BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1056

IN THE MATTER OF An Investigation Into Integrated Resource Planning Requirements.	OREGON DEPARTMENT OF ENERGY'S REPLY COMMENTS

The Oregon Department of Energy offers the following explanation of its proposed changes to Staff's Integrated Resource Planning Guidelines. A marked-up version of Staff's Proposed Guidelines is attached as Exhibit 1.

Volatility vs. Scenario Risks

Staff's guidelines correctly distinguish between annual cost volatility and risks that the present value of 20 years of revenue requirements (PVRR) will significantly exceed the expected level. The attached guidelines have attempted to clarify this difference. Staff incorrectly separates carbon risk into a third category of risk.

Annual cost volatility can only be calculated where there are historical records of the volatility of the inputs. There are historical records of annual volatility of loads, hydro project output, forced outage rates for power plants and fuel prices. These are useful for estimating the level of volatility of year-to-year costs.

These historical records have little value in estimating major risks to PVRR. The risks of major loss of industrial loads to international competition, sustained high natural gas prices and the impact of carbon regulation on fossil fuel prices have no historical precedents, so past variance of loads and fuel prices will fail to address these risks. There is an active market in European CO_2 allowances under the Kyoto Protocol so there are ways to empirically address CO_2 allowance costs under various carbon regulation scenarios. CO_2 regulatory uncertainties are no more analytically intractable than natural gas price or load uncertainties.

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There is no credible method to accurately forecast U.S. international competitiveness or natural gas prices. Liquefied natural gas (LNG) imports are the incremental U.S. gas supply. U.S. natural gas prices are now structurally linked to the world energy market, which is driven by crude oil prices. World oil prices are subject to geologic and technologic uncertainty and also to geo-political uncertainty, especially the behavior of a dwindling number of oil exporting countries. World prices for LNG are already being affected by implementation of the Kyoto Protocol. Spain is a major importer of LNG. As the incremental source of natural gas, LNG will set the U.S. wholesale natural gas price.

It makes little sense to separately address the uncertainties of future natural gas prices and CO_2 regulation. in the U.S and other countries. Because CO_2 regulations will increase the demand for natural gas, natural gas prices and CO_2 regulation is strongly linked. Separating carbon risk into a third risk category makes it impossible to understand this risk in the context of load loss and gas price risks.

Risk Analytics

Risk analysis is an important element in RFP design. The IRP risk analysis will only be intelligible to the extent it uses metrics and multi-objective decision making analysis. This is a long established analytical discipline and should be used in the IRP risk analysis.

Discount rate uncertainty may be overblown

The real cost of capital to utilities is used as the discount rate to calculate PVRR. Annual variations in the cost of capital for a utility will also affect its revenue requirements, if there is a rate case that year.

Staff has provided no evidence that there has been significant historical volatility in the real cost of capital. Nominal interest rates have been high, but these have been at times of high rates of inflation. Real rates have been fairly stable. The U.S. cannot have a real returns to capital substantially different from the rest of the world. Capital will flow into or out of the U.S. to erase a significant differential.

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Adding a discount rate risk analysis would add significant cost and complexity to the IRP process. Before requiring a discount rate risk analysis, Staff should show the historical volatility is significant. In no case should the discount rate be used in the scenario risk analysis. There is no reason to believe the worldwide cost of capital is likely to significantly change.

DATED this _____ day of September 2005.

Respectfully submitted,

HARDY MYERS
Attorney General

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Janet L. Prewitt, #85307
Assistant Attorney General
Of Attorneys for Oregon
Department of Energy

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 947-4500 / Fax: (503) 378-3802

CERTIFICATE OF SERVICE

I certify that on September 30, 2005, I served the foregoing OREGON DEPARTMENT OF ENERGY'S REPLY COMMENTS, upon the parties hereto by sending a true, exact and full copy by postage prepaid, regular mail, or shuttle mail, and by electronic mail:

