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IDAHO PUBLIC
UTILITIES COMMISSION

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION) OF AVISTA CORPORATION FOR THE) AUTHORITY TO INCREASE ITS RATES) AND CHARGES FOR ELECTRIC AND) NATURAL GAS SERVICE TO ELECTRIC AND) NATURAL GAS CUSTOMERS IN THE STATE) OF IDAHO))	CASE NO. AVU-E-04-01 CASE NO. AVU-G-04-01 REBUTTAL TESTIMONY OF TARA L. KNOX

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

Q. Please state your name, business address and present position with Avista Corporation?

A. My name is Tara L. Knox and my business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Rate Analyst in the Rates and Regulation Department.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes, I sponsored the electric and natural gas cost of service studies.

Q. What is the scope of your rebuttal testimony in this proceeding?

A. My testimony responds to the cost of service issues discussed in the testimony of Staff witness Fuss, Potlatch witness Peseau, and Coeur Silver Valley witness Yankel.

Q. Would you please summarize your rebuttal testimony?

A. With regard to natural gas cost of service, the Company finds Commission staff recommendation for allocation of underground storage costs and related capacity release revenues to be reasonable.

Regarding electric cost of service, the Company supports the following: 1) resource costs should be excluded from the O&M portion of the four-factor allocator used for common costs in the Company's cost of service study; 2) although 100% demand allocation is an approach that could be used to classify transmission costs as described by witness Peseau, it represents a material change from the peak credit methodology the Company has historically applied and should not be used; and 3) the cost of primary distribution plant Mr. Yankel proposes to assign to Schedule 25 customers is understated and cannot be reasonably estimated without considerable additional investigation. The Company recognizes, however, that the costs for these facilities probably fall between the Company's allocation and Mr. Yankel's estimated assignment. Therefore, the Company proposes an intermediate cost assignment.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. I am sponsoring two exhibits. Exhibit No. 28 includes revised Natural Gas Cost of Service summary information, and Exhibit No. 29 includes revised Electric Cost of Service summary information.

I. Gas Cost of Service Issues

Q. Please describe the issue regarding Natural Gas underground storage costs referred to earlier.

A. In the Company's cost of service study, underground storage costs and capacity release revenues are spread to customer classes based on annual consumption. Staff witness Fuss, on pages 11 through 13, recommends allocating underground storage costs by consumption only during the winter months to better match the benefits received from these assets. Mr. Fuss also recommends spreading underground storage capacity release revenue (offset to cost) by another similar allocation factor. This factor is created from a combination of winter monthly usage and scheduled withdrawals which essentially results in weighted winter consumption.

Q. What do you recommend in response to Mr. Fuss's proposal regarding underground storage costs?

A. I have no philosophical objection to using an allocation based on winter consumption to spread underground storage and related costs. In the Company's last natural gas general case in Idaho (Case No. WWP-G-88-5), the Company originally proposed using winter therms to allocate these costs for similar reasons, but at the conclusion of that case the Commission selected annual throughput as the preferred option.

I am somewhat concerned about the lack of consistency between the allocations used for underground storage costs versus the capacity release revenues. I see no reason why the same allocation factor should not be used for both. While the weighted allocation is slightly more refined, the winter therm allocator is more straightforward and less complicated. The resulting ratios are very similar and will produce nearly the same results. Therefore, I propose using the less complicated winter therm allocator for both underground storage costs and capacity release revenues.

Q. Have you prepared an exhibit summarizing the natural gas cost of service results associated with the Company's proposed changes described above?

A. Yes. Exhibit No. 28 is a summary of the natural gas cost of service results incorporating the proposed changes described above, and all non-contested natural gas adjustments to the pro-forma results discussed in Mr. Falkner's rebuttal testimony.

II. Electric Cost of Service Issues

Q. Moving on to electric cost of service, what issues are you addressing?

A. Three different cost of service issues were raised by the parties in this case that I will address. Potlatch witness Peseau recommends two changes to the cost of service study: a change to the calculation of the common cost allocator, and a change in the allocation methodology for transmission costs. Coeur Silver Valley witness Yankel recommends direct assignment of certain distribution costs to Schedule 25 customers.

