DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL FOR
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851
DAVID.MEYER@AVISTACORP.COM

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-15-05
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 13
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	TARA L. KNOX
	)	

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2014

				Production / Transmission					
Line	Column	Description of Adjustment	(000's)	**Revenue**	**Expense**	**Plant**	**Accumulated Depreciation**	**Deferred Debits/Credits**	**Deferred Tax**
1	1.00	Per Results Report		91,039	188,083	644,423	(248,128)	896	(62,349)
2	1.01	Deferred FIT Rate Base		-	-	-	-	-	(5,200)
3	1.02	Deferred Debits and Credits		-	(352)	-	-	(545)	-
4	1.03	Restate Capital 2014 EOP		-	-	15,958	(3,060)	-	(15,546)
5	1.04	Working Capital		-	-	-	-	-	-
6	2.01	Eliminate B & O Taxes		-	-	-	-	-	-
7	2.02	Uncollectible Expense		-	-	-	-	-	-
8	2.03	Regulatory Expense		-	-	-	-	-	-
9	2.04	Injuries and Damages		-	-	-	-	-	-
10	2.05	FIT/DFIT ITC/PTC Expense		-	-	-	-	-	-
11	2.06	SIT/SITC Expense		-	-	-	-	-	-
12	2.07	Revenue Normalization		-	5,041	-	-	-	-
13	2.08	Miscellaneous Restating		-	-	-	-	-	-
14	2.09	Restate Incentives		-	-	-	-	-	-
15	2.10	ID PCA		-	3,862	-	-	-	-
16	2.11	Nez Perce Settlement Adjustment		-	(13)	-	-	-	-
17	2.12	CS2 Levelized		-	(409)	-	-	-	-
18	2.13	Colstrip / CS2 Maintenance		-	2,758	-	-	-	-
19	2.14	Restate Debt Interest		-	-	-	-	-	-
20	3.01	Pro Forma Power Supply		(60,860)	(66,200)	-	-	-	-
21	3.02	Pro Forma Transmission Rev/Exp		118	149	-	-	-	-
23	3.03	Pro Forma Labor Non-Exec		-	436	-	-	-	-
24	3.04	Pro Forma Labor Exec		-	(8)	-	-	-	-
25	3.05	Pro Forma Employee Benefits		-	632	-	-	-	-
26	3.06	Pro Forma Insurance		-	-	-	-	-	-
27	3.07	Pro Forma Property Tax		-	1,054	-	-	-	-
28	3.08	Pro Forma IS/IT Costs		-	-	-	-	-	-
29	3.09	Planned Capital Add 2015 EOP		-	1,277	53,240	(7,978)	-	(1,630)
30	3.10	Planned Capital Add 2016 AMA		-	160	8,052	(4,850)	-	(1,358)
31	3.11	Pro Forma O&M Offsets		-	64	-	-	-	-
32	3.12	Pro Forma Lake Spokane 2-Yr Amort		-	237	-	-	-	-
33	3.13	Pro Forma Colstrip Settlement		-	(200)	-	-	-	-
34	3.14	Pro Forma Project Compass Deferral Amorts		-	-	-	-	-	-
35	2016 Pro Forma Total			30,297	136,571	721,673	(264,016)	351	(86,083)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2014

Proposed Production and Transmission Revenue Requirement
2016 Pro Forma
Calculation of Load Change Adjustment Rate

Line			($000's)	Debt Cost
1	Prod/Trans	Pro Forma Rate Base	371,925	
2	Cost of Capital	Proposed Rate of Return	7.620%	2.67%
3	Rate Base	Net Operating Income Requirement	$28,341	
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -35%)	($3,476)	
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	106,274	
6	Tax Effect	Net Operating Income Requirement (Net Expense x -.35%)	($37,196)	
7	Total Prod/Trans	Net Operating Income Requirement	$93,943	
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.)	0.65	
9	Prod/Trans	Revenue Requirement	$144,528	
10	Test Year WA Normalized Retail Load MWh		3,072,989	
11	Prod/Trans Rev Requirement per kWh		$ 0.04703	
12	Cost of Service Energy Classified Production/Transmission Costs		$76,005	Company Case at Unity AVU-E-15-05
13	Cost of Service Total Production/Transmission Costs		$149,021	Company Case at Unity AVU-E-15-05
14	Load Change Adjustment Rate per kWh (Line 11 * Line 12 / Line 13)		**$ 0.02399**	

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line	Column	Description of Adjustment (000's)	Revenue	Expense	Production / Transmission Plant	Accumulated Depreciation	Deferred Debits/Credits	Deferred Tax
1	1.00	Per Results Report	91,039	188,083	644,423	(248,128)	896	(62,349)
2	1.01	Deferred FIT Rate Base	-	-	-	-	-	(5,200)
3	1.02	Deferred Debits and Credits	-	(352)	-	-	(545)	-
4	1.03	Restate Capital 2014 EOP	-	-	15,958	(3,060)	-	(15,546)
5	1.04	Working Capital	-	-	-	-	-	-
6	2.01	Eliminate B & O Taxes	-	-	-	-	-	-
7	2.02	Uncollectible Expense	-	-	-	-	-	-
8	2.03	Regulatory Expense	-	-	-	-	-	-
9	2.04	Injuries and Damages	-	-	-	-	-	-
10	2.05	FIT/DFIT ITC/PTC Expense	-	-	-	-	-	-
11	2.06	SIT/SITC Expense	-	-	-	-	-	-
12	2.07	Revenue Normalization	-	5,041	-	-	-	-
13	2.08	Miscellaneous Restating	-	-	-	-	-	-
14	2.09	Restate Incentives	-	-	-	-	-	-
15	2.10	ID PCA	-	3,862	-	-	-	-
16	2.11	Nez Perce Settlement Adjustment	-	(13)	-	-	-	-
17	2.12	CS2 Levelized	-	(409)	-	-	-	-
18	2.13	Colstrip / CS2 Maintenance	-	2,758	-	-	-	-
19	2.14	Restate Debt Interest	-	-	-	-	-	-
20	3.01	Pro Forma Power Supply	(60,860)	(66,200)	-	-	-	-
21	3.02	Pro Forma Transmission Rev/Exp	118	149	-	-	-	-
23	3.03	Pro Forma Labor Non-Exec	-	436	-	-	-	-
24	3.04	Pro Forma Labor Exec	-	(8)	-	-	-	-
25	3.05	Pro Forma Employee Benefits	-	632	-	-	-	-
26	3.06	Pro Forma Insurance	-	-	-	-	-	-
27	3.07	Pro Forma Property Tax	-	1,054	-	-	-	-
28	3.08	Pro Forma IS/IT Costs	-	-	-	-	-	-
29	3.09	Planned Capital Add 2015 EOP	-	1,277	53,240	(7,978)	-	(1,630)
30	3.10	Planned Capital Add 2016 AMA	-	160	8,052	(4,850)	-	(1,358)
31	3.11	Pro Forma O&M Offsets	-	64	-	-	-	-
32	3.12	Pro Forma Lake Spokane 2-Yr Amort	-	237	-	-	-	-
33	3.13	Pro Forma Colstrip Settlement	-	(200)	-	-	-	-
34	3.14	Pro Forma Project Compass Deferral Amorts	-	-	-	-	-	-
35	17.01	Pro Forma Power Supply	(5,489)	3,287	-	-	-	-
36	17.02	Pro Forma Transmission Rev/Exp	-	69	-	-	-	-
37	17.03	Pro Forma Labor Non-Exec	-	225	-	-	-	-
38	17.04	Pro Forma Property Tax	-	624	-	-	-	-
39	17.05	Planned Capital Add 2017 AMA	-	573	29,879	(9,921)	-	(2,239)
40	2017 Pro Forma Total		24,808	141,349	751,552	(273,937)	351	(88,322)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2014

