Docket No. UE-920499
Staff Response to Data Request 579:

579. On page 8 lines 17-19 Ms. Sorrells state "..Transmission facilities are sized and operated to meet both demand and energy requirements of the utilities system." Please provide all information or documents relied upon or otherwise used to conclude that Puget Power sizes transmission for energy requirements.

Response:

Enclosed are documents which support or relate to the statement on page 8 that "..Transmission facilities are sized and operated to meet both demand and energy requirements of the utilities system."

Summary of Enclosures:

Puget's Integrated Resource Plan, 1992-93, Appendix F - In particular pages F1 and F3 support that Puget Power sizes transmission for energy requirements. Puget recognizes the economies of scale when it states that "the incremental cost of providing the additional capacity is a small percentage of the total project cost." Puget also states that "A 230 kV system can also provide greater efficiencies in operation. In many cases, power could be distributed at 115 kV, but the overall system losses would be much higher, requiring additional generating facilities to deliver the same amount of power." Therefore, Puget does consider energy requirements when sizing transmission.

Deposition responses of Colleen Lynch to staff and Public Counsel in Tr. Vol II, pages 69-72 and 114-125 in Docket No. UE-920499. This document has already been provided to all parties in this case. Therefore, in the interests of saving paper, it is not enclosed in this response. In particular, on pages 124-125, it is pointed out that irrigation customers are not allocated any portion of the demand-related transmission costs because they are off the system during the highest 200 hours of peak demand. However, it was recognized that it is necessary for the company to have non-generation related transmission facilities in order to serve irrigation customers. This statement supports the need to distribute non-generation related transmission costs in the same manner as generation related transmission costs in order to allocate costs fairly across customer classes who use transmission facilities.

NARUC "Electric Utility Cost Allocation Manual", January 1992, Washington D.C., pages 75 and 76 - In this manual, on page 75, it is recognized that in general, customers are allocated a portion of the fully-distributed cost of the transmission system on a basis similar to the way production costs are allocated. The reason for this is that the transmission system is essentially considered to

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be an extension of the production system, where the planning and operation of one is inexorably linked to the other. In the current case, by using the peak credit method, both the demand and energy elements of the transmission facilities are recognized.

Second Supplemental Order in Cause No. U-81-41, page 23 - the Commission states "We agree with the recommendation of POWER that transmission costs should not be fully allocated to demand but should be allocated both to energy and demand."

Transmission

Introduction

In the last decade, electrical transmission has assumed a vital role in providing energy to customers. With the population in the Puget Sound basin growing at a rate of 3% to 4% per year, it will be necessary for Puget Power to add transmission facilities, new distribution lines and substations in order to meet the increasing energy needs of the customers. These transmission lines will make it possible to meet the demand for reliable and cost-effective service for customers.

To meet these challenges, Puget Power has embarked on a corporate goal to build a backbone 230 kV transmission system. This transmission system, when expanded as planned, will provide Puget Power with a reliable, efficient and cost-effective system of new and rebuilt transmission facilities. This system will also allow Puget Power the flexibility to purchase the most economical energy resources and integrate current and future generation sources into the electrical system. Finally, this system will allow Puget Power to make a long-term commitment to plan and construct electrical facilities to meet the need for future growth.

The transmission system plays a key role in providing reliable electrical service. Large quantities of power are transmitted on the transmission system from the generator to the main load centers. Within the population centers, the power is redistributed on a network transmission system to the smaller load centers. Without an adequate system, the ability to deliver power during equipment failure or peak loads would be impaired.

Nationally, several issues have surfaced over the use of new and existing transmission facilities. One of these issues concerns a utility's access to other utilities' transmission systems. Also, electrical facilities themselves have become an issue from the standpoint of aesthetics, environmental effects and the health controversy of extremely low frequency electromagnetic fields (EMF). As a result, permits for construction of new transmission facilities are becoming increasingly more difficult to obtain.

