Northwest Power and Conservation Council

February 8, 2005

DECISION MEMORANDUM

TO: Council Members

FROM: John Shurts

SUBJECT: Fifth Power Plan -- Response to Comments

PROPOSED ACTION: Review and adopt the attached staff draft that responds to comments the Council received on the draft Fifth Power Plan.

SIGNIFICANCE: Adopting the response to comments completes the Council's adoption of the Fifth Power Plan.

BUDGETARY/ECONOMIC IMPACTS: None.

BACKGROUND:

In September 2004 the Council released the Draft Fifth Northwest Power Plan for public review and comment. In December, after reviewing the comments, the Council adopted the final power plan.

Section 4g of the Northwest Power Act requires the Council to insure widespread public involvement in the development of the power plan, including by consulting with and seeking the comments of Bonneville, the Bonneville customers and others and including the comments in the record of the Council's proceedings. We have always interpreted this to include the need for the Council to explain briefly how it considered and responded to key comments in finalizing the power plan.

The Council also follows the notice and comment rulemaking procedures of the federal Administrative Procedures Act in developing and adopting the power plan. Section 553 of the APA requires that agencies include with their final rules a "concise general statement of their basis and purpose," which the courts and others have also interpreted to require that the agency explain briefly how it considered and responded to key comment in finalizing the rule.

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The attached document satisfies both what is required by the Power Act and by the APA. It summarizes (1) the key issues involved in and underlying the Council's consideration and adoption of the Fifth Northwest Power Plan; (2) the comments of Bonneville, the Bonneville customers and others on the Draft Fifth Power Plan; and (3) how the Council responded to those comments and addressed those issues in its considerations on the Fifth Power Plan.

NOTE: I am facilitating the adoption of the response to comments, but I cannot claim any credit for what is written. The various members of the Power Division summarized and responded to the comments in their areas of expertise, Dick Watson assembled and edited pieces, and John Harrison gave it the final assembly and introductory writing and overall editing. Thanks to you all. John S.

ATTACHMENTS: The draft response to comments is attached.

Northwest Power and Conservation Council
Fifth Northwest Power Plan

Statement of Basis and Purpose for the Fifth Power Plan
and
Response to Comments on the Draft Fifth Power Plan

February 2005

Council Document 2005-XX

I. BACKGROUND

A. Statutory requirements

The Northwest Power and Conservation Council is required by the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Section 4.(d)(1)) to develop a regional conservation and electric power plan and to review it not less frequently than every five years.

According to the Act (Section 4.(e)(1)), the plan shall give priority to resources that the Council determines to be cost-effective, and the Act establishes the following priority for resources in the plan: first, to conservation, second to renewable resources, third to generating resources utilizing waste heat or generating resources of high fuel-conversion efficiency, and fourth to all other resources. The Act directs (Section 4.(e)(2)) that the plan shall set forth a general scheme for implementing conservation measures and developing electricity resources with due consideration by the Council for (A) environmental quality; (B) compatibility with the existing regional power system; (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish; and (D) other criteria that may be set forth in the plan.

The Act also requires that the plan shall include an energy conservation program including model conservation standards (Section 4.(e)(3)(A)); recommendation[s] for research and development (Section 4.(e)(3)(B)); a methodology for determining quantifiable environmental costs and benefits (Section 4.(e)(3)(C)); an electricity demand forecast of at least 20 years (Section 4.(e)(3)(D)); an analysis of electricity reserve and reliability requirements and cost-effective methods of providing reserves designed to insure adequate electric power at the lowest probable cost (Section 4.(e)(3)(E)); and the fish and wildlife program promulgated by the Council under Section 4.(h) of the Act to protect, mitigate and enhance fish and wildlife, and related spawning grounds and habitat, affected by the development and operation of any hydroelectric project on the Columbia River and its tributaries (Sections 4.(e)(3)(F) and 4.(h)(2)(A)).

B. Developing the Fifth Power Plan

In February 2002, the Council began development of its Fifth Northwest Power Plan by issuing a paper and requesting comments on elements the Council thought should be addressed in the new power plan. The existing power plan dated to 1998.

In response to comments on the paper, the Council began developing a draft power plan. Later in 2002, and in 2003, the Council developed a series of papers for public review and comment that explored in detail the elements the Council planned to include in the new power plan. These included, among others, energy conservation, demand response, high-voltage transmission, forecasts of future fuel prices and demand for electricity, and the future role of the Bonneville Power Administration in power supply.

In September 2004, the Council completed the Draft Fifth Northwest Power Plan and issued it for public review and comment. In December, after reviewing the comments, the Council adopted the new power plan. The adopted plan assures the Pacific Northwest region an adequate, efficient, economical, and reliable power supply. To accomplish the goals of the Act, the plan addresses future uncertainties; identifies realistic electricity conservation and generation

resource alternatives; analyzes the costs and risks that arise from the interaction of resource choices and uncertain futures; and lays out a flexible strategy for managing those costs and risks.

Section 4.(g)(1) of the Act requires the Council and the administrator of the Bonneville Power Administration to insure widespread public involvement in the formulation of regional power policies by maintaining comprehensive programs to inform the Northwest public of major regional power issues (Section 4.(g)(1) (A)); obtaining public views concerning major regional power issues (Section 4.(g)(1)(B)); securing advice and consultation from Bonneville customers and others (Section 4.(g)(1)(C)); consulting with Bonneville's customers (Section 4.(g)(2)(A)); and including the comments of such customers in the record of the Council's proceedings (Section 4.(g)(2)(B)).

This document summarizes 1) the key issues involved in and underlying the Council's consideration and adoption of the Fifth Northwest Power Plan; 2) the comments of Bonneville, the Bonneville customers and others on the Draft Fifth Power Plan; and 3) how the Council responded to those comments and addressed those issues in its considerations on the Fifth Power Plan.

This document also serves as the "statement of basis and purpose" called for in Section 553 of the federal Administrative Procedures Act to accompany agency decisions on final rules. The Council follows the notice and comment rulemaking procedures of the APA in developing and adopting the power plan.

C. Key conclusions

Consistent with the requirements of the Power Act and the Council's analyses in developing the plan, the primary conclusion of the plan is that the region should increase its efforts to secure cost-effective conservation, beginning immediately. Conservation is the least expensive, and least harmful to the environment, resource available. Development of conservation will reduce the likelihood of another electricity crisis like the one experienced in the West in 2000 and 2001.

In addition, demand response resources -- agreements between utilities and customers to reduce demand for power during periods of high prices and short supply -- should be put in place over the next few years so that they can be implemented quickly if needed.

From a regional standpoint, there is currently a surplus of generating capacity due to reduced demand and the construction of new generating plants over the past three years. Independent power producers (IPPs) own most of the surplus generation. The IPPs do not now have long-term contracts with regional utilities nor do they have firm transmission access to markets outside the region. The plan considers the independent power plants as resources available to serve the regional market, from which the region may purchase at market prices.

Wind power development at a moderate commercial scale should be undertaken at geographically diverse wind resource areas over the next five years to resolve uncertainties associated with this resource and to prepare for its eventual large-scale development. Wind projects currently being considered by regional utilities and state "system benefits charge" administrators could fulfill this goal.

Efforts to identify and develop cost-effective lost-opportunity generating resources, including combined heat and power (cogeneration) and biomass applications, should be reinforced.

The region should secure sites and permits to be prepared to start construction of new coal generating resources as early as 2010 with additional wind generation shortly thereafter. Later in the 20-year period some additional gas-fired generation could be needed. Needed transmission upgrades should be identified so all these resources can be constructed and brought on line quickly when required. If major transmission upgrades are needed, that work will have to begin before construction of the power plants.

