Docket No. UE-001878
PacifiCorp Exhibit ___, DLT-2
Witness: Taylor

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Joint Application of PACIFICORP and PACIFICORP, WASHINGTON, INC. for an Order Approving (1) the Transfer of Distribution Property from PacifiCorp to an Affiliate, PacifiCorp, Washington, Inc., (2) the Transfer by PacifiCorp of Certain Utility Property to an Affiliate, the Service Company, and (3) the Proposed Accounting Treatment for Regulatory Assets and Liabilities, and an Order Granting an Exemption under RCW 80.08.047 for the Issuance or Assumption of Securities and Encumbrance of Assets by PacifiCorp, Washington, Inc. and/or PacifiCorp	Docket No. UE-001878

PACIFICORP

EXHIBIT TO
DIRECT TESTIMONY OF
DAVID L. TAYLOR

June 2001

Annual Comparison
of Washington Revenue Requirement Analyses
under Commodity Competition case

		Total Annual Estimated Revenue Requirement									
	10-year NPV	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Load Forecast I											
Reference Case Revenue Requirement	$ 1,660,442	$ 241,752	$ 243,277	$ 246,813	$ 249,727	$ 257,435	$ 266,143	$ 268,893	$ 276,455	$ 288,423	$ 302,630
SRP Revenue Requirement	$ 1,654,877	$ 241,309	$ 242,061	$ 245,932	$ 248,959	$ 256,887	$ 265,073	$ 267,777	$ 275,516	$ 287,334	$ 301,791
Island States Revenue Requirement	$ 1,751,418	$ 251,854	$ 241,949	$ 248,701	$ 253,270	$ 262,835	$ 274,178	$ 299,960	$ 307,735	$ 327,249	$ 351,121
Load Forecast II											
Reference Case Revenue Requirement	$ 1,693,218	$ 241,752	$ 243,277	$ 246,813	$ 249,727	$ 262,310	$ 275,416	$ 280,173	$ 288,484	$ 301,794	$ 316,600
SRP Revenue Requirement	$ 1,689,055	$ 241,311	$ 242,078	$ 245,933	$ 248,959	$ 261,334	$ 273,866	$ 279,278	$ 287,740	$ 301,805	$ 318,686
Island States Revenue Requirement	$ 1,787,147	$ 251,856	$ 241,966	$ 248,701	$ 253,270	$ 267,709	$ 283,543	$ 312,007	$ 320,433	$ 342,186	$ 368,463
	20-year NPV	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Load Forecast I											
Reference Case Revenue Requirement	$ 2,567,986	$ 300,280	$ 314,180	$ 315,501	$ 331,557	$ 338,319	$ 342,019	$ 358,513	$ 367,996	$ 384,171	$ 408,119
SRP Revenue Requirement	$ 2,565,351	$ 300,583	$ 314,407	$ 321,415	$ 330,507	$ 338,183	$ 343,194	$ 359,165	$ 369,229	$ 386,670	$ 408,072
Island States Revenue Requirement	$ 2,735,347	$ 336,478	$ 346,285	$ 350,291	$ 360,905	$ 364,895	$ 371,644	$ 382,661	$ 397,824	$ 399,383	$ 419,282
Load Forecast II											
Reference Case Revenue Requirement	$ 2,676,980	$ 319,757	$ 337,886	$ 341,494	$ 360,019	$ 367,324	$ 372,987	$ 389,757	$ 401,595	$ 420,600	$ 446,885
SRP Revenue Requirement	$ 2,687,062	$ 322,809	$ 341,943	$ 349,878	$ 363,136	$ 372,426	$ 379,164	$ 396,994	$ 409,107	$ 426,899	$ 450,616
Island States Revenue Requirement	$ 2,859,289	$ 359,103	$ 373,858	$ 378,992	$ 393,571	$ 399,261	$ 408,180	$ 420,639	$ 438,210	$ 439,729	$ 462,336
	30-year NPV	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Forecast I											
Reference Case Revenue Requirement	$ 3,133,048	$ 430,693	$ 449,533	$ 469,046	$ 476,449	$ 507,911	$ 523,514	$ 546,193	$ 564,893	$ 587,529	$ 609,437
SRP Revenue Requirement	$ 3,132,322	$ 429,812	$ 448,009	$ 467,501	$ 476,537	$ 510,179	$ 530,443	$ 549,376	$ 569,910	$ 591,493	$ 615,274
Island States Revenue Requirement	$ 3,293,423	$ 431,031	$ 448,912	$ 467,910	$ 472,911	$ 496,189	$ 515,665	$ 533,767	$ 553,420	$ 574,096	$ 596,894
Load Forecast II											
Reference Case Revenue Requirement	$ 3,300,582	$ 472,711	$ 494,170	$ 516,305	$ 525,120	$ 560,822	$ 581,414	$ 604,282	$ 624,919	$ 650,128	$ 674,499
SRP Revenue Requirement	$ 3,314,686	$ 474,572	$ 495,101	$ 517,086	$ 527,906	$ 564,468	$ 587,398	$ 608,380	$ 631,756	$ 656,067	$ 682,949
Island States Revenue Requirement	$ 3,478,644	$ 476,019	$ 496,342	$ 517,876	$ 524,687	$ 550,927	$ 573,204	$ 593,491	$ 616,119	$ 639,740	$ 665,857

