November 19, 2004

Mr. Steve Crow
Executive Director
Northwest Power & Conservation Council
851 S.W. Sixth Ave. Suite 1100
Portland, Oregon 97204-1348

Dear Steve:

Portland General Electric Company (PGE) appreciates the opportunity to comment on the Northwest Power and Conservation Council's 5th Power Plan draft. PGE staff has participated in workshops and policy discussions about this plan over the last couple of years and we appreciate the amount of work that has gone into this draft. We offer the following comments to assist you in developing the final version of the 5th Power Plan.

Why is there a Council Power Plan and what is its role?

The Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) gave BPA the authority to acquire resources for its customers' net requirements[1] consistent with a power plan to be developed by the Council. Since the Regional Act was passed in 1980, events have occurred that have changed the fundamental structure of the electric industry in the country and in the region. In 1992 Congress passed the National Energy Policy Act of 1992 (NEPA-92) and in the late1990s the Federal Energy Regulatory Commission (FERC) issued Order 888 and subsequent clarifications. As a result the Northwest cannot be described as a cohesive electricity entity conducive to central planning by BPA and the Council. There are diverse players that affect how our regional wholesale market works including many that are not load serving utilities. Thus, though the law still requires the Council to develop a power plan every five years, one might ask to whom that power plan applies.

Independent power producers (IPPs) make decisions to buy or build plants based on their perception of the economics of the project. The investor-owned utilities make their resource decisions in an integrated resource process overseen by state commissions. The publicly owned utilities have decided the existing federal system should be allocated among them. They also agree that each utility should cover its own load growth – either through bilateral contracts with BPA at incremental cost or by the utilities acquiring their own resources. The boards or commissions of the publicly owned utilities will make those decisions based on the individual circumstances of each utility. The Council endorsed the plan to allocate the existing federal system in its Regional Dialogue

---

[1] Net Requirements means power to meet the firm power load of public bodies, cooperatives or investor-owned utilities in the region to the extent that such firm power load exceeds the capability of their own resources pursuant to Section 5 of the Regional Act

recommendations to BPA and in this plan[2]. In addition, The U.S. Government Accountability Office (GAO) has said that BPA should restrict its sales at cost to the existing federal system.

What, then, is the role of the Council's power plan in all of this? Given these changes, it would be useful if the Council's 5th Power Plan addressed this question clarifying the Council's position on the issues. At the end of the day the Council's Power Plan should be a tool that is helpful to the region.

What is BPA's role'

The region's utilities realize there is a need to change BPA's role going forward and the Council has concurred.

> Bonneville would sell electricity from the existing Federal Columbia River Power System to eligible customers at its cost. Customers that request more power than Bonneville can provide from the existing federal system would pay the additional cost of providing that service. This change would clarify who would exercise responsibility for resource development; it would result in an equitable distribution of the costs of growth; and it would prevent the value of the existing federal system from being diluted by the higher costs of new resources.[3]

The GAO has also pointed out that to stabilize its financial condition BPA must change its role in providing power to the region.

GAO recommends that BPA

- Reduce its future risk of being over-committed by (1) limiting the amount of power that BPA sells at its lowest cost-based rate and (2) charging incremental rates for any power sold beyond this amount that reflect BPA's cost of acquiring that power, and
- Identify specific activities, resources and time frames for implementing its risk management initiatives.[4]

Unfortunately, the 5th Power Plan is not consistent with BPA's future role. For example, Section 12 which discusses implementation indicates BPA should acquire conservation even if it does not need resources (does not have requests for service from customers). In so doing, the Council misinterprets the Regional Act which says at Section 6(a), "The Administrator shall acquire *such resources* through conservation measures" " (emphasis added). "Such resources" refers to the resources the Administrator would have acquired to serve BPA"s customers net requirements pursuant to Section 5 of the Regional Act. The Regional Act does not say BPA should acquire resources, even conservation, when BPA"s customers do not need them. Furthermore, under BPA"s future role, customers, not BPA, decide whether or not to have BPA acquire any resources for them.

IPP resources – How useful are they and does it make sense to factor them into the regional load/resource balance–

---

[2] Action BPA-1 at page AP-17.

[3] Northwest Power and Conservation Council Recommendations for the Future Role of the Bonneville Power Administration dated May 17, 2004.

[4] GAO-040694, Highlights

The Council"s conclusions regarding the IPP resources are disconnected from the realities of the marketplace. We appreciate that the Council has revised its thinking regarding IPP resources and no longer assumes that they are available to the region at the cost of fuel and O&M. That change alone, however, does not go far enough to truly reflect the realities of the electricity industry since NEPA-92 and Order 888.