D. Key actions

Here is a list of the key actions recommended by the Council in the plan:

1) Develop resources now that can reduce cost and risk to the region

- 700 average megawatts of conservation, 2005 - 2009
- 500 megawatts of demand response, 2005 - 2009
- Secure cost-effective cogeneration and renewable energy projects
- Develop cost-effective generating resources when needed

2) Prepare to construct additional resources

- Develop and maintain an inventory of ready-to-construct projects
- Resolve uncertainties associated with large-scale wind development
- Encourage use of state-of-the-art generating technology when siting and permitting projects
- Plan for needed transmission and work toward better integration of resource and transmission planning
- Improve utilization of available transmission capacity

3) Confirm the availability and cost of additional resources that promise cost and risk mitigation benefits

- Coal gasification with carbon sequestration
- Oil sands cogeneration
- Energy storage technologies
- Demonstration of renewable and high efficiency generation with Northwest potential

4) Establish the policy framework to ensure the ability to develop needed resources

- Carry out a process to establish adequacy standards for the Northwest and the rest of the Western system
- Work through the Grid West, Regional Representatives Group process to address emerging transmission issues by the end of 2005. If necessary, pursue alternative approaches to resolve issues
- Revise the role of the Bonneville Power Administration in power supply, consistent with the Council's May 2004 recommendations

5) Monitor key indicators that could signal changes in plans

- Periodically report on the regional load-resource situation and indicate whether there is a need to accelerate or slow resource development activities

- Monitor conservation development and be prepared to intensify efforts or develop alternative resources, if necessary
- Monitor efforts to resolve uncertainties regarding the cost and availability of wind generation, and prepare to develop alternatives, if necessary
- Monitor climate change science and policy for developments that would affect resource choices
- Prepare a biennial monitoring report and revise elements of the power plan as necessary
- Monitor progress in implementing the changes recommended for Bonneville's future role in power supply

II. RESPONSE TO COMMENTS

A. Conservation

ISSUE: Near-Term Conservation Targets

COMMENTS: The Bonneville Power Administration (Bonneville) commented that the Council should adopt longer-term (more than five years) targets for regional conservation acquisitions. The Northwest Energy Efficiency Alliance commented that the near-term goal is achievable. John Saven (Northwest Requirements Utilities), the Pacific Northwest Utility Conference Committee (PNUCC), the Public Power Council (PPC), and Tacoma Public Utilities commented that the near-term conservation targets are too high. The Pacific Northwest Generating Cooperative (PNGC) commented that it is not clear that the conservation targets reflect all factors that might affect the pace of conservation acquisition, such as future growth patterns, economic cycles, current economic conditions, and success of the programs and the implementation timing of conservation standards. PNGC commented that the plan failed to "infuse the capture of conservation " with practical day-to-day program limitations. Industrial Customers of Northwest Utilities (ICNU) commented that the plan targets do not account for practical limitations and social concerns (equity), political implications, and customer service objectives that may increase the cost of conservation.

RESPONSE: Discussion was added in the Action Plan and in Chapter 7 (Portfolio Analysis and Recommended Plan) reflecting the consistency of conservation targets across a wide range of future conditions for load growth, electricity market prices, and other factors over the five-year action plan period. The Council believes that its conservation targets are reasonable in comparison to the rate of conservation acquisition in recent years, that near-term rate impacts are relatively small, and that the long-run cost and risk of not achieving the targets is large. The final plan retains the five-year targets set forth in the draft. New near-term targets will be developed in the next power plan when more is known about the future conservation resources. The portfolio analysis indicates that annual conservation targets in the immediate few years following the Action Plan would not be significantly different from the targets for the Action Plan.

ISSUE: Conservation Implementation Strategies

COMMENTS: The Oregon Public Utilities Commission recommended the Council place additional emphasis on implementation and acquisition approaches to acquire conservation. NEEA supports plan recommendations for more coordination between local and market

transformation initiatives. On the other hand, the Springfield Utility Board (Springfield) expressed concern that the Council is too prescriptive with its conservation action plan and should focus instead on allowing utilities to decide how best to meet the conservation goals and then provide assistance to them. Springfield also made specific recommendations on 18 items in the action plan, again focusing on encouraging the Council to set goals but leave implementation to individual utilities rather than take part in regional implementation. PacifiCorp recommended the plan support Bonneville rate discount mechanisms for implementation. PNGC expressed concerns that Bonneville could employ the conservation targets in the plan to unfairly penalize its customer utilities that do not achieve their share of the conservation, even though the underachievement could result from circumstances that are beyond their control. Puget Sound Energy (Puget) asked the Council to identify how much conservation is achievable through codes and standards. ICNU commented that it does not support conservation solutions that only focus on increasing conservation acquisition budgets. ICNU questions the value of CNSV-3 development of a strategic conservation action plan. The Spokane Alliance recommended that the plan strategically target efforts that encourage conservation-related policy initiatives (like those of the Spokane Alliance) across the region. Western Montana G&T recommended that the plan provide direction not only on how much and what types of conservation the region should pursue, but also how that resource will be acquired. Washington Community Trade and Economic Development (CTED) recommended adopting highly transparent and technically sound accountability mechanisms for conservation and energy efficiency investments. CTED also urged the Council to ask Bonneville to develop ways to incorporate the plan's resource priorities into future contracts between Bonneville and the utilities.

RESPONSE: The Council recognizes that there are many strategies and details to be worked out, many forums where conservation decisions will be made, and that there are many entities that will implement conservation across the region. The conservation strategic plan, action CNSV-3 is intended to coordinate specific implementation details, mechanisms, budgets and action items for the acquisition of conservation identified in the plan. In addition, there are many details in Appendix D (Conservation Acquisition Strategies) that recommend implementation and acquisition approaches for specific measures. The Council believes its action items for conservation are necessary to achieve the conservation targets in a cost-efficient manner.

ISSUE: Conservation Cost-Effectiveness

COMMENTS: PNGC cites apparent confusion between the estimates of cost-effective conservation potential and the conservation targets in the portfolio model. Doug Smith of Gray's Harbor PUD questioned the Council's use of a total resource cost/benefit-cost ratio. The Springfield Utility Board (Springfield) commented that the Council should revise the avoided cost estimates in its benefits/cost analyses to utilize the full cost of incremental new generation and not the Mid-Columbia forecast of wholesale market prices for electricity. Springfield asked the Council to modify its total resource cost/benefit-cost ratio calculations to include benefits that customers perceive or are willing to pay for from measures such as windows and heat pumps. Springfield also recommended that the Council change its definition of "cost-effective" to emphasize "realistically cost-effective" for conservation activities that are "proven realistically cost-effective by customer demand." Finally, Springfield commented that the Council should not assume that existing codes and standards are fully implemented, or that baseline energy use is as efficient as the code assumes, particularly for items such as heat pumps and windows.

RESPONSE: In response to these concerns, the Council expanded sections of Chapter 3 (Conservation Resources) and Chapter 7 (Portfolio Analysis and Recommended Plan) to clarify the distinction between the estimation of conservation potential, the development of the conservation supply curves, the portfolio analysis that determines targets and the conservation action plan items.

With regard to avoided cost estimates, the Council believes the estimated market price of power better reflects the value of energy saved than other measures. Further, the conservation targets are based on 750 scenarios for future avoided costs used in the Council's portfolio model. This range of avoided costs reflects the range of possible long-term incremental cost of for the entire region.

With regard to perceived customer benefits, total resource cost calculations include benefits that can be quantified. The Council is not aware of quantified estimates of customer-perceived benefits of heat pumps and windows. If such information becomes available, it could be considered in the future. The Council agrees that there are situations where energy efficiency codes are not implemented or enforced and that stricter enforcement or application is desirable. However, estimates of conservation potential are based on assumptions of code compliance as a matter of prudence.

Finally, the Council did not revise its definition of cost-effectiveness or methodology for determining regional cost-effectiveness. The power plan relies on the definition of cost-effectiveness in the Northwest Power Act.

ISSUE: Rate Impacts of Conservation

COMMENTS: Portland General Electric (PGE) commented that rate impacts of conservation are not adequately addressed. ICNU questioned whether conservation makes sense in a time of surplus. The Benton County PUD expressed concern about increasing the regional conservation acquisition target at a time when Bonneville's customer utilities might face rate increases and in light of the fact that the cost of the conservation could have a rate impact.