Proposed Production and Transmission Revenue Requirement
2017 Pro Forma
Calculation of Load Change Adjustment Rate

Line			($000's)	Debt Cost
1	Prod/Trans	Pro Forma Rate Base	389,644	
2	Cost of Capital	Proposed Rate of Return	7.620%	2.67%
3	Rate Base	Net Operating Income Requirement	$29,691	
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -35%)	($3,641)	
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	116,541	
6	Tax Effect	Net Operating Income Requirement (Net Expense x -.35%)	($40,789)	
7	Total Prod/Trans	Net Operating Income Requirement	$101,801	
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.)	0.65	
9	Prod/Trans	Revenue Requirement	$156,618	
10	Test Year WA Normalized Retail Load MWh		3,072,989	
11	Prod/Trans Rev Requirement per kWh		$ 0.05097	
12	Cost of Service Energy Classified Production/Transmission Costs		$76,005	Company Case at Unity AVU-E-15-05
13	Cost of Service Total Production/Transmission Costs		$149,021	Company Case at Unity AVU-E-15-05
14	Load Change Adjustment Rate per kWh (Line 11 * Line 12 / Line 13) - 2017		**$ 0.02599**	

1. ELECTRIC COST OF SERVICE

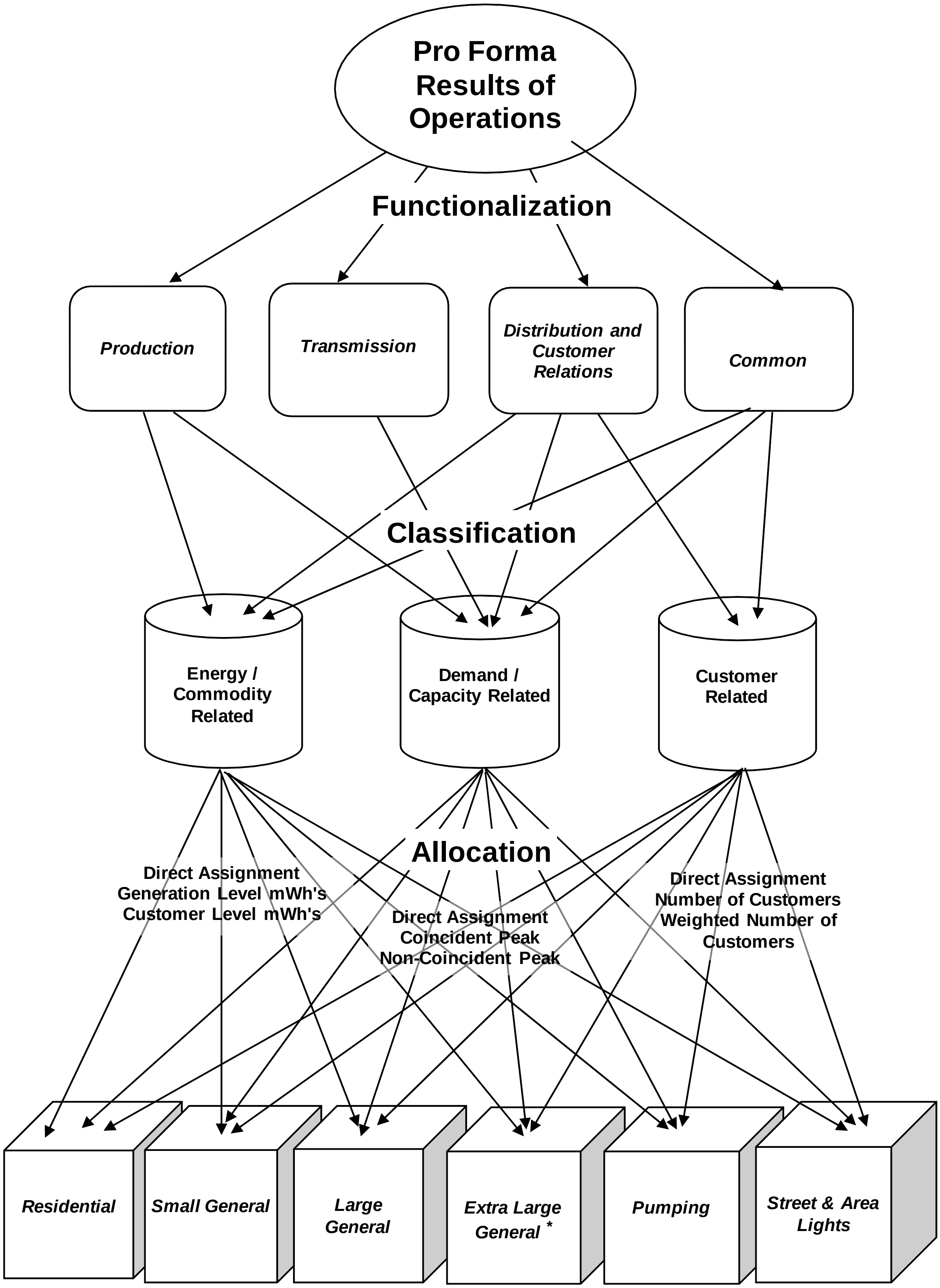
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. It indicates whether the revenue provided by customers recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers.