Annual Comparison
of Washington Revenue Requirement Analyses

under Cyclic Growth case

		Total Annual Estimated Revenue Requirement									
	10-year NPV	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Load Forecast I											
Reference Case Revenue Requirement	$ 1,680,780	$ 242,535	$ 245,302	$ 247,538	$ 250,549	$ 260,567	$ 273,390	$ 276,540	$ 282,008	$ 292,883	$ 306,153
SRP Revenue Requirement	$ 1,675,651	$ 243,418	$ 244,961	$ 246,811	$ 249,704	$ 259,738	$ 271,674	$ 274,718	$ 280,461	$ 291,317	$ 305,052
Island States Revenue Requirement	$ 1,817,863	$ 262,045	$ 257,869	$ 260,123	$ 263,507	$ 273,329	$ 290,443	$ 322,951	$ 320,865	$ 325,072	$ 334,839
Load Forecast II											
Reference Case Revenue Requirement	$ 1,712,572	$ 242,534	$ 245,302	$ 247,538	$ 250,548	$ 265,752	$ 282,756	$ 287,868	$ 293,643	$ 305,300	$ 318,613
SRP Revenue Requirement	$ 1,718,071	$ 243,421	$ 244,978	$ 246,811	$ 249,704	$ 267,171	$ 284,848	$ 289,889	$ 295,389	$ 306,865	$ 321,637
Island States Revenue Requirement	$ 1,860,665	$ 262,047	$ 257,886	$ 260,124	$ 263,505	$ 281,223	$ 303,970	$ 338,375	$ 335,813	$ 340,380	$ 351,031
	20-year NPV	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Load Forecast I											
Reference Case Revenue Requirement	$ 2,656,786	$ 319,669	$ 342,470	$ 340,913	$ 343,664	$ 348,647	$ 365,898	$ 383,382	$ 399,034	$ 425,760	$ 466,968
SRP Revenue Requirement	$ 2,650,592	$ 318,257	$ 340,202	$ 344,557	$ 341,824	$ 348,043	$ 365,577	$ 382,544	$ 398,788	$ 427,161	$ 466,193
Island States Revenue Requirement	$ 2,893,940	$ 349,679	$ 373,815	$ 392,658	$ 392,804	$ 396,723	$ 414,073	$ 421,443	$ 430,312	$ 446,193	$ 478,462
Load Forecast II											
Reference Case Revenue Requirement	$ 2,765,520	$ 337,787	$ 365,003	$ 367,135	$ 372,898	$ 378,851	$ 397,765	$ 415,236	$ 430,861	$ 464,087	$ 509,578
SRP Revenue Requirement	$ 2,801,694	$ 345,355	$ 375,572	$ 382,573	$ 381,717	$ 389,198	$ 410,582	$ 428,933	$ 446,240	$ 477,744	$ 517,986
Island States Revenue Requirement	$ 3,045,518	$ 375,916	$ 408,218	$ 430,740	$ 432,971	$ 438,344	$ 459,799	$ 468,114	$ 478,320	$ 496,847	$ 531,190
	30-year NPV	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Forecast I											
Reference Case Revenue Requirement	$ 3,336,831	$ 501,381	$ 526,833	$ 550,572	$ 565,923	$ 619,587	$ 640,985	$ 669,733	$ 694,889	$ 725,559	$ 754,615
SRP Revenue Requirement	$ 3,331,129	$ 499,648	$ 524,377	$ 547,923	$ 564,778	$ 620,586	$ 646,537	$ 671,424	$ 698,294	$ 727,852	$ 758,652
Island States Revenue Requirement	$ 3,546,540	$ 493,416	$ 517,114	$ 539,311	$ 548,267	$ 584,686	$ 608,635	$ 631,406	$ 656,038	$ 683,239	$ 711,538
Load Forecast II											
Reference Case Revenue Requirement	$ 3,514,002	$ 548,720	$ 577,467	$ 604,052	$ 621,696	$ 682,911	$ 709,748	$ 739,164	$ 766,805	$ 800,766	$ 832,762
SRP Revenue Requirement	$ 3,556,532	$ 554,469	$ 581,978	$ 608,556	$ 627,765	$ 687,171	$ 716,316	$ 743,824	$ 774,145	$ 806,958	$ 841,450
Island States Revenue Requirement	$ 3,773,679	$ 548,619	$ 575,329	$ 600,664	$ 612,065	$ 652,118	$ 679,576	$ 705,280	$ 733,676	$ 764,655	$ 797,154

Annual Comparison
of Washington Revenue Requirement Analyses
under Bullish Gas case

	10-year NPV	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
		Total Annual Estimated Revenue Requirement									
Load Forecast I											
Reference Case Revenue Requirement	$ 1,708,548	$ 245,783	$ 246,991	$ 248,655	$ 250,659	$ 259,831	$ 271,263	$ 279,882	$ 293,218	$ 313,210	$ 323,947
SRP Revenue Requirement	$ 1,706,746	$ 252,037	$ 247,480	$ 248,046	$ 249,781	$ 259,009	$ 269,690	$ 277,769	$ 290,436	$ 309,417	$ 321,281
Island States Revenue Requirement	$ 2,020,137	$ 332,881	$ 283,086	$ 283,982	$ 276,902	$ 273,857	$ 285,570	$ 338,489	$ 366,062	$ 397,716	$ 398,306
Load Forecast II											
Reference Case Revenue Requirement	$ 1,741,933	$ 245,783	$ 246,991	$ 248,655	$ 250,659	$ 265,019	$ 280,480	$ 291,383	$ 305,380	$ 326,984	$ 338,079
SRP Revenue Requirement	$ 1,760,106	$ 252,039	$ 247,497	$ 248,046	$ 249,781	$ 267,081	$ 283,057	$ 295,088	$ 310,619	$ 333,075	$ 344,804
Island States Revenue Requirement	$ 2,074,666	$ 332,884	$ 283,103	$ 283,982	$ 276,900	$ 282,214	$ 299,093	$ 356,149	$ 386,833	$ 422,024	$ 422,111