Q. Regarding the common cost allocator, can you summarize the issue?

A. Yes. Dr. Peseau points out that resource costs (purchased power and fuel) were not removed from the direct O&M expense portion of the four-factor allocator. He discusses various reasons to support the exclusion of purchased power and fuel expenses largely stemming from their volatility.

Q. Do you agree that resource costs should be excluded from the direct O&M expense portion of the four-factor allocator?

A. Yes. The theory behind moving to the four-factor allocation factor for common costs was to emulate the four-factor allocation used for the Company's utility and jurisdictional separation process. Examination of the detail behind the calculation of the utility four-factor shows that resource costs <u>are</u> excluded from the direct O&M expense factor calculation. Specifically, FERC Accounts 501, 547, 555, 557, & 565 are excluded from the electric utility allocation factor. These resource costs tend to be high dollar value transactions that do not require proportionate administrative support. Labor costs are also excluded from the direct O&M portion of the four-factor to avoid double counting. In light of this information, I find that the simplified direct O&M factor utilized in the Company Base Case study should have been refined to exclude accounts 501, 547, 555, 557, 565 and labor dollars. I have revised the Company's electric cost of service study to reflect this change.

Q. What is the effect on the Company's Base Case electric cost of service study when this one factor has been refined as you describe?

A. Exhibit No. 29, Page 1, lines 1 through 8 show the incremental changes to rate base, net income, rate of return and return ratio due entirely to modification of this one allocation factor. As you can see by the return ratio comparison below, while this modification changes the absolute results, the basic under-earning/over-earning relationships do not change a great deal.

Table 1

Rate Class	**Base Case Return Ratio**	**Revised 4-factor Return Ratio**	**Increase (Decrease)**
Residential Schedule 1	.42	.39	(0.03)
General Service Schedule 11-12	2.06	2.01	(0.05)
Large General Service Schedule 21-22	1.72	1.73	0.01
Extra Large General Service Schedule 25	.25	.27	0.02
Potlatch Lewiston Schedule 25P	1.11	1.19	0.08
Pumping Service Schedule 31-32	1.54	1.53	(0.01)
Street & Area Lights Schedules 41 - 49	.97	.87	(0.10)
Idaho Jurisdictional Total	1.00	1.00	

This information is derived from columns K through M on Exhibit 29, Page 1.

Q. Turning to the allocation of transmission costs, what is the issue here?

A. Dr. Peseau advocates using a 100% demand allocation for all transmission costs. He cites Idaho Power Company and Avista's FERC transmission tariff utilization of this approach to justify changing from Avista's traditional peak credit method.

Q. Do you agree with Dr. Peseau's argument that transmission costs embedded in bundled retail rates should be allocated in accordance with FERC tariffed wholesale rates?

A. No. The wholesale transmission tariff cost analysis is independent from transmission system cost analysis for jurisdictional ratemaking. From the perspective of jurisdictional retail ratemaking, the revenues from FERC transmission transactions are simply an offset to transmission cost. As long as this revenue offset is allocated in the same manner as the associated costs, customers are receiving a fair share of the benefits of non-retail usage of the transmission system. State Commissions have jurisdiction over bundled retail rate issues, and this Commission has consistently accepted Avista's combination of demand and energy for the allocation of transmission costs.

Q. Mr. Peseau mentions the Idaho Power Company transmission classification methodology. How does Pacificorp (governed by the Idaho Commission) allocate transmission costs?

A. Pacificorp, doing business as Utah Power in Idaho, also uses a combination of energy and demand for jurisdictional separation and Idaho cost of service purposes. Each company's system and circumstances should be evaluated on their own merits to determine the best fit.

Q. Please explain the peak credit classification theory the Company uses for production and transmission costs?

A. The peak credit theory acknowledges that baseload production facilities provide energy throughout the year as well as capacity during system peaks and likewise the transmission system is required not only for use during peak times but for everyday delivery of energy. The intent is to reflect how these systems are used by the consumers.

