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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-23-01
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC SERVICE	)	EXHIBIT NO. 16
TO ELECTRIC CUSTOMERS IN THE	)	
STATE OF IDAHO	)	MARCUS J. GARBARINO

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED JUNE 30, 2022

					Production / Transmission			
Line	Column	Description of Adjustment (000's)	Revenue	Expense	Plant	Acc Depreciation	Deferred D/C	Deferred Tax
1	1.00	Per Results Report	85,095	203,986	867,124	(327,054)	(22,221)	(98,757)
2	1.01	Accumulated Deferred FIT Rate Base	-	-	-	-	-	(1,420)
3	1.02	Deferred Debits, Credits & Reg Amortizations	-	56	-	-	-	-
5	1.03	Working Capital	-	-	-	-	-	-
4	1.04	Restate Capital 06.2022 EOP	-	-	30,515	(8,791)	-	(546)
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	-	(6,820)	-	-	-	-
13	2.08	Miscellaneous Restating	-	-	-	-	-	-
14	2.09	Restate Incentives	-	-	-	-	-	-
15	2.10	ID PCA	-	(1,702)	-	-	-	-
16	2.11	Nez Perce Settlement Adjustment	-	(34)	-	-	-	-
17	2.12	Colstrip / CS2 Maintenance	-	(130)	-	-	-	-
18	2.13	Restate Debt Interest	-	-	-	-	-	-
19	3.00P	Pro Forma Power Supply	2,241	1,899	-	-	-	-
20	3.00T	Pro Forma Transmission Rev/Exp	1,792	-	-	-	-	-
21	3.01	Pro Forma Labor Non-Exec	-	980	-	-	-	-
22	3.02	Pro Forma Labor Exec	-	-	-	-	-	-
23	3.03	Pro Forma Employee Benefits	-	(46)	-	-	-	-
24	3.04	Pro Forma IS/IT Costs	-	-	-	-	-	-
25	3.05	Pro Forma Property Tax	-	(282)	-	-	-	-
26	3.06	Pro Forma Insurance Expense	-	-	-	-	-	-
27	3.07	Pro Forma EDIT (RSGM)	-	-	-	-	-	-
28	3.08	Planned Capital Add 12.2022 EOP	-	463	16,673	(6,095)	-	(103)
29	3.09	Planned Capital Add 08.2023 EOP	-	796	15,280	(13,532)	-	(293)
30	3.10	Depreciation Study	-	198	-	-	-	-
31	3.11	Planned Capital Add 08.2024 AMA	-	697	16,454	(9,885)	-	(102)
32	3.12	Pro Forma Revenue & O&M Offsets	-	(14)	-	-	-	-
33	3.13	Pro Forma Fee Free Amortization	-	-	-	-	-	-
34	3.14	Pro Forma Regulatory Amortizations	-	-	-	-	-	-
35	3.15	Pro Forma Misc. O&M Expense	-	1,762	-	-	-	-
36	3.16	Pro Forma Wildfire Plan Expenses	-	(12)	-	-	-	-
37	3.17	Pro Forma Colstrip Capital Add & Amortizatic	-	-	2,450	-	-	-
38	Rate Year September 1, 2023 - August 31, 2024		89,128	201,798	948,496	(365,357)	(22,221)	(101,221)
39	24.00P	Pro Forma Power Supply	2,753	7,305	-	-	-	-
40	24.00T	Pro Forma Transmission Rev/Exp	(335)	-	-	-	-	-
41	24.01	Planned Capital Add 08.2024 EOP	-	-	12,014	(10,529)	-	(12)
42	24.02	Planned Capital Add 08.2025 AMA	-	612	14,258	(9,430)	-	1
43	24.03	Pro Forma Property Tax	-	454	-	-	-	-
44	24.04	Pro Forma Labor Non-Exec	-	391	-	-	-	-
45	24.05	Pro Forma Fee Free Amortization	-	-	-	-	-	-
46	24.06	Pro Forma Revenue & O&M Offsets	-	(93)	-	-	-	-
47	24.07	Pro Forma Misc. O&M Expense	-	812	-	-	-	-
48	24.08	Pro Forma Employee Benefits	-	94	-	-	-	-
49	24.09	Pro Forma Colstrip/CS2 Maintenance	-	246	-	-	-	-
50	Rate Year September 1, 2024 - August 31, 2025		91,546	211,619	974,768	(385,316)	(22,221)	(101,232)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED JUNE 30, 2022

Proposed Production and Transmission Revenue Requirement
Twelve Months Ended June 30, 2022 Pro Forma
Calculation of Load Change Adjustment Rate