	20-year NPV	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Load Forecast I											
Reference Case Revenue Requirement	$ 2,730,486	$ 319,384	$ 328,520	$ 339,701	$ 364,445	$ 377,218	$ 395,211	$ 410,701	$ 429,962	$ 456,275	$ 532,844
SRP Revenue Requirement	$ 2,726,127	$ 318,189	$ 327,819	$ 343,783	$ 360,944	$ 374,600	$ 393,168	$ 408,420	$ 428,490	$ 457,060	$ 531,501
Island States Revenue Requirement	$ 3,248,174	$ 388,402	$ 398,284	$ 415,085	$ 443,552	$ 457,413	$ 485,624	$ 492,572	$ 526,701	$ 523,184	$ 596,295
Load Forecast II											
Reference Case Revenue Requirement	$ 2,852,881	$ 340,292	$ 354,221	$ 367,849	$ 395,796	$ 409,688	$ 431,736	$ 447,916	$ 470,640	$ 502,134	$ 588,733
SRP Revenue Requirement	$ 2,916,707	$ 351,263	$ 366,154	$ 386,269	$ 411,744	$ 428,562	$ 452,809	$ 469,327	$ 495,059	$ 522,952	$ 601,227
Island States Revenue Requirement	$ 3,441,842	$ 422,188	$ 437,357	$ 458,272	$ 494,985	$ 512,100	$ 546,722	$ 553,896	$ 594,018	$ 589,256	$ 666,729

	30-year NPV	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Forecast I											
Reference Case Revenue Requirement	$ 3,521,278	$ 574,708	$ 608,209	$ 635,305	$ 656,543	$ 722,677	$ 748,985	$ 782,827	$ 813,419	$ 852,028	$ 887,044
SRP Revenue Requirement	$ 3,516,373	$ 572,297	$ 605,025	$ 631,801	$ 654,452	$ 722,791	$ 753,575	$ 783,474	$ 815,695	$ 853,150	$ 889,824
Island States Revenue Requirement	$ 4,078,621	$ 617,436	$ 651,824	$ 680,088	$ 696,438	$ 745,389	$ 777,425	$ 808,647	$ 842,268	$ 881,261	$ 919,503
Load Forecast II											
Reference Case Revenue Requirement	$ 3,736,323	$ 636,844	$ 675,429	$ 706,354	$ 731,480	$ 807,999	$ 841,471	$ 877,749	$ 912,728	$ 957,230	$ 997,486
SRP Revenue Requirement	$ 3,809,067	$ 646,249	$ 683,040	$ 714,156	$ 740,612	$ 813,598	$ 849,370	$ 883,740	$ 921,360	$ 964,429	$ 1,007,190
Island States Revenue Requirement	$ 4,373,970	$ 691,331	$ 729,772	$ 762,273	$ 782,228	$ 836,038	$ 872,876	$ 908,396	$ 947,223	$ 991,516	$ 1,035,563

PPL Exhibit T-____(ANM-T)
Witnesses: MacRitchie/Wright/Furman

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Joint Application of PACIFICORP and PACIFICORP, WASHINGTON, INC. for an Order Approving (1) the Transfer of Distribution Property from PacifiCorp to an Affiliate, PacifiCorp, Washington, Inc., (2) the Transfer by PacifiCorp of Certain Utility Property to an Affiliate, the Service Company, and (3) the Proposed Accounting Treatment for Regulatory Assets and Liabilities, and an Order Granting an Exemption under RCW 80.08.047 for the Issuance or Assumption of Securities and Encumbrance of Assets by PacifiCorp, Washington, Inc. and/or PacifiCorp	Docket No. UE-00____

PACIFICORP

DIRECT TESTIMONY OF
ANDREW N. MACRITCHIE, MATTHEW R. WRIGHT AND DONALD N. FURMAN

December 2000

Hive Down Policy Testimony

Q. Please state your name, business address and position with PacifiCorp or ("the Company").

A. My name is Andrew N. MacRitchie. My business address is 825 NE Multnomah, Suite 2000, Portland, OR 97232. I am employed by PacifiCorp as Senior Vice President, Power Delivery.

My name is Matthew R. Wright. My business address is 825 NE Multnomah, Suite 2000, Portland, OR 97232. I am employed by PacifiCorp as Vice President, Regulation.

My name is Donald N. Furman. My business address is 825 NE Multnomah, Suite 1500, Portland, OR 97232. I am employed by PacifiCorp as Vice President, Transmission.

Qualifications

Q. Mr. MacRitchie, please summarize your education and business experience.

A. I received a degree from Glasgow University in Electrical and Electronic Engineering. I obtained an MBA from Strathclyde Graduate Business School in 1992 and undertook an Executive Development Program at Wharton Business School in 1996. I joined ScottishPower in 1986, initially as a Project Team Leader on engineering IT projects. Since then, I have led, or taken part in, many of the significant change programs within the Company. I was a key member of the ScottishPower-PacifiCorp merger team and led the subsequent PacifiCorp Transition Team effort. I assumed my position of Executive Vice President, Power Delivery in May of 2000.

Q. Mr. Wright, please summarize your education and business experience.

A. I graduated from Portsmouth University in 1986 with a first class honors degree in Geography and subsequently obtained a Chartered Institute of Marketing Diploma in 1989 and a distinction level M.B.A. from the University of Hull in 1996. I participated in Scottish Power's Business Leadership Program in 1997, facilitated by Wharton Business School, and attended external courses at Harvard Business School.

