BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Acknowledgment of PACIFICORP Integrated Resource Plan 2003	)))))	Docket No. 03-2035-01

COMMENTS OF
LAND AND WATER FUND OF THE ROCKIES
ON PACIFICORP'S 2003 INTEGRATED RESOURCE PLAN

The Land and Water Fund of the Rockies (LAW Fund) requests that the Commission consider these comments on PacifiCorp's 2003 Integrated Resource Plan (IRP). We appreciate the Company's exemplary efforts to establish an effective public participation process and to incorporate input from a wide range of stakeholders into its IRP analysis. We also commend the thoroughness of the Company's analysis of resource options, and in particular its evaluation of the environmental aspects of utility resource acquisition and demand-side management (DSM). However, we do have concerns about whether the Company's action plan adequately manages scenario risks, especially climate change risk, and we believe its economic analysis of wind generation is overly conservative. We recommend that the Commission acknowledge the Company's 2003 IRP with the caveat that the analysis does not justify the Hunter 4 coal plant expansion at this time. Our review of the current IRP analysis suggests that a more advisable choice for the first baseload unit may be the Gadsby repowering in 2008, but additional analysis may be needed to confirm this result.

I. Analysis of Demand-Side Management Options

The Company has done a very good job overall of evaluating and implementing demand-side management (DSM) options in its 2003 IRP. The Company has made substantial improvements in its evaluation methodologies for DSM since RAMPP-6. The new modeling framework enables the Company to place appropriate value on DSM during peak demand periods when additional resources are most needed. The modeling of DSM as a decrement to load more realistically reflects how DSM acquisition impacts the load/resource balance and provides better information for evaluating the cost-effectiveness of DSM programs (*See* Appendix G). We also support the Company's development of hypothetical decrements to load as a planning tool for identifying additional DSM opportunities. The Company's IRP analysis confirms that DSM can make significant cost-effective contributions to meeting the Company's resource needs. The Commission should acknowledge the Company's action plan with respect to DSM.

DSM Action Plan: We appreciate the specificity of the Company's action plan on DSM. The action plan logically follows from the resource analysis. It sets target delivery dates for the rollout new DSM programs (Action Items 5-7, 14). It also acknowledges that the new DSM programs, while significant, do not reflect the full potential for DSM savings in the Company's service area and that additional savings may be available. A November 2002 report by the Southwest Energy Efficiency Project (SWEEP), entitled *The New Mother Lode: the Potential for More Efficient Electricity Use in the Southwest*, suggests that additional cost-effective DSM is available in the Company's Utah service area (available at www.swenergy.org/nml/index.html). The report estimates that, through aggressive investments in cost-effective energy efficiency, Utah's average growth rate for electricity use through 2020 could be reduced from 2.47 percent to 0.71 percent. Electricity usage for the state of Utah could be reduced by 4,830 GWh per year from a business-as-usual scenario through 2010 and 11,500 GWh per year through 2020. It estimates that Utah could achieve a 2.9 billion (NPV year 2000 dollars) in combined electricity and natural gas cost savings as a result of aggressive efficiency investments.[1]

As important as recognizing untapped potential, the action plan provides a clear roadmap for identifying additional DSM opportunities going forward. Those steps include a Market Potential study (Action Item 10); the design an additional 300 MW bundle of DSM (Action Items 11 and 12); and an evaluation of combined heat and power (CHP) sites (Action Item 8). Finally, the action plan states that in October 2003 the Company will revisit its DSM targets to incorporate the new analysis (Action Item 13). We look forward to working with the Company and other stakeholders to achieve this ambitious agenda.[2]

Avoided Transmission and Distribution Costs: One of the principal advantages of DSM is that it is generally available at the site of use and, as a result, does not require transmission and distribution. The Company's analysis of DSM includes avoided line losses but it does not include the economic value of avoided or deferred transmission and distribution investments. The Company declined to include these benefits in its DSM model, claiming they are too geographically specific (p.317). However, the Company's IRP identifies significant transmission constraints on its system and sizeable load growth, especially on the Wasatch Front. Particularly under these circumstances, it is reasonable to include estimates of avoided transmission and distribution savings attributable to DSM investment. For instance, the November 2002 SWEEP study estimates avoided distribution benefits for NERC Region 11 (Pacific Northwest, Utah, Wyoming) at 0.7 to 1.0 cents per kWh.

