ATTACHMENT A

MANITOBA HYDRO COST OF SERVICE REVIEW

REBUTTAL EVIDENCE

PREPARED BY

WILLIAM HARPER

ECONALYSIS CONSULTING SERVICES

Final Report

Cost of Service Methodology Review

British Columbia Hydro and Power Authority

December 20, 2013

leidos

December 20, 2013

Mr. Craig Godsoe
Sr. Solicitor and Counsel, Legal Services
British Columbia Hydro and Power Authority
333 Dusmuir, 16th Floor
Vancouver, B.C. V6B 5R3

Subject: **Final Report – 2013 Cost of Service Methodology Review**

Dear Mr. Godsoe:

SAIC Energy, Environment and Infrastructure, now called Leidos Engineering (Leidos), in conjunction with Cuthbert Consulting Inc. is pleased to submit this final report for the 2013 Cost of Service Methodology Review prepared for the British Columbia Hydro and Power Authority (BC Hydro). This report sets forth and summarizes the methodology, assumptions, analyses, and final results of the study.

The preparation of this study was a collaborative effort between BC Hydro, Leidos, and Cuthbert Consulting staff. I wish to express our appreciation for the friendly cooperation and assistance to all of those who provided the information and reviews necessary to successfully complete this study.

Once again, we appreciate the opportunity to be of service to BC Hydro.

Sincerely,

Leidos Engineering, LLC

Laurie A. Tomczyk

Laurie A. Tomczyk. P.E.
Project Manager

Cost of Service Methodology Review

British Columbia Hydro and Power Authority

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Section 3
REVIEW OF COST OF SERVICE METHODOLOGIES FOR SELECTED UTILITIES

Approach and Selection Method

To understand better how other comparable utilities have addressed the COS methodological issues identified in Section 2 of this report, SAIC in conjunction with BC Hydro staff conducted a review of COS studies and filings made by similar North American electric utilities. These utilities were selected based on the following criteria:

- Significant portion of generation derived from hydro resources, preferably utility owned but also as purchased power
- Primarily winter peaking system
- Preference for utilizing an embedded COS methodology, but not excluding utilities utilizing a marginal COS methodology
- Providing vertically integrated services, including generation, transmission, and distribution of power
- Relatively large size in terms of revenue (greater than $500 million revenues) and customers served (greater than 100,000 customers)

In reviewing a number of listings of North American electric utilities, it was determined that only BC Hydro met all of these criteria. Consequently, the selection process was modified to include those utilities that best met most of these criteria. Rate case filings or studies by nine utilities in ten separate jurisdictions were selected to include in the survey as follows:

- Avista Corporation–Idaho (filing made before the Idaho Public Utilities Commission)
- Avista Corporation–Washington (filing made before the Washington Utilities and Transportation Commission)
- Bonneville Power Administration (BPA)
- Hydro-Québec Distribution
- Idaho Power Company (Idaho Power) (filing made before the Idaho Public Utilities Commission)
- Manitoba Hydro

- Newfoundland Power Inc.
- Portland General Electric Company (Portland General)
- Puget Sound Energy
- Seattle City Light

For ease of reference, Avista Corporation–Idaho and Avista Corporation–Washington will be referred to as separate utilities throughout this report.

Characteristics of Utilities in Jurisdictional Review

Appendix A includes a table showing key characteristics of the utilities included in the jurisdictional review as well as each utility's rate filings or studies used for the review. The utilities included in the jurisdictional review are vertically integrated utilities that supply the majority of their own power needs and primarily serve retail customers with the following exceptions:

- BPA is a federal nonprofit agency based in the Pacific Northwest. BPA markets wholesale power from federal hydro projects in the Columbia River Basin, one nonfederal nuclear plant, and several other small nonfederal power plants. BPA's power services customers primarily include cooperatives, municipalities, and public utility districts, but they also serve other federal agencies, investor-owned utilities, direct service industries, a port district, and tribal utilities. They do not have any distribution assets.
- Since 2000, Hydro-Québec has been divided into three major divisions (Hydro-Québec Production, Hydro-Québec TransÉnergie, and Hydro-Québec Distribution). Hydro-Québec Production supplies Hydro-Québec Distribution with power from heritage resources, which are dedicated supply resources reserved for Quebec markets up to a maximum of specified maximum amount per year. To meet demand beyond that volume, Hydro-Québec Distribution must enter into supply contracts by conducting calls for tenders among interested power suppliers.
- Newfoundland Power purchases approximately 90 percent of its electricity requirements from Newfoundland and Labrador Hydro, and it generates the balance from its own smaller hydro stations.

Additional characteristics of the utilities included in the jurisdictional review are as follows:

- A significant portion of all the utilities' power supply needs are provided by hydro resources. The percentages of their power supply requirements that come from hydro resources range from 42 percent for Portland General Electric to 98 percent for Hydro-Québec, as compared to 89 percent for BC Hydro.
- With the exception of Idaho Power, the utilities are all winter peaking like BC Hydro.

- Portland General and Seattle City Light use primarily marginal COS methodologies, while the other utilities primarily use embedded COS methodologies similar to BC Hydro.
- Five of the utilities are investor owned, while the others are publically owned like BC Hydro. The investor-owned utilities include Avista, Idaho Power, Newfoundland Power, Portland General Electric, and Puget Sound Energy.
- Without including Newfoundland Power that purchases 90 percent of its electricity requirements, the percentages of the utilities' power supplies that they purchase, rather than generate themselves, range from approximately 3 percent for Manitoba Hydro to 58 percent for Portland General Electric. This compares to 40 percent for BC Hydro.
- The utilities' electric sales revenues range from about $600 million for Newfoundland Power to $12.1 billion for Hydro-Québec, and the number of electric retail customers ranges from approximately 240,000 for Newfoundland Power to 4.1 million for Hydro-Québec. In comparison, BC Hydro has approximate $4.4 billion per year in electric sales revenues and 1.9 million customers.

The primary sources of information used in the jurisdictional review were the most recent case rate filings or COS and rate design studies prepared by each of the utilities.[4] Review of this information focused on COS methodology issues, including classification and allocation methods, R/C ratio targets, and related issues identified previously in this report. The focus of the review was to identify the COS methodologies used, but the bases for the methods chosen by the utilities were noted when readily identifiable. The rate filings and studies identified in Appendix A were reviewed between February and May 2013, and results were tabulated in June 2013.

Key Findings

The following categories of key findings from the jurisdictional review are summarized below:

- Generation COS Methodologies
- Transmission COS Methodologies
- Distribution COS Methodologies
- DSM, Energy Efficiency, and Energy Conservation COS Methodologies
- Target and Actual R/C Ratios Used for Proposed Rate Designs

Tables showing the detailed results of the jurisdictional review are provided in Appendix B. Definitions of the classification and allocation methodologies used by utilities in the jurisdictional review, as well as descriptions of how they are used by the

4 Hydro-Québec Distribution staff provided oral and written information.

utilities, are provided in Appendix C. A discussion of the detailed results on classification methodologies is provided in Appendix D.

Generation COS Methodologies

The results of the jurisdictional review of generation COS methodologies and observations about those results are presented below.

Results of Jurisdictional Review

The types of generation COS methodologies used by the utilities included in the jurisdictional review by type of resource are presented below.

The approaches used to classify and allocate hydro plant in service and associated O&M costs, including water costs, are summarized in Table 6. More detailed information is provided in Table C-1 of Appendix C and the written descriptions of the hydro generation classification and allocation methodologies in Appendices C and D.

Table 6
Results of Jurisdictional Review
Hydro Generation Cost Classification and Allocation Methodologies

	Number of Utilities			% Classified as Demand-Related
	Plant In Service Costs (1)	O&M Costs Excl Water Costs (2)	Water Costs (2)	
Classification Methodologies				
Energy Only	1	2	3	0%
Generation Marginal Costs - Demand & Energy	na	1	1	35%
Generation Marginal Costs - Energy Only	na	1	1	0%
Hydro Peak Credit	1	1	na	42%
System Load Factor	3	2	3	34%-46%
System Load Factor/Energy Only (3)	na	1	na	44%
Thermal Peak Credit	1	1	1	19%
Demand-Related Allocation Methodologies				
1 CP	1	1	1	na
4 CP	na	1	1	na
12 CP	3	3	2	na
Ave of Loads During Select Peak Periods	1	1	1	na
Energy-Related Allocation Methodologies				
Annual Energy at Generation	4	4	4	na
Direct Assignment/Annual Energy at Generation (aMW)	na	1	1	na
Weighted Annual Energy at Generation	2	4	4	na

(1) Four utilities do not classify and allocate hydro generation plant in service costs because it is either not required for their COS approach or they do not have any hydro assets.
(2) One utility does not classify and allocate hydro O&M costs or water costs because they do not have any of their own hydro assets.
(3) One utility uses the System Load Factor method to classify all hydro O&M costs, with the exception of certain O&M expenses that are classified using the Energy Only method. This utility indicated they used the Electric Utility Cost Allocation Manual, published January 1992, by the National Association of Regulatory Utility Commissioners as their primary guide to classification.

The approaches used to classify and allocate non-peaking thermal plant in service and associated O&M costs, including fuel costs, are summarized in Table 7. More detailed information is provided in Table C-2 of Appendix C and the written descriptions of the non-peaking thermal generation classification and allocation methodologies in Appendices C and D.

Table 7
Results of Jurisdictional Review
Non-Peaking Thermal Generation Cost Classification and Allocation Methodologies

	Number of Utilities			% Classified as Demand-Related
	Plant In Service Costs (1)	O&M Costs Excl Fuel Costs (2)	Fuel Costs (2)	
Classification Methodologies				
Demand Only	1	1	1	100%
Energy Only	1	2	4	0%
Generation Marginal Costs - Energy Only	na	1	1	0%
Generation Marginal Costs - Demand & Energy	na	1	1	35%
System Load Factor	2	1	1	34%-46%
System Load Factor/Energy Only (3)	na	1	na	28%
Thermal Peak Credit	2	2	1	19%-42%
Demand-Related Allocation Methodologies				
1 CP	1	1	1	na
4 CP	na	1	1	na
12 CP	3	3	1	na
Ave of Loads During Select Peak Periods	1	1	1	na
Energy-Related Allocation Methodologies				
Annual Energy at Generation	3	3	3	na
Direct Assignment/Annual Energy at Generation (aMW)	na	1	1	na
Weighted Annual Energy at Generation	2	4	4	na

(1) Four utilities do not classify and allocate non-peaking thermal generation plant in service costs because it is either not required for their COS approach or they do not have any non-peaking thermal generation assets.
(2) One utility does not classify and allocate non-peaking thermal generation O&M costs or fuel costs because they do not have any of their own non-peaking thermal generation assets.
(3) One utility uses the System Load Factor method to classify all non-peaking thermal generation O&M costs, with the exception of certain O&M expenses that are classified using the Energy Only method. This utility indicated they used the Electric Utility Cost Allocation Manual, published January 1992, by the National Association of Regulatory Utility Commissioners as their primary guide to classification.

The approaches used to classify and allocate peaking thermal plant in service and associated O&M costs, including fuel costs, are summarized in Table 8. More detailed information is provided in Table C-3 of Appendix C and the written descriptions of the peaking thermal generation classification and allocation methodologies in Appendices C and D.

Table 8
Results of Jurisdictional Review
Peaking Thermal Generation Cost Classification and Allocation Methodologies

	Number of Utilities			% Classified as Demand-Related
	Plant In Service Costs (1)	O&M Costs Excl Fuel Costs (2)	Fuel Costs (2)	
Classification Methodologies				
Demand Only	3	2	1	100%
Demand Only/Energy Only (3)	na	1	na	85%
Energy Only	1	2	4	0%
Generation Marginal Costs - Energy Only	na	1	1	0%
Generation Marginal Costs - Demand & Energy	na	1	1	35%
System Load Factor	1	1	1	34%
Thermal Peak Credit	1	1	1	19%
Demand-Related Allocation Methodologies				
1 CP	1	1	1	na
3 CP	1	1	na	na
4 CP	na	1	1	na
12 CP	2	2	1	na
Ave of Loads During Select Peak Periods	1	1	1	na
Energy-Related Allocation Methodologies				
Annual Energy at Generation	2	2	3	na
Direct Assignment/Annual Energy at Generation (aMW)	na	1	1	na
Weighted Annual Energy at Generation	1	4	4	na

(1) Four utilities do not classify and allocate peaking thermal generation plant in service costs because it is either not required for their COS approach or they do not have any peaking thermal generation assets.
(2) One utility does not classify and allocate peaking thermal generation O&M costs or fuel costs because they do not have any of their own peaking thermal generation assets.
(3) One utility classifies all peaking thermal O&M costs using the Demand Only method, with the exception of certain O&M expenses that are classified using the Energy Only method. This utility indicated they used the Electric Utility Cost Allocation Manual, published January 1992, by the National Association of Regulatory Utility Commissioners as their primary guide to classification.

The approaches used to classify and allocate purchased power costs are summarized in Table 9. More detailed information is provided in Table C-4 of Appendix C and the written descriptions of the purchased power classification and allocation methodologies in Appendices C and D.

Table 9
Results of Jurisdictional Review
Purchased Power Cost Classification and Allocation Methodologies

	Number of Utilities	% Classified as Demand-Related
Classification Methodologies		
Derived from Classified Plant Costs	1	48%
Energy Only	3 (1)	0%
Generation Marginal Costs - Energy Only	1	0%
Generation Marginal Costs - Demand & Energy	1	35%
Supplier COS Results	1	30%
System Load Factor	3 (1)	34%-44%
Thermal Peak Credit	1	19%
Demand-Related Allocation Methodologies		
1 CP	1	na
4 CP	1	na
12 CP	3	na
Ave of Loads During Select Peak Periods	1	na
Relationship of Class to System Load Factors	1	na
Energy-Related Allocation Methodologies		
Annual Energy at Generation	5	na
Direct Assignment/Annual Energy at Generation (aMW)	1	na
Weighted Annual Energy at Generation	5	na

(1) One utility classifies purchased power costs from their supplier's heritage resources using the System Load Factor method. Other purchased power costs are classified using the Energy Only method.

The approaches used to classify and allocate net income from wholesale power sales revenues are summarized in Table 10. More detailed information is provided in Table C-5 of Appendix C and the written descriptions of the net income from wholesale power sales allocation methodologies in Appendices C and D.

Table 10
Results of Jurisdictional Review
Net Income from Wholesale Power Sales Cost
Classification and Allocation Methodologies

	Number of Programs (1)	% Classified as Demand-Related
Overall Approach		
Recognizes Wholesale Power Sales as Separate Class in COS	2	na
Allocates Wholesale Power Sales Revenues to Other Customer Classes	4	na
Classification Methodologies		
Derived from Classified Plant Costs	1	48%
Energy Only	1	0%
Generation Maginal Costs - Revenue Only (2)	1	0%
System Load Factor	1	34%
Demand-Related Allocation Methodologies		
12 CP	2	na
Energy-Related Allocation Methodologies		
Annual Energy at Generation/aMW	3	na
Weighted Annual Energy at Generation	1	na
Revenue-Related Allocation Methodologies		
Derived from Marginal Allocated Revenue Requirements (2)	1	na

(1) Four utilities either did not separately show how net income from wholesale power sales were handled in their COS study or they do not have any net income from wholesale power sales.
(2) One utility classifies net income from wholesale power sales as 100 percent revenue-related and then allocates the revenues to customer classes using the Derived from Marginal Allocated Revenue Requirements method.

Observations on Classification of Generation Costs

The following are overall observations regarding the classification methodologies used by the utilities in the jurisdictional review to classify generation costs:

- There is not one single predominant method used to classify generation costs, even by type of generation resource.
- Six of the utilities use the same approach to classify all costs for hydro, non-peaking thermal, and peaking thermal generation, well as purchased power costs. The majority of these utilities use Energy Only or Marginal Cost classification methods.

- The other utilities use different approaches based on the type of generation, especially for peaking thermal generation costs as compared to hydro and non-peaking thermal generation costs.
- The classification methodologies used for peaking thermal generation costs generally classify a higher percentage of costs as demand-related as compared to those methodologies used for other types of generation costs.
- Two utilities use different classification approaches for fuel and water costs as compared to other types of generation O&M costs. These utilities classify fuel and/or water costs as energy-related while other O&M costs are classified as both demand-related and energy-related.
- Three of the utilities either currently use a Peak Credit method to classify generation costs or recently switched from using a Peak Credit method. One utility currently using a Peak Credit methodology indicated that they would prefer to use a System Load Factor approach for classification, but they continued to use the Peak Credit approach in their rate filing to potentially limit the number of issues in their rate case. The utility that recently switched from using a Peak Credit method went to a System Load Factor method, and indicated it changed from using a Peak Credit method because the Peak Credit method is complicated to compute and apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and forth between energy and demand with changes in the cost of natural gas to fuel combustion turbines.

Hydro and Non-Peaking Thermal Generation

Observations specifically regarding the classification of hydro and non-peaking thermal generation costs by the utilities in the jurisdictional review are as follows:

- Six of the utilities use an approach that classifies some or all of their hydro generation plant in service costs and O&M costs as both demand-related and energy-related. Five of the utilities use an approach that classifies some or all of their non-peaking thermal generation plant in service costs and O&M costs as both demand- and energy-related. The percentages of costs classified as demand-related by these utilities range from 19 percent to 46 percent as shown in Tables 6 and 7 as well as Tables C-1 and C-2 in Appendix C.
- Hydro and non-peaking thermal generation plant in service costs and O&M costs are most commonly classified using Energy Only, System Load Factor, and Hydro/Thermal Peak Credit methods.
- Of the three utilities using the Energy Only methodology, one is required to use it by law and they subsequently allocate hydro and non-peaking thermal costs using a combination of direct assignments and the Annual Energy at Generation methodology, or average load. The other two use energy allocation factors weighted for marginal costs (i.e., Weighted Annual Energy Generation methods) to allocate hydro and non-peaking thermal generation costs to customer classes, and one of these two utilities only classifies certain

O&M costs using the Energy Only method with the balance of O&M costs being classified using the System Load Factor method.

Peaking Thermal Generation

Observations specifically regarding the classification of peaking thermal generation costs by the utilities in the jurisdictional review are as follows:

- Four of the utilities use an approach that classifies some or all of their peaking thermal generation plant in service costs and O&M costs as both demand-related and energy-related. The percentages of costs classified as demand-related by these utilities range from 19 percent to 85 percent as shown in Table 8 and Table C-3 in Appendix C.
- Peaking thermal generation plant in service costs and O&M costs are most commonly classified using Demand Only and Energy Only methods.
- Of the three utilities using the Energy Only methodology, one is required to use it by law and they subsequently allocate peaking thermal costs using a combination of direct assignments and the Annual Energy at Generation method, or average load. The other two use energy allocation factors weighted for marginal costs (i.e., Weighted Annual Energy Generation methodology) to allocate peaking thermal costs to customer classes, and one of these two utilities only classifies certain O&M costs using the Energy Only method with the balance of O&M costs being classified using the Demand Only method.

