Exhibit No. ___ (TLK-2)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-09_____

DOCKET NO. UG-09_____

EXHIBIT NO._____(TLK-2)

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

Exhibit No. ___(TLK-2)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
WASHINGTON ELECTRIC
TWELVE MONTHS ENDED SEPTEMBER 30, 2008

Line No.	Column	Description of Adjustment	(000's)	Production/Transmission Revenue	Expense	Rate Base
1	b	Per Results Report		159,899	355,486	615,840
2	c	Deferred FIT Rate Base			-	(86,478)
3	d	Deferred Gain on Office Building			-	
4	e	Colstrip 3 AFUDC Elimination		-	(202)	(1,956)
5	f	Colstrip Common AFUDC		-	-	436
6	g	Kettle Falls Disallow.		-	-	(854)
7	h	Customer Advances			-	
8	i	Depreciation True-up		-	(685)	-
9	j	Settlement Exchange Power		-	-	18,422
10		Actual		159,899	354,599	545,410
11	k	Eliminate B & O Taxes			-	
12	l	Property Tax			2,085	
13	m	Uncollect. Expense			-	
14	n	Regulatory Expense			-	
15	o	Injuries and Damages			-	
16	p	FIT			-	
17	q	Eliminate WA Power Cost Defer			(17,668)	
18	r	Nez Perce Settlement Adjustment			9	
19	s	Eliminate A/R Expenses			-	
20	t	Office Space Charges to Subsidiaries			-	
21	u	Restate Excise Taxes			-	
22	v	Net Gains/losses			-	
23	w	Revenue Normalization		171	2,618	
24	x	Misc Restating			-	
25	y	Restate Debt Interest			-	
26		Restated Total		160,070	341,643	545,410
27	PF1	Pro Forma Power Supply		(83,651)	(46,681)	-
28	PF2	Pro Forma Prod Property Adj		(3,654)	(13,576)	(12,500)
29	PF3	Pro Forma Labor Non-Exec			1,031	
30	PF4	Pro Forma Labor Exec			9	
31	PF5	Pro Forma Transmission Rev/Exp		24	103	-
32	PF6	Pro Forma Capital Add 2008			(77)	6,190
33	PF7	Pro Forma Capital Add 2009			1,199	5,375
34	PF9	Pro Forma Asset Management			874	-
35	PF11	Pro Forma Spokane Rvr Relicensing			3,636	23,325
36	PF12	Pro Forma CDA Tribe Settlement			829	16,819
37	PF13	Pro Forma Montana Lease			3,516	2,859
38	PF14	Pro Forma Colstrip Mercury Emiss. O&M			1,873	-
39	PF15	Pro Forma Incentives			-	
40	PF16	Pro Forma O&M Plant Expense			2,269	-
41	PF17	Pro Forma Employee Benefits			1,041	-
42	PF18	Pro Forma Insurance			-	
43	PF19	Pro Forma Clark Fork PM&E			656	-
44		Pro Forma Total		72,789	298,345	587,478

Exhibit No. ___(TLK-2)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
WASHINGTON ELECTRIC
TWELVE MONTHS ENDED SEPTEMBER 30, 2008

Proposed Production and Transmission Revenue Requirement
Calculation of Proposed Retail Revenue Credit Rate

Line			($000's)	Debt Cost
1	Prod/Trans	Pro Forma Rate Base	$587,478	
2		Proposed Rate of Return	8.680%	3.45%
3	Rate Base	Net Operating Income Requirement	$50,993	
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -35%)	($7,094)	
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	225,556	
6	Tax Effect	Net Operating Income Requirement (Net Expense x -.35%)	($78,945)	
7	Total Prod/Trans	Net Operating Income Requirement	$190,511	
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.)	0.65	
9	Prod/Trans	Revenue Requirement	$293,093	
10	12ME Sept 2008	WA Normalized Retail Load MWh	5,487,574	
11	Prod/Trans Rev Requirement per kWh (Retail Revenue Credit Rate)		**$ 0.05341**	

Exhibit No. ___ (TLK-3)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-09_____

DOCKET NO. UG-09_____

EXHIBIT NO._____(TLK-3)

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

ELECTRIC COST OF SERVICE

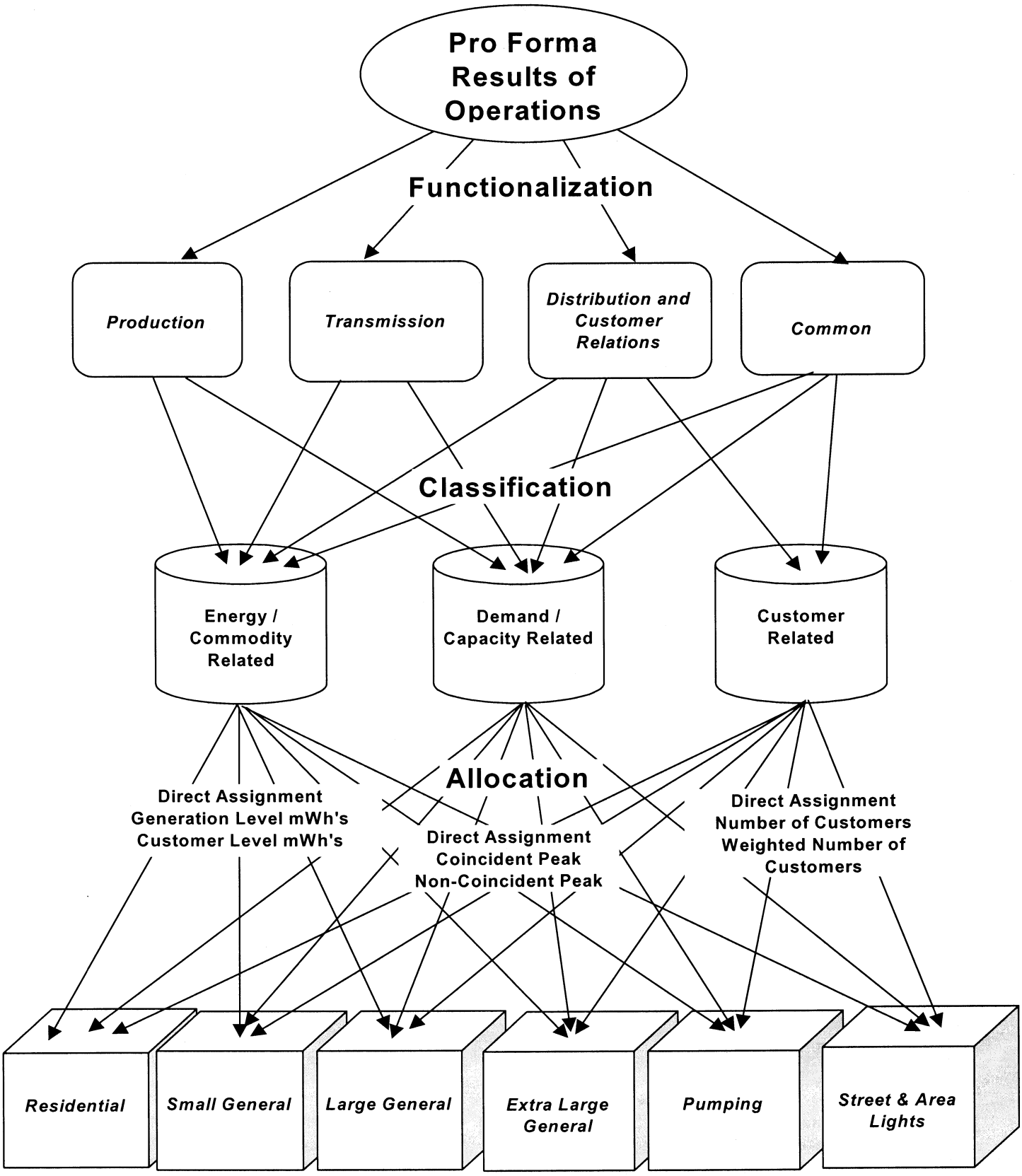
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. It indicates whether the revenue provided by the customers recovers the cost to serve those customers. The study 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.

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. In this study I have created 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 which 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.

ELECTRIC COST OF SERVICE STUDY FLOWCHART



Pro Forma Results of Operations by Customer Group

1

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 and Transmission Classification (Peak Credit)

This study utilizes a Peak Credit methodology to classify production and transmission costs into demand and energy classifications. The Peak Credit method acknowledges that baseload production facilities provide energy throughout the year as well as capacity during system peaks and likewise the transmission system is built not only for peak use, but also for everyday delivery of energy. The demand/energy ratio is determined by the relationship of the current replacement cost per kW generating capacity of the Company's peaking units to the current replacement cost per kW generating capacity of the Company's thermal or hydro plant. The peak credit ratio for thermal plant is 37.16% to demand and 62.84% to energy. The peak credit ratio for hydro plant is 35.82% to demand and 64.18% to energy. As an intermediate resource (between peaking and baseload) Coyote Springs II has been included with the thermal plant costs, while Boulder Park and Kettle Falls CT have been included with the peaking units.

Transmission costs are classified by fifty-fifty weighting of the thermal and hydro peak credit ratios resulting in the transmission peak credit ratio of 36.49% to demand and 63.51% to energy. Fuel and load dispatching expenses are classified entirely to energy. Peaking plant related costs are classified entirely to demand. Purchased Power and Other Power Supply expenses are classified to demand and energy by the relative amounts of assigned and allocated Production Plant in Service. WNP3 Settlement Exchange Power costs are classified as energy related.

