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Allocations Discussion Paper

(By Dave Taylor, March 4, 2003)

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Classification and Allocation of Generation Fixed Costs
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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.

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.

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.