RESPONSE: Discussion of near-term revenue requirements for conservation acquisition was expanded in the action plan. The Council believes that near-term rate impacts are relatively small, and the analysis in the plan indicates that the long-run cost and risk of not achieving the targets is large. In response to these issues, the Council also expanded its discussion of the derivation of conservation expenditure estimates in the Action Plan and in Appendix D.

ISSUE: Regulatory Barriers to Conservation

COMMENTS: The Natural Resources Defense Council (NRDC) recommended that the Council revise the action item regarding decoupling kilowatt-hour sales from conservation investments (Action CNSV-10) that reduce demand and, therefore, utilities' revenue. NRDC proposed a "simple true-up" of rates that would correct for any annual fluctuations in a utility's retail electricity sales as the result of successful conservation programs. ICNU recommended highlighting other options, such as creation of non-utility entities, like the Energy Trust of Oregon, to address the lost-revenue barrier discussed in Action CNSV-10.

RESPONSE: In response to NRDC, the Council revised action CNSV-10. The Council recognizes alternative strategies to utility-developed conservation, and the plan recommends a review of the performance and effectiveness of non-utility conservation acquisition entities in CNSV-11.

ISSUE: Low-Income Weatherization Policy

COMMENTS: A number of commentors criticized the Council's recommendations regarding weatherization of the homes of low-income people. The Sierra Club said the plan needs further analysis of low-income weatherization benefits. The Community Action Partnership said the plan lacks protection for low-income citizens and that the low-income weatherization provisions in the plan should be more specific. Curtis Webb said the plan should contain an analysis of how many low-income homes remain to be weatherized. The Montana Environmental Information Center and the Spokane Alliance expressed disappointment with the weatherization recommendations. Washington Community Trade and Economic Development (CTED) recommended the plan quantify how much cost-effective conservation can be achieved from weatherization, how much non-cost effective conservation can be achieved, the magnitude of the low income weatherization need, and also provide some guidance about how low-income issues fit into electricity planning. The Northwest Energy Coalition recommended that the Council estimate the potential number of low-income dwellings that need weatherization, include non-energy benefits such as health and safety and family economics in calculating the cost-effectiveness of low-income weatherization, and recommend a per-year target for weatherization of low-income homes.

RESPONSE: In response, the Council added discussion to CNSV-12 in the action plan (Low-income weatherization) to make clear that cost-effective conservation acquired as a result of low-income housing weatherization programs is a useful addition to the region's conservation portfolio, and that Bonneville and the region's utilities should continue to provide support for this activity where cost-effective savings are achieved. The Council also revised the text of the plan to recognize that weatherization has non-energy benefits as well as energy benefits, and that utilities can consider non-energy benefits in calculating the costs and benefits of weatherizing the homes of low-income people. The Council noted that utility system support for low income housing weatherization that is not cost-effective should not reduce the funding available for acquiring the cost-effective conservation targeted by the power plan. The Council decided not to set a numerical target for weatherizing low-income homes.

ISSUE: Disaggregating Conservation Targets

COMMENTS: Bonneville commented that the plan should include an estimate of naturally occurring conservation. The state of Oregon, on behalf of the departments of Fish and Wildlife, Environmental Quality, and Energy, and the Public Utilities Commission, commented that the power plan should disaggregate conservation acquisition targets by state.

RESPONSE: The Council's targets include all conservation. The Council cannot produce a viable estimate of naturally occurring conservation. Many factors contribute to the decision to adopt conservation measures and practices including utility programs, energy prices, market trends, codes and standards, customer behavior, and others. Distinguishing the influence of each of these is impractical. The Council added discussion to highlight the need track the overall progress toward adoption of measures and practices against the strategic conservation action plan recommendation (CNSV-3) and in MON-2. The Council was not able to develop state-specific conservation estimates in the final plan. However, the Council will work with the states and others to disaggregate acquisition targets where possible as part of its conservation coordination and implementation efforts.

ISSUE: Conservation Monitoring and Evaluation

COMMENTS: Oregon recommended asking Bonneville and utilities to report how they are meeting conservation targets. Washington Community Trade and Economic Development (CTED) recommended expanding conservation monitoring recommendations to include more effective tracking, financial accounting, regular reporting, and periodic adjustments to remaining potential. Bonneville asked the Council to develop estimates of the cost of monitoring and evaluation. Bonneville's comment on the absence of plan estimates of "naturally occurring" conservation highlighted the importance of the need to tracking total conservation accomplishments in the action plan period.

RESPONSE: Text in the Action Plan (CNSV-3 and in MON-2) was revised to put more emphasis and specificity on the need for and importance of monitoring and evaluating conservation performance. CNSV-8 was expanded to develop monitoring and evaluation cost estimates in the strategic conservation plan.

ISSUE: Bonneville's Role in Conservation Acquisition

COMMENT: Bonneville commented that the power plan overstates the Council's authority in the Northwest Power Act regarding conservation and generating resource acquisitions by Bonneville. Bonneville also commented that it should not be viewed as the "backstop" for regional conservation acquisition.

RESPONSE: The Council clarified this matter in its recommendations on the future role of Bonneville in regional power supply the Action Plan (BPA-3) and in Chapter 11 (Future Role of Bonneville). The Council revised these sections to make clear that if necessary, Bonneville must be prepared to use the full extent of its authorities to ensure that the cost-effective conservation and renewables identified in the Council's power plan are achieved on all its customers' loads. The Council reiterates that the focus needs to be on determining how to reliably acquire all the cost-effective conservation at the lowest cost to the utility system through all mechanisms available.

ISSUE: Level of Detail in Actions

COMMENTS: The Oregon agencies proposed clarifying comments on seven items in the Action Plan. Bonneville commented that the power plan should place more emphasis on finding the least-cost (to utilities) means of achieving the cost-effective conservation potential. Bonneville suggested that the Council provide greater detail about market transformation opportunities. Puget Sound Energy (Puget) asked the Council to explain why it recommended more market transformation funding.

RESPONSE: The Council revised some of the actions and did not revise others, in all cases consistent with what it sees as its role to convene, guide and focus implementation efforts in order to acquire the conservation in the power plan. The Council added emphasis in the strategic planning section of the Action Plan (Action CNSV-3) to highlight the need to find low-cost means to acquire conservation resources. The discussion of how to develop the regional strategic plan (CNSV-3) was expanded to encompass the resolution of several issues raised, including how much effort and budget to focus on various methods of implementation; addressing conservation infrastructure efforts, such as education and public outreach; and estimating annual expenditures for reporting and tracking conservation acquisitions. Market transformation opportunities were further explained or referenced in footnotes. Recommended deadlines for actions were added where the Council believes they are appropriate and attainable.

ISSUE: Financing and Realization Rate Assumptions

COMMENTS: Bonneville commented that it may not be able to use financing for "a significant portion" of the conservation investments because of constraints on its borrowing authority, which may increase conservation costs. The Benton County PUD questioned the Council's estimate that 85 percent of technically available conservation is achievable over the course of the 20-year planning period.

RESPONSE: The Council did not revise its financing assumptions (4 percent and 15-year terms). In practice, a large portion of conservation financing is expensed (revenue-financed), not capitalized. However, meaningful comparison of resource alternatives requires that their costs be calculated with comparable assumptions regarding financing. The Council clarified the source and purpose of the achievable conservation estimate in Chapter 3 ("Conservation Resources").

ISSUE: Model Conservation Standards for New Commercial Buildings

COMMENTS: In the draft power plan of September 2004, the Council proposed that the model conservation standard for new commercial buildings (one of many standards proposed) "capture savings equivalent to those achievable through constructing buildings to the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Standard 90.1-2001 (I-P Version) — Energy Standard for Buildings Except Low-Rise Residential Buildings (IESNA co-sponsored; ANSI approved; Continuous Maintenance Standard), I-P Edition and addenda a through am." But at the same time, the Council noted that the ASHRAE Standard 90.1-2001 "do not capture all regionally cost-effective savings."