I joined Manweb in 1987 as a Commercial Graduate and worked for a number of years in the area of pricing and economics. I became Commercial Manager, Distribution in 1994 and joined the ScottishPower Group in 1995 following the acquisition of Manweb. Since that time, I worked in many of ScottishPower's business units including Southern Water, as part of the Transition Team following its acquisition in 1996, and Corporate Strategy. I became involved in ScottishPower's international team in January 1998 and was a key member of the PacifiCorp merger team. I assumed my current position as Vice President, Regulation in November 1999.

Q. Mr. Furman, please summarize your education and business experience.

A. I received a Bachelor of Arts degree in Economics from Northwestern University in 1979. I graduated from Northwestern School of Law of Lewis and Clark College with a JD degree in 1982. I joined PacifiCorp in 1994 as Assistant Vice President of National Marketing. I subsequently held positions as President of PacifiCorp Power Marketing (a subsidiary of the Company), Vice President of Domestic Business Development, and Vice President of Transmission. I am currently on assignment to direct the Companies efforts to comply with FERC Order 2000 through the formation of RTO West. From 1982 to 1986, I was Assistant General Counsel with Portland General Electric Company, where I had responsibility for various regulatory and commercial matters. From 1986 to 1988, I was an associate with the Stoel Rives law firm in Portland, Oregon where I handled similar matters. In 1988, I relocated to Pittsburgh, where I was a shareholder in the firm of Babst, Calland, Clements and Zomnir, PC. I represented a variety of power project developers, industrial customers and publicly owned utilities.

Purpose

Q. What is the purpose of your direct testimony in these proceedings?

A. We are providing policy testimony in regard to the Company's application for the Public Service Commission of Wyoming approvals necessary to implement the proposed restructuring of the Company. Under the Company's proposal, ownership of PacifiCorp's utility assets would be allocated among a generation company, which will be the existing PacifiCorp renamed "PacifiCorp Generation Company," a service company to be named "PacifiCorp," and six newly-created electric companies "PacifiCorp, Washington, Inc.," "PacifiCorp, Oregon, Inc.," "PacifiCorp, Utah, Inc.," "PacifiCorp, Idaho, Inc.," "PacifiCorp, Wyoming, Inc.," and "PacifiCorp, California, Inc." Control of the Company's transmission assets would be transferred to a regional transmission organization, RTO West ("RTO"). Above all of these companies in the corporate structure would be a newly-formed, nonoperating U.S. holding company, "PacifiCorp Holdings, Inc."

Q. What other testimony has been filed in support of the Company's application?

A. Direct testimony has also been filed on behalf of Alex Miller. Mr. Miller's testimony describes how the Company proposes to accomplish this reorganization and the nature and proposed timing of regulatory approvals that are required in respect to it. Mr. Miller's testimony also sets forth principles for establishing the terms of the power sales contract that the Company proposes be entered into between PacifiCorp Generation Company and PacifiCorp, Washington, Inc. (the "Power Supply Contract").

Q. Does the Company intend to file additional direct testimony in this proceeding?

A. Yes. We intend to file additional testimony that provides greater detail with respect to the terms of the power supply contract, and the service company contract and which quantifies the economic impact of the proposed restructuring. Additionally, during the second quarter of 2001, we expect to amend our application in this docket so as to seek Commission authority to transfer control of PacifiCorp's transmission assets to RTO West.

Q. Why is there a delay in the filing of some of the testimony?

A. For reasons that will be explained later in our testimony, an integral part of the proposed restructuring is the development of a "resource plan" for purposes of implementing Oregon's industry restructuring legislation (SB 1149). The resource plan has been developed in a public process involving representatives of the public and staff members from many of our state commissions. Decisions reflected in our proposed resource plan will impact a number of the economic analyses related to our proposed reorganization and state-by-state resource dedication decisions. In addition, we were not inclined to propose specific terms of a Power Supply Contract until we had an opportunity to have further discussions with Commission staff members and customer representatives with respect to it. Similarly, we are delaying seeking Commission authority to participate in RTO West because details of those arrangements are still being developed. However, we did not wish the resource plan process to go forward in Oregon without giving our other state commissions an opportunity to begin to consider the policy issues raised by it. We believe SB 1149 can only be successfully implemented if we achieve consensus on a number of important issues among the states. We wished to begin the consensus building process as soon as possible.

Q. On what basis will the Company's assets be distributed among the various sister companies in the proposed new structure?

A. For the great bulk of our assets, the appropriate allocation is self evident. Generation and mining assets are easily identified and left in PacifiCorp Generation Company. The bulk of our distribution assets already have a situs allocation and will be transferred to the appropriate state electric company. Other assets and functions are clearly "shared" among the business units and there is little question that they should be assigned to the service company. Nonetheless, we expect that there will be some assets or functions that could conceivably be assigned to either the service company or spread among the state electric companies. We propose to deal with these circumstances on a case-by-case basis in a way that will best assure efficiency and world-class customer service and in a way consistent with revenue recovery methods approved in our RTO filing.

Q. Why is PacifiCorp proposing this restructuring?

A. PacifiCorp's corporate structure and the manner in which it establishes retail prices have been fundamentally unchanged for more than 35 years. While we have not changed our structure, the environment in which we operate has dramatically changed. We find ourselves facing high risk and much uncertainty. These circumstances are not in the best interests of our customers because they cause us to be reluctant to make major new investments in infrastructure. The current environment also gives rise to substantial risks and uncertainties for third parties considering investments in transmission or generation facilities that would contribute to system reliability.

Our testimony seeks to demonstrate our proposed restructuring will better position PacifiCorp to respond to a number of external developments and that it is very much in the public interest.