[1] The SWEEP study includes utility sponsored DSM programs along with other measures, such as improved building codes, to improve electricity use efficiency. Some of these measures are understandably beyond the scope of potential DSM programs. The savings are also for the entire state of Utah. The share of savings in PacifiCorp's Utah service area would be roughly 80 percent of that total. In addition, the cost savings estimates include savings in both electricity use and gas consumption; the report does not include a calculation of the potential Utah share of savings attributable solely to electricity use.

[2] In addition, we would like to express our appreciation for the Company's willingness to work collaboratively with stakeholders on improving its DSM programs this past year. This past summer, the Company, LAW Fund, Utah Energy Office (UEO) and SWEEP met periodically to design and evaluate six new DSM programs for the Utah service area. The action plan calls for three of those programs to be rolled out in the spring 2003 (Action Items 5-7). The remaining programs are being evaluated further (p.69).

Pilot Distributed PV Rebate Program: The Company should commit in its action plan to work with the Salt Lake City Million Solar Roofs (MSR) initiative and other stakeholders to design a pilot distributed rooftop photovoltaics (PV) rebate program in time for the next IRP. The Wasatch Front is faced with the dual challenges of increasing peak demand for electricity, along with deteriorating air quality, especially during the hot summer months when residential air conditioning demand is high. By providing power on peak with no air emissions, distributed rooftop PV can help address both of these challenges while helping reduce the need for expensive transmission upgrades in the Wasatch triangle. In its draft IRP, the Company had included a very preliminary modeling analysis of a distributed PV program, but that analysis was omitted from the final report, perhaps due to its preliminary nature. We appreciate the Company's willingness to conduct this preliminary analysis and look forward to working with the Company, Salt Lake City MSR initiative and other stakeholders to refine the analysis.

II. Analysis of Renewable Energy Resources

We recognize that the Company has made significant improvements in its evaluation methodology for wind generation. For example, the Company's use of hourly wind data is much improved over its initial approach of modeling wind as a firm flat block resource. However, despite these improvements, we believe further improvements could be made. First, the model assumes zero capacity value for wind towards meeting planning reserve margins -- an overly conservative assumption. Second, the current cost estimates for integrating wind onto the system appears to overstate those costs.

Use of Hourly Wind Data: The Company's use of hourly wind data to model wind -- rather than modeling wind as a firm flat block resource -- more accurately captures the economic value of wind generation on the PacifiCorp system. Initially, the Company had proposed to model wind as a $50 per MWh firm flat block. The $50 per MWh cost was based on $35 per MWh for the wind energy plus $15 per MWh for "firming up" the wind resource on the transmission system. In response to stakeholder comment, the Company changed its evaluation methodology for wind to use hourly wind data from existing wind sites. It then calculated integration costs outside the model and added those costs to the total cost of the wind resource (*See* Appendix L). The 1,450 MW of wind that is included in the hybrid portfolios was modeled using the hourly data.

Capacity Value of Wind: The Company's modeling assumption of $0 capacity value for wind in the 2003 IRP appears to be overly conservative and may significantly understate the economic value of wind to the system. Loss of Load Probability (LOLP) analysis can be used to aggregate the forced outage rates of conventional facilities along with the probability distribution for wind availability to determine an acceptable level of system reliability. *See, generally*, Milligan, M. *Modeling Utility-Scale Wind Power Plants Part 2: Capacity Credit*. http://www.nrel.gov/docs/fy02osti/29701.pdf June 2000. NREL/TP-500-27514. National Renewable Energy Laboratory. Nabe, C. *Capacity Credits for Wind Energy in Deregulated Electricity Markets – Limitations and Extensions*. Technische Universitat Berlin. http://www.energiewirtschaft.tuberlin.de/mitarbeiter/wind21-paper-V7-5-nabe.pdf. While the calculation of capacity value for wind necessarily entails a system-specific analysis, every study we have review indicates that that level of capacity credit is significantly greater than zero. *See* Giebel, Gregor, "Previous works on the Capacity Credit of Wind Energy"(available at http://www.drgiebel.de/WindPowerCapacityCreditLit.htm). Generally, studies tend to find that, for small contributions of wind energy (less than 5 percent of total demand), wind energy's capacity credit is roughly equal to the wind capacity factor. The capacity value then declines as more wind is added to the system. Diversity of wind sites can also improve capacity value. In Colorado, Xcel Energy performed a LOLP analysis for the proposed 162 MW Lamar Wind Project in Southeastern Colorado, which assigned a capacity value of 48 MW or 29.6 percent to the project for bid evaluation purposes. *See, generally,* Public Service Company of Colorado, *Revised Final Wind Energy RFP*, January 28, 2000, pp.9-10 (copies handed out at the November 19, 2002 wind workshop in Portland).