Purchased Power

Observations specifically regarding the classification of purchased power costs by the utilities in the jurisdictional review are as follows:

- Four of the utilities use an approach that classifies some or all of their purchased power costs as both demand-related and energy-related. The percentages of costs classified as demand-related by these utilities range from 19 percent to 48 percent as shown in Table 9 and Table C-4 in Appendix C.
- Purchased power costs are most commonly classified using the Energy Only or System Load Factor methods.
- Seven of the utilities use the same approaches for allocating purchased power costs as other types of generation costs. The other utilities use an allocator this is derived from total classified generation plant in service costs or their power supplier COS results.

Net Income from Wholesale Power Sales

With regard to the functionalization and classification of net income from wholesale power sales, two of the utilities recognize customers purchasing wholesale power as a separate customer class. The other utilities generally classify and allocate the net revenues consistent with the aggregate classification and allocation results for other generation resources. The percentages of net income classified as demand-related by these utilities range from 34 percent to 48 percent as shown in Table 10 and Table C-5 in Appendix C.

Observations on Allocation of Generation Costs

Observations regarding the approaches used by the utilities in the jurisdictional review to allocate demand-related generation costs are as follows:

- There is not one single predominant method used to allocate demand-related generation costs. However, the most common approach is the 12 CP method. This approach generally acknowledges that the majority of the utilities in the jurisdictional review experience their highest peaks in the winter, but they also experience high summer peaks.
- With one exception, each utility uses the same type of demand-related allocator for all their types of generation resources. The one exception uses 12 CP for all demand-related generation costs except for peaking thermal demand-related costs. These are allocated using a 3 CP approach.

Observations regarding the approaches used by the utilities in the jurisdictional review to allocate energy-related generation costs are as follows:

- There is not one single predominant method used to allocate energy-related generation costs. Both the Annual Energy at Generation and Weighted Annual Energy at Generation are used.
- Weighted Annual Energy at Generation is used primarily by utilities using either the Energy Only or Marginal Costs classification approaches.

Transmission COS Methodologies

The results of the jurisdictional review of transmission COS methodologies and observations about those results are presented below.

Results of Jurisdictional Review

The approaches used to classify and allocate transmission plant in service and associated O&M costs are shown in Table 11. More detailed information is provided in Table C-8 of Appendix C and the written descriptions of the transmission classification and allocation methodologies in Appendices C and D.

Table 11
Results of Jurisdictional Review
Transmission Costs Classification and Allocation Methodologies

	Number of Utilities		% Classified as
	Plant In Service Costs (1)	O&M Costs	Demand-Related
Classification Methodologies			
Demand Only	4	6 (2)	100%
Energy Only	na	1	0%
System Load Factor	1	1	34%
Thermal Peak Credit	1	1	19%
Transmission Division's Classified Rev Reqmt	na	1 (2)	43%
Transmission Marginal Costs - Demand Only	na	1 (3)	100%
Transmission Marginal Costs - Energy Only	na	1 (3)	0%
Demand-Related Allocation Methodologies			
1 CP	1	2 (2)	na
12 CP	2	2	na
1 NCP	1 (4)	2 (2)(4)	na
Weighted 12 CP	1	1	na
Ave of Loads During Select Peak Periods	2 (4)	3 (3)(4)	na
Energy-Related Allocation Methodologies			na
Annual Energy at Generation/aMW	2	5 (3)	na
Weighted Annual Energy at Generation	na	na	na

(1) Four utilities do not classify and allocate transmission plant in service costs because it is either not required for their COS approach or they do not have transmission assets.
(2) One utility classifies the costs charged to it by another division of the utility for generation-related transmission and interconnections with neighboring systems based on the transmission division's load factor. Network transmission costs, and costs related to customer connections, are classified as 100 percent demand-related. The demand-related costs for the generation-related transmission, interconnections with neighboring systems and network transmission costs are allocated using the 1 CP method. The costs related to customer connections are allocated using the 1 NCP method.
(3) One utility treats marginal transmission costs as demand-related and costs for wheeling by others as energy-related. Demand-related costs are allocated based on averages of peak loads during 48 costing period. Energy-related costs are allocated based on annual energy at generation.
(4) One utility sub-functionalizes their system into transmission and subtransmission. Transmission costs are allocated based on the average loads during the highest 50 peak hours in the summer and winter seasons. Subtransmission costs are allocated using the 1 NCP method.

Observations

The following are observations regarding the methodologies used by the utilities in the jurisdictional review to classify and allocate transmission costs:

- In the jurisdictional review, the Demand Only method is the most common classification method for transmission costs. However, several other methods are also used. The types of allocation factors used for demand-related transmission costs are spread fairly evenly between the 1CP, 12 CP, 1 NCP, and Average of Loads During Select Peak Periods methods.
- Three of the utilities use an approach that classifies some or all of their transmission plant in service costs and associated O&M costs as both demand-related and energy-related. The percentages of costs classified as demand-

related by these utilities range from 19 percent to 43 percent as shown in Table 11 and Table C-6 in Appendix C.

- Six of the utilities in the jurisdictional review use the same general approach to classify transmission resources as generation resources. Five utilities use the same general approach to allocate transmission demand-related costs and generation demand-related costs. Four utilities use the same approach to allocate transmission energy-related costs and generation energy-related costs.
- Three of the utilities sub-functionalize their transmission costs to separate out transmission by type of use such as (1) generation-related or long-distance related versus in-area or network-related, (2) backbone power transmission versus radial transmission/subtransmission being used primarily as high voltage distribution, etc.

Distribution COS Methodologies

The results of the jurisdictional review of distribution COS methodologies and observations about those results are presented below.

Results of Jurisdictional Review

The types of distribution COS methodologies used by the utilities included in the jurisdictional review by type of resource are presented below.

The approaches used to classify and allocate distribution substation plant in service and associated O&M costs are summarized in Table 12. More detailed information is provided in Table C-9 of Appendix C and the written descriptions of the distribution substation classification and allocation methodologies in Appendices C and D.

Table 12
Results of Jurisdictional Review
Distribution Substation Cost Classification and Allocation Methodologies

	Number of Utilities		% Classified as
	Plant In Service Costs (1)	O&M Costs (2)	Demand-Related
Classification Methodologies			
Demand Only	7	7	100%
Dist Substation Marginal Costs - Demand Only	na	2	100%
Demand-Related Allocation Methodologies			
1 NCP	3	4	na
12 NCP	3	3	na
Ave of Loads During Select Peak Periods	na	1	na
Substation 12 NCPs	1	1	na

(1) Three utilities do not classify and allocate distribution substation plant in service costs because it is either not required for their COS approach or they do not have distribution substation assets.
(2) One utility does not classify and allocate distribution substation O&M costs because it does not have distribution substation assets.

The approaches used to classify and allocate distribution lines plant in service and associated O&M costs are summarized in Table 13. More detailed information is provided in Table C-10 of Appendix C and the written descriptions of the distribution wires classification and allocation methodologies in Appendices C and D.

Table 13
Results of Jurisdictional Review
Distribution Lines Cost Classification and Allocation Methodologies

	Number of Utilities		% Classified as
	Plant In Service Costs (1)	O&M Costs (2)	Demand-Related
Classification Methodologies			
Computation Method	1	1	64%
Demand Only	3	3	100%
Distribution Lines Marginal Costs - Demand Only	na	2	100%
Historic Study	1	1	60%
Minimum System Study	2	2	64%-79%
Demand-Related Allocation Methodologies			
1 NCP	3	4	na
12 NCP	3	3	na
Ave of Loads During Select Peak Periods	na	1	na
Feeder 12 NCPs and Miles	1	1	na
Customer-Related Allocation Methodologies			
Number of Unweighted Customers	4	4	na

(1) Three utilities do not classify and allocate distribution line costs because it is either not required for their COS approach or they do not have distribution assets.
(2) One utility does not classify and allocate distribution line costs because it does not have any distribution assets.

The approaches used to classify and allocate distribution transformer plant in service and associated O&M costs are summarized in Table 14. More detailed information is provided in Table C-11 of Appendix C and the written descriptions of the distribution wires classification and allocation methodologies in Appendices C and D.

Table 14
Results of Jurisdictional Review
Distribution Transformer Cost Classification and Allocation Methodologies

	Number of Utilities		% Classified as
	Plant In Service Costs (1)	O&M Costs (2)	Demand-Related
Classification Methodologies			
Computation Method	1	1	64%
Customer Only	2	2	0%
Demand Only	3	3	100%
Distribution Transformer Marginal Costs - Customer Only	na	1	0%
Distribution Transformer Marginal Costs - Demand Only	na	1	100%
Zero Intercept Analysis	1	1	73%
Demand-Related Allocation Methodologies			
1 NCP	3	3	na
12 NCP	2	2	na
Connected Load	na	1	na
Customer-Related Allocation Methodologies			
Direct to Customer Classes	1	1	na
Number of Unweighted Customers	1	1	na
Number of Weighted Customers	2	3	na

(1) Three utilities do not classify and allocate distribution transformer plant in service costs because it is either not required for their COS approach or they do not have distribution assets.
(2) One utility does not classify and allocate distribution transformer O&M costs because it does not have any distribution assets.

The approaches used to classify and allocate distribution services plant in service are summarized in Table 15. More detailed information is provided in Table C-12 of Appendix C and the written description of the distribution services plant classification and allocation methodologies in Appendices C and D.

Table 15
Results of Jurisdictional Review
Distribution Services Cost Classification and Allocation Methodologies

	Number of Utilities (1)	% Classified as Demand-Related
Classification Methodologies		
Customer Only	7	0%
Distribution Services Marginal Costs - Customer Only	1	0%
Distribution Services Marginal Costs - Demand Only	1	100%
Demand-Related Allocation Methodologies		
Ave of Loads During Select Peak Periods	1	na
Customer-Related Allocation Methodologies		
Direct to Customer Classes/No. of Services	1	na
Number of Unweighted Customers	3	na
Number of Weighted Customers	4	na

(1) One utility does not classify and allocate distribution service plant in service costs because they do not have distribution assets.

The approaches used to classify and allocate distribution meters plant in service and associated O&M costs are summarized in Table 16. More detailed information is provided in Table C-13 of Appendix C and the written description of the distribution meter classification and allocation methodologies in Appendix D.

Table 16
Results of Jurisdictional Review
Distribution Meter Cost Classification and Allocation Methodologies

	Number of Utilities		% Classified as
	Plant In Service Costs (1)	O&M Costs (2)	Demand-Related
Classification Methodologies			
Customer Only	7	7	0%
Distribution Meter Marginal Costs - Customer Only	na	2	0%
Customer-Related Allocation Methodologies			
Book Value	1	1	na
Number of Weighted Customers	6	7	na
Number of Weighted Meters	na	1	na

(1) Three utilities do not classify and allocate distribution meter plant in service costs because it is either not required for their COS approach or they do not have distribution assets.
(2) One utility does not classify and allocate distribution meter O&M costs because it does not have any distribution assets.

Observations on Classification of Distribution Costs

The following are overall observations regarding the classification methodologies used by the utilities in the jurisdictional review to classify distribution costs:

- All the utilities classify distribution substation costs as 100 percent demand-related and distribution services and meter costs as 100 percent customer-related.
- Four utilities classify costs for distribution lines as both demand-related and energy-related, while only two utilities classify costs for transformers as both demand-related and customer-related. Of those costs classified as both demand-related and customer-related, the percentage classified as demand-related ranged from 60 percent to 79 percent. The other utilities classified these types of costs as either 100 percent demand-related or 100 percent customer-related.
- Three utilities use the same approach for classifying costs associated with distribution lines as for classifying distribution transformer costs. The others use different approaches.
- Seven of the utilities use the same demand-related allocator to allocate demand-related costs for distribution substations, lines, and transformers.
- The type of customer-related allocation factors used by the utilities generally varied by type of distribution costs. Most commonly, the methods used are either Number of Weighted Customers or Number of Unweighted Customers.

For the Number of Weighted Customer method, the type of weightings vary by type of distribution costs.

Distribution Substations

Observations specifically regarding classification of distribution substation costs by the utilities in the jurisdictional review are as follows:

- As stated above, all of the utilities with distribution assets classified associated plant in service and O&M costs as 100 percent demand-related.
- Seven of the utilities used the Demand Only method while the other two utilities, as part of their overall marginal cost methodology, treat their distribution substation marginal costs as 100 percent demand-related.

Distribution Lines

Observations specifically regarding classification of costs for lines by the utilities in the jurisdictional review are as follows:

- Five of the utilities in the jurisdictional survey classify costs for distribution lines as 100 percent demand-related. Of these utilities, three use the Demand Only method while the other two utilities, as part of their overall marginal cost methodology, treat their marginal costs for lines as 100 percent demand-related.
- None of the utilities classify 100 percent of costs for distribution lines as 100 percent customer-related.
- Four of the utilities use classification approaches that classify costs for distribution lines as both demand-related and customer-related. Some of the studies or approaches used to classify these costs appeared to be somewhat dated. Of those costs classified as both demand-related and customer-related, the percentage classified as demand-related ranged from 60 percent to 79 percent as shown in Table 13 and Table C-10 of Appendix C.

Distribution Transformers

Observations specifically regarding classification of transformer costs by the utilities in the jurisdictional review are as follows:

- Four of the utilities in the jurisdictional survey classify transformer costs as 100 percent demand-related. Of these utilities, three use the Demand Only method while the other utility, as part of their overall marginal cost methodology, treats their distribution transformer marginal costs as 100 percent demand-related.
- Three of the utilities in the jurisdictional survey classify transformer costs as 100 percent customer-related. Of these utilities, two use the Customer Only method while the other utility, as part of their overall marginal cost methodology, treats their distribution transformer marginal costs as 100 percent customer-related.

- Two of the utilities use classification approaches that classify transformer costs both demand-related and customer-related. Of those costs classified as both demand-related and customer-related, the percentage classified as demand-related range from 64 percent to 73 percent as shown in Table 14 and Table C-11 of Appendix C. The other utilities classify these types of costs as either 100 percent demand-related or 100 percent customer-related.

Distribution Services and Meters

All of the utilities in the jurisdictional review classify distribution services and meter costs as 100 percent customer-related. They all use the Customer Only method except the two utilities that, as part of their overall marginal cost methodology, treat their marginal costs for distribution services, and/or meters, as 100 percent customer-related.

Observations on Allocation of Distribution Costs

Observations regarding the approaches used by the utilities in the jurisdictional review to allocate demand-related and customer-related distribution costs are as follows:

- There is not one single predominant method used to allocate demand-related distribution costs. Both the 1 NCP and 12 NCP methods are common.
- Also, there is not one single predominant method used to allocate customer-related distribution costs. The Number of Unweighted Customers method and the Number of Weighted Customers method are most common, but it should be noted that the type of weightings used by those utilities that employ the Number of Weighted Customers method vary significantly between utilities and types of distribution costs.
- As discussed previously, the majority of the utilities use the same demand-related allocator to allocate demand-related costs for distribution substations, lines, and transformers.
- Some of the utilities use rather sophisticated distribution costs allocation methodologies that require detailed accounting data or feeder load data to either directly assign or allocate certain distribution costs. Not all facilities have this type of data available.

COS Methodologies for DSM, Energy Efficiency, and Conservation Programs

The results of the jurisdictional review of COS methodologies for DSM, energy efficiency, and conservation programs, and observations about those results, are presented below.

Results of Jurisdictional Review

The approaches used to functionalize, classify, and allocate DSM, energy efficiency, and conservation program costs by the utilities in the jurisdictional review are summarized in Table 17. More detailed information is provided in Table C-12 of Appendix C and the written description of the DSM, energy efficiency, and conservation program classification and allocation methodologies in Appendices C and D.

Table 17
Results of Jurisdictional Review
DSM, Energy Efficiency, and Conservation Program Cost
Classification and Allocation Methodologies

	Number of Programs (1)	% Functionized as Gen/Trans/Dist Related	% Classified as Demand-Related
Functionalization Methodologies			
Generation Only	7	100%	na
Derived from Other Functionalized O&M Costs	2	Gen 13%-95% / Trans 2%-10% / Dist 4%-59%	na
Supply Cost Savings	1	Gen 97% / Trans 3%	na
Classification Methodologies			
Demand Only	3	na	100%
Derived from Classified Plant Costs	1	na	48%
Derived from Other Classified O&M Costs	1	na	49%
Energy Only	1	na	0%
Generation Marginal Costs - Energy Only	1	na	0%
Supply Cost Savings	1	na	5%
System Load Factor	1	na	46%
Thermal Peak Credit	1	na	19%
Demand-Related Allocation Methodologies			
1 CP	2	na	na
3 CP	1	na	na
12 CP	2	na	na
Derived from Other Demand-Related Allocated C	2	na	na
Ave of Loads During Select Peak Periods	1	na	na
Energy-Related Allocation Methodologies			
Derived from Other Energy-Related Allocated O&	1	na	na
Annual Energy at Generation/aMW	4	na	na
Weighted Annual Energy at Generation	2	na	na

(1) Two of the utilities separately identified costs for multiple types of programs. Costs for DSM, energy efficiency, or conservation programs were not separately identified in three of the utilities' COS analyses.

Observations

Observations regarding the functionalization and classification of DSM, energy efficiency, and energy conservation costs by the utilities in the jurisdictional review are as follows:

- The majority of the utilities functionalize 100 percent of these costs to generation. The other utilities allocate the costs to multiple functions using functionalization factors derived from other types of functionalized costs or savings such as administrative and general expenses, supply costs savings, and total functionalized O&M costs. For those utilities allocating costs to multiple functions, the ranges of amounts allocated to each function are as follows:
  - Generation - 13 percent to 95 percent.
  - Transmission - 2 percent to 10 percent.
  - Distribution - 0 percent to 59 percent.
- For the majority of the utilities, the approaches used to classify some or all of their DSM, energy efficiency, and energy conservation costs differ from the approaches used for other types of generation resources.

Target R/C Ratios

The results of the jurisdictional review regarding approaches for establishing target R/C ratios for rate design are presented below.

Results of Jurisdictional Review

The utilities' approaches for establishing the R/C ratios for their proposed rate design are summarized in Table 18. More detailed information is provided in Table C-13 of Appendix C and the written description of the distribution meter classification and allocation methodologies in Appendices C and D.