Q. Does the Commission Staff take issue with the Company's peak credit approach to transmission costs?

A. No. Mr. Hessing accepted the Company cost of service methodology and pointed out the value inherent in maintaining consistent methodology over time.

Q. Do you agree with Dr. Peseau that transmission costs should be classified 100% as demand-related in the Company's cost of service study?

A. No. Although this an accepted approach, I think the Company's peak credit approach is equally valid and use of a consistent methodology over time is the overriding factor.

Q. Regarding Mr. Yankel's distribution plant assignment, what is the issue involved here?

A. Mr. Yankel has proposed incorporating a direct assignment of primary distribution costs in FERC Accounts 364, 365, 366, and 367 to Schedule 25 customers. The method he used to estimate these costs is a ratio based on the sum of the circuit mileage from the appropriate substation to each Schedule 25 customer.

Q. Isn't direct assignment of costs whenever possible preferred over allocation in a cost of service study?

A. Yes, as long as it is a viable assignment. In this case there are a number of problems with the flat circuit mileage approach to estimating the amounts assigned to these customers.

Q. What are the problems with Mr. Yankel's direct assignment?

A. First and foremost, the assignment process he uses does not account for the relative cost of the conductor and other materials that are necessary to support the capacity requirements of these extra large usage customers. The flat mileage based allocation implies that the major feeder lines necessary to ensure adequate capacity for these customers have the same cost per mile as simple single-phase circuits serving residential neighborhoods. This is clearly not the case. Additionally, the line mile measurement used by Mr. Yankel looked only at the direct route from the closest substation to the customer. Some of these customers may also receive power from alternative routes or other substations in the case of interruption in power along the direct route. To the extent that other substations may be found to be available as back-up resources, Mr. Yankel's assignment of primary distribution cost is understated, as well as the current substation costs assigned to these customers in the Company's study.

Q. What would be required to come up with an acceptable direct assignment of primary plant to these customers?

A. A thorough engineering cost analysis that incorporates the factors addressed above would be required. A dollar estimate could then be assigned to Schedule 25, with the remaining primary distribution plant allocated by non-coincident peak demand to the other customer groups.

Q. What does Mr. Yankel's analysis indicate?

A. There is material difference between a primary demand allocation, used by the Company, for these fourteen customers and Mr. Yankel's unweighted line mile analysis. Given the limited distances observed between the Schedule 25 customers and the substations that have been directly assigned to them, the Company believes that the demand allocation used in its study overstates the relative primary plant costs related to these customers.

Q. The discussion above indicates that Mr. Yankel's cost study understates primary distribution costs for Schedule 25 customers and the Company's Base Case study overstates them. Do you have a proposal in response to this issue?

A. Yes. I have prepared a cost of service scenario that provides reasonable movement between the two positions. In this analysis I have taken the plant dollars Schedule 25 customers were assigned for accounts 364, 365, 366, and 367 in Mr. Yankel's proposal and added to that assignment one-half the difference between the Base Case study demand allocated amounts and Mr. Yankel's amounts.

Q. What are the results of this scenario?

A. Exhibit No. 29, page 2 is the cost of service basic summary from this model run. The refinement of the four-factor allocator has also been incorporated into this analysis. On Exhibit No. 29, page 1, lines 9 through 16 I illustrate the incremental changes in rate base, net income, rate of return, and return ratios compared to the results with only the refined four-factor.

Table 2

Rate Class	Base Case Return Ratio	Rev 4-factor Return Ratio	Rev 4- factor & Direct Sch 25 Return Ratio	Increase (Decrease) vs Base Case
Residential Schedule 1	.42	.39	.36	(0.06)
General Service Sch 11-12	2.06	2.01	1.96	(0.10)
Lg General Svc Sch 21-22	1.72	1.73	1.68	(0.04)
Extra Lg Gen Svc Sch 25	.25	.27	.62	0.37
Potlatch Lewiston Sch 25P	1.11	1.19	1.19	0.08
Pumping Service Sch 31-32	1.54	1.53	1.48	(0.06)
St & Area Lts Sch 41 - 49	.97	.87	.86	(0.11)
Idaho Jurisdictional Total	1.00	1.00	1.00	

This information is derived from columns K through M on Exhibit 29, Page 1.