There are three basic steps involved in a cost of service study: functionalization, classification, and allocation. See flow chart below.

First, the expenses and rate base associated with the electric system under study are assigned to functional categories. The uniform system of accounts provides the basic segregation into production, transmission, and distribution. Traditionally customer accounting, customer information, and sales expenses are included in the distribution function, and administrative and general expenses and general plant rate base are allocated to all functions. This study includes a separate functional category for common costs. Administrative and general costs that cannot be directly assigned to the other functions have been placed in this category.

Second, the expenses and rate base items that cannot be directly assigned to customer groups are classified into three primary cost components: energy, demand or customer related. Energy related costs are allocated based on each rate schedule's share of commodity consumption. Demand (capacity) related costs are allocated to rate schedules on the basis of each schedule's contribution to peak demand. Customer related items are allocated to rate schedules based on the number of customers within each schedule. The number of customers may be weighted by appropriate factors such as relative cost of metering equipment. In addition to these three cost components, any revenue related expense is allocated based on the proportion of revenues by rate schedule.

1



Pro Forma Results of Operations by Customer Group

* Customer classes shown in this flowchart are illustrative and may not match the Company's actual rate schedules.

The final step is allocation of the costs to the various rate schedules utilizing the allocation factors selected for each specific cost item. These factors are derived from usage and customer information associated with the test period results of operations.

BASE CASE COST OF SERVICE STUDY

Production Classification (Load Factor Peak Credit)

This study utilizes a Peak Credit methodology to classify production costs into demand and energy classifications. The Peak Credit method 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. The peak credit ratio (the proportion of total production cost that is capacity related) is determined 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[1] which is 37.93% for the 2014 test year. The same classification ratio is applied to all production costs.

Production Allocation

Production demand related costs are allocated to the customer classes by class contribution to the average of the twelve monthly system coincident peak loads. Although the Company is usually 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. Energy related costs are allocated to class by pro forma annual kilowatt-hour sales adjusted for losses to reflect generation level consumption.

[1] 1 – (average MW÷ peak MW).

Transmission Classification and Allocation

Transmission costs are classified as 100% demand related due in part to the fact that the facilities are designed to meet system peak loads. These costs are then allocated to the customer classes by class contribution to the average of the twelve monthly system coincident peak loads (12CP). The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

Distribution Facilities Classification (Basic Customer)

The Basic Customer method considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution plant. All other distribution plant is then considered demand related. This division delineates plant installed solely for an individual customer from plant which is part of the broader system. The basic customer method provides a clearly definable division between plant that provides service only to individual customers, from plant that is part of the interconnected distribution network.

Customer Relations Distribution Cost Classification

Customer service, customer information and sales expenses are the core of the customer relations functional unit which is included with the distribution cost category. For the most part they are classified as customer related. Exceptions are sales expenses which are classified as energy related and uncollectible accounts expense which is considered separately as a revenue conversion item. Demand Side Management expenses (if any) recorded in Account 908 would be considered separately from the other customer information costs.

Any demand side management investment and amortization included in base rates would be classified implicitly to demand and energy by the sum of production plant in service, then allocated to rate schedules by coincident peak demand and energy consumption respectively. At this point in time, the Company's demand side management investments in base rates have been fully amortized except for some minor outstanding loan balances that will remain on the books until satisfied. All current demand side management costs are managed through the Schedule 91 Public Purpose Tariff Rider balancing account which is not included in this cost study.

Distribution Cost Allocation

Distribution demand related costs, which cannot be directly assigned, are allocated to customer class by the average of the twelve monthly non-coincident peaks for each class. Distribution facilities that serve only secondary voltage customers are either allocated by the non-coincident peaks of secondary voltage customers (excludes demand from customers receiving service at primary voltage)[2], or by the average number of secondary voltage customers. This includes secondary voltage overhead or underground conductors and devices, line transformers, and service lines to the customer's premises. The costs of specific substations and related primary voltage distribution facilities are directly assigned to Extra Large General Service customers (Schedule 25 and 25P) based on their load ratio share of the substation capacity from which they receive service.

Most customer costs are allocated by average number of customers. Weighted customer allocators have been developed using typical current cost of meters, estimated meter reading time, and direct assignment of billing costs for hand-billed customers. Street and area light customers are excluded from metering and meter reading expenses as their service is not metered.

[2] Customers taking service below 11 kV are secondary voltage customers, customers taking service at greater than 11kV are primary voltage customers.

Administrative and General Costs

Administrative and general costs which are directly associated with production, transmission, distribution, or customer relations functions are directly assigned to those functions and allocated to customer class by the relevant plant or number of customers. The remainder of administrative and general costs are considered common costs, and have been left in their own functional category. These common costs are classified by the implicit relationship of energy, demand and customer within the four-factor allocator applied to them. The four-factor allocator consists of a 25% weighting of each of the following: 1) operating & maintenance expenses excluding resource costs, labor expenses, and administrative and general expenses; 2) operating and maintenance labor expenses excluding administrative and general labor expenses; 3) net production, transmission, and distribution plant; and 4) number of customers.

Revenue Conversion Items

In this study uncollectible accounts and commission fees have been classified as revenue related and are allocated by pro forma revenue. These items vary with revenue and are included in the calculation of the revenue conversion factor. Income tax expense items are allocated to schedules by net income before income tax adjusted by interest expense.

For the functional summaries on pages 2 and 3 of the cost of service study, these items are assigned to component cost categories. The revenue related expense items have been reduced to a percent of all other costs and loaded onto each cost category by that ratio. Similarly, income tax items have been reduced to a percent of net income before tax then assigned to cost categories by relative rate base (as is net income).

The following matrix outlines the methodology applied in the Company Base Case cost of service study.