A utility's investment in a transmission system is a long-term commitment for the future. These electrical facilities have at least a 40 to 50-year useful life. When constructing these facilities, the capacity of the system to meet new growth must be considered. The incremental cost of providing the additional capacity is a small percentage of the total project cost. One of a utility's most important roles is to plan and construct facilities for future growth.

Functions of Transmission

Transmission facilities have different functions that need to be addressed. They are to:

- Deliver bulk power (i.e. from Columbia River generation)
- Deliver power to load centers (within Puget Sound Basin)
- Provide reliable service (reduce outages)
- Provide an efficient operating system (quick restoration)

Each function has an important effect on whether the system provides cost-effective, reliable power to customers.

Utilities use high voltage transmission as the most economical means to transmit large quantities of electrical power. When the electrical system was initially built, the generation sources and the fuel to run them were located near the load centers. Later, to take advantage of the opportunity to use natural resources, such as hydro power from the Columbia River, 500 kV transmission was installed. This bulk power transmission system also allows power to be transferred between different regions such as from the Northwest to the Southwest, over the 500 kV Pacific Intertie.

The amount of power that can be transmitted on the electrical system at different voltage levels is shown in Table 1.

Table 1

Power Capacity of Typical Voltage Classes

Voltage kV	Capacity MW	Comments
12.5	12	Standard distribution voltage
34.5	34	Distribution voltage for rural and dense load areas
115.0	240	Subtransmission voltage to distribute power to local substations
230.0	500	Transmission voltage to distribute power to load centers and local substations
500.0	2000	Bulk power transmission from generation or between regions

The actual capacity ratings of the distribution or transmission lines are determined by voltage, conductor size, the number of conductors and operating temperature. The actual power that can be transmitted is also limited by distance. The longer lines have more losses, voltage drop, and chances of outages.

Caution should be exercised in assuming, for example, that two 115 kV lines are equivalent to one 230 kV line. The power grid is a network system of parallel 500 kV, 230 kV and 115 kV lines. In many cases, the lower voltage system cannot replace the need for higher voltage transmission lines.

The 500 kV transmission system in the Northwest is primarily owned and operated by The Bonneville Power Administration (BPA). Puget Power is a co-owner of 500 kV transmission in Montana and is negotiating ownership rights on the 500 kV Third AC Intertie to California. The primary bulk power transmission voltage used by Puget Power is 230 kV. The 230 kV transmission system is utilized primarily to distribute the power from the 500 kV transmission system to the load centers. Some generation facilities are integrated into the system at 230 kV. The 230 kV system is also used to back up the 500 kV system during maintenance or forced outage conditions. The 230 kV transmission substations, located in the load centers, are used to distribute the power to the 115 kV subtransmission system that supplies local neighborhood substations.

An adequate 230 kV transmission system is needed in order to provide reliable service. Because the 230 kV system supplies significant quantities of power, its design is such that during an outage for maintenance or the forced outage of a facility, no customer should be out of service.

A 230 kV system can also provide greater efficiencies in operation. In many cases, power could be distributed at 115 kV, but the overall system losses would be much higher, requiring additional generating facilities to deliver the same amount of power. Using 230 kV for both transmission and subtransmission, fewer lines would be needed, but the cost of a 230 kV line is not twice the cost of a 115 kV line. Thus the net result of using a higher voltage system is reduced construction costs, reduced losses and fewer facilities.

In the 1920's, when Puget Power moved from local generation to remote generation, the losses in the system were 23 percent of generation. Today, with six times the peak, hundreds of thousands of additional customers, many more uses of electricity, and hundreds of miles of additional transmission, the system losses have been reduced to 7 percent of generation. This is due to higher voltages, the use of larger conductors, technology of interconnections and the networking of transmission systems.

Transmission Initiative

Puget Power has established a corporate goal to obtain long-term transmission access to existing and new power markets, and other utility systems. This goal recognizes the importance of transmission in the energy marketplace. Puget Power can take advantage of this market and other utility transmission systems by interconnecting with its neighbors' systems and expanding its own system.

