

Rocky Mountain Power
Exhibit RMP__(JKL-1)
Docket No. 15-035-__
Witness: Jeffrey K. Larsen

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jeffrey K. Larsen

December 2015

2017 Protocol

1 **2017 Protocol**

2 **I. Introduction:**

3 This 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol (the “2017 Protocol”) is the
4 result of general agreement that has been reached between representatives of PacifiCorp (or the
5 “Company”) and certain Commission staff members, consumer advocates and other interested
6 parties from Idaho, Oregon, Utah, and Wyoming (collectively referred to as the “Parties” or
7 individually as a “Party”) regarding issues arising with regards to the 2010 Protocol,
8 PacifiCorp’s status as a multi-jurisdictional utility and future inter-jurisdictional allocation
9 procedures.

10 The 2010 Protocol expires at midnight on December 31, 2016. The Parties have
11 determined that it is in their best interest or the interest of PacifiCorp’s customers to support a
12 new protocol governing inter-jurisdictional allocation procedures. This 2017 Protocol is
13 designed to provide PacifiCorp, State Commissions, and other interested Parties a transitional
14 allocation method while the impacts of the United States Environmental Protection Agency
15 (EPA) rules governing carbon pollution from existing power plants under section 111(d) of the
16 Clean Air Act (111(d)) and other multi-jurisdictional issues are better understood and can be
17 more fully analyzed for their allocation impacts on PacifiCorp and each State. During the term
18 of the 2017 Protocol, PacifiCorp will analyze alternative allocation methods including but not
19 limited to: corporate structure alternatives, divisional allocation methodologies, alternative
20 system allocation methodologies, potential implications of the EPA’s final Rule 111(d), and
21 possible formation of a regional independent system operator. PacifiCorp will present its
22 analyses of these issues to the Multi-State Protocol or MSP Workgroup and discuss them at
23 Commissioner Forums.

1 During the term of the 2017 Protocol, PacifiCorp commits that its generation and
2 transmission system will continue to be planned and operated prudently on an integrated basis
3 designed to achieve a least cost/least risk resource portfolio for PacifiCorp’s customers. This
4 commitment will not prevent PacifiCorp from filing for and requesting State Commission
5 approval to participate in a regional independent system operator organization.

6 The 2017 Protocol describes inter-jurisdictional allocation policies and procedures,
7 which, if applied by each of the States for rate proceedings filed after December 31, 2016, or as
8 otherwise agreed to in Section XIV, are intended to better afford, than would otherwise be the
9 case, PacifiCorp a reasonable opportunity to meet the goal of recovering its prudently incurred
10 cost of service.

11 The apportionment, assignment, or allocation of a particular expense or investment, or
12 allocation of a share of an expense or investment, to a State under the 2017 Protocol is not
13 intended to and will not prejudice the prudence of those costs. Nothing in the 2017 Protocol is
14 intended to abrogate a State Commission’s right and/or obligation to: (1) determine fair, just, and
15 reasonable rates based upon the law of that State and the record established in rate proceedings
16 conducted by that Commission; (2) consider the impact of changes in laws, regulations, or
17 circumstances on inter-jurisdictional allocation policies and procedures when determining fair,
18 just, and reasonable rates; or (3) establish different allocation policies and procedures for
19 purposes of allocation of costs and revenues within that State to different customers or customer
20 classes.

21 Parties who support the 2017 Protocol do so with the intent to continue to achieve
22 equitable resolutions to multi-jurisdictional allocation issues that are in the public interest. A
23 Party’s support of the 2017 Protocol will not, however, in any manner negate the necessary

1 flexibility of the regulatory process to address changed or unforeseen circumstances, including
2 but not limited to changes in laws or regulations, and a Party's support of the 2017 Protocol will
3 not bind or be used against that Party if a Party concludes that the 2017 Protocol no longer
4 produces results that are just, reasonable, and in the public interest, or provides the Company
5 with the opportunity to recover its prudently incurred cost of service. Support of the 2017
6 Protocol will not be deemed to constitute an acknowledgement by any Party of the validity or
7 invalidity of any particular method, theory, or principle of regulation, cost recovery, cost of
8 service, or rate design, and no Party will be deemed to have agreed that any particular method,
9 theory, or principle of regulation, cost recovery, cost of service, or rate design employed or
10 implied in the 2017 Protocol is appropriate for resolving any other issues.

11 The 2017 Protocol describes how the costs and revenues, including wholesale
12 transactions, associated with PacifiCorp's generation, transmission, and distribution systems will
13 be assigned or allocated among its six state jurisdictions.

14 Terms that are capitalized in the 2017 Protocol are either defined in the 2017 Protocol or
15 set forth in Appendix A.

16 A table identifying the allocation factor to be applied to each component of PacifiCorp's
17 revenue requirement calculation is included as Appendix B.

18 The algebraic derivation of each allocation factor is contained in Appendix C.

19 A description and numeric example of how Special Contracts and related discounts will
20 be reflected in rates is set forth in Appendix D.

21 Additional terms specific to each State, including an Equalization Adjustment, are
22 reflected in Section XIV.

1 **II. Effective Period and Expiration:**

2 The Parties agree to support Commission adoption or use of the 2017 Protocol in all
3 PacifiCorp rate proceedings filed after December 31, 2016, or as otherwise agreed to by Parties
4 in Section XIV, up to and including December 31, 2018.

5 The 2017 Protocol will expire December 31, 2018, unless all State Commissions that
6 approved the 2017 Protocol determine, by no later than March 31, 2017, that the term of the
7 2017 Protocol will be extended by an optional one-year extension through December 31, 2019.
8 In determining whether the 2017 Protocol should or should not be extended, each State
9 Commission can take such steps or provide such processes for public input as that Commission
10 determines to be necessary or appropriate under applicable State laws.

11 A Commissioner Forum will be held annually, beginning in January 2017, to discuss
12 inter-jurisdictional allocation issues and whether the 2017 Protocol should be extended for an
13 additional one-year term, as described above.

14 **III. Classification of Resources:**

15 All Resource Fixed Costs, Wholesale Contracts, and Short-term Firm Purchases and Firm
16 Sales will be classified as 75 percent Demand-Related and 25 percent Energy-Related. All Non-
17 Firm Purchases and Sales will be classified as 100 percent Energy-Related.

18 **IV. Allocation of Resource Costs and Wholesale Revenues:**

19 Resources will be assigned to one of two categories for inter-jurisdictional allocation
20 purposes: State Resources or System Resources. A complete description of allocation factors to
21 be used is set forth in Appendix B.

22 There are four types of State Resources. The remaining types of Resources are System
23 Resources, which constitute the substantial majority of PacifiCorp's Resources. Benefits and

1 costs associated with each category and type of Resource will be assigned or allocated to
2 Jurisdictions on the following basis:

3 **A. State Resources**

4 Benefits and costs associated with the four types of State Resources will be
5 assigned as follows:

- 6 1. Demand-Side Management (“DSM”) Programs: Costs associated with
7 DSM Programs, including Class 1 DSM Programs, will be assigned on a
8 situs basis to the Jurisdiction in which the investment is made. Benefits
9 from these programs, in the form of reduced consumption and contribution
10 to Coincident Peak, will be reflected in the Load-Based Dynamic
11 Allocation Factors.
- 12 2. Portfolio Standards: Costs associated with Resources acquired to comply
13 with a Jurisdiction’s Portfolio Standard adopted, either through legislative
14 enactment or a State’s Commission, the portion of which exceeds the costs
15 PacifiCorp would have otherwise incurred, will be assigned on a situs
16 basis to the Jurisdiction adopting the Portfolio Standard.
- 17 3. Qualifying Facility Contracts: Costs associated with Qualifying Facility
18 Contracts, the portion of which exceeds the costs PacifiCorp would have
19 otherwise incurred acquiring Comparable Resources will be assigned on a
20 situs basis to the Jurisdiction that approved the contract.
- 21 4. Jurisdiction-Specific Initiatives: Costs and benefits associated with
22 Resources acquired in accordance with a Jurisdiction-specific initiative
23 will be assigned on a situs basis to the Jurisdiction adopting the initiative.

1 This includes, but is not limited to, the costs and benefits of incentive
2 programs, net-metering tariffs, feed-in tariffs, capacity standard programs,
3 solar subscription programs, electric vehicle programs, and the acquisition
4 of renewable energy certificates.

5 **B. System Resources**

6 All Resources that are not State Resources are System Resources and will be
7 allocated as follows:

- 8 1. Generally, all Fixed Costs associated with System Resources and all costs
9 incurred under Wholesale Contracts will be allocated based upon the
10 System Generation (“SG”) Factor.
- 11 2. Generally, all Variable Costs associated with System Resources will be
12 allocated based upon the System Energy (“SE”) Factor.
- 13 3. Revenues received by PacifiCorp under Wholesale Contracts will be
14 allocated based upon the SG Factor.

15 **C. Equalization Adjustment**

16 The 2017 Protocol includes an Equalization Adjustment to be applied to each
17 State’s revenue requirement, as summarized in Section XIV, for purposes of
18 ratemaking proceedings filed prior to the expiration of the 2017 Protocol. The
19 Equalization Adjustment recognizes differences among the States in the 2010
20 Protocol Agreement implemented in each State and the respective treatment of the
21 embedded cost differential (“ECD”) adjustment – i.e. Baseline ECD, Dynamic
22 ECD, or no ECD. The 2017 Protocol with the Equalization Adjustment is

1 designed to allow PacifiCorp the opportunity to equitably allocate revenue
2 requirement components in rate recovery proceedings in the States.