Table 18
Results of Jurisdictional Review
Approaches for Establishing R/C Ratios for Proposed Rate Design

		Based on Existing Rates		Based on Proposed Rates
Approaches for Establishing R/C Ratios for Proposed Rate Design	Target R/C Ratios	Total System R/C Ratio	Range of Class R/C Ratios	Range of Class R/C Ratios
Across-the-Board Increases	na	92%	81% - 119%	89% - 130%
Across the Board Increases w/ Specified Residential R/C Ratio	na	na	na	83% - 134%
Caps on Rate Increases	100%	92%	41% - 106%	48 % - 104%
COS Results as a "Guide"	na	96%	86% - 107%	90% - 111%
Dictated by Law	100%	na	na	100%
Dictated by City Council Resolutions	100%	96%	79% - 103%	100%
Limits on Rate Increases and Decreases	100%	92%	57% - 216%	66% - 216%
Mutiple Guidelines	95% - 105%	92%	81% - 98%	93% - 105%
Target Range of R/C Ratios	90% - 110%	100%	95% - 113%	96% - 110%
Target Range of R/C Ratios /Across-the-Board Rate Changes	95% - 105%	100%	89% - 108%	94% - 114%

The information in Table 18 shows the following:

- **Across-the-Board Increases –** Two utilities primarily used across-the-board increases in their rate design approach, with provincial law requiring one utility to keep the residential R/C ratio at 0.83. This resulted in class R/C ratios for proposed rates in the range of 89 percent to 130 percent and 83 percent to 134 percent for these two utilities, respectively.
- **Caps on Rate Increases –** One of the utilities limited rate increases to a maximum increase of 17 percent per class, and the resulting range of class R/C ratios for proposed rates was 48 percent to 104 percent.
- **COS Results as a "Guide" –** One of the utilities indicated they use the COS results as a "guide" for rate design. The range of R/C ratios resulting from their proposed rates was 90 percent to 111 percent.
- **Dictated by Law/City Resolutions –** Two of the utilities identified target R/C ratios of 100 percent in their rate design objectives and proposed rates generally brought customer classes to R/C ratios of 100 percent. The rate design approaches used by these two utilities are largely dictated by law or city council resolutions.
- **Limits on Rate Increases and Decreases –** One utility uses the following guidelines to move their customer classes toward R/C ratios of 100 percent: (1) no decreases for any rate class and (2) a cap of 1.5 times the system average rate increase for any class. The range of R/C ratios resulting from their proposed rates was 66 percent to 216 percent.
- **Multiple Guidelines –** One of the utilities reported that a range of target R/C ratios for rate design equal to 95 percent to 105 percent was among their rate design objectives. With some additional guidelines that limited increases and

decreases, the utility's range of class R/C ratios resulting from their proposed rate designs was 93 percent to 105 percent.

- **Target Range of R/C Ratios –** One of the utilities reported a range of target R/C ratios for rate design equal to 90 percent to 110 percent, and their proposed rates resulted in all class R/C ratios being within the target range. The range of R/C ratios resulting from the proposed rates was 96 percent to 110 percent.
- **Target Range of R/C Ratios/Across-the-Board Rate Increases –** One of the utilities reported that a range of 95 percent to 105 percent for targeted class R/C ratios was among their rate design objectives, but then proposed across-the-board rate increases that resulted in class R/C ratios for proposed rates in the range of 94 percent to 114 percent.

Observations

In general, the utilities in the jurisdictional review all indicated they advocate movement towards cost based rates in their rate design proposals, but other objectives such as rate stability and minimizing customer impacts were also of importance. Only one utility proposed rates that brought all their customer classes with their target range of R/C ratios. As shown in Table 18, the rates proposed by several of the utilities result in class R/C ratios outside a range of 90 percent to 110 percent. Most of the utilities have multiple guidelines or rate design objectives that are used for rate rebalancing.

Appendix A
UTILITIES IN JURISDICTIONAL REVIEW

Please see the table showing characteristics of utilities included in the jurisdictional review on the following page.

Table A-1
Comparison of Utilities for Jurisdictional Review

	Peak Season	Hydro Power % (incl purchases)	Number of Electric Customers	Total Electric Sales Revenues	Ownership	Electric Functions	Purchased as % of total kWh	Exports as % of kWh Sales	Service Area	Last Filing/COS Analysis	Docket	Type of RR	Type of COS
Avista	Winter	51%	360,000	$800 million	Private	Vertically integrated	49%	31%	Electric and natural gas customers in northern Idaho (1)	2012	AVU-E-12-08	Historical	Embedded
									Electric and natural gas customers in eastern Washington	2011	UE-120436	Historical	Embedded
Bonneville Power	Winter	80%	146 (455 transmission customers)	$3,200 million	Government	G&T (generation and transmission)	10%	8%	Electric customers in the Pacific Northwest including utilities, federal agencies, industries, and port districts	2012	BP-14	Prospective	Embedded (2)
Hydro-Québec Distribution	Winter	98%	4,060,000	$12,100 million	Government	Four divisions (G & T & D & Equipmt Services) with only T & D being regulated (3)	16%	14%	Quebec	2012	Demande R-3814-2012	Prospective	Embedded
Idaho Power	Summer	63%	410,000	$1,000 million	Private	Vertically integrated	15%	26%	Eastern Oregon and Southern Idaho	2011 2011	UE 233 (Oregon) IPC-E-11-08 (Idaho)	Prospective	Embedded (4)
Manitoba Hydro	Winter	96%	540,000	$1600 million	Government	Vertically integrated	3%	33%	Maintoba	2012	2012/13 AND 2013/14 GENERAL RATE APPLICATION	Prospective	Embedded (5)
Newfoundland Power	Winter	69%	240,000	$600 million	Private	Vertically integrated, but most power needs are met with purchased power	90% from Newfoundland and Labrador Hydro	<1%	Approximately 86% of consumers in province	2012	2013/2014 General Rate Application	Historical	Embedded
Portland General Electric	Winter	42%	810,000	$1,800 million	Private	Vertically integrated	58%	14%	Portland and surrounding communities	2010	UE-215	Prospective	Marginal
Puget Sound Energy	Winter	54%	1,100,000	$2,200 million	Private	Vertically integrated	54%	23%	Puget Sound region of Western Washington	2011	UE-111048	Historic	Embedded
Seattle City Light	Winter	92%	400,000	$800 million	Government	Vertically integrated	56%	41%	Seattle and parts of its metro areas	2012	NA	Prospective	Marginal
BC Hydro	Winter	89%	1,870,000	$4,400 million	Government	Vertically integrated	40%	32%	British Columbia	2007	2007 Rate Design Application	Prospective	Embedded

(1) Also services natural gas customers in southern and eastern Oregon.
(2) Marginal costs are used for rate design purposes.
(3) The Regie de L'energie only regulates the transmission and distribution functions. Beyond their heritage pool volume, Hydro-Quebec Production competes with other generators in response to Hydro-Quebec Distribution's calls for tenders, which determine the cost of electric power other than the heritage pool. Heritage pool power if provided at fixed $/kWh rate to Distribution.
(4) Energy-related production plant and expenses are allocated based on annual energy at generation with monthly marginal energy cost weightings (averaged with unweighted values).
(5) Energy-related production plant and expenses are allocated based on annual energy at generation with seasonal/time-of-day marginal energy cost weightings.

Classification Methodologies for Generation and Transmission Resources

The following approaches are used by the utilities surveyed to classify generation and transmission plant in service costs and associated O&M costs, purchased power costs, net income from wholesale power sales, and DSM, energy efficiency, and energy conservation program costs:

- **Commission Ordered** – One utility uses this approach. BC Hydro classifies its hydro plant in service as 55 percent demand-related and 45 percent energy-related based on the 2007 BCUC Order.
- **Demand Only** – Using this approach, generation plant in service and associated O&M expenses are classified as 100 percent demand-related.

  Seven utilities, including BC Hydro, use this approach as follows:

  - Avista Corporation–Idaho, Portland General, and Newfoundland Power classify all transmission plant in service and associated O&M expenses as demand-related.
  - BC Hydro uses this approach to classify plant in service associated with peaking thermal generation, diesel generation in integrated areas, and transmission assets and lines.
  - Hydro-Québec Distribution classifies network transmission costs and customer interconnection costs as 100 percent demand-related.
  - Idaho Power uses this methodology to classify peaking thermal plant in service costs, as well as certain related O&M costs excluding fuel, and DSM incentive payments. They also use it to classify all transmission plant in service costs and associated O&M costs, with the exception of costs associated with wheeling by others.
  - Manitoba Hydro classifies all transmission and subtransmission plant in service, and associated O&M costs, as demand-related.
  - Newfoundland Power uses this methodology to classify non-peaking thermal plant in service and peaking thermal plant in service, as well as associated O&M costs including fuel, and DSM incentive account expenses.

- **Derived from Classified Generation Plant Costs** – Using this approach, the percentage of total generation plant in service that is classified as demand-related (versus energy-related) is first calculated. Then the share of costs being classified that is attributable to demand is equal to that percentage.

  Two utilities use this approach as follows:

  - Avista Corporation–Idaho uses the demand/energy split for total classified generation plant in service to classify purchased power costs between demand and energy, as well as DSM investment in rate base, related amortization expense, and net income from wholesale power sales.
  - BC Hydro uses the demand/energy split for total classified generation plant in service to classify O&M costs for hydro and peaking thermal generation resources, as well as generation-related DSM costs.

- **Derived from Classified Transmission Plant Costs** – Using this approach, the percentage of total transmission plant in service that is classified as demand-related (versus meter-related) is first calculated. Then the share of costs being classified that is attributable to demand is equal to that percentage.

  One utility uses this approach. BC Hydro uses the demand/meter split for classifying transmission assets, lines, and meters, domestic transmission costs for wheeling of power from heritage resources as well as transmission-related DSM costs.

- **Derived from Classified Generation Revenue Requirement** – One utility uses this approach. BC Hydro classifies subsidiary net income based on the classified generation revenue requirement excluding subsidiary net income.

- **Derived from Other Classified O&M Costs** – One utility uses this approach. Newfoundland Power functionalizes, classifies, and allocates conservation and DSM general costs based on the percentages of corporate administration and general expenses functionalized, classified, and allocated to customer classes.

- **Energy Only** – Using this approach, generation and transmission plant in service and associated O&M expenses are classified as 100 percent energy-related.

  Six utilities use this approach, including BC Hydro, as follows:

  - Avista Corporation–Idaho uses this methodology to classify hydro water costs as well as non-peaking and peaking fuel costs.
  - BC Hydro uses this methodology to classify (1) fuel costs associated with thermal generation, (2) plant in service, O&M costs, and fuel costs associated with diesel generation in non-integrated areas, (3) purchased power costs including market purchases and capacity and energy payments associated with purchases from IPPs, and (4) revenues from power sales including surplus sales and sales to Powerex.

  - BPA's cost of COS methodology generally treats all generation and purchased power-related costs, as well as conservation and energy efficiency costs, as energy-related for subsequent allocation to customer classes using a combination of energy-related allocation factors and direct assignment. It also treats all transmission O&M costs as energy-related.
  - Hydro-Québec Distribution uses this methodology to classify purchased power costs from non-heritage resources.
  - Idaho Power uses this methodology for classifying certain O&M costs associated with hydro and non-peaking thermal plant in service that are not classified using the system load factor approach including non-peaking plant fuel costs. In addition, this methodology is also used for classifying certain O&M costs associated with peaking thermal plant O&M costs, excluding fuel, that are not classified using the energy-only approach. Finally, it is used to classify costs associated with wheeling by others and net income from wholesale power sales.
  - Manitoba Hydro's methodology generally treats all generation and purchased power-related costs as energy-related for subsequent allocation to customer classes using weighted energy non-peaking-related allocation factors.

- **Hydro Peak Credit** – One utility uses this approach. Avista Corporation–Idaho uses the ratio of its current replacement cost per kilowatt (kW) of their peaking units to the current replacement cost per kW of their hydro plant to classify hydro plant and related O&M costs, excluding water costs. The share of hydro costs attributable to demand is equal to the ratio.
- **Marginal Costs** – Using a marginal cost approach, utilities generally (1) calculate marginal production and transmission capacity and energy costs for a test year, thus identifying the demand-related and/or energy-related portions of marginal costs, (2) allocate demand-related and/or energy-related components of marginal costs to customer classes, and (3) allocate embedded costs for generation and transmission based on the percentages by class of total allocated marginal capacity and energy costs.

  Two utilities use somewhat different approaches to calculate marginal generation costs as follows:

  - **Generation Marginal Costs – Demand and Energy** – Portland General separately calculates long-run marginal production capacity and energy costs for a test year, thus identifying the demand-related and energy-related portions of marginal generation costs.
  - **Generation Marginal Costs – Energy Only** – Seattle City Light uses forecasted hourly wholesale per megawatt hour (MWh) market prices plus externality costs as their marginal energy generation costs, so all marginal generation costs are considered energy-related.

One utility, Seattle City Light, uses this approach and calculates marginal transmission costs as follows:

- o **Transmission Marginal Costs – Demand Only –** First, annualized costs for transmission service in Seattle City Light's service area are calculated. Historical three-year annual average transmission O&M costs are adjusted for inflation. Annualized capital-related costs are based on replacement costs for in-service area transmission lines. Based on how these marginal costs are subsequently allocated, these costs are considered 100 percent demand-related.
- o **Transmission Marginal Costs – Energy Only** – Seattle City Light calculates marginal costs for long-distance transmission service as BPA's monthly transmission service price on a $ per MW basis multiplied by estimated peak system load multiplied by 12. Based on how these marginal costs are subsequently allocated, these costs are considered 100 percent energy-related.

- **Meter Only** – One utility uses this approach. BC Hydro classifies transmission meters as 100 percent meter related.
- **Revenue Only –** One utility uses this approach. Seattle City Light classifies 100 percent of their net income from wholesale power sales as revenue related.
- **Supplier COS Results** – One utility uses this approach. Newfoundland Power purchases the majority of their power from Newfoundland and Labrador Hydro. Newfoundland Power classifies purchased power based on Newfoundland and Labrador Hydro's classified cost to serve Newfoundland Power for the 2007 forecast test year. Newfoundland and Labrador Hydro use the System Load Factor method to classify hydro resources and associated transmission resources, and a combination of plant capacity factor and demand-only methods for thermal generation and associated transmission resources. Other transmission resources used to serve Newfoundland Power are classified as demand-related.
- **Supply Cost Savings –** One utility uses this approach. Newfoundland Power uses it for classifying conservation and demand management programs developed for the purpose of obtaining measureable changes in customer usage. The programs are classified between demand and energy reflective of the supply cost savings that occurred (95 percent to production energy, 2 percent to production demand, and 3 percent to substation demand).
- **System Load Factor** – Using this method, the utility's electric system load factor for the test year is first calculated as the ratio of system average demand divided by system peak demand. Then the share of plant in service and/or associated O&M costs attributable to demand is equal to one minus the load factor.

  Four utilities use this approach as follows:

  - Avista Corporation–Washington uses this methodology to classify (1) all of its hydro, non-peaking thermal, peaking thermal, and renewables plant costs, (2) associated generation O&M costs including fuel and water costs, (3) purchased power costs, (4) transmission plant in service costs, (5) associated transmission O&M costs, and (6) net income from wholesale power sales.
  - Hydro-Québec Distribution uses this methodology to classify purchased power costs from heritage resources and generation-related transmission costs and costs for interconnections with neighboring systems based on the load factor of Hydro-Québec Transmission Division (TransÉnergie).
  - Idaho Power uses this methodology for classifying (1) hydro plant in service and non-peaking thermal plant in service, (2) certain O&M costs associated with hydro and non-peaking thermal plant including hydro water costs, (3) purchased power costs, and (4) customer assistance costs for energy efficiency programs..
  - Newfoundland Power uses this methodology to classify hydro plant in service and related O&M costs including water costs.
- **Thermal Peak Credit** – Two utilities use this methodology, but their approaches somewhat differ as follows:
  - Avista Corporation–Idaho uses the ratio of their current replacement cost per kW of their peaking units to the current replacement cost per kW of their thermal plant for classification of costs associated with non-peaking thermal resources and renewables, excluding thermal fuel costs.
  - Puget Sound Energy's approach uses the ratio of the cost per kW-year of generating capacity for a proxy peaking generating resource to the cost per kW-year of generating capacity for a proxy baseload generating resource (thermal peak credit). The share of production costs attributable to demand is equal to the ratio. Puget Sound Energy uses this approach to classify all of its generation plant in service accounts and related O&M costs including water costs, thermal fuel costs, and purchased power costs, as well as weatherization customer assistance costs. Using this method, the ratio of the per unit cost of peaking plant divided by per unit cost of baseload plant is first calculated. The share of generation plant in service and associated O&M costs attributable to demand is equal to the ratio. Puget Sound Energy also uses the thermal peak credit approach for classifying transmission plant in service and associated O&M costs. Peak credit percentages are applied to transmission costs by Puget Sound Energy under the theory that transmission lines are constructed to deliver energy and capacity provided by generating plant, and in the same proportion as it is being provided.

- **Water Rental Rates** – One utility uses this approach. BC Hydro allocates water rental costs based on the underlying fixed and variable rental charges.

Allocation Methodologies for Generation and Transmission Resources

The following approaches are used by the utilities in the jurisdictional review to allocate demand-related, revenue-related, and meter-related generation and transmission plant in service costs and associated O&M costs, purchased power costs, net income from wholesale power sales, and DSM, energy efficiency, conservation costs:

- **1 CP** – This approach first determines the system peak that is the highest system demand during the entire year. Then each class's CP percentage is the ratio of that class's demand at the time that the system peak occurred divided by the system peak demand at that time that the system peak occurred.

  Two utilities use this approach as follows:

  - Hydro-Québec Distribution uses 1 CP for allocation of demand-related transmission O&M expenses, with the exception of costs associated with customer connections.
  - Newfoundland Power uses 1 CP to allocate demand-related hydro, non-peaking thermal, and peaking thermal generation plant in service costs and associated demand-related O&M costs. In addition, they use it to allocate demand-related costs for (1) conservation and demand management programs developed for the purpose of obtaining measureable changes in customer usage, (2) transfers to the reserve stabilization fund associated with their demand management incentives, and (3) transmission plant in service and associated O&M.

- **3 CP** – This approach first determines the three months with the highest monthly system peak demands over a twelve-month period, and then determines each class's demand at the time of those three monthly system peak demands. Each class's 3 CP percentage is then determined as the ratio of the sum of the class's demands at the time of the three highest system peaks divided by the sum of the three highest system peak demands.

  One utility uses this approach. Idaho Power uses 3 CP during the summer months to allocate demand-related plant in service and associated O&M costs for peaking resources that are primarily used during the summer as well as demand-related DSM costs for incentive payments and costs for customer assistance related to energy efficiency programs.

- **4 CP** – This approach first determines the four months with the highest monthly system peak demands over a twelve-month period, and then determines each class's demand at the time of those four monthly system peak demands. Each class's 4 CP percentage is then determined as the ratio of the sum of the class's demands at the time of the four highest system peaks divided by the sum of the four highest system peak demands.

