—BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH—

ALLOCATIONS DISCUSSION PAPER

(BY DAVE TAYLOR, MARCH 4, 2003)

ARTIE POWELL

DPU EXHIBIT 2.1DIR-COS

DOCKET NO.11-035-200

DIVISION OF PUBLIC UTILITIES

June 22, 2012

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		
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

Description	Ttl Fixed $/kW-Yr	Convert to Mills: Expected Utilization	Convert to Mills: Ttl Fixed Mills/kWh	Total Variable Costs Mills/kWh	Total 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.