERVICES

The following charges are applicable to Scheduling and Non-Scheduling ESSs:

(1)	Application Processing Fee	$400.00 with Application
(2)	Registration Renewal Fee	$200.00
(3)	Electronic Data Interchange Testing	$100.00 per man-hour for all hours in excess of 16 hours annually
(4)	Change of Effective Date Request (Rule K)	$ 35.00
(5)	Switching Fee (Rule K) (Applicable for each Enrollment or Drop DASR, not applicable for Rescind or Change DASRs)	$ 20.00
(6)	Customer Change of Location (Rule K)	$7,000.00

ESS BILLING SERVICES

(1)	ESS Consolidated Bill Billing Credit	$ 0.63 per bill
(2)	Late Pay Charge	2.0 % of delinquent balances for products and services purchased under this Tariff.

CUSTOMER INFORMATION

ESS Web Portal Historical Usage Download for Interval Data Charge	$ 20.00 per Service Point Identification (SPID)	**(C)** **(C)**

BILLING AND PAYMENT

Charges incurred for Schedule 600 services are the responsibility of the ESS for which service was provided and are due and payable as described in the Company's General Rules and Regulations.

SCHEDULE 600 (Concluded)

SPECIAL CONDITION

The ESS must purchase firm Transmission Service under the Company's OATT for not less than one-month duration and will be charged at the OATT monthly rate for firm transmission.

PGE SYSTEM LOSSES

The ESS will schedule sufficient Energy to provide for the following losses on the Company's system:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Losses:	4.74%	2.85%	1.45%	**(R)(I)**

SCHEDULE 489
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW more than once within the preceding 13 months and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Service Points (SPs). Each SP must have a Facility Capacity of at least 250 kW. Customers with existing enrolled SPs meeting the 1 MWa criteria above may, in a subsequent enrollment window enroll additional SPs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per SP*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,340.00	$1,890.00	$3,970.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.53	$1.49	$1.49	(R)
Over 4,000 kW	$1.22	$1.18	$1.18	
per kW of monthly On-Peak Demand	$2.61	$2.53	$1.27	(I)
System Usage Charge				
per kWh	(0.014) ¢	(0.015) ¢	(0.015) ¢	(R)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the SP.
*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's SPs under this schedule. **(C)**

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.793 per kW of monthly Demand.

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

SCHEDULE 489 (Continued)

MINIMUM CHARGE **(M)**

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

ON AND OFF PEAK HOURS

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

Subtransmission Delivery Voltage	1.0356
Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

REACTIVE DEMAND CHARGE

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option **(T)** during Enrollment Periods* A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service under the **(T)** minimum Five-Year Option subsequent to Enrollment Period* L must provide not less than **(M)** three years notice to terminate service under this schedule. Such notices will be binding.

(N)

* A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 489 (Continued)

(D)
(M)

SPECIAL CONDITIONS (Continued)

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

8. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and the arrangement and operation of such equipment will be subject to the approval of the Company.

9. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill. **(M)**

SCHEDULE 489 (Concluded) (T)

TERM (M)

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers enrolled for service during Enrollment Periods* A through L must give the Company not less than two years notice to terminate service under this schedule. Customers enrolled for service subsequent to Enrollment Period* L must give the Company not less than three years notice to terminate service under this schedule. Such notices will be binding. (T) (T)

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule. (M)

* A list of Enrollment Periods can be found in Schedule 129. (N)