Two utilities use this approach as follows:

- BC Hydro uses this approach to allocate demand-related hydro O&M and water rental costs and demand-related O&M costs associated with peaking thermal generation. BC Hydro also uses this approach to allocate demand-related O&M associated with transmission assets, lines, and meters, and demand-related transmission costs related to heritage resources. Finally, BC Hydro uses this approach to allocate demand-related DSM costs and subsidiary net income.
- Portland General allocates marginal capacity-related generation O&M costs using the demands from the months of January, July, August and September. They also allocate demand-related transmission O&M costs using the demands from the same four months.

- **12 CP** – This approach first determines the highest system peak demand for each month over a twelve-month period, and then each class's demand at the time of each system peak. Each class's 12 CP percentage is then determined by taking the ratio of the sum of the class's demands at the time of the twelve system peaks dividing by the sum of the twelve system peak demands.

  Three utilities use this approach as follows:

  - Avista Corporation–Washington and Avista Corporation–Idaho both use this approach to allocate all demand-related generation and transmission plant in service costs and associated O&M costs as well as demand-related net income from wholesale sales. Avista Corporation–Idaho also uses it to allocate amortization expenses related to weatherization and DSM investment. They indicated that although they are usually winter peaking utilities, they experience high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.
  - Idaho Power also uses the 12 CP approach to allocate demand-related plant in service and associated costs for hydro and non-peaking thermal resources. They also use it to allocate demand-related transmission plant in service and related O&M costs.

- **1 NCP** – This approach first determines each class's NCP load during the year regardless of when the other class's or system peak loads occur. Then each class's NCP percentage is the ratio of that class's NCP demand at the time class peaked divided by the sum of all the classes' NCP demands.

  Two utilities use this methodology:

  - Hydro Quebec Distribution uses this approach to allocate demand-related transmission O&M expenses associated with customer connections.
  - Manitoba Hydro uses this approach to allocate demand-related O&M costs associated with sub-transmission.

- **Average of Loads During Select Periods** – This approach first determines the average loads of each class during selected period(s). Each class's allocation percentage is the ratio of that class's average load during the selected period(s) divided by the sum of all classes' loads during the selected period(s).

  Three utilities use this approach as follows:

  - Manitoba Hydro utilizes a summer and winter coincident demand peak allocator based upon the average of the highest 50 peak hours in each season, adjusted for losses, for transmission facilities larger than 100 kV. Peak loads on the transmission system are approximately equivalent in magnitude in both seasons. High winter loads are caused by domestic retail space heating, while summer loads can be comparatively high because of export sales.
  - Puget Sound Energy allocates (1) demand-related generation plant in service costs and related O&M costs, (2) demand-related transmission plant in service and related O&M costs, and (3) weatherization customer assistance expenses based on each class's average contribution to the average hourly class loads that occurred coincident with the top 75 system hourly loads during the test year. The percentage allocated to each class is the ratio of that class's average demand during the 75 peak hours divided by the average system peak demand during those 75 peak hours.[7]
  - Seattle City Light uses class contributions to the highest average system MW load in 48 costing periods during the year to allocate marginal demand-related costs for transmission in their service area.[8]

- **Derived from Marginal Allocated Revenue Requirements** - Seattle City Light's net revenues from wholesale sales are allocated based on the shares of the total marginal revenue requirements allocated by marginal cost shares.

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7 Puget Sound Energy uses estimated peak demands at 23 degrees Fahrenheit to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. They determined that over the last 15 years, the largest number of hours in any one year that the hourly temperature was 23 degrees or colder was 75 hours.

8 For the last several rate reviews, estimates of projected consumption for aggregations of the hourly data were used (four costing periods each month or 48 per year) with the expectation that statistical errors in individual hours would, on average, balance out in the forecast periods. The total energy estimated for each period is then divided by the number of hours in the period to estimate the expected average hourly consumption. The coincident peaks for classes as total groups are then determined for the costing period with the largest hourly average consumption. Class contribution percentages to average MW per hour in the costing period during the year with the maximum load are used to allocate costs.

- **Derived from Other Demand-Related Allocated Costs** – One utility uses this approach. Newfoundland Power allocates demand-related conservation and DSM general costs based on the percentage allocations of total demand-related corporate administration and general expenses to customer classes. They also allocate demand-related curtailable service options costs based on the percentage allocations of total demand-related O&M costs.
- **Meter Replacement Costs** – One utility uses this approach. BC Hydro uses relative meter replacement costs for customers served at transmission voltages to allocate meter-related O&M costs for transmission assets, lines, and meter, and demand-related domestic transmission costs related to heritage resources. BC Hydro also uses this approach for allocating transmission meter-related DSM costs.
- **Relationship of Class to System Utilization Factors** – Using this approach, the ratio of class to system utilization factors is a key component in the calculation of the allocation factors.

  One utility uses this approach. Hydro-Québec Distribution allocates demand-related purchased power costs from heritage resources based on the relationship between the specific load factor (i.e., utilization factor), of each class of consumers and the total distribution load factor. A class load factor, or utilization factor, is equal to the class average annual MW divided by the class non-coincident peak MW within a defined 300-hour peak period. For example, assuming a class load factor of 48.0 percent, class power losses of 9 percent, and system power losses of 8 percent, and heritage pool demand-related costs of 0.96¢ per kWh, the allocated cost to the class would be 0.96¢/kWh X 65.6%/48.0% X (1+9%)/(1+8%) = 1.32 ¢/kWh. This cost would then be multiplied by class annual energy consumption with appropriate adjustments for losses.

The following approaches are used by the utilities in the jurisdictional review to allocate energy-related, revenue-related, and meter-related generation and transmission plant in service costs and associated O&M costs, purchased power costs, net income from wholesale power sales, and DSM, energy efficiency, conservation costs:

- **Annual Energy at Generation** – Using this approach, costs are allocated to each class based on the ratio of annual energy needed to serve that class, including adjustment for losses, divided by the sum of the annual energy needed to serve all customer classes.

  Eight utilities use this methodology as follows:

  - Avista Corporation–Idaho uses this approach for allocating (1) energy-related generation plant in service, associated O&M costs, and purchased power costs, (2) energy-related amortization expenses for weatherization and DSM investment, and (3) energy-related net income from wholesale power sales.

- Avista Corporation–Washington, uses this approach for allocating energy-related generation and transmission plant in service, associated O&M costs, purchased power costs, and net income from wholesale power sales.
- BC Hydro uses this approach to allocate (1) energy-related O&M costs for hydro, peaking thermal, and diesel generation in non-integrated areas, (2) energy-related water renal and fuel costs, (3) energy-related purchased power costs, and (4) energy-related subsidiary net income and revenues from power sales.
- Hydro-Québec Distribution takes energy-related heritage pool costs on a cents per kWh basis multiplied by class annual energy consumption with appropriate adjustments to determine each class's share of energy-related heritage pool costs. They also use this approach for allocating energy-related transmission costs for generation-related transmission and interconnections with neighboring systems.
- Newfoundland Power also uses this approach to allocate energy-related costs for conservation and demand management programs developed for the purpose of obtaining measureable changes in customer usage.
- Puget Sound Energy uses this approach for allocating energy-related generation plant in service, associated O&M costs, and purchased power costs.
- Seattle City Light uses class contribution percentages to average annual system demand, or aMW, to allocate marginal costs for long-distance transmission services.

- **Derived from Other Energy -Related Allocated Costs** – One utility uses this approach. Newfoundland Power allocates conservation and demand management general costs based on the percentage allocations of energy-related corporate administration and general expenses to customer classes.
- **Direct Assignment/Annual Energy at Generation (aMW)** – One utility uses this approach. BPA uses a combination of direct assignment and the Annual Energy at Generation method, or aMW, to allocate energy-related generation and transmission costs and conservation and energy efficiency costs.
- **Weighted Annual Energy at Generation** – Using this approach, costs are allocated to each class based on the ratio of annual energy needed to serve that class, weighted for various factors and adjusted for losses, divided by the sum of weighted annual energy for all customer classes.

  Five utilities use variations of this approach as follows:

  - Hydro-Québec Distribution allocates purchased power costs from non-heritage resources using an "hourly method" that consists of (1) the establishment of an hourly weighted-cost for all the different supply contracts on the basis of their duration during the year and (2) the attribution of those costs on the basis of the hourly consumption for each customer class.

- Idaho Power uses allocation factors derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocation factors used in their approach.
- Manitoba Hydro's energy-related generation cost allocator, referred to as weighted energy, weights energy consumption for three time-of-day periods in four seasons, according to the power prices used in the Manitoba Hydro's Surplus Energy Program (SEP), which are effectively short-run marginal costs. By weighting energy according to SEP prices, the Manitoba Hydro's approach accounts for the differences in economic value of the underlying resources to supply energy by timeframe.
- Portland General uses hourly energy at generation by class multiplied by final hourly marginal energy costs in dollar per kWh to allocate marginal energy-related generation costs.
- Seattle City Light uses hourly energy at generation by class multiplied by forecasted hourly dollar per MWh market energy prices plus forecasted hourly dollar per MWh externality costs to determine allocated marginal energy-related costs.

Also, the two utilities that use primarily a marginal COS approach use a form of the Derived from Other Allocated Costs method to allocate embedded generation and transmission costs in that costs are allocated using the percentages by class of marginal capacity and/or energy costs.

Classification Methodologies for Distribution Resources

The following approaches are used by the utilities surveyed to classify distribution plant in service costs and associated O&M expense:

- **Commission Ordered** – One utility uses this approach. BC Hydro uses the 65 percent demand-related and 35 percent customer-related split as ordered in the 2007 BCUC Order to classify distribution and customer care O&M costs.
- **Computation Method** – One utility uses this approach. Idaho Power classifies distribution lines and transformer plant in service costs and associated O&M costs using a fixed and variable ratio computation method used in prior rate cases. The ratios are periodically updated according to

system capacity utilization measurements based on three-year average load duration curves.

- **Customer Only** – Using this approach, distribution plant in service and/or O&M expenses are classified as 100 percent customer-related.

  Seven of the utilities use this approach to classify various types of distribution plant in service and O&M expenses as follows:

  - Hydro-Québec Distribution and Puget Sound Energy use this approach to classify distribution transformer, services, and meter plant in service and associated O&M expenses.
  - Avista Corporation–Washington, Avista Corporation–Idaho, Idaho Power Company–Idaho, Manitoba Hydro, and Newfoundland Power use this approach to classify distribution services and meter plant in service and associated O&M expenses

- **Demand Only** – Using this approach, distribution plant in service and/or O&M expenses are classified as 100 percent demand-related.

  Seven of the utilities use this approach to classify various types of distribution plant in service and O&M expenses as follows:

  - Avista Corporation–Washington and Avista Corporation–Idaho use this approach to classify all distribution plant in service and related O&M costs except for services and meters plant in service and related O&M costs.
  - Hydro-Québec Distribution uses this approach to classify distribution substation plant in service and associated O&M expenses.
  - Idaho Power–Idaho and Newfoundland Power use this approach to classify distribution substation plant in service and related O&M expenses.
  - Manitoba Hydro uses this approach to classify distribution substation and transformer plant in service and related O&M expenses.
  - Puget Sound Energy uses this approach to classify plant in service and related O&M costs for distribution substations as well as distribution lines.

- **Historic Study** – One utility uses this approach. Manitoba Hydro classifies distribution lines plant in service costs and related O&M costs using the results of a study completed in 1990.

- **Marginal Costs** – In general, utilities using a marginal cost approach (1) calculate marginal demand-related and/or customer-related distribution costs for a test year, (2) allocate demand-related and/or customer-related components of marginal costs to customer classes, and (3) allocate embedded costs for distribution based on the percentages by class of total allocated marginal capacity and energy costs.

Two utilities use various different approaches to classify marginal distribution costs as follows:

- o **Distribution Services Marginal Costs – Demand Only** – Portland General treats marginal costs for distribution services as demand-related.
- o **Distribution Services Marginal Costs – Demand Only** – Seattle City Light treats marginal costs for distribution services as demand-related.
- o **Distribution Substations Marginal Costs – Demand Only** – Portland General and Seattle City Light treat marginal costs for distribution substations as demand-related.
- o **Distribution Lines Marginal Costs – Demand Only** – Portland General and Seattle City Light treat marginal costs for distribution lines as demand-related.
- o **Distribution Transformers Marginal Costs – Customer Only** – Portland General treats marginal costs for distribution transformers as customer-related.
- o **Distribution Transformers Marginal Costs – Demand Only** – Seattle City Light treats marginal costs for distribution transformers as demand-related.
- o **Distribution Meters Marginal Costs – Customer Only** – Portland General and Seattle City Light treat marginal costs for meters as customer-related.

- **Minimum System Study** – Using this method, it is assumed that a minimum-size distribution system can be built to serve the minimum load requirements of the customer. In order to determine the customer-related portion of the utility's distribution system, it is assumed that the utility's lines, transformers, services, etc., are all replaced by the corresponding minimum size assets. Using replacement costs, the value for the minimum system distribution system is compared to the value of replacing all the poles, lines, transformers, services, etc. The ratio of the value of the minimum system to the value of the replacement of all the poles, lines, transformers, services, etc. reflects the percentage of the customer-related portion to be used in categorizing costs.

  Two of the utilities use this approach. Both Hydro-Québec Distribution and Newfoundland Power use this approach to classify distribution plant in service costs and associated O&M costs.

- **Zero Intercept Analysis** – Using this method, data on costs of various sizes of equipment is first gathered to determine a common investment per customer-related to a no-demand situation. This method uses a linear regression on the equipment cost data to determine the dollar value of the common investment in a specific type of distribution plant. The point of zero intercept is the customer-related per unit cost. Multiplying that cost by the number of customers yields the customer-related cost of that type of distribution plant in service. The remainder of the cost is demand-related.

One utility uses this approach. Newfoundland Power classifies distribution transformer plant in service and associated O&M costs using the zero intercept analysis.

Allocation Methodologies for Distribution Resources

The approaches used by the surveyed utilities for allocation of demand-related distribution plant in service and associated O&M costs are summarized below:

- **1 NCP** – Five utilities use this approach as follows:
    - BC Hydro uses this approach to allocate demand-related distribution and customer care O&M costs.
    - Idaho Power, Manitoba Hydro, and Newfoundland Power use this approach to allocate all demand-related distribution plant in service and associated O&M costs.
    - Portland General uses 1 NCP to calculate allocated marginal distribution substation and feeder costs. Marginal substation costs are allocated to each rate schedule by multiplying marginal substation cost dollar per kW multiplied by class NCP. Marginal feeder costs for each rate schedule are allocated to each rate schedule by multiplying average marginal feeder cost dollar per kW multiplied by class NCP.
- **12 NCP** – Three utilities use this approach. Avista Corporation–Washington, Avista Corporation–Idaho, and Hydro Quebec use this approach for allocating all demand-related distribution plant in service and associated O&M costs.
- **Average of Loads During Select Periods** – One utility uses this approach. Seattle City Light takes marginal dollar per kW operating and annualized capital costs for distribution substations and lines for each rate schedule and multiplies them by class contributions to the highest average system MW load in 48 costing periods during the year to calculate marginal costs for each rate schedule.
- **Connected Load** – One utility uses this approach. Seattle City Light takes annualized dollar per kW marginal transformer costs for each rate schedule multiplied by connected load (sum of non-coincident peaks of customers) of each class to determine allocated marginal transformer costs.
- **Feeder 12 NCPs and Miles** – One utility uses this approach. Puget Sound Energy uses its customer and distribution feeder databases to associate each customer with a feeder. Monthly NCP load factors are then used for each customer class to determine each class's contribution to each feeder's monthly NCP as a percent of each month's peak on the feeder. Each class's contribution to monthly peak load on the feeder is multiplied by the number of overhead and underground miles on the feeder. These load-weighted line

miles are then added across all the feeders to develop the total load-weighted overhead and underground distribution line miles allocated to each class. Allocation factors for overhead and underground lines are then developed by dividing the total load weighted line miles attributable to each class by the total load-weighted line miles for all classes. The overhead allocation factors are applied to costs for overhead lines and the underground allocation factors are applied to costs for underground lines.

- **Substation 12 NCPs** – One utility uses this approach. Puget Sound Energy first determines each class's contribution to the peaks of individual distribution substations, as a percent of those peaks, by using the average hourly consumption of each class's load on the substation, divided by the NCP load factor of that class in that month. Each class's contribution to the peak load on each individual substation is then averaged across the months of the year. This average monthly contribution to each substation's peak load is then multiplied by the booked cost of the individual substation to derive the allocated cost of each substation. These allocated substation costs are then summed by customer class and compared with Puget Sound Energy's total substation investment to develop the substation cost allocations.

The approaches used by the surveyed utilities for allocation of customer-related and meter-related distribution plant in service and associated O&M costs are summarized below:

- **Book Value** – One utility uses this approach. Puget Sound Energy allocates customer-related distribution plant in service costs associated with meters based on the meter book values per class.
- **Blended Number of Bills/Revenue** – One utility uses this approach. BC Hydro uses this approach for allocating customer care O&M costs classified as customer-related. The blended allocator is 90 percent based on the percentage of bills by rate class and 10 percent based on the percentage of forecast revenues by rate class.
- **Direct to Customer Classes/Number of Services** – One utility uses this approach. Puget Sound Energy allocates customer-related distribution plant in service costs associated with underground services directly to the residential class. Overhead services are allocated to customer classes based on number of overhead services provided per class.
- **Number of Weighted Customers** – Using this approach, costs are allocated based on the weighted number of customers in a class versus total number of weighted customers. The weightings represent varying levels of effort or investment for different rate classes.

  Nine utilities use this approach as follows:

  - Avista Corporation–Washington and Avista Corporation–Idaho use this approach to allocate customer-related distribution plant in service and O&M costs associated with meters.

- Hydro-Québec Distribution and Newfoundland Power use this approach to allocate customer-related distribution plant in service and O&M costs associated with line transformers, service drops, and meters.
- Idaho Power – Idaho and Manitoba Hydro use this approach to allocate customer-related distribution plant in service and O&M costs associated with service drops and meters.
- Newfoundland Power uses this approach to allocate customer-related distribution plant in service costs associated with lines, transformers, services, and meters based on weighted number of customers.
- Portland General uses this approach to allocate customer-related distribution plant in service and O&M costs associated with transformers, service drops, and meters.
- Seattle City Light uses this approach to allocate customer-related distribution plant in service and O&M costs associated with meters.

- **Number of Weighted Meters –** One utility uses this approach. Seattle City Light calculates marginal meter costs by customer class by taking annual per meter O&M cost plus annualized capital costs per meter for each customer class and multiplying by number of meters in each class.
- **Number of Unweighted Customers** – Using this approach, costs are allocated based on the percentage of customers in each class.