IPUC Case No. AVU-E-15-05 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Production Plant			
1	Thermal Production	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
2	Hydro Production	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
3	Other Production (Coyote Springs)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
4	Other Production	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Transmission Plant			
5	All Transmission	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
	Distribution Plant			
6	360 Land	D = Distribution	Demand	D03 Non-coincident Peak Demand (NCP)
7	361 Structures	D = Distribution	Demand	D04/D05/D06 Direct Assign Large / Non-coincident Peak Demand Excl DA
8	362 Station Equipment	D = Distribution	Demand	D04/D05/D06 Direct Assign Large / Non-coincident Peak Demand Excl DA
9	364 Poles Towers & Fixtures	D = Distribution	Demand	D04/D05/D07/D08 Direct Assign Large & Lights / NCP Excl DA / NCP Secondary
10	365 Overhead Conductors & Devices	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
11	366 Underground Conduit	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
12	367 Underground Conductors & Devices	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
13	368 Line Transformers	D = Distribution	Demand	D07 Non-coincident Peak Demand Secondary
14	369 Services	D = Distribution	Customer	C02 Secondary Customers unweighted Excl Lighting
15	370 Meters	D = Distribution	Customer	C04 Customers weighted by Current Typical Meter Cost
16	373 Street and Area Lighting Systems	D = Distribution	Customer	C05 Direct Assignment to Street and Area Lights
	General Plant			
17	All General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Intangible Plant			
18	301 Organization	O=Other	Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
19	302 Franchises & Consents - Hydro Relicensing	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
20	303 Misc Intangible Plant - Transmission Agreements	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
21	303 Misc Intangible Plant - Software	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Reserve for Depreciation/Amortization			
22	Intangible	P/T/O	Follows Related Plant	S01/S02/S23 Sum of Production Plant / Sum of Transmission Plant / Corp Cost Allocator
23	Production	P = Production	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
24	Transmission	T = Transmission	Follows Related Plant	D01 Coincident Peak Demand (12CP)
25	Distribution	D = Distribution	Follows Related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
26	General	O=Other	Follows Related Plant	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Other Rate Base			
27	252 Customer Advances for Construction	D = Distribution	Customer	S13 Sum of Account 369 Services Plant
28	282/190 Accumulated Deferred Income Tax	P/T/D/O	Per Functional Analysis	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
29	Hydro Relicensing Related Settlements	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
30	Demand Side Management Investment	DSM	Demand/Energy by Load Factor Peak Credit	S01 Sum of Production Plant
31	Working Capital	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant

IPUC Case No. AVU-E-15-05 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Production O&M			
1	Thermal	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
2	Thermal Fuel (501)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
3	Hydro	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
4	Water for Power (536)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
5	Other (Coyote Springs)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
6	Other Fuel (547)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
7	Other	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
8	Purchased Power and Other Expenses (555 and 557)	P = Production	Demand/Energy by Load Factor Peak Credit	S01 Sum of Production Plant
9	System Control & Misc (556)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Transmission O&M			
10	All Transmission	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
	Distribution O&M			
11	580 OP Super & Engineering	D = Distribution	Demand/Customer from Other Dist Op Exp	S16 Sum of Other Distribution Operating Expenses
12	581 Load Dispatching	D = Distribution	Demand	D03 Non-coincident Peak Demand
13	582 Station Expenses	D = Distribution	Demand	S09 Sum of Account 362 Station Equipment
14	583 Overhead Lines	D = Distribution	Demand	S10 Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
15	584 Underground Lines	D = Distribution	Demand	S11 Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
16	585 Street Lights	D = Distribution	Customer	S15 Sum of Account 373 Street Light and Signal Systems
17	586 Meters	D = Distribution	Customer	S14 Sum of Account 370 Meters
18	587 Customer Installations	D = Distribution	Customer	S13 Sum of Account 369 Services
19	588 Misc Operating Expense	D = Distribution	Demand/Customer from Other Dist Op Exp	S16 Sum of Other Distribution Operating Expenses
20	589 Rents	D = Distribution	Demand	D03 Non-coincident Peak Demand
21	590 MT Super & Engineering	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17 Sum of Other Distribution Maintenance Expenses
22	591 MT of Structures	D = Distribution	Demand	S08 Sum of Account 361 Structures & Improvements
23	592 MT of Station Equipment	D = Distribution	Demand	S09 Sum of Account 362 Station Equipment
24	593 MT of Overhead Lines	D = Distribution	Demand	S10 Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
25	594 MT of Underground Lines	D = Distribution	Demand	S11 Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
26	595 MT of Line Transformers	D = Distribution	Demand	S12 Sum of Account 368 Line Transformers
27	596 MT of Street Lights	D = Distribution	Customer	S15 Sum of Account 373 Street Light and Signal Systems
28	597 MT of Meters	D = Distribution	Customer	S14 Sum of Account 370 Meters
29	598 Misc Maintenance Expense	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17 Sum of Other Distribution Maintenance Expenses
	Customer Accounts Expenses			
30	901 Supervision	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
31	902 Meter Reading	C = Customer Relations	Customer	C03/C06 Customers Weighted by Est. Meter Reading Time/Direct Assign Handbilled Cust
32	903 Customer Records & Collections	C = Customer Relations	Customer	C01/C06 All Customers unweighted / Direct Assign Handbilled Cust
33	904 Uncollectible Accounts	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
34	905 Misc Cust Accounts	C = Customer Relations	Customer	C01 All Customers unweighted
	Customer Service & Info Expenses			
35	907 Supervision	C = Customer Relations	Customer	C01 All Customers unweighted
36	908 Customer Assistance	C = Customer Relations	Customer	C01 All Customers unweighted
37	908 DSM Amortization Expenses	DSM	Demand/Energy from Production Plant	S01 Sum of Production Plant
38	909 Advertising	C = Customer Relations	Customer	C01 All Customers unweighted
39	910 Misc Cust Service & Info	C = Customer Relations	Customer	C01 All Customers unweighted
	Sales Expenses			
40	911 - 916	C = Customer Relations	Energy	E02 Annual Generation Level Consumption