Line			Rate Year 09.2023 - 08.2024 ($000's)	Debt Cost	Rate Year 09.2024 - 08.2025 ($000's)	Debt Cost	
1	Prod/Trans	Pro Forma Rate Base	459,697		465,999		
2	Cost of Capital	Proposed Rate of Return	7.59%	2.46%	7.59%	2.46%	
3	Rate Base	Net Operating Income Requirement	$34,891		$35,369		
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -21%)	($2,375)		($2,407)		
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	112,670		120,073		
6	Tax Effect	Net Operating Income Requirement (Net Expense x -21%)	($23,661)		($25,215)		
7	Total Prod/Trans	Net Operating Income Requirement	$121,525		$127,820		
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.)	0.79		0.79		
9	Prod/Trans	Revenue Requirement	$153,829		$161,797		
10	Test Year WA Normalized Retail Load MWh		3,082,930		3,082,930		
11	Prod/Trans Rev Requirement per kWh		$ 0.04990		$ 0.05248		
12	Cost of Service Energy Classified Production/Transmission Costs		$78,973		$78,973		Company Case at Unity AVU-E-23-01
13	Cost of Service Total Production/Transmission Costs		$156,177		$156,177		Company Case at Unity AVU-E-23-01
14	Load Change Adjustment Rate per kWh (Line 11 * Line 12 / Line 13)		**$ 0.02523**		**$ 0.02654**		

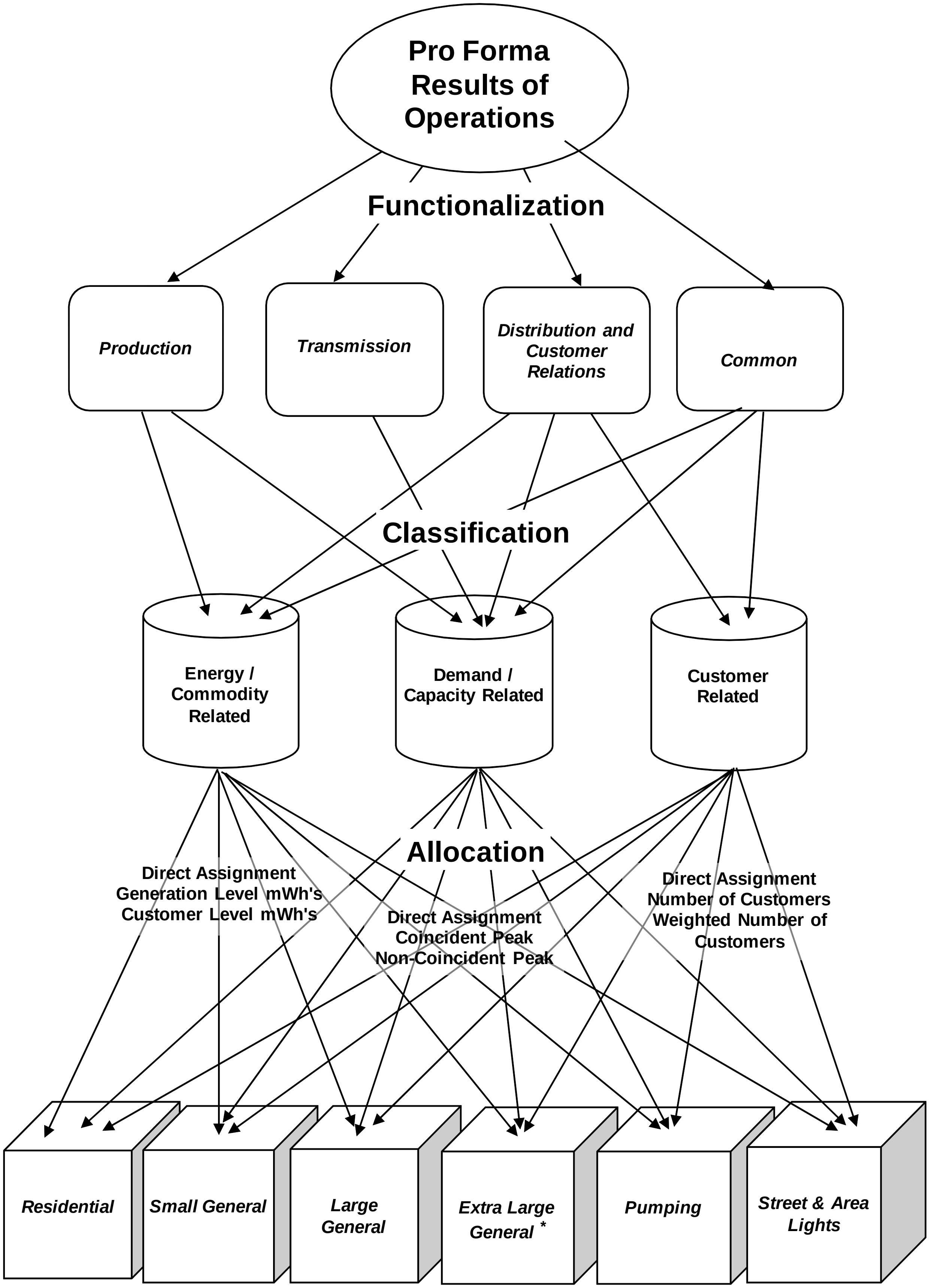
ELECTRIC COST OF SERVICE

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.