Production and Transmission Allocation

Production and transmission 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 technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

Energy related costs are allocated to class by pro forma annual kilowatthour sales adjusted for losses to reflect generation level consumption.

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 which benefits an individual customer from plant which is part of the system. The basic customer method provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network. Additionally, the basic customer method has been explicitly accepted for both electric and gas cost of service in the State of Washington.

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.

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 allocated by non-coincident peak excluding all primary and transmission voltage customers. This includes line transformers, services, and secondary voltage overhead or underground conductors and devices. The costs of specific substations and related primary voltage distribution facilities are directly assigned to Extra Large General Service customers based on their load ratio share of the substation capacity from which they receive service. The remaining primary voltage overhead or underground conductors and devices are allocated by non-coincident peak for all customers except those that received directly assignment (Schedule 25).

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.

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 remaining administrative and general costs are considered common costs, and have been left in their own functional category. These common costs are allocated to rate class by factors equivalent to those approved for Puget Sound Power and Light (now PSE) in Docket No. UE-920499 and indirectly classified by the implicit relationship of energy, demand and customer that make up the various allocation factors applied to the costs.

Common plant items are allocated to rate class by either relative: production, transmission, distribution plant; production, transmission, distribution labor subtotal; or operating and maintenance labor total. Most common administrative and general expenses are allocated to rate class by relative operating and maintenance expenses before administrative and general expenses excluding purchased power, fuel, wheeling, and revenue items. Property insurance expense is allocated by plant totals. Injuries & damages and pensions & benefits expenses are allocated by operating and maintenance labor expense totals.

Revenue Conversion Items

In this study state excise tax, 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 then 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.

WUTC Docket No. UE-09____ Methodology Matrix
Avista Utilities Washington Jurisdiction
Electric Cost of Service Methodology

Exhibit No. ___(TLK-3)

Line	Account	Functional Category	Classification	Allocation
	Production Plant			
1	Thermal Production	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
2	Nuclear Production (Settlement Exchange)	P = Production	Energy	E02 Annual Generation Level Consumption
3	Hydro Production	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
4	Other Production (Coyote Springs)	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
5	Other Production	P = Production	Demand	D01 Coincident Peak Demand
	Transmission Plant			
6	All Transmission	T = Transmission	Demand/Energy by Trans Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Distribution Plant			
7	360 Land	D = Distribution	Demand	D08 Non-coincident Peak Demand Primary
8	361 Structures	D = Distribution	Demand	D03/D04/D05 Direct Assign Large / Non-coincident Peak Demand Excl DA
9	362 Station Equipment	D = Distribution	Demand	D03/D04/D05 Direct Assign Large / Non-coincident Peak Demand Excl DA
10	364 Poles Towers & Fixtures	D = Distribution	Demand	D03/D04/D06/D07 Primary NCP Excl DA / Secondary NCP / Direct Assign Lights / Direct Assign La
11	365 Overhead Conductors & Devices	D = Distribution	Demand	D03/D04/D06 Primary NCP Excl DA / Secondary NCP / Direct Assign Large
12	366 Underground Conduit	D = Distribution	Demand	D03/D04/D06 Primary NCP Excl DA / Secondary NCP / Direct Assign Large
13	367 Underground Conductors & Devices	D = Distribution	Demand	D03/D04/D06 Primary NCP Excl DA / Secondary NCP / Direct Assign Large
14	368 Line Transformers	D = Distribution	Demand	D06 Non-coincident Peak Demand Secondary only
15	369 Services	D = Distribution	Customer	C02 Secondary Customers unweighted Excl Lighting
16	370 Meters	D = Distribution	Customer	C04 Customers weighted by Current Typical Meter Cost
17	373 Street and Area Lighting Systems	D = Distribution	Customer	C05 Direct Assignment to Street and Area Lights
	General Plant			
18	All General	P/T/D	Demand/Energy/Customer as in related Labor or Plant	S22/S05/S21 Labor O&M Total, P/T/D Plant Total, Labor P/T/D O&M Subtotal
	Intangible Plant			
19	301 Organization	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant
20	302 Franchises & Consents	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
21	303 Misc Intangible Plant - Transmission Agreements	T = Transmission	Demand/Energy by Trans Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
22	303 Misc Intangible Plant - Software	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant
	Reserve for Depreciation/Amortization			
23	Intangible	P/T/D/G	Follows Related Plant	S01/S02/S06 Sum of Production Plant / Sum of Transmission Plant / P/T/D/G Total
24	Production	P = Production	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
25	Transmission	T = Transmission	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
26	Distribution	D = Distribution	Follows Related Plant	D02/D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
27	General	P/T/D	Demand/Energy/Customer as in related Labor or Plant	S22/S05/S21 Labor O&M Total, P/T/D Plant Total, Labor P/T/D O&M Subtotal
	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	Follows Related Plant	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
30	Gain on Sale of General Office Building	P/T/D	Demand/Energy/Customer from Plant	S04 Sum of General Plant
40	Hydro Relicensing Related Settlements	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Production O&M			
41	Thermal	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
42	Thermal Fuel (501)	P = Production	Energy	E02 Annual Generation Level Consumption
43	Hydro	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
44	Water for Power (536)	P = Production	Energy	E02 Annual Generation Level Consumption

Line	Account	Functional Category	Classification	Allocation
	Production O&M continued			
1	Other (Coyote Springs)	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
2	Other Fuel (547)	P = Production	Energy	E02 Annual Generation Level Consumption
3	Other	P = Production	Demand	D01 Coincident Peak Demand
4	Purchased Power and Other Expenses (555 and 557)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
5	System Control & Misc (556)	P = Production	Energy	E02 Annual Generation Level Consumption
	Transmission O&M			
6	All Transmission	T = Transmission	Demand/Energy by Trans Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Distribution O&M			
7	580 OP Super & Engineering	D = Distribution	Demand/Customer from Other Dist Op Exp	S16 Sum of Other Distribution Operating Expenses
8	581 Load Dispatching	D = Distribution	Demand	D02 Non-coincident Peak Demand
9	582 Station Expenses	D = Distribution	Demand	S09 Sum of Account 362 Station Equipment
10	583 Overhead Lines	D = Distribution	Demand	S10 Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
11	584 Underground Lines	D = Distribution	Demand	S11 Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
12	585 Street Lights	D = Distribution	Customer	S15 Sum of Account 373 Street Light and Signal Systems
13	586 Meters	D = Distribution	Customer	S14 Sum of Account 370 Meters
14	587 Customer Installations	D = Distribution	Customer	S13 Sum of Account 369 Services
15	588 Misc Operating Expense	D = Distribution	Demand/Customer from Other Dist Op Exp	S16 Sum of Other Distribution Operating Expenses
16	589 Rents	D = Distribution	Demand	D02 Non-coincident Peak Demand
17	590 MT Super & Engineering	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17 Sum of Other Distribution Maintenance Expenses
18	591 MT of Structures	D = Distribution	Demand	S08 Sum of Account 361 Structures & Improvements
19	592 MT of Station Equipment	D = Distribution	Demand	S09 Sum of Account 362 Station Equipment
20	593 MT of Overhead Lines	D = Distribution	Demand	S10 Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
21	594 MT of Underground Lines	D = Distribution	Demand	S11 Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
22	595 MT of Line Transformers	D = Distribution	Demand	S12 Sum of Account 368 Line Transformers
23	596 MT of Street Lights	D = Distribution	Customer	S15 Sum of Account 373 Street Light and Signal Systems
24	597 MT of Meters	D = Distribution	Customer	S14 Sum of Account 370 Meters
25	598 Misc Maintenance Expense	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17 Sum of Other Distribution Maintenance Expenses
	Customer Accounts Expenses			
26	901 Supervision	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
27	902 Meter Reading	C = Customer Relations	Customer	C03 Customers Weighted by Estimated Meter Reading Time
28	903 Customer Records & Collections	C = Customer Relations	Customer	C01 All Customers unweighted
29	904 Uncollectible Accounts	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
30	905 Misc Cust Accounts	C = Customer Relations	Customer	C01 All Customers unweighted
	Customer Service & Info Expenses			
31	907 Supervision	C = Customer Relations	Customer	C01 All Customers unweighted
32	908 Customer Assistance	C = Customer Relations	Customer	C01 All Customers unweighted
33	909 Advertising	C = Customer Relations	Customer	C01 All Customers unweighted
34	910 Misc Cust Service & Info	C = Customer Relations	Customer	C01 All Customers unweighted
	Sales Expenses			
35	911 - 916	C = Customer Relations	Energy	E02 Annual Generation Level Consumption

WUTC Docket No. UE-09____ Methodology Matrix
Avista Utilities Washington Jurisdiction
Electric Cost of Service Methodology

Exhibit No. ___(TLK-3)