IPUC Case No. AVU-E-15-05 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Admin & General Expenses			
1	920 - 927 & 930 -935 Assigned to Production	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
2	920 - 927 & 930 -935 Assigned to Transmission	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
3	920 - 927 & 930 - 935 Assigned to Distribution	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
4	920 - 927 & 930 - 935 Assigned to Customer Relations	C = Customer Relations	Customer	C01 All Customers unweighted
5	920 - 935 Assigned to Other	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
6	928 FERC Commission Fees	P = Production	Energy	E02 Annual Generation Level Consumption
7	928 IPUC Commission Fees	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
	Depreciation & Amortization Expense			
8	Intangible	P/T/O	Demand/Energy/Customer as in related Plant	S01/S02/S23 Sum of Production Plant / Sum of Transmission Plant / Corp Cost Alloctor
9	Production	P = Production	Demand/Energy by Peak Credit as in related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
10	Transmission	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
11	Distribution	D = Distribution	Demand/Customer as in related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
12	General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Taxes			
13	Property Tax	P/T/D/O	Demand/Energy/Customer from related Plant	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
14	State kWh Generation Taxes	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
15	Misc Production Taxes	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
16	Misc Distribution Taxes	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
17	Idaho State Income Tax	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
18	Federal Income Tax	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
19	Deferred FIT	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
	Other Income Related Items			
20	Boulder Write-off Amort & Misc Renewable Items	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
21	Compass Deferral Amortization	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Operating Revenues			
22	Sales of Electricity- Retail	R = Revenue from Rates	Revenue	Input Pro Forma Revenue per Revenue Study
23	Sales for Resale (447)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
24	Misc Service Revenue (451)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
25	Sales of Water & Water Power (453)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
26	Rent from Production Property (454)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
27	Rent from Transmission Property (454)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
28	Rent from Distribution Property (454)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
29	Other Electric Revenues - Generation (456)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
30	Other Electric Revenues - Wheeling (456)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
31	Other Electric Revenues - Energy Delivery (456)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
	Salaries & Wages (allocation factor input)			
	Operation & Maintenance Expenses			
32	Production Total	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
33	Transmission Total	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
34	Distribution Total	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
35	Customer Accounts Total	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
36	Customer Service Total	C = Customer Relations	Customer	C01 All Customers unweighted
37	Sales Total	C = Customer Relations	Energy	E02 Annual Generation Level Consumption
38	Admin & General Total	O=Other	Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
39	Interest Expense (allocation factor input)	R = Revenue Conversion	Demand/Energy/Customer from Rate Base components	S07 Total Rate Base

Sumcost | AVISTA UTILITIES | Idaho Jurisdiction
Scenario: AVU-E-15-05 Company Case | Cost of Service Basic Summary | Electric Utility | 06/01/15
Load Factor Peak Credit | For the Twelve Months Ended December 31, 2014
Transmission By Demand 12 CP

	(b)	(c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Description		System Total	Residential Service Sch 1	General Service Sch 11-12	Large Gen Service Sch 21-22	Extra Large Gen Service Sch 25	Extra Large Service CP Sch 25P	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
	Plant In Service									
1	Production Plant		462,520,000	185,601,024	56,795,187	104,760,947	44,014,350	61,798,348	7,964,545	1,585,598
2	Transmission Plant		228,650,000	101,336,136	29,553,862	51,177,090	19,435,547	23,591,167	3,154,266	401,933
3	Distribution Plant		518,091,000	268,384,769	74,768,105	116,239,045	13,824,308	2,904,536	17,395,138	24,575,100
4	Intangible Plant		81,039,000	39,578,104	10,794,232	15,483,668	5,618,743	7,324,154	1,478,734	761,365
5	General Plant		108,516,000	60,756,256	15,349,881	17,332,673	5,269,692	6,202,298	2,081,470	1,523,730
6	Total Plant In Service		1,398,816,000	655,656,288	187,261,267	304,993,422	88,162,640	101,820,504	32,074,153	28,847,725
	Accum Depreciation									
7	Production Plant		(195,006,000)	(78,252,429)	(23,945,780)	(44,168,929)	(18,557,170)	(26,055,195)	(3,357,983)	(668,514)
8	Transmission Plant		(70,554,000)	(31,269,056)	(9,119,367)	(15,791,596)	(5,997,182)	(7,279,472)	(973,305)	(124,023)
9	Distribution Plant		(184,500,000)	(95,938,435)	(26,215,650)	(39,999,659)	(4,181,922)	(714,960)	(6,040,197)	(11,409,177)
10	Intangible Plant		(17,698,000)	(9,350,629)	(2,438,313)	(3,067,175)	(1,024,217)	(1,276,958)	(331,155)	(209,552)
11	General Plant		(38,026,000)	(21,290,108)	(5,378,880)	(6,073,687)	(1,846,597)	(2,173,399)	(729,385)	(533,943)
12	Total Accumulated Depreciation		(505,784,000)	(236,100,657)	(67,097,991)	(109,101,046)	(31,607,088)	(37,499,983)	(11,432,024)	(12,945,210)
13	Net Plant		893,032,000	419,555,631	120,163,276	195,892,376	56,555,551	64,320,521	20,642,129	15,902,515
14	Accumulated Deferred FIT		(165,948,000)	(77,937,157)	(22,214,442)	(35,994,813)	(10,488,286)	(12,178,639)	(3,778,127)	(3,356,534)
15	Miscellaneous Rate Base		22,141,000	9,980,398	2,933,204	5,082,482	1,456,704	1,671,657	525,617	490,938
16	Total Rate Base		749,225,000	351,598,872	100,882,038	164,980,044	47,523,969	53,813,539	17,389,618	13,036,920
17	Revenue From Retail Rates		244,977,000	104,939,000	36,296,000	54,364,000	17,152,500	23,458,500	5,277,000	3,490,000
18	Other Operating Revenues		32,379,000	13,468,504	4,056,599	7,314,573	2,882,234	3,890,874	572,708	193,508
19	Total Revenues		277,356,000	118,407,504	40,352,599	61,678,573	20,034,734	27,349,374	5,849,708	3,683,508
	Operating Expenses									
20	Production Expenses		100,829,000	40,460,879	12,381,307	22,837,805	9,595,094	13,471,992	1,736,265	345,659
21	Transmission Expenses		10,691,000	4,738,179	1,381,851	2,392,890	908,749	1,103,053	147,484	18,793
22	Distribution Expenses		11,953,000	6,014,349	1,748,809	2,646,810	371,538	78,334	399,468	693,693
23	Customer Accounting Expenses		4,427,000	3,268,783	704,988	219,817	77,293	82,842	57,483	15,794
24	Customer Information Expenses		606,000	494,408	98,625	5,531	43	5	6,684	704
25	Sales Expenses		0	0	0	0	0	0	0	0
26	Admin & General Expenses		23,830,000	13,017,034	3,352,708	3,995,545	1,211,819	1,436,177	467,570	349,147
27	Total O&M Expenses		152,336,000	67,993,632	19,668,289	32,098,398	12,164,536	16,172,402	2,814,954	1,423,790
28	Taxes Other Than Income Taxes		11,233,000	4,964,057	1,460,903	2,532,003	830,736	1,032,144	238,350	174,808
29	Other Income Related Items		1,223,000	701,548	174,974	188,265	54,451	61,797	23,667	18,298
	Depreciation Expense									
30	Production Plant Depreciation		9,929,000	3,984,331	1,219,233	2,248,922	944,864	1,326,636	170,976	34,038
31	Transmission Plant Depreciation		4,135,000	1,832,604	534,464	925,507	351,480	426,632	57,043	7,269
32	Distribution Plant Depreciation		15,729,000	8,304,311	2,406,094	3,409,076	374,078	50,083	533,362	651,995
33	General Plant Depreciation		12,432,000	6,960,465	1,758,540	1,985,696	603,716	710,559	238,461	174,564
34	Amortization Expense		3,143,000	1,273,999	388,011	710,797	294,220	409,179	54,311	12,483
35	Total Depreciation Expense		45,368,000	22,355,709	6,306,342	9,279,999	2,568,358	2,923,089	1,054,153	880,349
36	Income Tax		18,236,000	5,025,415	3,882,988	5,091,106	1,216,371	2,211,545	484,684	323,892
37	Total Operating Expenses		228,396,000	101,040,362	31,493,495	49,189,770	16,834,451	22,400,977	4,615,808	2,821,137
38	Net Income		48,960,000	17,367,142	8,859,104	12,488,803	3,200,282	4,948,397	1,233,901	862,371
39	Rate of Return		6.53%	4.94%	8.78%	7.57%	6.73%	9.20%	7.10%	6.61%
40	Return Ratio		1.00	0.76	1.34	1.16	1.03	1.41	1.09	1.01
41	Interest Expense		20,004,000	9,387,546	2,693,509	4,404,899	1,268,870	1,436,799	464,296	348,080
42	Revenue Related Operating Expenses		1,435,000	614,700	212,611	318,448	100,474	137,413	30,911	20,443