The staff of the Oregon Department of Energy recommended exceptions in the proposed Model Conservation Standards for new commercial buildings in cases where analysis showed the ASHRAE standard not cost-effective.

RESPONSE: Information the Council received after the release of the draft power plan — from public comments and from a report commissioned by the Council staff on the status of existing codes in the region — confirmed that the commercial building energy standards already adopted in the four states of the region contain many energy efficiency provisions that already exceed ASHRAE Standard 90.1 provisions, and produce power savings that are cost-effective for the region and economically feasible for consumers. Based on that information, the Council recommends revising the model conservation standard for new commercial buildings to call for commercial buildings to be constructed to capture savings equivalent to those available by adopting the most efficient provisions from either ASHRAE Standard 90.1 or the state codes already existing, so long as those provisions satisfy the requirements for model conservation standards set forth in the Power Act. A revised proposal was posted on the Council website.

Because this revised proposal for a new commercial building model conservation standard specifies provision in addition to what was proposed in the draft power plan, and in an exercise of caution, the Council decided to seek public comment and consult with the entities specified in the Power Act before finalizing this standard. The Council adopted as final without change all the other model conservation standards and surcharge policy as proposed in the draft power plan. The Council does not recommend that the model conservation standards be subject to surcharge under Section 4.(f)(2) of the Act. The Council plans to adopt the final standard at its February 2004 meeting.

ISSUE: Recommended Technical Modifications

COMMENTS: Bonneville commented on several technical errors in a table and in associated footnotes regarding utility cost estimates. Bonneville commented that certain standards for reach-in refrigeration are outdated, that savings for some measures were too large and that savings for other measures were omitted. That while changing the estimates may not change the overall 20-year, or even five-year, targets from the perspective of a least-cost, least-risk plan, better analysis could prevent the misapplication of resources in the near term that could reduce cost-effectiveness and cost-efficiency and jeopardize attaining the targets. Gary Curtis and John Jennings commented that the Council's estimate of potential energy savings from installation of energy-efficient windows in commercial buildings was too low and the methodology suspect. Oregon recommended the Council include a discussion of cost-effectiveness methodology as it might apply to conservation resources. Puget Sound Energy (Puget) asked for explanation of assumptions for penetration used for heat pump water heaters. Snohomish County PUD asked technical questions on assumptions used in heat pump water heater and commercial roof-top heating, ventilation and air conditioning (HVAC) measures.

RESPONSE: Errors and footnotes were corrected. The Council reviewed and revised its savings estimates for commercial windows upward and expressed support for research that would better identify window baseline characteristics and that might demonstrate higher potential savings. The Council revised its discussion of estimates for package roof-top optimization, low-pressure distribution and several other measures with caveats about the uncertainty of potential costs and savings. The Council amended the discussion of the conservation strategic plan to highlight the importance of reviewing and revising conservation estimates, as new data become available, and adapting regional conservation plans and programs as a result. The Council discusses cost-effectiveness methodology for conservation in Appendix E ("Conservation Cost-Effectiveness Determination Methodology"), and for demand response in actions DR-2 and DR-4 of the Action Plan.

B. Reconciliation with Utility Resource Plans; Role of Independent Power Generation

COMMENTS: Some commentators, for example the Pacific Northwest Utilities Conference Committee (PNUCC) noted differences between the Council's plan and the integrated resource plans of several utilities. These plans proposed development of generating resources in advance of the time at which development could occur in the Council's plan. Some these commentators urged the Council's plan to be reconciled with utility IRPs. Questions were also raised regarding the reliance on the Northwest Independent Power Producer (IPP) generation in the plan. Some thought the treatment of IPP generation was reasonable (Pasco/Great Northern Development) or reasonable with caveats for unique situations that may face individual utilities (PacifiCorp, Idaho Electric Industry Advisory Committee). Others thought that IPP generation is not really reliable for the region (Tacoma, IPUC).

RESPONSE: In the short term, the main difference between the utilities' IRPs and the Council's plan is the treatment of market purchases. Some utilities view both short-term market purchases and the prospect for long-term contracts with existing counterparties as risky. As an alternative, they build and own new capacity. The Council's plan explicitly quantifies the risk associated with market purchases and concludes that greater reliance on these purchases, especially over the

next five to 10 years, is not only reasonable, but prudent and cost effective. Indeed the Council's analysis finds greater risk in overbuilding during the next decade.

A reconciliation of the utility resource plans with the Council's plan reveals a great deal of similarity through 2010 when resources included in the Council plan's base resources are excluded. These include the Port Westward combustion turbine, some combined-cycle generation purchased from IPPs, a single-cycle peaking plant, and approximately 1,000 megawatts (capacity) of wind development. Missing from the utility IRP data are forecasts of conservation. We assume that the utilities will shoulder their proportionate share of regional conservation, and that should make the resulting net loads comparable between the utilities' plans and that of the Council. What remains before 2010 is a sliver of resources that grows to as much as 800 megawatts. This sliver is an estimate, probably on the high side, of the difference between the plans. The PNUCC, in fact, states that some portion of this probably will be IPP purchases. The Council believes that the region's reliance on this magnitude of market purchases, either short-term or through long-term contracts, does not represent an extraordinary risk and provides economic benefit.

In assessing the wholesale power market as a resource for regional load, the Council carefully evaluated the status of independent power producer (IPP) generation in the region. The PNUCC Northwest Regional Forecast identifies approximately 3,200 average megawatts of IPP generation (3,500 MW capacity) that is not under contract Northwest load. Most of the generation is in the form of gas-fired combined cycle combustion turbines located in Washington and Oregon, much of it west of the Cascades. The 1,300 MW Centralia coal-fired power plant located in western Washington is also part of that total. The Council also surveyed the independent power producers of the region through the Northwest Independent Power Producers Coalition (NIPPC). NIPPC identified 3,600 MW (capacity) in Oregon and Washington. Of that, approximately 1,400 MW (capacity) is under contract through 2005, 950 MW is under contract through 2008, and 430 MW is under contract beyond 2008. NIPPC noted, "... virtually all IPP capacity is, as a result of transmission constraints and by design, committed exclusively to the Northwest."[1]

The Council considered the question of whether the region could physically count on power from the IPPs being available to the region. The IPPs generally do not have firmed transmission access to markets outside the region. This limits their ability to enter into long-term export contracts that could make the power unavailable to the region, although shorter-term or seasonal transactions are possible. However, even if some IPPs were able to execute long-term export contracts, the diversity in seasonality throughout the West makes it unlikely that there would be generation outside the Northwest to serve the IPPs export obligation at those times when the Northwest was most likely to need the power. Moreover, when the need in the Northwest arises and causes prices to exceed those outside the region, it is economically rational for market participants to counter-schedule the energy back to the Pacific Northwest.

[1] Letter from Northwest Independent Power Producers Coalition Executive Director Robert Kahn to Power Division Director Dick Watson, June 8, 2004.

The Council regards the IPP contribution to the market a significant source of power availability, price stability and predictability. The Council chose to model the availability of this IPP generation in the market explicitly. Indeed, the alternative of modeling ownership purchase or long-term contracts with IPP generators was considered. The Council discarded this approach, however, because the region has no way of knowing what terms parties eventually might enter into through bilateral purchase or contract negotiation.

Beyond 2010, the utilities' plans, collectively, depart more significantly from the Council's plan. Like the utilities' plans, the Council's plan calls for significant additions of new capacity, but largely wind generation rather than coal-fired generation. If the new coal is new capacity, as opposed to purchases from the Centralia plants, this would be a major difference. The difference in the perception of the risks associated with capital-intensive, long lead-time resources with vulnerability to carbon penalties and fuel-price risk would be evident and real. The Council acknowledges that there are some uncertainties about the ability to develop the amount of wind called for in its plan. The plan includes an action item to resolve those uncertainties in time to permit turning to alternatives if necessary.