The current assumption of zero capacity value for wind may significantly understate the economic value of wind to the PacifiCorp system. The Company has already built in a 15 percent reserve margin into its build strategy. A failure to account for the capacity value of wind could result in the construction of unnecessary generating capacity, increasing costs to ratepayers. PacifiCorp's stress test of a 15% capacity value for wind – a very conservative assumption of wind capacity value -- shows a $103-107 million decrease in PVRR for the diversified portfolios (p.131).[3] The Company also notes that, if wind contributes to the planning margin at its capacity factor (32 to 36 percent) – a high-end assumption -- then capacity requirements could be reduced by approximately 475 MW (p.131).

Level of Wind Integration Costs: We appreciate the Company's proactive steps to refine its methodology for evaluating the integration costs of wind. Currently, the Company's technical analysis represents a very conservative approach, assuming that every hourly change in wind output must be matched one-to-one by another resource moving in the opposite direction. For this and other reasons, the Company's imbalance cost estimates of $5-6 per MWh represent a high upper limit on these costs. To assume that every hourly change in wind output must be matched by a change in the output of another generator ignores the times when wind output changes are matched by changes in loads. Wind can be increasing its output when loads are rising, or declining when loads are falling. A statistical method for taking these times into account must be employed to fairly analyze wind integration costs.

Studies elsewhere indicate that the integration of wind at the levels contemplated by the action plan will not result in significant costs. A recent study of the Xcel Energy's

[3] The Company, in its 15 percent capacity value stress test, reduces the flat market contract by 15 percent to reflect the reduced capacity requirements (pp.130-131). Generally, an optimization model would scale back the most expensive resource first subject to other modeling constraints. It is not clear from the information presented in the IRP whether the flat market contract does, in fact, represent the most expensive resource. If a more expensive resource could be displaced, the avoided capacity savings would increase.

Minnesota system shows wind integration costs of $1.85 per MWh. *See* Daniel Brooks et al., *Assessing the Impacts of Wind Generation on System Operations at Xcel Energy – North and Bonneville Power Administration* (available at www.uwig.org). Work by Eric Hirst for the Bonneville Power Administration found that the cost of integrating wind on the Boneville system "is likely to be well under $5/MWh of wind output for 1000 MW of wind capacity." Eric Hirst, "Integrating Wind Energy With the BPA Power System: Preliminary Study," p.35 (September 2002). The BPA has committed to continuing study of wind integration costs using more data representing longer periods of time than those in the Hirst work. At this point, there is no evidence of higher costs for wind integration than Hirst's initial estimates.

Further estimation and modeling of these costs will lead to better results, but this effort should take place in parallel with a concerted effort to develop wind resources in the near-term and to gain real experience. Even if the costs did reach the upper limits portrayed in the Company's analysis (which is not likely), such costs would not become a major issue, if at all, until the latter years of the planning period when the cumulative amounts of wind on the system would become more significant.

Timing of Wind Resource Acquisition: We support the Company's decision to conduct an RPF for wind in March 2003.[4] The IRP analysis indicated that wind generation would be a cost effective addition to the Company's resource portfolio. The best way for the Company to resolve the uncertainties it has identified is to gain actual experience with wind on its system. The RFP will help the company obtain actual data on the availability of wind resources on its system and the costs of those resources. The Company indicated that, in conducting the RFP, it will not be artificially constrained by the target delivery dates for wind set forth in its action plan.[5] We strongly agree with this approach. In response to stakeholder requests, the Company did perform a stress case on moving the target delivery date for wind acquisition up by one year, and it found only minor increases in PVRR (p.132). Again, this analysis may understate the potential economic value of wind – including the potential economic value of acquiring wind sooner – because it attributes zero capacity value to wind. As part of its evaluation of the RFP solicitation, the Company should include LOLP analysis or another framework for calculating the capacity value of wind to the PacifiCorp system.