Line	Account	Functional Category	Classification	Allocation
	Admin & General Expenses			
1	920 - 926 & 930 -935 Assigned to Production	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
2	920 - 926 & 930 -935 Assigned to Transmission	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
3	920 - 926 & 930 - 935 Assigned to Distribution	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
4	920 - 926 & 930 - 935 Assigned to Customer Relations	C = Customer Relations	Customer	C01 All Customers unweighted
5	Other 920-923, 928-931 Salaries, supplies, etc	P/T/D	Demand/Energy/Customer from O&M Expenses	S19 Sum of expenses excluding Purch Power, Fuel, Wheeling, Uncollectibles, Tariff Rider
6	924 Property Insurance	P/T/D	Demand/Energy/Customer from Plant	S06 Sum of Production, Transmission, Distribution, and General Plant
7	Other 925-926 Inj & Dam, Pensions & Benefits	P/T/D	Demand/Energy/Customer from Labor O&M Total	S22 Sum of Labor O&M Expenses
8	928 FERC Commission Fees	P = Production	Energy	E02 Annual Generation Level Consumption
9	927,928 Franchise Fees, WUTC Commission Fees	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
10	935 Maintenance of General Plant	P/T/D	Demand/Energy/Customer from Plant	S04 Sum of General Plant
	Depreciation & Amortization Expense			
11	Intangible	P/T/D/G	Demand/Energy/Customer as in related Plant	S01/S02/S06 Sum of Production Plant / Sum of Transmission Plant / Sum of P/T/D/G Plant
12	Production	P = Production	Demand/Energy as in related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
13	Transmission	T = Transmission	Demand/Energy as in related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
14	Distribution	D = Distribution	Demand/Customer as in related Plant	D02/D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
15	General	P/T/D	Demand/Energy/Customer as in related Labor or Plant	S22/S05/S21 Labor O&M Total, P/T/D Plant Total, Labor P/T/D O&M Subtotal
	Taxes			
16	Property Tax	P/T/D/O	Demand/Energy/Customer from Related Plant	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
17	State kWh Generation Taxes	P = Production	Demand/Energy by Combo Peak Credits & Energy	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
18	Misc Production Taxes	P = Production	Demand/Energy by Combo Peak Credits & Energy	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
19	Misc Distribution Taxes	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
20	Washington State Excise Tax	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
21	Federal Income Taxes - Current and/or Deferred	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Tax less Interest Expense
	Other Income Related Items			
22	Settlement Exchange Power (shown as Nuclear Deprecia	P = Production	Energy	E02 Generation Level Consumption
23	Amortization of Gain on Sale of Misc Property	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
	Operating Revenues			
24	Sales of Electricity- Retail	R = Revenue from Rates	Revenue	Input Pro Forma Revenue per Revenue Study
25	Sales for Resale (447)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
26	Optional Renewable Revenue	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
27	Special Contract (Standby) Revenue	P = Production	Demand	D01 Coincident Peak Demand
28	Misc Service Revenue (451)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
29	Sales of Water & Water Power (453)	P = Production	Demand	D01 Coincident Peak Demand
30	Rent from Production Property (454)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
31	Rent from Distribution Property (454)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
32	Other Electric Revenues - Generation (456)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
33	Other Electric Revenues - Wheeling (456)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
34	Other Electric Revenues - Energy Delivery (456)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
	Salaries & Wages (allocators)			
	Operation & Maintenance Expenses			
35	Production Total	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
36	Transmission Total	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
37	Distribution Total	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
38	Customer Accounts Total	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
39	Customer Service Total	C = Customer Relations	Customer	C01 All Customers unweighted
40	Sales Total	C = Customer Relations	Energy	E02 Annual Generation Level Consumption
41	Admin & General Total	P/T/D	Demand/Energy/Customer from Related Plant	S05 Sum of Production, Transmission and Distribution Plant

Exhibit No. ___ (TLK-4)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-09_____

DOCKET NO. UG-09_____

EXHIBIT NO._____(TLK-4)

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

Sumcost
Scenario: Company Base Case
UE-011595 Method w/DA Poles & Wires

AVISTA UTILITIES
Cost of Service Basic Summary
For the Twelve Months Ended September 30, 2008

Washington Jurisdiction
Electric Utility

01-19-09

	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Description				System Total	Residential Service Sch 1	General Service Sch 11-12	Large Gen Service Sch 21-22	Extra Large Gen Service Sch 25	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
	Plant In Service										
1	Production Plant				758,032,000	344,885,757	59,643,025	215,525,878	117,744,649	17,251,014	2,981,677
2	Transmission Plant				296,316,000	134,472,521	23,282,525	84,374,918	46,235,937	6,767,400	1,182,698
3	Distribution Plant				607,539,000	318,789,711	59,582,137	164,156,521	20,342,361	13,472,879	31,195,391
4	Intangible Plant				78,478,000	36,096,351	6,295,180	22,223,009	11,468,207	1,787,453	607,801
5	General Plant				109,598,000	58,123,763	10,331,185	26,749,014	9,714,208	2,317,109	2,362,721
6	Total Plant In Service				1,849,963,000	892,368,104	159,134,051	513,029,341	205,505,362	41,595,855	38,330,288
	Accum Depreciation										
7	Production Plant				(313,797,000)	(141,955,254)	(24,614,110)	(89,516,913)	(49,237,780)	(7,198,005)	(1,274,937)
8	Transmission Plant				(103,059,000)	(46,769,677)	(8,097,685)	(29,345,681)	(16,080,905)	(2,353,709)	(411,343)
9	Distribution Plant				(197,662,000)	(102,111,506)	(18,729,209)	(51,290,218)	(5,799,651)	(4,196,136)	(15,535,280)
10	Intangible Plant				(12,626,000)	(6,008,899)	(1,065,003)	(3,522,735)	(1,529,903)	(284,960)	(214,500)
11	General Plant				(48,432,000)	(25,635,134)	(4,557,512)	(11,858,652)	(4,307,511)	(1,025,475)	(1,047,716)
12	Total Accumulated Depreciation				(675,576,000)	(322,480,470)	(57,063,521)	(185,534,199)	(76,955,750)	(15,058,285)	(18,483,776)
13	Net Plant				1,174,387,000	569,887,634	102,070,531	327,495,141	128,549,612	26,537,570	19,846,512
14	Accumulated Deferred FIT				(171,073,000)	(82,349,977)	(14,634,323)	(47,324,342)	(19,703,177)	(3,841,456)	(3,219,725)
15	Miscellaneous Rate Base				3,762,000	1,597,287	283,733	1,142,112	636,958	89,313	12,598
16	Total Rate Base				1,007,076,000	489,134,944	87,719,940	281,312,912	109,483,394	22,785,426	16,639,384
17	Revenue From Retail Rates				390,953,000	170,783,000	41,837,000	118,120,000	46,035,000	8,504,000	5,674,000
18	Other Operating Revenues				76,186,000	34,888,215	6,055,857	21,614,673	11,447,709	1,731,520	448,026
19	Total Revenues				467,139,000	205,671,215	47,892,857	139,734,673	57,482,709	10,235,520	6,122,026
	Operating Expenses										
20	Production Expenses				240,417,000	106,877,996	18,682,936	69,270,376	38,869,209	5,645,823	1,070,661
21	Transmission Expenses				18,490,000	8,391,032	1,452,820	5,264,961	2,885,104	422,283	73,800
22	Distribution Expenses				20,922,000	10,409,836	2,246,882	5,617,376	738,843	512,607	1,396,456
23	Customer Accounting Expenses				8,584,000	6,708,890	1,187,733	442,862	110,396	113,650	20,469
24	Customer Information Expenses				693,000	594,808	80,390	9,910	66	6,906	920
25	Sales Expenses				683,000	297,827	52,536	198,907	113,956	16,443	3,331
26	Admin & General Expenses				40,476,000	20,807,245	3,808,282	10,104,127	3,977,914	882,865	895,568
27	Total O&M Expenses				330,265,000	154,087,634	27,511,578	90,908,519	46,695,487	7,600,577	3,461,205
28	Taxes Other Than Income Taxes				30,772,000	13,993,347	2,931,480	8,963,339	3,729,920	683,446	470,468
29	Other Income Related Items				(122,000)	(64,016)	(11,965)	(32,964)	(4,085)	(2,705)	(6,264)
	Depreciation Expense										
30	Production Plant Depreciation				19,350,000	8,821,389	1,524,126	5,495,220	2,994,898	439,133	75,233
31	Transmission Plant Depreciation				5,968,000	2,708,365	468,925	1,699,367	931,222	136,300	23,820
32	Distribution Plant Depreciation				16,562,000	8,464,558	1,610,092	4,753,398	657,795	378,107	698,049
33	General Plant Depreciation				9,083,000	4,675,570	831,744	2,314,313	872,933	195,964	192,476
34	Amortization Expense				2,982,000	1,356,924	234,645	847,782	463,078	67,850	11,720
35	Total Depreciation Expense				53,945,000	26,026,807	4,669,533	15,110,080	5,919,926	1,217,353	1,001,300
36	Income Tax				8,250,000	(2,468,955)	4,594,736	7,095,159	(1,240,066)	(23,169)	292,296
37	Total Operating Expenses				423,110,000	191,574,816	39,695,363	122,044,133	55,101,183	9,475,501	5,219,004
38	Net Income				44,029,000	14,096,399	8,197,494	17,690,540	2,381,526	760,018	903,022
39	Rate of Return				4.37%	2.88%	9.35%	6.29%	2.18%	3.34%	5.43%
40	Return Ratio				1.00	0.66	2.14	1.44	0.50	0.76	1.24
41	Interest Expense				34,744,000	16,875,096	3,026,327	9,705,261	3,777,164	786,094	574,057

Sumcost
Scenario: Company Base Case
UE-011595 Method w/DA Poles & Wires

AVISTA UTILITIES
Revenue to Cost by Functional Component Summary
For the Twelve Months Ended September 30, 2008

