Exhibit No. ___(DLT-2) Docket No. UE-03____ 2003 PP&L Rate Case Witness: David L. Taylor

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,)) Docket No. UE-03
Complainant,	
•	
vs.)
)
PACIFICORP dba Pacific Power & Light)
Company,)
)
Respondent	

PACIFICORP

EXHIBIT OF DAVID L. TAYLOR

Classification of Generation Costs

December 2003

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 His	torical Gene	eration Plan	t Jurisdictio	onal Allocat	on Factor		
	PPL-	PPL-	PPL-	PPL-	UPL-	UPL-	UPL-	MERGED
	WA	OR	CA	WY	ID	WY	UT	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 Ret					
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
4.7	0.054.016	20 (20 072	1 701 429	12 420 725	6,826,133	2,592,210	40,355,756	104,578,250
24 Months of Energy	8,954,016	30,628,972	1,791,438	13,429,725			38.6%	100.09
24 Months Energy Factor	8.6%	29.3%	1.7%	12.8%	6.5%	2.5%	38.0%	100.0%
			Compos	ite Factor				
Generation Plant Factor	8.9%	30.3%	1.9%	12.1%	6.2%	2.2%	38.3%	100.0
Allocation Factor = 60 CP Fa	ctor X 50% + 2	4 Month Energ	y Factor X 509	%				

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								4			
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:

Curre	nt PacifiCo	rp Generati	on Plant All	ocation Fact	or (Modified	l Accord)		
		Pr	e Merger Inve	stment				
	PPL-	PPL-	PPL-	PPL-	UPL-	UPL-	UPL-	
// // // // // // // // // // // // //	WA	OR	CA	WY	ID	WY	UT	TOTAL
			Sum of 12 C			1.050	25.071	00.700
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 M	TWh				
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)	29.270				13.7%	5.5%	80.8%	100.0%
			Composite Fa	etor				
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 7	5% + Energy I	actor X 25%						
						.,		
		Po	st Merger Inv	estment				
	PPL-	PPL-	PPL-	PPL-	UPL-	UPL-	UPL-	MERGED
	WA	OR	CA	WY	ID	WY	UT	TOTAL
			Sum of 12 C					
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 M		2.406.070	1 266 700	20,070,975	52,232,925
2001	4,413,518	15,025,360	865,652	7,083,751	3,406,870	1,366,799	38.4%	32,232,923 100.0%
System Energy Factor (SE)	8.4%	28.8%	1.7%	13.6%	6.5%	2.6%	38.4%	100.0%
			Composite Fa	actor				
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								
/ inocation i dottor - 12 CV i dottor / 1								

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 Fact	ors				
	D	Е	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	+1		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.

				Pea	k & Average (1	CP)				
	D	Е	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							-	1		
Average MW Component		- 1		1				1		
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	Е	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.

Demand - SCCT

Energy - SCCT

100%

0%

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%		

51,912,407	5,926	0,117	4,142	00,010	1 /3/0	0170
		Cla	assification Me	hods		
Method	T	Current Bac	ifiCorp Method		Demand	75%
wetnoa		Current rac	mcorp memou		Energy	25%
Basis for Method	Agreed upon by PIT	ΓΔ hecause it mee	t a balance of object	tives including shar	ing of merger benefits	2070
Calculation	Demand componen			avoo, molaamig onar	mg or morgon somethic	
Method		Cost Accou	unting Method		Demand	100%
					Energy	0%
Basis for Method	Plant capacity is bu			ilt it is fixed		
Calculation	100% of fixed costs	are demand relate	ed			
Method		Average & F	Excess Method		Demand	27%
viculou		7o.ugu u			Energy	73%
Basis for Method	Energy component	equal to system lo	ad factor %		<u></u>	
Calculation	Energy component	% = Annual MWH	/ 8760 / 1CP			
Method		Peak & Aver	age (Single CP)		Demand	58%
					Energy	42%
Basis for Method	Demand Componer				erage Demand	
Calculation	Demand Componer	nt % = 1CP / (1CP	+ (Annual MWH / 8	760))		
Method	T	Poak & Ave	erage (12 CP)		Demand	55%
vietriou		reak & Av	erage (12 Cr)		Energy	45%
Basis for Method	Demand Componer	nt equal Peak Dem	nand divided by Sur	n of Peak and Avera		
Calculation	Demand Componer					
	1	D 1 0 4	(40.00 (4)		T Domand T	92%
Method		Peak & Aver	rage (12 CP + 1)		Demand Energy	92% 8%
Basis for Method	The Energy Compo	nent has equal va	lue to each of the m	onthly peaks	Lileigy	0 70
Calculation	Demand Componer	nt equal to 12/13 o	of Fixed Costs. Ene	ray Component equ	al to 1/13 of Fixed Cost	S
Jarodialion				<u> </u>		
Method	В	ase - Intermediate	e - Peak (BIP) Met	nod	Demand - Base	25%
					Energy - Base	75%
					Demand - Int	50%
					Energy - Int	50%
					Demand - Peak	75%
	<u> </u>	DUO 2: 5: 5:	11	-1 3 -2-1	Energy - Peak	25%
Basis for Method	Proposed by Orego	on PUC Staff. Sim	ilar to Equivalent Pe	eaker Method		
Calculation	1					
Method	1	Production S	stacking Method		Demand - Base	49%
TOUTOU					Energy - Base	51%
					Demand - Peak	100%
					Energy - Peak	0%
Basis for Method	Generation needed classified as demar		d energy requireme	nts is classified as e	nergy related. Remain	ng plant is
Calculation	Base Load Energy	Component % = N	in Load Hour / 1CF			
	T	F			I Domand Coal I	200/
Method		Equivalent P	eaker Method 1		Demand - Coal	38%
					Energy - Coal	62%
					Demand - CCCT Energy - CCCT	94% 6%
					Darrand COOT	4000/

