Classification and Allocation of Generation Fixed Costs
Discussion Paper
By: Dave Taylor
March 4, 2003

Introduction

One of the key questions to be resolved in the Multi State Process is that of classification and allocation of the fixed costs associated with generation resources. This is the case whether the final MSP resolution is based on a dynamic total system sharing of costs and resources as proposed by Utah, or whether the resolution is bases on a control area approach where resources are first directly assigned to the east and west control areas with a sharing of costs and resources separately in each control area. Even a direct assignment of resources to individual states requires a decision on classification and allocation to determine the shares of plants to assign to each state.

All parties to MSP agree that any classification and allocation of generation costs need to be based on principle of cost causation. Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For generation resources, cost causation attempts to determine what influences a utility's production plant investment decisions. In this process, classification relates to separating the portion of generation costs that are expended to meet the Company's peak demand requirements from the portion of generation costs that are expended to meet the Company's energy requirements. Allocation relates to the methods applied to apportion the demand and energy related components of generation costs between the states we serve. Often times the classification and allocation process get combined into a set of composite allocation factors that perform both steps of the process.

A wide variety of classification and allocation options are currently used by utilities across the country and Utah Power, Pacific Power and PacifiCorp have used several different methods in the past. Many of these methods, as well as a number of new alternatives have been discussed during MSP. Of the total system allocation options, the classification of plant between demand and energy components seems to have the largest impact on state revenue requirements. Larger energy classifications assign more costs to high load factor states while larger demand classifications assign more cost to lower load factor states. The choice of the 75% demand 25% energy classification for generation and transmission plant was the last allocation decision made by PITA after the merger.

Several states use the same classification and allocation procedures for both jurisdictional allocation and allocation of costs between customer classes. The classification of plant has even greater impacts on the allocation of costs between customer classes, which makes this an issue of great concern for the intervening industrial customers.

This paper reviews the methodologies used by PacifiCorp and its predecessors in the past, some of the methods used by other utilities, and those proposed by the participants in MSP.

Historical Perspective

Prior to the Utah Pacific merger, Pacific Power classified generation fixed costs as 50% demand related and 50% energy related. The demand component was allocated to states using an allocation factor based on the summation of each state's contribution to the system coincident peak for each of the 60 preceding months (60 CP). The energy component was allocated using each state's energy usage for the previous 24 months. This is shown in the example below:

PP&L Historical Generation Plant Jurisdictional Allocation Factor

	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	MERGED TOTAL
Sum of 12 CP's								
1997	7,504	26,572	1,743	10,005	5,063	1,369	30,615	82,871
1998	8,099	27,733	1,815	9,977	5,112	1,791	31,936	86,463
1999	8,295	26,903	2,029	9,118	5,197	1,748	32,273	85,563
2000	8,135	27,679	1,719	9,567	5,146	1,760	34,786	88,791
2001	7,778	26,754	1,539	10,551	5,108	1,978	35,071	88,780
60 CP	39,811	135,640	8,845	49,218	25,626	8,646	164,680	432,468
60 CP Factor	9.2%	31.4%	2.0%	11.4%	5.9%	2.0%	38.1%	100.0%
Total Retail MWh								
2000	4,540,498	15,603,612	925,786	6,345,974	3,419,263	1,225,410	20,284,781	52,345,325
2001	4,413,518	15,025,360	865,652	7,083,751	3,406,870	1,366,799	20,070,975	52,232,925
24 Months of Energy	8,954,016	30,628,972	1,791,438	13,429,725	6,826,133	2,592,210	40,355,756	104,578,250
24 Months Energy Factor	8.6%	29.3%	1.7%	12.8%	6.5%	2.5%	38.6%	100.0%
Composite Factor								
Generation Plant Factor	8.9%	30.3%	1.9%	12.1%	6.2%	2.2%	38.3%	100.0%
Allocation Factor = 60 CP Factor X 50% + 24 Month Energy Factor X 50%								

Prior to the merger, Utah Power classified all generation fixed costs as 100% demand related and allocated those costs using each states contributions to the system coincident peak for the eight critical months of the test period (8 CP) with March, April, May, and October being excluded.

Old Utah Power Generation Allocation Factor

2001

Month	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total System
January	723,744	2,739,428	142,784	888,677	370,179	175,778	2,652,253	7,692,843
February	687,411	2,689,629	146,431	901,580	341,777	175,579	2,652,713	7,595,120
March								
April								
May								
June	681,653	2,123,911	152,418	882,970	491,283	152,048	3,110,502	7,594,785
July	656,533	1,986,895	128,961	891,751	564,363	161,343	3,463,757	7,853,603
August	627,146	2,121,632	124,452	934,472	420,647	156,288	3,514,018	7,898,655
September	626,812	1,923,541	119,509	881,017	391,106	150,279	3,208,631	7,300,895
October								
November	670,076	2,169,395	118,765	897,491	410,725	170,314	2,981,676	7,418,442
December	691,537	2,346,343	131,577	900,452	422,902	178,549	3,017,000	7,688,360
8 CP	5,364,912	18,100,774	1,064,897	7,178,410	3,412,982	1,320,178	24,600,550	61,042,703
8 CP Factor	8.8%	29.7%	1.7%	11.8%	5.6%	2.2%	40.3%	100.0%

Since the merger PacifiCorp has classified generation fixed costs as 75% demand related and 25% energy related with the demand component being allocated using contributions to the system coincident peak all 12 months of the year. Because of the different cost basis of the Pacific Power and Utah Power fleet of plants, the investment in generation resources (Pre Merger Investment) that each company brought to the merger continued to be allocated separately to the Pacific Power and Utah Power states. All new investment in generation resources (Post Merger Investment) is allocated system wide. This is shown in the example below:

Current PacifiCorp Generation Plant Allocation Factor (Modified Accord)								
Pre Merger Investment								
	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	TOTAL
Sum of 12 CP's								
2001	7,778	26,754	1,539	10,551	5,108	1,978	35,071	88,780
Division Capacity Pacific (DC-P)	16.7%	57.4%	3.3%	22.6%				100.0%
Division Capacity Utah (DC-U)					12.1%	4.7%	83.2%	100.0%
Total Retail MWh								
2001	4,413,518	15,025,360	865,652	7,083,751	3,406,870	1,366,799	20,070,975	52,232,925
Division Energy Pacific (DE-P)	16.1%	54.9%	3.2%	25.9%				100.0%
Division Energy Utah (DE-U)					13.7%	5.5%	80.8%	100.0%
Composite Factor								
Division Generation Pacific (DG-P)	16.5%	56.8%	3.3%	23.4%	0.0%	0.0%	0.0%	100.0%
Division Generation Utah (DG-U)	0.0%	0.0%	0.0%	0.0%	12.5%	4.9%	82.6%	100.0%
Allocation Factor = 12 CP Factor X 75% + Energy Factor X 25%								
Post Merger Investment								
	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	MERGED TOTAL
Sum of 12 CP's								
2001	7,778	26,754	1,539	10,551	5,108	1,978	35,071	88,780
System Capacity (SC)	8.8%	30.1%	1.7%	11.9%	5.8%	2.2%	39.5%	100.0%
Total Retail MWh								
2001	4,413,518	15,025,360	865,652	7,083,751	3,406,870	1,366,799	20,070,975	52,232,925
System Energy Factor (SE)	8.4%	28.8%	1.7%	13.6%	6.5%	2.6%	38.4%	100.0%
Composite Factor								
System Generation Factor (SG)	8.7%	29.8%	1.7%	12.3%	5.9%	2.3%	39.2%	100.0%
Allocation Factor = 12 CP Factor X 75% + Energy Factor X 25%								

The choice of the 75% demand 25% energy classification for generation and transmission plant was the last allocation decision made by PITA after the merger. The PITA analysis indicated that a wide range of demand and energy classification could be supported on a technical basis. The demand energy classification was the swing issue employed to balance the sharing of merger benefits between all the states and 75% demand 25% energy was selected because it produced an overall cost allocation result that was acceptable to all the states.

Methods used by other Utilities

The Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners (NARUC) combines their discussion of classification and allocation alternatives for generation resources. The manual lists a range of alternatives, most of which are used by some utilities. While the Cost Allocation Manual was published as a guide for allocation of costs between customer classes, the cost causation principles discussed should also be applicable to jurisdictional allocation.

Cost Accounting Approach

The cost accounting approach identifies all production costs as either fixed or variable. The assumption is that plant capacity is built to meet peak demand and once it is built it is fixed. Therefore all fixed costs are considered demand related and variable costs are considered energy related. The demand related costs are allocated using class, or state, contributions to system peak (CP). The allocation can use the single system annual peak, or it can use the monthly system peak from more than one month of the year. The three common methods are the single peak, summer winter average peak, and the sum of all 12 CPs. The use of all twelve monthly CPs has been adopted by FERC and seems to be the most common among electric utilities.

100% Demand Factors										
	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
1 CP Factor	100%	0%	8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
12 CP			8,067,405	27,115,372	1,746,245	9,824,030	5,190,516	1,812,264	34,259,181	88,015,012
12 CP Factor	100%	0%	9.17%	30.81%	1.98%	11.16%	5.90%	2.06%	38.92%	100.00%
Summer / Winter CP			1,443,622	4,672,892	309,461	1,689,646	957,261	322,124	6,509,073	15,904,079
Summer / Winter CP Factor	100%	0%	9.08%	29.38%	1.95%	10.62%	6.02%	2.03%	40.93%	100.00%

Peak and Average

The Peak and Average method considers that average demand (or annual energy usage / 8760) is a significant cost driver along with coincident peak demand. Under the peak and average method, the demand related classification of fixed costs is calculated by dividing the system annual CP by the sum of the annual CP and the average demand (CP / (CP + average demand)). The demand component is allocated using each state's contribution to the system single coincident peak. For PacifiCorp, this method classifies 60% of fixed generation costs as demand related compared to the 75% used today.