Washington Jurisdiction
Electric Utility

01-19-09

	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Description				System Total	Residential Service Sch 1	General Service Sch 11-12	Large Gen Service Sch 21-22	Extra Large Gen Service Sch 25	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
	Functional Cost Components at Current Return by Schedule										
1	Production				237,315,000	100,032,407	21,790,484	73,243,038	35,742,005	5,405,544	1,101,522
2	Transmission				32,265,260	12,560,104	3,853,328	11,087,365	3,954,075	666,341	144,047
3	Distribution				72,782,323	33,859,259	11,148,582	21,217,838	1,817,408	1,398,463	3,340,772
4	Common				48,590,417	24,331,230	5,044,606	12,571,760	4,521,511	1,033,651	1,087,659
5	Total Current Rate Revenue				390,953,000	170,783,000	41,837,000	118,120,000	46,035,000	8,504,000	5,674,000
	Expressed as $/kWh										
6	Production				$0.04325	$0.04202	$0.05189	$0.04597	$0.03823	$0.04112	$0.04137
7	Transmission				$0.00588	$0.00528	$0.00918	$0.00696	$0.00423	$0.00507	$0.00541
8	Distribution				$0.01326	$0.01422	$0.02655	$0.01332	$0.00194	$0.01064	$0.12546
9	Common				$0.00886	$0.01022	$0.01201	$0.00789	$0.00484	$0.00786	$0.04084
10	Total Current Melded Rates				$0.07125	$0.07173	$0.09962	$0.07414	$0.04924	$0.06469	$0.21308
	Functional Cost Components at Uniform Current Return										
11	Production				238,180,284	105,749,142	18,496,589	68,675,002	38,589,476	5,602,664	1,067,410
12	Transmission				32,602,228	14,795,367	2,561,665	9,283,368	5,087,118	744,585	130,127
13	Distribution				71,536,306	39,493,160	7,598,307	17,433,683	2,379,027	1,566,645	3,065,485
14	Common				48,634,182	25,136,973	4,566,450	12,081,645	4,728,373	1,056,412	1,064,329
15	Total Uniform Current Cost				390,953,000	185,174,641	33,223,011	107,473,697	50,783,995	8,970,305	5,327,351
	Expressed as $/kWh										
16	Production				$0.04341	$0.04442	$0.04404	$0.04310	$0.04128	$0.04262	$0.04008
17	Transmission				$0.00594	$0.00621	$0.00610	$0.00583	$0.00544	$0.00566	$0.00489
18	Distribution				$0.01304	$0.01659	$0.01809	$0.01094	$0.00254	$0.01192	$0.11512
19	Common				$0.00886	$0.01056	$0.01087	$0.00758	$0.00506	$0.00804	$0.03997
20	Total Current Uniform Melded Rates				$0.07125	$0.07778	$0.07911	$0.06745	$0.05432	$0.06824	$0.20006
21	**Revenue to Cost Ratio at Current Rates**				1.00	0.92	1.26	1.10	0.91	0.95	1.07
	Functional Cost Components at Proposed Return by Schedule										
22	Production				267,001,484	112,601,621	24,185,445	82,233,419	40,728,377	6,046,721	1,205,900
23	Transmission				43,954,132	17,476,193	4,792,747	14,638,821	5,938,787	920,928	186,657
24	Distribution				97,578,564	46,249,965	13,730,644	28,667,665	2,801,184	1,945,689	4,183,415
25	Common				52,180,820	26,102,221	5,392,164	13,536,095	4,883,652	1,107,661	1,159,028
26	Total Proposed Rate Revenue				460,715,000	202,430,000	48,101,000	139,076,000	54,352,000	10,021,000	6,735,000
	Expressed as $/kWh										
27	Production				$0.04866	$0.04729	$0.05759	$0.05161	$0.04357	$0.04600	$0.04529
28	Transmission				$0.00801	$0.00734	$0.01141	$0.00919	$0.00635	$0.00701	$0.00701
29	Distribution				$0.01778	$0.01943	$0.03269	$0.01799	$0.00300	$0.01480	$0.15710
30	Common				$0.00951	$0.01096	$0.01284	$0.00850	$0.00522	$0.00843	$0.04353
31	Total Proposed Melded Rates				$0.08396	$0.08502	$0.11453	$0.08729	$0.05814	$0.07623	$0.25292
	Functional Cost Components at Uniform Requested Return										
32	Production				267,648,527	119,206,767	20,819,878	77,035,144	43,136,137	6,269,789	1,180,812
33	Transmission				44,200,490	20,058,827	3,472,978	12,585,931	6,896,864	1,009,471	176,419
34	Distribution				96,616,982	52,759,404	10,103,118	24,361,420	3,276,077	2,136,009	3,980,954
35	Common				52,249,001	27,033,181	4,903,604	12,978,360	5,058,570	1,133,418	1,141,869
36	Total Uniform Cost				460,715,000	219,058,178	39,299,578	126,960,855	58,367,647	10,548,686	6,480,055
	Expressed as $/kWh										
37	Production				$0.04878	$0.05007	$0.04957	$0.04835	$0.04614	$0.04770	$0.04434
38	Transmission				$0.00806	$0.00843	$0.00827	$0.00790	$0.00738	$0.00768	$0.00663
39	Distribution				$0.01761	$0.02216	$0.02406	$0.01529	$0.00350	$0.01625	$0.14950
40	Common				$0.00952	$0.01135	$0.01168	$0.00815	$0.00541	$0.00862	$0.04288
41	Total Uniform Melded Rates				$0.08396	$0.09201	$0.09358	$0.07968	$0.06244	$0.08025	$0.24335
42	**Revenue to Cost Ratio at Proposed Rates**				1.00	0.92	1.22	1.10	0.93	0.95	1.04
43	**Current Revenue to Proposed Cost Ratio**				**0.85**	**0.78**	**1.06**	**0.93**	**0.79**	**0.81**	**0.88**

Sumcost
Scenario: Company Base Case
UE-011595 Method w/DA Poles & Wires

AVISTA UTILITIES
Revenue to Cost By Classification Summary
For the Twelve Months Ended September 30, 2008

Washington Jurisdiction
Electric Utility

01-19-09

	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Description				System Total	Residential Service Sch 1	General Service Sch 11-12	Large Gen Service Sch 21-22	Extra Large Gen Service Sch 25	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
	Cost Classifications at Current Return by Schedule										
1	Energy				236,932,638	98,897,035	21,057,489	73,258,501	36,983,729	5,539,560	1,196,325
2	Demand				127,526,822	53,344,971	16,188,016	43,746,579	9,036,225	2,539,798	2,671,231
3	Customer				26,493,540	18,540,993	4,591,495	1,114,920	15,046	424,642	1,806,444
4	Total Current Rate Revenue				390,953,000	170,783,000	41,837,000	118,120,000	46,035,000	8,504,000	5,674,000
	Expressed as Unit Cost										
5	Energy	$/kWh			$0.04318	$0.04154	$0.05014	$0.04598	$0.03956	$0.04214	$0.04493
6	Demand	$/kW/mo			$10.01	$9.15	$14.49	$11.49	$5.58	$9.07	$33.24
7	Customer	$/Cust/mo			$9.55	$7.79	$14.27	$28.11	$56.99	$15.37	$490.61
	Cost Classifications at Uniform Current Return										
8	Energy				237,625,693	103,618,256	18,277,966	69,202,771	39,646,900	5,720,865	1,158,936
9	Demand				126,446,836	61,697,772	11,128,536	37,238,111	11,120,625	2,805,446	2,456,346
10	Customer				26,880,471	19,858,613	3,816,509	1,032,815	16,471	443,994	1,712,069
11	Total Uniform Current Cost				390,953,000	185,174,641	33,223,011	107,473,697	50,783,995	8,970,305	5,327,351
	Expressed as Unit Cost										
12	Energy	$/kWh			$0.04331	$0.04352	$0.04352	$0.04343	$0.04241	$0.04352	$0.04352
13	Demand	$/kW/mo			$9.93	$10.58	$9.96	$9.78	$6.87	$10.02	$30.57
14	Customer	$/Cust/mo			$9.69	$8.34	$11.86	$26.04	$62.39	$16.07	$464.98
15	**Revenue to Cost Ratio at Current Rates**				1.00	0.92	1.26	1.10	0.91	0.95	1.07
	Cost Classifications at Proposed Return by Schedule										
16	Energy				262,682,144	109,276,531	23,078,305	81,240,150	41,647,163	6,129,264	1,310,731
17	Demand				167,562,649	71,715,213	19,867,685	56,559,328	12,687,295	3,404,143	3,328,985
18	Customer				30,470,207	21,438,256	5,155,010	1,276,523	17,541	487,593	2,095,283
19	Total Proposed Rate Revenue				460,715,000	202,430,000	48,101,000	139,076,000	54,352,000	10,021,000	6,735,000
	Expressed as Unit Cost										
20	Energy	$/kWh			$0.04787	$0.04590	$0.05495	$0.05099	$0.04455	$0.04663	$0.04922
21	Demand	$/kW/mo			$13.16	$12.30	$17.79	$14.85	$7.83	$12.16	$41.42
22	Customer	$/Cust/mo			$10.99	$9.01	$16.02	$32.19	$66.44	$17.64	$569.06
	Cost Classifications at Uniform Requested Return										
23	Energy				263,111,369	114,731,453	20,238,302	76,624,862	43,899,083	6,334,436	1,283,233
24	Demand				166,542,625	81,366,083	14,698,115	49,152,903	14,449,818	3,704,759	3,170,947
25	Customer				31,061,006	22,960,641	4,363,161	1,183,090	18,746	509,492	2,025,875
26	Total Uniform Cost				460,715,000	219,058,178	39,299,578	126,960,855	58,367,647	10,548,686	6,480,055
	Expressed as Unit Cost										
27	Energy	$/kWh			$0.04795	$0.04819	$0.04819	$0.04809	$0.04696	$0.04819	$0.04819
28	Demand	$/kW/mo			$13.08	$13.96	$13.16	$12.91	$8.92	$13.24	$39.46
29	Customer	$/Cust/mo			$11.20	$9.65	$13.56	$29.83	$71.01	$18.44	$550.21
30	**Revenue to Cost Ratio at Proposed Rates**				1.00	0.92	1.22	1.10	0.93	0.95	1.04
31	**Current Revenue to Proposed Cost Ratio**				**0.85**	**0.78**	**1.06**	**0.93**	**0.79**	**0.81**	**0.88**