3 **V. Re-functionalization and Allocation of Transmission Costs and Revenues**

4 Before filing any request to approve a reclassification of facilities as transmission or
5 distribution with FERC, PacifiCorp will submit filings seeking review and authorization of any
6 such reclassification with the State Commissions. The cost responsibility for any assets
7 reclassified under FERC policy will be assigned or allocated consistent with other assets in the
8 relevant function.

9 Costs associated with transmission assets, and firm wheeling expenses and revenues, will
10 be classified as 75 percent Demand-Related, 25 percent Energy-Related and allocated based
11 upon the SG Factor. Non-firm wheeling expenses and revenues will be allocated based upon the
12 SE Factor. In the event that PacifiCorp joins a regional independent system operator, the
13 allocation of transmission costs and revenues may be reevaluated and revised as provided for in
14 Section XIII.

15 **VI. Assignment of Distribution Costs:**

16 All distribution-related expenses and investment that can be directly assigned will be
17 directly assigned to the State where they are located. Those costs that cannot be directly
18 assigned will be allocated consistent with the factors set forth in Appendix B.

19 **VII. Allocation of Administrative and General Costs:**

20 Administrative and General Costs, General Plant costs, and Intangible Plant costs will be
21 allocated consistent with the factors set forth in Appendix B.

22 **VIII. Allocation of Special Contracts:**

23 Revenues associated with Special Contracts will be included in State revenues, and loads

1 of Special Contract customers will be included in Load-Based Dynamic Allocation Factors as
2 appropriate (see Appendix D). Special Contracts may or may not include Customer Ancillary
3 Service Contract attributes. Load curtailments and buy-through arrangements will be handled as
4 appropriate (see Appendix D).

5 **IX. Allocation of Gain or Loss from Sale of Resources or Transmission Assets:**

6 Any loss or gain from the sale of a Company-owned Resource or transmission asset will
7 be allocated based upon the allocation factor used to allocate the Fixed Costs of the Resource or
8 the transmission asset at the time of its sale. Each Commission will determine the appropriate
9 allocation of loss or gain allocated to that Jurisdiction as between customers and PacifiCorp
10 shareholders.

11 **X. State Programs Regarding Access to Alternative Electricity Suppliers:**

12 **A. Treatment of Oregon Direct Access Programs:**

13 This Section describes treatment of loads lost to Oregon Direct Access Programs during
14 the term of the 2017 Protocol.

15 1. Customers electing PacifiCorp's one- and three-year Oregon Direct
16 Access Programs – The load of customers electing to be served on PacifiCorp's one- and
17 three-year Oregon Direct Access Programs will be included in the Load-Based Dynamic
18 Allocation Factors for all Resources, and the transition cost payments from these
19 customers will be situs assigned to Oregon.

20 2. Customers electing PacifiCorp's five year opt-out program under the
21 Oregon Direct Access Program – The treatment will be consistent with Order No. 15-
22 060, as clarified through Order No. 15-067, of the Oregon Public Utility Commission in
23 Docket UE 267, and Oregon Schedule 296, which allow Oregon Direct Access Program

1 Customers to permanently opt-out of cost-of-service rates after payment of ten years of
2 transition costs in Oregon. During the ten-year period for which Oregon Direct Access
3 Customers are paying transition costs, the Oregon Direct Access Customers' loads will
4 be included in Load-Based Dynamic Allocation Factors, and the transition cost payments
5 from these customers will be situs-assigned to Oregon. At the end of the 10-year period
6 covered by the transition cost payments, the loads of the Oregon Direct Access
7 Customers will be excluded from Load-Based Dynamic Allocation Factors. Thereafter,
8 if an Oregon Direct Access Customer elects to return to Oregon cost-of-service rates by
9 providing four-years notice under Schedule 267, its load will be included in Load-Based
10 Dynamic Allocation Factors at the time the customer returns to Oregon cost of service
11 rates.

12 3. To the extent Oregon adopts new laws or regulations regarding Oregon
13 Direct Access Programs, Oregon's treatment of loads lost to Oregon Direct Access
14 Programs may be re-determined in a manner consistent with the new laws and
15 regulations. In the event Oregon adopts such new laws or regulations, the Company will
16 inform the State Commissions and the Parties of the same.

17 **B. Utah Eligible Customer Program:**

18 If, pursuant to Utah Code Annotated Section 54-3-32, an eligible customer in Utah
19 transfers service to a non-utility energy supplier, the Public Service Commission of Utah will
20 make determinations under Utah law as contemplated therein. The Company will inform the
21 State Commissions and the Parties of the Public Service Commission of Utah's determinations.

22 **C. Other State Actions:**

23 In the event any State adopts laws or regulations governing customer access to alternative

1 electricity suppliers, the Company will inform the State Commissions and the Parties of the
2 same.

3 **XI. Loss or Increase in Load:**

4 Any loss or increase in retail load occurring as a result of condemnation or
5 municipalization, sale, or acquisition of new service territory that involves less than five percent
6 of system load, realignment of service territories, changes in economic conditions, or gain or loss
7 of large customers will be reflected in changes in the Load-Based Dynamic Allocation Factors.
8 The allocation of costs and benefits arising from merger, sale, or acquisition transactions
9 proposed by the Company involving more than five percent of system load will be considered on
10 a case-by-case basis in the course of Commission approval proceedings.

11 **XII. Commission Regulation of Resources:**

12 PacifiCorp will plan and acquire new Resources on a system-wide least-cost, least-risk
13 basis. Prudently incurred investments in Resources will be reflected in rates consistent with the
14 laws and regulations in each State, as approved by individual State Commissions.

15 **XIII. Interpretation and Governance:**

16 **A. Issues of Interpretation**

17 If questions of interpretation of the 2017 Protocol arise during rate proceedings, audits of
18 results of PacifiCorp's operations, or both, Parties will attempt, consistent with their legal
19 obligations, to resolve them in good faith in light of the language of the 2017 Protocol and the
20 intent of the Parties.

21 **B. Commissioner Forum**

22 A Commissioner Forum will be held annually beginning January 2017 to discuss the
23 2017 Protocol and other inter-jurisdictional allocation issues that may arise. All seated

1 commissioners from each Jurisdiction will be invited to participate in all Commissioner Forums.

2 Each Commissioner Forum will be a public meeting and all interested parties will be
3 allowed to attend. Prior to attending a Commissioner Forum, each Commission can take such
4 steps and provide such process for public input as the Commission determines to be necessary or
5 appropriate under applicable State laws.

6 At the Commissioner Forum, commissioners will be invited to discuss and may make
7 recommendations regarding extension of the 2017 Protocol and other inter-jurisdictional
8 allocation issues that may arise.

9 **C. MSP Workgroup**

10 The MSP Workgroup will be open to any utility regulatory agency, customer, and other
11 person or entity potentially affected by inter-jurisdictional allocation procedures that expresses
12 an interest in participating. The MSP Workgroup may create sub-committees to investigate,
13 evaluate, or make recommendations as to specified issues. MSP Workgroup meetings may be
14 held in person or by telephone.

15 The Company will promptly convene one or more MSP Workgroup meetings: (i) to
16 discuss the possibility of a new inter-jurisdictional allocation agreement if any Commission
17 indicates that the 2017 Protocol should not be extended pursuant to Section II or as a result of
18 new developments pursuant to Section X, (ii) to discuss an inter-jurisdictional allocation issue
19 identified by any Commission, or (iii) to discuss any other inter-jurisdictional allocation issue
20 raised by any interested stakeholders. MSP Parties will work in good faith to achieve resolution
21 of any issues brought before the MSP Workgroup.

22 Before each annual Commissioner Forum, PacifiCorp will convene an MSP Workgroup
23 meeting for the purpose of discussing and monitoring emerging inter-jurisdictional allocation

1 issues facing PacifiCorp and its customers, the status and implications of Rule 111(d), or the
2 development of a regional independent system operator, in order to inform discussions at the
3 Commissioner Forum. PacifiCorp will provide reasonable staffing and resources to provide
4 minutes of any MSP Workgroup meeting, coordinate MSP Workgroup activities and conduct
5 studies and analysis as agreed to by the MSP Workgroup, and as suggested by the Commissioner
6 Forum.

7 **D. Proposals for New Inter-Jurisdictional Allocation Procedures**

8 Proposals for new inter-jurisdictional allocation procedures, including any changes to the
9 2017 Protocol, ranging from minor modifications to major modifications, may be submitted by
10 any Party or any Commission utilizing the 2017 Protocol. Proposals shall be provided to the
11 Company for the purpose of circulating the proposals to the other Parties and State Commissions
12 and initiating discussions to attempt to address and resolve specific concerns.

13 If any Party intends to propose a new inter-jurisdictional allocation procedure, the Party
14 will attempt, consistent with their legal obligations, to: (1) bring that proposal to the
15 Commissioner Forum or the MSP Workgroup and (2) resolve the proposal in good faith.

16 A Party's initial support or acceptance of the 2017 Protocol will not bind or be used
17 against that Party if unforeseen or changed circumstances, including new developments pursuant
18 to Section X, cause that Party to conclude that the 2017 Protocol no longer produces just and
19 reasonable results, reasonable cost recovery for the Company, or is not in the public interest.
20 Before a Party asks a Commission to deviate from the terms of the 2017 Protocol, the Parties,
21 will be invited by the Company to enter into a discussion, or series of discussions, to attempt to
22 address and resolve their concerns at MSP Workgroup meetings and/or a Commissioner Forum,
23 consistent with any applicable legal obligations.

1 **E. Interdependency among Commission Approvals**

2 The 2017 Protocol has been developed by the Parties as an integrated, interdependent,
 3 organic whole. Support by any Party or Commission of the 2017 Protocol is expressly
 4 conditioned upon similar support of the 2017 Protocol by the Commissions of at least the States
 5 of Idaho, Oregon, Utah, and Wyoming, without material alteration. If a Commission materially
 6 deletes, alters, or conditions approval of the 2017 Protocol, Parties shall promptly meet and
 7 discuss the implications of the material alteration, and will have the opportunity to accept or
 8 reject continued support of the 2017 Protocol in light of such action.