NW ENERGY COALITION 219 FIRST ST STE 100 SEATTLE WA 98104	RATES & REGULATORY AFFAIRS PORTLAND GENERAL ELECTRIC RATES & REGULATORY AFFAIRS 121 SW SALMON STREET, 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com
SUSAN K ACKERMAN NIPPC PO BOX 10207 PORTLAND OR 97296-0207 susan.k.ackerman@comcast.net	STEPHANIE S ANDRUS DEPARTMENT OF JUSTICE REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@state.or.us
KATHERINE BARNARD CASCADE NATURAL GAS PO BOX 24464 SEATTLE WA 98124 kbarnard@cngc.com	PHIL CARVER OREGON DEPARTMENT OF ENERGY 625 MARION ST NE STE 1 SALEM OR 97301-3742 philip.h.carver@state.or.us
MELINDA J DAVISON DAVISON VAN CLEVE PC 333 SW TAYLOR, STE. 400 PORTLAND OR 97204 mail@dvclaw.com	CAREL DE WINKEL OREGON DEPARTMENT OF ENERGY 625 MARION STREET NE SALEM OR 97301 carel.dewinkel@state.or.us
JASON EISDORFER CITIZENS' UTILITY BOARD OF OREGON 610 SW BROADWAY STE 308 PORTLAND OR 97205 jason@oregoncub.org	ANN L FISHER AF LEGAL & CONSULTING SERVICES 2005 SW 71ST AVE PORTLAND OR 97225-3705 energlaw@aol.com
TROY GAGLIANO RENEWABLE NORTHWEST PROJECT 917 SW OAK, SUITE 303 PORTLAND OR 97205 troy@rnp.org	ANN ENGLISH GRAVATT RENEWABLE NORTHWEST PROJECT 917 SW OAK - STE 303 PORTLAND OR 97205 ann@rnp.org

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 947-4500 / Fax: (503) 378-3802

DAVID E HAMILTON NORRIS & STEVENS 621 SW MORRISON ST STE 800 PORTLAND OR 97205-3825 davidh@norrstev.com	JOHN HANSON NORTHWEST NATURAL 220 NW 2ND AVE PORTLAND OR 97209-3991 john.hanson@nwnatural.com
ROBERT D KAHN NIPPC 7900 SE 28TH ST STE 200 MERCER ISLAND WA 98040 rkahn@nippc.org	BARTON L KLINE IDAHO POWER COMPANY PO BOX 70 BOISE ID 83707-0070 bkline@idahopower.com
KATHERINE A MCDOWELL STOEL RIVES LLP 900 SW FIFTH AVE STE 1600 PORTLAND OR 97204-1268 kamcdowell@stoel.com	DAVID J MEYER AVISTA CORPORATION PO BOX 3727 SPOKANE WA 99220-3727 david.meyer@avistacorp.com
ALEX MILLER NORTHWEST NATURAL GAS COMPANY 220 NW SECOND AVE PORTLAND OR 97209-3991 alex.miller@nwnatural.com	GREGORY W SAID IDAHO POWER COMPANY PO BOX 70 BOISE ID 83707 gsaid@idahopower.com
IRION SANGER DAVISON VAN CLEVE 333 SW TAYLOR, STE 400 PORTLAND OR 97204 ias@dvclaw.com	V DENISE SAUNDERS PORTLAND GENERAL ELECTRIC 121 SW SALMON ST 1WTC1301 PORTLAND OR 97204 denise.saunders@pgn.com
STEVEN SCHLEIMER CALPINE CORPORATION 4160 DUBLIN BLVD DUBLIN CA 94568-3169 sschleimer@calpine.com	LISA C SCHWARTZ PUBLIC UTILITY COMMISSION OF OREGON PO BOX 2148 SALEM OR 97308-2148 lisa.c.schwartz@state.or.us
JOHN W STEPHENS ESLER STEPHENS & BUCKLEY 888 SW FIFTH AVE STE 700 PORTLAND OR 97204-2021 stephens@eslerstephens.com	JON T STOLTZ CASCADE NATURAL GAS PO BOX 24464 SEATTLE WA 98124 jstoltz@cngc.com
BONNIE TATOM PUBLIC UTILITY COMMISSION PO BOX 2148 SALEM OR 97308-2148 bonnie.tatom@state.or.us	MARK P TRINCHERO DAVIS WRIGHT TREMAINE LLP 1300 SW FIFTH AVE STE 2300 PORTLAND OR 97201-5682 marktrinchero@dwt.com
STEVEN WEISS NORTHWEST ENERGY COALITION 4422 OREGON TRAIL CT NE SALEM OR 97305 steve@nwenergy.org	RICHARD T WINTERS AVISTA UTILITIES PO BOX 3727 SPOKANE WA 99220-3727 dick.winters@avistacorp.com