Q. What external developments are you referring to?

A. These developments include: (1) direct access initiatives in Oregon and elsewhere; (2) the need to provide independent control of our transmission assets, consistent with expectations of the Federal Energy Regulatory Commission ("FERC"); (3) fundamental changes that have occurred in wholesale power markets; (4) the risk of generation supply shortages; (5) industry consolidation; (6) the divergent policy goals of the state commissions that regulate us; (7) the limitations of traditional cost-of-service regulation; and (8) the breakdown of the Company's interjurisdictional cost allocation process. While we will discuss each of these developments in turn, we believe that they are all strongly interrelated and demand a comprehensive response that will appropriately position PacifiCorp to provide its customers with high quality service at reasonable prices in the decades ahead.

Direct Access Initiatives

Q. How have direct access initiatives influenced the Company's decision?

A. The different states in which PacifiCorp serves have had different attitudes and responses to the notion of mandating or permitting retail competition in the sale of electricity. While we understand that it is the right and responsibility of each state to respond to these issues as it sees fit, we have come to understand that under our current structure, direct access initiatives, or lack of initiatives, taken in one of our states, have consequences for our customers in other states and create new and unacceptable risks for our shareholders. We believe means need to be found to permit each state to pursue (or not to pursue) direct access in its own way and at its own pace without adverse impact to customers in other states or losses to our shareholders.

Q. Please describe how events in one state can have such broader implications.

A. Among the seven states where we once provided retail electric service, California and Montana were the first to enact retail access legislation. We found it very difficult to reconcile the approaches taken in those states with the balance of our operations in other states that remained subject to traditional cost-of-service regulation. For example, in California, there was a strong policy favoring divestiture of generating assets and an apparent requirement that PacifiCorp cede control over its transmission system to the California ISO. Neither of these steps would be appropriate in light of PacifiCorp's operations in six other states. Additionally, California enacted a code of conduct directed at the three major utilities operating in that state that was not compatible with our corporate structure. Concerns such as this substantially contributed to the Company's decision to seek to dispose of its California and Montana service territories which, fortunately, are relatively small compared to the balance of our operations.

Oregon was the next one of our retail jurisdictions to pursue direct access. S.B. 1149 was enacted by the Oregon Legislature during the summer of 1999. The Oregon Public Utility Commission ("OPUC") commenced a rulemaking proceeding in January of this year which culminated in an order adopting administrative rules implementing S.B. 1149 ("Oregon Rules"). In adopting S.B. 1149, the Oregon Legislature determined that, at least until further experience is gained, only non-residential customers should have direct access to retail electric markets and that residential customers would have "portfolio" rate options available to them that reflected competing wholesale offerings for market power and "green" resources.

A critical element of the Oregon Rules is a requirement that both Oregon "electric companies" (Portland General Electric Company and PacifiCorp) file proposed "resource plans" with the OPUC. The resource plan process will require PacifiCorp to identify (1) a portion of its total generating resources that it proposes to allocate to Oregon; (2) specify what portion of this Oregon share should be dedicated to serve the current and reasonably-expected loads of residential and small non-residential customers; and (3) specify what portion should be "released to the competitive market" by either being deregulated or sold. The Oregon resource planning process presents significant new issues for PacifiCorp and its regulators in all of its jurisdictions.

Q. Please describe these issues.

A. There are a number of concerns, but let us describe three of the most perplexing areas. Heretofore, fixed shares of PacifiCorp's specific generating and transmission resources were not allocated among its various state jurisdictions. The perspective has been that PacifiCorp has a single bulk power system that is dispatched on an optimal basis for the benefit of all of its customers. Generally speaking, the fixed costs of that single system have been allocated based upon each state's relative contribution to system peak demand in any given year and the variable costs have been allocated based upon each state's relative energy consumption during any given year. PacifiCorp has concluded that the expectation in the Oregon Rules that a portion of its generating resources be "released to the competitive market" cannot be achieved in the context of the current system of interjurisdictional cost allocations because, among other reasons, the current system assumes dynamic changes in cost assignments whereas a permanent "release" to the market assumes a fixed interjurisdictional dedication of resources.

The Oregon Rules also contemplate that PacifiCorp's cost-of-service rates to residential customers, and those small non-residential customers who do not elect direct access, will be based upon the cost of those generating resources permanently dedicated to serving those customers as reflected in the resource plan. This too is contrary to past practice, where cost-of-service rates were based upon an allocation of the costs of operating PacifiCorp's entire system. PacifiCorp does not believe that a meaningful cost-of-service rate can be derived from a relatively small subset of its generating resources because that subset does not and will not operate independent from the whole. For example the capacity of a "slice" of PacifiCorp's generating resources that corresponds to the percentage of the Company's generation costs that have historically been supported by Oregon cost-of-service customers is not nearly large enough to cover the peak loads of Oregon cost-of-service customers. That is because in winter months, Oregon draws on generating capacity that is supported by other states and during summer months, generating capacity supported by Oregon is available to support summer-peaking states. Additionally, for reasons such as this, the apparent average cost of operating the entire system, absent the portion of the system allocated to Oregon, will be different (and likely higher) than the actual average cost of operating the entire system. That is to say, an inappropriate balkanization of our generating system could result in an increase in our cost of service in some or all of our retail jurisdictions.

Finally, the Oregon Rules contemplate that to the extent Oregon cost-of-service customers "outgrow" the resources allocated to them in the resource plan, additional resources acquired to serve them will not be included in the Company's Oregon rate base and that such incremental requirements will be served at a market price. This is contrary to the past practice of assuming that all new rate base additions are constructed to serve the entire system and allocated accordingly. It is not at all clear how we can accommodate Oregon's expectations within the current interjurisdictional cost allocation system.