Q. How would you interpret the results shown here?

A. There is a material increase in the rate of return for Schedule 25 customers. Naturally, in this type of cost study where the system total remains fixed, if one group is relieved of cost responsibility, all other groups then absorb a portion of those costs. As can be observed from Table 2 above, the negative impact on the other customer groups is not nearly as dramatic as the positive impact on Schedule 25.

Q. Have you shared this analysis with Mr. Hirschkorn for his work on rate spread?

A. Yes. He was provided with a copy of the information on Exhibit No. 29, Page 2 for incorporation into his rebuttal testimony.

Q. Does this conclude your pre-filed rebuttal testimony?

A. Yes.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-G-04-01
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC AND	)	EXHIBIT NO. 28
NATURAL GAS CUSTOMERS IN THE STATE	)	
OF IDAHO	)	TARA L. KNOX
	)	

FOR AVISTA CORPORATION

(NATURAL GAS)

Sumcost
Company Rebuttal Case
As Filed Except UG by Winter Therms

AVISTA UTILITIES
Cost of Service General Summary
For The Twelve Months Ended December 31, 2002

Natural Gas Utility
Idaho Jurisdiction

7-7-04

	(b) Description	(c) (d) (e)	(f) System Total	(g) Residential Service Sch 101	(h) Small Firm Service Sch 111	(i) Large Firm Service Sch 121	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Plant In Service							
1	Production Plant							
2	Underground Storage Plant		5,041,000	3,825,407	882,095	114,729	30,267	188,503
3	Distribution Plant		87,598,000	75,115,371	10,131,341	937,240	199,847	1,214,201
4	Intangible Plant		766,000	652,766	91,047	8,694	1,902	11,591
5	General Plant		5,943,000	5,064,228	706,537	67,486	14,762	89,987
6	Total Plant In Service		99,348,000	84,657,773	11,811,019	1,128,149	246,778	1,504,281
	Accum Depreciation							
7	Production Plant							
8	Underground Storage Plant		(2,294,000)	(1,740,822)	(401,414)	(52,209)	(13,773)	(85,782)
9	Distribution Plant		(26,397,000)	(22,793,740)	(2,880,654)	(299,560)	(63,624)	(359,421)
10	Intangible Plant		(626,000)	(533,435)	(74,422)	(7,109)	(1,555)	(9,479)
11	General Plant		(2,076,000)	(1,769,029)	(246,806)	(23,574)	(5,157)	(31,434)
12	Total Accumulated Depreciation		(31,393,000)	(26,837,027)	(3,603,296)	(382,452)	(84,110)	(486,115)
13	Net Plant		67,955,000	57,820,746	8,207,723	745,696	162,668	1,018,166
14	Accumlulated Deferred FIT		(9,831,000)	(8,377,326)	(1,168,762)	(111,636)	(24,420)	(148,856)
15	Miscellaneous Rate Base		2,315,000	1,708,793	413,156	68,398	16,278	108,376
16	Total Rate Base		60,439,000	51,152,214	7,452,117	702,458	154,526	977,685
17	Revenue From Retail Rates		51,419,000	40,114,000	8,954,000	1,522,000	385,000	444,000
18	Other Operating Revenues		1,156,000	923,063	174,952	20,538	5,163	32,283
19	Total Revenues		52,575,000	41,037,063	9,128,952	1,542,538	390,163	476,283
	Operating Expenses							
20	Purchased Gas Costs		35,803,000	27,300,352	6,924,182	1,262,412	312,556	3,497
21	Underground Storage Expenses		134,000	101,687	23,448	3,050	805	5,011
22	Distribution Expenses		2,207,000	1,895,249	222,617	40,382	8,744	40,008
23	Customer Accounting Expenses		2,064,000	2,008,196	47,555	5,266	1,315	1,668
24	Customer Information Expenses		260,000	222,668	23,961	4,925	1,035	7,411
25	Sales Expenses		224,000	221,746	2,181	38	8	27
26	Admin & General Expenses		3,666,000	3,012,554	444,167	75,878	20,644	112,757
27	Total O&M Expenses		44,358,000	34,762,453	7,688,111	1,391,951	345,107	170,378
28	Taxes Other Than Income Taxes		876,000	746,673	104,021	9,923	2,168	13,215
29	Depreciation Expense							
30	Underground Storage Plant Depr		105,000	79,680	18,373	2,390	630	3,926
31	Distribution Plant Depreciation		2,125,000	1,841,640	226,067	23,626	5,013	28,653
32	General Plant Depreciation		321,000	273,535	38,162	3,645	797	4,860
33	Amortization of Intangible Plant		260,000	221,555	30,910	2,952	646	3,937
34	Total Depr & Amort Expense		2,811,000	2,416,409	313,513	32,614	7,087	41,377
35	Income Tax		1,251,000	503,655	511,382	57,111	21,809	157,042
36	Total Operating Expenses		49,296,000	38,429,191	8,617,027	1,491,598	376,171	382,013
37	Net Income		3,279,000	2,607,873	511,926	50,940	13,992	94,270
38	Rate of Return		5.43%	5.10%	6.87%	7.25%	9.05%	9.64%
39	Return Ratio		1.00	0.94	1.27	1.34	1.67	1.78
40	Interest Expense		2,902,000	2,456,092	357,816	33,729	7,420	46,944