Peak & Average (1 CP)										
	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
Average MW (MWh / 8760)			516,055	1,744,790	112,149	746,574	386,399	143,767	2,276,339	5,926,074
Demand Component Demand Allocation Factor Single CP / (CP + (MWh/8760))	58%		8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
Energy Component Average MW Component Allocation Factor (1 - Demand		42%	8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Total Allocation Factor	58%	42%	8.83%	28.27%	1.97%	11.27%	6.65%	2.10%	40.91%	100.00%

Average and Excess

The Average and Excess method also considers that average demand to be a significant cost driver, and that excess demand (individual class or state NCP less average demand) drives the demand component. Under the average and excess method, the energy related component of fixed costs is determined to be equal to the system annual load factor. The demand component is allocated using each state's excess demand, annual non-coincident peak (NCP) less average annual demand (annual MWh / 8760). For PacifiCorp, this method would classify 70% to 75% of fixed generation costs as energy related compared to the 25% used today. This method was proposed by Utah Power in the 1980s and rejected by the three state commissions in favor of the 8 CP method.

Average & Excess											
	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual NCP			782,957	2,639,481	188,904	897,121	671,089	184,209	3,502,529	8,866,290
Average MW (MWh / 8760)			516,055	1,744,790	112,149	746,574	386,399	143,767	2,276,339	5,926,074
Excess MW			266,902	894,690	76,755	150,547	284,690	40,443	1,226,189	2,940,216
Average MW Component Allocation Factor (System Annual		73%	8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Excess Demand Component Allocation Factor (1 - SALF)	27%		9.08%	30.43%	2.61%	5.12%	9.68%	1.38%	41.70%	100.00%
Total Allocation Factor	27%	73%	8.81%	29.71%	2.09%	10.58%	7.37%	2.14%	39.30%	100.00%

Equivalent Peaker Method

The premises of this methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and base load units because of the additional energy loads they must serve. Thus, the cost of peaking capacity is regarded as peak demand-related and classified as demand-related. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related. The demand related component is generally allocated using the single system peak or the loads during the narrow peak period. The Company currently uses the equivalent peaker method in its avoided cost and marginal cost studies. Based on information in the current IRP, this method would classify about 40% of generation fixed cost as demand related and 60% as energy related.

Equivalent Peaker 1 CP										
	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
1 CP Factor	38%		8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
Annual Energy		62%	4,520,645,706	15,284,363,431	982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
Energy Factor			8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Compopsite Factor	38%	62%	8.79%	28.67%	1.94%	11.73%	6.60%	2.21%	40.05%	100.00%

Base – Intermediate – Peak (BIP) Method

Under the BIP Method, base load plants are classified with a large energy component and allocated across all months of the year. Intermediate or Mid-range resources costs are assigned to individual months of the year based according to the operating hours in a given month and allocated using loads in each particular month. Peaking units are more heavily classified as demand related and allocated only to the months when the peaking resources are dispatched to meet retail load. The Oregon PUC Staff has proposed this method as one alternative in MSP.

Attachment 1 summarizes some of the available approaches for classification of generation fixed costs Attachment 2 contains a summary of the methods used by a small sample of utilities. Attachment 3 shows examples of the allocation methods discussed in this paper applied to PacifiCorp loads.

Classification Options for Generation Fixed Costs

PacifiCorp Total Retail Load Data (1999 - 2001 Average)						
Annual Energy	Average Demand	Annual CP	Min Load Hour	12 Monthly CP	1 CP Load Factor	12 CP Load Factor
MWH	MWA	MW	MW	MW		
51,912,407	5,926	8,117	4,142	88,015	73%	81%

Classification Methods

Method	**Current PacifiCorp Method**	Demand	75%
		Energy	25%
Basis for Method	Agreed upon by PITA because it meet a balance of objectives, including sharing of merger benefits		
Calculation	Demand component deemed to be 75%		

Method	**Cost Accounting Method**	Demand	100%
		Energy	0%
Basis for Method	Plant capacity is built to meet peak demand, once it is built it is fixed		
Calculation	100% of fixed costs are demand related		

Method	**Average & Excess Method**	Demand	27%
		Energy	73%
Basis for Method	Energy component equal to system load factor %		
Calculation	Energy component % = Annual MWH / 8760 / 1CP		

Method	**Peak & Average (Single CP)**	Demand	58%
		Energy	42%
Basis for Method	Demand Component equal to Peak Demand divided by Sum of Peak and Average Demand		
Calculation	Demand Component % = 1CP / (1CP + (Annual MWH / 8760))		

Method	**Peak & Average (12 CP)**	Demand	55%
		Energy	45%
Basis for Method	Demand Component equal Peak Demand divided by Sum of Peak and Average Demand		
Calculation	Demand Component % = (12CP/12) / ((12CP/12) + (Annual MWH / 8760))		

Method	**Peak & Average (12 CP + 1)**	Demand	92%
		Energy	8%
Basis for Method	The Energy Component has equal value to each of the monthly peaks		
Calculation	Demand Component equal to 12/13 of Fixed Costs. Energy Component equal to 1/13 of Fixed Costs		

Method	**Base - Intermediate - Peak (BIP) Method**	Demand - Base	25%
		Energy - Base	75%
		Demand - Int	50%
		Energy - Int	50%
		Demand - Peak	75%
		Energy - Peak	25%
Basis for Method	Proposed by Oregon PUC Staff. Similar to Equivalent Peaker Method		
Calculation			

Method	**Production Stacking Method**	Demand - Base	49%
		Energy - Base	51%
		Demand - Peak	100%
		Energy - Peak	0%
Basis for Method	Generation needed to serve base load energy requirements is classified as energy related. Remaining plant is classified as demand related		
Calculation	Base Load Energy Component % = Min Load Hour / 1CP		

Method	**Equivalent Peaker Method 1**	Demand - Coal	38%
		Energy - Coal	62%
		Demand - CCCT	94%
		Energy - CCCT	6%
		Demand - SCCT	100%
		Energy - SCCT	0%
Basis for Method	Increases in peak demand require the addition of peaking capacity only, costs of more expensive units are because		

Classification Options for Generation Fixed Costs

PacifiCorp Total Retail Load Data (1999 - 2001 Average)						
Annual Energy	Average Demand	Annual CP	Min Load Hour	12 Monthly CP	1 CP Load Factor	12 CP Load Factor
MWH	MWA	MW	MW	MW		
51,912,407	5,926	8,117	4,142	88,015	73%	81%

Classification Methods

Calculation	Demand Component % = Annual $ MW SCCT / Annual $ MW Actual Unit

PacifiCorp
2003 Integrated Resource Plan
Potential Resource Cost
Demand & Energy Related Components of Fixed & Variable Costs
Generation Costs Only

Equivalent Peaker Method					
		Convert to Mills		Total	Total
Description	Ttl Fixed $/kW-Yr	Expected Utilization	Ttl Fixed Mills/kWh	Variable Costs Mills/kWh	Resource Cost Mills/kWh
Simple Cycle Turbine					
Average IRP Costs	$ 58.32	16%	46.91	65.02	111.92
Demand Related Costs	$ 58.32	16%	$ 46.91	$ -	$ 46.91
Energy Related Costs	$ -	16%	$ -	$ 65.02	$ 65.02
Demand Related %	100%		100%	0%	42%
Energy Related %	0%		0%	100%	58%
Combined Cycle Turbine					
Average IRP Costs	$ 62.07	80%	8.94	33.56	42.50
Demand Related Costs	$ 58.32	80%	$ 8.40	$ -	$ 8.40
Energy Related Costs	$ 3.75	80%	$ 0.54	$ 33.56	$ 34.10
Demand Related %	94%		94%	0%	20%
Energy Related %	6%		6%	100%	80%
Base Load Coal					
Average IRP Costs	$ 154.72	91%	19.41	17.35	36.76
Demand Related Costs	$ 58.32	91%	$ 7.32	$ -	$ 7.32
Energy Related Costs	$ 96.40	91%	$ 12.09	$ 17.35	$ 29.44
Demand Related %	38%		38%	0%	20%
Energy Related %	62%		62%	100%	80%

Other Options for Base Load Coal					
Demand Related Costs	$ 154.72	91%	$ 19.41	$ -	$ 19.41
Energy Related Costs	$ -	91%	$ -	$ 17.35	$ 17.35
Demand Related %	100%		100%	0%	53%
Energy Related %	0%		0%	100%	47%
Demand Related Costs	$ 116.04	91%	$ 14.56	$ -	$ 14.56
Energy Related Costs	$ 38.68	91%	$ 4.85	$ 17.35	$ 22.20
Demand Related %	75%		75%	0%	40%
Energy Related %	25%		25%	100%	60%
Demand Related Costs	$ 77.36	91%	$ 9.70	$ -	$ 9.70
Energy Related Costs	$ 77.36	91%	$ 9.70	$ 17.35	$ 27.05
Demand Related %	50%		50%	0%	26%
Energy Related %	50%		50%	100%	74%
Demand Related Costs	$ 38.68	91%	$ 4.85	$ -	$ 4.85
Energy Related Costs	$ 116.04	91%	$ 14.56	$ 17.35	$ 31.91
Demand Related %	25%		25%	0%	13%
Energy Related %	75%		75%	100%	87%