9 **XIV. Additional State-Specific Terms:**

10 For the period that the 2017 Protocol remains in effect, a 2017 Protocol Adjustment will
 11 be added to each State’s annual revenue requirement. For California, Idaho, Utah, and Wyoming,
 12 the 2017 Protocol Adjustment is the sum of the Baseline ECD and the Equalization Adjustment.
 13 For Oregon, the 2017 Protocol Adjustment is the sum of the Baseline ECD, which is dynamic
 14 with the parameters described in paragraph three below, and the Equalization Adjustment. The
 15 Parties agree to an annual Equalization Adjustment of \$9.074 million, with specific State-by-
 16 State 2017 Protocol Adjustment impacts as summarized in this table:

Revenue Requirement (\$000)	Total					
	Company	California	Oregon	Utah	Idaho	Wyoming
2017 Protocol Baseline ECD **	(9,578)	(324)	(8,238) *	0	836	(1,851)
2017 Protocol Equalization Adjustment	9,074	324	2,600	4,400	150	1,600
2017 Protocol Adjustment		(0)	(5,638)	4,400	986	(251)

* Oregon's 2017 Protocol Baseline ECD is dynamic and will change over time with the parameters described in paragraph 3 below. For the other states, the 2017 Protocol Baseline ECD is fixed and does not change over time.
 ** 2017 Protocol Baseline ECD amounts shown in the table for California, Oregon, and Wyoming are based on the test year data as filed by the Company in the 2015 Wyoming general rate case (Docket 20000-469-ER-15) on March 3, 2015. The amount for Idaho's 2017 Protocol Baseline ECD is its 2010 Protocol Fixed ECD amount. Utah's 2017 Protocol Baseline ECD is zero based on its 2010 Protocol agreement.

1 State specific implementation is summarized below:

- 2 1. California’s 2017 Protocol Adjustment is zero.
- 3 2. The Idaho Parties and PacifiCorp agree to an annual Idaho 2017 Protocol Adjustment of
4 \$0.986 million to be added to Idaho’s 2017 Protocol revenue requirement. Idaho’s
5 Equalization Adjustment is \$0.150 million. The Idaho 2017 Protocol Adjustment shall be
6 included in base rates through a general rate case beginning January 1, 2018, or to the
7 extent that a case is filed so the rate effective date is later than that date, the Equalization
8 Adjustment shall be deferred on a monthly basis (\$12,500 per month) from January 1,
9 2018, forward as a regulatory asset until the rate effective date of PacifiCorp’s next Idaho
10 general rate case at which time (1) the deferred costs and (2) the ongoing impact of
11 Idaho’s 2017 Protocol Adjustment shall be included in rates.
- 12 3. The Public Utility Commission of Oregon Staff (“Commission Staff”), the Citizens’
13 Utility Board of Oregon (“CUB”), and PacifiCorp (“Oregon Parties”), agree to an Oregon
14 Equalization Adjustment of \$2.6 million. The Oregon Parties agree that Oregon’s
15 Equalization Adjustment of \$2.6 million annually (or \$216,667 monthly) be deferred
16 from January 1, 2017, until the 2017 Protocol Equalization Adjustment is reflected in
17 base rates through the Company’s next general rate case. The Oregon Parties agree that
18 the 2017 Protocol Equalization Adjustment deferral will be reflected as a debit (reduction
19 to the existing credit balance to be returned to customers) in the Open Access
20 Transmission Tariff (“OATT”) revenue deferral account originally established through
21 docket UE 246.¹ The Parties agree that the Company will file a new tariff to return to

¹ As a result of the stipulation and Commission Order No. 12-493 in docket UE-246, the Company filed for, and the Commission approved the Company’s application to defer incremental OATT revenues from January 1, 2013, until
(Continued...)

1 Oregon customers the balance of the OATT revenue deferral, net of the 2017 Protocol
2 Equalization Adjustment deferral, within 60 days of an Oregon Commission order
3 approving of the 2017 Protocol. The Company commits to continued evaluation of
4 alternative inter-jurisdictional allocation methods, including consideration of corporate
5 structure alternatives, divisional allocation methodologies, and potential implications of
6 the Environmental Protection Agency's final Rule 111(d), and possible formation of a
7 regional independent system operator. The Company will distribute or present the results
8 of its analysis, based on information available, no later than March 31, 2017. If
9 PacifiCorp does not distribute or present the results of its analysis on or before March 31,
10 2017, for each month the analysis is not provided after that date \$216,667 will be credited
11 to the OATT revenue deferral balance unless otherwise waived by the Commission for
12 good cause. The Company agrees that during the effective period of this agreement
13 regarding the 2017 Protocol, the Company will not have any pending general rate case
14 that requests rates effective before January 1, 2018. Oregon Parties may file for deferrals
15 during the general rate case stay-out period, but such filings will be subject to the
16 Commission's guidelines for deferrals established in docket UM 1147, unless otherwise
17 authorized by the Commission. This provision will not alter the operation or application
18 of existing or new rate adjustment mechanisms authorized by the Commission, including
19 but not limited to PacifiCorp's Transition Adjustment Mechanism, the Power Cost
20 Adjustment Mechanism, and the Renewable Adjustment Clause. The Oregon Parties
21 agree that for the duration of the 2017 Protocol, Oregon's results of operations reports

(...continued)

these revenues are reflected in base rates. Commission Order Nos. 13-045, 14-023, and 15-020 approved the Company's applications to defer these incremental revenues for 2013, 2014, and 2015, respectively.

1 and general rate case filings will reflect a Dynamic ECD calculated consistent with the
2 2010 Protocol inter-jurisdictional allocation methodology with the parameters as
3 described below:

- 4 ▪ For the Company's first Oregon general rate case filing under the 2017 Protocol
5 (which will be effective no earlier than January 1, 2018), the Dynamic ECD value for
6 Oregon will be set at a level no less than \$8.238m (the baseline value of Oregon's
7 ECD used to negotiate each State's contribution to the 2017 Protocol Equalization
8 Adjustment), and will be capped at \$10.5 million; and
- 9 ▪ If the 2017 Protocol is extended to 2019, and the Company files a second Oregon
10 general rate case using the 2017 Protocol, the Dynamic ECD in that general rate case
11 filing will be set at a level no less than \$8.238m and will be capped at \$11.0 million.
12 The Dynamic ECD provisions apply only to the 2017 Protocol as an integrated
13 agreement and do not in any way limit or compromise any party's ability to argue for
14 a different ECD or hydro endowment calculation in any future inter-jurisdictional
15 allocation methodologies.

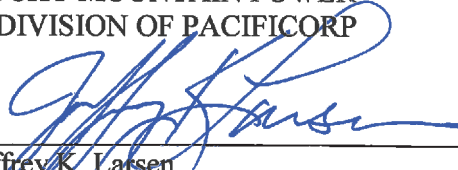
16 The Oregon Parties agree that unless there is formal action by the Public Utility
17 Commission of Oregon to adopt an alternate allocation methodology by January 1, 2019,
18 or unless the 2017 Protocol is extended through 2019 under the terms of the 2017
19 Protocol, PacifiCorp will use the Revised Protocol allocation method for general rate case
20 filings in Oregon after January 1, 2019. The Oregon Parties have negotiated this
21 settlement as an integrated agreement. If the Public Utility Commission of Oregon
22 rejects all or any material portion of this agreement or imposes additional material
23 conditions in approving this agreement, any of the Oregon Parties are entitled to

1 withdraw from the settlement. If the Public Utility Commission of Oregon rejects the
2 2017 Protocol, this agreement terminates upon the date of the order rejecting the 2017
3 Protocol.

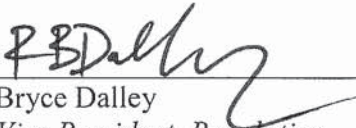
4 4. The Utah Parties and PacifiCorp agree to an annual Utah Equalization Adjustment of
5 \$4.4 million and a 2017 Protocol Adjustment of the same amount. The Company agrees
6 that it will not file a Utah general rate case or major plant addition case prior to May 1,
7 2016, and new rates will not be effective prior to January 1, 2017. Utah's 2017 Protocol
8 Adjustment shall be included in base rates through a general rate case with rates effective
9 beginning on or after January 1, 2017. To the extent that a Utah general rate case or
10 major plant addition case is filed with a rate effective date later than that date, Utah's
11 Equalization Adjustment shall be deferred on a monthly basis, (\$366,667 per month),
12 from January 1, 2017, forward as a regulatory asset until the rate effective date of
13 PacifiCorp's next Utah general rate case at which time (1) the deferred costs and (2) the
14 ongoing impact of Utah's 2017 Protocol Adjustment shall be included in rates. The
15 deferred cost amortization period will be determined in the first case that the deferral of
16 the Utah Equalization Adjustment is proposed for inclusion in rates.

17 5. The Wyoming Parties and PacifiCorp agree to an annual credit for Wyoming's 2017
18 Protocol Adjustment of \$0.251 million to be netted against Wyoming's 2017 Protocol
19 revenue requirement. If the Company does not file a general rate case prior to January 1,
20 2017, Wyoming's Equalization Adjustment of \$1.6 million annually shall be deferred, as
21 a regulatory asset, on a monthly basis, (\$133,333 per month), beginning July 1, 2017,
22 until the rate effective date of PacifiCorp's next Wyoming general rate case, at which
23 time (1) the deferred costs and (2) Wyoming's ongoing impact of the 2017 Protocol


1 Adjustment shall be included in rates. The deferred cost amortization period will be
 2 determined in the first case that the deferral of the Wyoming Equalization Adjustment is
 3 proposed for inclusion in rates. If a Wyoming general rate case is filed prior to January 1,
 4 2017, then the Wyoming Equalization Adjustment shall not be deferred and will only be
 5 included in base rates from the rate effective date of a general rate case filing occurring
 6 on or after January 1, 2017. The Wyoming Parties also agree that the Company no longer
 7 is required to file Revised Protocol results (Tab 9) as part of its results of operations
 8 reports effective January 1, 2017.