As shown in the flow chart below, there are three basic steps involved in a cost of service study: functionalization, classification, and allocation.

First, the expenses and rate base associated with the electric system under study are assigned to functional categories. The FERC 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 (capacity), or customer-related. Energy-related costs are allocated based on each rate schedule's share of commodity consumption. Demand-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.



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 year 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 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 36.35% for the twelve-months-ended June 30, 2022 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.

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 (Schedules 41 – 49) are excluded from metering and meter reading expenses as their service is not metered.

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

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

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.

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 AMI/MDM Software	D = Distribution	Customer	C01 All Customers unweighted
22	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			
23	Intangible	P/T/D/O	Follows Related Plant	S01/S02/C01/S23 Sum of Prod. Plant / Sum of Trans. Plant / All Cust. / Corp Cost Allocator
24	Production	P = Production	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
25	Transmission	T = Transmission	Follows Related Plant	D01 Coincident Peak Demand (12CP)
26	Distribution	D = Distribution	Follows Related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
27	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			
28	252 Customer Advances for Construction	D = Distribution	Customer	S13 Sum of Account 369 Services Plant
29	282/190 Accumulated Deferred Income Tax	P/T/D/O	Per Functional Analysis	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
30	Regultory Asset AFUDC	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant
31	Colstrip Deferred Amortization	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
32	Demand Side Management Investment	DSM	Demand/Energy by Load Factor Peak Credit	S01 Sum of Production Plant
33	Working Capital	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant
34	Tax Reform Rate Base Adjustment	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant

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 Customers Weighted by Est. Meter Reading Time
32	903 Customer Records & Collections	C = Customer Relations	Customer	C01 All Customers unweighted
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

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
8	928 Intervenor Funding	C = Customer Relations	Customer	C07/C08 Direct Assign to Residential and Small Commercial per IPUC Order
	Depreciation & Amortization Expense			
9	Intangible	P/T/D/O	Follows Related Plant	S01/S02/C01/S23 Sum of Prod. Plant / Sum of Trans. Plant / All Cust. / Corp Cost Allocator
10	Production	P = Production	Demand/Energy by Peak Credit as in related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
11	Transmission	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
12	Distribution	D = Distribution	Demand/Customer as in related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
13	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	AFUDC Regulatory Deferral/Amortization	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant
22	FISERVE (Fee Free) Deferral/Amortization	D = Distribution	Customer	C07 Direct Assign Residential
	Operating Revenues			
23	Sales of Electricity- Retail	R = Revenue from Rates	Revenue	Input Pro Forma Revenue per Revenue Study
24	Sales for Resale (447)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
25	Misc Service Revenue (451)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
26	Sales of Water & Water Power (453)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
27	Rent from Production Property (454)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
28	Rent from Transmission Property (454)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
29	Rent from Distribution Property (454)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
30	Other Electric Revenues - Generation (456)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
31	Other Electric Revenues - Wheeling (456)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
32	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			
33	Production Total	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
34	Transmission Total	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
35	Distribution Total	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
36	Customer Accounts Total	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
37	Customer Service Total	C = Customer Relations	Customer	C01 All Customers unweighted
38	Sales Total	C = Customer Relations	Energy	E02 Annual Generation Level Consumption
39	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
40	Interest Expense (allocation factor input)	R = Revenue Conversion	Demand/Energy/Customer from Rate Base components	S07 Total Rate Base