On the surface, it appears logical to assume that plants already constructed and operating would provide power at lower cost than building new plants. From a global perspective, it then follows that the region should rely on those resources before building new ones. Given that all but one of the northwest investor owned utilities have issued Requests for Proposals for power supply resources and virtually all of the 3000 MW of IPP resources remain uncommitted, it appears the global perspective is not consistent with the perspective of at least those utilities that are pursuing other options. We believe there are fundamental reasons for this disconnect.

First, we believe that the uncommitted new IPP resources were sited in places designed to optimize access to multiple markets. Since the plants were uncommitted, the developer could not afford to risk having only one market in which to sell generation. While that makes sense from an IPP perspective, a utility looks for the optimal resource to meets its needs. Least cost and high reliability are the factors that drive utility decision-making. Fundamentally, a generation resource that is sited to serve multiple markets is not likely to be the least cost resource for any one of those markets.

Second, the premise that operating resources must produce power at lower cost than new resources is not necessarily the case. Again, resources sited to serve multiple markets will almost certainly have higher transmission costs than resources sited closer to loads. On top of that, regional transmission constraints make certain of those resources unavailable to some utilities on a firm basis. Also, most of the uncommitted resources were constructed during the energy crisis, or shortly thereafter, during a time when equipment and construction costs were very high especially as compared to current costs. It is natural to assume that the owners of these resources would seek to recover their embedded cost in conjunction with any long-term sale commitment. However, fully covering the costs of those plants often makes them uneconomic compared to new resources. Finally, gas-fired generation plants located in Washington are subject to a 3.85 percent state gas tax on all fuel consumed. At an assumed $4.00/MMBtu price of gas, that tax amounts to approximately $1.00/MWh. Transmission costs and constraints, relatively high embedded costs, and different operating costs for different locations ultimately contradict the premise that these uncommitted regional resources should be counted on to serve any one utility"s load. The realities of the market and individual utility resource planning requirements do not support such a premise and we respectfully suggest the Power Plan be modified as such. We are concerned that failure to do so will have unintended consequences when the investor-owned utilities address their resource needs with their respective state commissions.

Plan assumptions and conclusions appear to be disconnected from current markets.

The Council plan assumed that the Western Energy Crisis of 2001-2002 was the result of resource inadequacy. While inadequacy was a factor, the market structure and lack of controls in California"s PX and ISO greatly increased the damage.

The Council"s plan recommends developing 700 MW of Demand Response (DR) over the next five years. The Plan also defines DR as "chosen voluntarily by the consumer". Unfortunately some of the longer-term DR measures the Council Plan cites during the Energy Crisis were not DR at all, but merely businesses failing as a result of the energy crisis and/or recession. The Council Plan admits that their evaluation of DR mechanisms is subjective and intended to stimulate comment and discussion. The voluntary nature of DR and the subjective nature of the evaluation do not seem like good foundations for a resource that the region would need to rely on at times of peak usage such as an Arctic Express. The region needs to carefully define and understand DR and decide whether it is a power resource or a reliability tool.

Renewables targets and regional capability.
PGE is a strong supporter of renewable resources and included 200 MW (65 MWa) of wind resources in its portfolio pursuant to its 2003 RFP. The approach in the plan to phase in wind generation seems appropriate as the region can learn from experience. However, based on our experience the prices for wind in the Council Plan seem low and the price in the market for wind tags is not $6.00 per MWh but is in the $3.00 to $5.00 per MWh range. In addition, the Council"s plan does not address the issues involved in integrating intermittent wind resources to loads. For example, the $4.00 to $8.00 per MWh costs for shaping and firming are only valid as long as wind integration can be handled by the hydroelectric system. Once thermal resources are needed to integrate wind, the cost increases.

Energy efficiency and the role of the Energy Trust of Oregon versus utilities.
Since the passage of Senate Bill 1149, conservation for the customers of the investor-owned utilities in Oregon has become the responsibility of the Energy Trust of Oregon. Publicly owned utilities do their own conservation measures throughout the region and investor-owned utilities do their own conservation outside of Oregon. The region"s utilities made clear in the Joint Customer Proposal in 2003 that they favor an approach similar to the current BPA Conservation and Renewable Discount (C&RD). We applaud the fact the plan supports that view. However, it should be noted that conservation is almost all capital cost which means higher front-end costs. The Council"s plan uses levelized costs for conservation and does not seem to adequately address the rate impacts associated with those large front-end costs.

Thank you again for the opportunity to comment.

Sincerely,

Pamela G. Lesh

Pamela Grace Lesh
Vice President
Regulatory Affairs and Strategic Planning