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[4] PacifiCorp, on page 161 of its IRP, states that "[d]ue to competitive confidentiality concerns, and potential conflict of interest, it is also not envisioned that third parties would directly participate in the preparation of a formal RFP." We fail to see the need or desirability for complete confidentiality in this regard. Third party participation could assist in ensuring that the RFP is designed to solicit a broad array of competitive bids and do not inadvertently discriminate against certain alternatives. It is not clear what is confidential about a draft RFP. In fact, the Colorado Least Cost Planning Rules explicitly provide for third party review of the draft RFP's. The results of the solicitation could contain confidential price information and location on wind sites, but that confidentiality can be preserved through appropriate confidentiality agreements and the screening out of conflicted parties. Similarly, the competitive solicitation rules in Arizona provide for third party access to the RFP results.

[5] Currently, the Company's action plan calls for the Company to acquire 200 MW of wind on the East side of its system by 2007 (Action Item 19) and to acquire 100 MW of wind on the West side of its system by 2006 (Action Item 20).

The Renewables Portfolio: We support the intent behind the Renewables Portfolio to test the cost-effectiveness of adding additional wind to the system. However, the current IRP analysis does not contain sufficient information to determine whether the incremental addition of wind would be desirable. The Renewables portfolio was hamstrung in the analysis due to assumption of zero capacity credit for wind. As a result, even though the Renewables Portfolio would add an additional 1,146 MW of wind and 100 MW of geothermal, it would still require the addition of the three baseload units identified in the Diversified IV portfolio. Under these circumstances, the fact that the Renewables Portfolio came in more expensive than the four diversified portfolios is not surprising.

It is interesting, though, that the Alternative Technologies II portfolio appears to have a lower PVRR than the Renewables Portfolio (*See* Figure 7.1, p.92). The Alternative Technologies portfolios were designed to include increased investments in wind, DSM, geothermal, fuel cells and CHP so as to test the possibility of displacing the need for one of the three baseload units on the East side of the system. At the request of stakeholders, the Company removed the DSM, geothermal, fuel cells and CHP from the Alternative Technologies Portfolio to create the Renewables Portfolio, based on the assumption that the fuel cells and CHP would unduly drive up the costs of the portfolio. In its place, the Company substituted an additional 480 MW CCCT at Mona and other changes. Interestingly, the scorecard results indicated that the PVRR for the Alternative Technologies II portfolio was $208 million less than for the Renewables Portfolio. While further analysis is needed, this does suggest that, once the capacity value for wind is included, it may indeed be economical to replace one or more of the planned thermal baseload units with concerted investments in renewable energy, DSM and distributed generation.

III. Analysis of Thermal Units

Timing and Sequencing of Thermal Baseload Units: The modeling results under the base case scenario indicate that the construction of the first baseload unit on the East side of the system in 2008 rather than 2007 would result in cost savings, but the results are far less conclusive as to the appropriate fuel type of the first unit. Diversified Portfolios I, II, and III differ principally in the sequencing of the three baseload units and the start date of the first baseload unit. Diversified Portfolio I would construct the first baseload unit in 2008 while Diversified Portfolios II and III would construct the first unit a year earlier in 2007. Diversified Portfolio I also differs from Diversified Portfolios II and III in that it would construct the Hunter 4 coal unit first, followed by the two gas units. Diversified II and III would construct the two gas units first but in different orders, followed by the coal unit. Diversified II would lead with the Mona CCCT in 2007, while Diversified III starts with the Gadsby repowering in 2007.

Table 7.11 (p.134) indicates that the cost advantage of the Diversified Portfolio I over Diversified Portfolios II and III under the base case scenario is due principally to the timing of the first baseload unit rather than its fuel type. The current Diversified

Portfolio I would have the Hunter 4 expansion come on-line in 2008, the Gadsby repowering in 2009 and the Mona CCCT in 2012. As stated above, Diversified Portfolio I differs from Diversified Portfolios II and III in that it would have the first baseload unit come on-line in 2008 rather than 2007. In response to stakeholder requests, the Company performed a sensitivity on the differences in the start dates for the first baseload unit. Table 7.11 reports the results by holding the start date for the first baseload unit constant (2008) while varying the sequencing of the units.