Sumcost | AVISTA UTILITIES | Idaho Jurisdiction
Scenario: AVU-E-15-05 Company Case | Revenue to Cost by Functional Component Summary | Electric Utility | 06/01/15
Load Factor Peak Credit | For the Twelve Months Ended December 31, 2014
Transmission By Demand 12 CP

	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Description				System Total	Residential Service Sch 1	General Service Sch 11-12	Large Gen Service Sch 21-22	Extra Large Gen Service Sch 25	Extra Large Service CP Sch 25P	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
	Functional Cost Components at Current Return by Schedule											
1	Production				119,247,384	44,960,305	15,595,938	27,698,214	11,327,318	17,185,169	2,073,970	406,470
2	Transmission				24,438,553	9,153,271	3,769,059	5,926,188	2,093,280	3,103,158	350,770	42,826
3	Distribution				58,402,753	28,313,907	10,308,388	13,393,271	1,583,557	393,699	1,995,088	2,414,843
4	Common				42,888,310	22,511,517	6,622,614	7,346,327	2,148,346	2,776,474	857,172	625,861
5	Total Current Rate Revenue				244,977,000	104,939,000	36,296,000	54,364,000	17,152,500	23,458,500	5,277,000	3,490,000
	Expressed as $/kWh											
6	Production				$0.03881	$0.03918	$0.04296	$0.03964	$0.03583	$0.03618	$0.03516	$0.02991
7	Transmission				$0.00795	$0.00798	$0.01038	$0.00848	$0.00662	$0.00653	$0.00595	$0.00315
8	Distribution				$0.01901	$0.02468	$0.02840	$0.01917	$0.00501	$0.00083	$0.03382	$0.17772
9	Common				$0.01396	$0.01962	$0.01824	$0.01051	$0.00679	$0.00584	$0.01453	$0.04606
10	Total Current Melded Rates				$0.07972	$0.09146	$0.09999	$0.07780	$0.05425	$0.04938	$0.08946	$0.25684
	Functional Cost Components at Uniform Current Return											
11	Production				118,255,620	47,453,871	14,521,210	26,784,941	11,253,447	15,800,402	2,036,349	405,401
12	Transmission				24,185,192	10,718,714	3,126,026	5,413,198	2,055,773	2,495,329	333,639	42,514
13	Distribution				59,345,208	31,998,921	8,841,153	12,325,248	1,557,206	312,341	1,909,088	2,401,251
14	Common				43,190,979	23,962,769	6,091,594	7,040,927	2,130,810	2,503,131	838,031	623,718
15	Total Uniform Current Cost				244,977,000	114,134,274	32,579,983	51,564,314	16,997,236	21,111,202	5,117,107	3,472,884
	Expressed as $/kWh											
16	Production				$0.03848	$0.04136	$0.04000	$0.03833	$0.03559	$0.03326	$0.03452	$0.02984
17	Transmission				$0.00787	$0.00934	$0.00861	$0.00775	$0.00650	$0.00525	$0.00566	$0.00313
18	Distribution				$0.01931	$0.02789	$0.02436	$0.01764	$0.00493	$0.00066	$0.03237	$0.17672
19	Common				$0.01406	$0.02088	$0.01678	$0.01008	$0.00674	$0.00527	$0.01421	$0.04590
20	Total Current Uniform Melded Rates				$0.07972	$0.09947	$0.08975	$0.07379	$0.05376	$0.04444	$0.08675	$0.25558
21	Revenue to Cost Ratio at Current Rates				1.00	0.92	1.11	1.05	1.01	1.11	1.03	1.00
	Functional Cost Components at Proposed Return by Schedule											
22	Production				123,319,900	46,953,104	15,982,878	28,534,220	11,717,438	17,570,381	2,141,727	420,152
23	Transmission				26,792,976	10,404,447	4,000,607	6,395,834	2,291,377	3,272,269	381,629	46,814
24	Distribution				63,344,676	31,259,105	10,836,708	14,371,046	1,722,731	416,335	2,149,996	2,588,754
25	Common				44,749,448	23,671,344	6,813,807	7,625,900	2,240,954	2,852,515	891,648	653,280
26	Total Proposed Rate Revenue				258,207,000	112,288,000	37,634,000	56,927,000	17,972,500	24,111,500	5,565,000	3,709,000
	Expressed as $/kWh											
27	Production				$0.04013	$0.04092	$0.04403	$0.04083	$0.03706	$0.03699	$0.03631	$0.03092
28	Transmission				$0.00872	$0.00907	$0.01102	$0.00915	$0.00725	$0.00689	$0.00647	$0.00345
29	Distribution				$0.02061	$0.02724	$0.02985	$0.02057	$0.00545	$0.00088	$0.03645	$0.19052
30	Common				$0.01456	$0.02063	$0.01877	$0.01091	$0.00709	$0.00600	$0.01512	$0.04808
31	Total Proposed Melded Rates				$0.08402	$0.09786	$0.10368	$0.08146	$0.05684	$0.05076	$0.09434	$0.27296
	Functional Cost Components at Uniform Requested Return											
32	Production				122,451,054	49,137,423	15,036,389	27,735,208	11,652,693	16,360,963	2,108,594	419,783
33	Transmission				26,570,232	11,775,747	3,434,301	5,947,024	2,258,504	2,741,407	366,541	46,706
34	Distribution				64,171,541	34,487,113	9,544,547	13,436,645	1,699,635	345,279	2,074,255	2,584,067
35	Common				45,014,174	24,942,615	6,346,149	7,358,709	2,225,585	2,613,785	874,790	652,541
36	Total Uniform Cost				258,207,000	120,342,899	34,361,385	54,477,586	17,836,417	22,061,435	5,424,180	3,703,098
	Expressed as $/kWh											
37	Production				$0.03985	$0.04283	$0.04142	$0.03969	$0.03685	$0.03444	$0.03575	$0.03089
38	Transmission				$0.00865	$0.01026	$0.00946	$0.00851	$0.00714	$0.00577	$0.00621	$0.00344
39	Distribution				$0.02088	$0.03006	$0.02629	$0.01923	$0.00538	$0.00073	$0.03517	$0.19017
40	Common				$0.01465	$0.02174	$0.01748	$0.01053	$0.00704	$0.00550	$0.01483	$0.04802
41	Total Uniform Melded Rates				$0.08402	$0.10488	$0.09466	$0.07796	$0.05641	$0.04644	$0.09196	$0.27253
42	Revenue to Cost Ratio at Proposed Rates				1.00	0.93	1.10	1.04	1.01	1.09	1.03	1.00
43	Current Revenue to Proposed Cost Ratio				0.95	0.87	1.06	1.00	0.96	1.06	0.97	0.94
44	Target Revenue Increase				13,230,000	15,404,000	(1,935,000)	114,000	684,000	(1,397,000)	147,000	213,000