That said, the Council has acknowledged that there can be circumstances under which utilities might need to undertake resource development in advance of the plan's schedule. For example, localized peaking requirements could account for the earlier development of single-cycle generation in the utility plans. Localized transmission constraints could make it difficult to serve some areas with power from IPPs. Similarly a utility that is very resource-short compared to the region as a whole could wish to reduce its vulnerability to market risk by building additional generation. Neither of these conditions is captured in the Council's aggregate regional analysis. These and other reasons are discussed extensively in the Overview.

C. Natural gas prices

The Council forecasts a range of long-term natural gas price trends. These are summarized in Chapter 2 and described in detail in Appendix B. In addition, the Council introduced substantial shorter-term variations in natural gas prices into the portfolio model analysis. These variations were mentioned in Chapter 2 and described further in Chapter 6.

COMMENTS: There were only a few official comments regarding natural gas prices. Bonneville commented that the Council did not explore the possibility of lower prices such as occurred during the 1990s. They also noted that the Council's medium price is close to theirs, but perhaps $.50 higher. Bill Pasco of Great Northern Power Development suggested that the Council may need to raise its natural gas price forecast to reflect the new Energy Information Administration (EIA) forecast that came out in December 2004. Snohomish PUD cited a forecast that was higher than the Council's medium case. In addition to these official comments we received an email communication that shared new forecasts from TransCanada Pipeline. We also received a series of communications from Phil Carver of the ODOE that our oil and natural gas price forecasts were too low.

RESPONSE: The comments we received made it clear that the draft plan had not communicated the important role of the portfolio model assumptions regarding natural gas prices, nor their relationship to the low-to-high range of trend forecasts. The range of price variation that is

evaluated in the portfolio analysis is much wider than the range of trend forecasts, especially on the high side. Both higher and lower forecasts influence the choice of the resource recommendations.

Following the comment period, the staff compared the new EIA forecast of natural gas and oil prices to the Council's range. Both the oil and natural gas price forecasts of EIA were between the Council's medium-low and medium-high forecasts. The EIA forecasts started out near the Council's medium-low forecast in 2010, but increased faster, ending near the medium-high forecast by 2025. The TransCanada forecast was comparable to our medium case and generally supported the Council's forecast. The Council has reviewed a number of other forecasts that are both higher and lower than its medium forecast. This diversity of views about future natural gas prices is the reason for analyzing a wide range of possibilities and the risks they pose.

Because comments suggest both higher and lower natural gas price forecasts, and because the Council's analysis in fact utilized a wider range of uncertainty in its portfolio analysis, the trend forecasts were not changed in the final plan. However, additional discussion and graphics were added to Chapter 2 and Appendix B to clarify the role of the portfolio model analysis of natural gas price uncertainty. Fuel price monitoring and reporting on a regular basis is called for in the action plan so that any significant changes in fuel market conditions or trends can be identified in a timely manner.

D. Demand Forecast

A 20-year forecast of electricity demand is a required part of the power plan.

COMMENTS: There was only one comment on demand forecasts. NorthWestern Energy commented that the Council's plan is designed to meet the coincident peak electricity needs of the region. They argued that the Council should be planning for meeting the non-coincident peak demand.

RESPONSE: The Council's demand forecast range is average annual energy. In the resource analysis with Aurora, Genesys or with the Portfolio Model, these average energy loads are allocated to seasons, months and hours. The Council disagrees that regional resource planning should plan to meet non-coincident peak loads. An efficient dispatch of resources, with adequate transmission capacity, will enable the region to meet coincident peak loads. There is no need to carry resource capacity to meet summer peaks in one area and winter peaks in another as if they occurred at the same time.

E. Wind power

Issue: Near-term development

The draft plan called on the region to be prepared to begin construction of at least 200 megawatts of new wind power by 2013 with the possibility of approximately 5,000 megawatts of new wind becoming cost-effective by the end of the planning period. In addition, the draft plan assumed that approximately 1,100 megawatts of new wind capacity would be developed through 2012 in response to regional system benefit charge (SBC) incentives (all SBC-driven resources were modeled as wind, though in practice a greater diversity of resource types is expected).

COMMENTS: Many respondents including Renewables Northwest, NWEC, CUB, MT Environmental Info Center, Energy Trust of OR, Zilkha Renewable Energy, Snake River Alliance and Idaho Electric Industry Advisory Committee, noted that the draft plan greatly underestimated the likely development of wind in the near-term.

RESPONSE: This comment appears to have largely resulted from insufficient description of the assumptions underlying the base-case portfolio analysis. The base case includes 1,100 MW of windpower by 2012, driven by system benefit charge and other renewable incentives (other types of renewable resources will likely be developed in addition to wind, however, modeling considerations limit the diversity of resources that can be evaluated). This windpower is in addition to the 5,000 MW of new wind recommended for development in the final plan. Additional clarification of this assumption has been provided in the "Developing a Base Case" section of Chapter 7. In addition, the earliest development of additional new wind moved forward to 2011 in the final base-case portfolio analysis. Also, it is possible that additional wind will be developed in the near-term, both to serve specific utility needs as described in the Overview and to serve out-of-region loads.

ISSUE: Wind power integration costs

Wind power integration costs include the cost of shaping the intermittent output of wind farms to load and the cost of transmitting power from the point of wind farm interconnection to the point of bulk power delivery. Integration costs sometimes also include the cost of interconnecting the wind farm to the nearest suitable substation and substation construction, if required. In the Council plan, these latter costs are assumed to be included in wind-farm capital cost estimates. Shaping costs were assumed to be $4/MWh (year 2000 dollars) for the first 2,500 MW of new wind west of the Continental Divide. Shaping cost of $8/MWh were assumed for the second 2,500 MW block as hydropower shaping capability became more limited. Because of more limited local hydropower availability, shaping costs for wind power developed east of the Continental Divide were assumed to be $8/MWh. Wheeling was assumed to cost $15/kW/yr, representing the cost of a single wheel, for all blocks of windpower. Because of the uncertainty of these and other assumptions regarding windpower, the draft plan included an action to confirm the cost-effectiveness of large-scale wind resource development.

COMMENTS: Numerous comments regarding wind integration costs were received, generally asserting the wind shaping cost assumptions were low. WMG&T, CUB, ICNU, Tacoma Power, PNUCC and Snohomish PUD remarked that integration costs could use additional analysis. BPA (Malin) remarked that the integration cost for the second block of wind was too low, and Grant PUD commented that the $4/MWh cost would only be valid for the first 500 MW of new wind development and would increase exponentially after that. In further remarks, Grant PUD (Noteboom) asserted that shaping costs should be $6/MWh, minimum.

In addition, concern was expressed (Grant PUD) about the ability of the hydrosystem to provide shaping services for wind in addition to overall load following services and operations for fish.

Regarding transmission costs, both BPA (Malin) and Grant PUD (Noteboom) remarked that wind transmission costs may be low

RESPONSE: Following receipt of initial comments concerning wind integration costs, the Council discussed shaping costs with individuals at Bonneville and PacifiCorp having experience with wind shaping and transmission costs (Elliot Mainzer, et. al, BPA, and Ken Dragoon, PacifiCorp). These discussions suggested that while the costs for shaping moderate amounts (~1,000MW) of new wind capacity are reasonably well understood, the costs of shaping additional capacity are increasingly uncertain. Moreover, the assumptions of the draft plan may be somewhat low. In response, the Council, for the final plan, increased the cost of shaping the first 2,500 MW of new wind west of the Continental Divide to $4.55/MWh and the cost of shaping an additional 2,500 MW to $9.50/MWh. The cost of shaping wind east of the Continental Divide also was increased to $9.50/MWh (Chapter 5).

As a result of these discussions, it also was concluded that while a utility with hydropower or other shaping capability might be able to move wind to load and shape it using a single transmission wheel, many utilities would need to secure shaping services from utilities having such capability. This could incur additional wheeling costs. Consequently the assumed transmission wheeling costs for wind were increased to $20/kW/yr (2000 dollars) in the final plan (Chapter 5).