Exhibit No. 28
T. Knox
Avista Corporation

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	))))))))	CASE NO. AVU-E-04-01 EXHIBIT NO. 29 TARA L. KNOX

FOR AVISTA CORPORATION

(ELECTRIC)

AVISTA UTILITIES
Case No. AVU-E-04-1
Electric Cost of Service
Incremental Changes from Rebuttal Modifications

Change No. 1
Refined Calculation of Direct O&M Portion of Common Cost Four-Factor Allocator

Line No.	Rate Class A	Base Case Rate Base B	No. 1 Revised Rate Base C	Change in Rate Base D = C - B	Base Case Net Income E	No. 1 Revised Net Income F	Change in Net Income G = F - E	Base Case ROR H = E / B	No. 1 Revised ROR I = F / C	Change in ROR J = I - H	Base Case Return Ratio K = H / H8	No. 1 Revised Return Ratio L = I / I8	Change in Return Ratio M = L - K
1	Residential Service Sch 1	176,835,747	177,123,211	287,464	3,481,468	3,269,419	(212,049)	1.97%	1.85%	-0.12%	0.42	0.39	(0.03)
2	General Service Sch 11-12	42,426,805	42,530,861	104,056	4,114,596	4,037,839	(76,757)	9.70%	9.49%	-0.21%	2.06	2.01	(0.05)
3	Large General Service Sch 21-22	101,346,966	101,286,364	(60,602)	8,228,962	8,273,666	44,704	8.12%	8.17%	0.05%	1.72	1.73	0.01
4	Extra Large General Service Sch 25	36,287,625	36,241,356	(46,269)	423,081	457,211	34,130	1.17%	1.26%	0.09%	0.25	0.27	0.02
5	Potlatch Lewiston Sch 25P	68,852,070	68,523,292	(328,778)	3,607,736	3,850,260	242,524	5.24%	5.62%	0.38%	1.11	1.19	0.08
6	Pumping Service Sch 31-32	7,363,992	7,367,901	3,909	533,495	530,612	(2,883)	7.24%	7.20%	-0.04%	1.54	1.53	(0.01)
7	Street & Area Lights Sch 41-49	7,093,797	7,134,016	40,219	322,661	292,994	(29,667)	4.55%	4.11%	-0.44%	0.97	0.87	(0.10)
8	Idaho Jurisdictional Total	440,207,000	440,207,000	-	20,712,000	20,712,000	-	4.71%	4.71%	0.00%	1.00	1.00	-