B	C	D	E	F	G	H	I	J
	Total	**Sch 1**	**Sch 11-12**	**Sch 21-22**	**Sch 25**	**Sch 25P**	**Sch 31-32**	**Sch 41-49**
Plant In Service								
Production Plant	559,658,000	245,460,274	80,330,112	106,202,091	57,156,587	58,381,442	10,752,428	1,375,066
Transmission Plant	361,980,000	172,554,502	51,110,139	72,061,603	30,883,544	28,975,633	6,099,845	294,735
Distribution Plant	801,874,000	430,960,880	131,049,672	145,450,111	25,838,005	3,182,866	29,720,261	35,672,206
Intangible Plant	118,780,000	66,135,617	18,233,744	17,128,371	7,362,861	6,663,057	2,442,331	814,020
General Plant	168,687,000	98,340,103	26,440,234	22,932,151	8,653,395	7,083,147	3,713,291	1,524,678
Total Plant In Service	2,010,979,000	1,013,451,375	307,163,901	363,774,326	129,894,391	104,286,145	52,728,156	39,680,706
Accum Depreciation								
Production Plant	-264,664,000	-116,078,923	-37,988,359	-50,223,297	-27,029,527	-27,608,765	-5,084,856	-650,273
Transmission Plant	-100,966,000	-48,130,112	-14,255,998	-20,099,928	-8,614,255	-8,082,087	-1,701,412	-82,209
Distribution Plant	-296,376,000	-163,614,551	-49,714,587	-50,921,827	-7,929,275	-857,925	-10,770,681	-12,567,153
Intangible Plant	-58,885,000	-34,046,392	-9,166,504	-8,020,371	-3,192,186	-2,734,819	-1,246,915	-477,812
General Plant	-68,908,000	-40,171,559	-10,800,735	-9,367,697	-3,534,879	-2,893,439	-1,516,865	-622,825
Total Accumulated Depreciation	-789,799,000	-402,041,537	-121,926,184	-138,633,120	-50,300,122	-42,177,035	-20,320,729	-14,400,273
Net Plant	1,221,180,000	611,409,838	185,237,716	225,141,206	79,594,270	62,109,110	32,407,427	25,280,433
Accumulated Deferred FIT	-200,382,000	-100,172,954	-30,495,469	-36,503,457	-13,330,335	-10,900,490	-5,188,407	-3,790,888
Miscellaneous Rate Base	14,140,000	6,331,490	2,124,277	3,001,884	1,075,994	863,988	409,836	332,531
Total Rate Base	1,034,938,000	517,568,374	156,866,524	191,639,633	67,339,929	52,072,609	27,628,856	21,822,075
Revenue From Retail Rates	275,654,000	134,665,000	43,855,000	47,036,000	20,704,000	19,143,000	6,208,000	4,043,000
Other Operating Revenues	95,228,000	42,769,075	13,765,347	18,117,328	9,122,472	9,066,862	1,913,719	473,197
Total Revenues	370,882,000	177,434,075	57,620,347	65,153,328	29,826,472	28,209,862	8,121,719	4,516,197
Operating Expenses								
Production Expenses	159,700,000	70,042,786	22,922,426	30,305,068	16,309,794	16,659,310	3,068,236	392,379
Transmission Expenses	11,853,000	5,650,280	1,673,597	2,359,650	1,011,279	948,804	199,739	9,651
Distribution Expenses	17,720,000	9,720,366	3,036,500	3,287,709	706,820	128,463	677,921	162,221
Customer Accounting Expenses	4,089,000	3,165,610	676,577	109,224	39,185	35,998	50,447	11,960
Customer Information Expenses	452,000	368,625	75,200	2,637	35	3	4,908	591
Sales Expenses	0	0	0	0	0	0	0	0
Admin & General Expenses	42,758,000	23,868,575	6,644,081	6,377,747	2,373,715	1,946,652	992,897	554,332
Total O&M Expenses	236,572,000	112,816,242	35,028,381	42,442,035	20,440,828	19,719,232	4,994,148	1,131,134
Taxes Other Than Income Taxes	14,074,000	6,964,481	2,119,537	2,531,922	1,022,260	897,412	337,416	200,973
Other Income Related Items	1,463,000	1,090,815	234,172	121,603	-8,357	-42,773	37,435	30,104
Depreciation Expense								
Production Plant Depreciation	14,985,000	6,572,268	2,150,861	2,843,591	1,530,384	1,563,179	287,899	36,818
Transmission Plant Depreciation	8,342,000	3,976,600	1,177,857	1,660,694	711,726	667,757	140,574	6,792
Distribution Plant Depreciation	19,745,000	10,719,421	3,376,881	3,386,891	589,174	70,389	725,678	876,565
General Plant Depreciation	8,764,000	5,109,182	1,373,682	1,191,422	449,580	367,999	192,921	79,213
Amortization Expense	15,525,000	8,107,735	2,378,805	2,631,916	958,424	783,742	386,132	278,246
Total Depreciation Expense	67,361,000	34,485,206	10,458,086	11,714,513	4,239,288	3,453,067	1,733,204	1,277,635
Income Tax	2,343,000	843,688	534,569	327,622	223,523	261,985	30,682	120,932
Total Operating Expenses	321,813,000	156,200,433	48,374,744	57,137,695	25,917,542	24,288,922	7,132,885	2,760,778
Net Operating Income	**49,069,000**	**21,233,641**	**9,245,602**	**8,015,633**	**3,908,930**	**3,920,940**	**988,834**	**1,755,419**
Rate of Return	**4.74%**	**4.10%**	**5.89%**	**4.18%**	**5.80%**	**7.53%**	**3.58%**	**8.04%**
Return Ratio	**1.00**	**0.87**	**1.24**	**0.88**	**1.22**	**1.59**	**0.75**	**1.70**
Interest Expense	25,459,000	12,731,945	3,858,845	4,714,247	1,656,531	1,280,962	679,657	536,813