  Five utilities use this approach as follows:

  - Avista Corporation–Washington and Avista Corporation–Idaho use this approach to allocate customer-related costs associated with services drops.
  - BC Hydro uses this approach to allocate customer-related distribution O&M costs.
  - Hydro-Québec Distribution uses this approach to allocate customer-related lines plant in service costs and related O&M costs.
  - Idaho Power Company uses this to approach to allocate customer-related lines and transformers plant in service costs and associated O&M costs.

Also, the two utilities that use primarily a marginal COS approach use a form of the Derived from Other Allocated Costs method to allocate embedded distribution costs in that costs are allocated using the percentages by class of marginal demand and/or customers.

Table C-1
Results of Jurisdictional Review
COS Methodologies for Hydro Resources

	Classification									Allocation Approach	
	Hydro Plant In Service Costs			Hydro O&M Costs			Hydro Water Costs				
Utility	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand Related	Energy Related
Avista Corporation - Washington	34%	66%	System Load Factor [1]	34%	66%	System Load Factor [1]	34%	66%	System Load Factor [1]	12 CP [2]	Annual Energy at Generation
Avista Corporation - Idaho	42%	58%	Hydro Peak Credit [3]	42%	58%	Hydro Peak Credit [3]	0%	100%	Energy Only	12 CP [4]	Annual Energy at Generation
Bonneville Power Administration	na	na	na	0%	100%	Energy Only	0%	100%	Energy Only	na	Direct Assignment/Annual Energy at Generation (aMW)
Hydro-Québec Distribution	na	na	na [5]	na	na	na [5]	na	na	na [5]	na	na [5]
Idaho Power	46%	54%	System Load Factor	44%	56%	System Load Factor/Energy Only [6]	46%	54%	System Load Factor	12 CP	Weighted Annual Energy at Generation [7]
Manitoba Hydro	0%	100%	Energy Only	0%	100%	Energy Only	0%	100%	Energy Only	na	Weighted Annual Energy at Generation [8]
Newfoundland Power	46%	54%	System Load Factor [9]	46%	54%	System Load Factor [9]	46%	54%	System Load Factor [9]	1 CP	Annual Energy at Generation
Portland General	na	na	na	35%	65%	Generation Marginal Costs - Demand & Energy [10]	35%	65%	Generation Marginal Costs - Demand & Energy [10]	4 CP [10]	Weighted Annual Energy at Generation [10]
Puget Sound Energy	19%	81%	Thermal Peak Credit	19%	81%	Thermal Peak Credit	19%	81%	Thermal Peak Credit	Ave of Loads During Select Peak Periods [11]	Annual Energy at Generation
Seattle City Light	na	na	na	0%	100%	Generation Marginal Costs - Energy Only [12]	0%	100%	Generation Marginal Costs - Energy Only [12]	na	Weighted Annual Energy at Generation [12]

(1) In Avista Corporation - Washington's prior cost of service studies, Avista's electric system resource costs were classified to energy and demand using Hydro and Thermal Peak Credit methods. This Peak Credit method created separate peak credit ratios applied to thermal plant in service and hydro plant in service. It was determined that the prior methodology was complicated to compute and apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and forth between energy and demand with changes in the cost of natural gas to fuel combustion turbines. Therefore, Avista changed to an approach using the electric system load factor inherent in the test year. The share of production costs attributable to demand is one minus the load factor (average MW divided by peak MW). Avista indicated the method (1) acknowledges that all energy production costs contain both capacity and energy components as they provide energy throughout the year as well as capacity during system peaks, (2) provides a less complex way to determine a fair apportionment of production and transmission costs between energy and demand, (3) is directly related to their system, and (4) is expected to be stable over time.

(2) Avista Corporation - Idaho indicated that it is usually a winter peaking utility, but it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(3) Avista Corporation - Idaho indicated that a system load factor approach to classification would be preferable, but to potentially limit the number of issues in their case, Avista used the prior traditional Peak Credit method in the cost of service study.

(4) Avista Corporation - Idaho indicated that although it is usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(5) Since 2000, Hydro-Québec has been divided in three major divisions (production, transmission and distribution). For the purposes of rate determination, Hydro-Québec Distribution does not have any production plant in its assets.

(6) Idaho Power uses the System Load Factor method to classify all hydro plant in service and O&M accounts except non-labor electric operation expenses and electric plant maintenance expenses. Hydro non-labor electric operation expenses and electric plant maintenance expenses as energy related. Idaho Power indicated they used the Electric Utility Cost Allocation Manual, published January 1992, by the National Association of Regulatory Utility Commissioners as their primary guide to classification.

(7) Allocators are derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocators used in this study

(8) The generation cost allocator, referred to as weighted energy, weights energy consumption for three time-of-day periods in four seasons, according to the power prices used in the Manitoba Hydro's Surplus Energy Program (SEP), which are effectively short-run marginal costs. By weighting energy according to SEP prices, the Company's approach accounts for the differences in economic value of the underlying resources to supply energy, by timeframe.

(9) Classification is based the system load factor taken from Newfoundland and Labrador Hydro's COS for 2007 Forecast Test Year for Island Interconnected.

(10) Portland General separately calculates long-run marginal production capacity and energy costs for a test year thus identifying the demand-related and energy-related portions of marginal generation costs. The 4 CP method, including the months January, July, August, and September, is used to allocate marginal capacity costs. To allocate marginal energy costs, Portland General uses hourly energy at generation by class multiplied by final hourly marginal energy costs in $/kWh. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs using percentages by class of total marginal capacity and energy costs.

(11) Puget Sound Energy allocates costs based on each class's share of average hourly class loads that occurred coincident with the top 75 system hourly loads during test year. Puget Sound Energy uses estimated peak demands at 23 degrees Fahrenheit to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. They determined that over the last 15 years, the largest number of hours in any one year that the hourly temperature was 23 degrees or colder was 75 hours. Therefore, they are allocating generation and transmission demand costs using this methodology.

(12) Seattle City Light uses hourly energy at generation by class multiplied by forecasted hourly $/MWh market energy prices plus forecasted hourly $/MWh externality costs to determine allocated marginal energy-related costs. Seattle City Light then allocates embedded O&M costs for hydro, non-peaking thermal, peaking thermal, and other renewables plant as well as conservation O&M, capital-related, and overhead expenses using allocated class percentages of marginal costs for market purchases plus externalities plus long-distance transmission.

Table C-2
Results of Jurisdictional Review
COS Methodologies for Non-Peaking Thermal Resources

	Classification									Allocation Approach	
	Non-Peaking Thermal Plant In Service Costs			Non-Peaking Thermal O&M Costs			Non-Peaking Thermal Fuel Costs				
Utility	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand Related	Energy Related
Avista Corporation - Washington	34%	66%	System Load Factor (1)	34%	66%	System Load Factor (1)	34%	66%	System Load Factor (1)	12 CP (2)	Annual Energy at Generation
Avista Corporation - Idaho	42%	58%	Thermal Peak Credit (3)	42%	58%	Thermal Peak Credit (3)	0%	100%	Energy Only	12 CP (4)	Annual Energy at Generation
Bonneville Power Administration	na	na	na	0%	100%	Energy Only	0%	100%	Energy Only	na	Direct Assignment/Annual Energy at Generation (aMW)
Hydro-Québec Distribution	na	na	na (5)	na	na	na (5)	na	na	na (5)	na	na (5)
Idaho Power	46%	54%	System Load Factor	28%	72%	System Load Factor/Energy Only (6)	0%	100%	Energy Only	12 CP	Weighted Annual Energy at Generation (7)
Manitoba Hydro	0%	100%	Energy Only	0%	100%	Energy Only	0%	100%	Energy Only	na	Weighted Annual Energy at Generation (8)
Newfoundland Power	100%	0%	Demand Only	100%	0%	Demand Only	100%	0%	Demand Only	1 CP	na
Portland General	na	na	na	35%	65%	Generation Marginal Costs - Demand & Energy (9)	35%	65%	Generation Marginal Costs - Demand & Energy (9)	4 CP (10)	Weighted Annual Energy at Generation (11)
Puget Sound Energy	19%	81%	Thermal Peak Credit	19%	81%	Thermal Peak Credit	19%	81%	Thermal Peak Credit	Ave of Loads During 75 Peak Hours (12)	Annual Energy at Generation
Seattle City Light	na	na	na	0%	100%	Generation Marginal Costs - Energy Only (13)	0%	100%	Generation Marginal Costs - Energy Only (13)	na	Weighted Annual Energy at Generation (14)

(1) In Avista Corporation - Washington's prior cost of service studies, Avista's electric system resource costs were classified to energy and demand using Hydro and Thermal Peak Credit methods. This Peak Credit method created separate peak credit ratios applied to thermal plant in service and hydro plant in service. It was determined that the prior methodology was complicated to compute and apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and forth between energy and demand with changes in the cost of natural gas to fuel combustion turbines. Therefore, Avista changed to an approach using the electric system load factor inherent in the test year. The share of production costs attributable to demand is one minus the load factor (average MW divided by peak MW). Avista indicated the method (1) acknowledges that all energy production costs contain both capacity and energy components as they provide energy throughout the year as well as capacity during system peaks, (2) provides a less complex way to determine a fair apportionment of production and transmission costs between energy and demand, (3) is directly related to their system, and (4) is expected to be stable over time.

(2) Avista Corporation - Idaho indicated that it is usually a winter peaking utility, but it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(3) Avista Corporation - Idaho indicated that a system load factor approach to classification would be preferable, but to potentially limit the number of issues in their case, Avista used the prior traditional Peak Credit method in the cost of service study.

(4) Avista Corporation - Idaho indicated that although it is usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(5) Since 2000, Hydro-Québec has been divided in three major divisions (production, transmission and distribution). For the purposes of rate determination, Hydro-Québec Distribution does not have any production plant in its assets.

(6) Idaho Power uses the System Load Factor method to classify all non-peaking thermal plant in service and O&M accounts except non-labor steam operation, non-labor electric operation, non-labor boiler plant maintenance, and non-labor electric plant maintenance expenses that are classified direct to energy. Idaho Power indicated they used the Electric Utility Cost Allocation Manual, published January 1992, by the National Association of Regulatory Utility Commissioners as their primary guide to classification.

(7) Allocators derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocators used in this study.

(8) The generation cost allocator, referred to as weighted energy, weights energy consumption for three time-of-day periods in four seasons, according to the power prices used in the Manitoba Hydro's Surplus Energy Program (SEP), which are effectively short-run marginal costs. By weighting energy according to SEP prices, Manitoba Hydro's approach accounts for the differences in economic value of the underlying resources to supply energy, by timeframe.

(9) Portland General Electric Company separately calculates long-run marginal production capacity and energy costs for a test year thus identifying the demand-related and energy-related portions of marginal generation costs.

(10) Portland General uses the 4 CP method, including the months January, July, August, and September, to allocate marginal capacity costs. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs using percentages by class of total marginal capacity and energy costs.

(11) Portland General uses hourly energy at generation by class multiplied by final hourly marginal energy costs in $/kWh to determine marginal capacity costs by class. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs using percentages by class of total marginal capacity and energy costs.

(12) Puget Sound Energy allocates costs based on each class's share of average hourly class loads that occurred coincident with the top 75 system hourly loads during test year. Puget Sound Energy uses estimated peak demands at 23 degrees Fahrenheit to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. They determined that over the last 15 years, the largest number of hours in any one year that the hourly temperature was 23 degrees or colder was 75 hours. Therefore, they are allocating generation and transmission demand costs using this methodology.

(13) Seattle City Light uses hourly energy at generation by class multiplied by forecasted hourly $/MWh market energy prices plus forecasted hourly $/MWh externality costs to determine allocated marginal energy-related costs. Seattle City Light then allocates embedded O&M costs for hydro, non-peaking thermal, peaking thermal, and other renewables plant as well as conservation O&M, capital-related, and overhead expenses using allocated class percentages of marginal costs for market purchases plus externalities plus long-distance transmission.

Table C-3
Results of Jurisdictional Review
COS Methodologies for Peaking Thermal Resources

	Classification									Allocation Approach	
	Peaking Thermal Plant In Service Costs			Peaking Thermal O&M Costs			Peaking Thermal Fuel Costs				
Utility	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand Related	Energy Related
Avista Corporation - Washington	34%	66%	System Load Factor (1)	34%	66%	System Load Factor (1)	34%	66%	System Load Factor (1)	12 CP (2)	Annual Energy at Generation
Avista Corporation - Idaho	100%	0%	Demand Only	100%	0%	Demand Only	0%	100%	Energy Only	12 CP (3)	Annual Energy at Generation
Bonneville Power Administration	na	na	na	0%	100%	Energy Only	0%	100%	Energy Only	na	Direct Assignment/Annual Energy at Generation (aMW)
Hydro-Québec Distribution	na	na	na (4)	na	na	na (4)	na	na	na (4)	na	na (4)
Idaho Power	100%	0%	Demand Only	85%	15%	Demand Only/Energy Only (5)	0%	100%	Energy Only	3 CP	Weighted Annual Energy at Generation (6)
Manitoba Hydro	0%	100%	Energy Only	0%	100%	Energy Only	0%	100%	Energy Only	na	Weighted Annual Energy at Generation (7)
Newfoundland Power	100%	0%	Demand Only	100%	0%	Demand Only	100%	0%	Demand Only	1 CP	na
Portland General	na	na	na	35%	65%	Generation Marginal Costs - Demand & Energy (8)(4)	35%	65%	Generation Marginal Costs - Demand & Energy (8)	4 CP (9)	Weighted Annual Energy at Generation (10)
Puget Sound Energy	19%	81%	Thermal Peak Credit	19%	81%	Thermal Peak Credit	19%	81%	Thermal Peak Credit	Ave of Loads During Select Peak Periods (11)	Annual Energy at Generation
Seattle City Light	na	na	na	0%	100%	Generation Marginal Costs - Energy Only (12)	0%	100%	Generation Marginal Costs - Energy Only (12)	na	Weighted Annual Energy at Generation (13)

(1) In Avista Corporation - Washington's prior cost of service studies, Avista's electric system resource costs were classified to energy and demand using Hydro and Thermal Peak Credit methods. This Peak Credit method created separate peak credit ratios applied to thermal plant in service and hydro plant in service. It was determined that the prior methodology was complicated to compute and apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and forth between energy and demand with changes in the cost of natural gas to fuel combustion turbines. Therefore, Avista changed to an approach using the electric system load factor inherent in the test year. The share of production costs attributable to demand is one minus the load factor (average MW divided by peak MW). Avista indicated the method (1) acknowledges that all energy production costs contain both capacity and energy components as they provide energy throughout the year as well as capacity during system peaks, (2) provides a less complex way to determine a fair apportionment of production and transmission costs between energy and demand, (3) is directly related to their system, and (4) is expected to be stable over time.

(2) Avista Corporation - Idaho indicated that it is usually a winter peaking utility, but it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(3) Avista Corporation - Idaho indicated that although it is usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(4) Since 2000, Hydro-Québec has been divided in three major divisions (production, transmission and distribution). For the purposes of rate determination, Hydro-Québec Distribution does not have any production plant in its assets.

(5) All O&M expenses are classified direct to demand except non-labor generating operation and non-labor generating and electric plant maintenance expenses direct to energy. Idaho power indicated they used the Electric Utility Cost Allocation Manual, published January 1992, by the National Association of Regulatory Utility Commissioners as their primary guide to classification.

(6) Allocators derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocators used in this study.

(7) The generation cost allocator, referred to as weighted energy, weights energy consumption for three time-of-day periods in four seasons, according to the power prices used in the Manitoba Hydro's Surplus Energy Program (SEP), which are effectively short-run marginal costs. By weighting energy according to SEP prices, the Manitoba Hydro's approach accounts for the differences in economic value of the underlying resources to supply energy, by timeframe.

(8) Portland General separately calculates long-run marginal production capacity and energy costs for a test year thus identifying the demand-related and energy-related portions of marginal generation costs.

(9) Portland General uses the 4 CP method, including the months January, July, August, and September, to allocate marginal capacity costs. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs using percentages by class of total marginal capacity and energy costs.

(10) Portland General uses hourly energy at generation by class multiplied by final hourly marginal energy costs in $/kWh to determine marginal capacity costs by class. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs, using percentages by class of total marginal capacity and energy costs.

(11) Puget Sound allocates costs based on each class's share of average hourly class loads that occurred coincident with the top 75 system hourly loads during test year. Puget Sound Energy uses estimated peak demands at 23 degrees Fahrenheit to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. They determined that over the last 15 years, the largest number of hours in any one year that the hourly temperature was 23 degrees or colder was 75 hours. Therefore, they are allocating generation and transmission demand costs using this methodology.

(12) Seattle City Light uses forecasted hourly wholesale per MWh market prices plus externality costs as their marginal energy generation costs, so all marginal costs are considered energy-related.

(13) Seattle City Light uses hourly energy at generation by class multiplied by forecasted hourly $/MWh market energy prices plus forecasted hourly $/MWh externality costs to determine allocated marginal energy-related costs. Seattle City Light then allocates embedded O&M costs for hydro, non-peaking thermal, peaking thermal, and other renewables plant as well as conservation O&M, capital-related, and overhead expenses using allocated class percentages of marginal costs for market purchases plus externalities plus long-distance transmission.

Table C-4
Results of Jurisdictional Review
COS Methodologies for Purchased Power Costs

Utility	Classification Approach			Allocation Approach	
	Demand %	Energy %	Approach	Demand Related	Energy Related
Avista Corporation - Washington	34%	66%	System Load Factor [1]	12 CP [2]	Annual Energy at Generation
Avista Corporation - Idaho	48%	52%	Derived from Classified Plant Costs [3][1]	12 CP [4]	Annual Energy at Generation
Bonneville Power Administration	0%	100%	Energy Only	na	Direct Assignment/Annual Energy at Generation (aMW)
Hydro-Québec Distribution					
Heritage Resources [5]	34%	66%	System Load Factor [5][6]	Relationship of Class to System Load Factors [7][6]	Annual Energy at Generation [8]
Non-Heritage Resources	0%	100%	Energy Only [9]	na	Weighted Annual Energy at Generation [10]
Idaho Power	46%	54%	System Load Factor [11]	12 CP	Weighted Annual Energy at Generation [12]
Manitoba Hydro	0%	100%	Energy Only	na	Weighted Annual Energy at Generation [13]
Newfoundland Power	30%	70%	Supplier COS Results [14]	1 CP	Annual Energy at Generation
Portland General	35%	65%	Generation Marginal Costs - Demand & Energy [15]	4 CP [16]	Weighted Annual Energy at Generation [17]
Puget Sound Energy	19%	81%	Thermal Peak Credit	Ave of Loads During Select Peak Periods [18]	Annual Energy at Generation
Seattle City Light	0%	100%	Generation Marginal Costs - Energy Only [19]	na	Weighted Annual Energy at Generation [20]

(1) In Avista Corporation - Washington's prior cost of service studies, Avista's electric system resource costs were classified to energy and demand using Hydro and Thermal Peak Credit methods. This Peak Credit method created separate peak credit ratios applied to thermal plant in service and hydro plant in service. It was determined that the prior methodology was complicated to compute and apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and forth between energy and demand with changes in the cost of natural gas to fuel combustion turbines. Therefore, Avista changed to an approach using the electric

system load factor inherent in the test year. The share of production costs attributable to demand is one minus the load factor (average MW divided by peak MW). Avista indicated the method (1) acknowledges that all energy production costs contain both capacity and energy components as they provide energy throughout the year as well as capacity during system peaks, (2) provides a less complex way to determine a fair apportionment of production and transmission costs between energy and demand, (3) is directly related to their system, and (4) is expected to be stable over time.