Change No. 2
Compromise Direct Assignment of Primary Distribution Plant

Line No.	Rate Class A	No. 1 Revised Rate Base B	No. 2 Revised Rate Base C	Change in Rate Base D = C - B	No. 1 Revised Net Income E	No. 2 Revised Net Income F	Change in Net Income G = F - E	No. 1 Revised ROR H = E / B	No. 2 Revised ROR I = F / C	Change in ROR J = I - H	No. 1 Revised Return Ratio K = H / H16	No. 2 Revised Return Ratio L = I / I16	Change in Return Ratio M = L - K
9	Residential Service Sch 1	177,123,211	179,437,046	2,313,835	3,269,419	3,036,993	(232,426)	1.85%	1.69%	-0.16%	0.39	0.36	(0.03)
10	General Service Sch 11-12	42,530,861	43,132,910	602,049	4,037,839	3,977,362	(60,477)	9.49%	9.22%	-0.27%	2.01	1.96	(0.05)
11	Large General Service Sch 21-22	101,286,364	102,869,332	1,582,968	8,273,666	8,114,655	(159,011)	8.17%	7.89%	-0.28%	1.73	1.68	(0.05)
12	Extra Large General Service Sch 25	36,241,356	31,603,676	(4,637,680)	457,211	923,070	465,859	1.26%	2.92%	1.66%	0.27	0.62	0.35
13	Potlatch Lewiston Sch 25P	68,523,292	68,523,292	-	3,850,260	3,850,260	-	5.62%	5.62%	0.00%	1.19	1.19	-
14	Pumping Service Sch 31-32	7,367,901	7,472,228	104,327	530,612	520,132	(10,480)	7.20%	6.96%	-0.24%	1.53	1.48	(0.05)
15	Street & Area Lights Sch 41-49	7,134,016	7,168,517	34,501	292,994	289,528	(3,466)	4.11%	4.04%	-0.07%	0.87	0.86	(0.01)
16	Idaho Jurisdictional Total	440,207,000	440,207,000	-	20,712,000	20,712,000	-	4.71%	4.71%	0.00%	1.00	1.00	-