Increases in peak demand require the addition of peaking capacity only, costs of more expensive units are because

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

Basis for Method

Calculation

PacifiCorp 2003 Integrated Resource Plan Potential Resource Cost

Demand & Energy Related Components of Fixed & Variable Costs Generation Costs Only

]	Equival	ent Peak	er Method	d			
			Convert	to Mills	Total		Total
	T	tl Fixed	Expected	Ttl Fixed	Variable	R	esource
Description	\$	/kW-Yr	Utilization	Mills/kWh	Costs		Cost
•					Mills/kWh	М	ills/kWh
	 C:	la Cruala '	Turkin a		1 141113/ K 14 11	1 1/1	1113/14 14 11
Average IRP Costs	Siiii	ple Cycle ' 58.32	1 urome 16%	46.91	65.02		111.92
Average IKF Costs	O.	30.32	1070	40.71	03.02		111,72
Demand Related Costs	18	58.32	16%	\$ 46.91	\$ -	\$	46.91
Energy Related Costs	\$		16%		\$ 65.02	\$	65.02
Demand Related %	Ψ	100%	1070	100%		-	42%
Energy Related %		0%		0%	<u> </u>		58%
				=			
	Comb	ined Cycl	e Turbine		<u> </u>	I	
Average IRP Costs	T\$	62.07	80%	8.94	33.56		42.50
ATTEMBET ITE COSIS	Ψ	J	0070	0,71	35.00		
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%	1000	94%	0%		20%
Energy Related %		6%		6%	100%		80%
	E	ase Load	Coal				
Average IRP Costs	\$	154.72	91%	19.41	17.35		36.76
			0.00		200	<u> </u>	
Demand Related Costs	\$	58.32	91%		\$ -	\$	7.32
Energy Related Costs	\$	96.40	91%		\$ 17.35	\$	29.44
Demand Related %		38%		38%		0.0000000000000000000000000000000000000	20%
Energy Related %		62%		62%	100%		80%
Oth	er Opti	ons for E	Base Load	Coal			
Demand Related Costs	S	154.72	91%		\$ -	\$	19.41
Energy Related Costs	\$	-	91%		\$ 17.35	\$	17.35
Demand Related %		100%	10 mg 1 mg 1	100%	0%		53%
Energy Related %		0%		- 0%	100%		479
Demand Related Costs	1 \$	116.04	91%	\$ 14.56	ls -	1 \$	14.56
	\$	38.68	91%		\$ 17.35	\$	22.20
Energy Related Costs Demand Related %	J.	75%	9170	75%			40%
Energy Related %		25%		25%			60%
Energy Related 76	<u> </u>	4370		2370	10076		007
Demand Related Costs	\$	77.36	91%		\$ -	\$	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	 \$ -	l \$	4.85
Energy Related Costs	\$	116.04	91%		\$ 17.35	\$	31.91
	D D	25%	9170	3 14.30 25%			139
Demand Related %						9 (000000000000000000000000000000000000	
Energy Related %		75%		75%	100%		87

Utility Classification/Allocation Survey Results

<u>Utility</u>	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 hour Energy based on class temperature and loss- adjusted energy use.	Commission order issued in 1987. Demand = 1/2 fixed costs of SCCT rs.
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	621,089	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-0R	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
12 CP	422	77%	%22	91%	%68	95%	%08	81%
1 CP	71%	78%	%89	%68	71%	%56	%99	73%
1 NCP	%99	%99	29%	83%	28%	%82	%59	