<p>ROCKY MOUNTAIN POWER A DIVISION OF PACIFICORP</p>  <p>Jeffrey K. Larsen <i>Vice President, Regulation</i></p>	<p>PACIFIC POWER A DIVISION OF PACIFICORP</p> <p>Bryce Dalley <i>Vice President, Regulation</i></p>
<p>IDAHO PUBLIC UTILITIES COMMISSION STAFF</p> <p>Terri Carlock <i>Deputy Administrator of Idaho Public Utilities Commission Staff</i></p>	<p>OREGON PUBLIC UTILITY COMMISSION</p> <p>Jason W. Jones <i>Counsel for Oregon Public Utility Commission Staff</i></p>
<p>CITIZENS UTILITY BOARD OF OREGON</p> <p>Bob Jenks <i>Executive Director of Citizens Utility Board of Oregon</i></p>	<p>UTAH DIVISION OF PUBLIC UTILITIES</p> <p>Chris Parker <i>Director of Utah Division of Public Utilities</i></p>
<p>UTAH OFFICE OF CONSUMER SERVICES</p> <p>Michelle Beck <i>Director of Utah Office of Consumer Services</i></p>	<p>UTAH ASSOCIATION OF ENERGY USERS</p> <p>Gary Dodge <i>Attorney for Utah Association of Energy Users</i></p>

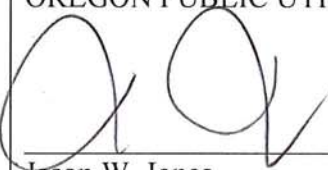
1 Adjustment shall be included in rates. The deferred cost amortization period will be
 2 determined in the first case that the deferral of the Wyoming Equalization Adjustment is
 3 proposed for inclusion in rates. If a Wyoming general rate case is filed prior to January 1,
 4 2017, then the Wyoming Equalization Adjustment shall not be deferred and will only be
 5 included in base rates from the rate effective date of a general rate case filing occurring
 6 on or after January 1, 2017. The Wyoming Parties also agree that the Company no longer
 7 is required to file Revised Protocol results (Tab 9) as part of its results of operations
 8 reports effective January 1, 2017.

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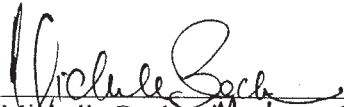
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<p>WYOMING PUBLIC SERVICE COMMISSION STAFF</p> <hr/> <p>Darrell Zlomke <i>Commission Administrator for Wyoming Public Service Commission</i></p>	

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WYOMING PUBLIC SERVICE COMMISSION STAFF  * <hr/> Darrell Zlonke <i>Commission Administrator for Wyoming Public Service Commission</i>	

*This signature does not represent the position of any Wyoming Public Service Commission Commissioner or any Commission staff not directly involved with the negotiations leading to this Settlement Agreement (the “2017 Protocol”).

2017 Protocol – Appendix A Defined Terms

2017 Protocol - Appendix A

Defined Terms

For purposes of this 2017 Protocol, these terms will have the following meanings:

“2010 Protocol” means the PacifiCorp inter-jurisdictional allocation method that was approved by the Idaho, Oregon, Utah, and Wyoming Commissions in 2012 to apply to all PacifiCorp rate proceedings filed after each commission’s approval and before December 31, 2016.

“2017 Protocol Adjustment” means the result of netting the 2016 Baseline ECD against the \$9.074 million Equalization Adjustment for each State’s revenue requirement as specified in Section XIV of the 2017 Protocol. The 2017 Protocol Adjustment is intended to cause PacifiCorp and each of the States participating in the 2017 Protocol to bear a reasonable proportion of the allocation shortfall resulting from differences in the 2010 Protocol inter-jurisdictional allocation procedures utilized by such States.

“Administrative and General Costs” means costs included in FERC accounts 920 through 935.

“Class 1 DSM Programs” means DSM Programs designed to reduce peak loads.

“Coincident Peak” means the hour each month that the combined demand of all PacifiCorp retail customers is greatest. In States using a historic test period Coincident Peak is based upon actual, metered load data adjusted for normalized weather conditions and in States using future test periods Coincident Peak is based upon forecasted normalized loads, in both cases adjusted as appropriate for interruptibility of Special Contracts.

“Commission” means a utility regulatory commission in a Jurisdiction.

“Commissioner Forum” means an annual public meeting held in January of each year beginning in 2017 to which all seated commissioners from each Jurisdiction will be invited to discuss the 2017 Protocol and other inter-jurisdictional allocation issues.

“Company” means PacifiCorp.

“Comparable Resource” means Resources with similar capacity factors, start-up costs, and other output and operating characteristics.

“Customer Ancillary Service Contracts” means contracts between the Company and a retail customer pursuant to which the Company pays the customer for the right to curtail service so as to lower the costs of operating the Company’s system.

“Demand-Related” means capital and other Fixed Costs or revenues incurred or received by the Company in order to be prepared to meet the maximum demand imposed upon its system.

“Demand-Side Management Programs” or “DSM Programs” means programs intended to reduce electricity use through activities or programs that promote electric energy efficiency or conservation, more efficient management of electric energy loads, or reductions in peak demand.

“Embedded Cost Differential” or “ECD” means the sum of (1) PacifiCorp’s total production costs of Pre-2005 Resources expressed in dollars per megawatt-hour compared to the Hydro-Electric Resources forecasted production costs expressed in dollars per megawatt-hour multiplied by the Hydro-Electric Resources megawatt-hours of production, and (2) the differential between the Pre-2005 Resources dollars per megawatt-hour compared to Mid-Columbia Contracts forecasted costs in dollars per megawatt-hour multiplied by the Mid-Columbia Contracts megawatt-hours.

- **“Baseline ECD”** means the amount of the ECD for each State to be used in the determination of the 2017 Protocol Adjustment. For the states of California, and Wyoming, their Baseline ECD amounts are based on the test year data, as filed by the Company in the 2015 Wyoming General Rate Case (Docket 20000-469-ER-15, Exhibit SRM-2), on March 3, 2015. Idaho’s Baseline ECD is its 2010 Protocol Fixed ECD amount. Utah’s 2017 Protocol Baseline ECD is zero based on its 2010 Protocol agreement. For Oregon, the Baseline ECD is dynamic with the parameters described in paragraph three of Section XIV.

- “Dynamic ECD” means the ECD components are updated to the test period utilized in the filing.

“**Energy-Related**” means costs and revenues, such as fuel costs and transmission costs, or sales revenues that vary with the amount of energy delivered by the Company to its customers during any hour plus any portion of Fixed Costs that have been deemed to have been incurred or received by the Company in order to meet its energy requirements.

“**Equalization Adjustment**” means a fixed dollar adjustment to be applied to each State’s revenue requirement as reflected in Section XIV of the 2017 Protocol intended to cause PacifiCorp and each of the States participating in the 2017 Protocol to bear a reasonable proportion of the allocation shortfall resulting from differences in current inter-jurisdictional allocation procedures utilized by such states.

“**FERC**” means the Federal Energy Regulatory Commission.

“**Fixed Costs**” means costs incurred by the Company that do not vary with the amount of energy delivered by the Company to its customers during any hour.

“**General Plant**” means capital investment included in FERC accounts 389 through 399.

“**Hydro-Electric Resources**” means Company-owned hydro-electric plants located in Oregon, Washington or California.

“**Intangible Plant**” means capital investment included in FERC accounts 301 through 303.

“**Jurisdiction**” means any one of the six states where the Company provides retail service.

“**Load-Based Dynamic Allocation Factor**” means an allocation factor that is calculated using States’ monthly energy usage and/or States’ contribution to monthly system Coincident Peak.

“**Mid-Columbia Contracts**” means the various power sales agreements between PacifiCorp and Public Utility District No. 2 of Grant County, PacifiCorp and Douglas County Public Utility District, and PacifiCorp and Chelan County Public Utility District, specifically: the

Power Sales Contract with Public Utility District No. 2 of Grant County dated May 22, 1956; the Power Sales Contract with Public Utility District No. 2 of Grant County dated June 22, 1959; the Priest Rapids Project Product Sales Contract with Public Utility District No. 2 of Grant County dated December 31, 2001; the Additional Products Sales Agreement with Public Utility District No. 2 of Grant County dated December 31, 2001; the Priest Rapids Project Reasonable Portion Power Sales Contract with Public Utility District No. 2 of Grant County dated December 31, 2001; the Power Sales Contract with Douglas County Public Utility District dated September 18, 1963; the Power Sales Contract with Chelan County Public Utility District dated November 14, 1957 and all successor contracts thereto.

“Multi-State Protocol Workgroup” or “MSP Workgroup” means a group consisting of utility regulatory agencies, customers and others potentially affected by inter-jurisdictional allocation procedures who desire to participate in a cooperative workgroup context and who agree to comply with reasonable confidentiality and other procedures adopted by the MSP Workgroup.

“Non-Firm Purchases and Sales” means transactions at wholesale that are not Wholesale Contracts or Short-Term Purchases and Sales.

“Oregon Direct Access Customers” means Oregon retail electricity consumers that procure electricity from a supplier other than PacifiCorp under an Oregon Direct Access Program.