A	B	C	D	E	F	G	H	I	J
594									
595									
701	**SUMMARY BY FUNCTION ANALYSIS**								
702									
703		**Total**	**Sch 1**	**Sch 11-12**	**Sch 21-22**	**Sch 25**	**Sch 25P**	**Sch 31-32**	**Sch 41-49**
704	**Functional Cost Components at Current Rates**								
705	Production	115,295,839	49,577,759	16,947,343	21,493,260	12,032,815	12,796,219	2,143,500	304,942
706	Transmission	24,020,748	10,638,202	3,782,282	4,482,478	2,266,477	2,471,086	354,042	26,181
707	Distribution	64,119,950	34,857,087	11,661,677	10,202,765	2,242,511	361,702	2,057,249	2,736,959
708	Common	72,217,464	39,591,952	11,463,698	10,857,497	4,162,197	3,513,992	1,653,208	974,918
709	Total Current Rate Revenue	275,654,000	134,665,000	43,855,000	47,036,000	20,704,000	19,143,000	6,208,000	4,043,000
710									
711									
712									
713	Expressed as $/kWh								
714	Production	$0.03740	$0.03871	$0.03807	$0.03788	$0.03459	$0.03477	$0.03393	$0.02923
715	Transmission	$0.00779	$0.00831	$0.00850	$0.00790	$0.00652	$0.00671	$0.00560	$0.00251
716	Distribution	$0.02080	$0.02721	$0.02620	$0.01798	$0.00645	$0.00098	$0.03256	$0.26234
717	Common	$0.02342	$0.03091	$0.02575	$0.01914	$0.01196	$0.00955	$0.02617	$0.09345
718	Total Current Rate Revenue	$0.08941	$0.10513	$0.09851	$0.08290	$0.05952	$0.05202	$0.09826	$0.38752
719									
720	**Functional Cost Components at Uniform Current Return**								
721	Production	114,833,344	50,364,730	16,482,522	21,791,060	11,727,666	11,978,988	2,206,235	282,143
722	Transmission	23,910,548	11,398,068	3,376,074	4,760,021	2,040,009	1,913,982	402,925	19,469
723	Distribution	64,586,127	36,458,489	10,783,918	10,699,357	2,061,440	299,402	2,263,874	2,019,646
724	Common	72,323,981	40,085,339	11,220,492	10,964,872	4,085,900	3,350,961	1,688,732	927,685
725	Total Uniform Current Cost	275,654,000	138,306,627	41,863,007	48,215,311	19,915,015	17,543,332	6,561,766	3,248,943
726									
727									
728									
729	Expressed as $/kWh								
730	Production	$0.03725	$0.03932	$0.03702	$0.03841	$0.03371	$0.03255	$0.03492	$0.02704
731	Transmission	$0.00776	$0.00890	$0.00758	$0.00839	$0.00586	$0.00520	$0.00638	$0.00187
732	Distribution	$0.02095	$0.02846	$0.02422	$0.01886	$0.00593	$0.00081	$0.03583	$0.19358
733	Common	$0.02346	$0.03130	$0.02520	$0.01933	$0.01175	$0.00911	$0.02673	$0.08892
734	Total Current Rate Revenue	$0.08941	$0.10798	$0.09404	$0.08498	$0.05725	$0.04767	$0.10385	$0.31141
735									
736	**Revnue to Cost Ratio at Current Rates**	**1.00**	**0.97**	**1.05**	**0.98**	**1.04**	**1.09**	**0.95**	**1.24**
737									
738									
739	**Functional Cost Components at Proposed Return by Schedule**								
740	Production	124,847,235	53,535,839	18,339,485	23,109,715	13,121,762	14,126,272	2,293,402	320,760
741	Transmission	32,387,035	14,452,866	4,996,775	5,986,012	3,073,374	3,376,589	470,594	30,825
742	Distribution	79,212,864	42,898,782	14,286,697	12,893,372	2,887,740	462,979	2,550,014	3,233,280
743	Common	76,668,710	42,075,069	12,192,595	11,440,918	4,434,692	3,779,512	1,738,174	1,007,751
744	Total Proposed Rate Revenue	313,115,844	152,962,556	49,815,553	53,430,018	23,517,567	21,745,351	7,052,184	4,592,616
745									
746									
747									
748	Expressed as $/kWh								
749	Production	$0.04050	$0.04180	$0.04120	$0.04073	$0.03772	$0.03839	$0.03630	$0.03074
750	Transmission	$0.01051	$0.01128	$0.01122	$0.01055	$0.00883	$0.00918	$0.00745	$0.00295
751	Distribution	$0.02569	$0.03349	$0.03209	$0.02272	$0.00830	$0.00126	$0.04036	$0.30991
752	Common	$0.02487	$0.03285	$0.02739	$0.02016	$0.01275	$0.01027	$0.02751	$0.09659
753	Total Proposed Melded Rates	$0.10156	$0.11942	$0.11190	$0.09417	$0.06760	$0.05909	$0.11162	$0.44020
754									
755	**Functional Cost Components at Uniform Proposed Return**								
756	Production	124,073,250	54,417,258	17,808,766	23,544,448	12,671,316	12,942,860	2,383,757	304,845
757	Transmission	32,104,150	15,303,928	4,532,979	6,391,172	2,739,074	2,569,860	540,998	26,140
758	Distribution	80,168,585	44,692,377	13,284,496	13,618,303	2,620,453	372,764	2,847,608	2,732,586
759	Common	76,769,858	42,627,670	11,914,910	11,597,665	4,322,065	3,543,429	1,789,338	974,781
760	Total Uniform Proposed Cost	313,115,844	157,041,232	47,541,149	55,151,588	22,352,908	19,428,914	7,561,701	4,038,352
761									
762									
763									
764	Expressed as $/kWh								
765	Production	$0.04025	$0.04248	$0.04000	$0.04150	$0.03643	$0.03517	$0.03773	$0.02922
766	Transmission	$0.01041	$0.01195	$0.01018	$0.01126	$0.00787	$0.00698	$0.00856	$0.00251
767	Distribution	$0.02600	$0.03489	$0.02984	$0.02400	$0.00753	$0.00101	$0.04507	$0.26192
768	Common	$0.02490	$0.03328	$0.02676	$0.02044	$0.01242	$0.00963	$0.02832	$0.09343
769	Total Uniform Melded Rates	$0.10156	$0.12260	$0.10679	$0.09720	$0.06426	$0.05279	$0.11968	$0.38707
770									
771	**Revenue to Cost Ratio at Proposed Rates**	**1.00**	**0.97**	**1.05**	**0.97**	**1.05**	**1.12**	**0.93**	**1.14**
772	**Current Revenue to Proposed Cost Ratio**	**0.88**	**0.86**	**0.92**	**0.85**	**0.93**	**0.99**	**0.82**	**1.00**
773									
774	**Target Revenue Change**	**37,462,000**	**22,376,000**	**3,686,000**	**8,116,000**	**1,649,000**	**286,000**	**1,354,000**	**-5,000**