Exhibit No. ___ (TLK-5)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-09_____

DOCKET NO. UG-09_____

EXHIBIT NO._____(TLK-5)

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

AVISTA UTILITIES
Demand Allocator Sensitivity Analysis
Case No. AVU-E-09-01

Line No	(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	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Base Case										
1	Total Rate Base				1,007,076,000	489,134,944	87,719,940	281,312,912	109,483,394	22,785,426	16,639,384
2	Net Income at Present Rates				44,029,000	14,096,399	8,197,494	17,690,540	2,381,526	760,018	903,022
3	Rate of Return				4.37%	2.88%	9.35%	6.29%	2.18%	3.34%	5.43%
4	Return Ratio-Base Case				1.00	0.66	2.14	1.44	0.50	0.76	1.24
	Scenario 1 - Non-Coincident Peak Twice Base Case										
5	Total Rate Base				1,007,076,000	489,199,411	87,732,292	281,355,022	109,360,480	22,788,522	16,640,273
6	Net Income at Present Rates				44,029,000	14,092,999	8,196,843	17,688,319	2,388,009	759,855	902,976
7	Rate of Return				4.37%	2.88%	9.34%	6.29%	2.18%	3.33%	5.43%
8	Return Ratio-Scenario 1				1.00	0.66	2.14	1.44	0.50	0.76	1.24
	Scenario 2 - Over-Unity Non-Coincident Peak Increased and Under-Unity Non-Coincident Peak Decreased										
9	Total Rate Base				1,007,076,000	467,108,788	92,971,355	298,763,734	109,486,940	21,727,788	17,017,396
10	Net Income at Present Rates				44,029,000	15,359,363	7,897,872	16,688,305	2,381,343	820,662	881,455
11	Rate of Return				4.37%	3.29%	8.49%	5.59%	2.18%	3.78%	5.18%
12	Return Ratio-Scenario 2				1.00	0.75	1.94	1.28	0.50	0.86	1.18
	Scenario 3 - Coincident Peaks 6.25% of Peak Days										
13	Total Rate Base				1,007,076,000	487,775,935	87,180,326	282,509,316	109,483,394	23,487,645	16,639,384
14	Net Income at Present Rates				44,029,000	14,203,091	8,239,858	17,596,614	2,381,526	704,889	903,022
15	Rate of Return				4.37%	2.91%	9.45%	6.23%	2.18%	3.00%	5.43%
16	Return Ratio-Scenario 3				1.00	0.67	2.16	1.42	0.50	0.69	1.24
	Scenario 4 - Over-Unity Coincident Peak Increased and Under-Unity Coincident Peak Decreased										
17	Total Rate Base				1,007,076,000	478,800,273	90,175,907	289,558,654	109,483,394	22,344,427	16,713,346
18	Net Income at Present Rates				44,029,000	14,907,746	8,004,683	17,043,189	2,381,526	794,640	897,216
19	Rate of Return				4.37%	3.11%	8.88%	5.89%	2.18%	3.56%	5.37%
20	Return Ratio-Scenario 4				1.00	0.71	2.03	1.35	0.50	0.81	1.23

Exhibit No. ___ (TLK-6)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-09_____

DOCKET NO. UG-09_____

EXHIBIT NO._____(TLK-6)

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

NATURAL GAS COST OF SERVICE STUDY

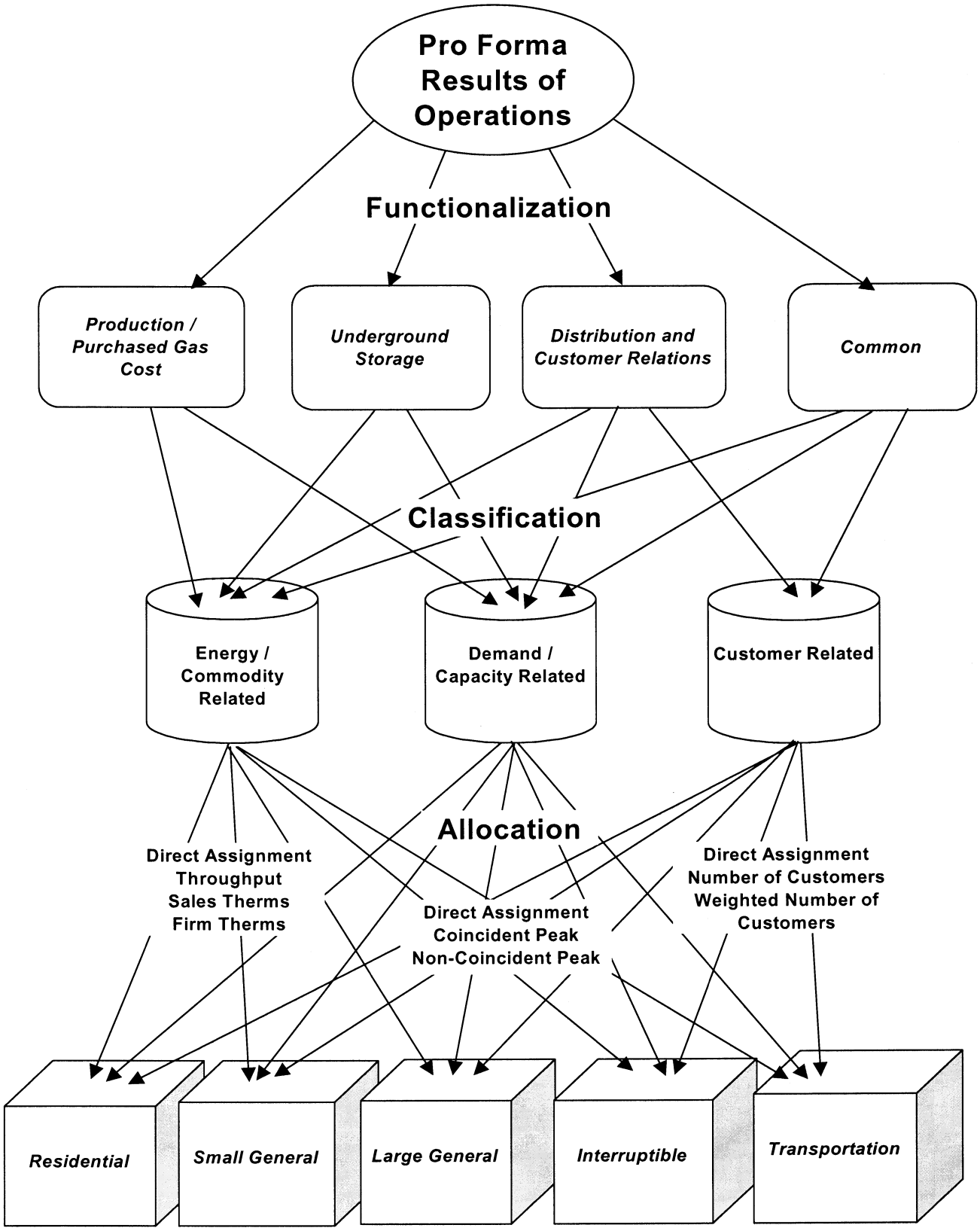
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing natural gas service to designated groups of customers. It indicates whether the revenue provided by the customer group recovers the cost to serve those customers. 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.

First, the expenses and rate base associated with the natural gas system under study are assigned to functional categories. The uniform system of accounts provides the basic segregation into production, underground storage, 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. In this study I have created 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 are classified into three primary cost components: demand, commodity or customer related. Demand (capacity) related costs are allocated to rate schedules on the basis of each schedule's contribution to system peak demand. Commodity (energy) related costs are allocated based on each rate schedule's share of commodity consumption. 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.

NATURAL GAS COST OF SERVICE STUDY FLOWCHART



Pro Forma Results of Operations by Customer Group

1

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 - Purchased Gas Costs

The Company owns no natural gas production facilities serving the Washington jurisdiction. The natural gas costs included in the production function include the cost of gas purchased to serve sales customers, pipeline transportation to get it to our system, and expenses of the gas supply department.

The demand and commodity components of account 804 have been determined directly from the weighted average cost of gas (WACOG) approved in the most recent purchased gas adjustment (PGA) filing effective November 1, 2008. The January 16, 2009 gas cost reduction to customer charges was accomplished through Schedule 155 which is excluded from base revenues. The allocation of the commodity portion of pro forma gas cost agrees with the WACOG based computation of commodity-related gas costs. Likewise, the allocation of the demand portion of pro forma gas cost agrees with the WACOG based computation demand-related gas costs. Gas research contributions have been assigned to sales schedules by test period sales volumes weighted by the GTI Voluntary Collection rates currently used to determine the contributions.

The expenses of the gas supply department recorded in accounts 813 are classified as commodity related costs. The gas scheduling dispatch process includes transportation customers, so estimated scheduling dispatch labor expenses are allocated by throughput. The remaining gas supply department expenses are allocated by sales volumes.