Q. Why should states other than Oregon countenance a permanent allocation of a fixed portion of the Company's generation to Oregon or any other state?

A. Because of its concerns about issues such as this, PacifiCorp did not support SB 1149. However, SB 1149 became law. While we recognize that no state is obligated to embrace the policy decisions that have been made in Oregon, a failure to reach a consensus on the interjurisdictional allocation issues raised by SB 1149 will condemn the Company, its regulators and its customers to years of "gridlock" and contentiousness that is not in anyone's interest.

Q. Are current direct access initiatives limited to Oregon?

A. No. A legislative task force is studying the matter in Utah. The Wyoming Commission has encouraged the Company and its industrial customers to determine whether a consensus proposal can be developed.

Q. Do these activities have implications for other states?

A. Inevitably they do. In Utah, for example, a coalition of industrial customers drafted and aggressively promoted an industry restructuring bill that would have the effect of precluding PacifiCorp from providing regulated electric service in Utah after July 1, 2002 and which would afford the Utah Commission authority to require PacifiCorp to divest its generating plants. The authors of this proposal were apparently unaware of its consequences for a multi-state utility. While we were strongly opposed to this initiative and do not expect it to be successful, it again illustrates how, under our current structure and regulation, customers in all of our jurisdictions can be profoundly impacted by restructuring efforts in a single state. Even a more limited approach, which allows only the very largest industrial customers in Utah to go to market, would raise significant issues as to which customers are entitled to the benefits of and responsible for the costs of the "freed-up" generation.

Transmission Issues

Q. What is occurring in respect to the PacifiCorp's transmission system?

A. On January 6, 1999, in Order 2000, the FERC required all public utilities under its jurisdiction (including PacifiCorp) to file, by October 15, 2000, either: (a) a comprehensive filing to create a regional transmission organization ("RTO") or (b) a detailed explanation of why such a filing could not be made.

Q. Why did the FERC take this initiative?

A. The FERC recognizes that the demands placed on the transmission grid have changed with the changing structure of the electrical industry. The FERC has determined that independent RTOs offering transmission products and services on a fair and non-discriminatory basis is necessary for competitive power markets to succeed. The move to RTOs is a logical next step in wholesale electricity deregulation which began with the passage of the Energy Policy Act of 1992. A key purpose of that Act was to encourage competition and thereby reduce prices paid by ultimate consumers of electricity. To implement the Energy Policy Act, the FERC issued Orders 888 and 889 in 1996. Those orders required utilities that owned transmission systems to separate their "merchant" and transmission functions to ensure that the merchant function did not enjoy preferential treatment.

In Order 2000, the FERC concluded that RTOs are required to address potential problems that it believes were not fully resolved by its Orders 888 and 889.

Q. What are these unresolved issues?

A. Currently, electricity moving across states and regions may pass over transmission lines owned by several utilities. Each time it crosses into one of these "control areas," a rate is charged by the utility that operates it. This accumulation of charges is called "pancaking". Because an RTO will be regional, it will be able to assure delivery over longer distances without rate pancaking. The FERC believes that RTO formation should result in better management of congestion across constrained transmission paths, resolve conflicts in scheduling between utilities, promote more competitive power markets and more efficiently manage differences in transmission maintenance practices and schedules.

RTO formation will resolve current uncertainty as to who bears responsibility for upgrading the region's transmission grid and should reduce regulatory risks and create incentives for investment in new transmission facilities.

Another major concern is system reliability. The FERC believes that a single operator of a regional grid would eliminate reliability constraints caused by separate utility decision making, assure better coordination during system emergencies and provide improved coordination of generation and transmission system outages.

Q. Does PacifiCorp agree that participation in an RTO will achieve the benefits envisioned by the FERC?

A. Yes. PacifiCorp believes that a properly-structured RTO can be a significant source of benefits for electricity consumers.

Q. What is required of an RTO?

A. The FERC has afforded considerable flexibility to the various geographic areas of the United States regarding what form their RTO may take. However, the FERC expects that an RTO possess certain minimum characteristics and perform specified minimum functions.

The four minimum characteristics are:

1. The RTO must be independent from power market participants.
2. The RTO must have an appropriate scope and geographic configuration.
3. The RTO must possess operational authority for all transmission facilities under its control.
4. The RTO must have exclusive authority to maintain short-term reliability.

Q. How has PacifiCorp responded to FERC Order 2000?

A. PacifiCorp concluded that it should take a leadership role in ensuring that the benefits of an RTO are maximized. It has joined with seven other investor-owned utilities and the Bonneville Power Administration (commonly referred to as "the filing utilities") to form a non-profit corporation known as "RTO West" to fund and develop an RTO proposal. RTO West will encompass transmission facilities currently in the Northwest Power Pool and those owned by the Nevada Power Company. We are hopeful that other transmission owners will subsequently join, including entities in British Columbia and Alberta, Canada.

Q. How will RTO West be organized?

A. RTO West will be a non-profit independent system operator, or ISO. While it will have full control of all facilities needed for bulk power transfers, it will not own wires and poles. It will be governed by an independent board of directors with a "stakeholder" advisory board.

Q. Have the filing utilities made a filing with FERC in response to Order 2000?

A. Yes. On October 23, 2000 the filing utilities filed their proposal to form RTO West. A copy of the filing is included as Application Exhibit 4.

Q. What action of this Commission will eventually be required in connection with PacifiCorp's participation in RTO West?

A. This Commission must approve transfer of control of PacifiCorp's transmission assets to RTO West pursuant to [statute].