Sumcost | AVISTA UTILITIES | Idaho Jurisdiction

Scenario: AVU-E-15-05 Company Case | Revenue to Cost By Classification Summary | Electric Utility | 06/01/15

Load Factor Peak Credit | For the Twelve Months Ended December 31, 2014

Transmission By Demand 12 CP

	(b)	(c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
				Residential	General	Large Gen	Extra Large	Extra Large	Pumping	Street &
			System	Service	Service	Service	Gen Service	Service CP	Service	Area Lights
	Description		Total	Sch 1	Sch 11-12	Sch 21-22	Sch 25	Sch 25P	Sch 31-32	Sch 41-49
	Cost Classifications at Current Return by Schedule									
1	Energy		83,297,726	29,272,301	10,529,372	19,443,695	8,404,276	13,660,177	1,620,539	367,365
2	Demand		133,789,480	55,814,981	20,457,257	34,415,079	8,713,778	9,793,921	3,243,502	1,350,962
3	Customer		27,889,794	19,851,718	5,309,371	505,227	34,446	4,401	412,958	1,771,673
4	Total Current Rate Revenue		244,977,000	104,939,000	36,296,000	54,364,000	17,152,500	23,458,500	5,277,000	3,490,000
	Expressed as Unit Cost									
5	Energy	$/kWh	$0.02711	$0.02551	$0.02901	$0.02782	$0.02658	$0.02876	$0.02747	$0.02704
6	Demand	$/kW/mo	$9.92	$7.01	$12.47	$18.18	$13.64	$10.71	$8.23	$32.29
7	Customer	$/Cust/mo	$18.42	$16.07	$21.55	$36.57	$318.95	$366.78	$24.73	$1,007.20
	Cost Classifications at Uniform Current Return									
8	Energy		82,352,327	30,937,377	9,787,437	18,787,576	8,348,148	12,534,968	1,590,445	366,376
9	Demand		133,928,115	62,056,769	17,923,752	32,294,490	8,614,767	8,572,069	3,123,364	1,342,905
10	Customer		28,696,558	21,140,128	4,868,794	482,248	34,321	4,165	403,298	1,763,603
11	Total Uniform Current Cost		244,977,000	114,134,274	32,579,983	51,564,314	16,997,236	21,111,202	5,117,107	3,472,884
	Expressed as Unit Cost									
12	Energy	$/kWh	$0.02680	$0.02696	$0.02696	$0.02689	$0.02640	$0.02639	$0.02696	$0.02696
13	Demand	$/kW/mo	$9.93	$7.79	$10.93	$17.06	$13.48	$9.37	$7.93	$32.10
14	Customer	$/Cust/mo	$18.96	$17.12	$19.76	$34.91	$317.78	$347.11	$24.15	$1,002.62
15	Revenue to Cost Ratio at Current Rates		1.00	0.92	1.11	1.05	1.01	1.11	1.03	1.00
	Cost Classifications at Proposed Return by Schedule									
16	Energy		86,172,451	30,602,995	10,796,497	20,044,305	8,700,695	13,973,187	1,674,743	380,030
17	Demand		142,814,030	60,803,601	21,369,503	36,356,432	9,236,698	10,133,846	3,459,899	1,454,052
18	Customer		29,220,519	20,881,405	5,468,001	526,263	35,108	4,467	430,358	1,874,918
19	Total Proposed Rate Revenue		258,207,000	112,288,000	37,634,000	56,927,000	17,972,500	24,111,500	5,565,000	3,709,000
	Expressed as Unit Cost									
20	Energy	$/kWh	$0.02804	$0.02667	$0.02974	$0.02868	$0.02752	$0.02941	$0.02839	$0.02797
21	Demand	$/kW/mo	$10.59	$7.63	$13.03	$19.21	$14.45	$11.08	$8.78	$34.76
22	Customer	$/Cust/mo	$19.30	$16.91	$22.19	$38.09	$325.07	$372.26	$25.77	$1,065.90
	Cost Classifications at Uniform Requested Return									
23	Energy		85,344,825	32,061,572	10,143,090	19,470,275	8,651,501	12,990,461	1,648,238	379,689
24	Demand		142,932,748	66,271,297	19,138,301	34,501,153	9,149,919	9,066,713	3,354,092	1,451,273
25	Customer		29,929,427	22,010,030	5,079,994	506,159	34,998	4,261	421,850	1,872,136
26	Total Uniform Cost		258,207,000	120,342,899	34,361,385	54,477,586	17,836,417	22,061,435	5,424,180	3,703,098
	Expressed as Unit Cost									
27	Energy	$/kWh	$0.02777	$0.02794	$0.02794	$0.02786	$0.02736	$0.02735	$0.02794	$0.02794
28	Demand	$/kW/mo	$10.60	$8.32	$11.67	$18.23	$14.32	$9.91	$8.51	$34.69
29	Customer	$/Cust/mo	$19.77	$17.82	$20.62	$36.64	$324.05	$355.07	$25.27	$1,064.32
30	Revenue to Cost Ratio at Proposed Rates		1.00	0.93	1.10	1.04	1.01	1.09	1.03	1.00
31	Current Revenue to Proposed Cost Ratio		0.95	0.87	1.06	1.00	0.96	1.06	0.97	0.94
32	Annual Consumption (mWh's)		3,072,989	1,147,395	362,993	698,804	316,177	475,047	58,986	13,588
33	Estimated Annual Billing Demand (kW)		13,489,000	7,966,469	1,640,110	1,892,799	639,000	914,862	393,923	41,837
34	Monthly Average Number of Customers		126,154	102,923	20,531	1,151	9	1	1,391	147