“Oregon Direct Access Program” means Oregon laws, regulations and orders that permit PacifiCorp’s Oregon retail consumers to purchase electricity directly from a supplier other than PacifiCorp.

“Portfolio Standard” means a law or regulation that requires PacifiCorp to acquire: (a) a particular type of Resource, (b) a particular quantity of Resources, (c) Resources in a prescribed manner or (d) Resources located in a particular geographic area.

“Pre-2005 Resources” means Resources (other than Mid-Columbia Contracts and Hydro-Electric Resources) that were part of the Company’s integrated system prior to January 1, 2005.

“Qualifying Facility Contracts” means contracts to purchase the output of small power production or cogeneration facilities developed under the Public Utility Regulatory Policies Act of 1978 (PURPA) and related State laws and regulations.

“Resources” means Company-owned and leased generating plants and mines, Wholesale Contracts, Short-Term Firm Purchases and Firm Sales and Non-firm Purchases and Sales.

“System Energy Factor” or “SE Factor” - refer to Appendix B.

“System Generation Factor” or “SG Factor” - refer to Appendix B.

“Short-Term Firm Purchases and Firm Sales” means physical or financial contracts pursuant to which PacifiCorp purchases, sells or exchanges firm power at wholesale and Customer Ancillary Service Contracts that are less than one year in duration.

“Special Contract” means a contract entered between PacifiCorp and one of its retail customers with prices, terms, and conditions based on the specific circumstances of that customer. Special Contracts may account for Customer Ancillary Services Contract attributes.

“State” means any state that is utilizing the 2017 Protocol for inter-jurisdictional allocation purposes, and is intended to include the states of California, Idaho, Oregon, Utah, or Wyoming.

“State Resources” means Resources whose costs are assigned to a single jurisdiction to accommodate jurisdiction-specific policy preferences.

“System Resources” means Resources that are not State Resources and whose associated costs and revenues are allocated among all States on a dynamic basis.

“Variable Costs” means costs incurred by the Company that vary with the amount of energy delivered by the Company to its customers during any hour.

“Wholesale Contracts” means physical or financial contracts pursuant to which PacifiCorp purchases, sells or exchanges firm long-term power and/or energy at wholesale or Customer Ancillary Service Contracts as discussed in Appendix D.

2017 Protocol – Appendix B

Allocation Factor Applied to each Component of Revenue Requirement

2017 Protocol - Appendix B
Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
Sales to Ultimate Customers		
440	Residential Sales Direct assigned - Jurisdiction	S
442	Commercial & Industrial Sales Direct assigned - Jurisdiction	S
444	Public Street & Highway Lighting Direct assigned - Jurisdiction	S
445	Other Sales to Public Authority Direct assigned - Jurisdiction	S
448	Interdepartmental Direct assigned - Jurisdiction	S
447	Sales for Resale Direct assigned - Jurisdiction Non-Firm Firm	S SE SG
449	Provision for Rate Refund Direct assigned - Jurisdiction	S SG
Other Electric Operating Revenues		
450	Forfeited Discounts & Interest Direct assigned - Jurisdiction	S
451	Misc Electric Revenue Direct assigned - Jurisdiction Other - Common	S SO
453	Water Sales Common	SG
454	Rent of Electric Property Direct assigned - Jurisdiction Common Other - Common	S SG SO
456	Other Electric Revenue Direct assigned - Jurisdiction Wheeling Non-firm, Other Common Wheeling - Firm, Other Customer Related	S SE SO SG CN
Miscellaneous Revenues		
41160	Gain on Sale of Utility Plant - CR Direct assigned - Jurisdiction Production, Transmission General Office	S SG SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
41170	Loss on Sale of Utility Plant	
	Direct assigned - Jurisdiction	S
	Production, Transmission	SG
	General Office	SO
4118	Gain from Emission Allowances	
	SO2 Emission Allowance sales	SE
41181	Gain from Disposition of NOX Credits	
	NOX Emission Allowance sales	SE
421	(Gain) / Loss on Sale of Utility Plant	
	Direct assigned - Jurisdiction	S
	Production, Transmission	SG
	General Office	SO
	Customer Related	CN
Miscellaneous Expenses		
4311	Interest on Customer Deposits	
	Customer Service Deposits	CN
	Direct assigned - Jurisdiction	S
Steam Power Generation		
500, 502, 504-514	Operation Supervision & Engineering	
	Remaining Steam Plants	SG
501	Fuel Related	
	Remaining steam plants	SE
503	Steam From Other Sources	
	Steam Royalties	SE
Nuclear Power Generation		
517 - 532	Nuclear Power O&M	
	Nuclear Plants	SG
Hydraulic Power Generation		
535 - 545	Hydro O&M	
	Pacific Hydro	SG
	East Hydro	SG
Other Power Generation		
546, 548-554	Operation Super & Engineering	
	Other Production Plant	SG
547	Fuel	
	Other Fuel Expense	SE
Other Power Supply		
555	Purchased Power	
	Direct assigned - Jurisdiction	S
	Firm	SG
	Non-firm	SE

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
556	System Control & Load Dispatch		
		Other Expenses	SG
557	Other Expenses		
		Direct assigned - Jurisdiction	S
		Other Expenses	SG
		Cholla Transaction	SGCT
TRANSMISSION EXPENSE			
560-564, 566-573	Transmission O&M		
		Transmission Plant	SG
565	Transmission of Electricity by Others		
		Firm Wheeling	SG
		Non-Firm Wheeling	SE
DISTRIBUTION EXPENSE			
580 - 598	Distribution O&M		
		Direct assigned - Jurisdiction	S
		Other Distribution	SNPD
CUSTOMER ACCOUNTS EXPENSE			
901 - 905	Customer Accounts O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
CUSTOMER SERVICE EXPENSE			
907 - 910	Customer Service O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
SALES EXPENSE			
911 - 916	Sales Expense O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
ADMINISTRATIVE & GEN EXPENSE			
920-935	Administrative & General Expense		
		Direct assigned - Jurisdiction	S
		Customer Related	CN
		General	SO
		FERC Regulatory Expense	SG
DEPRECIATION EXPENSE			
403SP	Steam Depreciation		
		Steam Plants	SG
403NP	Nuclear Depreciation		
		Nuclear Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
403HP	Hydro Depreciation	
	Pacific Hydro	SG
	East Hydro	SG
403OP	Other Production Depreciation	
	Other Production Plant	SG
403TP	Transmission Depreciation	
	Transmission Plant	SG
403	Distribution Depreciation Direct assigned - Jurisdiction	
	Land & Land Rights	S
	Structures	S
	Station Equipment	S
	Storage Battery Equipment	S
	Poles & Towers	S
	OH Conductors	S
	UG Conduit	S
	UG Conductor	S
	Line Trans	S
	Services	S
	Meters	S
	Inst Cust Prem	S
	Leased Property	S
Street Lighting	S	
403GP	General Depreciation	
	Distribution	S
	Remaining Steam Plants	SG
	Mining	SE
	Pacific Hydro	SG
	East Hydro	SG
	Transmission	SG
	Customer Related	CN
	General SO	SO
403MP	Mining Depreciation	
	Remaining Mining Plant	SE
AMORTIZATION EXPENSE		
404GP	Amort of LT Plant - Capital Lease Gen	
	Direct assigned - Jurisdiction	S
	General	SO
	Customer Related	CN
404SP	Amort of LT Plant - Cap Lease Steam	
	Steam Production Plant	SG
404IP	Amort of LT Plant - Intangible Plant	
	Distribution	S
	Production, Transmission	SG
	General	SO
	Mining Plant	SE
Customer Related	CN	