The Variation 2 listed in Table 7.11 modifies the sequencing of the baseload units in Diversified Portfolio I to bring the Gadsby repowering on-line in 2008, the Mona CCCT in 2009 and the Hunter 4 coal plant expansion in 2012. The modeling results indicated that the difference in PVRR between the current Diversified Portfolio I and Variation 2 would only be an increase of $4 million out of an estimate PVRR of over $12.3 billion, which comes out to a 0.03 percent increase in PVRR. Recall that the only difference between Diversified Portfolio III and Diversified Portfolio I, Version 2 is the earlier start date for the Gadsby repowering. This suggests that the $47 million cost advantage of Diversified Portfolio I over Diversified Portfolio III is due principally to the time value of deferring the first baseload unit from 2007 until 2008 and not to the choice of fuel type for that first unit. The $4 million difference between leading with the Hunter 4 unit rather than the Gadsby repowering in 2008 is minor relative to the overall costs of the portfolio.

The Variation 3 listed in Table 7.11 modifies Diversified Portfolio I to bring the Gadsby repowering on-line in 2008, the Mona CCCT in 2009 and then to add a second CCCT at Mona in 2012 rather than constructing the Hunter 4 coal unit. This Variation 3 on Diversified Portfolio I appears to be identical to Diversified Portfolio IV. The modeling results indicate there would be an $82 million increase in PVRR, or 0.67 percent, between the current Diversified I portfolio and Variation 3. This corresponds to the results in Figure 7.1 on page 92. Thus, while the results do indicate there might be a very slight cost advantage under the $8 base case scenario to constructing Hunter 4 either in 2008, as would be the case under the current Diversified Portfolio I, or in 2012, as would be the case under Variation 3 (or Diversified Portfolio IV), the difference would appear to be minor compared to the $12.3 billion overall cost of the portfolio.

Integrated Gasification Combined Cycle Technology: The 2003 IRP should give more serious consideration to advanced coal combustion technologies such as integrated gasification combined cycle (IGCC) (see p.70). IGCC is commercially viable today. Approximately 160 IGCC plants using a variety of feedstocks (including coal) to produce a variety of products (including power, chemicals, and fuel) are in operation worldwide, and approximately 35 additional facilities are in various stages of development, design and construction. On March 26, 2002, the Ohio EPA issued a permit for the Lima Energy project, a 580 MW IGCC facility consisting of two 290 MW combined cycle turbines. The facility is permitted to accept coal, petroleum coke and refuse-derived fuel. In addition, in June 2002, Wisconsin Electric Power Company applied to the Wisconsin Department of Natural Resources for air permits for a 540 MW IGCC unit at the Elm Road site in Oak Creek, Wisconsin. Both the Lima Energy and Elm Road projects were designed to utilize either Ohio coals (Lima) or eastern bituminous coals (Elm Road). Coal gasification, however, is a flexible technology that can be designed for Western coals.

IGCC has significant efficiency and environmental advantages over conventional pulverized coal units. Recognizing this, both the New Mexico Environment Department and the Illinois Environmental Protection Agency have determined that the Clean Air Act requires that air permit applications for the construction of coal-fired electricity generating facilities must include consideration of IGCC in the Best Available Control Technology (BACT) analysis. In an IGCC facility, the syngas (synthesis gas that is converted to fuel) is cleaned prior to combustion. As a result, criteria pollutants for a coal-based IGCC are below those of even the most modern pulverized coal plants with additional controls. NOx emissions are approximately half those of modern pulverized coal plants without any post-combustion controls. Sulfur is also removed from the syngas in pre-combustion cleanup so that emissions are less than half those of new conventional coal plants. Particulate emissions are also reduced by 99.9 percent using IGCC technology relative to conventional coal technologies. Mercury control costs are also significantly less than for pulverized coal units. Depending on the cooling technology, water use can also be reduced relative to conventional coal facilities.