A	B	C	D	E	F	G	H	I	J
594									
595									
784	**SUMMARY BY CLASSIFICATION WITH UNIT COST ANALYSIS**								
785									
786		**Total**	**Sch 1**	**Sch 11-12**	**Sch 21-22**	**Sch 25**	**Sch 25P**	**Sch 31-32**	**Sch 41-49**
787	**Cost by Classification at Curr. Return by Schedule**								
788	Energy	88,432,479	36,116,831	13,083,841	16,011,708	10,070,217	11,068,803	1,759,502	321,577
789	Demand	153,113,598	74,038,513	24,954,985	30,642,753	10,626,008	8,073,142	4,021,880	756,319
790	Customer	34,107,922	24,509,656	5,816,174	381,539	7,776	1,055	426,619	2,965,104
791	Total Current Rate Revenue	275,654,000	134,665,000	43,855,000	47,036,000	20,704,000	19,143,000	6,208,000	4,043,000
792									
793	Revenue per kWh at Current Rates								
794	Energy	$0.02868	$0.02820	$0.02939	$0.02822	$0.02895	$0.03008	$0.02785	$0.03082
795	Demand	$0.04966	$0.05780	$0.05606	$0.05401	$0.03055	$0.02194	$0.06366	$0.07249
796	Customer	$0.01106	$0.01913	$0.01306	$0.00067	$0.00002	$0.00000	$0.00675	$0.28420
797	Total Revenue per kWh at Current Rates	$0.08941	$0.10513	$0.09851	$0.08290	$0.05952	$0.05202	$0.09826	$0.38752
798									
799	Cost per Unit at Current Rates								
800	Energy	$0.02868	$0.02820	$0.02939	$0.02822	$0.02895	$0.03008	$0.02785	$0.03082
801	Demand	$11.18	$8.87	$13.13	$20.99	$14.29	$10.26	$9.28	$25.83
802	Customer	$20.14	$17.74	$20.64	$38.61	$58.91	$87.90	$23.20	$1,338.04
803									
804	**Cost by Classification at Uniform Current Return**								
805	Energy	87,954,576	36,661,884	12,741,948	16,222,649	9,826,934	10,394,114	1,808,429	298,618
806	Demand	153,963,251	76,722,938	23,464,733	31,607,192	10,080,414	7,148,200	4,315,248	624,526
807	Customer	33,736,173	24,921,804	5,656,325	385,469	7,667	1,018	438,089	2,325,799
808	Total Uniform Current Cost	275,654,000	138,306,627	41,863,007	48,215,311	19,915,015	17,543,332	6,561,766	3,248,943
809									
810	Cost per kWh at Current Return								
811	Energy	$0.02853	$0.02862	$0.02862	$0.02859	$0.02825	$0.02824	$0.02862	$0.02862
812	Demand	$0.04994	$0.05990	$0.05271	$0.05571	$0.02898	$0.01942	$0.06830	$0.05986
813	Customer	$0.01094	$0.01946	$0.01271	$0.00068	$0.00002	$0.00000	$0.00693	$0.22293
814	Total Cost per kWh at Current Return	$0.08941	$0.10798	$0.09404	$0.08498	$0.05725	$0.04767	$0.10385	$0.31141
815									
816	Cost per Unit at Uniform Current Return								
817	Energy	$0.02853	$0.02862	$0.02862	$0.02859	$0.02825	$0.02824	$0.02862	$0.02862
818	Demand	$11.24	$9.19	$12.35	$21.65	$13.56	$9.08	$9.95	$21.33
819	Customer	$19.92	$18.04	$20.07	$39.01	$58.08	$84.85	$23.82	$1,049.55
820									