Underground Storage

Underground storage rate base, operating and maintenance expenses are classified as commodity related. Twenty percent of underground storage costs are allocated to customer groups by annual throughput, the remaining eighty percent are allocated by sales therms. This allocation methodology for underground storage costs matches the treatment of underground storage transportation costs in the last PGA filing. It is based on analysis, performed in conjunction with the Washington Natural (now PSE) Docket No. UG-940814, that evaluated the extent to which transportation customers utilized the Jackson Prairie underground storage facility.

Distribution Facilities Classification (Peak and Average)

Distribution mains and regulator station equipment (both general use and city gate stations) are classified as demand and commodity related using the peak and average ratio for the distribution system. Peak demand is defined as the average of the five-day sustained peaks from the most recent three years. Average daily load is calculated by dividing annual throughput by 365 (days in the year). The average daily load is divided by peak load to arrive at the system load factor of 39%. This proportion is classified as commodity related. The remaining 61% is classified as demand related. Meters, services and industrial measuring & regulating equipment are classified as customer related distribution plant. Distribution operating and maintenance expenses are classified (and allocated) in relation to the plant accounts they are associated with.

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 these costs are classified as customer related. Exceptions include uncollectible accounts expense, which is considered separately as a revenue conversion item, and Demand Side Management amortization expense recorded in Account 908. The demand side management investment costs

and amortization expense are included with the distribution function and classified to demand and commodity by the peak and average ratio.

Distribution Cost Allocation

Demand related distribution costs are allocated to customer groups (rate schedules) by each group's contribution to the three year average five-day sustained peak. Commodity related distribution costs are allocated to customer groups by annual throughput. Distribution main investment has been segregated into large and small mains. Small mains are defined as less than four inches, with large mains being four inches or greater. The small main costs use the same demand and commodity data, but large usage customers (Schedules 131 and 146) that connect to large system mains have been excluded from the allocations.

Most customer related costs are allocated by the annualized number of customers billed during the test period. Meter investment costs are allocated using the number of customers weighted by the relative current cost of meters in service at September 30, 2008. Services investment costs are allocated using the number of customers weighted by the relative current cost of typical service installations. Industrial measuring and regulating equipment investment costs are allocated by number of customers weighted by industrial meters at current cost.

Administrative and General Costs

General and intangible rate base items are allocated by the sum of Underground Storage and Distribution plant. Administrative and general expenses are segregated into plant related, labor related, revenue related and other. The plant related items are allocated based on total plant in service. Labor related items are allocated by operating and maintenance labor expense. Revenue related items are allocated by pro forma revenue. Other administrative and general expenses are allocated 50% by annual throughput (classified commodity related) and 50% by the

sum of operating and maintenance expenses not including purchased gas cost or administrative & general expenses. Whenever costs are allocated by sums of other items within the study, classifications are imputed from the relationship embedded in the summed items.

Special Contract Customer Revenue

Several special contract customers receive transportation service from the Company. Rates for these customers were individually negotiated to cover any incremental costs and retain some contribution to margin. The rates for these customers are not being adjusted in this case. The revenue from these special contract customers has been segregated from general rate revenue and allocated back to all the other rate classes by relative rate base. In treating these revenues like other operating revenues their system contribution reduces costs for all rate schedules.

Revenue Conversion Items

In this study uncollectible accounts, state excise tax, 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 the 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 assigned to cost categories by relative rate base (as is net income).

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

WUTC Docket No. UG-09 ____ Methodology Matrix
Avista Utilities Washington Jurisdiction
Natural Gas Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Underground Storage Plant			
1	350 - 357 Underground Storage	Underground Storage	Commodity to match PGA items	E01/E04 Annual Throughput / Annual Sales Therms
	Distribution Plant			
2	374 Land	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
3	375 Structures	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
4	376(S) Small Mains	Distribution	Demand/Commodity by Peak & Average	D02/E06 Coincident peak, annual therms (both excl lg use cust)
5	376(L) Large Mains	Distribution	Demand/Commodity by Peak & Average	D01/E01/D06/D07 Coincident peak (all), annual throughput (all), direct assign Sch 131, direct assign Sch 146
6	378 M&R General	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
7	379 M&R City Gate	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
8	380 Services	Distribution	Customer	C02, Customers weighted by current typical service cost
9	381 Meters	Distribution	Customer	C03, Customers weighted by average current meter cost
10	385 Industrial M&R	Distribution	Customer	C06, Customers weighted by industrial meter cost
11	387 Other	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
	General Plant			
12	389-399 All General Plant	Common	Demand/Commodity/Customer from UG & D Plant	S03 Sum of Underground Storage and Distribution Plant in Service
	Intangible Plant			
13	303 Misc Intangible Plant	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
14	303 Computer Software	Common	Demand/Commodity/Customer from UG & D Plant	S03 Sum of Underground Storage and Distribution Plant in Service
	Reserve for Depreciation			
15	Underground Storage	Underground Storage	Commodity same as related plant	Allocations linked to related plant accounts
16	Distribution	Distribution	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
17	General	Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
18	Intangible	Distribution/Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
	Other Rate Base			
19	Accumulated Deferred FIT	All	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
20	Constuction Advances	Distribution	Customer	C10 Residential only
21	Gas Inventory	Underground Storage	Commodity from Underground Storage Plant	S14 Sum of Underground Storage Plant in Service
22	Gain on Sale of Office Bldg	Common	Demand/Commodity/Customer from UG & D Plant	S03 Sum of Underground Storage and Distribution Plant in Service
23	DSM Investment	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
	Purchased Gas Expenses			
24	804 Purchased Gas Cost	Production	Demand/Commodity from PGA Tracker WACOG	D05/E07 PGA Demand / PGA Commodity
25	804 Gas Research Contributions	Production	Commodity	E08 GTI Expense (Weighted Annual Sales Therms)
26	807 Purchased Gas Expenses	Production	Commodity	E01/E04 Annual Throughput / Annual Sales Therms
27	813 Other Gas Expenses	Production	Commodity	E04 Annual Sales Therms

WUTC Docket No. UG-09 ____ Methodology Matrix
Avista Utilities Washington Jurisdiction
Natural Gas Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Underground Storage O&M			
1	814 - 837 Underground Storage Exp	Underground Storage	Commodity	E01/E04 Annual Throughput / Annual Sales Therms
	Distribution O&M			
2	870 OP Super & Engineering	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
3	871 Load Dispatching	Distribution	Commodity	E01 Annual throughput
4	874 Mains & Services	Distribution	Demand/Commodity/Customer from related plant	S06 Sum of Mains and Services Plant in Service
5	875 M&R Station - General	Distribution	Demand/Commodity from related plant	S08 Sum of Meas & Reg Station - General Plant in Service
6	876 M&R Station - Industrial	Distribution	Customer from related plant	S19 Sum of Meas & Reg Station - Industrial Plant in Service
7	877 M&R Station - City Gate	Distribution	Demand/Commodity from related plant	S09 Sum of Meas & Reg Station - City Gate Plant in Service
8	878 Meter & House Regulator	Distribution	Customer from related plant	S07 Sum of Meter and Installation Plant in Service
9	879 Customer Installations	Distribution	Customer	C05, Customers weighted by average current meter cost
10	880 Other OP Expenses	Distribution	Demand/Commodity/Customer from other dist expenses	S04 Sum of Accounts 870 - 879 and 881 - 894
11	881 Rents	Distribution	Demand/Commodity/Customer from other dist expenses	S04 Sum of Accounts 870 - 879 and 881 - 894
12	885 MT Super & Engineering	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
13	886 MT of Structures	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
14	887 MT of Mains	Distribution	Demand/Commodity from related plant	S21 Sum of Distribution Mains Plant in Service
15	889 MT of M&R General	Distribution	Demand/Commodity from related plant	S08 Sum of Meas & Reg Station - General Plant in Service
16	890 MT of M&R Industrial	Distribution	Customer from related plant	S19 Sum of Meas & Reg Station - Industrial Plant in Service
17	891 MT of M&R City Gate	Distribution	Demand/Commodity from related plant	S09 Sum of Meas & Reg Station - City Gate Plant in Service
18	892 MT of Services	Distribution	Customer from related plant	S20 Sum of Services Plant in Services
19	893 MT of Meters & Hs Reg	Distribution	Customer from related plant	S07 Sum of Meter and Installation Plant in Service
20	894 MT of Other Equipment	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
	Customer Accounting Expenses			
21	901 Supervision	Customer Relations	Customer	C01 All customers (unweighted)
22	902 Meter Reading	Customer Relations	Customer	C01 All customers (unweighted)
23	903 Customer Records & Collections	Customer Relations	Customer	C01 All customers (unweighted)
24	904 Uncollectible Accounts	Revenue Conversion	Revenue	R03 Retail Sales Revenue
25	905 Misc Cust Accounts	Customer Relations	Customer	C01 All customers (unweighted)
	Customer Service & Info Expenses			
26	907 Supervision	Customer Relations	Customer	C01 All customers (unweighted)
27	908 Customer Assistance	Customer Relations	Customer	C01 All customers (unweighted)
28	908 DSM Amortization	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
29	909 Advertising	Customer Relations	Customer	C01 All customers (unweighted)
30	910 Misc Cust Service & Info	Customer Relations	Customer	C01 All customers (unweighted)
	Sales Expenses			
31	911 - 916 Sales Expenses	Customer Relations	Customer	C01 All customers (unweighted)