With regard to the issue of the capabilities of the hydrosystem to provide wind shaping, load following and fish operations, an Action Plan item was added for the Council to undertake a study of this issue.

F. Value of green tags

A market premium for electricity from some renewable energy projects is created by consumer green power subscriptions, utility resource portfolio acquisitions, renewable portfolio standards and other factors. Renewable energy credits ("green tags") are a mechanism for trading the premium separate from project electrical output. For the draft plan, the Council credited wind power and other new renewable resources with green tag revenues of about $6/MWh (year 2000 dollars) in the near-term. For deterministic analyses such as the power price forecast, tag revenue was assumed to decline to about $3/MWh (2000 dollars) by 2025 as the enactment of carbon dioxide penalties for fossil fuel generation offset some of the premium value of renewable energy. Tag value is treated stochastically in the portfolio analysis. In the draft portfolio analysis, the probability of any green tag value declined over time, and tag value was assumed to drop to zero if any level of carbon dioxide penalty were enacted (also a stochastic variable). The mean value of green tags over all futures declined from $6.70 in 2005 to $1.00 in 2025 (2004 dollars).

COMMENTS: Bonneville commented that tag values for wind rarely exceed about $4.50/MWh. Grant County PUD recommended omitting the green tag premium as it affects only the value, not the cost of wind.

RESPONSE: The Council retained the tag premium in the final plan, as wind and other renewable resources would not otherwise be credited with a revenue stream available to renewable resources separate from the revenue stream associated with the energy generated by the project. This revenue stream is analogous to the co-production credit received by

cogeneration facilities and the byproduct credits occasionally credited to certain fossil-fuel-fired generating facilities.

Following release of the draft power plan, the Council undertook an assessment of green tag values, including interviews with persons engaged in green tag trading. Carrie Plemons of PPM Energy recommended that tag values should start at $3.50/MWh with increasing uncertainty over time to a range of $1 to $8/MWh by 2025. Ms Plemons also remarked that tags would retain some value, even if carbon dioxide penalties are enacted. George Tung of RE Trends Weekly corroborated Ms Plemons' comments. Peter West of the Energy Trust of Oregon recommended a near-term tag value of $4/MWh, with increasing uncertainty over time to a range of $1 to more than $10/MWH by 2025. Mr. West also commented that tag values should retain some value if carbon dioxide penalties are enacted.

For the final plan, the Council assumed a near-term tag value of $3.50, increasing slightly and with increasing uncertainty over time to a range of $1 to $8/MWh by 2025. Green tag value and the carbon dioxide penalty were decoupled. The mean value of green tags across all futures in the base case portfolio analysis increases from $3.53 in 2005 to $4.51 in 2024 (2004 dollars).

G. Climate Change Risks

ISSUE: Carbon dioxide penalty

A number of industrialized nations are taking action to limit the production of greenhouse gasses. Within the United States, Oregon and Washington and other states, and some local governments, have initiated efforts to control carbon dioxide production. It appears increasingly likely that federal climate change policy involving some level of carbon dioxide (CO2) control eventually will be enacted in the United States. In the power plan, climate control policy is viewed as a cost risk to the power system of uncertain magnitude and timing. A fuel carbon content tax is used as a proxy for whatever form CO2 control ultimately may take. CO2 control cost is treated stochastically in the portfolio analysis. In the base case, a carbon tax can arise in any fourth election year, 2008 or later, and once enacted is fixed in value. The value is selected from a uniform distribution between zero and $15 per ton if enacted between 2008 and 2016; and between zero and $30 per ton if enacted thereafter. The resulting mean value (used for deterministic analyses) is zero through 2007, $0.29/ton CO2 in 2008 and rises to $6.87/ton CO2 in 2021 and later.

COMMENTS: A range of comments was received on the Council's assumptions regarding future CO2 penalties. The State of Oregon (Oregon Department of Energy) regarded the cost as too low. Climate Solutions recommended that the Council assume a much higher likelihood of higher values earlier in the planning period. The IPUC thought that the assumed cost of future climate mitigation may be understated and all (portfolio modeling) scenarios should include a CO2 control cost of some amount greater than zero. PacifiCorp noted that the Council's assumptions are roughly equivalent to PacifiCorp's assumptions in its 2002 and forthcoming IRPs. In contrast, Tacoma Power commented that the assumed value was "bullish" and Great Northern Power Development commented that a carbon tax is "not inevitable or even likely, especially at the higher levels assumed in the draft plan".

RESPONSE: Because Oregon and Washington have implemented (albeit low) CO2 offset requirements for new power plants, there is clearly non-zero probability of CO2 penalties. Increasing concern, internationally and at the state and local government levels and among the general public, suggests that greenhouse gas mitigation requirements and associated CO2 penalties or control costs are likely to increase in probability and magnitude over time. The maximum penalty/offset cost likely to be experienced during the planning period will be a function of the cost and availability of CO2-free or low-CO2 energy production facilities and consideration of the near-term economic impact of climate change policy. The rapidly improving economics of wind power (Chapter 5 and Appendix I), likely emergence of a new generation of nuclear power plants (elsewhere, if not in the Northwest) (Chapter 5), and emergence of commercial coal gasification with CO2 sequestration potential (Chapter 5, Appendix I and Appendix K) suggests that there is a reasonable probability that CO2 penalties/offset costs are unlikely to exceed the $30/ton cap used in the draft portfolio analysis. Consequently, the Council chose to remain with the assumptions of the draft plan.

ISSUE: Global warming policy
The Council incorporated the estimated cost of possible future greenhouse gas control requirements in its assessment of resource cost-effectiveness but did not take an advocacy position with respect to greenhouse gas reduction.

COMMENTS: Several respondents, including NWEC, Climate Solutions, CUB, and MT Environmental Info Center, commented that the Council ought to advocate for reduction of greenhouse gasses.

RESPONSE: Consistent with the Power Act, the Council through its power plan addresses the environmental consequences of power system resource development through the type of resources recommended for development and through research and development recommendations. In recommending resources for development, the Council is required to give priority to resources determined to be cost-effective with "due consideration" to environmental quality, compatibility with the existing regional power system and protection, and mitigation and enhancement of fish and wildlife. Cost-effectiveness requires a resource to be reliable and available within the time needed, and to meet or reduce demand and an estimated incremental system cost no greater than that of the least-cost similarly reliable and available resource. In the methodology developed by the Council, system cost is an estimate of all direct life cycle costs plus quantifiable environmental costs and benefits that are determined to be attributable to the resource. Therefore, the set of resources recommended in the plan for development implicitly should minimize total economic and environmental costs.

The cost of regulated environmental impacts, such those resulting from criteria air pollutants, are reflected in the estimates of resource performance, and capital and operating costs, including the performance and cost effects of expected environmental controls. This presumes that regulations are set such that the cost of further emission reduction exceeds the environmental cost of the emissions. Greenhouse gas production, including CO2 production from fossil-fueled generating resources, however, is unregulated at the federal level in the United States. Increasing acceptance of the existence, mechanisms and possible consequences of global climate change has led to increasing recognition that CO2 production will have adverse environmental

consequences. Therefore, the cost of some (but currently unknown) incremental level of regulation must be less that the incremental cost of prospective damages.

The Council's responsibility, therefore, is to attempt to identify the point where the incremental cost of CO2 control will equal the incremental cost of CO2 damages. This, unfortunately, is not feasible. Alternatively, the Council has chosen to estimate the cost of CO2 control as a proxy for the economically optimal cost of CO2 regulation. Because even the cost of CO2 control is highly uncertain, the Council has chosen to estimate the cost of future CO2 control using a stochastic method described in Chapters 6 and 7 of the plan. The Council believes this method provides the best approach currently available for quantifying the environmental cost of greenhouse gas production associated with the resources assessed in the plan.