IGCC is also better able to manage climate change risks than conventional pulverized coal facilities. Because IGCC plants are typically 10 to 15 percent more efficient in terms of heat rate than conventional pulverized coal plants, CO_2 emissions are reduced by that same amount. In addition, the concentrated CO_2 in the pre-combustion gas stream can be captured and sequestered at a fraction of the cost of post-combustion carbon capture and sequestration at a conventional coal plant, thereby increasing the flexibility to respond to future climate change requirements. *See* Jeremy David and Howard Hertzog, "The Cost of Carbon Capture," presented at the 5th International Conference on Greenhouse Gas Control, Cairns, Queensland, Australia, August 14-15, 2000. In contrast, the opportunities for economical capture and sequestration of CO_2 from conventional pulverized coal units are limited.

None of the Diversified Portfolios includes consideration of IGCC as a resource alternative. Carbon capture and sequestration is not likely to be economical for IGCC or any other power plant at the $8 per ton of CO_2 level included in the base case scenario. However, if the market price for carbon dioxide emissions increased, carbon capture and sequestration could become a viable option for ICGG. Had the Company included IGCC in its portfolio options that contain coal and included consideration of carbon capture and sequestration costs, the IRP risk analysis might have shown that the ability of IGCC to economically capture and sequester carbon creates an economic advantage for IGCC over conventional pulverized coal under one or more of the carbon risk scenarios.

The IGCC Stress Test: Responding to stakeholder comments, PacifiCorp did include a stress test to compare IGCC to pulverized coal in its final IRP (pp.132-133). The stress test replaced Diversified Portfolio III's plan for a pulverized coal unit at Hunter 4 unit in 2012 with a 370 MW IGCC unit plus a CCCT at Mona. The stress test calculated that the switch from pulverized coal to a combination of IGCC and gas would result in a $177 million increase in PVRR.

While we appreciate PacifiCorp's willingness to perform the stress test, the results may be misleading in several important respects. By combining IGCC with a gas unit, it does not isolate the relative merits of the two coal combustion technologies. As a result, even though the report acknowledges that IGCC is more efficient in terms of heat rate than a pulverized coal unit, the analysis states that the IGCC portfolio would have "greater fuel costs" (p.132). Further, the stress test only looks at the base case scenario with CO_2 costs of $8 per ton. As explained above, the potential economic advantage of IGCC to sequester carbon over conventional coal would probably not appear until the higher CO_2 cost scenarios.

Further, the modeling assumptions may have overstated the cost differential in capital costs between pulverized coal and IGCC. The report does not specify the capital cost assumptions that were used for the stress test, but Table C.19 lists the capital costs at $1,369 per kW for a pulverized coal unit at Hunter 4; capital costs of $1,431 per kW for a Utah greenfield pulverized coal unit; and capital costs of $1,797 per kW for a greenfield IGCC unit. This translates into a $408 per kW cost differential between Hunter 4 and IGCC and a $366 per kW differential between a greenfield pulverized coal unit and IGCC. If these cost assumptions were used in the IGCC stress test, then the capital cost differential between pulverized coal and IGCC may be overstated, especially given that the IGCC would not be projected to come on-line until 2012. By way of comparison, an October 2002 draft Report prepared for the U.S. Department of Energy National Energy Technology Laboratory, entitled *Power Generation for California with CO2 Removed for Use in Enhanced Oil Recovery*, uses $1,469 per KW for the capital cost estimate of an greenfield IGCC plant constructed in the Four Corners region in 2010. This is roughly equivalent to the $1,431 per kW capital cost estimate for a greenfield pulverized coal unit used in the IRP analysis.

In addition, the IRP's capacity factor assumptions for IGCC appear to be dated. The analysis assumes a 71.3 percent capacity factor for IGCC (*See* Table E.12, at p.292). The low capacity factor appears to be the result of a forced outage rate of 10 percent and a maintenance outage rate of 5 percent (*See* Table C.19, at p.213). However, the assumed availability and outage rates for IGCC do not appear to be representative of what IGCC is capable of achieving today. It is probably even less representative of what will be possible in 2012. It is correct that the initial test IGCC units were constructed with a single gasifier design and, as a result, achieved lower unit availability than typical baseload units. However, IGCC units can be constructed with multiple gasifiers to improve unit availability to reach levels comparable to those of conventional baseload facilities. For instance, the Eastman Chemical plant in Kingsport, Tennessee has utilized a dual-gasifier design to produce chemicals from syngas and has experienced an 98 percent availability since 1986.[6]

[6] Smith, R.G., "Eastman Chemical Plant Kingsport Plant Chemicals from Coal Operations1983-2000," 2000 Gasification Technologies Conference.