WUTC Docket No. UG-09 ____ Methodology Matrix
Avista Utilities Washington Jurisdiction
Natural Gas Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Admin & General Expenses			
1	920 Salaries	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
2	921 Office Supplies	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
3	922 Admin Expenses Transferred	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
4	923 Outside Services	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
5	924 Property Insurance	Common	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
6	925 Injuries & Damages	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
7	926 Pensions & Benefits	Common	Demand/Commodity/Customer from Labpr O&M	S13 O&M Labor Expense
9	928 Regulatory Commision	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
10	928 Commission Fees	Revenue Conversion	Revenue	R01 Retail Sales Revenue
11	930 Miscellaneous General	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
12	931 Rents	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
13	931 CSS Rent	Customer Relations	Customer	C01 All customers (unweighted)
14	935 MT of General Plant	Common	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
	Depreciation Expense			
15	Underground Storage	Underground Storage	Commodity same as related plant	Allocations linked to related plant accounts
16	Distribution	Distribution	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
17	General	Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
18	Intangible	Distribution/Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
	Taxes			
19	Property Tax	All	Demand/Commodity/Customer from related plant	S14/S15/S16 Sum of UG Plant/Sum of Dist Plant/Sum of Gen Plant
20	Miscellaneous Dist Tax	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
21	State Excise Tax	Revenue Conversion	Revenue	R01 Retail Sales Revenue
22	Federal Income Tax	Revenue Conversion	Revenue	R02 Net Income before Taxes Less Interest Expense
23	Deferred FIT	Revenue Conversion	Revenue	R02 Net Income before Taxes Less Interest Expense
24	ITC	Revenue Conversion	Revenue	R02 Net Income before Taxes Less Interest Expense
	Operating Revenues			
25	Revenue from Rates	Revenue	Revenue	Pro Forma Revenue per Revenue Study
26	Special Contract Revenue	All	Demand/Commodity/Customer from Rate Base	S01 Sum of Rate Base
27	Off System Sales	Production	Commodity	E04 Sales Therms
28	Miscellaneous Service Revenue	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
29	Rent From Gas Property	All	Demand/Commodity/Customer from Rate Base	S01 Sum of Rate Base

Exhibit No. ___ (TLK-7)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-09_____

DOCKET NO. UG-09_____

EXHIBIT NO._____(TLK-7)

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

Sumcost
Company Base Case
UG Storage 80% Sales / 20% Throughput

AVISTA UTILITIES
Cost of Service General Summary
For the Twelve Months Ended September 30, 2008

Natural Gas Utility
Washington Jurisdiction

19-Jan-09

	(b)	(c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)
	Description		System Total	Residential Service Sch 101	Small Firm Service Sch 111	Large Firm Service Sch 121	Interrupt Service Sch 131	Transport Service Sch 146
	Plant In Service							
1	Production Plant							
2	Underground Storage Plant		22,826,000	14,996,828	6,329,832	842,401	82,740	574,200
3	Distribution Plant		253,055,000	194,962,848	46,769,001	4,556,471	216,352	6,550,328
4	Intangible Plant		3,334,000	2,539,852	639,652	64,827	3,553	86,115
5	General Plant		27,246,000	20,735,612	5,244,039	533,192	29,538	703,618
6	Total Plant In Service		306,461,000	233,235,139	58,982,524	5,996,892	332,184	7,914,261
	Accum Depreciation							
7	Production Plant							
8	Underground Storage Plant		(8,167,000)	(5,365,771)	(2,264,774)	(301,406)	(29,604)	(205,445)
9	Distribution Plant		(89,619,000)	(69,858,793)	(15,845,999)	(1,624,372)	(69,248)	(2,220,588)
10	Intangible Plant		(1,323,000)	(1,007,143)	(254,416)	(25,845)	(1,428)	(34,168)
11	General Plant		(10,274,000)	(7,819,044)	(1,977,437)	(201,058)	(11,138)	(265,322)
12	Total Accumulated Depreciation		(109,383,000)	(84,050,752)	(20,342,627)	(2,152,681)	(111,418)	(2,725,523)
13	Net Plant		197,078,000	149,184,388	38,639,897	3,844,211	220,766	5,188,738
14	Accumlulated Deferred FIT		(30,809,000)	(23,447,491)	(5,929,605)	(602,877)	(33,395)	(795,633)
15	Miscellaneous Rate Base		11,994,000	7,855,536	3,345,966	445,688	43,830	302,980
16	Total Rate Base		178,263,000	133,592,433	36,056,259	3,687,022	231,201	4,696,085
17	Revenue From Retail Rates		215,587,000	150,653,394	55,578,115	6,991,327	653,476	1,710,687
18	Other Operating Revenues		1,852,000	1,388,226	374,332	38,265	2,395	48,781
19	Total Revenues		217,439,000	152,041,621	55,952,447	7,029,592	655,872	1,759,469
	Operating Expenses							
20	Purchased Gas Costs		158,107,000	106,721,476	44,906,397	5,873,749	565,292	40,086
21	Underground Storage Expenses		410,000	269,373	113,696	15,131	1,486	10,314
22	Distribution Expenses		6,981,000	5,301,331	1,354,674	114,040	7,527	203,428
23	Customer Accounting Expenses		5,053,000	4,809,585	216,816	19,434	1,753	5,412
24	Customer Information Expenses		746,000	614,278	88,894	9,397	879	32,553
25	Sales Expenses		539,000	530,307	8,459	122	4	109
26	Admin & General Expenses		10,510,000	7,576,844	2,031,673	235,385	20,433	645,666
27	Total O&M Expenses		182,346,000	125,823,194	48,720,609	6,267,257	597,373	937,567
28	Taxes Other Than Income Taxes		10,609,000	7,535,099	2,605,804	318,657	28,308	121,132
29	Depreciation Expense							
30	Underground Storage Plant Depr		299,000	196,445	82,915	11,035	1,084	7,521
31	Distribution Plant Depreciation		5,268,000	4,249,923	822,831	73,289	4,179	117,778
32	General Plant Depreciation		1,804,000	1,372,937	347,216	35,303	1,956	46,588
33	Amortization of Intangible Plant		622,000	473,421	119,678	12,164	673	16,063
34	Total Depr & Amort Expense		7,993,000	6,292,726	1,372,640	131,792	7,892	187,951
35	Income Tax		4,077,000	3,067,988	792,245	72,813	5,647	138,307
36	Total Operating Expenses		205,025,000	142,719,007	53,491,298	6,790,519	639,219	1,384,957
37	Net Income		12,414,000	9,322,614	2,461,150	239,072	16,652	374,512
38	Rate of Return		6.96%	6.98%	6.83%	6.48%	7.20%	7.97%
39	Return Ratio		1.00	1.00	0.98	0.93	1.03	1.15
40	Interest Expense		6,150,000	4,608,884	1,243,926	127,201	7,976	162,013

Sumcost
Company Base Case
UG Storage 80% Sales / 20% Throughput

AVISTA UTILITIES
Summary by Function with Margin Analysis
For the Twelve Months Ended September 30, 2008