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

Annual Energy Energy Factor PPL-OR Total PPL-OR PP					7	Allocation Factors	ors				
D E PPL-OR PPL-CA PPL-WA PPL-OR						Energy Factor					
100% 0.0% 15.84.465.3431 982.427.759 6.539.986.792 3.384.855.701 1.259.395.669 19.940.731.890 51.912. 100% 0.0% 15.24.44 1.225.765 1		۵	ш	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
D E PPL-WM	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
D E PPL-MA PPL-OR PPL-NY UPL-ID UPL-UT Tol 100% 0% 8.83% 29.77% 1.35% 10.12% 10.12% 1.37% 1.36.529 8. 1.35.50% 1.3	Energy Factor	%0	100%	8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
D E PPL-WA PPL-OR PPL-CA PP							***************************************				
D E PPL-WA PPL-OR PPL-WY UPL-WY					•	00% Demand Fact				•	
100% 0% 782,957 2,639,481 188,904 897,121 671,089 184,209 3,502,529 8, 3,50% 100% 0% 8,83% 29,77% 2,13% 10,12% 7,57% 2,08% 39,50% 8, 3,50% 8, 3,50% 8, 3,50% 8, 3,50% 8, 3,50% 8, 3,50% 8, 3,50% 8, 3,50% 8, 3,50% 8, 3,50% 8, 3,50% 8, 3,50% 8, 3,50% 42,73% 8, 3,50% 8, 3,50% 42,73% 8, 3,50% 8, 2,7% 42,73% 8, 3,50% 42,73% 8, 3,50% 1,255,50% 1,255,60% 1,36% 42,73% 1,556,60% 42,73% 1,556,70% 1,556,70% 1,556,70% 1,556,70% 42,73% 1,556,70% 1,5		Q	Ш	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
100% 0% 6.83% 29.77% 2.13% 10.12% 7.57% 2.08% 39.50% 100% 0% 7.24,444 2.225,765 164,145 836,193 547,088 151,073 3.468,372 8. 100% 0% 8.92% 2.742% 2.02% 16,244,386 6.74% 1.86% 42,73% 8. 100% 0% 8.92% 2.226,766 31,188,789 162,247,386 102,226,607 2.9841,039 633,740,345 1,525,608 100% 0% 137,595,882 428,580,566 31,188,789 162,247,386 102,226,607 2.9841,039 633,740,345 1,525,608 100% 0% 9,02% 22,146,372 1,746,245 9,824,030 5,190,516 1,86% 41,559 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 1,525,608 </td <td>Annual NCP</td> <td></td> <td></td> <td>782,957</td> <td>2,639,481</td> <td>188,904</td> <td>897,121</td> <td>671,089</td> <td>184,209</td> <td>3,502,529</td> <td>8,866,290</td>	Annual NCP			782,957	2,639,481	188,904	897,121	671,089	184,209	3,502,529	8,866,290
100% 0% 724,444 2,225,765 164,145 836,193 547,088 151,073 3,468,372 8 100% 0% 8,92% 2,742% 2,02% 10,30% 6,74% 1,56% 42,73% 8 100% 0% 9,02% 22,42% 2,02% 10,30% 6,70% 1,96% 41,55% 1,525, 100% 0% 9,02% 28,10% 2,04% 10,64% 6,70% 1,96% 41,55% 1,525, 100% 0% 9,17% 28,10% 1,746,245 9,824,030 5,190,516 1,812,264 34,259,181 88, 100% 0% 9,17% 30,81% 1,746,245 9,824,030 5,190,516 1,812,264 34,259,181 88, 100% 0% 9,17% 30,81% 1,746,245 9,824,030 5,190,516 1,812,264 34,259,181 88, 100% 0% 20,70% 1,7278,526 17,116% 5,88% 2,09% 33,174,561 86,50	1 NCP Factor	100%		8.83%	29.77%	2.13%	10.12%	7.57%	2.08%	39.50%	100.00%
100% 0% 724,444 2,225,765 164,145 836,193 547,088 151,073 3,468,372 8. 100% 0% 8,92% 27,42% 2,02% 10,30% 6,74% 1,86% 42,73% 8. 100% 0% 9,02% 28,10% 2,02% 10,64% 10,64% 6,77% 1,96% 41,55% 1,525, 100% 0% 9,02% 28,10% 1,746,245 9,824,030 5,190,516 1,812,264 34,259,181 86, 100% 0% 9,17% 20,745,325 17,746,245 96,911,310 50,986,550 1,812,264 34,259,181 86, 100% 0% 9,17% 20,6% 1,16% 5,98% 2,06% 33,977,4,561 86,0 100% 0% 9,08% 265,785,252 17,278,56 96,911,310 50,986,550 16,132,475 339,174,561 86,0 100% 0% 9,08% 29,38% 1,59% 1,689,646 95,7261 32,03% 40,93% <											
100% 0% 8.92% 27.42% 10.30% 6.74% 1.86% 42.73% 100% 0% 137,595,882 428,580,566 31,188,789 162,247,386 102,228,607 29,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,039 633,740,345 1,525,841,349 1,525,841,345 1,525,841,345 1,525,841,345 1,525,841,345 1,525,841,373 1,525,841,345 1,525,841,345 1,525,841,345 1,525,841,445 1,525,841,445 1,525,841,445 1,525,841,445 1,525,841,445 1,525,841,445 1,525,841,445 1,525,841,445 1,525,841,445 1,525,841,445 1,525,841,445 1,525,841,445 1,525,841,445 1,525,841,445 1,525,841,445	Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