(2) Avista Corporation - Idaho indicated that it is usually a winter peaking utility, but it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(3) Based on total classified gross generation plant in service.

(4) Avista Corporation - Idaho indicated that although it is usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(5) Since 2000, Hydro-Québec has been divided into three major divisions (Hydro-Québec Production, Hydro-Québec TransÉnergie , and Hydro-Québec Distribution). Hydro-Québec Production supplies Hydro-Québec Distribution with power from heritage resources. Bill 116, enacted in June 2000, introduced the concept of "heritage pool electricity" which is dedicated supply reserved for Quebec markets. The embedded cost of the supply of heritage pool electricity (from the production division to the distribution division) is fixed by law, for a maximum of 165 TWh/year at 2,79 ¢/kWh, which includes the energy and demand components. From year 2014 and for the following ones, this cost will be annually indexed at the inflation rate. It is to note that from year 2014 and the following ones, the industrial consumers will be exempted from the increase of the 2.79 ¢/kWh.

(6) System load factor, or utilization factor, is equal to system average annual MW divided by system peak MW within a defined 300-hour peak period. Using the system load factor, the 2.79 ¢/kWh cost of heritage pool electricity is classified as 65.6% energy related (1.83 ¢/kWh) and 34% demand related (0.96 ¢/kWh).

(7) Based on the relationship between specific load factor (i.e., utilization factor), of each class of consumers and the total distribution load factor (i.e., utilization factor). A class load factor, or utilization factor, is equal to the class average annual MW divided by the class non-coincident peak MW within a defined 300-hour peak period. For example, assuming a class load factor of 48.0%, class power losses of 9%, and system power losses of 8%, and heritage pool demand-related costs of 0.96 ¢/kWh, the allocated cost to the class would be 0.96 ¢/kWh X 65.6%/48.0% X (1+9%)/(1+8%) = 1.32 ¢/kWh. This cost would then be multiplied by class annual energy consumption with appropriate adjustments for losses.

(8) Energy-related heritage pool costs on a cents per kWh basis multiplied by class annual energy consumption with appropriate adjustments for losses.

(9) The cost of electric power over the heritage pool electricity is determined by way of a tender solicitation governed by procedure and a code of ethics submitted to the Régie's approval. It can include hydro-electric energy, thermal, wind power and biomass.

(10) The allocation to customers is called the "hourly method" and consists of (1) the establishment of an hourly weighted-cost for all the different supply contracts on the basis of their duration during the year and (2) the attribution of those costs on the basis of the hourly consumption for each customer class.

(11) Purchased power expenses booked to FERC Account 555 are classified as demand-and energy-related in the same manner as steam and hydro generation plant in service with the reasoning being that if the Company had chosen to build and operate a power plant to serve the same customer loads served by purchased power, the plant in service would have been classified as both demand and energy.

(12) Allocators derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocators used in this study.

(13) The generation cost allocator, referred to as weighted energy, weights energy consumption for three time-of-day periods in four seasons, according to the power prices used in the Manitoba Hydro's Surplus Energy Program (SEP), which are effectively short-run marginal costs. By weighting energy according to SEP prices, the Company's approach accounts for the differences in economic value of the underlying resources to supply energy, by timeframe.

(14) Based on results, before deficit allocation, of Newfoundland and Labrador Hydro cost of service results for 2007 forecast test year. Newfoundland & Labrador Hydro used system load factor to classify hydro resources and associated transmission resources and a combination of plant capacity factor and demand-only methods for thermal generation and associated transmission resources. Other transmission resources used to serve Newfoundland Power were classified as demand-related and allocated based on 1 CP.

(15) Portland General Electric Company separately calculates long-run marginal production capacity and energy costs for a test year thus identifying the demand-related and energy-related portions of marginal generation costs.

(16) Portland General uses the 4 CP method, including the months January, July, August, and September, to allocate marginal capacity costs. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs using percentages by class of total marginal capacity and energy costs.

(17) Portland General uses hourly energy at generation by class multiplied by final hourly marginal energy costs in $/kWh to determine marginal capacity costs by class. Portland General subsequently allocates embedded hydro, non-peaking thermal, peaking thermal, and other renewables O&M costs as well as fuel and water costs and purchased power costs, using percentages by class of total marginal capacity and energy costs.

(18) Puget Sound allocates costs based on each class's share of average hourly class loads that occurred coincident with the top 75 system hourly loads during test year. Puget Sound Energy uses estimated peak demands at 23 degrees Fahrenheit to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. They determined that over the last 15 years, the largest number of hours in any one year that the hourly temperature was 23 degrees or colder was 75 hours. Therefore, they are allocating generation and transmission demand costs using this methodology.

(19) Seattle City Light uses forecasted hourly wholesale per MWh market prices plus externality costs as their marginal energy generation costs, so all marginal costs are considered energy-related.

(20) Seattle City Light uses hourly energy at generation by class multiplied by forecasted hourly $/MWh market energy prices plus forecasted hourly $/MWh externality costs to determine allocated marginal energy-related costs. Seattle City Light then allocates embedded O&M costs for hydro, non-peaking thermal, peaking thermal, and other renewables plant as well as conservation O&M, capital-related, and overhead expenses using allocated class percentages of marginal costs for market purchases plus externalities plus long-distance transmission.

Table C-5
Results of Jurisdictional Review
COS Methodologies for Net Income from Wholesale Power Sales

	Recognized	Classification Approach				Allocation Approach		
Utility	as Separate Class	Demand %	Energy %	Revenue %	Approach	Demand Related	Energy Related	Revenue Related
Avista Corporation - Washington	No	34%	66%	0%	System Load Factor	12 CP	Annual Energy at Generation	na
Avista Corporation - Idaho	No	48%	52%	0%	Derived from Classified Plant Costs (1)	12 CP	Annual Energy at Generation	na
Bonneville Power Administration	na	0%	100%	0%	Energy Only	na	Annual Energy at Generation (aMW)	na
Hydro-Québec Distribution	na	na	na	0%	na	na	na	na
Idaho Power Company	No	0%	100%	0%	Energy Only	na	Weighted Annual Energy at Generation (2)	na
Manitoba Hydro	Yes (3)	na	na	0%	na	na	na	na
Newfoundland Power	na	na	na	0%	na	na	na	na
Portland General	na	na	na	0%	na	na	na	na
Puget Sound Energy	Yes (4)	na	na	0%	na	na	na	na
Seattle City Light	No	na (6)	na (6)	100%	Generation Marginal Costs - Revenue Only (5)	na	na	Derived from Marginal Allocated Revenue Requirement (5)

(1) Based on total classified gross generation plant in service.

(2) Allocators derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocators used in this study.

(3) Manitoba Hydro recognizes Export Sales as a separate class in their COS study. Additionally, the COS study differentiates between Dependable and Opportunity export sales. Dependable export sales have been assigned a share of embedded generation and transmission costs as done previously; Opportunity exports have been assigned the costs of purchased power excluding wind purchases, with remaining opportunity sales in excess of power purchases attracting water rentals fees and variable hydraulic generation O&M only.

(4) Puget Sound energy recognizes their Resale Class as a separate class in their COS study.

(5) Seattle City Light's net wholesale revenue offset is apportioned among all customer classes on the basis of the shares of the revenue requirements allocated by marginal cost shares.

Table C-6
Results of Jurisdictional Review
COS Methodologies for Transmission Resources

	Classification						Allocation Approach	
	Transmission Plant In Service Costs			Transmission O&M Costs				
Utility	Demand %	Energy %	Approach	Demand %	Energy %	Approach	Demand Related	Energy Related
Avista Corporation - Washington	34%	66%	System Load Factor (1)	34%	66%	System Load Factor (1)	12 CP (2)	Annual Energy at Generation
Avista Corporation - Idaho	100%	0%	Demand Only	100%	0%	Demand Only	12 CP (3)	na
Bonneville Power Administration	na	na	na	0%	100%	Energy Only	na	Direct Assignment/Annual Energy at Generation (aMW)
Hydro-Québec Distribution								
Generation Related	na	na	na (4)	43%	57%	Transmission Division's Classified Rev Reqmt(5)	1 CP	Annual Energy at Generation
Interconnections w/ Neighboring Systems	na	na	na (4)	43%	57%	Transmission Division's Classified Rev Reqmt(5)	1 CP	Annual Energy at Generation
Network	na	na	na (4)	100%	0%	Demand Only	1 CP	na
Customer Connections	na	na	na (4)	100%	0%	Demand Only	1 NCP	na
Idaho Power	100%	0%	Demand Only	100%	0%	Demand Only	Weighted 12 CP (6)	na
Manitoba Hydro (7)								
Transmission	100%	0%	Demand Only	100%	0%	Demand Only	Ave of Loads During Select Peak Periods (8)	na
Subtransmission	100%	0%	Demand Only	100%	0%	Demand Only	1 NCP	na
Newfoundland Power	100%	0%	Demand Only	100%	0%	Demand Only	1 CP	na
Portland General	na	na	na	100%	0%	Demand Only(9)	4 CP (10)	na
Puget Sound Energy (11)	19%	81%	Thermal Peak Credit(12)	19%	81%	Thermal Peak Credit(12)	Ave of Loads During Select Peak Periods (13)	Annual Energy at Generation
Seattle City Light								
Transmission In Service Area	na	na	na	100%	0%	Transmission Marginal Costs - Demand Only(14)	Ave of Loads During Peak Costing Period (15)	na
Long-Distance Transmission Services	na	na	na	0%	100%	Transmission Marginal Costs - Energy Only(16)	na	Annual Energy at Generation (aMW) (17)

(1) Avista Corporation - Washington indicated that in prior rate cases, transmission costs were assigned to energy and demand by a 50/50 weighting of the Thermal and Hydro Peak Credit ratios. However, in this rate case they are using a System Load Factor method to classify transmission. Reportedly in Washington, transmission costs have traditionally been treated as an extension of the generation system, therefore, the revised Peak Credit ratio was also been applied to transmission costs in their study. Avista identified several benefits to the system load factor approach for identifying the demand-related proportion of production costs: (1) It is simple and straightforward to calculate, (2) it is directly related to the system and test year under evaluation, and (3) the relationship should remain relatively stable from year to year.

(2) Avista Corporation - Idaho indicated that it is usually a winter peaking utility, but it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(3) Avista Corporation - Idaho indicated the use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season and it aligns with FERC Open Access transmission cost methodology.

(4) Since 2000, Hydro-Québec has been divided in three major divisions (production, transmission and distribution). For the purposes of rate determination, Hydro-Québec Distribution does not have any transmission plant in its assets.

(5) Transmission costs are classified by prorating them based on the classification results in Hydro Quebec TransÉnergie's request to change rates and conditions of transmission services for the test year 2012.

(6) Idaho Power uses the 12 CP method weighted for marginal costs.

(7) Manitoba Hydro defines transmission facilities to include only transmission lines which would be recognized for inclusion in their Open Access Transmission Tariff. Radial/non-grid transmission facilities (voltage greater than 100 kV and lower 66 kV and 33 kV) are included in the Subtransmission function. Subtransmission is classified as 100% demand related and allocated based on NCP.

(8) Manitoba Hydro utilizes a summer and winter coincident demand peak allocator based upon the average of the highest 50 peak hours in each season, adjusted for losses, for transmission facilities larger than 100 kV. Peak loads on the transmission system are approximately equivalent in magnitude in both seasons. High winter loads are caused by domestic retail space heating, while summer loads can be comparatively high because of export sales.

(9) Marginal transmission costs are not developed. Embedded transmission costs are classified 100 percent to demand.

(10) The 4 CP method, including the months January, July, August, and September, is used to allocate demand-related transmission costs.

(11) Includes costs for wheeling by others.

(12) Puget Sound Energy allocates costs based on each class's share of average hourly class loads that occurred coincident with the top 75 system hourly loads during test year. Puget Sound Energy uses estimated peak demands at 23 degrees Fahrenheit to determine peak generation requirements for a temperature normal year in its Integrated Resource Plan. They determined that over the last 15 years, the largest number of hours in any one year that the hourly temperature was 23 degrees or colder was 75 hours. Therefore, they are allocating generation and transmission demand costs using this methodology.

(13) Seattle City Light calculates marginal transmission costs based on historical three-year annual average transmission O&M costs adjusted for inflation. Annualized capital-related costs are based on replacement costs for in-service area transmission lines. Based on how these costs are subsequently allocated, they can be considered demand-related.

(14) For the last several rate reviews, estimates of projected consumption for aggregations of the hourly data were used (four costing periods each month or 48 per year) with the expectation that statistical errors in individual hours would, on average, balance out in the forecast periods. The total energy estimated for each period is then divided by the number of hours in the period to estimate the expected average hourly consumption. The coincident peaks for classes as total groups are then determined for the costing period with the largest hourly average consumption. Class contribution percentages to average MW per hour in the costing period during the year with the maximum load are used to allocate costs.

(15) Seattle City Light calculates marginal costs for long-distance transmission services as BPA monthly transmission service price on a $/MW basis multiplied by estimated peak system load multiplied by 12. Based on the approach used to subsequently allocate these costs, they can be considered energy-related.

(16) Seattle City Light uses class contribution percentages to average annual system demand for allocating long-distance transmission service costs. Embedded costs for long-distance transmission services are allocated using class percentages of allocated marginal costs for market purchases plus externalities plus long-distance transmission.

Table C-7
Results of Jurisdictional Review
COS Methodologies for Distribution Substations

	Classification						Allocation Approach	
	Distribution Substation Plant In Service Costs			Distribution Substation O&M Costs				
Utility	Demand %	Customer %	Approach	Demand %	Customer %	Approach	Demand Related	Customer Related
Avista Corporation - Washington [1]	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Avista Corporation - Idaho	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Bonneville Power Administration	na	na	na	na	na	na	na	na
Hydro-Québec Distribution	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Idaho Power	100%	0%	Demand Only	100%	0%	Demand Only	1 NCP	na
Manitoba Hydro	100%	0%	Demand Only	100%	0%	Demand Only	1 NCP	na
Newfoundland Power	100%	0%	Demand Only	100%	0%	Demand Only	1 NCP	na
Portland General	na	na	na	100%	0%	Dist Substation Marginal Costs - Demand Only [2]	1 NCP [3]	na
Puget Sound Energy	100%	0%	Demand Only	100%	0%	Demand Only	Substation 12 NCPs [4]	na
Seattle City Light	na	na	na	100%	0%	Dist Substation Marginal Costs - Demand Only [5]	Ave of Peak Loads During Select Periods [6]	na

(1) Avista Corporation - Washington used the "Basic Customer" classification method for their distribution system that considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution. All other distribution is then considered demand related. According to Avista, the Basic Customer method (1) provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network and (2) has been explicitly accepted for both electric and gas cost of service in the State of Washington.

(2) Marginal $/kW costs were calculated by annualizing the sum of growth-related substation capital expenditures over projected 5-year period and dividing by the growth in system NCP.

(3) Marginal costs allocated to each rate schedule by multiplying marginal subtransmission cost $/kW multiplied by class NCP.

(4) For each month, each customer class's contribution to the peaks of individual distribution substations, as a percent of those peaks, is calculated using the average hourly consumption of each class's load on the substation, divided by the NCP load factor of that class in that month. Each class's contribution to the peak load on each individual substation is then averaged across the months of the year. This average monthly contribution to each substation's peak load is then multiplied by the booked cost of the individual substation in 2010 dollars to derive the allocated cost of each substation. These allocated substation costs are then summed by customer class and compared with PSE's total substation investment in 2010 dollars to develop the substation cost allocations for FERC Accounts 360-362.

(5) Marginal O&M costs are calculated as most recent historical annual O&M costs on a $/MW of total substation capacity basis, adjusted to represent costs for servicing a new marginal substation and for inflation, and then multiplied by total system substation capacity. Marginal annualized capital costs are calculated as annualized substation capital replacement cost on a $/MW of total substation capacity basis multiplied by total system substation capacity.

(6) Class contribution percentages to highest average system MW load in 48 costing periods during year.

Table C-8
Results of Jurisdictional Review
COS Methodologies for Distribution Lines

	Classification						Allocation Approach	
	Distribution Lines Plant In Service Costs			Distribution Lines, Poles, Towers, and Fixtures O&M Costs				
Utility	Demand %	Customer %	Approach	Demand %	Customer %	Approach	Demand Related	Customer Related
Avista Corporation - Washington (1)	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Avista Corporation - Idaho	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Bonneville Power Administration	na	na	na	na	na	na	na	na
Hydro-Québec Distribution	79%	21%	Minimum System Study (2)	79%	21%	Minimum System Study (2)	12 NCP	Number of Unweighted Customers
Idaho Power	64%	36%	Computation Method (3)	64%	36%	Computation Method (3)	1 NCP	Number of Unweighted Customers
Manitoba Hydro	60%	40%	Historic Study (4)	60%	40%	Historic Study (4)	1 NCP	Number of Unweighted Customers
Newfoundland Power	64%	36%	Minimum System Study	64%	36%	Minimum System Study	1 NCP	Number of Unweighted Customers
Portland General	na	na	na	100%	0%	Distribution Lines Marginal Costs - Demand Only (5)	1 NCP (6)	na
Puget Sound Energy	100%	0%	Demand Only	100%	0%	Demand Only	Feeder 12 NCPs and Miles (7)	na
Seattle City Light	na	na	na	100%	0%	Distribution Lines Marginal Costs - Demand Only (8)	Ave of Peak Loads During Select Peak Periods (9)	na

(1) Avista Corporation - Washington used the "Basic Customer" classification method for their distribution system that considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution. All other distribution is then considered demand related. According to Avista, the Basic Customer method (i) provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network and (2) has been explicitly accepted for both electric and gas cost of service in the State of Washington.

(2) The Minimum System Study was filed with the Regie in 2004. The classification between demand and customer is updated each year.