	(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) Potlatch Ex Lg Gen Svc Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Plant In Service									
1	Production Plant		300,269,000	103,855,863	23,871,210	64,089,462	28,322,636	74,527,729	4,560,417	1,041,683
2	Transmission Plant		109,001,000	37,345,154	8,575,673	23,320,080	10,300,710	27,407,393	1,663,998	387,992
3	Distribution Plant		257,643,000	127,399,434	32,593,642	69,004,590	8,879,815	2,125,817	5,152,270	12,487,432
4	Intangible Plant		11,353,000	4,974,306	1,112,097	2,134,464	821,049	2,045,161	171,273	94,650
5	General Plant		36,524,000	19,370,982	4,260,122	5,958,606	1,868,684	4,053,191	543,524	468,892
6	Total Plant In Service		714,790,000	292,945,738	70,412,744	164,507,202	50,192,894	110,159,291	12,091,481	14,480,649
	Accum Depreciation									
7	Production Plant		(91,465,000)	(31,590,537)	(7,260,043)	(19,529,251)	(8,629,804)	(22,746,584)	(1,390,227)	(318,554)
8	Transmission Plant		(36,394,000)	(12,469,056)	(2,863,304)	(7,786,268)	(3,439,272)	(9,150,968)	(555,587)	(129,546)
9	Distribution Plant		(75,640,000)	(37,336,907)	(9,619,755)	(19,099,874)	(2,146,430)	(546,491)	(1,492,853)	(5,397,690)
10	Intangible Plant		(1,893,000)	(920,776)	(203,944)	(331,272)	(115,953)	(272,465)	(28,354)	(20,236)
11	General Plant		(16,434,000)	(8,715,987)	(1,916,845)	(2,681,079)	(840,816)	(1,823,736)	(244,559)	(210,978)
12	Total Accumulated Depreciation		(221,826,000)	(91,033,263)	(21,863,891)	(49,427,744)	(15,172,273)	(34,540,244)	(3,711,580)	(6,077,004)
13	Net Plant		492,964,000	201,912,475	48,548,853	115,079,458	35,020,621	75,619,047	8,379,901	8,403,646
14	Accumulated Deferred FIT		(61,593,000)	(25,223,999)	(6,070,048)	(14,216,118)	(4,320,525)	(9,457,927)	(1,043,785)	(1,260,598)
15	Miscellaneous Rate Base		8,836,000	2,748,569	654,105	2,005,992	903,580	2,362,172	136,112	25,470
16	Total Rate Base		440,207,000	179,437,046	43,132,910	102,869,332	31,603,676	68,523,292	7,472,228	7,168,517
17	Revenue From Retail Rates		146,248,000	52,648,000	16,212,000	34,804,000	10,475,000	27,696,000	2,549,000	1,864,000
18	Other Operating Revenues		21,677,000	7,589,955	1,752,962	4,664,028	2,005,124	5,226,957	332,591	105,383
19	Total Revenues		167,925,000	60,237,955	17,964,962	39,468,028	12,480,124	32,922,957	2,881,591	1,969,383
	Operating Expenses									
20	Production Expenses		79,522,000	27,179,034	6,239,677	17,023,454	7,518,503	20,060,876	1,215,561	284,895
21	Transmission Expenses		5,485,000	1,879,232	431,533	1,173,481	518,338	1,379,158	83,733	19,524
22	Distribution Expenses		6,495,000	2,929,307	902,478	1,794,858	272,303	67,378	150,887	377,789
23	Customer Accounting Expenses		4,296,000	3,174,073	712,481	196,952	55,870	96,200	51,053	9,370
24	Customer Information Expenses		1,480,000	589,887	129,334	283,641	124,152	326,637	21,592	4,756
25	Sales Expenses		421,000	134,538	30,672	91,568	40,311	115,486	6,659	1,767
26	Admin & General Expenses		17,888,000	9,093,327	2,028,086	3,118,712	973,301	2,154,072	272,384	248,118
27	Total O&M Expenses		115,587,000	44,979,397	10,474,262	23,682,665	9,502,778	24,199,807	1,801,870	946,220
28	Taxes Other Than Income Taxes		7,438,000	3,081,908	753,505	1,782,908	490,405	1,013,124	130,425	185,726
29	Other Income Related Items		0	0	0	0	0	0	0	0
	Depreciation Expense									
30	Production Plant Depreciation		7,933,000	2,759,593	634,649	1,690,789	747,420	1,953,357	120,107	27,085
31	Transmission Plant Depreciation		2,532,000	867,496	199,206	541,706	239,277	636,650	38,653	9,013
32	Distribution Plant Depreciation		5,670,000	2,757,911	712,447	1,456,706	174,736	48,654	111,808	407,738
33	General Plant Depreciation		3,892,000	2,064,173	453,959	634,949	199,127	431,908	57,918	49,965
34	Amortization Expense		367,000	134,172	31,004	77,216	34,225	83,910	5,401	1,073
35	Total Depreciation Expense		20,394,000	8,583,345	2,031,264	4,401,366	1,394,785	3,154,480	333,887	494,873
36	Income Tax		3,794,000	556,313	728,569	1,486,433	169,087	705,286	95,277	53,035
37	Total Operating Expenses		147,213,000	57,200,963	13,987,600	31,353,373	11,557,054	29,072,697	2,361,459	1,679,855
38	Net Income		20,712,000	3,036,993	3,977,362	8,114,655	923,070	3,850,260	520,132	289,528
39	Rate of Return		4.71%	1.69%	9.22%	7.89%	2.92%	5.62%	6.96%	4.04%
40	Return Ratio		1.00	0.36	1.96	1.68	0.62	1.19	1.48	0.86
41	Interest Expense		20,250,000	8,254,299	1,984,161	4,732,101	1,453,803	3,152,146	343,731	329,760