821	**Revenue to Cost Ratio at Current Rates**	**1.00**	**0.97**	**1.05**	**0.98**	**1.04**	**1.09**	**0.95**	**1.24**
822									
823									
824	**Cost by Classification at Proposed Return by Schedule**								
825	Energy	95,442,669	38,858,521	14,107,930	17,156,841	10,938,478	12,166,964	1,876,427	337,508
826	Demand	180,522,222	87,521,754	29,412,705	35,870,286	12,570,925	9,577,273	4,721,722	847,557
827	Customer	37,150,953	26,582,282	6,294,918	402,890	8,165	1,114	454,034	3,407,551
828	Total Proposed Rate Revenue	313,115,844	152,962,556	49,815,553	53,430,018	23,517,567	21,745,351	7,052,184	4,592,616
829									
830	Revenue per kWh at Proposed Rates								
831	Energy	$0.03096	$0.03034	$0.03169	$0.03024	$0.03144	$0.03306	$0.02970	$0.03235
832	Demand	$0.05856	$0.06833	$0.06607	$0.06322	$0.03614	$0.02602	$0.07473	$0.08124
833	Customer	$0.01205	$0.02075	$0.01414	$0.00071	$0.00002	$0.00000	$0.00719	$0.32661
834	Total Revenue per kWh at Prop. Rates	$0.10156	$0.11942	$0.11190	$0.09417	$0.06760	$0.05909	$0.11162	$0.44020
835									
836	Cost per Unit at Proposed Rates								
837	Energy	$0.03096	$0.03034	$0.03169	$0.03024	$0.03144	$0.03306	$0.02970	$0.03235
838	Demand	$13.18	$10.49	$15.48	$24.57	$16.91	$12.17	$10.89	$28.94
839	Customer	$21.93	$19.24	$22.34	$40.77	$61.85	$92.86	$24.69	$1,537.70
840									
841	**Cost by Classification at Uniform Proposed Return**								
842	Energy	94,689,027	39,468,988	13,717,566	17,464,775	10,579,357	11,189,964	1,946,895	321,482
843	Demand	181,420,961	90,528,350	27,711,176	37,278,185	11,765,547	8,237,889	5,144,250	755,563
844	Customer	37,005,856	27,043,893	6,112,408	408,628	8,004	1,061	470,555	2,961,307
845	Total Uniform Proposed Cost	313,115,844	157,041,232	47,541,149	55,151,588	22,352,908	19,428,914	7,561,701	4,038,352
846									
847	Cost per kWh at Proposed Return								
848	Energy	$0.03071	$0.03081	$0.03081	$0.03078	$0.03041	$0.03041	$0.03081	$0.03081
849	Demand	$0.05885	$0.07068	$0.06225	$0.06570	$0.03382	$0.02238	$0.08142	$0.07242
850	Customer	$0.01200	$0.02111	$0.01373	$0.00072	$0.00002	$0.00000	$0.00745	$0.28384
851	Total Cost per kWh at Proposed Return	$0.10156	$0.12260	$0.10679	$0.09720	$0.06426	$0.05279	$0.11968	$0.38707
852									
853	Cost per Unit at Uniform Proposed Return								
854	Energy	$0.03071	$0.03081	$0.03081	$0.03078	$0.03041	$0.03041	$0.03081	$0.03081
855	Demand	$13.24	$10.85	$14.58	$25.53	$15.83	$10.47	$11.87	$25.80
856	Customer	$21.85	$19.58	$21.69	$41.35	$60.64	$88.45	$25.58	$1,336.33
857									
858	**Revenue to Cost Ratio at Prop. Rates**	**1.00**	**0.97**	**1.05**	**0.97**	**1.05**	**1.12**	**0.93**	**1.14**