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 947-4500 / Fax: (503) 378-3802

LINCOLN WOLVERTON EAST FORK ECONOMICS PO BOX 620 LA CENTER WA 98629 lwolv@tds.net	PAUL M WRIGLEY PACIFIC POWER & LIGHT 825 NE MULTNOMAH STE 800 PORTLAND OR 97232 paul.wrigley@pacificorp.com

DATED: September 30, 2005

____
Janet L. Prewitt, #85307
Assistant Attorney General

HARDY MYERS
Attorney General

PETER D. SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

September 30, 2005

Public Utility Commission of Oregon
Attention: Filing Center
550 Capitol Street NE, Suite 215
Salem, OR 97301-2148

Re: *In the Matter an Investigation Into Integrated Resource Planning Requirements*
Docket No. UM 1056
DOJ File No. 330-050-GN0433-02

Enclosed for filing is an original and five copies of OREGON DEPARTMENT OF ENERGY'S REPLY COMMENTS, exhibits and certificate of service.

Sincerely,

/s/ Janet L. Prewitt
Assistant Attorney General
Natural Resources Section

Enclosures

c: UM 1056 Service List

JLP:jrs/GENN9695

1162 Court Street NE, Salem, OR 97301-4096 Telephone: (503) 947-4500 Fax: (503) 378-3802 TTY: (503) 378-5938

Staff's Proposed Guidelines
Integrated Resource Planning for Energy Utilities[1]
Docket UM 1056

1. The plan must meet four substantive requirements:

One, all resources[2] must be evaluated on a consistent and comparable basis.

- All known resources for meeting the utility's load must be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchasing and transportation – and demand-side options which focus on conservation and demand response.
- Utilities should compare resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.
- Consistent assumptions and methods should be used for evaluation of all resources.
- The real after-tax marginal weighted-average cost of capital should be used to discount all future resource costs.
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Deleted: Utilities should analyze how their preferred portfolio would change over a range of reasonable discount rates.

Two, annual cost volatility and uncertainty must be considered.

- At a minimum, utilities should address the following sources of annual cost volatility and uncertainty:
  – Electric utility plans should address volatility of annual costs due to variations in load requirements, hydroelectric generation, plant forced outages, fuel prices and electricity prices. These plans should also address the scenario risks of sustained high or low loads and high or low fuel prices with CO_2 regulations being one factor of fuel price risk.
  – Natural gas utility plans should address demand (peak, swing and base-load), commodity supply and price, and transportation availability and price.
- Utilities should identify in the plan any additional sources of uncertainty.
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Comment: This distinction is incorporated above.

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Three, the primary goal must be the selection of a mix of resources with the best combination of expected costs and risks for the utility and its ratepayers.

- The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities also must consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.

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[1] Unless otherwise indicated, the guidelines apply to both electric and natural gas utilities.
[2] "Resource" is the general term used throughout this document for an option that meets customers' energy needs. For electric utilities, that includes power purchases, generating facilities and fuel, and transmission. For natural gas facilities, that includes gas supply purchases, transportation and storage facilities.

- Utilities should use present value of revenue requirements (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines as well as short-lived resources such as gas supply and short-term power purchases.
- To address risk, the utility should at a minimum:
  - Use two measures of PVRR risk: one that measures the annual variability of costs through the 20 year planning horizon and another that measures the severity of bad outcomes (e.g. expected value of the worst 10 percent of outcomes).
  - Discuss the proposed use of physical and financial hedging and their impact on costs and risks.
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- The utility should explain how its resource choices appropriately balance expected cost and risks. This should include an explicit discussion of the trade offs between expected PVRR and the all the types of risks considered in the IRP. This discussion should be explicit enough to develop consistent bid evaluation criteria in the request for proposals that will follow acknowledgement of the IRP.

Comment: The impact of a range of CO_2 adders would be integrated into the assessment of fuel price uncertainties.