Utility Classification/Allocation Survey Results

Utility	Classification/Allocation Method	Methodology Basis
Avista Utilities	Peak Credit Method; Base Load Plant - estimated replacement cost, usually 25-30% Demand. Peaking Plant - 100% Demand.	Unsure of history; used for > 20 years.
Consumer Power	12 Coincident Peak; 75% Demand/25% Energy	Commission order issued in 1976.
Duke Power	1 Coincident Peak (summer); 100% Demand	Used for >10 Years.
Georgia Power	12 Coincident Peak; 100% Demand	Commission order.
Gulf Power (South Carolina)	12 Coincident Peak; 12/13 Demand, 1/13 Energy	Commission order.
Idaho Power Company	60% Demand / 40% Energy	Commission accepted; used for years.
New York State Gas & Electric	Fully unbundled - no longer own generation plant.	N/A
Public Service Group (New Jersey)	Fully unbundled - no longer own generation plant.	N/A
Puget Sound Energy	Peak Credit Method Demand 16%, Energy 84% of total production costs. Demand Component allocated on system 200 peak hours. Energy based on class temperature and loss-adjusted energy use.	Commission order issued in 1987. Demand = 1/2 fixed costs of SCCT
Salt River Project	Ave & Excess; system average load factor used to determine energy component. Approx. 55% Energy, 45% Demand	Determined by Board of Directors.
Southern Company (S. Carolina)	12 Coincident Peak; 100% Demand	Commission order; used for approx. 20 years.
Virginia Power (North Carolina)	Summer/Winter Ave Peak; 100% Demand	Commission order issued in early 1980's.
Virginia Power (Virginia)	Ave & Excess; 100% Demand	Commission order issued in 1970's.

PacifiCorp Allocation Factor Options
1999 - 2001 (3 Year Average)

Values

			PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual Energy			4,520,645,706	15,284,363,431	982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
Annual NCP			782,957	2,639,481	188,904	897,121	671,089	184,209	3,502,529	8,866,290
12 CP			8,067,405	27,115,372	1,746,245	9,824,030	5,190,516	1,812,264	34,259,181	88,015,012
12 Mo. X 10 Top Hrs			78,718,279	265,785,252	17,278,526	96,911,310	50,988,550	18,132,475	339,174,561	866,988,953
Summer / Winter CP			1,443,622	4,672,892	309,461	1,689,646	957,261	322,124	6,509,073	15,904,079
Summer 3 / Winter 3 CP			4,257,445	14,055,127	944,166	4,995,627	2,814,373	934,102	18,206,956	46,207,797
Summer 3 / Winter 3 X Top 10 Hrs			41,588,486	137,363,948	9,195,820	49,236,321	27,816,554	9,291,642	181,116,815	455,609,587
Top 200 Hours			137,595,882	428,580,566	31,188,789	162,247,386	102,228,607	29,841,039	633,740,345	1,525,422,614
Minimum System Load Hour			320,600	1,136,707	66,520	686,920	293,975	132,074	1,504,743	4,141,540

Load Factors

			PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
12 CP			77%	77%	77%	91%	89%	95%	80%	81%
1 CP			71%	78%	68%	89%	71%	95%	66%	73%
1 NCP			66%	66%	59%	83%	58%	78%	65%	

PacifiCorp Allocation Factor Options
1999 - 2001 (3 Year Average)

Allocation Factors

Energy Factor	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual Energy			4,520,645,706	15,284,363,431	982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
Energy Factor	0%	100%	8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%

100% Demand Factors	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual NCP			782,957	2,639,481	188,904	897,121	671,089	184,209	3,502,529	8,866,290
1 NCP Factor	100%	0%	8.83%	29.77%	2.13%	10.12%	7.57%	2.08%	39.50%	100.00%
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
1 CP Factor	100%	0%	8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
Top 200 Hours			137,595,882	428,580,566	31,188,789	162,247,386	102,228,607	29,841,039	633,740,345	1,525,422,614
Top 200 Hrs Factor	100%	0%	9.02%	28.10%	2.04%	10.64%	6.70%	1.96%	41.55%	100.00%
12 CP			8,067,405	27,115,372	1,746,245	9,824,030	5,190,516	1,812,264	34,259,181	88,015,012
12 CP Factor	100%	0%	9.17%	30.81%	1.98%	11.16%	5.90%	2.06%	38.92%	100.00%
12 Mo. X 10 Top Hrs			78,718,279	265,785,252	17,278,526	96,911,310	50,988,550	18,132,475	339,174,561	866,988,953
12 CP X 10 Top Hrs Factor	100%	0%	9.08%	30.66%	1.99%	11.18%	5.88%	2.09%	39.12%	100.00%
Summer / Winter CP			1,443,622	4,672,892	309,461	1,689,646	957,261	322,124	6,509,073	15,904,079
Summer / Winter CP Factor	100%	0%	9.08%	29.38%	1.95%	10.62%	6.02%	2.03%	40.93%	100.00%
Summer 3 / Winter 3 CP			4,257,445	14,055,127	944,166	4,995,627	2,814,373	934,102	18,206,956	46,207,797
Summer 3 / Winter 3 CP Factor	100%	0%	9.21%	30.42%	2.04%	10.81%	6.09%	2.02%	39.40%	100.00%
Summer 3 / Winter 3 X Top 10 Hrs			41,588,486	137,363,948	9,195,820	49,236,321	27,816,554	9,291,642	181,116,815	455,609,587
Summer 3 / Winter 3 X Top 10 Factor	100%	0%	9.13%	30.15%	2.02%	10.81%	6.11%	2.04%	39.75%	100.00%

PacifiCorp Allocation Factor Options
1999 - 2001 (3 Year Average)

Composite Demand / Energy Factors

12 CP Annual Energy Composite

	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
12 CP			8,067,405	27,115,372	1,746,245	9,824,030	5,190,516	1,812,264	34,259,181	88,015,012
12 CP Factor			9.17%	30.81%	1.98%	11.16%	5.90%	2.06%	38.92%	100.00%
Annual Energy			4,520,645,706	15,284,363,431	982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
Energy Factor			8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Composite Factor	75%	25%	9.05%	30.47%	1.96%	11.52%	6.05%	2.15%	38.80%	100.00%
Composite Factor	50%	50%	8.94%	30.13%	1.94%	11.88%	6.21%	2.24%	38.67%	100.00%
Composite Factor	25%	75%	8.82%	29.78%	1.92%	12.24%	6.36%	2.33%	38.54%	100.00%

1 CP Annual Energy Composite

	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
1 CP Factor			8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
Annual Energy			4,520,645,706	15,284,363,431	982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
Energy Factor			8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Composite Factor	75%	25%	8.87%	27.93%	1.99%	10.88%	6.69%	2.00%	41.65%	100.00%
Composite Factor	50%	50%	8.82%	28.43%	1.96%	11.45%	6.63%	2.14%	40.57%	100.00%
Composite Factor	25%	75%	8.76%	28.94%	1.92%	12.02%	6.58%	2.28%	39.49%	100.00%

1 NCP Annual Energy Composite

	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual NCP			782,957	2,639,481	188,904	897,121	671,089	184,209	3,502,529	8,866,290
1 NCP Factor			8.83%	29.77%	2.13%	10.12%	7.57%	2.08%	39.50%	100.00%
Annual Energy			4,520,645,706	15,284,363,431	982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
Energy Factor			8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Composite Factor	75%	25%	8.80%	29.69%	2.07%	10.74%	7.31%	2.16%	39.23%	100.00%
Composite Factor	50%	50%	8.77%	29.61%	2.01%	11.36%	7.04%	2.25%	38.96%	100.00%
Composite Factor	25%	75%	8.74%	29.52%	1.95%	11.98%	6.78%	2.34%	38.69%	100.00%

PacifiCorp Allocation Factor Options
1999 - 2001 (3 Year Average)

Average & Excess

	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual NCP			782,957	2,639,481	188,904	897,121	671,089	184,209	3,502,529	8,866,290
Average MW (MWh / 8760)			516,055	1,744,790	112,149	746,574	386,399	143,767	2,276,339	5,926,074
Excess MW			266,902	894,690	76,755	150,547	284,690	40,443	1,226,189	2,940,216
Average MW Component Allocation Factor (System Annual Load Factor)		73%	8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Excess Demand Component Allocation Factor (1 - SALF)	27%		9.08%	30.43%	2.61%	5.12%	9.68%	1.38%	41.70%	100.00%
Total Allocation Factor	27%	73%	8.81%	29.71%	2.09%	10.58%	7.37%	2.14%	39.30%	100.00%

Peak & Average (1 CP)

	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
Average MW (MWh / 8760)			516,055	1,744,790	112,149	746,574	386,399	143,767	2,276,339	5,926,074
Demand Component Demand Allocation Factor Single CP / (CP + (MWh/8760))	58%		8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
Energy Component Average MW Component Allocation Factor (1 - Demand Component)		42%	8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Total Allocation Factor	58%	42%	8.83%	28.27%	1.97%	11.27%	6.65%	2.10%	40.91%	100.00%

Peak & Average (12 CP)

	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Average of 12 CP			672,284	2,259,614	145,520	818,669	432,543	151,022	2,854,932	7,334,584
Average MW (MWh / 8760)			516,055	1,744,790	112,149	746,574	386,399	143,767	2,276,339	5,926,074
Demand Component Demand Allocation Factor Ave 12 CP / (Ave 12CP + (MWh/8760))	55%		9.17%	30.81%	1.98%	11.16%	5.90%	2.06%	38.92%	100.00%
Energy Component Average MW Component Allocation Factor (1 - Demand Component)		45%	8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Total Allocation Factor	55%	45%	8.96%	30.20%	1.94%	11.80%	6.18%	2.22%	38.70%	100.00%