(3) Fixed and variable ratio computation method used in prior rate cases. Updated periodically according to a system capacity utilization measurement based on a three-year average load duration curve.

(4) The proportions classified to demand and customer based upon a 1990 study by Ernst & Young and accepted for use by Manitoba Hydro since 1991. Manitoba Hydro will rely on a 70/30 split of primary and secondary voltage in their PCOSS13.

(5) Marginal costs are calculated using the following steps: (1) calculate replacement costs of distribution feeders, (2) for each feeder, allocate cost responsibility based on rate schedule's proportionate contribution to NCP, (3) calculate $/kW cost by totaling the cost responsibilities for all feeders and dividing by the sum of each schedule's NCP, (4) and annualize costs by applying an economic carrying charge.

(6) For each rate schedule, multiply average marginal feeder cost $/kW multiplied by class NCP.

(7) Puget Sound Energy uses its customer and distribution feeder databases to associate each customer with a feeder. Monthly NCP load factors are then used for each customer class to determine each class's contribution to each feeder's monthly NCP as a percent of each month's peak on the feeder. Each class's contribution to monthly peak load on the feeder is multiplied by the number of overhead and underground miles on the feeder. These load-weighted line miles are then added across all the feeders to develop the total load-weighted overhead and underground distribution line miles allocated to each class. Allocation factors for

overhead and underground lines are then developed by dividing the total load weighted line miles attributable to each class by the total load-weighted line miles for all classes. The overhead allocators are applied to FERC Accounts 364 and 365, and the underground allocators are applied to FERC Accounts 366 and 367.

(8) Marginal O&M costs are calculated as the historical three-year annual average wires O&M costs adjusted for inflation. Marginal capital costs are calculated as the annualized cost to replace wires and related equipment.

(9) Class contribution percentages to highest average system MW load in 48 costing periods during year.

Table C-9
Results of Jurisdictional Review
COS Methodologies for Distribution Transformers

Utility	Classification						Allocation Approach	
	Distribution Transformers Plant In Service Costs			Distribution Transformers O&M Costs				
	Demand %	Customer %	Approach	Demand %	Customer %	Approach	Demand Related	Customer Related
Avista Corporation - Washington (1)	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Avista Corporation - Idaho	100%	0%	Demand Only	100%	0%	Demand Only	12 NCP	na
Bonneville Power Administration	na	na	na	na	na	na	na	na
Hydro-Québec Distribution	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers (2)
Idaho Power	64%	36%	Computation Method (3)	64%	36%	Computation Method (3)	1 NCP	Number of Unweighted Customers
Manitoba Hydro	100%	0%	Demand Only	100%	0%	Demand Only	1 NCP	na
Newfoundland Power	73%	27%	Zero Intercept Analysis	73%	27%	Zero Intercept Analysis	1 NCP	Number of Weighted Customers (2)
Portland General	na	na	na	0%	100%	Distribution Transformer Marginal Costs - Customer Only (4)	na	Number of Weighted Customers (5)
Puget Sound Energy	na	100%	Customer Only	na	100%	Customer Only	na	Direct to Customer Classes (6)
Seattle City Light	na	na	na	100%	0%	Distribution Transformer Marginal Costs - Demand Only (7)	Connected Load	na

(1) Avista Corporation - Washington used the "Basic Customer" classification method for their distribution system that considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution. All other distribution is then considered demand related. According to Avista, the Basic Customer method (1) provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network and (2) has been explicitly accepted for both electric and gas cost of service in the State of Washington.

(2) Number of customers, weighted for the specific cost of line transformers per class.

(3) Fixed and variable ratio computation method used in prior rate cases. Updated according to a system capacity utilization measurement based on a three-year average load duration curve.

(4) Marginal transformer costs are calculated by estimating the cost $/customer of providing the average customer a transformer.

(5) For each rate schedule, Portland General multiplies average marginal transformer costs $/customer by number of customers.

(6) Determines current costs, including installation, for transformers on system and directly assigns to classes if possible with remaining transformers allocated to each class based upon the class's relative contribution to embedded line transformer costs.

(7) Marginal annual transformer O&M cost per kW of load is calculated using an assumed factor for O&M as a % of annual capital cost for each customer class and then multiplied by the connected load (sum of noncoincident peaks of customers) of each class. Annualized capital costs are calculated as annualized cost to replace transformers per kW of load by customer class multiplied by connected load (sum of noncoincident peaks of customers) of each class.

Table C-10
Results of Jurisdictional Review
COS Methodologies of Distribution Services

	Classification			Allocation Approach	
	Distribution Services Plant In Service Costs				
Utility	Demand %	Customer %	Approach	Demand Related	Customer Related
Avista Corporation - Washington (1)	0%	100%	Customer Only	na	Number of Unweighted Customers
Avista Corporation - Idaho	0%	100%	Customer Only	na	Number of Unweighted Customers
Bonneville Power Administration	na	na	na	na	na
Hydro-Québec Distribution	0%	100%	Customer Only	na	Number of Weighted Customers
Idaho Power	0%	100%	Customer Only	na	Number of Weighted Customers
Manitoba Hydro	0%	100%	Customer Only	na	Number of Weighted Customers
Newfoundland Power	0%	100%	Customer Only	na	Number of Weighted Customers
Portland General	na	na	Dist Services Marginal Costs - Customer Only	na	Number of Unweighted Customers
Puget Sound Energy	na	100%	Customer Only	na	Direct to Customer Classes/No. of Services (2)
Seattle City Light	na	na	Dist Services Marginal Costs - Demand Only	100%	Ave of Peak Loads During Select Periods (6)

(1) Avista Corporation - Washington used the "Basic Customer" classification method for their distribution system that considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution. All other distribution is then considered demand related. According to Avista, the Basic Customer method (1) provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network and (2) has been explicitly accepted for both electric and gas cost of service in the State of Washington.

(2) Underground services are allocated direct to residential class. Overhead services are allocated to customer classes based on number of overhead services per class.

Table C-11
Results of Jurisdictional Review
COS Methodologies for Distribution Meters

Utility	Classification			Classification			Allocation Approach	
	Distribution Meters Plant In Service Costs			Distribution Meters O&M				
	Demand %	Customer %	Approach	Demand %	Customer/Meter %	Approach	Demand Related	Customer/Meter Related
Avista Corporation - Washington (1)	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers
Avista Corporation - Idaho	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers
Bonneville Power Administration	na	na	na	na	na	na	na	na
Hydro-Québec Distribution	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers
Idaho Power	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers
Manitoba Hydro	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers
Newfoundland Power	0%	100%	Customer Only	0%	100%	Customer Only	na	Number of Weighted Customers
Portland General	na	na	na	0%	100%	Distribution Meter Marginal Costs - Customer Only (2)	na	Number of Weighted Customers (3)
Puget Sound Energy	na	100%	Customer Only	na	100%	Customer Only	na	Book Value (4)
Seattle City Light	na	na	na	0%	100%	Distribution Meter Marginal Costs - Customer Only (5)	na	Number of Weighted Meters (6)

(1) Avista Corporation - Washington used the "Basic Customer" classification method for their distribution system that considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution. All other distribution is then considered demand related. According to Avista, the Basic Customer method (1) provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network and (2) has been explicitly accepted for both electric and gas cost of service in the State of Washington.

(2) Marginal meter costs are calculated as the installed cost $/customer of a new AMI meter for each rate schedule multiplied by a carrying charge.

(3) For each rate schedule, Portland General multiplies the average marginal meter cost $/customer by number of customers.

(4) Based on book value by class.

(5) Marginal meter O&M costs per meter are calculated as the annual per meter O&M cost by customer class. Annualized marginal capital costs per meter are calculated as the annualized per meter cost to replace meters by customer class.

(6) For each rate schedule, Seattle City Light multiplies the average marginal meter cost $/customer by number of customers.

Table C-12
Results of Jurisdictional Review
COS Methodologies for DSM, Energy Efficiency, Conservation Assets and Costs

		Functionalization Approach					Classification Approach				Allocation Approach	
Utility	Type	Generation %	Transmission %	Distribution %	Customer Care %	Approach	Demand %	Energy %	Customer %	Approach	Demand Related	Energy Related
Avista Corporation - Washington	na	na	na	na	na	na	na	na	na	na	na	na
Avista Corporation - Idaho	Amortization of Weatherization and DSM Investment	100%	0%	0%	0%	Generation Only	48%	52%	0%	Derived from Classified Plant Costs (1)	12 CP (2)	Annual Energy at Generation
Bonneville Power Administration	Conservation and Energy Efficiency Costs	100%	0%	0%	0%	Generation Only	0%	100%	0%	Energy Only	na	Annual Energy at Generation (aMW)
Hydro-Québec Distribution	na	na	na	na	na	na	na	na	0%	na	na	na
Idaho Power Company	Customer Assistance for Energy Efficiency Programs	100%	0%	0%	0%	Generation Only	46%	54%	0%	System Load Factor	12 CP	Weighted Annual Energy at Generation (3)
Idaho Power Company	Demand Response Incentive Payments	100%	0%	0%	0%	Generation Only	100%	0%	0%	Demand Only	3 CP (summer)	na
Manitoba Hydro	na	na	na	na	na	na	na	na	0%	na	na	na
Newfoundland Power	Conservation and DSM General Costs	13%	10%	59%	18%	Derived from Other Functionalized O&M Costs (4)	49%	6%	45%	Derived from Other Classified O&M Costs (4)	Derived from Other Demand-Related Allocated O&M Costs (4)	Derived from Other Energy -Related Allocated O&M Costs (4)
Newfoundland Power	Costs to Develop Measurement Programs	97%	3%	0%	0%	Supply Cost Savings (5)	5%	95%	0%	Supply Cost Savings (5)	1 CP	Annual Energy at Generation
Newfoundland Power	Curtailable Service Option Costs (6)	95%	2%	4%	0%	Derived from Other Functionalized O&M Costs (6)	100%	0%	0%	Demand Only	Derived from Other Demand-Related Allocated O&M Costs (6)	na
Newfoundland Power	Demand Management Incentive Account (7)	100%	0%	0%	0%	Generation Only (7)	100%	0%	0%	Demand Only (7)	1 CP	na
Portland General	na	na	na	na	na	na	na	na	na	na	na	na
Puget Sound Energy	Weatherization Customer Assistance	100%	0%	0%	0%	Generation Only	19%	81%	0%	Thermal Peak Credit	Ave Loads During Select Peak Periods (8)	Annual Energy at Generation
Seattle City Light	Conservation O&M, Capital-Related, and Overhead Exp	100%	0%	0%	0%	Generation Only	0%	100%	0%	Marginal Costs (9)	na	Weighted Annual Energy at Generation (10)

(1) Based on total classified gross generation plant in service.

(2) Avista indicated that although they are usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

(3) Allocators derived by averaging the energy values for each customer class with the normalized energy values weighted by marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the allocators used in this study.

(4) Conservation and demand management general costs are functionalized, classified, and allocated based on corporate administration and general expenses.

(5) Costs for conservation and demand management programs developed for the purpose of obtaining measureable changes in customer usage are classified between demand and energy reflective of the supply cost savings which occurred in 2011 (95% to production energy, 2% to production demand, and 3% to substation demand).

(6) The functional classification of curtailable service option costs is based on direct O&M costs classified as related to demand. Allocation based on associated demand-related O&M costs.

(7) Transfers to the reserve stabilization fund associated with the demand management incentive are shown under purchased power expenses and classified 100% to demand.

(8) Puget Sound allocates costs based on each class's share of average hourly class loads that occurred coincident with the top 75 system hourly loads during test year.

(9) Seattle City Light uses forecasted hourly wholesale per MWh market prices plus externality costs as their marginal energy generation costs, so all marginal costs are considered energy-related.

(10) Seattle City Light uses hourly energy at generation by class multiplied by forecasted hourly $/MWh market energy prices plus forecasted hourly $/MWh externality costs to determine allocated marginal energy-related costs. Seattle City Light then allocates embedded O&M costs for hydro, non-peaking thermal, peaking thermal, and other renewables plant as well as conservation O&M, capital-related, and overhead expenses using allocated class percentages of marginal costs for market purchases plus externalities plus long-distance transmission.

Table C-13
Results of Jurisdictional Review
Target and Actual R/C Ratios Used for Proposed Rate Design

Utility	Approach for Setting R/C Ratios for Proposed Rates	Target R/C Ratios	Based on Existing Rates: Total System R/C Ratio	Based on Existing Rates: Range of Class R/C Ratios	Based on Proposed Rates: Range of Class R/C Ratios
Avista Corporation - Washington	na (1)	na (1)	92%	81% - 119%	89% - 130%
Avista Corporation - Idaho	COS Results as a Guide (2)	na (2)	96%	86% - 107%	90% - 111%
Bonneville Power Administration	Dictated by Law (3)	100% (3)	na	na	100% (3)
Hydro-Québec Distribution	na (4)	na (4)	na	na	83% - 134%
Idaho Power	Limits on Rate Increases and Decreases (5)	100% (5)	92%	57 % - 216%	66% - 216%
Manitoba Hydro	Target Range of R/C Ratios/Across-the-Board Rate Changes (6)	95% - 105%	100% (7)	89% - 108%	94% - 114% (8)
Newfoundland Power	Target Range of R/C Ratios (9)	90% - 110%	100% (7)	95% - 113%	96% - 110%
Portland General	Caps on Rate Increases (10)	100%	92%	41% - 106%	48% - 104%
Puget Sound Energy	Mutiple Guidelines (11)	95% - 105%	92%	81% -98% (12)	93% - 105 (12)
Seattle City Light	Set by City Council Resolutions (13)	100%	96%	79% - 103%	100% (13)

(1) Avista Corporation - Washington proposed across-the-board increases.

(2) Avista Corporation – Idaho only indicated that they used COS results as "guide" to spreading overall revenue increases to rate schedules.

(3) The entire process used by BPA to allocate costs to customer classes and then design rates is largely dictated by the Northwest Power Act. The process includes the following steps: (i) COS analysis in which various types of costs are allocated to the various classes, or rate pools, of customers using allocation factors calculated based on loads and resources, ii) a rate directives step in which costs are reallocated between rate pools to ensure that the relationships between the rates for the different classes of customers comport with the rate directives in the law., and (iii) the final rate design step that produces the final rates.

(4) Hydro-Québec Distribution indicated that since 2004 uniform increases have been applied. Also, by law, they cannot deliberately modify the R/C ratio of 0.83 for their residential class.

(5) In Idaho Power's most recent rate filing, target revenues for rate design were established based on the following: (i) no decrease for any rate class, (ii) cap any class rate increases at 1.5 times the system average rate increase, and (iii) reallocate any shortfall in revenue collection created by capping increases to classes receiving uncapped revenues. Idaho Power's ratemaking proposals general advocate movement towards cost of service results, but other objectives such as rate stability are considered.

(6) Manitoba Hydro's rate design objectives include a long-term target to have all class R/C ratios in the range of 95 percent to 105 percent with all classes being gradually moved toward R/C ratios of unity. In conformity with the principles of gradualism and sensitivity to customer impacts, Manitoba Hydro limits annual adjustments to revenues by customer class to less than two percentage points greater than the overall proposed increase.

(7) Manitoba Hydro and Newfoundland Power reported their RCC ratios based on current rates with a base of 100%.

(8) Estimated based on two proposed across-the-board increase of 2.5% and 3.5%.

(9) Newfoundland Power reports their RCC ratios based on current rates with a base of 100%. The Company's rate change plan proposes to (i) vary the rate increase by customer rate class so cost recovery for each class is within the target revenue to cost ratio range of 90% to 110%, and (ii) to implement changes in customer rate designs in accordance with the Retail Rate Review. The revenue to cost ratios for the small general service classes are greater than 110%. The Company's rate proposals in this Application were developed, in part, to bring the revenue to cost ratios for those classes with R/C ratios above 100% within the target range. This indicates that a higher than average or average increase will be required for the other classes.

(10) Portland General proposed to move rate classes to an R/C ratio of 1.0 with a maximum increase of 17 percent for any class.

(11) Based upon the parity percentages shown in Puget Sound Energy's COS results and the goal to move towards full parity (a parity percentage of 100 percent) in a gradual manner, they proposed the following in their last rate filing: (i) Apply, with two exceptions, an adjusted average rate increase to retail classes within 5% of full parity; (ii) Apply a rate increase that is 75% of the adjusted average to the class that is more than 5% above full parity; and (iii) Apply an increase that is 125% of the average to the one retail class that is 5% or more below full parity.

(12) Ranges shown are for retail classes only.

(13) Seattle City Light's rate design objectives are primarily set through Seattle City Council resolutions. An R/C ratio of 1.0 has long been recognized as a guideline. Deviations have been allowed if they would accomplish some other goal. It is recognized that in order to promote rate stability, deviations from the cost standard might be necessary. This was the case in every rate increase since the goal of cost-based rates was first proposed until their last rate case in 2006 that established rates for the two year period 2007-08. That rate case discontinued a "gradualism" policy that shifted some revenue requirements away from cost-of-service allocations in order to satisfy social policy concerns. Seattle City Light's most recent rate proposal continues cost-of-service based rates as the standard, with the only deviation being the reflection of franchise agreement provisions.

Appendix D
CLASSIFICATION METHODOLOGIES BY RESOURCE FROM JURISDICTIONAL REVIEW

The detailed results of the jurisdictional review regarding classification methodologies are discussed below for generation, transmission, and distribution resources.

Generation Classification Approaches

The classification approaches used for each type of generation resource cost, purchased power costs, and net income from wholesale power sales are shown in Tables C-1 through C-6 and Table C-12 in Appendix C and summarized below:

- **Hydro Generation Resources** – As shown in Table C-1, the following approaches are used to classify hydro generation resources:
    - **Energy Only** – Four utilities use this approach to classify hydro plant in service and associated O&M costs. Avista Corporation–Idaho uses this approach to classify hydro water costs. BPA classifies all hydro O&M expenses as energy-related, and Manitoba Hydro classifies all hydro plant in service and O&M expenses as energy-related. Idaho Power classifies only hydro non-labor electric operation expenses and electric plant maintenance expenses as energy-related.
    - **Generation Marginal Costs** – Two utilities use this approach for generation costs. Portland General and Seattle City Light use a marginal COS methodology by first developing marginal capacity, or demand, costs and/or marginal energy costs that are subsequently allocated to customer classes. Portland General calculates long-run marginal production capacity and energy costs for a test year thus identifying the demand-related and energy-related portions of marginal generation costs. The other utility, Seattle City Light, uses forecasted hourly wholesale per MWh market prices plus externality costs as their marginal energy generation costs, so all marginal costs are considered energy-related. The embedded costs for hydro generation, as well as other types of generation, are then allocated by both utilities based on the percentages by class of total allocated marginal generation costs.
    - **Hydro and Thermal Peak Credit** – Two utilities use this approach to classify hydro plant in service and associated O&M costs. Avista Corporation–Idaho uses the Hydro Peak Credit method for hydro plant in service and associated O&M, excluding water costs, while Puget Sound Energy uses the Thermal Peak Credit method for all hydro plant in service and O&M costs.