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
404MP	Amort of LT Plant - Mining Plant Mining Plant	SE
404HP	Amortization of Other Electric Plant Pacific Hydro East Hydro	SG SG
405	Amortization of Other Electric Plant Direct assigned - Jurisdiction	S
406	Amortization of Plant Acquisition Adj Direct assigned - Jurisdiction Production Plant	S SG
407	Amort of Prop Losses, Unrec Plant, etc Direct assigned - Jurisdiction Production, Transmission Trojan	S SG TROJP
Taxes Other Than Income		
408	Taxes Other Than Income Direct assigned - Jurisdiction Property System Taxes Misc Energy Misc Production	S GPS SO SE SG
DEFERRED ITC		
41140	Deferred Investment Tax Credit - Fed ITC	DGU
41141	Deferred Investment Tax Credit - Idaho ITC	DGU
Interest Expense		
427	Interest on Long-Term Debt Direct assigned - Jurisdiction Interest Expense	S SNP
428	Amortization of Debt Disc & Exp Interest Expense	SNP
429	Amortization of Premium on Debt Interest Expense	SNP
431	Other Interest Expense Interest Expense	SNP
432	AFUDC - Borrowed AFUDC	SNP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
Interest & Dividends		
419	Interest & Dividends	
	Interest & Dividends	SNP
DEFERRED INCOME TAXES		
41010	Deferred Income Tax - Federal-DR	
	Direct assigned - Jurisdiction	S
	Electric Plant in Service	DITEXP
	Pacific Hydro	SG
	Production, Transmission	SG
	Customer Related	CN
	General	SO
	Property Tax related	GPS
	Miscellaneous	SNP
	Trojan	TROJD
	Distribution	SNPD
	Mining Plant	SE
	Bad Debt	BADDEBT
	Tax Depreciation	TAXDEPR
41011	Deferred Income Tax - State-DR	
	Direct assigned - Jurisdiction	S
	Electric Plant in Service	DITEXP
	Pacific Hydro	SG
	Production, Transmission	SG
	Customer Related	CN
	General	SO
	Property Tax related	GPS
	Miscellaneous	SNP
	Trojan	TROJD
	Distribution	SNPD
	Mining Plant	SE
	Bad Debt	BADDEBT
	Tax Depreciation	TAXDEPR
41110	Deferred Income Tax - Federal-CR	
	Direct assigned - Jurisdiction	S
	Electric Plant in Service	DITEXP
	Pacific Hydro	SG
	Production, Transmission	SG
	Customer Related	CN
	General	SO
	Property Tax related	GPS
	Miscellaneous	SNP
	Trojan	TROJD
	Distribution	SNPD
	Mining Plant	SE
	Contributions in aid of construction	CIAC
	Production, Other	SGCT
	Book Depreciation	SCHMDEXP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
41111	Deferred Income Tax - State-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Contributions in aid of construction	CIAC
		Production, Other	SGCT
		Book Depreciation	SCHMDEXP
SCHEDULE - M ADDITIONS			
SCHMAF	Additions - Flow Through		
		Direct assigned - Jurisdiction	S
SCHMAP	Additions - Permanent		
		Direct assigned - Jurisdiction	S
		Mining related	SE
		General	SO
		Production / Transmission	SG
		Depreciation	SCHMDEXP
SCHMAT	Additions - Temporary		
		Direct assigned - Jurisdiction	S
		Contributions in aid of construction	CIAC
		Miscellaneous	SNP
		Trojan	TROJD
		Pacific Hydro	SG
		Mining Plant	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	SCHMDEXP
		Distribution	SNPD
		Production, Other	SGCT
SCHEDULE - M DEDUCTIONS			
SCHMDF	Deductions - Flow Through		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Pacific Hydro	SG
SCHMDP	Deductions - Permanent		
		Direct assigned - Jurisdiction	S
		Mining Related	SE
		Miscellaneous	SNP
		General	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
SCHMDT	Deductions - Temporary	
	Direct assigned - Jurisdiction	S
	Bad Debt	BADDEBT
	Miscellaneous	SNP
	Pacific Hydro	SG
	Mining related	SE
	Production, Transmission	SG
	Property Tax	GPS
	General	SO
	Depreciation	TAXDEPR
	Distribution	SNPD
	Customer Related	CN
State Income Taxes		
40911	State Income Taxes	
	Income Before Taxes	CALCULATED
40911	Renewable Energy Tax Credit	SG
40910	FIT True-up	S
40910	Renewable Energy Tax Credit	SG
	PMI	SE
	Foreign Tax Credit	SO
Steam Production Plant		
310 - 316		
	Steam Plants	SG
Nuclear Production Plant		
320-325		
	Nuclear Plant	SG
Hydraulic Plant		
330-336		
	Pacific Hydro	SG
	East Hydro	SG
Other Production Plant		
340-346		
	Other Production Plant	S
	Other Production Plant	SG
TRANSMISSION PLANT		
350-359		
	Transmission Plant	SG
DISTRIBUTION PLANT		
360-373		
	Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
GENERAL PLANT		
389 - 398	Distribution	S
	Pacific Hydro	SG
	East Hydro	SG
	Production / Transmission	SG
	Customer Related	CN
	General	SO
	Mining	SE
399	Coal Mine	
	Remaining Mining Plant	SE
399L	WIDCO Capital Lease	
	WIDCO Capital Lease	SE
1011390	General Capital Leases	
	Direct assigned - Jurisdiction	S
	General	SO
	Generation / Transmission	SG
INTANGIBLE PLANT		
301	Organization	
	Direct assigned - Jurisdiction	S
302	Franchise & Consent	
	Direct assigned - Jurisdiction	S
	Production, Transmission	SG
303	Miscellaneous Intangible Plant	
	Distribution	S
	Pacific Hydro	SG
	East Hydro	SG
	Production / Transmission	SG
	Customer Related	CN
	General	SO
	Mining	SE
303	Less Non-Utility Plant	
	Direct assigned - Jurisdiction	S
Rate Base Additions		
105	Plant Held For Future Use	
	Direct assigned - Jurisdiction	S
	Production, Transmission	SG
	Mining Plant	SE
114	Electric Plant Acquisition Adjustments	
	Direct assigned - Jurisdiction	S
	Production Plant	SG
115	Accum Provision for Asset Acquisition Adjustments	
	Direct assigned - Jurisdiction	S
	Production Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
120	Nuclear Fuel	Nuclear Fuel	SE
124	Weatherization	Direct assigned - Jurisdiction General	S SO
128	Pensions	General	SO
182W	Weatherization	Direct assigned - Jurisdiction	S
186W	Weatherization	Direct assigned - Jurisdiction	S
151	Fuel Stock	Steam Production Plant	SE
152	Fuel Stock - Undistributed	Steam Production Plant	SE
25316	DG&T Working Capital Deposit	Mining Plant	SE
25317	DG&T Working Capital Deposit	Mining Plant	SE
25319	Provo Working Capital Deposit	Mining Plant	SE
154	Materials and Supplies	Direct assigned - Jurisdiction Production, Transmission Mining Production - Common General Distribution Production, Other	S SG SE SG SO SNPD SG
163	Stores Expense Undistributed	General	SO
25318	Provo Working Capital Deposit	Provo Working Capital Deposit	SG
165	Prepayments	Direct assigned - Jurisdiction Property Tax Production, Transmission Mining General	S GPS SG SE SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
182M	Misc Regulatory Assets	
	Direct assigned - Jurisdiction	S
	Production, Transmission	SG
	Mining	SE
	General	SO
	Production, Other	SGCT
186M	Misc Deferred Debits	
	Direct assigned - Jurisdiction	S
	Production, Transmission	SG
	General	SO
	Mining	SE
	Production - Common	SG
Working Capital		
CWC	Cash Working Capital	
	Direct assigned - Jurisdiction	S
OWC	Other Working Capital	
131	Cash	SNP
135	Working Funds	SG
141	Notes Receivable	SO
143	Other Accounts Receivable	SO
232	Accounts Payable	SO
	Accounts Payable	SE
	Accounts Payable	SG
253	Deferred Hedge	SE
25330	Other Deferred Credits - Misc	SE
230	Other Deferred Credits - Misc	SE
254105	ARO Reg Liability	SE
Miscellaneous Rate Base		
18221	Unrec Plant & Reg Study Costs	
	Direct assigned - Jurisdiction	S
18222	Nuclear Plant - Trojan	
	Trojan Plant	TROJP
	Trojan Plant	TROJD
141	Notes Receivable	
	Employee Loans - Hunter Plant	SG
Rate Base Deductions		
235	Customer Service Deposits	
	Direct assigned - Jurisdiction	S
2281	Prov for Property Insurance	SO
2282	Prov for Injuries & Damages	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
2283	Prov for Pensions and Benefits	SO
22841	Accum Misc Oper Prov-Black Lung	
	Mining	SE
	Other Production	SG
22842	Accum Misc Oper Prov-Trojan	
	Trojan Plant	TROJD
254105	FAS 143 ARO Regulatory Liability	
	Trojan Plant	TROJP
	Trojan Plant	TROJD
230	Asset Retirement Obligation	
	Trojan Plant	TROJP
	Trojan Plant	TROJD
252	Customer Advances for Construction	
	Direct assigned - Jurisdiction	S
	Production, Transmission	SG
	Customer Related	CN
25398	S02 Emissions	SE
25399	Other Deferred Credits	
	Direct assigned - Jurisdiction	S
	Production, Transmission	SG
	General	SO
	Mining	SE
254	Regulatory Liabilities	
	Regulatory Liabilities	S
	Regulatory Liabilities	SE
	Insurance Provision	SO
190	Accumulated Deferred Income Taxes	
	Direct assigned - Jurisdiction	S
	Bad Debt	BADDEBT
	Pacific Hydro	SG
	Production, Transmission	SG
	Customer Related	CN
	General	SO
	Miscellaneous	SNP
	Trojan	TROJD
	Distribution	SNPD
	Mining Plant	SE
281	Accumulated Deferred Income Taxes	
	Production, Transmission	SG
282	Accumulated Deferred Income Taxes	
	Direct assigned - Jurisdiction	S
	Depreciation	DITBAL
	Hydro Pacific	SG
	Production, Transmission	SG
	Customer Related	CN
	General	SO
	Miscellaneous	SNP
	Trojan	TROJP
	Depreciation	TAXDEPR
	Depreciation	SCHMDEXP
	System Gross Plant	GPS
	Contribution in Aid of Construction	CIAC
	Mining	SE