IDAHO ELECTRIC

Meter, Services, Meter Reading & Billing Costs by Schedule at Proposed Rate of Return

A	B	C	D	E	F	G	H	I	J
		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**
1	Services	$ 71,826,000	$ 58,668,812	$ 11,968,544	$ 407,456	$ -	$ -	$ 781,188	$ -
2	Services Accum. Depr.	$ (33,192,000)	$ (27,111,843)	$ (5,530,865)	$ (188,292)	$ -	$ -	$ (361,000)	$ -
3	Total Services	$ 38,634,000	$ 31,556,970	$ 6,437,679	$ 219,164	$ -	$ -	$ 420,188	$ -
4	Meters	$ 24,698,000	$ 16,227,694	$ 6,432,749	$ 1,217,790	$ 31,953	$ 4,599	$ 783,215	$ -
5	Meters Accum. Depr.	$ (18,983,000)	$ (12,472,682)	$ (4,944,241)	$ (935,999)	$ (24,560)	$ (3,535)	$ (601,983)	$ -
6	Total Meters	$ 5,715,000	$ 3,755,011	$ 1,488,507	$ 281,791	$ 7,394	$ 1,064	$ 181,232	$ -
7	Total Rate Base	$ 44,349,000	$ 35,311,981	$ 7,926,186	$ 500,955	$ 7,394	$ 1,064	$ 601,420	$ -
8	Return on Rate Base @ 7.59%	$ 3,366,089	$ 2,680,179	$ 601,598	$ 38,022	$ 561	$ 81	$ 45,648	$ -
9	Tax Benefit of Interest Expense	$ (229,107)	$ (182,422)	$ (40,947)	$ (2,588)	$ (38)	$ (5)	$ (3,107)	$ -
10	Revenue Conversion Factor	0.78701	0.78701	0.78701	0.78701	0.78701	0.78701	0.78701	0.78701
11	Rate Base Revenue Requirement	$ 3,985,970	$ 3,173,747	$ 712,385	$ 45,024	$ 665	$ 96	$ 54,054	$ -
12	Services Depr Exp	$ 1,432,000	$ 1,169,684	$ 238,618	$ 8,123	$ -	$ -	$ 15,575	$ -
13	Meters Depr Exp	$ 2,225,000	$ 1,461,925	$ 579,515	$ 109,709	$ 2,879	$ 414	$ 70,559	$ -
14	Services Exp	$ 308,000	$ 251,580	$ 51,323	$ 1,747	$ -	$ -	$ 3,350	$ -
15	Meters Exp	$ 344,000	$ 226,023	$ 89,597	$ 16,962	$ 445	$ 64	$ 10,909	$ -
16	Meters Exp	$ 8,000	$ 5,256	$ 2,084	$ 394	$ 10	$ 1	$ 254	$ -
17	Meter Reading	$ 233,000	$ 190,270	$ 38,815	$ 1,361	$ 18	$ 2	$ 2,533	$ -
18	Billing Exp	$ 3,232,000	$ 2,635,830	$ 537,714	$ 18,855	$ 252	$ 23	$ 35,097	$ 4,229
19	Total Expenses	$ 7,782,000	$ 5,940,569	$ 1,537,666	$ 157,152	$ 3,604	$ 504	$ 138,276	$ 4,229
20	Revenue Conversion Factor	0.99621	0.99621	0.99621	0.99621	0.99621	0.99621	0.99621	0.99621
21	Expense Revenue Requirement	$ 7,811,606	$ 5,963,170	$ 1,543,516	$ 157,750	$ 3,618	$ 506	$ 138,802	$ 4,245
22	Total Customer Costs	$ 11,797,576	$ 9,136,917	$ 2,255,900	$ 202,774	$ 4,282	$ 602	$ 192,856	$ 4,245
23	Total Customers Bills	1,693,693	1,381,277	281,783	9,881	132	12	18,392	2,216
24	Avg Unit Cost	**$ 6.97**	**$ 6.61**	**$ 8.01**	**$ 20.52**	**$ 32.44**	**$ 50.16**	**$ 10.49**	**$ 1.92**
25	Total Customer Related Cost	$37,150,953	$26,582,282	$6,294,918	$402,890	$8,165	$1,114	$454,034	$3,407,551
26	Customer Related Unit Cost per Month	$21.93	$19.24	$22.34	$40.77	$61.85	$92.86	$24.69	$1,537.70
27	Distribution Demand Related Cost	$62,803,837	32,929,005	10,417,759	13,363,429	2,614,641	371,623	2,603,829	503,552
28	Distribution Demand Cost per Customer/Mo	$37.08	$23.84	$36.97	$1,352.44	$19,807.88	$30,968.58	$141.57	$227.23
29	**Total Customer and Distribution Demand**	**$59.02**	**$43.08**	**$59.31**	**$1,393.21**	**$19,869.74**	**$31,061.44**	**$166.26**	**$1,764.94**