PacifiCorp Allocation Factor Options
1999 - 2001 (3 Year Average)

Equivalent Peaker 1 CP										
	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
1 CP Factor			8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
Annual Energy			4,520,645,706	15,284,363,431	982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
Energy Factor			8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Composite Factor	38%	62%	8.79%	28.67%	1.94%	11.73%	6.60%	2.21%	40.05%	100.00%

Equivalent Peaker Summer Winter CP										
	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Summer / Winter CP			1,443,622	4,672,892	309,461	1,689,646	957,261	322,124	6,509,073	15,904,079
Summer / Winter CP Factor			9.08%	29.38%	1.95%	10.62%	6.02%	2.03%	40.93%	100.00%
Annual Energy			4,520,645,706	15,284,363,431	982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
Energy Factor			8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Composite Factor	38%	62%	8.85%	29.42%	1.91%	11.85%	6.33%	2.27%	39.37%	100.00%

Systemwide
Rationalized Indicators of System Demand Stress
Sorted by Year (w/o Emergency Purchases)

Months/Year	Firm Peak Demand (A)	Probability of Contribution to Peak (B)	Cost to Bring Reserve Margin To 15% (C)	Average of (A) (B) & (C) = (D)	Weighted Average of (A)*2 (B) & (C) = (E)
FY 2004					
April	83%	0%	25%	36%	48%
May	86%	14%	47%	49%	58%
June	92%	59%	46%	66%	72%
July	100%	100%	97%	99%	99%
August	99%	99%	100%	99%	99%
September	93%	35%	54%	60%	68%
October	86%	10%	12%	36%	49%
November	89%	29%	21%	46%	57%
December	93%	82%	46%	74%	79%
January	92%	89%	37%	73%	77%
February	90%	47%	22%	53%	62%
March	86%	7%	45%	46%	56%
FY 2005					
April	83%	0%	28%	37%	49%
May	86%	10%	43%	46%	56%
June	93%	57%	57%	69%	75%
July	100%	95%	94%	96%	97%
August	100%	95%	100%	98%	99%
September	94%	40%	67%	67%	74%
October	86%	7%	15%	36%	49%
November	93%	58%	48%	67%	73%
December	95%	100%	57%	84%	87%
January	92%	89%	39%	73%	78%
February	93%	73%	45%	70%	76%
March	90%	20%	57%	56%	64%
FY 2006					
April	83%	0%	33%	39%	50%
May	85%	8%	44%	46%	55%
June	92%	57%	69%	73%	78%
July	100%	92%	93%	95%	96%
August	100%	98%	100%	99%	99%
September	94%	39%	72%	68%	75%
October	86%	5%	16%	36%	48%
November	92%	45%	39%	59%	67%
December	95%	93%	49%	79%	83%
January	94%	100%	42%	79%	82%
February	95%	86%	49%	77%	81%
March	91%	24%	57%	57%	66%
FY 2007					
April	80%	0%	23%	34%	46%
May	86%	8%	53%	49%	59%
June	91%	49%	65%	68%	74%
July	99%	88%	92%	93%	95%
August	100%	100%	100%	100%	100%
September	94%	32%	71%	66%	73%
October	83%	0%	8%	30%	43%
November	89%	22%	31%	47%	58%
December	91%	54%	39%	62%	69%
January	90%	80%	36%	69%	74%
February	92%	57%	41%	63%	70%
March	87%	7%	47%	47%	57%
FY 2008					
April	81%	0%	15%	32%	44%
May	88%	16%	46%	50%	59%
June	93%	55%	61%	70%	76%
July	99%	83%	93%	92%	94%
August	100%	85%	100%	95%	96%
September	91%	29%	61%	60%	68%
October	87%	4%	30%	40%	52%
November	92%	43%	49%	61%	69%
December	94%	86%	57%	79%	83%
January	94%	100%	55%	83%	86%
February	93%	58%	48%	66%	73%
March	88%	13%	56%	52%	61%

PacifiCorp
Exhibit No. 14
Case No. PAC-E-02-3
Witness: David L. Taylor

PacifiCorp
Ancillary Service Contract Example
Effect on Revenue Requirement

	Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1 **Loads**					
2 Sum of 12 monthly CP demand (MW) (Firm and Interruptible)		72,000	24,000	36,000	12,000
3 Annual Energy (MWh) (Firm and Interruptible)		42,000,000	14,000,000	21,000,000	7,000,000
4 Operating Reserve interruptible sum of CPs (MW)		1,200	-	-	1,200
5 Economic Curtailment Option sum of 12 CPs (MW)		900	-	900	-
6 Economic Curtailment Annual Energy (MWh)		37,500	-	37,500	-
7					
8 **Allocation Factors**					
9 SE factor (includes "interruptible" load)	SE	100%	33%	50%	17%
10 SC factor (includes "interruptible" load)	SC	100%	33%	50%	17%
11 SG factor (includes "interruptible" load)	SG	100%	33%	50%	17%
12					
13					
14	**No Ancillary Service Contracts**				
15					
16 **Cost of Service**					
17 Energy Cost	SE	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
18 Demand Related Costs	SG	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
19 Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
20					
21 **Revenues**					
22 Special Contract Revenue	Situs	$ 60,000,000		$ 20,000,000	$ 40,000,000
23 **Revenues from all other customers**	Situs	**$ 1,440,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 210,000,000**
24					
25					
26	**With Ancillary Service Contracts**				
27					
28 **Contract A**					
29 Tariff Equivalent Revenue					$ 40,000,000
30 Discount for 100 MW of Operating Reserves					$ (4,000,000)
31 Net Cost to Contract Customer					$ 36,000,000
32					
33 **Contract B**				$ 20,000,000	
34 Tariff Equivalent Revenue				$ (3,000,000)	
35 Discount for 75 MW X 500 Hours of Economic Curtailment				$ 17,000,000	
36 Net Cost to Contract Customer					
37					
38 **Cost of Service**					
39 Energy Cost	SE	$ 498,500,000	$ 166,166,667	$ 249,250,000	$ 83,083,333
40 Demand Related Costs	SG	$ 994,500,000	$ 331,500,000	$ 497,250,000	$ 165,750,000
41 Ancillary Service Contract - Operating Reserves	SG	$ 4,000,000	$ 1,333,333	$ 2,000,000	$ 666,667
42 Ancillary Service Contract - Econimic Curtailment (Demand)	SG	$ 1,500,000	$ 500,000	$ 750,000	$ 250,000
43 Ancillary Service Contract - Econimic Curtailment (Energy)	SE	$ 1,500,000	$ 500,000	$ 750,000	$ 250,000
44 Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
45					
46 **Revenues**					
47 Special Contract Revenue	Situs	$ 60,000,000		$ 20,000,000	$ 40,000,000
48 **Revenues from all other customers**	Situs	**$ 1,440,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 210,000,000**

Extra East Load Resource MSP Study 1.4
Revenue Requirement Driver Analysis Compared with West Resource Sensitivity
with Clean Air 1 and Hydro Relicensing 1
$(,000)
2010

	Total Company	California	Oregon	Washington	Utah	Idaho	Wyoming
New Generation Resource	23,850	391	6,199	1,917	11,238	1,238	2,867
SG Factor - Extra East Load	100.0000%	1.6395%	25.9914%	8.0394%	47.1179%	5.1908%	12.0210%
Net Other Steam Plant							
Extra East Load (MSP Study 1.4)	462,536	7,583	120,220	37,185	217,937	24,009	55,602
West Resource (MSP Study 1.4)	462,537	7,720	122,390	37,857	213,522	24,442	56,605
Difference	(0)	(137)	(2,171)	(671)	4,415	(433)	(1,003)
Net Other Generation Plant							
Extra East Load (MSP Study 1.4)	68,328	1,120	17,759	5,493	32,195	3,547	8,214
West Resource (MSP Study 1.4)	68,328	1,140	18,080	5,592	31,543	3,611	8,362
Difference	-	(20)	(321)	(99)	652	(64)	(148)
Net Transmission Plant							
Extra East Load (MSP Study 1.4)	224,501	3,681	58,351	18,049	105,780	11,653	26,987
West Resource (MSP Study 1.4)	224,501	3,747	59,405	18,375	103,637	11,864	27,474
Difference	-	(66)	(1,054)	(326)	2,143	(210)	(487)
Net Other Plant							
Extra East Load (MSP Study 1.4)	411,401	15,409	104,001	33,992	196,974	21,346	39,679
West Resource (MSP Study 1.4)	411,307	15,437	104,400	34,114	196,064	21,427	39,865
Difference	94	(28)	(399)	(121)	910	(81)	(187)
Total Net Rate Base							
Extra East Load (MSP Study 1.4)	1,190,617	28,184	306,530	96,637	564,124	61,793	133,348
West Resource (MSP Study 1.4)	1,166,673	28,044	304,275	95,937	544,767	61,344	132,306
Difference	23,943	139	2,255	699	19,358	449	1,043
New Generation Resource O&M	3,087	51	802	248	1,454	160	371
SG Factor - Extra East Load	100.0000%	1.6395%	25.9914%	8.0394%	47.1179%	5.1908%	12.0210%
Other Steam O&M							
Extra East Load (MSP Study 1.4)	285,945	4,688	74,321	22,988	134,731	14,843	34,374
West Resource (MSP Study 1.4)	285,945	4,773	75,663	23,403	132,002	15,110	34,994
Difference	-	(85)	(1,342)	(415)	2,729	(268)	(620)
Other O&M							
Extra East Load (MSP Study 1.4)	233,498	6,206	55,025	17,468	119,102	11,024	24,673
West Resource (MSP Study 1.4)	233,498	6,238	55,528	17,623	118,079	11,124	24,906
Difference	-	(32)	(503)	(156)	1,023	(100)	(232)
Total O&M							
Extra East Load (MSP Study 1.4)	522,530	10,944	130,149	40,704	255,288	26,027	59,418
West Resource (MSP Study 1.4)	519,445	11,010	131,192	41,027	250,081	26,235	59,899
Difference	3,086	(66)	(1,043)	(323)	5,207	(208)	(482)
A&G							
Extra East Load (MSP Study 1.4)	290,935	6,449	79,365	24,828	128,822	16,222	35,249
West Resource (MSP Study 1.4)	290,935	6,521	80,182	25,068	127,191	16,379	35,593
Difference	-	(72)	(817)	(240)	1,630	(157)	(343)
Other Fixed Cost Drivers							
Extra East Load (MSP Study 1.4)	1,122,365	31,992	320,188	94,785	490,177	56,686	128,536
West Resource (MSP Study 1.4)	1,108,771	32,005	320,257	94,806	477,571	55,686	128,446
Difference	13,594	(13)	(69)	(21)	12,606	1,000	91
Net Power Costs							
Extra East Load (MSP Study 1.4)	922,244	14,931	237,469	73,138	430,032	49,819	116,855
West Resource (MSP Study 1.4)	901,610	14,846	236,150	72,730	411,440	50,425	116,019
Difference	20,634	85	1,319	408	18,592	(606)	836
Total Revenue Requirements							
Extra East Load (MSP Study 1.4)	4,048,690	92,500	1,073,701	330,092	1,868,443	210,547	473,407
West Resource (MSP Study 1.4)	3,987,433	92,427	1,072,056	329,568	1,811,050	210,069	472,263
Difference	61,257	73	1,645	524	57,393	478	1,144
% Increase	1.536%	0.079%	0.153%	0.159%	3.169%	0.228%	0.242%
% of Total Change	100.000%	0.119%	2.685%	0.855%	93.692%	0.780%	1.868%