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
283	Accumulated Deferred Income Taxes	
	Direct assigned - Jurisdiction	S
	Depreciation	DITBAL
	Hydro Pacific	SG
	Production, Transmission	SG
	Customer Related	CN
	General	SO
	Miscellaneous	SNP
	Trojan	TROJD
	Production, Other	SGCT
	Property Tax	GPS
	Mining Plant	SE
255	Accumulated Investment Tax Credit	
	Direct assigned - Jurisdiction	S
	Investment Tax Credits	ITC84
	Investment Tax Credits	ITC85
	Investment Tax Credits	ITC86
	Investment Tax Credits	ITC88
	Investment Tax Credits	ITC89
	Investment Tax Credits	ITC90
	Investment Tax Credits	SG
PRODUCTION PLANT ACCUM DEPRECIATION		
108SP	Steam Prod Plant Accumulated Depr	
	Steam Plants	SG
108NP	Nuclear Prod Plant Accumulated Depr	
	Nuclear Plant	SG
108HP	Hydraulic Prod Plant Accum Depr	
	Pacific Hydro	SG
	East Hydro	SG
108OP	Other Production Plant - Accum Depr	
	Other Production Plant	SG
TRANS PLANT ACCUM DEPR		
108TP	Transmission Plant Accumulated Depr	
	Transmission Plant	SG
DISTRIBUTION PLANT ACCUM DEPR		
108360 - 108373	Distribution Plant Accumulated Depr	
	Direct assigned - Jurisdiction	S
108D00	Unclassified Dist Plant - Acct 300	
	Direct assigned - Jurisdiction	S
108DS	Unclassified Dist Sub Plant - Acct 300	
	Direct assigned - Jurisdiction	S
108DP	Unclassified Dist Sub Plant - Acct 300	
	Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
GENERAL PLANT ACCUM DEPR		
108GP	General Plant Accumulated Depr	
	Distribution	S
	Pacific Hydro	SG
	East Hydro	SG
	Production / Transmission	SG
	Customer Related	CN
	General SO	SO
	Mining Plant	SE
108MP	Mining Plant Accumulated Depr.	
	Mining Plant	SE
108MP	Less Centralia Situs Depreciation	
	Direct assigned - Jurisdiction	S
1081390	Accum Depr - Capital Lease	
	General	SO
1081399	Accum Depr - Capital Lease	
	Direct assigned - Jurisdiction	S
ACCUM PROVISION FOR AMORTIZATION		
111SP	Accum Prov for Amort-Steam	
	Steam Plants	SG
111GP	Accum Prov for Amort-General	
	Distribution	S
	Pacific Hydro	SG
	East Hydro	SG
	Production / Transmission	SG
	Customer Related	CN
	General SO	SO
111HP	Accum Prov for Amort-Hydro	
	Pacific Hydro	SG
	East Hydro	SG
111IP	Accum Prov for Amort-Intangible Plant	
	Distribution	S
	Pacific Hydro	SG
	Production, Transmission	SG
	General	SO
	Mining	SE
	Customer Related	CN
111IP	Less Non-Utility Plant	
	Direct assigned - Jurisdiction	S
111399	Accum Prov for Amort-Mining	
	Mining Plant	SE

2017 Protocol - Appendix C
Allocation Factors
Algebraic Derivations

Allocation Factors

PacifiCorp serves eight jurisdictions. Jurisdictions are represented by the index i = California, Idaho, Oregon, Utah, Washington, Eastern Wyoming, Western Wyoming, & FERC.

The following assumptions are made in the factor derivations:

It is assumed that the 12CP ($j=1$ to 12) method is used in defining the System Capacity (“SC”)

It is assumed that twelve months ($j=1$ to 12) method is used in defining the System Energy (“SE”).

In defining the System Generation (“SG”) factor, the weighting of 75 percent System Capacity, 25 percent System Energy is assumed to continue.

While it is agreed that the peak loads & input energy should be temperature adjusted, no decision has been made upon the methodology to do these adjustments.

System Capacity Factor (“SC”)

$$SC_i = \frac{\sum_{j=1}^{12} TAP_{ij}}{\sum_{i=1}^8 \sum_{j=1}^{12} TAP_{ij}}$$

where:

SC_i = **System Capacity Factor** for jurisdiction i .
 TAP_{ij} = Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

System Energy Factor (“SE”)

$$SE_i = \frac{\sum_{j=1}^{12} TAE_{ij}}{\sum_{i=1}^8 \sum_{j=1}^{12} TAE_{ij}}$$

where:

- SE_i = **System Energy Factor** for jurisdiction i.
 TAE_{ij} = Temperature Adjusted Input Energy of jurisdiction i in month j.

System Generation Factor (“SG”)

$$SG_i = .75 * SC_i + .25 * SE_i$$

where:

- SG_i = **System Generation Factor** for jurisdiction i.
 SC_i = System Capacity for jurisdiction i.
 SE_i = System Energy for jurisdiction i.

Division Generation - Pacific Factor (“DGP”)

$$DGP_i = \frac{SG_i^*}{\sum_{i=1}^8 SG_i^*}$$

where:

- DGP_i = **Division Generation - Pacific Factor** for jurisdiction i.
 SG_i^* = SG_i if i is a Pacific jurisdiction, otherwise
 SG_i^* = 0.
 SG_i = System Generation for jurisdiction i.

Division Generation - Utah Factor (“DGU”)

$$DGU_i = \frac{SG_i^*}{\sum_{i=1}^{i=8} SG_i^*}$$

where:

DGU_i = **Division Generation - Utah Factor** for jurisdiction i.

SG_i^* = SG_i if i is a Utah jurisdiction, otherwise

SG_i^* = 0.

SG_i = System Generation for jurisdiction i.

System Net Plant - Distribution Factor (“SNPD”)

$$SNPD_i = \frac{PD_i - ADPD_i}{(PD - ADPD)}$$

where:

$SNPD_i$ = **System Net Plant - Distribution Factor** for jurisdiction i.

PD_i = Distribution Plant - for jurisdiction i.

$ADPD_i$ = Accumulated Depreciation Distribution Plant - for jurisdiction i.

PD = Distribution Plant.

$ADPD$ = Accumulated Depreciation Distribution Plant.

System Gross Plant - System Factor (“GPS”)

$$GPS_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i}{\sum_{i=1}^{i=8} (PP_i + PT_i + PD_i + PG_i + PI_i)}$$

- $GP-S_i$ = **Gross Plant - System Factor** for jurisdiction i.
- PP_i = Production Plant for jurisdiction i.
- PT_i = Transmission Plant for jurisdiction i.
- PD_i = Distribution Plant for jurisdiction i.
- PG_i = General Plant for jurisdiction i.
- PI_i = Intangible Plant for jurisdiction i.

System Net Plant Factor (“SNP”)

$$SNP_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - ADPP_i - ADPT_i - ADPD_i - ADPG_i - ADPI_i}{\sum_{i=1}^{i=8} (PP_i + PT_i + PD_i + PG_i + PI_i - ADPP_i - ADPT_i - ADPD_i - ADPG_i - ADPI_i)}$$

- SNP_i = **System Net Plant Factor** for jurisdiction i.
- PP_i = Production Plant for jurisdiction i.
- PT_i = Transmission Plant for jurisdiction i.
- PD_i = Distribution Plant for jurisdiction i.
- PG_i = General Plant for jurisdiction i.
- PI_i = Intangible Plant for jurisdiction i.
- $ADPP_i$ = Accumulated Depreciation Production Plant for jurisdiction i.
- $ADPT_i$ = Accumulated Depreciation Transmission Plant for jurisdiction i.
- $ADPD_i$ = Accumulated Depreciation Distribution Plant for jurisdiction i.
- $ADPG_i$ = Accumulated Depreciation General Plant for jurisdiction i.
- $ADPI_i$ = Accumulated Depreciation Intangible Plant for jurisdiction i.

System Overhead - Gross Factor (“SO”)

$$SOG_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - PP_{oi} - PT_{oi} - PD_{oi} - PG_{oi} - PI_{oi}}{\sum_{i=1}^{i=8} (PP_i + PT_i + PD_i + PG_i + PP_i - PP_{oi} - PT_{oi} - PD_{oi} - PG_{oi} - PI_{oi})}$$

- SOG_i = **System Overhead - Gross Factor** for jurisdiction i.
- PP_i = Gross Production Plant for jurisdiction i.
- PT_i = Gross Transmission Plant for jurisdiction i.
- PD_i = Gross Distribution Plant for jurisdiction i.
- PG_i = Gross General Plant for jurisdiction i.
- PI_i = Gross Intangible Plant for jurisdiction i.
- PP_{oi} = Gross Production Plant for jurisdiction i allocated on a SO factor.
- PT_{oi} = Gross Transmission Plant for jurisdiction i allocated on a SO factor
- PD_{oi} = Gross Distribution Plant for jurisdiction i allocated on a SO factor
- PG_{oi} = Gross General Plant for jurisdiction i allocated on a SO factor
- PI_{oi} = Gross Intangible Plant for jurisdiction i allocated on a SO factor

Income Before Taxes Factor (“IBT”)

$$IBT_i = \frac{TIBT_i}{\sum_{i=1}^{i=8} TIBT_i}$$

- IBT_i = **Income before Taxes Factor** for jurisdiction i.
- $TIBT_i$ = Total Income before Taxes for jurisdiction i.

Bad Debt Expense Factor (“BADDEBT”)

$$BADDEBT_i = \frac{ACCT904_i}{\sum_{i=1}^{i=8} ACCT904_i}$$

$BADDEBT_i$ = **Bad Debt Expense Factor** for jurisdiction i.
 $ACCT904_i$ = Balance in Account 904 for jurisdiction i.

Customer Number Factor (“CN”)

$$CN_i = \frac{CUST_i}{\sum_{i=1}^{i=8} CUST_i}$$

where:

CN_i = **Customer Number Factor** for jurisdiction i.
 $CUST_i$ = Total Electric Customers for jurisdiction i.

Contributions in Aid of Construction (“CIAC”)

$$CIAC_i = \frac{CIACNA_i}{\sum_{i=1}^{i=8} CIACNA_i}$$

where:

$CIAC_i$ = **Contributions in Aid of Construction Factor** for jurisdiction i.
 $CIACNA_i$ = Contributions in Aid of Construction – Net additions for jurisdiction i.