Partly as a result of the quantification of the cost of CO2 control, resources not producing CO2 ranked highly in the recommended plan. Nearly all of the available conservation and all of the available windpower was chosen for development. The principal exception is a relatively small amount (435 MW) of coal gasification power generation. The cost-effectiveness of this resource is attributable to low fuel costs and moderate capital costs that appear to offset the cost of CO2 production. This technology displaces conventional coal-steam generation that has significantly higher CO2 production. Further reflecting the Council's attention to the likely need to control CO2 production, the Council recommends research and development actions to 1) confirm the ability to develop the wind power included in the portfolio; 2) confirm the ability to shape the output of the wind power using the hydropower system without compromising fish recovery and protection measures; 3) periodically assess the commercial status of coal gasification; and 4) demonstrate the potential for CO2 sequestration in the Northwest.

Issue: Climate Change Science and Impacts

The Council has the responsibility to assess any potential impacts of climate change on the power system and to recommend mitigating actions whenever appropriate. In the plan, the Council identifies two ways in which climate change could affect the power supply. The first is the impact of potential new carbon-control measures on the cost of fossil-fuel burning resources and their effect on tax credits and other incentives pertaining to renewable resources as discussed above. The second is the potential change in temperature, precipitation, and river flows, which would affect demand, hydroelectric generation, and river operations for fish and wildlife.

Using data provided by scientists at the University of Washington regarding potential precipitation and temperature changes over the next 20 to 40 years, the Council analyzed the impacts to electricity demand and to river flows. General conclusions indicate that during winter months electricity demand should decline due to higher temperatures, and river flows likely would increase due to higher rainfall (as opposed to snowfall). During summer months, electricity demand should increase, also due to higher temperatures, and river flows likely would decrease due to a smaller snowpack and runoff. Potential future consequences of these impacts include 1) an increase in winter flood control operations; 2) greater summer peaking problems; and 3) greater deficiencies in maintaining summer flows for migrating salmon. The Council did not incorporate potential changes in river flows or potential changes in power demand into its final plan analysis because of the high level of uncertainty in the climate modeling results.

COMMENT: Phil Carver of the Oregon Department of Energy commented that Appendix N did not emphasize that the science behind climate change has become stronger over the last 15 years and that the trend is likely to continue. He also commented that the appendix is dismissive of potential sea level rises and notes that sea levels could rise higher and sooner than anticipated in the appendix. He also made several other comments regarding new information that had become available since the draft appendix was released.

RESPONSE: Many of the technical updates were incorporated into the final appendix. The text was changed to emphasize that the science has become stronger and that although many uncertainties still exist regarding global warming, a preponderance of scientific opinion asserts that the Earth is warming. However, the Council is not tasked with addressing, nor does it have the resources to resolve, existing uncertainties associated with global warming. The Council must consider not only the impacts of potential climate change and related policy measures but also the uncertainty in how climate changes and policies will be manifested. The first section of Appendix N is designed to be a representation of the "state of the science" regarding global warming, not an endorsement of any particular conclusion.

COMMENT: The Columbia River Inter-Tribal Commission (CRITFC) commented that climate change impacts to power demand and river flows should have been incorporated into the portfolio analysis for the final plan. The Oregon Department of Energy also made a similar comment, asserting that the uncertainties surrounding climate change in the plan are "overblown" and that the Council should be more proactive regarding the environment.

RESPONSE: Based on discussions with scientists from the University of Washington, the Council chose not to include any long-term climate-change impacts to temperature or river flows in its final portfolio analysis for this plan. As mentioned in the appendix, global climate models are not well suited to analyze small areas such as the Northwest. "Downscaling" methods to translate global results into regional results exist but they are preliminary and are still being refined. In addition, different global models yield vastly different results for average changes in precipitation and consequent runoff volumes. At this time there is no way of validating one global model over another. While it is important to understand all possible outcomes of climate change, the Council's position is that the data and results are too premature for inclusion in the portfolio model. The appropriate action for the Council and the region is to continue to monitor the science and to refine analysis of potential impacts to the power system. The plan includes an action item to that effect.

H. Coal

ISSUE: Inclusion of coal in the recommended resource portfolio

The least-risk plan resulting from the portfolio analysis included addition of 400 MW of coal-fired capacity as early as 2013. Consequently, the draft plan included the recommendation that the region be prepared to construct 400 MW of new coal-fired power generation by 2009. Conventional (pulverized) coal-fired plants were the technology modeled in the least-cost plan. Although coal gasification combined-cycle plants were tested in a sensitivity run, and although this resulted in a superior plan, coal gasification technology was not included in the draft portfolio recommendations because of uncertainties concerning the commercial prospects for gasified coal generation. Coal gasification power generation was substituted for conventional

pulverized coal in the final plan because of recent developments indicating that the technology is moving to the early states of commercial development.

COMMENTS: Numerous and generally polarized comments were received regarding inclusion of coal in the recommended plan. Renewables Northwest, CUB, Sierra Club, MT Environmental Info Center, Oregon Dept. of Energy, Energy Trust of OR, League of Women Voters of OR, Mountaineers, Zilkha Renewable Energy, Solar Washington Association, Republicans for Environmental Protection, and Snake River Alliance all opposed including coal in the recommended portfolio. In contrast, PSE, WESCO Resources, Inc, Bull Mountain Land Co., and MT Large Customer Group supported inclusion of coal and in some cases (WESCO Resources, Great Northern), recommended the inclusion of a greater amount of coal. A few respondents (NRDC, WA CTED, Climate Solutions) suggested that if coal were necessary that coal-gasification power generation technology be recommended.

RESPONSE: Coal consistently appeared in the least cost plan under base case assumptions - but generally limited in amount to one or two 400 MW units in the 2013 time frame. A sensitivity study comparing coal gasification power generation (without CO2 sequestration) to conventional pulverized coal prepared for the draft portfolio analysis favored coal gasification over conventional coal, presumably because of the higher efficiency, declining costs, and lower CO2 production associated with coal gasification power generation. Coal gasification, however, was not included because of uncertainty regarding commercial availability of the technology by the time needed.

Recent industry developments, including announcements immediately before and after release of the draft plan, suggest that IGCC technology have reached the early stages of commercial availability. As discussed in Appendix I, equipment vendors representing the principal coal gasification technologies and architect-engineers have recently formed consortiums to provide wraparound plant performance warranties and full design/build/operate services. These services are necessary and likely sufficient to ensure that the technology continues commercialization. In response, several utilities and independent power developers have announced intent to construct coal gasification power generation capacity.

This evidence is sufficiently persuasive to allow the Council to assume that the technology would be available by the time that the portfolio analysis suggests that new coal resources would be cost-effective. Coal gasification power generation was retested to confirm its superior cost-effectiveness compared to conventional coal-steam generation and substituted for conventional coal in the final plan. Because of its early stage of commercial development, a new action item was included in the plan to review the commercial status of coal gasification power generation technology within two years of plan adoption.

Because of the potential suitability of certain geologic formations within the Northwest for carbon sequestration and the apparent value of reducing the CO2 production associated with coal-based generation, the final plan also calls for investigating the feasibility of developing the proposed coal-gasification combined-cycle power plant recommended in the plan with advanced coal gasification technology demonstration capability, including carbon separation and sequestration.

I. Least-Risk, Least-Cost Plan

Issue: How to chose the preferred alternative

The portfolio analysis analyzes a large number of alternative plans (1,000 or more) over 750 different futures. It identifies a subset of those plans, each of which represents the lowest average power system cost over those 750 futures for a given level of risk.[2] Risk is represented by the average cost of the most costly 10 percent of the futures. There is a relationship between the average cost and risk. As the risk is reduced, the average cost increases. This is because the lower-risk plans incorporate additional resources. Adding these resources reduces exposure to the market and the associated risks but incurs additional construction and operating costs. It also reduces the highest costs but incurs higher costs on average. The increase in average cost could be thought of as the insurance premium associated with lowering risk. In choosing a specific plan, the Council chose the least-risk, least-cost plan – one that incorporates the development of a larger and more diverse resource set than do higher-risk plans.

COMMENTS: Most commentors supported that choice. However, some (Northwest Energy Coalition, Sierra Club) argued that the decrease in risk did not justify the increase in average cost. They suggested that the Council should have chosen a higher risk plan, one composed entirely of conservation and wind with the balance made up by market purchases.