100% 0% 137,565,882 428,580,566 31,188,789 162,247,386 102,228,607 29,841,039 633,740,345 1,525, 100% 0% 9,02% 28,10% 2.04% 10.64% 6,70% 1,96% 41,55% 1,525, 100% 0% 9,02% 27,115,372 1,746,245 9,824,030 5,190,516 1,812,264 34,259,181 88,6 100% 0% 9,17% 30,81% 1,98% 11,16% 5,90% 2,06% 34,259,181 88,6 100% 0% 9,08% 26,785,252 17,278,526 96,911,310 50,988,550 18,132,475 339,12% 86,5 100% 0% 9,08% 30,66% 1,99% 11,18% 5,88% 2,09% 339,12% 15, 100% 0% 9,08% 1,95% 1,062% 0,08% 2,03% 40,93% 15, 100% 0% 4,257,445 14,055,127 944,166 4,995,627 2,814,373 93,40% 39,40% 39,	1 CP Factor	100%		8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
100% 0% 137,595,882 428,580,566 31,188,789 162,247,386 102,228,607 29,841,039 633,740,345 1,525,807 100% 0% 9,02% 28,10% 1,746,245 9,824,030 5,190,516 1,812,264 34,259,181 88, 100% 0% 9,17% 30,81% 1,746,245 9,824,030 5,190,516 1,812,264 34,259,181 88, 100% 0% 9,17% 20,81% 1,7278,526 96,911,310 50,988,550 18,132,475 339,174,561 866, 100% 0% 9,08% 2,65785,282 17,278,526 96,911,310 50,988,550 18,132,475 339,174,561 866, 100% 0% 9,08% 2,65785,282 1,99% 11,18% 56,88% 2,09% 339,174,561 866, 100% 0% 9,08% 29,38% 1,98% 1,689,646 957,261 32,09% 40,93% 15, 100% 0% 4,257,445 14,055,127 944,166 4,995,627 <t< td=""><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></t<>											
100% 0% 9.02% 28.10% 2.04% 10.64% 6.70% 1.96% 41.55% 100% 0% 9.02% 27.115.372 1,746.245 9.824.030 5,190,516 1,812,264 34.259,181 88. 100% 0% 9.17% 20.81% 17,278,526 96,911,310 50,988,550 18,132,475 339,174,561 866, 100% 0% 9.08% 30.66% 1,99% 11.18% 5.88% 2.09% 39,174,561 866, 100% 0% 9.08% 30.66% 1,99% 11.18% 5.88% 2.09% 39,12% 866, 100% 0% 9.08% 29.38% 1,95% 10.62% 6.02% 2.03% 40.93% 46,509,073 15, 100% 0% 9.08% 29.38% 1,95% 10.62% 2.03% 40.93% 40.93% 100% 0% 9.21% 30.42% 2.04% 10.81% 6.09% 2.02% 9.20% 46.509,073 45.50 <t< td=""><td>Top 200 Hours</td><td></td><td></td><td>137,595,882</td><td>428,580,566</td><td>31,188,789</td><td>162,247,386</td><td>102,228,607</td><td>29,841,039</td><td>633,740,345</td><td>1,525,422,614</td></t<>	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
100% 0% 9.007.405 27.115.372 1,746.245 9,824.030 5,190,516 1,812.264 34.259,181 88. 100% 0% 9.17% 30.81% 1,786.245 96,911,310 50,988,550 18,132,475 339,174,561 866, 100% 0% 9.08% 30.66% 1,99% 11.18% 5.88% 2.09% 39,174,561 866, 100% 0% 9.08% 30.66% 1,99% 11.18% 5.88% 2.09% 39,174,561 866, 100% 0% 1,443,622 4,672,892 309,461 1,689,646 957,261 322,124 6,509,073 15, 100% 0% 4,257,445 14,055,127 944,166 4,995,627 2,814,373 934,102 18,206,956 46, 100% 0% 9,21% 30,42% 2,04% 1,081% 6,09% 2,03% 40,99% 46,995,627 2,814,373 934,102 18,206,996 46,996,627 2,814,373 934,102 18,206,996 39,4102 <	Top 200 Hrs Factor	100%		9.02%	28.10%	2.04%	10.64%	6.70%	1.96%	41.55%	100.00%
100% 0% 8,067,405 27,115,372 1,746,245 9,824,030 5,190,516 1,812,264 34,259,181 88. 100% 0% 9,17% 265,785,252 17,278,526 96,911,310 50,988,550 18,132,475 339,174,561 866, 100% 0% 78,718,279 265,785,252 17,278,526 96,911,310 50,988,550 18,132,475 339,174,561 866, 100% 0% 9,08% 265,785,252 17,278,526 96,911,310 50,988,550 18,132,475 339,174,561 866, 100% 0% 1,443,622 4,672,892 309,461 1,689,646 957,261 322,124 6,509,073 15, 100% 0% 9,08% 29,38% 1,95% 10,62% 6,02% 2,03% 40,93% 100% 0% 4,257,445 14,055,127 944,166 4,995,627 2,814,373 934,102 18,206,966 46,995,627 100% 0% 9,21% 14,055,127 944,166 40,936,627 2,814											
100% 0% 9.17% 30.81% 1.98% 11.16% 5.90% 2.06% 38.92% 100% 0% 78,718,279 265,785,252 17,278,526 96,911,310 50,988,550 18,132,475 339,174,561 866, 100% 0% 9.08% 265,785,262 17,278,526 96,911,310 50,988,550 18,132,475 339,174,561 866, 100% 0% 9.08% 29.38% 1,689,646 957,261 322,124 6,509,073 15, 100% 0% 9.08% 29.38% 1,95% 1,62% 2,03% 40,93% 40,93% 100% 0% 4,257,445 14,055,127 944,166 4,995,627 2,814,373 934,102 18,206,956 46,96 100% 0% 9,21% 10,65% 2,04% 10,81% 6,09% 2,02% 39,40% 46,96 100% 0% 9,21% 10,65% 2,04% 10,81% 6,09% 2,02% 39,40% 46,96 100%	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