Schedule M - Deductions (“SCHMD”)

$$SCHMD_i = \frac{DEPRC_i}{\sum_{i=1}^{i=8} DEPRC_i}$$

where:

$$\begin{aligned} SCHMD_i &= \text{Schedule M - Deductions (SCHMD) Factor for jurisdiction i.} \\ DEPRC_i &= \text{Depreciation in Accounts 403.1 - 403.9 for jurisdiction i.} \end{aligned}$$

Trojan Plant (“TROJP”)

$$TROJP_i = \frac{ACCT18222_i}{\sum_{i=1}^{i=8} ACCT18222_i}$$

where:

$$\begin{aligned} TROJP_i &= \text{Trojan Plant (TROJP) Factor for jurisdiction i.} \\ ACCT18222_i &= \text{Allocated Adjusted Balance in Account 182.22 for jurisdiction i.} \end{aligned}$$

Trojan Decommissioning (“TROJD”)

$$TROJD_i = \frac{ACCT22842_i}{\sum_{i=1}^{i=8} ACCT22842_i}$$

where:

$$\begin{aligned} TROJD_i &= \text{Trojan Decommissioning (TROJD) Factor for jurisdiction i.} \\ ACCT22842_i &= \text{Allocated Adjusted Balance in Account 228.42 for jurisdiction i.} \end{aligned}$$

Tax Depreciation (“TAXDEPR”)

$$TAXDEPR_i = \frac{TAXDEPRA_i}{\sum_{i=1}^{i=8} TAXDEPRA_i}$$

where:

$$\begin{aligned} TAXDEPR_i &= \text{Tax Depreciation (TAXDEPR) Factor for jurisdiction i.} \\ TAXDEPRA_i &= \text{Tax Depreciation allocated to jurisdiction i.} \end{aligned}$$

(Tax Depreciation is allocated based on functional pre merger and post merger splits of plant using Divisional and System allocations from above. Each jurisdiction’s total allocated portion of Tax depreciation is determined by its total allocated ratio of these functional pre and post merger splits to the total Company Tax Depreciation.)

Deferred Tax Expense (“DITEXP”)

$$DITEXP_i = \frac{DITEXPA_i}{\sum_{i=1}^{i=8} DITEXPA_i}$$

where:

$$\begin{aligned} DITEXP_i &= \text{Deferred Tax Expense (DITEXP) Factor for jurisdiction i.} \\ DITEXPA_i &= \text{Deferred Tax Expense allocated to jurisdiction i.} \end{aligned}$$

(Deferred Tax Expense is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

Deferred Tax Balance (“DITBAL”)

$$DITBAL_i = \frac{DITBALA_i}{\sum_{i=1}^{i=8} DITBALA_i}$$

where:

$DITBAL_i$ = **Deferred Tax Balance (DITBAL) Factor** for jurisdiction i.
 $DITBALA_i$ = Deferred Tax Balance allocated to jurisdiction i.

(Deferred Tax Balance is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

2017 Protocol – Appendix D Special Contracts

2017 Protocol - Appendix D Special Contracts

Special Contracts without Ancillary Service Contract Attributes

For allocation purposes Special Contracts without identifiable Ancillary Service Contract attributes are viewed as one transaction.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the reduction in load will be reflected in the host jurisdiction's Load-Based Dynamic Allocation Factors.

Actual revenues received from Special Contract customer will be assigned to the State where the Special Contract customer is located.

See example in Table 1

Special Contracts with Ancillary Service Contract Attributes

For allocation purposes Special Contracts with Ancillary Service Contract attributes are viewed as two transactions. PacifiCorp sells the customer electricity at the retail service rate and then buys the electricity back during the interruption period at the Ancillary Service Contract rate.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the host jurisdiction's Load-Based Dynamic Allocation Factors and the retail service revenue are calculated as though the interruption did not occur.

Revenues received from Special Contract customer, before any discounts for Customer Ancillary Service attributes of the Special Contract, will be assigned to the State where the Special Contract customer is located.

Discounts from tariff prices provided for in Special Contracts that recognize the Customer Ancillary Service Contract attributes of the Contract, and payments to retail customers for Customer Ancillary Services will be allocated among States on the same basis as System Resources.

See example in Table 2

Buy-through of Economic Curtailment

When a buy-through option is provided with economic curtailment, the load, costs and revenue associated with a customer buying through economic curtailment will be excluded from the calculation of State revenue requirements. The cost associated with the buy-through will be removed from the calculation of net power costs, the Special Contract customer load associated with the buy-through will be not be included in the calculation of Load-Based Dynamic Allocation Factors, and the revenue associated with the buy-through will not be included in State revenues.

2017 Protocol - Appendix D - Table 1
Interruptible Contract Without Ancillary Service Contract Attributes
Effect on Revenue Requirement

	<u>Factor</u>	<u>Total system</u>	<u>Jurisdiction 1</u>	<u>Jurisdiction 2</u>	<u>Jurisdiction 3</u>
1 Loads					
2 Jurisdictional Loads - No Interruptible Service					
3		72,000	24,000	36,000	12,000
4		42,000,000	14,000,000	21,000,000	7,000,000
5					
6 Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7		71,700	24,000	35,700	12,000
8		41,962,500	14,000,000	20,962,500	7,000,000
9					
10 Special Contract Customer Revenue and Load - Non Interruptible Service					
11		\$ 20,000,000		\$ 20,000,000	
12		900	-	900	-
13		500,000	-	500,000	-
14					
15 Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16		\$ 16,000,000		\$ 16,000,000	
17					
18		\$ 16,000,000		\$ 16,000,000	
19		600	-	600	-
20		462,500	-	462,500	-
21					
22		\$4,000,000			
23					
24 Allocation Factors					
25 No Interruptible Service					
26	SE1	100.00%	33.33%	50.00%	16.67%
27	SC1	100.00%	33.33%	50.00%	16.67%
28	SG1	100.00%	33.33%	50.00%	16.67%
29					
30 With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE2	100.00%	33.36%	49.96%	16.68%
32	SC2	100.00%	33.47%	49.79%	16.74%
33	SG2	100.00%	33.45%	49.83%	16.72%
34					
35					
No Interruptible Service					
36					
37					
38 Cost of Service					
39	SE1	\$ 500,000,000	\$ 166,666,667	\$ 250,000,000	\$ 83,333,333
40	SG1	\$ 1,000,000,000	\$ 333,333,333	\$ 500,000,000	\$ 166,666,667
41		\$ 1,500,000,000	\$ 500,000,000	\$ 750,000,000	\$ 250,000,000
42					
43 Revenues					
44	Situs	\$ 20,000,000		\$ 20,000,000	
45	Situs	\$ 1,480,000,000	\$ 500,000,000	\$ 730,000,000	\$ 250,000,000
46					
47					
With Interruptible Service					
48					
49					
50 Cost of Service					
51	SE2	\$ 498,000,000	\$ 166,148,347	\$ 248,777,480	\$ 83,074,173
52	SG2	\$ 998,000,000	\$ 334,058,577	\$ 496,912,134	\$ 167,029,289
53		\$ 1,496,000,000	\$ 500,206,924	\$ 745,689,614	\$ 250,103,462
54					
55 Revenues					
56	Situs	\$ 16,000,000		\$ 16,000,000	
57	Situs	\$ 1,480,000,000	\$ 500,206,924	\$ 729,689,614	\$ 250,103,462

2017 Protocol - Appendix D - Table 2 Interruptible Contract With Ancillary Service Contract Attributes Effect on Revenue Requirement

	<u>Factor</u>	<u>Total system</u>	<u>Jurisdiction 1</u>	<u>Jurisdiction 2</u>	<u>Jurisdiction 3</u>
1 Loads					
2 Jurisdictional Loads - No Interruptible Service					
3		72,000	24,000	36,000	12,000
4		42,000,000	14,000,000	21,000,000	7,000,000
5					
6 Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7		71,700	24,000	35,700	12,000
8		41,962,500	14,000,000	20,962,500	7,000,000
9					
10 Special Contract Customer Revenue and Load - Non Interruptible Service					
11		\$ 20,000,000		\$ 20,000,000	
12		900	-	900	-
13		500,000	-	500,000	-
14					
15 Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16		\$ 20,000,000		\$ 20,000,000	
17				\$ (4,000,000)	
18		\$ 16,000,000		\$ 16,000,000	
19		600	-	600	-
20		462,500	-	462,500	-
21					
22		\$4,000,000			
23					
24 Allocation Factors					
25 No Interruptible Service					
26	SE1	100.00%	33.33%	50.00%	16.67%
27	SC1	100.00%	33.33%	50.00%	16.67%
28	SG1	100.00%	33.33%	50.00%	16.67%
29					
30 With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE2	100.00%	33.36%	49.96%	16.68%
32	SC2	100.00%	33.47%	49.79%	16.74%
33	SG2	100.00%	33.45%	49.83%	16.72%
34					
35					
No Interruptible Service					
36					
37					
38 Cost of Service					
39	SE1	\$ 500,000,000	\$ 166,666,667	\$ 250,000,000	\$ 83,333,333
40	SG1	\$ 1,000,000,000	\$ 333,333,333	\$ 500,000,000	\$ 166,666,667
41		\$ 1,500,000,000	\$ 500,000,000	\$ 750,000,000	\$ 250,000,000
42					
43 Revenues					
44	Situs	\$ 20,000,000		\$ 20,000,000	
45	Situs	\$ 1,480,000,000	\$ 500,000,000	\$ 730,000,000	\$ 250,000,000
46					
47					
With Interruptible Service & Ancillary Service Contract					
48					
49					
50 Cost of Service					
51	SE1	\$ 498,000,000	\$ 166,000,000	\$ 249,000,000	\$ 83,000,000
52	SG1	\$ 998,000,000	\$ 332,666,667	\$ 499,000,000	\$ 166,333,333
53	SG1	\$ 2,000,000	\$ 666,667	\$ 1,000,000	\$ 333,333
54	SE1	\$ 2,000,000	\$ 666,667	\$ 1,000,000	\$ 333,333
55		\$ 1,500,000,000	\$ 500,000,000	\$ 750,000,000	\$ 250,000,000
56					
57 Revenues					
58	Situs	\$ 20,000,000		\$ 20,000,000	
59	Situs	\$ 1,480,000,000	\$ 500,000,000	\$ 730,000,000	\$ 250,000,000