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Four, the plan must demonstrate that it is consistent with the long-run public interest as expressed in state of Oregon and federal energy policies. (Issues 2a, 3, 4 and 5)

2. The utility must meet these procedural requirements:
   - The public must be allowed significant involvement in the preparation of the plan.
     - Participation must include opportunities to contribute information and ideas as well as to receive information. It also must include the opportunity to make relevant inquiries of the utility formulating the plan.
   - The utility should make public in the plan any information that is relevant to its resource evaluation and action plan. At the same time, confidential information must be protected.
     - Information that is confidential when specifically identified may be made publicly available in an aggregated format or through a blinding procedure.
     - The Commission allows information that is exempt from public disclosure under the Public Records Law – for example, trade secrets – to be treated confidentially. Parties may have access to confidential information in compliance with a protective order. (Issue 6)
   - The utility must provide to the public interim reports outlining its progress on development of the plan.
   - The utility must provide a draft plan for public review and comment prior to filing a final plan with the Commission.

3. Plan filing, review and updates will follow this schedule:

- The utility must file an integrated resource plan between two and three years of the previous filing. If the utility does not intend to take any significant resource action within two years, the utility may request a waiver.
- The utility should present the results of its filed plan at a Commission public meeting prior to the deadline for written public comment.
- Commission staff and parties should complete their comments and recommendations within six months of IRP filing.
- The Commission will consider acknowledgment of the filed plan at a public meeting. If the Commission finds that further work on a plan is needed, it will provide comments to the utility. This process should eventually lead to acknowledgment of the plan.
- The Commission will provide direction in its acknowledgment order for any additional analyses or other actions that the utility should undertake in the next planning cycle.
- Each year the utility must submit an update for its most recently acknowledged plan. The update is due on or before the IRP filing anniversary date. The update is an informational filing that provides an assessment of what has changed since acknowledgment that affects the action plan including such conditions as loads, expiration of resource contracts, supply-side and demand-side resource acquisitions and resource costs. The update should explain any deviations from the acknowledged action plan such as actual conservation savings vs. targeted savings. The utility will summarize the update at a Commission public meeting.
  (Issues 1a and 7, 2b, c and d)

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4. At a minimum, the plan should include the following elements:
   - An explanation of how the utility met each of the Commission's procedural requirements
   - An explanation of how the plan meets each of the Commission's substantive requirements
   - A range of 20-year load forecasts with an explanation of major assumptions
   - For electric utilities:
     – Determination of the levels of peaking capacity and energy capability expected for each year of the plan given existing resources
     – Identification of capacity and energy needed to bridge the gap between expected loads and resources for each load scenario
     – Modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested
   - For natural gas utilities:
     – Determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan given existing resources

  - Identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources
- Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology
- Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs
- Identification of key assumptions about the future — for example, fuel prices and environmental compliance costs — and alternative scenarios considered
- Construction of a representative set of resource portfolios to test various fuel types, technologies, lead times, in-service dates, durations and locations
- Evaluation pitting the portfolios against possible economic, environmental and social circumstances
- Results of testing and rank ordering of the portfolios by cost and risk metric(s) and interpretation of those results
- Analysis of the uncertainties associated with each portfolio evaluated
- Selection of a portfolio that represents the best combination for the utility and ratepayers of expected PVRR and the risk metrics used. This should indicate how the utility balances the metrics of risk and expected PVRR. Risks metrics at a minimum should include annual cost volatility and some measure of scenario risk (e.g. the PVRR of the worst 10 percent of outcomes). This analysis should identify the trade-off ratios used for these metrics, the constraints applied to these metrics or some other analytical technique for multi-objective decision making.
- Identification and explanation of any inconsistencies of the selected portfolio with state and federal energy policies and any barriers to implementation
- An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP

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5. The utility should specify the key attributes of each resource evaluated and each resource included in the action plan, including operating characteristics, resource type, fuel and sources if applicable, technology, in-service date, duration and general location – system-wide or delivered to a specific portion of the system. (Issue 9)

6. Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission system development as resource options. Such analysis should consider the value of such development for additional short-term purchases, additional sales, accessing less costly resources in remote locations, and acquiring alternative fuel supplies. Potential savings in distribution system costs should

be identified in the plan for resources that can significantly reduce such costs, including conservation, demand response, combined heat and power facilities, customer standby generation, solar resources, liquefied natural gas and gas storage. (Issue 11a)

7. Utilities must consider the availability of public purpose funds in assessing the optimal level of new renewable resources to acquire. They also must demonstrate how their action plan is affected by such funding and explain what steps they are taking to secure public purpose funds for planned renewable resources if there are above-market costs.