100% 0% 78,718,279 265,785,252 17,278,526 96,911,310 50,988,550 18,132,475 339,174,561 866, 100% 0% 9.08% 20,66% 1,128% 5,88% 2.09% 339,174,561 866, 100% 0% 9.08% 29.38% 1,99% 1,118% 5,88% 2.09% 39,12% 100% 0% 9.08% 29.38% 1,95% 1,65% 6.02% 2.03% 40,93% 100% 0% 4,257,445 14,055,127 944,166 4,995,627 2,814,373 934,102 18,206,956 46,96 100% 0% 9,21% 30,42% 2,04% 10,81% 6,09% 2,02% 39,40% 46,56 100% 0% 9,21% 30,15% 9,195,820 49,236,321 27,816,554 9,291,642 181,116,815 455, 100% 0% 9,13% 30,15% 2,02% 49,291,642 181,116,815 455,	12 CP Factor	100%		9.17%	30.81%	1.98%	11.16%	2.90%	2.06%	38.92%	100.00%
100% 0% 78,718,279 265,785,252 17,278,526 96,911,310 50,988,550 18,132,475 339,174,561 866,139,174,561 100% 0% 9.08% 30.66% 17,278,526 11,89% 5.88% 2.09% 39,12% 100% 0% 1,443,622 4,672,892 309,461 1,689,646 957,261 322,124 6,509,073 15, 100% 0% 9.08% 29.38% 1,95% 10,62% 6.02% 2.03% 40,93% 15, 100% 0% 9.21% 14,055,127 944,166 4,995,627 2,814,373 934,102 18,206,956 46, 100% 0% 9.21% 30.42% 2.04% 9195,820 49,295,627 2,814,373 934,102 18,206,956 46, 100% 0% 9.21% 30.42% 2.04% 9195,820 49,236,321 27,816,554 9,291,642 181,116,815 455, 100% 0% 9.13% 30.15% 2.02% 49,236,321 27,816,5											
100% 0% 9.08% 30.66% 1.99% 11.18% 5.88% 2.09% 39.12% 100% 0% 1,443,622 4,672,892 309,461 1,689,646 957,261 322,124 6,509,073 15, 100% 0% 9.08% 29.38% 1,96% 1,062% 6.02% 2.03% 40.93% 16, 100% 0% 4,257,445 14,055,127 944,166 4,995,627 2,814,373 934,102 18,206,956 46, 100% 0% 9,21% 30.42% 2,04% 10,81% 6,09% 2,02% 39,40% 39,40% 100% 0% 9,21% 30,43 2,04% 49,236,321 27,816,554 9,291,642 181,116,815 455, 100% 0% 9,13% 9,195,820 49,236,321 27,816,554 9,291,642 181,116,815 455,	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
100% 0% 4,257,445 4,055,127 4,057,2892 309,461 1,689,646 957,261 322,124 6,509,073 15,100% 100% 0% 9,08% 29,38% 1,95% 1,062% 6,02% 2,03% 40,93% 16,509,073 15,100% 100% 0% 4,257,445 14,055,127 944,166 4,995,627 2,814,373 934,102 18,206,956 46, 46, 46, 46, 46, 46, 46, 46, 46, 46,	12 CP X 10 Top Hrs Factor	100%		9.08%	30.66%	1.99%	11.18%	2.88%	2.09%	39.12%	100.00%
100% 0% 9.08% 29.38% 1.95% 10.62% 6.02% 2.03% 40.93% 100% 0% 4.257,445 14.055,127 944,166 4.995,627 2,814,373 934,102 18.206,956 46, 100% 0% 9.21% 30.42% 2.04% 10.81% 6.09% 2.02% 39.40% 100% 10% 0% 9.195,820 49,236,321 27,816,554 9,291,642 181,116,815 455, 100% 0% 9.13% 30.15% 2.02% 10.81% 6.11% 2.04% 39.75%	Summer / Winter CP			1,443,622	4 672 892	309.461	1.689.646	957.261	322.124	6.509.073	15,904,079
100% 0% 9.21% 14,055,127 944,166 4,995,627 2,814,373 934,102 18,206,956 46, 100% 0% 9.21% 30.42% 2.04% 10.81% 6.09% 2.02% 39.40% 100% 0% 9.21% 30.42% 2.04% 49,236,321 27,816,554 9,291,642 181,116,815 455, 100% 0% 9.13% 30.15% 2.02% 10.81% 6.11% 2.04% 39.75%	Summer / Winter CP Factor	100%		80.6	29.38%	1.95%	10.62%	6.02%	2.03%	40.93%	100.00%
100% 0% 9.21% 14,055,127 944,166 4,995,627 2,814,373 934,102 18,206,956 46, 100% 0% 9.21% 30.42% 2.04% 10.81% 6.09% 2.02% 39.40% 39.40% 100% 0% 9.21% 30.42% 2.04% 49,236,321 27,816,554 9,291,642 181,116,815 455,110 100% 0% 9.13% 30.15% 2.02% 10.81% 6.11% 2.04% 39.75%											
100% 0% 9.21% 30.42% 2.04% 10.81% 6.09% 2.02% 39.40% 100% 41,588,486 137,363,948 9,195,820 49,236,321 27,816,554 9,291,642 181,116,815 455, 100% 0% 9.13% 30.15% 2.02% 10.81% 6.11% 2.04% 39.75%	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
tor 100% 0% 9.13% 30.15% 2.02% 10.81% 2.02% 27.816,554 9.291,642 181,116,815 455.	Summer 3 / Winter 3 CP Factor	100%		9.21%	30.42%	2.04%	10.81%	%60.9	2.02%	39.40%	100.00%
tor 100% 0% 9.13% 30.15% 2.02% 10.81% 6.11% 2.04% 39.75%	Summer 3 / Winter 3 × Ton 10 Hrs			41 509 496	127 263 049	0 105 920	AD 028 321	27 816 EEA	0 201 642	181 116 815	155 600 587
0% 9.13% 30.15% 2.02% 10.81% 6.11% 2.04% 39.75%	Saminist of Whitel of A Top 10 118		1	1,000,400	046,000,101	9,190,020	13,400,04	+00,010,12	2,01,046	210,011,10	100,000
	Summer 3 / Winter 3 X Top 10 Factor	100%		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)