Wholesale Power Markets and New Generation

Q. How have wholesale power markets changed?

A. Last summer, the extreme volatility of prices in Western wholesale markets was a subject of front-page news. From time to time, prices reached levels that were not conceived of two years ago.

Q. What are the implications of this price volatility for PacifiCorp and its retail customers?

A. For the past several decades, PacifiCorp participated in wholesale markets as a means of disposing of short-term surpluses of generation and dispatching its system in a manner that lowered its costs to its retail customers. Until the mid- to late-1990's, the Company's wholesale power marketing activities centered around long term contracts that generated attractive margins with relatively little risk. The margins from these contracts were credited against retail prices under the "revenue credit" method and contributed substantially to moderating or eliminating retail price increases. Because the wholesale power market has now grown far more competitive and because of the uncertainty surrounding future prices, the market has shifted to relatively short-term transactions with razor-thin margins. We have even had intervener witnesses in recent rate proceedings who have suggested that the Company has lost money on its short-term firm transactions. While we do not agree with this conclusion, it seems clear that without incurring risks on behalf of our retail customers that we believe would be imprudent, we are no longer able to generate total margins from new wholesale sales that are sufficient to materially reduce retail prices. Over time, our existing long-term sale contracts are expiring or dropping below current market prices, resulting in significant upward pressure on our retail revenue requirement.

Q. What do you believe is the cause of the recent price volatility in wholesale power markets?

A. No one seems to be able to fully explain this phenomenon and we do not profess to have all the answers. However, it appears that the market remains immature in that mechanisms are not in place that cause demand to appropriately respond to high prices and new generation has not been constructed at a rate that provides an adequate cushion at times of peak demand on the system. The industry is at an uncomfortable stage of being half regulated and half unregulated and not knowing what future changes will occur. An unfortunate and paradoxical side effect of the developments in California last summer is that the durability of the deregulation initiatives that have occurred is thrown into question. The entities who one would expect to construct new generation are more inclined to sit on the sidelines as the political process in California runs its course and to puzzle about the future role of price caps in an ostensibly deregulated market.

Furthermore, under existing circumstances, utilities have an obligation to serve retail customers at a fixed price, independent of their cost of supply and have no easy means of negotiating arrangements with retail customers to reduce their demand at times of extraordinarily high market prices, even if such arrangements were highly attractive to customers.

On the supply side of the equation, there remains great uncertainty as to when and how deregulation will evolve and whether utilities will retain an obligation to serve. Under these circumstances, there are substantial risks and few incentives for either utilities or independent power producers to construct new generation. We believe that as the "rules of the game" are clarified, the market will operate in a more predictable and satisfactory fashion. However, we think a "wait and see" attitude on the part of policy makers may well exacerbate current market irregularities.

Distribution Issues

Q. So far, your testimony has addressed generation supply and transmission issues. Are changes also occurring in the industry with respect to the distribution function?

A. Yes. We perceive a world-wide trend toward the consolidation of the distribution function. It appears that in order to optimize efficiency and customer service in the distribution, metering and billing functions, a customer base much larger than PacifiCorp's is required. Each year, there are fewer and fewer providers of distribution services as a result of corporate mergers and acquisitions that are motivated by a desire to reduce costs and remain competitive.

Q. Does PacifiCorp view this as a positive development?

A. Yes and no. On one hand, we understand that customers and shareholders will continue to demand greater and greater efficiency and levels of customer service and that they are entitled to do so. On the other hand, we appreciate that customers and regulators are uncomfortable with consolidation to the extent that it results in a sense of isolation from the distribution services provider. We believe that a means needs to be found to benefit from economies of scale, while retaining a close connection with local customers, communities and regulators.

<u>State Regulatory Policies</u>

Q. Do PacifiCorp's regulators have similar views in respect to the industry developments that you have described?

A. Our regulators share a concern that customers receive the best possible service at the lowest possible price. Our regulators also appear to recognize an obligation to be fair to the Company and to permit it to have a reasonable opportunity to earn an adequate rate of return. However, there seems to be considerable divergence in views as to how these goals are best accomplished.

Q. Please provide examples of these differing views.

A. As indicated previously, our state regulators and legislators have highly divergent views as to the appropriate nature and timing of direct access. Our regulators have differing views concerning the desirability of load growth and how any load growth that does occur should be met. Some of our regulators are more enthusiastic about renewable resources and demand side management than others. The OPUC is supportive of demand-side and renewable resources, but now expects them to be funded out of "public purpose charges" and no longer reflected in our electricity rates. Some states favor our construction of new coal plants. Others favor our meeting all our future requirements from the market. Some regulators support special contracts that will further local economic development, others are skeptical about such arrangements. Most of our commissions expect us to continue to conduct a least-cost planning process, whereas SB 1149 appears to render such a process moot in respect to serving our Oregon cost-of-service load.

Q. How does PacifiCorp respond to such diversity of opinion?

A. Under current circumstances, not especially well. Our policies tend to represent a common denominator of responses to regulation that does not appear to cause any of our regulators to conclude that we are being particularly responsive to their concerns.

Q. Do you believe that changes are required in the manner in which PacifiCorp is regulated?

A. Yes. The notion that strict cost-of-service regulation is imperfect is not a novel one. There appears to be widespread recognition that traditional cost-of-service regulation is cumbersome and provides limited incentives for utilities to innovate or become more efficient. While we acknowledge the need for continued regulation of monopoly utility functions, we believe that more emphasis should be placed on reviewing and regulating results, rather than regulating companies.