In order to accomplish this goal, a 230 kV system will have to be built from the Canadian border to the southern part of Thurston County and from the Columbia River to Kitsap County. This future system is illustrated in Figure 1. The new transmission system will consist of at least two circuits in most areas in order to provide the necessary reliability and transfer capability. Figure 2 shows the number of miles of new and rebuilt 230 kV lines that are planned for the next 10 to 15 years. If Puget Power builds as planned, it will double the miles of 230 kV transmission. Because much of this is rebuild, the total mileage of 115 kV transmission will be reduced.

Puget Power has recently negotiated power contracts with other utilities. When the resource is outside the area served by Puget Power, it is necessary to negotiate access to other utilities' transmission systems. This is the situation with the 300 MW exchange contract with Pacific Gas & Electric (PG&E), a California utility. Puget Power has been negotiating with BPA to gain access to the 3rd 500 kV AC Pacific Intertie for the seasonal transfer of power between Puget Power and PG&E.

BPA is proposing to rebuild its existing single-circuit 230 kV line between Custer Substation and Sedro-Woolley to double-circuit on the existing right-of-way. To allow for future long-term transmission needs and to optimize the use of the existing corridor, consideration may be given to constructing the 230 kV double-circuit line to 500 kV standards instead, and operating it at 230 kV. Puget Power proposes to install a 230-115 kV transformer at BPA's Bellingham Substation and rebuild two 115 kV lines from its Bellingham Substation to BPA's Bellingham Substation.

II. METHODS OF ALLOCATING TRANSMISSION PLANT

A utility keeps track of its transmission plant costs in a manner suitable for ratemaking purposes in order to charge customers a cost-based rate for providing them with transmission services. These costs may be rolled-in or subfunctionalized to effect the appropriate assignment of costs based on the contribution of each customer group to the applicable plant cost category.

Costs are assigned using one of two general principles: (1) allocation; or (2) direct assignment. Allocation is an indirect method of cost assignment under which customer cost responsibilities are usually measured in terms of usages, e.g., KW, KWH or KVA. The premise of cost allocation is that the cost of providing transmission service to a customer is proportional to the demand that customer imposes on the system or its components. There are several methods discussed below to calculate these relationships. Direct assignment, as its name implies, rests on the premise that, insofar as facilities are used exclusively by a customer, the costs of those facilities can be imposed directly on that customer.

After transmission costs are separated into appropriate demand or energy allocation categories, it is necessary to then select a method of assigning cost allocation responsibility to various customers. In general, customers are allocated a portion of the fully distributed (embedded) cost of the transmission system on a basis similar to the way production costs are allocated. The reason for this is that the transmission system is essentially considered to be an extension of the production system, where the planning and operation of one is inexorably linked to the other. Thus, the major factors that drive production costs, it is argued, tend to drive transmission costs as well.

On the other hand, the transmission system is designed to reliably and economically deliver bulk power supply throughout the system, even under adverse operating conditions. In transmission contingency planning, the keystone to reliability is redundancy which translates, in effect, to capacity being built in excess of that which is minimally required to deliver load. The redundant character of the transmission system then gives rise to the theory that its capacity is separable into two functional components: (1) an energy-delivery system component, allocable on an energy basis; and (2) a reliability component, allocable on the basis of some demand or capacity measurement. This particular approach, however, is not in common usage.