12 CP PPL-VMA PPL-CM PPL-CM PPL-CM PPL-CM PPL-MV P					Compo	Composite Demand / Energy Factors	rgy Factors				
D E PPL-WA PPL-OR PP					12 CP	Annual Energy C	omposite				
γ 6 057 405 27.15.572 17.46.924 96.539 968.705 5.90.516 1.82.224 34.269.181 8.26.908 1.26.908		۵	ш	PPL-WA		PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
The color The	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
3y 4,520,645,706 15,284,363,431 982,427,759 6,539,865,727 1,126,365,570 1,126,365,570 1,126,396,570	12 CP Factor			9.17%	30.81%	1.98%	11.16%	2:30%	2.06%	38.92%	100.00%
protection Figh 29.44% 1.88% 1.2.60% 6.52% 2.43% 38.41% actor 75% 25% 25% 30.47% 1.98% 1.18% 6.05% 2.15% 38.41% actor 50% 75% 8.94% 20.47% 1.92% 1.18% 6.18% 2.13% 3.86.7% 38.64% actor 50% 75% 8.82% 29.78% 1.92% 1.2.24% 6.58% 2.13% 38.64% 38.64% actor 50% 75% 8.82% 29.78% 1.92% PPL-MY UPL-MY UPL-MY 1.0.40% 2.34% 38.64% Y 724,444 2.25,766 PPL-CA PPL-MY UPL-MY UPL-MY UPL-MY Y 75% 8.82% 2.74% 1.62% 6.59,986,792 3.348,372 3.848,372 3.848,372 A 4.520,44% 15,244% 1.38% 1.2.60% 2.13% 1.1.269 3.848,372 3.844,8 3.44% A	Annual Energy			4,520,645,706		982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
actor 75% 25% 9.05% 3.047% 1.96% 11.52% 6.05% 2.15% 38.90% actor 25% 50% 8.82% 3.047% 1.94% 1.18% 6.21% 2.24% 38.67% actor 25% 75% 8.82% 3.047% 1.92% 1.12,24% 6.21% 2.24% 38.67% actor 25% 75% 1.82% 1.92% 1.12,24% 6.21% 2.15% 38.67% Actor 1.00 PPL-OR PPL-OR <th< td=""><td>Energy Factor</td><td></td><td></td><td>8.71%</td><td></td><td>1.89%</td><td>12.60%</td><td>6.52%</td><td>2.43%</td><td>38.41%</td><td>100.00%</td></th<>	Energy Factor			8.71%		1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
actor 60% 60% 8.94% 30.13% 1.94% 11.88% 6.21% 2.24% 38.67% actor 7.58% 75% 8.82% 29.78% 1.92% 11.224% 6.36% 2.33% 2.24% 38.67% actor 7.58% 75% 8.82% 29.78% 11.92% 11.224% 6.36% 2.33% 1.88.67% 2.84% 2.84% 2.22.742% 2.224% 2.22	Composite Factor	75%	<u> </u>	9.05%		1.96%	11.52%	6.05%	2.15%	38.80%	100.00%
Column C	Composite Factor	20%				1.94%	11.88%	6.21%	2.24%	38.67%	100.00%
D E PPL-WA PPL-CA PPL-CA PPL-WY UPL-UT To	Composite Factor	25%				1.92%	12.24%	9:36%	2.33%	38.54%	100.00%
D E PPL-WA PPL-OR PPL-OR PPL-OR PPL-OR PPL-OR PPL-OR PPL-MY PPL-OR PPL-MY PPL-OR PPL-MY PPL-MY PPL-OR PPL-MY PP					90 8)					
Decomposition Decompositio					- 1	Allinai Elleryy Co	Julposite				
1,000, 2,000,			ш	PPL-WA	ď	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
3y 8 92% 27.42% 2.02% 10.30% 6.74% 1.86% 42.73% 42.73% 3y 1 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 actor 75% 25% 8.87% 27.93% 1.39% 10.88% 6.69% 2.03% 41.65% 51.43% 41.65% 51.43% 41.65% 51.43% 41.65% 51.43% 41.65% 51.43% 41.65% 51.43% 51.44% 41.65% 51.43% 51.44% 41.65% 51.43% 51.44% 41.65% 51.43% 51.44% 51.44% 51.44% 51.44% 51.44% 51.44% 51.44% 41.65% 51.44%	Annual CP			724,444		164,145	836,193	547,088	151,073	3,468,372	8,117,080
3y 4,520,645,706 15,284,385,3431 982,427,759 6,539,986,792 3,384,855,701 1,259,395,569 19,940,731,690 51,912,834 part 8,7% 8,7% 29,44% 1,89% 1,260% 6,52% 1,29% 1,260% 6,58% 2,43% 1,940,731,690 51,914 1,95% 1,99% 1,198% 6,68% 2,20% 41,65% 1,940,731,690 51,914 40,57% 41,65%	1 CP Factor			8.92%		2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
ort 8,71% 29.44% 1.89% 12.60% 6.52% 2.43% 38.41% 38.41% actor 75% 25% 8.77% 27.93% 1.99% 10.88% 6.69% 2.00% 41.65% 41.65% actor 50% 50% 8.87% 28.43% 1.98% 1.1.45% 6.69% 2.14% 40.57% 40.57% actor 25% 75% 8.76% 28.94% 1.92% 11.45% 6.68% 2.14% 40.57% 40.57% actor 25% 75% 8.76% 28.94% PPL-CA PPL-WA UPL-UD UPL-UT To r 782.95 2.639.481 PPL-CA PPL-WA UPL-UD UPL-WY UPL-UT To r 8.83% 2.93.481 982,427,759 6,539,986,792 3.384,855,701 1,259,385,569 19,940,731,690 51,940,731,690 51,940,731,690 51,940,731,690 51,940,731,690 2.15% 2.25% 2.25% 38,96% 2.25% 38,96% 2.25%	Annual Energy			4,520,645,706	1	982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