Sumcost
Scenario: AVU-E-15-05 Company Case
Load Factor Peak Credit
Transmission By Demand 12 CP

AVISTA UTILITIES
Customer Cost Analysis
For the Twelve Months Ended December 31, 2014

Idaho Jurisdiction
Electric Utility

06/01/15

	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 1	(h) General Service Sch 11-12	(i) Large Gen Service Sch 21-22	(j) Extra Large Gen Service Sch 25	(k) Extra Large Service CP Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Meter, Services, Meter Reading & Billing Costs by Schedule at Requested Rate of Return											
	Rate Base											
1	Services				50,011,000	40,861,193	8,151,038	446,368	0	0	552,401	0
2	Services Accum. Depr.				(22,180,000)	(18,122,038)	(3,615,005)	(197,965)	0	0	(244,991)	0
3	Total Services				27,831,000	22,739,154	4,536,033	248,402	0	0	307,410	0
4	Meters				21,523,000	13,832,911	5,684,375	1,262,674	24,386	4,289	714,366	0
5	Meters Accum. Depr.				(5,093,000)	(3,273,290)	(1,345,097)	(298,787)	(5,770)	(1,015)	(169,041)	0
6	Total Meters				16,430,000	10,559,621	4,339,278	963,887	18,615	3,274	545,325	0
7	Total Rate Base				44,261,000	33,298,776	8,875,311	1,212,289	18,615	3,274	852,735	0
8	Return on Rate Base @ 7.62%				3,372,691	2,537,369	676,299	92,377	1,418	249	64,978	0
9	Tax Benefit of Interest				(413,613)	(311,172)	(82,939)	(11,329)	(174)	(31)	(7,969)	0
10	Revenue Conversion Factor				0.61459	0.61459	0.61459	0.61459	0.61459	0.61459	0.61459	0.61459
11	Rate Base Revenue Requirement				4,814,696	3,622,229	965,453	131,872	2,025	356	92,760	0
	Expenses											
12	Services Depr Exp				1,349,000	1,102,192	219,867	12,040	0	0	14,901	0
13	Meters Depr Exp				1,640,000	1,054,034	433,135	96,213	1,858	327	54,433	0
14	Services Operations Exp				304,000	248,381	49,547	2,713	0	0	3,358	0
15	Meters Operating Exp				431,000	277,005	113,830	25,285	488	86	14,305	0
16	Meters Maintenance Exp				3,000	1,928	792	176	3	1	100	0
17	Meter Reading				324,000	251,412	50,152	2,812	14,602	1,622	3,399	0
18	Billing				3,065,000	2,498,095	498,323	27,945	2,977	331	33,772	3,558
19	Total Expenses				7,116,000	5,433,049	1,365,647	167,184	19,929	2,366	124,267	3,558
20	Revenue Conversion Factor				0.994222	0.994222	0.994222	0.994222	0.994222	0.994222	0.994222	0.994222
21	Expense Revenue Requirement				7,157,355	5,464,624	1,373,584	168,156	20,045	2,380	124,989	3,578
22	Total Meter, Service, Meter Reading, and Billing Cost				**11,972,052**	**9,086,853**	**2,339,037**	**300,028**	**22,070**	**2,736**	**217,749**	**3,578**
23	Total Customer Bills				1,513,846	1,235,079	246,375	13,816	108	12	16,697	1,759
24	Average Unit Cost per Month				$7.91	$7.36	$9.49	$21.72	$204.35	$228.03	$13.04	$2.03
	Distribution Fixed Costs per Customer											
25	Total Customer Related Cost				29,929,427	22,010,030	5,079,994	506,159	34,998	4,261	421,850	1,872,136
26	Customer Related Unit Cost per Month				$19.77	$17.82	$20.62	$36.64	$324.05	$355.07	$25.27	$1,064.32
27	Total Distribution Demand Related Cost				59,101,272	29,117,754	8,302,771	15,737,755	2,024,135	417,326	2,197,623	1,303,910
28	Dist Demand Related Unit Cost per Month				$39.04	$23.58	$33.70	$1,139.10	$18,741.99	$34,777.14	$131.62	$741.28
29	Total Distribution Unit Cost per Month				**$58.81**	**$41.40**	**$54.32**	**$1,175.73**	**$19,066.04**	**$35,132.21**	**$156.88**	**$1,805.60**