   All utilities should fully analyze conservation resources in portfolio modeling on par with supply-side resources, accounting for the cost and risk reduction benefits of conservation resources under all futures evaluated. Unless a third party funds and administers conservation programs, the utility should include in the action plan all least-cost/least-risk conservation resources for meeting projected load growth, specifying annual savings targets.

   A conservation potential study should be conducted periodically for each utility's entire service area. Along with any updates of energy usage trends and conservation costs, the study should form the basis for the 20-year conservation supply curves the utility uses in portfolio modeling.

   If the Energy Trust or other entity acquires conservation on behalf of the utility's Oregon customers, the utility should incorporate the entity's conservation projections in resource planning. Further, both should work cooperatively on the 20-year conservation assessments for the utility's service area, as well as joint load management opportunities. Such assessments should incorporate the utility's load research data as well as its knowledge of energy usage trends by customer type.
   (Issues 12 and 13)

8. Plans should evaluate demand response resources on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities). Rate design should be treated as a potential demand response resource. The analysis of demand response resources also should account for potential distribution system savings in load growth areas. Utilities should develop supply curves for a wide variety of demand response resources spanning a wide range of costs. The utilities should use these supply curves to evaluate demand response in the risk modeling of portfolios. (Issue 14)

9. Utilities should include in their risk analysis of fuel price costs possible regulatory compliance costs for carbon dioxide (CO_2) emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-

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695, from zero to \$40 (1990\$). Utilities should forecast the likely path of U.S. CO_2 emissions for their expected path of CO_2 regulatory costs.

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Utilities should perform sensitivity analyses on a range of cost adders for nitrogen oxides, sulfur oxides and mercury, if applicable, including those based on market-based cap-and-trade programs as well as on projected changes in state and federal requirements or their implementation. Compliance cost projections should consider damages from pollution and estimates of mitigation costs. Sensitivity analyses are no longer required for total suspended particulates. (Issue 15)

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The utility's load-resource balance should reflect customer loads to be served by an alternative electricity or natural gas supplier over the planning horizon. (Issue 17)

11. Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a least-cost/least-risk resource portfolio for all their retail customers. (Issue 8)

12. Potential ratemaking treatment should not affect the selection of the least-cost/least-risk portfolio. The utility should advise the Commission during the planning process if it does not have reasonable incentives to acquire a resource that is part of that portfolio. (Issues 1d and 22)

13. To address reliability:
    - Electric utilities should analyze planning margin within the risk modeling of the actual portfolios being considered. The analysis should include varying loads, forced outages, hydro availability, fuel costs (including a range of CO_2 adders) and wholesale electricity prices and should allow for market purchases within transmission constraints. Loss of load probability and expected unserved energy should be evaluated by year and by forecast scenario.
    - Natural gas utilities should analyze on an integrated basis gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing and base-load system requirements.
    - The plan should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.

    (Issue 21)

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14. Electric utilities should evaluate distributed generation technologies on par with other supply-side resources, including comparative costs for plant capital expenditures, transmission and environmental compliance. Electric utilities also should consider and where possible quantify the additional benefits of distributed generation, such as potential distribution system cost savings within load growth areas. (Issue 20)

15. The utility should identify in the action plan its acquisition strategy for each resource. Gas utilities should describe in the IRP their proposed bidding process for gas supply and transportation, whether formal or informal. Electric utilities should identify those resources that will be acquired through competitive bidding and indicate if they plan to have a utility resource considered in that process, whether utility-built or built by a third party and transferred to utility ownership. For all utilities, the competitive bidding process should follow IRP acknowledgment. The cost and risk decision criteria for selecting resources in the bidding process should be consistent with the decision criteria for selecting resources in the acknowledged IRP. (Issues 1c and 16)