PacifiCorp
State by State Revenue Requirement Impact
Percent Change in Revenue Requirement

	2005 NPV @ 8.823%	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
California (compared to Modified Accord)															
Hydro + Coal Endowments	0.48%	-0.34%	-0.74%	-1.01%	-0.43%	-0.14%	0.25%	0.70%	1.31%	1.68%	1.84%	1.73%	1.51%	1.43%	1.81%
Total MSP Solution (Including Seasonal)	0.43%	-0.33%	-0.75%	-1.01%	-0.46%	-0.16%	0.22%	0.64%	1.23%	1.57%	1.76%	1.65%	1.44%	1.35%	1.74%
Oregon (compared to Modified Accord)															
Hydro + Coal Endowments	0.63%	-0.50%	-1.05%	-1.41%	-0.60%	-0.20%	0.33%	0.94%	1.75%	2.24%	2.46%	2.32%	2.02%	1.89%	2.36%
Total MSP Solution (Including Seasonal)	0.35%	-0.65%	-1.33%	-1.67%	-0.85%	-0.42%	0.15%	0.75%	1.45%	1.67%	1.95%	1.98%	1.71%	1.62%	2.10%
Washington (compared to Modified Accord)															
Hydro + Coal Endowments	0.68%	-0.49%	-1.04%	-1.40%	-0.60%	-0.19%	0.34%	0.96%	1.78%	2.28%	2.49%	2.35%	2.05%	1.94%	2.33%
Total MSP Solution (Including Seasonal)	0.78%	-0.44%	-1.00%	-1.35%	-0.51%	-0.11%	0.42%	1.06%	1.92%	2.50%	2.70%	2.49%	2.17%	2.05%	2.41%
Utah (compared to Rolled-In)															
Hydro + Coal Endowments	-0.22%	1.85%	1.82%	1.78%	1.00%	0.50%	-0.07%	-0.65%	-1.30%	-1.62%	-1.80%	-1.76%	-1.63%	-1.59%	-1.45%
Total MSP Solution (Including Seasonal)	0.02%	1.98%	2.05%	2.01%	1.22%	0.69%	0.09%	-0.49%	-1.06%	-1.20%	-1.42%	-1.47%	-1.37%	-1.35%	-1.24%
Idaho (compared to Rolled-In)															
Hydro + Coal Endowments	0.12%	2.09%	2.04%	1.97%	1.15%	0.65%	0.07%	-0.49%	-1.12%	-1.42%	-1.59%	-1.56%	-1.42%	-1.37%	-1.25%
Total MSP Solution (Including Seasonal)	0.16%	2.25%	2.29%	2.15%	1.24%	0.73%	0.09%	-0.53%	-1.15%	-1.40%	-1.56%	-1.64%	-1.55%	-1.52%	-1.37%
Wyoming (compared to Modified Accord)															
Hydro + Coal Endowments	0.43%	-0.50%	-0.90%	-1.16%	-0.57%	-0.29%	0.10%	0.61%	1.28%	1.69%	1.86%	1.79%	1.60%	1.49%	1.82%
Total MSP Solution (Including Seasonal)	0.08%	-0.67%	-1.20%	-1.49%	-0.90%	-0.59%	-0.14%	0.36%	0.92%	1.09%	1.29%	1.29%	1.16%	1.08%	1.46%

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
Sales to Ultimate Customers			
440	Residential Sales		
		Direct assigned - Jurisdiction	S
442	Commercial & Industrial Sales		
		Direct assigned - Jurisdiction	S
444	Public Street & Highway Lighting		
		Direct assigned - Jurisdiction	S
445	Other Sales to Public Authority		
		Direct assigned - Jurisdiction	S
448	Interdepartmental		
		Direct assigned - Jurisdiction	S
447	Sales for Resale		
		Direct assigned - Jurisdiction	S
		Non-Firm	SE
		Firm	SG
449	Provision for Rate Refund		
		Direct assigned - Jurisdiction	S
			SG
Other Electric Operating Revenues			
450	Forfeited Discounts & Interest		
		Direct assigned - Jurisdiction	S
451	Misc Electric Revenue		
		Direct assigned - Jurisdiction	S
		Other - Common	SO
454	Rent of Electric Property		
		Direct assigned - Jurisdiction	S
		Common	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
456	Other Electric Revenue		
		Direct assigned - Jurisdiction	S
		Wheeling Non-firm, Other	SE
		Common	SO
		Wheeling - Firm, Other	SG
Miscellaneous Revenues			
41160	Gain on Sale of Utility Plant - CR		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
41170	Loss on Sale of Utility Plant		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
4118	Gain from Emission Allowances		
		SO2 Emission Allowance sales	SE
41181	Gain from Disposition of NOX Credits		
		NOX Emission Allowance sales	SE
421	(Gain) / Loss on Sale of Utility Plant		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
Miscellaneous Expenses			
4311	Interest on Customer Deposits		
		Utah Customer Service Deposits	CN

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Steam Power Generation			
500, 502, 504-514	Operation Supervision & Engineering		
		Remaining Steam Plants	SG
		Peaking Plants	SSCCT
		Cholla	SSGCH
		Huntington	DGU
501	Fuel Related		
		Remaining steam plants	SE
		Peaking Plants	SSECT
		Cholla	SSECH
		Huntington	DEU
503	Steam From Other Sources		
		Steam Royalties	SE
Nuclear Power Generation			
517 - 532	Nuclear Power O&M		
		Nuclear Plants	SG
Hydraulic Power Generation			
535 - 545	Hydro O&M		
		Pacific Hydro	DGP
		East Hydro	SG
Other Power Generation			
546, 548-554	Operation Super & Engineering		
		Other Production Plant	SG
547	Fuel		
		Other Fuel Expense	SE
Other Power Supply			
555	Purchased Power		
		Direct assigned - Jurisdiction	S
		Firm	SG
		Non-firm	SE
		Mid C Contracts, 100 MW Hydro Extension	DGP
		Peaking Contracts	SSGC
556 - 557	System Control & Load Dispatch		
		Other Expenses	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
TRANSMISSION EXPENSE			
560-564, 566-573	Transmission O&M		
		Transmission Plant	SG
565	Transmission of Electricity by Others		
		Firm Wheeling	SG
		Non-Firm Wheeling	SE
DISTRIBUTION EXPENSE			
580 - 598	Distribution O&M		
		Direct assigned - Jurisdiction	S
		Other Distribution	SNPD
CUSTOMER ACCOUNTS EXPENSE			
901 - 905	Customer Accounts O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
CUSTOMER SERVICE EXPENSE			
907 - 910	Customer Service O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
SALES EXPENSE			
911 - 916	Sales Expense O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
ADMINISTRATIVE & GEN EXPENSE			
920-935	Administrative & General Expense		
		Direct assigned - Jurisdiction	S
		Customer Related	CN
		General	SO
		FERC Regulatory Expense	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
DEPRECIATION EXPENSE			
403SP	Steam Depreciation		
		Remaining Steam Plants	SG
		Peaking Plants	SSCCT
		Cholla	SSGCH
		Huntington	DGU
403NP	Nuclear Depreciation		
		Nuclear Plant	SG
403HP	Hydro Depreciation		
		Pacific Hydro	DGP
		East Hydro	SG
403OP	Other Production Depreciation		
		Other Production Plant	SG
403TP	Transmission Depreciation		
		Transmission Plant	SG
403	Distribution Depreciation Direct assigned - Jurisdiction		
		Land & Land Rights	S
		Structures	S
		Station Equipment	S
		Poles & Towers	S
		OH Conductors	S
		UG Conduit	S
		UG Conductor	S
		Line Trans	S
		Services	S
		Meters	S
		Inst Cust Prem	S
		Leased Property	S
		Street Lighting	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
403GP	General Depreciation		
		Distribution	S
		Remaining Steam Plants	SG
		Peaking Plants	SSCCT
		Cholla	SSGCH
		Huntington	DGU
		Pacific Hydro	DGP
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General SO	SO
403MP	Mining Depreciation		
		Remaining Mining Plant	SE
		Deer Creek/Energy West (Huntington)	DGU