Natural Gas Utility
Washington Jurisdiction

19-Jan-09

	(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
	Functional Cost Components at Current Rates							
1	Production		165,442,628	111,672,991	46,989,902	6,146,271	591,520	41,945
2	Underground Storage		3,078,149	2,031,991	839,774	106,429	11,554	88,400
3	Distribution		32,572,828	26,327,595	4,987,662	432,503	26,079	798,990
4	Common		14,493,395	10,620,817	2,760,778	306,124	24,323	781,352
5	**Total Current Rate Revenue**		**215,587,000**	**150,653,394**	**55,578,115**	**6,991,327**	**653,476**	**1,710,687**
6	Exclude Cost of Gas w / Revenue Exp.		164,492,500	111,047,028	46,730,609	6,112,344	588,209	14,311
7	**Total Margin Revenue at Current Rates**		**51,094,500**	**39,606,366**	**8,847,507**	**878,983**	**65,268**	**1,696,377**
	Margin per Therm at Current Rates							
8	Production		$0.00472	$0.00528	$0.00518	$0.00509	$0.00506	$0.00109
9	Underground Storage		$0.01529	$0.01713	$0.01677	$0.01597	$0.01765	$0.00349
10	Distribution		$0.16176	$0.22191	$0.09960	$0.06490	$0.03984	$0.03155
11	Common		$0.07198	$0.08952	$0.05513	$0.04593	$0.03716	$0.03085
12	Total Current Margin Melded Rate per Therm		**$0.25374**	**$0.33383**	**$0.17668**	**$0.13189**	**$0.09971**	**$0.06698**
	Functional Cost Components at Uniform Current Return							
13	Production		165,442,628	111,672,991	46,989,902	6,146,271	591,520	41,945
14	Underground Storage		3,086,659	2,027,954	855,955	113,914	11,189	77,646
15	Distribution		32,564,716	26,301,078	5,050,279	453,040	25,561	734,758
16	Common		14,492,997	10,617,836	2,767,939	308,655	24,254	774,313
17	Total Uniform Current Cost		**215,587,000**	**150,619,859**	**55,664,075**	**7,021,880**	**652,523**	**1,628,663**
18	Exclude Cost of Gas w / Revenue Exp.		164,492,500	111,047,028	46,730,609	6,112,344	588,209	14,311
19	Total Uniform Current Margin		**51,094,500**	**39,572,831**	**8,933,466**	**909,536**	**64,314**	**1,614,352**
	Margin per Therm at Uniform Current Return							
20	Production		$0.00472	$0.00528	$0.00518	$0.00509	$0.00506	$0.00109
21	Underground Storage		$0.01533	$0.01709	$0.01709	$0.01709	$0.01709	$0.00307
22	Distribution		$0.16172	$0.22169	$0.10085	$0.06798	$0.03905	$0.02901
23	Common		$0.07197	$0.08950	$0.05527	$0.04631	$0.03705	$0.03057
24	Total Current Uniform Margin Melded Rate per Therm		**$0.25374**	**$0.33355**	**$0.17840**	**$0.13648**	**$0.09825**	**$0.06374**
25	**Margin to Cost Ratio at Current Rates**		**1.00**	**1.00**	**0.99**	**0.97**	**1.01**	**1.05**
	Functional Cost Components at Proposed Rates							
26	Production		165,437,870	111,669,779	46,988,550	6,146,094	591,503	41,944
27	Underground Storage		3,763,395	2,463,803	1,043,414	138,862	13,639	103,677
28	Distribution		36,380,286	29,163,884	5,775,664	521,486	29,029	890,224
29	Common		14,923,449	10,939,479	2,850,835	317,084	24,721	791,330
30	**Total Proposed Rate Revenue**		**220,505,000**	**154,236,944**	**56,658,464**	**7,123,526**	**658,891**	**1,827,175**
31	Exclude Cost of Gas w / Revenue Exp.		164,487,769	111,043,834	46,729,264	6,112,168	588,192	14,310
32	**Total Margin Revenue at Proposed Rates**		**56,017,231**	**43,193,110**	**9,929,200**	**1,011,357**	**70,699**	**1,812,865**
	Margin per Therm at Proposed Rates							
33	Production		$0.00472	$0.00528	$0.00518	$0.00509	$0.00506	$0.00109
34	Underground Storage		$0.01869	$0.02077	$0.02084	$0.02084	$0.02084	$0.00409
35	Distribution		$0.18067	$0.24582	$0.11534	$0.07825	$0.04435	$0.03515
36	Common		$0.07411	$0.09221	$0.05693	$0.04758	$0.03777	$0.03124
37	Total Proposed Margin Melded Rate per Therm		**$0.27819**	**$0.36406**	**$0.19828**	**$0.15176**	**$0.10801**	**$0.07158**
	Functional Cost Components at Uniform Proposed Return							
38	Production		165,437,870	111,669,779	46,988,550	6,146,094	591,503	41,944
39	Underground Storage		3,762,656	2,472,089	1,043,414	138,862	13,639	94,652
40	Distribution		36,380,813	29,218,316	5,775,664	521,486	29,029	836,319
41	Common		14,923,661	10,945,599	2,850,835	317,084	24,721	785,423
42	Total Uniform Proposed Cost		**220,505,000**	**154,305,782**	**56,658,464**	**7,123,526**	**658,891**	**1,758,337**
43	Exclude Cost of Gas w / Revenue Exp.		164,487,769	111,043,834	46,729,264	6,112,168	588,192	14,310
44	Total Uniform Proposed Margin		**56,017,231**	**43,261,948**	**9,929,200**	**1,011,357**	**70,699**	**1,744,027**
	Margin per Therm at Uniform Proposed Return							
45	Production		$0.00472	$0.00528	$0.00518	$0.00509	$0.00506	$0.00109
46	Underground Storage		$0.01869	$0.02084	$0.02084	$0.02084	$0.02084	$0.00374
47	Distribution		$0.18067	$0.24627	$0.11534	$0.07825	$0.04435	$0.03302
48	Common		$0.07411	$0.09226	$0.05693	$0.04758	$0.03777	$0.03101
49	Total Proposed Uniform Margin Melded Rate per Therm		**$0.27819**	**$0.36464**	**$0.19828**	**$0.15176**	**$0.10801**	**$0.06886**
50	**Margin to Cost Ratio at Proposed Rates**		**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.04**
51	**Current Margin to Proposed Cost Ratio**		**0.91**	**0.92**	**0.89**	**0.87**	**0.92**	**0.97**

Sumcost
Company Base Case
UG Storage 80% Sales / 20% Throughput

AVISTA UTILITIES
Summary by Classification with Unit Cost Analysis
For the Twelve Months Ended September 30, 2008

Natural Gas Utility
Washington Jurisdiction

19-Jan-09

	(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
	Cost by Classification at Current Return by Schedule							
1	Commodity		163,284,840	109,379,172	46,120,945	6,125,258	588,792	1,070,672
2	Demand		27,029,037	18,524,734	7,304,372	771,989	51,117	376,826
3	Customer		25,273,123	22,749,488	2,152,798	94,079	13,568	263,189
4	Total Current Rate Revenue		215,587,000	150,653,394	55,578,115	6,991,327	653,476	1,710,687
	Revenue per Therm at Current Rates							
5	Commodity		$0.81090	$0.92193	$0.92102	$0.91911	$0.89951	$0.04227
6	Demand		$0.13423	$0.15614	$0.14587	$0.11584	$0.07809	$0.01488
7	Customer		$0.12551	$0.19175	$0.04299	$0.01412	$0.02073	$0.01039
8	Total Revenue per Therm at Current Rates		$1.07064	$1.26982	$1.10988	$1.04907	$0.99833	$0.06754
	Cost per Unit at Current Rates							
9	Commodity Cost per Therm		$0.81090	$0.92193	$0.92102	$0.91911	$0.89951	$0.04227
10	Demand Cost per Peak Day Therms		$18.08	$19.01	$20.08	$21.26	$15.53	$3.22
11	Customer Cost per Customer per Month		$14.66	$13.41	$79.55	$241.23	$1,130.66	$756.29
	Cost by Classification at Uniform Current Return							
12	Commodity		163,289,564	109,369,989	46,157,758	6,142,288	588,274	1,031,256
13	Demand		27,034,917	18,516,305	7,334,259	782,360	50,896	351,097
14	Customer		25,262,519	22,733,565	2,172,058	97,233	13,353	246,310
15	Total Uniform Current Cost		215,587,000	150,619,859	55,664,075	7,021,880	652,523	1,628,663
	Cost per Therm at Current Return							
16	Commodity		$0.81092	$0.92185	$0.92176	$0.92167	$0.89872	$0.04072
17	Demand		$0.13426	$0.15607	$0.14646	$0.11740	$0.07776	$0.01386
18	Customer		$0.12546	$0.19162	$0.04338	$0.01459	$0.02040	$0.00973
19	Total Cost per Therm at Current Return		$1.07064	$1.26954	$1.11159	$1.05365	$0.99688	$0.06431
	Cost per Unit at Uniform Current Return							
20	Commodity Cost per Therm		$0.81092	$0.92185	$0.92176	$0.92167	$0.89872	$0.04072
21	Demand Cost per Peak Day Therms		$18.09	$19.01	$20.16	$21.54	$15.46	$3.00
22	Customer Cost per Customer per Month		$14.65	$13.40	$80.27	$249.31	$1,112.77	$707.79
23	**Revenue to Cost Ratio at Current Rates**		**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.05**
	Cost by Classification at Proposed Return by Schedule							
24	Commodity		164,858,779	110,358,561	46,582,969	6,198,877	591,730	1,126,642
25	Demand		28,388,973	19,425,978	7,680,345	816,908	52,371	413,371
26	Customer		27,257,248	24,452,405	2,395,149	107,741	14,791	287,162
27	Total Proposed Rate Revenue		220,505,000	154,236,944	56,658,464	7,123,526	658,891	1,827,175
	Revenue per Therm at Proposed Rates							
28	Commodity		$0.81871	$0.93019	$0.93025	$0.93016	$0.90400	$0.04448
29	Demand		$0.14098	$0.16374	$0.15337	$0.12258	$0.08001	$0.01632
30	Customer		$0.13536	$0.20610	$0.04783	$0.01617	$0.02260	$0.01134
31	Total Revenue per Therm at Proposed Rates		$1.09506	$1.30003	$1.13145	$1.06891	$1.00661	$0.07214
	Cost per Unit at Proposed Rates							
32	Commodity Cost per Therm		$0.81871	$0.93019	$0.93025	$0.93016	$0.90400	$0.04448
33	Demand Cost per Peak Day Therms		$18.99	$19.94	$21.11	$22.50	$15.91	$3.53
34	Customer Cost per Customer per Month		$15.81	$14.41	$88.51	$276.26	$1,232.56	$825.18
	Cost by Classification at Uniform Proposed Return							
35	Commodity		164,844,551	110,377,412	46,582,969	6,198,877	591,730	1,093,563
36	Demand		28,384,682	19,443,280	7,680,345	816,908	52,371	391,777
37	Customer		27,275,768	24,485,090	2,395,149	107,741	14,791	272,997
38	Total Uniform Proposed Cost		220,505,000	154,305,782	56,658,464	7,123,526	658,891	1,758,337
	Cost per Therm at Proposed Return							
39	Commodity		$0.81864	$0.93034	$0.93025	$0.93016	$0.90400	$0.04318
40	Demand		$0.14096	$0.16388	$0.15337	$0.12258	$0.08001	$0.01547
41	Customer		$0.13546	$0.20638	$0.04783	$0.01617	$0.02260	$0.01078
42	Total Cost per Therm at Proposed Return		$1.09506	$1.30061	$1.13145	$1.06891	$1.00661	$0.06943
	Cost per Unit at Uniform Proposed Return							
43	Commodity Cost per Therm		$0.81864	$0.93034	$0.93025	$0.93016	$0.90400	$0.04318
44	Demand Cost per Peak Day Therms		$18.99	$19.96	$21.11	$22.50	$15.91	$3.35
45	Customer Cost per Customer per Month		$15.82	$14.43	$88.51	$276.26	$1,232.56	$784.47
46	**Revenue to Cost Ratio at Proposed Rates**		**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.04**
47	**Current Revenue to Proposed Cost Ratio**		**0.98**	**0.98**	**0.98**	**0.98**	**0.99**	**0.97**