- **System Load Factor** – Three utilities use this approach to classify hydro plant in service and associated O&M costs. Avista Corporation–Washington and Newfoundland Power use this approach to classify all hydro plant in service and associated O&M costs. Idaho Power uses it to classify all hydro plant in service and O&M accounts except non-labor electric operation expenses and electric plant maintenance expenses.

- **Non-Peaking Thermal Generation Resources** – As shown in Table C-2, the following approaches are used to classify non-peaking thermal generation resources:
  - **Demand Only** – One utility, Newfoundland Power, classifies all non-peaking thermal generation plant in service costs and O&M costs, including fuel, as demand-related.
  - **Energy Only** – Four utilities use this approach for classifying non-peaking thermal generation resources. BPA classifies non-peaking thermal generation resources and O&M expenses as energy-related, and Manitoba Hydro classifies all non-peaking thermal generation plant in service and O&M costs, including fuel, as energy-related. Idaho Power classifies non-peaking thermal generation costs for fuel, non-labor steam operation, non-labor electric operation, non-labor boiler plant maintenance, and non-labor electric plant maintenance expenses direct to energy. Avista Corporation–Idaho uses this approach to classify non-peaking thermal generation fuel.
  - **Marginal Costs** – The two utilities that use a marginal COS methodology, Portland General and Seattle City Light, use the same approach for non-peaking thermal generation resources as hydro resources, as discussed above.
  - **System Load Factor** – Two utilities use this approach to classify non-peaking thermal generation plant in service costs and associated O&M costs. Avista Corporation–Washington uses this approach to classify all non-renewables plant in service and associated O&M costs including fuel. Idaho Power uses it to classify all baseload/thermal plant in service and O&M accounts except fuel, non-labor steam operation, non-labor electric operation, non-labor boiler plant maintenance, and non-labor electric plant maintenance expenses that are classified direct to energy.
  - **Thermal Peak Credit** – Two utilities use this approach to classify non-peaking plant in service and associated O&M costs. Avista Corporation–Idaho uses the Thermal Peak Credit method for non-peaking plant in service and associated O&M, excluding fuel, while Puget Sound Energy uses a thermal peak credit approach for all non-renewables plant in service and O&M costs including fuel.

- **Peaking Thermal Generation Resources** – As shown in Table C-3, the following approaches are used to classify peaking thermal generation resources:
  - **Demand Only** – Three utilities use this approach to classify peaking thermal generation resources plant in service and associated O&M costs. Avista–Idaho uses this approach to classify peaking thermal generation plant in service and O&M costs, excluding fuel. Newfoundland Power uses this approach to classify peaking thermal generation resources plant in service and associated O&M costs, including fuel. Idaho Power uses this approach to classify peaking thermal generation plant in service and O&M expenses except fuel, non-labor generating operation, and non-labor generating and electric plant maintenance expenses.
  - **Energy Only** – Four utilities use this approach for peaking thermal generation resources. Avista–Idaho uses this approach to classify peaking thermal generation fuel. BPA classifies peaking thermal generation resources O&M costs, including fuel, as energy-related. Manitoba Hydro classifies all peaking thermal generation plant in service costs and O&M accounts, including fuel, as energy-related. Idaho Power uses this approach to classify peaking thermal generation fuel, non-labor generating operation, and non-labor generating and electric plant maintenance expenses.
  - **Generation Marginal Costs** – The two utilities that use a marginal COS methodology, Portland General and Seattle City Light, use the same approach for classifying peaking thermal generation resources as hydro resources as discussed above.
  - **System Load Factor** – Only one utility, Avista Corporation–Washington, uses this approach to classify peaking thermal generation plant in service cost and associated O&M costs including fuel.
  - **Thermal Peak Credit** – One utility, Puget Sound Energy, uses this approach for all peaking thermal generation plant in service and O&M costs including fuel.
- **Purchased Power Costs** – As shown in Table C-4, the following approaches are used to classify purchased power costs:
  - **Derived from Classified Plant Costs** – One utility, Avista–Idaho, uses the demand/energy split for total classified generation plant in service to classify purchased power costs between demand and energy.
  - **Energy Only** – Two utilities, BPA and Manitoba Hydro, classify purchased power expenses as energy-related. In addition, Hydro-Québec Distribution classifies purchased power costs from non-Heritage resources as 100 percent energy-related.

- **Generation Marginal Costs** – The two utilities that use a marginal COS methodology, Portland General and Seattle City Light, use the same approach for purchased power as hydro resources as discussed above.
- **Supplier COS Results** – One utility uses this approach. Newfoundland Power purchases the majority of their power from Newfoundland and Labrador Hydro. Newfoundland Power classifies purchased power based on Newfoundland and Labrador Hydro's classified cost to serve Newfoundland Power for the 2007 forecast test year. Newfoundland and Labrador Hydro use the System Load Factor method to classify hydro resources and associated transmission resources and a combination of plant capacity factor and demand-only methods for thermal generation and associated transmission resources. Other transmission resources used to serve Newfoundland Power are classified as demand-related and allocated based on 1 CP.
- **System Load Factor** – Three utilities, Avista Corporation–Washington, Hydro-Québec Distribution, and Idaho Power and use this approach to classify purchased power costs. This is the same approach Avista uses for all other generation plant in service and O&M costs. Idaho Power's purchased power expenses are also classified as demand-related and energy-related in the same manner as steam and hydro generation plant in service with the reasoning being that if Idaho Power had chosen to build and operate a power plant to serve the same customer loads served by purchased power, the plant would have been classified as both demand and energy. Hydro-Québec Distribution uses the System Load Factor Method, or utilization factor approach, to classify purchased power costs from heritage resources.[9]
- **Thermal Peak Credit** – One utility, Puget Sound Energy, uses this approach to classify purchased power costs.

- **Net Income from Wholesale Power Sales** – As shown in Table C-5, the following approaches are used to classify net income from wholesale power sales:
    - **Energy Only** – Two utilities, BPA and Idaho Power, use this approach to classify net income from wholesale power sales.
    - **Derived from Classified Plant Costs** – One utility, Avista Corporation–Idaho, uses this approach to classify net income from wholesale power sales based on classified gross generation plant in service in service.

9 The utilization factor is equal to system average annual MW divided by system peak MW within a defined 300-hour peak period. Using the system load factor, the 2.79¢/kWh fixed cost of heritage pool electricity is classified as 65.6 percent energy-related (1.83¢/kWh) and 34 percent demand related (0.96 ¢/kWh).

  - **Generation Marginal Costs – Revenue Only** – One utility uses this approach. Seattle City Light's net income from wholesale power sales is apportioned among all customer classes based on the shares of the revenue requirements allocated by marginal cost shares.
  - **System Load Factor** – One utility, Avista Corporation–Washington, uses this approach to classify net income from wholesale power sales.

Transmission Classification Approaches

As shown in Table C-7 of Appendix C, the following approaches are used to classify transmission resource costs:

- **Demand Only** – Six utilities use this methodology:
  - Avista Corporation–Idaho, Portland General, and Newfoundland Power classify all transmission plant in service and associated O&M expenses as demand-related.
  - Manitoba Hydro classifies all transmission and subtransmission plant in service, and associated O&M costs, as demand-related.
  - Idaho Power classifies all transmission plant in service and associated O&M costs, with the exception of costs associated with wheeling by others, as demand-related as well.
  - Hydro Québec classifies network transmission costs and customer interconnection costs as 100 percent demand-related.
- **Energy Only** – Two utilities use this methodology:
  - Idaho Power classifies costs associated with wheeling by others as energy-related.
  - BPA classifies all transmission O&M costs as energy-related.
- **System Load Factor** – Two utilities use this methodology:
  - Avista Corporation–Washington uses this approach to allocate transmission plant in service and related O&M. Although Avista Corporation–Washington has traditionally applied the peak credit rating ratio to transmissions costs, the System Load Factor method was used to classify transmission plant in service and associated O&M costs in the most recent rate case.
  - Hydro-Québec Distribution classifies generation-related transmission costs and costs for interconnections with neighboring systems based on the load factor of Hydro-Québec Transmission Division (TransÉnergie).
- **Thermal Peak Credit** – One utility uses this methodology. Puget Sound Energy's uses this approach for classifying transmission plant in service and associated O&M costs. Peak credit percentages are applied to transmission

costs by Puget Sound Energy under the theory that transmission lines are constructed to deliver energy and capacity provided by generating plant, and in the same proportion as it is being provided.

- **Transmission Marginal Costs** – Using this approach, utilities (1) calculate marginal transmission demand-related and energy-related costs for a test year, thus identifying the demand-related and energy-related portions of marginal costs, (2) allocate the demand-related and energy-related components of marginal transmission costs to customer classes, and (3) allocate the embedded costs for transmission based on the percentages by class of total allocated marginal demand-related and energy-related costs.

  One utility, Seattle City Light, uses this approach and calculates marginal transmission costs as follows:

  - Costs for Transmission in Service Area: First, annualized costs for transmission service in Seattle City Light's service area are calculated. Historical three-year annual average transmission O&M costs are adjusted for inflation. Annualized capital-related costs are based on replacement costs for in-service area transmission lines. Based on how these marginal costs are subsequently allocated, these costs are considered 100 percent demand-related.
  - Costs for Long-Distance Transmission Services: Seattle City Light calculates marginal costs for long-distance transmission service as BPA's monthly transmission service price on a dollar per MW basis multiplied by estimated peak system load multiplied by 12. Based on how these marginal costs are subsequently allocated, these costs are considered 100 percent energy-related.

Distribution Classification Approaches

The classification approaches used for each type of distribution resource cost are shown in Tables C-7 through C-12 in Appendix C and summarized below:

- **Distribution Substations** – As shown in Table C-7, the following approaches are used to classify plant in service and O&M costs associated with distribution substations:
  - **Demand Only** – Seven utilities use this approach to classify distribution substation plant in service and associated O&M costs. These utilities include Avista Corporation–Washington, Avista Corporation–Idaho, Hydro Québec Distribution, Idaho Power Company–Idaho, Manitoba Hydro, Newfoundland Power, and Puget Sound Energy.
  - **Transmission Substation Marginal Costs** – Two utilities use this approach to determine classified marginal distribution substation costs as follows:

  - Portland General treats marginal costs associated with substations as demand-related in their analyses. Portland General Electric calculates marginal dollar per kW substation costs by annualizing the sum of growth-related substation capital expenditures over projected 5-year period and dividing by the growth in system NCP. These dollar per kW marginal costs are subsequently multiplied by class NCPs to allocate marginal costs.
  - Seattle City Light treats marginal costs associated with substations as demand-related in their analyses. They calculate marginal substation O&M costs as the most recent historical annual O&M costs on a dollar per MW of total substation capacity basis, adjusted to represent costs for servicing a new marginal substation and for inflation, and then multiplied by total system substation capacity. Marginal annualized capital costs are calculated as annualized substation capital replacement cost on a $/MW of total substation capacity basis multiplied by total system substation capacity. These dollar per MW marginal costs are subsequently multiplied by class contribution percentages to average MW per hour in the costing period during the year with the maximum load are used to allocate marginal costs.

- **Distribution Lines** – As shown in Table C-8, the following approaches are used to classify plant in service and O&M costs associated with distribution lines:
  - **Computation Method** – One utility uses this approach. Idaho Power Company–Idaho uses a fixed and variable ratio computation method used in prior rate cases. The computations are updated periodically according to a system capacity utilization measurement based on a three-year average load duration curve.
  - **Demand Only** – Three utilities use this approach. These utilities include Avista Corporation–Washington, Avista Corporation–Idaho, and Puget Sound Energy.
  - **Distribution Lines Marginal Costs** – Two utilities use this approach to determine classified marginal distribution costs associated with lines as follows:
    - Portland General treats marginal costs associated with lines as demand-related in their analyses. They calculate marginal distribution feeder costs using the following steps: (1) calculate replacement costs of distribution feeders, (2) for each feeder, allocate cost responsibility based on rate schedule's proportionate contribution to NCP, (3) calculate the dollar per kW cost by totaling the cost responsibilities for all feeders and dividing by the sum of each schedule's NCP, and (4) annualize

costs by applying an economic carrying charge. These dollar per kW marginal costs are subsequently multiplied by class NCPs to allocate marginal costs.

- Seattle City Light treats marginal costs associated with lines (including service lines) as demand-related in their analyses. They calculate marginal O&M costs for lines as the historical three-year annual average lines O&M costs adjusted for inflation. Marginal capital costs are calculated as the annualized cost to replace lines and related equipment. These costs are subsequently allocated based on class contribution percentages to average MW per hour in the costing period during the year with the maximum load.

- **Historic Study** – One utility uses this approach. The proportions Manitoba Hydro classifies to demand and customer are based upon a 1990 study by Ernst & Young and accepted for use by Manitoba Hydro since 1991.
- **Minimum System Study** – Two utilities use this approach. These utilities include Hydro Québec Distribution and Newfoundland Power.

- **Distribution Transformers** – As shown in Table C-9, the following approaches are used to classify plant in service and O&M costs associated with distribution transformers:
  - **Computation Method** – One utility uses this approach. Idaho Power Company uses a fixed and variable ratio computation method used in prior rate cases. The computations are updated periodically according to a system capacity utilization measurement based on a three-year average load duration curve.
  - **Customer Only** – Two utilities use this approach. These utilities are Hydro Québec Distribution and Puget Sound Energy.
  - **Demand Only** – Three utilities use this approach. These utilities include Avista Corporation–Washington, Avista Corporation–Idaho, and Manitoba Hydro.
  - **Distribution Transformer Marginal Costs** – Two utilities use this approach to determine classified marginal distribution costs associated with lines as follows:
    - Portland General treats marginal costs associated with transformers as customer-related in their analyses. Portland General Electric calculates transformer costs by estimating the cost dollar per customer of providing the average customer a transformer. These dollar per customer marginal costs are subsequently multiplied by number of customers to determine allocated marginal costs.

    - Seattle City Light treats marginal costs associated with transformers as demand-related in their analyses. They calculate marginal transformer O&M cost per kW of load using an assumed factor for O&M as a percentage of annual transformer capital cost for each customer class. Annualized capital costs area assumed to be equal to the costs to replace transformers per kW of load. The dollar per kW annualized capital and O&M costs by customer class are subsequently multiplied by connected loads (sum of non-coincident peaks of customers) by class to determine marginal costs by class.
  - **Zero Intercept Analysis** – One utility, Newfoundland Power, uses this approach.
- **Distribution Services** – As shown in Table C-10, the following approaches are used to classify plant in service costs associated with distribution service drops:
  - **Customer Only** – Seven utilities use this approach. These include Avista Corporation–Washington, Avista Corporation–Idaho, Hydro Québec Distribution, Idaho Power, Manitoba Hydro, Newfoundland Power, and Puget Sound Energy.
  - **Distribution Services Marginal Costs** – Two utilities use this approach to determine classified marginal distribution costs associated with service lines as follows:
    - Portland General treats marginal costs associated with service drops as customer-related in their analyses. Portland General Electric calculates service line costs by estimating the cost dollar per customer of providing the average customer a service line. These dollar per customer marginal costs are subsequently multiplied by number of customers to determine allocated marginal costs.
    - Seattle City Light treats marginal costs associated wires including service lines as demand-related in their analyses. They calculate marginal O&M costs for wires as the historical three-year annual average wires O&M costs adjusted for inflation. Marginal capital costs are calculated as the annualized cost to replace wires and related equipment. These costs are subsequently allocated based on class contribution percentages to average MW per hour in the costing period during the year with the maximum load.
- **Distribution Meters** – As shown in Table C-11, the following approaches are used to classify plant in service and O&M costs associated with distribution meters:
  - **Customer Only** – Seven utilities use this approach. These include Avista Corporation–Washington, Avista Corporation–Idaho, Hydro

Québec Distribution, Idaho Power Company–Idaho, Manitoba Hydro, Newfoundland Power, and Puget Sound Energy.

- **Distribution Meters Marginal Costs** – Two utilities use this approach to determine classified marginal distribution costs associated with meters as follows:
  - Portland General treats marginal costs associated with meters as customer-related in their analyses. They calculate marginal meter costs as the installed cost on a dollar per customer basis of a new advanced metering infrastructure meter for each rate schedule multiplied by a carrying charge. For each rate schedule, Portland General subsequently multiplies the average marginal meter cost on a dollar per customer basis by number of customers to determine marginal meter costs by class.
  - Seattle City Light treats marginal costs associated meters as customer-related in their analyses. They calculate marginal meter O&M costs per meter as the annual per meter O&M cost by customer class. Annualized marginal capital costs per meter are calculated as the annualized per meter cost to replace meters by customer class. Total marginal costs by customer class are subsequently calculated by taking annual per meter O&M cost plus annualized capital costs per meter for each customer class and multiplying by number of meters in each class.

DSM, Energy Efficiency, and Conservation Classification Approaches

As shown in Table C-12 of Appendix C, the following approaches are used to classify costs associated with DSM, energy efficiency, and conservation programs:

- **Demand Only** – Two utilities use this approach. Idaho Power classifies DSM incentive payments as 100 percent demand-related. Newfoundland Power classifies curtailable service option costs and transfers to the reserve stabilization fund associated with the demand management incentive as 100 percent demand-related.
- **Derived from Classified Plant Costs** – One utility, Avista–Idaho, uses the demand/energy split for total classified generation plant in service to classify DSM investment in rate base and related amortization expense.
- **Derived from Other Classified O&M Costs** – One utility uses this approach. Newfoundland Power functionalizes, classifies and allocates conservation and demand management general costs based on corporate administration and general expenses.
- **Energy Only** – One utility uses this approach. BPA classifies conservation and energy efficiency costs as energy-related.

- **Generation Marginal Costs** –One utility uses this approach. Seattle City Light uses the same approach for conservation O&M, and associated capital-related and overhead–related costs as hydro resources as discussed above.
- **Supply Cost Savings** – One utility uses this approach. Newfoundland Power costs for conservation and demand management programs developed for the purpose of obtaining measureable changes in customer usage are classified between demand and energy reflective of the supply cost savings which occurred in 2011 (95 percent to production energy, 2 percent to production demand, and 3 percent to substation demand).
- **System Load Factor** – One utility uses this approach. Idaho Power classifies customer assistance costs for energy efficiency programs using the System Load Factor method.
- **Thermal Peak Credit** – One utility, Puget Sound Energy, uses the Thermal Peak Credit method to classify DSM costs.