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
AMORTIZATION EXPENSE			
404GP	Amort of LT Plant - Capital Lease Gen		
		Direct assigned - Jurisdiction	S
		General	SO
		Customer Related	CN
404SP	Amort of LT Plant - Cap Lease Steam		
		Steam Production Plant	SG
404IP	Amort of LT Plant - Intangible Plant		
		Distribution	S
		Production, Transmission	SG
		General	SO
		Mining Plant	SE
		Customer Related	CN
404MP	Amort of LT Plant - Mining Plant		
		Mining Plant	SE
404HP	Amortization of Other Electric Plant		
		Pacific Hydro	DGP
		East Hydro	SG
405	Amortization of Other Electric Plant		
		Direct assigned - Jurisdiction	S
406	Amortization of Plant Acquisition Adj		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
407	Amort of Prop Losses, Unrec Plant, etc		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Trojan	TROJP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Taxes Other Than Income			
408	Taxes Other Than Income		
		Direct assigned - Jurisdiction	S
		Property	GPS
		General Payroll Taxes	SO
		Misc Energy	SE
		Misc Production	SG
DEFERRED ITC			
41140	Deferred Investment Tax Credit - Fed		
		ITC	DGU
41141	Deferred Investment Tax Credit - Idaho		
		ITC	DGU
Interest Expense			
427	Interest on Long-Term Debt		
		Direct assigned - Jurisdiction	S
		Interest Expense	SNP
428	Amortization of Debt Disc & Exp		
		Interest Expense	SNP
429	Amortization of Premium on Debt		
		Interest Expense	SNP
431	Other Interest Expense		
		Interest Expense	SNP
432	AFUDC - Borrowed		
		AFUDC	SNP
Interest & Dividends			
419	Interest & Dividends		
		Interest & Dividends	SNP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
DEFERRED INCOME TAXES			
41010	Deferred Income Tax - Federal-DR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	DGP
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJP
		Distribution	SNPD
		Mining Plant	SE
41011	Deferred Income Tax - State-DR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	DGP
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJP
		Distribution	SNPD
		Mining Plant	SE
41110	Deferred Income Tax - Federal-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	DGP
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJP
		Distribution	SNPD
		Mining Plant	SE

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
41111	Deferred Income Tax - State-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	DGP
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJP
		Distribution	SNPD
		Mining Plant	SE

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
SCHEDULE - M ADDITIONS			
SCHMAF	Additions - Flow Through		
		Direct assigned - Jurisdiction	S
SCHMAP	Additions - Permanent		
		Mining related	SE
		General	SO
SCHMAT	Additions - Temporary		
		Direct assigned - Jurisdiction	S
		Contributions in aid of construction	CIAC
		Miscellaneous	SNP
		Trojan	TROJP
		Pacific Hydro	DGP
		Mining Plant	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	SCHMDEXP
SCHEDULE - M DEDUCTIONS			
SCHMDF	Deductions - Flow Through		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Pacific Hydro	DGP
SCHMDP	Deductions - Permanent		
		Direct assigned - Jurisdiction	S
		Mining Related	SE
		Miscellaneous	SNP
		General	SO
SCHMDT	Deductions - Temporary		
		Direct assigned - Jurisdiction	S
		Bad Debt	BADDEBT
		Miscellaneous	SNP
		Pacific Hydro	DGP
		Mining related	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	TAXDEPR
		Distribution	SNPD

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
State Income Taxes			
40911	State Income Taxes		
		Income Before Taxes	IBT
40910		FIT True-up	S
40910		Wyoming Wind Tax Credit	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION	ALLOCATION FACTOR
Steam Production Plant		
310 - 316		
	Remaining Steam Plants	SG
	Peaking Plants	SSCCT
	Cholla	SSGCH
	Huntington	DGU
Nuclear Production Plant		
320-325		
	Nuclear Plant	SG
Hydraulic Plant		
330-336		
	Pacific Hydro	DGP
	East Hydro	SG
Other Production Plant		
340-346		
	Other Production Plant	SG
TRANSMISSION PLANT		
350-359		
	Transmission Plant	SG
DISTRIBUTION PLANT		
360-373		
	Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
GENERAL PLANT			
389 - 398			
		Distribution	S
		Remaining Steam Plants	SG
		Peaking Plants	SSCCT
		Cholla	SSGCH
		Huntington	DGU
		Pacific Hydro	DGP
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General SO	SO
399	Coal Mine		
		Remaining Mining Plant	SE
		Deer Creek/Energy West (Huntington)	DEU
399L	WIDCO Capital Lease		
		WIDCO Capital Lease	SE
1011390	General Capital Leases		
		Direct assigned - Jurisdiction	S
		General	SO
GP	Unclassified Gen Plant - Acct 300		
		Distribution	S
		Remaining Steam Plants	SG
		Peaking Plants	SSCCT
		Cholla	SSGCH
		Huntington	DGU
		Pacific Hydro	DGP
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
INTANGIBLE PLANT			
301	Organization		
		Direct assigned - Jurisdiction	S
302	Franchise & Consent		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
303	Miscellaneous Intangible Plant		
		Distribution	S
		Remaining Steam Plants	SG
		Peaking Plants	SSCCT
		Cholla	SSGCH
		Huntington	DGU
		Pacific Hydro	DGP
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General	SO
303	Less Non-Utility Plant		
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Rate Base Additions			
105	Plant Held For Future Use		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining Plant	SE
114	Electric Plant Acquisition Adjustments		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
115	Accum Provision for Asset Acquisition Adjustments		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
120	Nuclear Fuel		
		Nuclear Fuel	SE
124	Weatherization		
		Direct assigned - Jurisdiction	S
		General	SO
182W	Weatherization		
		Direct assigned - Jurisdiction	S
186W	Weatherization		
		Direct assigned - Jurisdiction	S
151	Fuel Stock		
		Other Steam Production Plant	SE
		Huntington	DEU
152	Fuel Stock - Undistributed		
		Other Steam Production Plant	SE
		Huntington	DEU
25316	DG&T Working Capital Deposit		
		Mining Plant	SE
25317	DG&T Working Capital Deposit		
		Mining Plant	SE

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
25319	Provo Working Capital Deposit		
		Mining Plant	SE
154	Materials and Supplies		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
		General	SO
		Production - Common	SNPPS
		Hydro	SNPPH
		Distribution	SNPD
			SG
163	Stores Expense Undistributed		
		General	SO
25318	Provo Working Capital Deposit		
		Provo Working Capital Deposit	SNPPS
165	Prepayments		
		Direct assigned - Jurisdiction	S
		Property Tax	GPS
		Production, Transmission	SG
		Mining	SE
		General	SO
182M	Misc Regulatory Assets		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Cholla Transaction Costs	SSGCH
		Mining	SE
		General	SO
186M	Misc Deferred Debits		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General	SO
		Mining	SE
		Production - Common	SNPPS

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Working Capital			
CWC	Cash Working Capital		
		Direct assigned - Jurisdiction	S
OWC		Other Working Capital	
131		Cash	SNP
135		Working Funds	SG
143		Other Accounts Receivable	SO
232		Accounts Payable	SO
232		Accounts Payable	SE
253		Deferred Hedge	SE
25330		Other Deferred Credits - Misc	SE
Miscellaneous Rate Base			
18221	Unrec Plant & Reg Study Costs		
		Direct assigned - Jurisdiction	S
18222	Nuclear Plant - Trojan		
		Trojan Plant	TROJP
		Trojan Plant	TROJD
141	Impact Housing - Notes Receivable		
		Employee Loans - Hunter Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Rate Base Deductions			
235	Customer Service Deposits		
		Direct assigned - Jurisdiction	S
2281	Prov for Property Insurance		SO
2282	Prov for Injuries & Damages		SO
2283	Prov for Pensions and Benefits		SO
22841	Accum Misc Oper Prov-Black Lung		
		Mining	SE
22842	Accum Misc Oper Prov-Trojan		
		Trojan Plant	TROJD
252	Customer Advances for Construction		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Customer Related	CN
25399	Other Deferred Credits		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
190	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Bad Debt	BADDEBT
		Pacific Hydro	DGP
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJP
281	Accumulated Deferred Income Taxes		
		Production, Transmission	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
282	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Depreciation	DITBAL
		Hydro Pacific	DGP
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJP
283	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Depreciation	DITBAL
		Hydro Pacific	DGP
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJP
255	Accumulated Investment Tax Credit		
		Direct assigned - Jurisdiction	S
		Investment Tax Credits	ITC84
		Investment Tax Credits	ITC85
		Investment Tax Credits	ITC86
		Investment Tax Credits	ITC88
		Investment Tax Credits	ITC89
		Investment Tax Credits	ITC90
		Investment Tax Credits	DGU