IV. Risk Analysis

Analysis of Climate Change Risk: We applaud PacifiCorp deserves for having the foresight to address climate change risk in its resource evaluation methodologies. The Company's 2003 IRP demonstrates leadership on this issue. The scenario analysis methodology for modeling carbon risk in the current IRP represents a significant improvement over the expected value analysis used in previous IRP's. As the Company explains, the likelihood of each of the carbon risk scenarios cannot be reasonably represented by know statistical processes (p.38).

We believe the Company has developed an appropriate framework for evaluating climate change risk. The $8 per ton CO_2 adder in the base case scenario beginning in 2009 is a conservative but reasonable estimate of potential increased costs from carbon regulations over the planning period. This estimate is generally consistent with the findings of a recent market survey of industry participants on the expected prices for carbon credits over the next decade. *See* Natsource, *Assessment of Private Sector Anticipatory Response to Greenhouse Gas Market Development*, prepared for Environment Canada, June 2002. It should be noted, though, that the base case estimate of $8 per ton for CO_2 credits, while higher than currently prevailing market prices, is at the low end of the range of estimates from multiple analytic studies on future carbon dioxide costs. *See, e.g.*, Tellus Institute, *The American Way to the Kyoto Protocol*, prepared for the World Wildlife Find, 2001. Andrew Plantinga, Thomas Mauldin, and Douglas Miller, "An Econometric Analysis of the Costs of Sequestering Carbon in Forests," *American Journal of Agricultural Economics*, November 1999: 812-824. Richard Newell and Robert Stavins, "Climate Change and Forest Sinks: Factors Affecting the Costs of Carbon Sequestration," *Journal of Environmental Economics and Management*, 2000: 211-235. Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, 2000. Charles Kolstad and Michael Toman, "The Economics of Climate Policy," Resources for the Future Discussion Paper 00-40REV, 2001. Thus, while we accept the characterization of the $25 per ton and $40 per ton of CO_2 sensitivities as high-end estimates, it must be emphasized that these estimates do provide useful information on the potential environmental risks of portfolios with high CO_2 emissions. They should not be dismissed as unrealistic scenarios.

Need for Action Plan on Climate Change: While future regulatory costs serve as an instructive analytic framework for evaluating climate change risk to ratepayers, we recommend that the Company should manage and seek to reduce its carbon emissions as a matter of responsible business practices and good public policy quite apart from future regulatory requirements. The current scientific consensus on climate change is that climate change could impose large costs on agriculture, businesses, and consumers as they try to adapt to changes in precipitation, temperature and other weather patterns.

The ecological impacts of climate change could also be significant. In a report prepared at the request of the Bush administration, the National Research Council stated that the "U.S. National Assessment makes a strong case that ecosystems are the most vulnerable to the projected rate and magnitude of climate change, in part because the available adaptation options are very limited. Significant climate change will cause disruptions to many U.S. ecosystems, including wetlands, forests, grasslands, rivers and lakes." National Research Council, *Climate Change Science: An Analysis of Some Key Questions*, Washington, D.C.: National Academy Press, p.20.[7]

The Company should explicitly address how its resource legacy and future resource choices are contributing to greater climatic variability and how to foster resource acquisition decisions that have less adverse impacts on the environment. Such a strategy would also be consistent with the public policy objectives of growing numbers of its customers. For example, the State of Oregon has established the Climate Trust to help manage the state's carbon emissions. Similarly, Salt Lake City, as a member of the International Council for Local Environmental Initiatives, Cities for Climate Protection Project, has established a goal of a 21 percent decrease in greenhouse gas emissions from 2000 levels. The Company's resource choices will significantly impact the City's ability to reach its climate change goals.

The 2003 IRP's Action Plan for Managing Scenario Risks: We support the Company decision to model climate change risk as a scenario risk rather than as a stochastic risk but we also urge caution. While it may make sense to model scenario risks and stochastic risks separately, both types of risk are equally deserving of attention in the development of the action plan. The risk to ratepayers of future climate change costs is no less real than gas price risk, hydro availability or other risks that can be represented stochastically. We are concerned that the Company's current action plan may not adequately balance both stochastic risks and scenario risks and, as a result, may unduly expose ratepayers to the risks of increased costs from future climate change regulations.