Customer transmission cost responsibility in the cost of service is expressed in terms of allocation ratios. These ratios are usually developed on the basis of customer demands to the sum of all demands deemed to be imposed on the total system or subsystem. Thus, the demand of the customer is included in both the numerator and denominator of the allocation factor and the customer is accordingly allocated a portion of the total costs. Since firm power loads are the highest order of electric service, all fixed costs are deemed incurred to provide such service. Conversely, non-firm service may either be opportunity-type sales without availability assurances, or sales from surplus capacity with limited assurances of availability. Thus, revenues derived from these sales, usually based on negotiated rates, may recover costs anywhere in the range of zero to the amount of the fully distributed costs. With value of service negotiated prices, revenues may even exceed fully distributed costs. In recognition of this cost or price flexibility, the demands for non-firm customers are usually excluded from the allocation factor determinations and, concomitantly, the revenues collected from non-firm customers are treated as credits in the cost of service.

Numerical examples for several allocation methods are provided with data contained in Table 5-1.

TABLE 5-1

1988 SYSTEM AND CUSTOMER DATA - TRANSMISSION LEVEL

	SYSTEM			CUSTOMER GROUP		
Month	KWH (millions)[1]	CP Demand (MW)[1]	NCP Demand (MW)[2]	CP Demand (MW)[1]	NCP Demand (MW)[1]	KWH (millions)[3]
Jan	5610	10520	11074	337	319	166
Feb	5130	10570	11126	344	315	153
Mar	5590	10180	10716	354	344	179
Apr	5400	10620	11178	361	358	180
May	5670	11190	11779	410	403	210
Jun	5860	12090	12726	431	427	215
Jul	6580	13730	14453	524	515	268
Aug	6910	14610	15379	524	520	271
Sep	6410	15050	15842	491	489	246
Oct	6110	12380	13032	405	405	211
Nov	5500	10770	11337	364	336	169
Dec	5700	11120	11705	355	347	181
Total	70470	142830	150347	4900	4778	2449

1 Basic data supplied by Southern California Edison Company.

2 Assuming .95 coincidence factor.

3 Assuming 70% monthly load factor.

As a result of the average system costs we here recognize, it will be necessary for the company to recalculate its Schedule 94 relating to the energy exchange credit for qualifying residential and farm load under the Regional Power Act. In its calculations, the company should use the KWH sales represented in the 1980 pro forma test year.

VII. RATE DESIGN ISSUES

A. Cost of Service Study

In this proceeding, Puget presented a cost of service study. We find the study which Puget presented to be, in general, an acceptable indication of its costs of providing service and in compliance with our requirements as stated in Cause No. U-78-05. We will suggest some refinements to the analysis for future studies.

Mr. DeFrawi, a witness for the Federal Executive Agencies, criticized the company's use of a single peak for the determination of inter-class allocations. We agree with his criticisms and, in the next proceeding, expect that the company will have refined its analysis to account for coincident peak inter-class cost allocations. Mr. DeFrawi's five-month coincident peak is acceptable, but it may not be the only multi-peak allocation method which would produce acceptable results. A change from single to coincident multiple peak analysis will have small results on the ultimate conclusions of the cost study if other policy and judgment factors remain constant.

We have above rejected Mr. Louiselle's suggestion of a fuel rider rate, to be calculated on a bi-monthly basis through the use of bi-monthly hearing process. We will not speak further to that issue.

We believe that the factors which led to the previous institution of seasonal rates remain significant and valid and we accept the proposal to continue the seasonal rate concept. The deferred accounting procedure which we here adopt will also result in seasonal rate variations. We will not now change the seasonal rate design.

Various of the parties have alleged that the rate of return should be assumed constant among the customer classes, and others have described reasons why it might be appropriate to consider that each customer class has a separate and identifiable rate of return requirement because of factors including risk in the service of that customer class. We are not prepared on this record to make a determination that each of the customer classes requires an individually calculated rate of return.

We agree with the recommendation of POWER that transmission costs should not be fully allocated to demand but should be allocated both to energy and to demand. We agree with POWER's presentation that increases to the customer charge and to the initial block of consumption should be minimized.

In the tariffs we authorize to be refiled, the residential single-phase customer charge shall be limited to $3.60, and increases to the Schedule 7 (residential) consumption blocks shall be on an equal percentage basis. In other regards the company tariff requests should be implemented.