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
PRODUCTION PLANT ACCUM DEPRECIATION			
108SP	Steam Prod Plant Accumulated Depr		
		Remaining Steam Plants	SG
		Peaking Plants	SSCCT
		Cholla	SSGCH
		Huntington	DGU
108NP	Nuclear Prod Plant Accumulated Depr		
		Nuclear Plant	SG
108HP	Hydraulic Prod Plant Accum Depr		
		Pacific Hydro	DGP
		East Hydro	SG
108OP	Other Production Plant - Accum Depr		
		Other Production Plant	SG
TRANS PLANT ACCUM DEPR			
108TP	Transmission Plant Accumulated Depr		
		Transmission Plant	SG
DISTRIBUTION PLANT ACCUM DEPR			
108360 - 108373	Distribution Plant Accumulated Depr		
		Direct assigned - Jurisdiction	S
108D00	Unclassified Dist Plant - Acct 300		
		Direct assigned - Jurisdiction	S
108DS	Unclassified Dist Sub Plant - Acct 300		
		Direct assigned - Jurisdiction	S
108DP	Unclassified Dist Sub Plant - Acct 300		
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
GENERAL PLANT ACCUM DEPR			
108GP	General Plant Accumulated Depr		
		Distribution	S
		Remaining Steam Plants	SG
		Peaking Plants	SSCCT
		Cholla	SSGCH
		Huntington	DGU
		Pacific Hydro	DGP
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General SO	SO
108MP	Mining Plant Accumulated Depr.		
		Other Mining Plant	SE
		Deer Creek/Energy West (Huntington)	DEU
108MP	Less Centralia Situs Depreciation		
		Direct assigned - Jurisdiction	S
1081390	Accum Depr - Capital Lease		
		General	SO
1081399	Accum Depr - Capital Lease		
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
ACCUM PROVISION FOR AMORTIZATION			
111SP	Accum Prov for Amort-Steam		
		Remaining Steam Plants	SG
		Peaking Plants	SSCCT
		Cholla	SSGCH
		Huntington	DGU
111GP	Accum Prov for Amort-General		
		Distribution	S
		Remaining Steam Plants	SG
		Peaking Plants	SSCCT
		Cholla	SSGCH
		Huntington	DGU
		Pacific Hydro	DGP
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General SO	SO
111HP	Accum Prov for Amort-Hydro		
		Pacific Hydro	DGP
		East Hydro	SG
111IP	Accum Prov for Amort-Intangible Plant		
		Distribution	S
		Pacific Hydro	DGP
		Production, Transmission	SG
		General	SO
		Mining	SE
		Customer Related	CN
111IP	Less Non-Utility Plant		
		Direct assigned - Jurisdiction	S
111399	Accum Prov for Amort-Mining		
		Other Mining Plant	SE
		Deer Creek/Energy West (Huntington)	DEU

Allocation Factors

PacifiCorp serves eight jurisdictions. Jurisdictions are represented by the index i = California, Idaho, Oregon, Utah, Washington, Eastern Wyoming, Western Wyoming, & FERC.

The following assumptions are made in the factor definitions:

It is assumed that the 12CP (j=1 to 12) method is used in defining the System Capacity.

It is assumed that twelve months (j=1 to 12) method is used in defining the System Energy.

In defining the System Generation Factor, the weighting of 75% System Capacity, 25% System Energy is assumed to continue.

While it is agreed that the peak loads & input energy should be temperature adjusted, no decision has been made upon the methodology to do these adjustments.

System Capacity Factor (SC)

$$SCi = \frac{\sum_{j=1}^{12} TAP_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} TAP_{ij}}$$

where:

SC_i = **System Capacity Factor** for jurisdiction i.
TAP_{ij} = Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

System Energy Factor (SE)

$$SEi = \frac{\sum_{j=1}^{12} TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} TAE_{ij}}$$

where:

SE_i = **System Energy Factor** for jurisdiction i.

$TAEi_j$ = Temperature Adjusted Input Energy of jurisdiction i in month j.

Division Energy - Pacific Factor (DEP)

$$DEP_i = \frac{SE_i^*}{\sum_{i=1}^{i=8} SE_i^*}$$

where:

DEP_i = **Division Energy - Pacific Factor** for jurisdiction i.

$SE_i^* = SE_i$ if i is a Pacific jurisdiction, otherwise

$SE_i^* = 0.$

SE_i = System Energy for jurisdiction i.

Division Energy - Utah Factor (DEU)

$$DEU_i = \frac{SE_i^*}{\sum_{i=1}^{i=8} SE_i^*}$$

where:

DEU_i = **Division Energy - Utah Factor** for jurisdiction i.

$SE_i^* = SE_i$ if i is a Utah jurisdiction, otherwise

$SE_i^* = 0.$

SE_i = System Energy for jurisdiction i.

System Generation Factor (SG)

$$SG_i = .75 * SC_i + .25 * SE_i$$

where:

SG_i	=	**System Generation Factor** for jurisdiction i.
SC_i	=	System Capacity for jurisdiction i.
SE_i	=	System Energy for jurisdiction i.

Seasonal System Capacity Combustion Turbine (SSCCT)

$$SSCCTi = \frac{\sum_{j=1}^{12} WMO_{jct} * TAP_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jct} * TAP_{ij}}$$

where:

$SSCCTi$ = **Seasonal System Capacity Combustion Turbine Factor** for jurisdiction i.

$WMO_{jct} = \frac{\sum_{ct=1}^{n} E_{jct}}{\sum_{j=1}^{12}\sum_{i=1}^{8} E_{jct}}$ Weighted monthly energy generation of combustion turbine

where:

E_{jct} = Monthly Energy generation of combustion turbine ct in month j.

n = Number of combustion turbines

TAP_{ij} = Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

Seasonal System Energy Combustion Turbine (SSECT)

$$SSECTi = \frac{\sum_{j=1}^{12} WMO_{jct} * TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jct} * TAE_{ij}}$$

where:

$SSECTi$ = **Seasonal System Capacity Combustion Turbine Factor** for jurisdiction i.

$$WMO_{jct} = \frac{\sum_{ct=1}^{n} E_{jct}}{\sum_{j=1}^{12}\sum_{i=1}^{8} E_{jct}}$$ Weighted monthly energy generation of combustion turbine

where:

E_{jct} = Monthly Energy generation of combustion turbine ct in month j.

n = Number of combustion turbines

TAE_{ij} = Temperature Adjusted Input Energy of jurisdiction i in month j.

Seasonal System Generation Purchases (SSGP)

$$SSGPi = \left(\frac{\sum_{j=1}^{12} WMO_{jsp} * TAP_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jsp} * TAP_{ij}} \right) * .75 + \left(\frac{\sum_{j=1}^{12} WMO_{jsp} * TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jsp} * TAE_{ij}} \right) * .25$$

where:

$SSGPi$ = **Seasonal System Generation Purchases Factor** for jurisdiction i.

$$WMO_{jsp} = \frac{\sum_{sp=1}^{n} E_{jsp}}{\sum_{j=1}^{12}\sum_{i=1}^{8} E_{jsp}}$$ Weighted monthly energy from seasonal purchases

where:

E_{jsp} = Monthly Energy from seasonal purchases sp in month j.
n = Number of seasonal purchases

TAP_{ij} = Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

TAE_{ij} = Temperature Adjusted Input Energy of jurisdiction i in month j.

Seasonal System Generation Cholla (SSGCH)

$$SSGCHi = \left(\frac{\sum_{j=1}^{12} WMO_{jch} * TAP_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jch} * TAP_{ij}} \right) * .75 + \left(\frac{\sum_{j=1}^{12} WMO_{jch} * TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jch} * TAE_{ij}} \right) * .25$$

where:

$SSGCHi$ = **Seasonal System Generation Cholla Factor** for jurisdiction i.

$WMO_{jch} = \dfrac{E_{jch}}{\sum_{j=1}^{12}\sum_{i=1}^{8} E_{jch}}$ Weighted monthly energy generation of Cholla plant

where:

E_{jch} = Monthly Energy generation of Cholla plant ch in month j.

TAP_{ij} = Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

TAE_{ij} = Temperature Adjusted Energy Output of jurisdiction i in month j.

Seasonal System Energy Cholla (SSECH)

$$SSECHi = \frac{\sum_{j=1}^{12} WMO_{jch} * TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} WMO_{jch} * TAE_{ij}}$$

where:

$SSECHi$ = **Seasonal System Energy Cholla Factor** for jurisdiction i.

$WMO_{jch} = \frac{E_{jch}}{\sum_{j=1}^{12}\sum_{i=1}^{8} E_{jch}}$ Weighted monthly energy generation of Cholla plant

where:

E_{jch} = Monthly Energy generation of Cholla plant ch in month j.

TAE_{ij} = Temperature Adjusted Energy Output of jurisdiction i in month j.

Division Generation - Pacific Factor (DGP)

$$DGP_i = \frac{SG_i^*}{\sum_{i=1}^{i=8} SG_i^*}$$

where:

DGP_i = **Division Generation - Pacific Factor** for jurisdiction i.

$SG_i^* = SG_i$ if i is a Pacific jurisdiction, otherwise

$SG_i^* = 0$.

SG_i = System Generation for jurisdiction i.

Division Generation - Utah Factor (DGU)

$$DGU_i = \frac{SG_i^*}{\sum_{i=1}^{i=8} SG_i^*}$$

where:

DGU_i = **Division Generation - Utah Factor** for jurisdiction i.

$SG_i^* = SG_i$ if i is a Utah jurisdiction, otherwise

$SG_i^* = 0.$

SG_i = System Generation for jurisdiction i.