Based on the information presented in the IRP, we do not believe that the current Diversified Portfolio I represents the best balancing of costs and risks. The IRP analysis does suggest that there could be cost savings to constructing the first thermal unit in 2008 rather than 2007. The IRP analysis, does not, however, support the selection of Hunter 4 expansion as the first unit. The stress analysis illustrates that the potential economic advantage of constructing Hunter 4 in 2008 rather than the Gadsby repowering is small to non-existent. The difference in PVRR between the current Diversified Portfolio I and Variation 2 would only be an increase of $4 million out of an estimate PVRR of over $12.3 billion, which comes out to only a 0.03 percent increase in PVRR.

In contrast, the scenario risk analysis illustrates that that the potential downside risks to the construction of the Hunter 4 coal unit rather than the Gadsby repowering in 2008 could be significant. As discussed previously, based on multiple studies of potential costs of carbon regulations, we believe the Company's base case estimate of $8 per ton of CO_2 is conservative but reasonable. However, it bears re-emphasizing that the

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[7] The reference is to the U.S. National Assessment is to: U.S. National Assessment, U.S. Global Climate Change Research Program, "Climate Change Impacts on the United States: The Potential Consequences of Climate Variability and Change," 2001, Cambridge University Press.

$25 per ton and $40 per ton scenarios do provide useful information on potential carbon risk and should not be dismissed as unrealistic. At page 122, the IRP analysis notes that the PVRR for Diversified Portfolio I is lowest under the $0 per ton, $2 per ton and $8 per ton scenarios for CO2 allowance costs. It notes, however, that:

> Somewhere between $8/ton and $25/ton, the merit switches to Diversified IV with Diversified II placing second. The all gas portfolio, Diversified IV, stays in first place thereafter as the CO2 allowance cost increases (p.122).

That "somewhere" is not identified in the analysis. Table E6 does estimate, though, that at a $25 per ton CO_2 price, the PVRR of the Diversified I Portfolio exceeds the Diversified I portfolio by approximately $58.4 million and, at the $40 per ton CO_2 price, the Diversified I Portfolio exceeds the Diversified IV portfolio by nearly $212 million.

Based on the current IRP analysis, it is not clear to what extent the cost advantage of Diversified Portfolio I over the other diversified portfolios under the low-end and base case carbon risk scenarios can be attributed to the timing of the first baseload unit in 2008 rather than in 2007. As discussed above, the Version 2 stress case to Diversified Portfolio I illustrates that, once the timing of the Gadsby repowering in Diversified III is moved from 2007 to 2008, the potential cost advantage of leading with Hunter 4 in 2008 rather than the Gadsby repowering all but disappears. It may be the case that the relative ranking in terms of PVRR among the diversified portfolios may change if the start dates for the first baseload unit under Diversified Portfolios II and III are postponed until 2008. Additional analysis is needed on this point.

We recommend that the Commission acknowledge PacifiCorp's 2003 IRP with the caveat that the analysis does not justify the Hunter 4 coal plant expansion at this time. We believe that the analysis suggests that a more advisable choice for the first baseload unit would be the Gadsby repowering in 2008.[8] One of the principal advantages of deferring a decision on Hunter 4 is that it would provide additional time to resolve uncertainty over the direction of future climate change regulations. A delay would preserve the option of switching the third baseload unit to gas or IGCC if circumstances warrant. A delay would allow additional time to resolve the current uncertainty over the capacity value of wind and the potential for cost-effective DSM to reduce or perhaps even eliminate the need for a third baseload unit on the East side of the system at sizeable savings to ratepayers. A delay would also provide the Company with greater flexibility to manage its carbon emissions and help reduce the impacts of electricity generation on the Earth's climate.

[8] The Gadsby site is located in Salt Lake City in the Wasatch Front, an area that is already experiencing air quality problems. Without additional site-specific analysis of the potential air quality impacts of repowering the Gadsby facility, it is premature to conclude whether the facility would be acceptable from a facility siting standpoint.

Respectfully Submitted,

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DATE: March 31, 2003