actor 75% 25% 8.87% 27.93% 1.99% 10.88% 6.69% 2.00% 41.65% actor 50% 60% 8.82% 28.43% 1.96% 11.45% 6.63% 2.14% 40.57% actor 50% 50% 8.76% 28.94% 1.96% 1.202% 6.63% 2.14% 40.57% actor 25% 75% 8.76% 28.94% 1.96% PPL-NY UPL-NY UPL-UT To r A PPL-NA PPL-OR PPL-CA PPL-NY UPL-NY UPL-UT To r B PPL-NA PPL-OR PPL-NY UPL-NY UPL-UT To r 782.957 2.639.481 1.88.904 897.121 671.089 UPL-WY UPL-UT To r 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 51.940,731.690 r B B C B <th< td=""><td>Energy Factor</td><td></td><td></td><td>8.71%</td><td></td><td>1.89%</td><td>12.60%</td><td>6.52%</td><td>2.43%</td><td>38.41%</td><td>100.00%</td></th<>	Energy Factor			8.71%		1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
actor 50% 50% 6.0% 8.82% 28.43% 1.96% 11.45% 6.63% 2.14% 40.57% actor 25% 75% 8.76% 28.94% 1.92% 11.02% 6.63% 2.14% 40.57% actor 25% 75% 8.76% 28.94% PPL-CA PPL-CA PPL-WY UPL-WY UPL-WY UPL-UT To r A 782.957 2.639.481 188.904 897.121 671.089 184.209 35.02.529 8 r B 8.83% 2.9.77% 2.13% 10.12% 7.57% 2.08% 39.50% 1.912. r B 8.83% 2.94% 1.89% 1.2.60% 3.384.855.701 1.259.395.569 19.940,731.690 51.912. r B 8.80% 2.94% 1.89% 2.07% 7.04% 2.43% 39.20% r B 8.80% 2.96% 2.96% 2.01% 1.36% 7.04% 2.25% 38.96%	Composite Factor	75%		8.87%	27.93%	1.99%	10.88%	%69.9	2.00%	41.65%	100.00%
actor 25% 75% 8.76% 8.76% 1.92% 1.92% 12.02% 6.58% 2.28% 39.49% I A Long Annual Energy Composite I A PPL-WA I NCP Annual Energy Composite I A PPL-WA I PPL-WA I NPL-UNT UPL-UNT	Composite Factor	20%	ł		28.43%	1.96%	11.45%	6.63%	2.14%	40.57%	100.00%
1 NCP Annual Energy Composite r PPL-WA PPL-OR PPL-OR PPL-WY UPL-UV UPL-UV Tol.12% UPL-WY UPL-UV Tol.12% UPL-WY UPL-UT Tol.12% Tol.12% UPL-WY UPL-UT Tol.12% Tol.12% UPL-WY UPL-UT Tol.12%	Composite Factor	25%	1 1	8.76%	28.94%	1.92%	12.02%	6.58%	2.28%	39.49%	100.00%
r PPL-WA PPL-OR					ANCE		210000				
r FL-WA FL-				AW JOO	00	Doi CA	AN IOO	2 2	WW IGH	F1 101	Total
r 8.83% 29.77% 2.13% 10.12% 7.57% 2.08% 39.50% 3y 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 51,912,312 actor 75% 25% 8.80% 29,69% 2,07% 10,74% 7,34% 2,16% 39,23% actor 50% 60% 8,77% 29,61% 2,01% 11,36% 7,04% 2,25% 38,96% actor 25% 8,74% 29,61% 1,95% 11,36% 6,78% 2,25% 38,96%	Annual NCP	1	1	782.957		188 904	897.121	671.089	184 209	3.502.529	8.866.290
4,520,645,706 15,284,383,431 982,427,759 6,539,986,792 3,384,855,701 1,259,395,569 19,940,731,690 51,912 7,5% 25% 8.71% 29,44% 1,89% 2,07% 10,74% 7,31% 2,16% 38,486 51,91 50% 50% 8.77% 29,61% 2,01% 11,36% 7,04% 2,25% 38,96% 55% 75% 8.74% 29,61% 2,01% 11,36% 7,04% 2,25% 38,96% 6,5% 75% 8,74% 29,52% 1,95% 1,98% 6,78% 2,34% 38,69%	1 NCP Factor			8.83%		2.13%	10.12%	7.57%	2.08%	39.50%	100.00%
75% 25% 8.77% 29.44% 1.89% 12.60% 6.52% 2.43% 38.41% 75% 25% 8.80% 29.69% 2.07% 10.74% 7.31% 2.16% 39.23% 50% 50% 8.77% 29.61% 2.01% 11.36% 7.04% 2.25% 38.96% 50% 75% 8.74% 29.52% 1.95% 11.98% 6.78% 2.34% 38.69%	Annual Energy			4,520,645,706	1	982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
75% 25% 8.80% 29.69% 2.07% 10.74% 7.31% 2.16% 39.23% 50% 50% 8.77% 29.61% 2.01% 11.36% 7.04% 2.25% 38.96% 50% 75% 8.74% 29.52% 1.95% 11.98% 6.78% 2.34% 38.69%	Energy Factor			8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
50% 50% 8.77% 29.61% 2.01% 11.36% 7.04% 2.25% 38.96% - 25% 75% 8.74% 29.52% 1.95% 11.98% 6.78% 2.34% 38.69%	Composite Factor	75%		8.80%	29.69%	2.07%	10.74%	7.31%	2.16%	39.23%	100.00%
. 25% 75% 8.74% 29.52% 1.95% 11.98% 6.78% 2.34% 38.69%	Composite Factor	20%	ŧ I		29.61%	2.01%	11.36%	7.04%	2.25%	38.96%	100.00%
	Composite Factor	25%		8.74%	29.52%	1.95%	11.98%	%82'9	2.34%	38.69%	100.00%