System Net Plant Production - Steam Factor (SNPPS)

$$SNPPS_i = \frac{SG_i * (PPSO - ADPPSO) + DGU_i * (PPSRH - ADPPSRH) + SSCCT_i * (PPSCT - ADPPSCT) + SSGCH_i * (PPSCH - ADPPSCH)}{(PPS - ADPPS)}$$

where:

$SNPPS_i$	=	**System Net Plant - Steam Factor** for jurisdiction i.
SG_i	=	System Generation for jurisdiction i.
DGU_i	=	Division Generation - Utah for jurisdiction i.
$SSCCT_i$	=	Seasonal System Capacity Combustion Turbine Generation for jurisdiction i.
$SSGCH_i$	=	Seasonal System Generation Cholla for jurisdiction i.
$PPSO$	=	Steam Production Plant less Huntington, Combustion Turbine and Cholla.
$ADPPSO$	=	Accumulated Depreciation Steam Production Plant less Huntington, Combustion Turbine and Cholla.
$PPSRH$	=	Steam Production Plant – Huntington.
$ADPPSRH$	=	Accumulated Depreciation Steam Production Plant – Huntington.
$PPSCT$	=	Steam Production Plant – Combustion Turbine.
$ADPPSCT$	=	Accumulated Depreciation Steam Production Plant – Combustion Turbine.
$PPSCH$	=	Steam Production Plant – Cholla.
$ADPPSCH$	=	Accumulated Depreciation Steam Production Plant – Cholla.
PPS	=	Steam Production Plant .
$ADPPS$	=	Accumulated Depreciation Steam Production Plant.

System Net Plant Production - Hydro Factor (SNPPH)

$$SNPPH_i = \frac{SG_i * (PPHE - ADPPHE) + DGP_i * (PPHRP - ADPPHRP)}{(PPH - ADPPH)}$$

where:

$SNPPH_i$	=	**System Net Plant - Hydro Factor** for jurisdiction i.
SG_i	=	System Generation for jurisdiction i.
DGP_i	=	Division Generation - Pacific for jurisdiction i.
$PPHE$	=	Hydro Production Plant – East.
$ADPPHE$	=	Accumulated Depreciation & Amortization Hydro Production Plant - East.
$PPHRP$	=	Hydro Production Plant - Pacific.
$ADPPHRP$	=	Accumulated Depreciation & Amortization Hydro Production Plant - Pacific.
PPH	=	Hydro Production Plant.
$ADPPH$	=	Accumulated Depreciation & Amortization Hydro Production Plant.

System Net Plant - Distribution Factor (SNPD)

$$SNPD_i = \frac{PD_i - ADPD_i}{(PD - ADPD)}$$

where:

$SNPD_i$	=	**System Net Plant - Distribution Factor** for jurisdiction i.
PD_i	=	Distribution Plant - for jurisdiction i.
$ADPD_i$	=	Accumulated Depreciation Distribution Plant - for jurisdiction i.
PD	=	Distribution Plant.
$ADPD$	=	Accumulated Depreciation Distribution Plant.

System Gross Plant - System Factor (GPS)

$$GPS_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i}{\sum_{i=1}^{i=8} (PP_i + PT_i + PD_i + PG_i + PI_i)}$$

$GP\text{-}S_i$ = **Gross Plant - System Factor** for jurisdiction i.
PP_i = Production Plant for jurisdiction i.
PT_i = Transmission Plant for jurisdiction i.
PD_i = Distribution Plant for jurisdiction i.
PG_i = General Plant for jurisdiction i.
PI_i = Intangible Plant for jurisdiction i.

System Net Plant Factor (SNP)

$$SNP_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - ADPP_i - ADPT_i - ADPD_i - ADPG_i - ADPI_i}{\sum_{i=1}^{i=8} (PP_i + PT_i + PD_i + PG_i + PI_i - ADPPi - ADPT_i - ADPD_i - ADPG_i - ADPI_i)}$$

SNP_i = **System Net Plant Factor** for jurisdiction i.
PP_i = Production Plant for jurisdiction i.
PT_i = Transmission Plant for jurisdiction i.
PD_i = Distribution Plant for jurisdiction i.
PG_i = General Plant for jurisdiction i.
PI_i = Intangible Plant for jurisdiction i.
$ADPP_i$ = Accumulated Depreciation Production Plant for jurisdiction i.
$ADPT_i$ = Accumulated Depreciation Transmission Plant for jurisdiction i.
$ADPD_i$ = Accumulated Depreciation Distribution Plant for jurisdiction i.
$ADPG_i$ = Accumulated Depreciation General Plant for jurisdiction i.
$ADPI_i$ = Accumulated Depreciation Intangible Plant for jurisdiction i.

System Overhead - Gross Factor (SO)

$$SOG_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - PP_{oi} - PT_{oi} - PD_{oi} - PG_{oi} - PI_{oi}}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PP_i - PP_oi - PI_{oi} - PD_{oi} - PG_{oi} - PI_{oi})}$$

SOG_i = **System Overhead - Gross Factor** for jurisdiction i.
PP_i = Gross Production Plant for jurisdiction i.
PT_i = Gross Transmission Plant for jurisdiction i.
PD_i = Gross Distribution Plant for jurisdiction i.
PG_i = Gross General Plant for jurisdiction i.
PI_i = Gross Intangible Plant for jurisdiction i.
PP_{oi} = Gross Production Plant for jurisdiction i allocated on a SO factor.
PT_{oi} = Gross Transmission Plant for jurisdiction i allocated on a SO factor
PD_{oi} = Gross Distribution Plant for jurisdiction i allocated on a SO factor
PG_{oi} = Gross General Plant for jurisdiction i allocated on a SO factor
PI_{oi} = Gross Intangible Plant for jurisdiction i allocated on a SO factor

Income Before Taxes Factor (IBT)

$$IBT_i = \frac{TIBT_i}{\sum_{i=1}^{i=8} TIBT_i}$$

$IBTi$ = **Income before Taxes Factor** for jurisdiction i.
$TIBTi$ = Total Income before Taxes for jurisdiction i.

Bad Debt Expense Factor (BADDEBT)

$$BADDEBT_i = \frac{ACCT904_i}{\sum_{i=1}^{i=8} ACCT904_i}$$

$BADDEBT_i$ = **Bad Debt Expense Factor** for jurisdiction i.
$ACCT904i$ = Balance in Account 904 for jurisdiction i.

Customer Number Factor (CN)

$$CN_i = \frac{CUST_i}{\sum_{i=1}^{i=8} CUST_i}$$

where:
CN_i = **Customer Number Factor** for jurisdiction i.
$CUST_i$ = Total Electric Customers for jurisdiction i.

Contributions in Aid of Construction (CIAC)

$$CIAC_i = \frac{CIACNA_i}{\sum_{i=1}^{i=8} CIACNA_i}$$

where:
$CIAC_i$ = **Contributions in Aid of Construction Factor** for jurisdiction i.
$CIACNA_i$ = Contributions in Aid of Construction – Net additions for jurisdiction i.

Schedule M - Deductions (SCHMD)

$$SCHMD_i = \frac{DEPRC_i}{\sum_{i=1}^{i=8} DEPRC_i}$$

where:

$SCHMD_i$	=	**Schedule M - Deductions (SCHMD) Factor** for jurisdiction i.
$DEPRC_i$	=	Depreciation in Accounts 403.1 - 403.9 for jurisdiction i.

Trojan Plant (TROJP)

$$TROJP_i = \frac{ACCT18222_i}{\sum_{i=1}^{i=8} ACCT18222_i}$$

where:

$TROJP_i$	=	**Trojan Plant (TROJP) Factor** for jurisdiction i.
$ACCT18222_i$	=	Allocated Adjusted Balance in Account 182.22 for jurisdiction i.

Trojan Decommissioning (TROJD)

$$TROJD_i = \frac{ACCT22842_i}{\sum_{i=1}^{i=8} ACCT22842_i}$$

where:

$TROJD_i$	=	**Trojan Decommissioning (TROJD) Factor** for jurisdiction i.
$ACCT22842_i$	=	Allocated Adjusted Balance in Account 228.42 for jurisdiction i.

Tax Depreciation (TAXDEPR)

$$TAXDEPR_i = \frac{TAXDEPRA_i}{\sum_{i=1}^{i=8} TAXDEPRA_i}$$

where:

$TAXDEPR_i$ = **Tax Depreciation (TAXDEPR) Factor** for jurisdiction i.
$TAXDEPRA_i$ = Tax Depreciation allocated to jurisdiction i.

(Tax Depreciation is allocated based on functional pre merger and post merger splits of plant using Divisional and System allocations from above. Each jurisdiction's total allocated portion of Tax depreciation is determined by its total allocated ratio of these functional pre and post merger splits to the total Company Tax Depreciation.)

Deferred Tax Expense (DITEXP)

$$DITEXP_i = \frac{DITEXPA_i}{\sum_{i=1}^{i=8} DITEXPA_i}$$

where:

$DITEXP_i$ = **Deferred Tax Expense (DITEXP) Factor** for jurisdiction i.
$DITEXPA_i$ = Deferred Tax Expense allocated to jurisdiction i.

(Deferred Tax Expense is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

<u>Deferred Tax Balance (DITBAL)</u>

$$DITBAL_i = \frac{DITBALA_i}{\sum_{i=1}^{i=8} DITBALA_i}$$

where:

$DITBAL_i$	=	**Deferred Tax Balance (DITBAL) Factor** for jurisdiction i.
$DITBALA_i$	=	Deferred Tax Balance allocated to jurisdiction i.

(Deferred Tax Balance is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)