RESPONSE: The Council believes that to take that position reflects too narrow a view of average cost and risk. The cost and risk measures produced in the portfolio analysis focus entirely on costs and risks to the power system. They do not reflect the broader costs to society and the environment that occur when, as occurred in 2000 and 2001, the power system experiences extremely high costs. In 2000-2001, inadequate power supply triggered high prices that, in turn, resulted in plant closures and layoffs, below-average agricultural production, and curtailment of river operations that are intended to aid the downstream migration of juvenile salmonids. None of these costs is reflected in the risk measure used in developing the plan. In developing the plan, additional indicators of potential disruption were examined. These included the likelihood of high retail rates and rate volatility and the level of dependence on high-cost market purchases (Chapter 7). These all showed the higher-risk, lower-cost plans also pose a greater potential for economic disruption.

For these reasons, the Council believes it was justified in choosing the lowest-risk, lowest-cost plan. A secondary factor is that the insurance cost of the lower-risk plan has little near-term cost. The least-risk, least-cost plan and plans with higher risk are virtually identical through the end of the decade. The major risks occur later in the planning period, as do the additional resource costs associated with lower-risk plans. The Council will revise its power plan before that time.

J. Demand Response

ISSUE: Is it a resource?

COMMENTS: Most of the comments received supported the inclusion of demand response as a component of the Fifth Power Plan. BPA pointed out that demand response was not a "resource"

[2] Power system cost is the cost of operating and expanding the power system over the 20-year planning period. The capital costs of the existing system are not counted, as those are sunk costs and are common to all the plans.

by the formal definition in the Power Act, but agreed that consideration of demand response as one of the components of the Plan was worthwhile. We received several comments that the amount of demand response available is uncertain; some (e.g., PGE) asserted that our assumptions were somewhat optimistic, and some (e.g., Climate Solutions) asserted that our assumptions could underestimate the true potential.

RESPONSE: The final plan makes the distinction between "resource" as it is defined in the Power Act and "resource" as it is defined by the Council, on page 4-1. The Council agrees that the potential is uncertain; action items DR-1, DR-3, DR-4, DR-5, DR-6 and DR-8 are designed to resolve some of that uncertainty.

K. Resource Adequacy

COMMENTS: The Bonneville Power Administration recommended a much stronger role for the Council in this area, especially in developing an adequacy metric and standard for the Northwest. Bonneville suggested that the Council take a proactive approach and re-establish the Northwest Adequacy Forum, where these issues could be discussed. Similarly, PNUCC noted a role for the Council in this issue. Marsha Smith of the Idaho PUC cautioned that processes already underway should not be duplicated.

RESPONSE: The Council incorporated Bonneville's comments in action item ADQ-2, which calls for the Council to re-establish a Northwest Adequacy Forum. The forum is intended to help develop metrics and standards for the Northwest and will ensure that those standards are consistent with Westwide efforts to develop adequacy standards.

L. Transmission

COMMENT: The Bonneville Power Administration commented that there needs to be stronger integration of power and transmission planning, including highlighting wind resource transmission problems, and supported the Council's working closely with the transmission planning efforts of the Seams Steering Group - Western Interconnection (SSG-WI) and the Northwest Transmission Assessment Committee (NTAC). WESCO Resources commented that the plan should consider new transmission to accommodate new generation. The Washington State Department of Community, Trade and Economic Development (WA CTED) supported better integration of resource and transmission planning through participation in existing regional transmission planning processes but suggested that the Council might also consider taking on a stronger analytic role itself.

RESPONSE: The Action Plan recognizes that transmission planning and construction can be the longest lead-time item in power plant development. The Council committed to continue working with existing regional planning groups as the most effective means to ensure closer integration of resource and transmission planning. The Council will work to specifically address the needs of wind and other location-bound resources in transmission planning and will incorporate the results of the transmission planning work into the Council's power plan.

COMMENT: The Public Power Council (PPC), Tacoma Power, and Snohomish County PUD commented that the Council should not commit to Grid West, that it was likely to be too

expensive for any benefits that might flow from it and that there were other regional alternatives to address existing transmission system problems. The Northwest Energy Coalition and the Snake River Alliance urged the Council to take a more active leadership role in addressing the region's transmission problems.

RESPONSE: The Council believes that it is too soon to evaluate the costs and benefits of the Grid West proposal because the proposal itself is not yet developed sufficiently. The Council believes that Grid West could offer a reasonable framework for addressing the transmission issues facing the region. But the Council also is committed to working with parties in the region to find alternative means of addressing the issues if Grid West fails to maintain sufficient regional support to move forward.

M. Fish and Wildlife

COMMENT: Several commentors (Audubon of WA, MT Environmental Info Center, Snake River Alliance) suggested that the plan had insufficient or no consideration of fish operations and needs.

RESPONSE: Power system impacts and resource adequacy effects on fish and wildlife operations were analyzed and addressed in the development of the plan. To emphasize how this was done, a more complete summary of this issue was added to the executive summary and the overview.

COMMENT: PNUCC recommended that the Council establish a cost effectiveness test for fish operations and measure all fish and wildlife activities pertaining to the power system against this standard.

RESPONSE: Cost effectiveness tests for fish and wildlife operations and their impacts to the power system were a part of the Council's fish and wildlife program mainstem amendments, adopted in 2003. The need for the region to continue to develop cost effectiveness methodologies is reiterated in this power plan. It is recognized as being a very difficult and, in some commentors' views, an almost impossible task, but the region must continue to refine its biological and physical analyses in this area.

COMMENT: Some commentors, in particular the state of Oregon, suggested that the Council should establish a metric and standard to assess the success of implementing fish and wildlife measures related to the operation of the hydroelectric system. In particular, the suggestions were to continue to explore a probabilistic measure similar to the loss-of-load probability used for resource adequacy.

RESPONSE: A probabilistic metric and related standard to measure the power system's success at providing operations for fish and wildlife is not yet ready. More regional discussion is needed before such a metric (and standard) could be fully developed and implemented. Part of the problem is distinguishing between a "planning" metric and standard and an "operations" standard. Even if a planning standard were developed, no clear method of translating this into a usable operations standard has been developed. The Council recognizes that this is an important issue and encourages these regional discussions to continue.

N. Future Role of the Bonneville Power Administration in power supply

COMMENT: The plan reiterates the Council's earlier recommendations regarding the future role of Bonneville in power supply. There was general agreement with these recommendations. The Council added an action plan item to monitor progress toward implementation of those recommendations. Some (Northwest Requirements Utilities, Inland Power and Light) expressed the concern that allocation of the existing system, as recommended by the Council, risks the benefits of coordinated and efficient operation.

RESPONSE: The Council believes this comment is really directed at the "slice" product whereby a customer purchases a percentage of the output of the system along with some limited operational flexibility. This has been a concern for some parties ever since Bonneville first offered the slice product. The crux of the concern is the potential for cost transfers from slice to non-slice customers. The slice product is not central to the Council's objective for the future role of Bonneville. That objective is that Bonneville serve the demands that exceed the capability of the existing system at the cost of providing that power. The Council would like to see Bonneville offer a range of power products that meet the needs of its customers *provided* that it can do so in a way that is efficient, fair and equitable for all customers. If, after objective analysis, Bonneville demonstrates that the slice product cannot meet those criteria, the Council would not object to its modification or, if absolutely necessary, elimination. The Council and others in the region would want to review any such analysis and have the opportunity to comment before Bonneville would act. The Council added an action plan item to monitor progress toward implementation of its recommendations.

COMMENT: Others (Bonneville, Tacoma, Litchfield) commented that Bonneville should not be expected to "backstop" conservation acquisition by regional customers (i.e., step in and acquire the conservation if customers fail to).

RESPONSE: The plan was clarified to say that "Bonneville should use the full extent of its authority to ensure that all cost-effective conservation is captured in an efficient, low-cost, and timely way." See Page 11-8.

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