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

						Average & Excess	9:		_		
	۵	Ш	Н	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)		L	-	516,055	1,744,790	112,149	746,574	386,399	143,767	2,276,339	5,926,074
Excess MW		\square	H	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	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%
				With the second		Peak & Average (1 CP)	CP)		-		
		Ш	H	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP	L	L	╀	724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
Average MW (MWh / 8760)		Ц	H	516,055	1,744,790	112,149	746,574	386,399	143,767	2,276,339	5,926,074
Demand Component Demand Allocation Factor CP / (CP + (MWh/8760))	28%			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	45%	8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100,00%
Total Allocation Factor	28%	42%	%	8.83%	28.27%	1.97%	11.27%	6.65%	2.10%	40.91%	100.00%

				<u>a</u>	Peak & Average (12 CP)	CP)		-		
	۵	ш	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))	22%		9.17%	30.81%	1.98%	11.16%	5.90%	7.06%	38.92%	100.00%
Energy Component	L									
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	22%	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	1 CP				
		ш	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		L	8.92%		2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
	_	L								
Annual Energy		L	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		L	8.71%	6 29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
		L								
Composite Factor	38%	38% 62%	% 8.79%	6 28.67%	1.94%	11.73%	909.9	2.21%	40.05%	100.00%
				Fourty	Enrivalent Boaker Summer Winter CP	r Winter CP				
				in and an	Silling Cana					
	۵	Ш	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%		1.95%	10.62%	6.02%	2.03%	40.93%	100.00%
		L								
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%	6 29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
	_	L								
Composite Eartor	38%	%69	% A R5%	79 42%	1 91%	11 85%	6.33%	2 2 7 %	39.37%	100.00%