We believe that greater emphasis should be placed on benchmarking companies and rewarding companies who perform better than their peers. Regulators should pay less attention to issues such as how costs are booked by a utility in any particular test period and focus more on how the average costs of performing any particular function compare to the average costs incurred by our competitors. The result would be a more streamlined process and one that focuses on whether consumers are being well served at a reasonable price. It appears to us that paying undue attention to process and accounting debates, rather than outcomes, stifles innovation and provides no particular incentives for superior performance.

Q. Do you have other concerns with the regulatory process as it impacts PacifiCorp?

A. Yes. While we understand that this is a subject with much history and strong views behind it, we are compelled to observe that the existing mechanisms for the interjurisdictional allocation of the Company's costs are clearly broken. From a shareholder perspective, the Company continues to suffer a material earnings shortfall because of an understanding reached ten years ago in the context of a merger that has provided huge benefits to all of the Company's customers. For those of us who are relatively new to the scene, the perpetuation of this earnings shortfall seems bizarre and unfair. The continued gridlock over interjurisdictional cost allocations is also not in the best interests of our customers because it creates perverse incentives and disincentives.

A striking example is the sale of the Company's interest in the Centralia Plant and Mine. All of our Commissions agreed that the sale was in the public interest. Yet, in order to accomplish the sale, the Company was required to sustain a loss, even though the plant and mine were sold for hundreds of millions of dollars above their book value. Had the Company instead sold a former "Utah Power plant," at a comparable gain, and the same allocation methodology had been followed, a large percentage of the gain would have flowed to shareholders. Each of our commissions believed that they had a rational and principled basis for their treatment of the Centralia gain and yet the totality of their actions resulted in a patently unfair and irrational outcome. Similar issues will arise when the Company faces the need to make investments in new generation. PacifiCorp would then be called upon to put billions of dollars at risk with no confidence that some amount of its investment will "fall through a crack" because its commissions take differing views in regard to the relative responsibilities of the customers in their state or the appropriateness of rate base additions.

Benefits of the Proposed Reorganization

Q. In light of the concerns you have raised, why is the proposed corporate restructuring of the Company in the public interest?

A. Most fundamentally, the restructuring will permit each of our jurisdictions to pursue regulatory policies that they deem appropriate without impacting customers in other states or causing our shareholders to be unfairly treated.

Q. Why is a corporate separation necessary to accomplish this outcome?

A. If nothing else, events of the last five years demonstrate that it is no longer realistic to assume that six separate commissions and six separate legislatures can agree among themselves as to how a single utility ought to be regulated. Even if at some point, consensus emerged, there would be no assurance that it would be durable. The corporate separation creates six separate public utilities, each regulated by only a single state.

Q. How is the Company's participation in an RTO related to the proposed reorganization?

A. As we suggested at the beginning of our testimony, we believe that all of the issues we have discussed, including direct access, interjurisdictional cost allocations and RTO formation are inextricably linked and require a comprehensive resolution. For example, many people believe that in those states that favor some form of direct access, markets will not be fully competitive in the absence of an RTO. In turn, RTO formation may result in a reallocation of transmission costs which would be difficult to accomplish unless our various jurisdictions understand how generation costs are going to be allocated. As demonstrated by our Oregon experience, any given state is hard-pressed to implement direct access in a manner that does not have adverse consequences on other jurisdictions or shareholders unless there is a permanent allocation of the economic benefits and costs of our existing generation among the states. This allocation must be made in manner that does not give rise to operational inefficiencies.

Q. How will the proposed reorganization impact how the company is regulated?

A. We think it will substantially improve it.

Each state commission will have a single electric company to regulate and each will be free to consider innovative alternatives to traditional cost-of-service regulation. We expect that the most successful of those innovations will be adopted by other states.

We would also hope that the creation of the service company will be a vehicle for each of our commissions to consider performance-based regulation of the transfer prices between the service company and the state electric companies that will benchmark the quality and cost of services being provided with less emphasis on traditional means of regulating affiliated interests. In particular, we would hope that the service company could afford all our customers the benefits of economies of scale by contracting for services with non-affiliates. At the same time, each commission would retain local control over the policies of the electric company that they regulate.

The proposed Power Sales Contracts between PacifiCorp Generation Company and each of the state electric companies (other than PacifiCorp, California, Inc.) provide a means of resolving the increasing dilemma posed by the "revenue credit" method of dealing with the Company's wholesale sales. As explained by Mr. Miller, the contracts are intended to be structured in a fashion that affords our retail customers the remaining economic benefit of existing generation and long term sales contracts, while not relying on new wholesale contracts to moderate retail prices.

We believe that the proposed Power Supply Contracts will permit a permanent allocation of generation entitlement and cost responsibility among the various states, while permitting the system to be dispatched as a whole on an optimal basis. We believe the contract approach is far superior than attempting a "physical" separation of our generation among the various states.

Finally, we would hope that these proceedings would put behind us all of the controversy and disfunctionality associated with existing interjurisdictional allocation mechanisms.

Q. What effect do you expect the reorganization will have on the availability of new generation?

A. The reorganization and follow-on legislative and regulatory actions should clarify the rules, roles and responsibilities for the construction of new generation in each of our states. In particular, the terms of the Power Sales Contracts establish that each of the state electric companies will have the option of buying future power requirements from PacifiCorp Generation Company or third-party suppliers. This ought to provide substantial opportunities and stimulus for a competitive independent power industry. With the rules, roles and responsibilities so clarified, PacifiCorp and independent power producers will be free to make investment decisions that are not unduly burdened by legislative and regulatory uncertainty.

Q. Does this conclude your direct testimony?

A. Yes.