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July 25, 2007

Attention: Filing Center
Public Utility Commission of Oregon
550 Capitol Street NE, #215
PO Box 2148
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Re: *In the Matter of the PUBLIC UTILITY COMMISSION OF OREGON Staff's Investigation into the Treatment of CO_2 Risk in the Integrated Resource Process (IRP) Process*
PUC Docket No. UM1302
DOJ File No. 330-030-GN0300-07

Enclosed are an original and five copies of the Oregon Department of Energy's Initial Comments in the above-captioned matter for filing with the PUC today.

Sincerely,

/s/ *Janet L. Prewitt*

Janet L. Prewitt
Assistant Attorney General
Natural Resources Section

Enclosures
c: UM 1302 Service List

JLP:jrs/GENU7434

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1302

In the Matter of the PUBLIC UTILITY COMMISSION OF OREGON Staff's Investigation into the Treatment of CO_2 Risk in the Integrated Resource Process (IRP) Process	))))))	**OREGON DEPARTMENT OF ENERGY'S INITIAL COMMENTS**

Introduction and Background

As noted in the Oregon Department of Energy's September 19, 2006 Initial Comments in UM 1208 (pages 2 and 3):[1]

> "ODOE Attachment 1 is slides from presentation that Dr. James E. Hansen made to the Climate Change Research Conference in Sacramento, California on Sept. 13 2006. Dr. Hansen is the Director of the Goddard Institute for Space Studies, the climate division of the National Aeronautics and Space Administration. (see http://www.giss.nasa.gov/about/). These slides present the science behind the Governor's greenhouse gas goal of a 75 percent reduction in emissions by 2050 [now a statutory goal].
>
> Dr. Hansen notes on slide 38 that for a 75 percent reduction by 2050 all new power plants built in developed countries after 2012 will need to geologically sequester their CO_2. All coal-fired power plants that do not sequester CO_2 must be "bulldozed" during the period 2025-2050. This, combined with a gradually increasing carbon tax and other measures, will stabilize the global temperature rise at 1 degree C (slide 18) beyond today's level.
>
> The alternative of a business-as-usual strategy is a 3 degree C temperature rise this century. This will likely lead to extinction of 50 percent of multi-cellular plant and animal species and sea level rise of several meters this century. Many more meters of sea level rise would occur in the following centuries (slides 18 and 28).
>
> A six meter sea level rise would displace 11 million Americans and hundreds of millions of people worldwide (slide 25). Equilibrium sea level rise for a temperature increase of about 3 degrees C is 25 meters (±10 m) which would occur over several centuries (slide 28). This rise would not occur at a smooth uniform rate. Nor would the impacts of sea level rise be gradual. The population displacement would occur during storm surges, as seen in New Orleans last year. While that

[1] http://edocs.puc.state.or.us/efdocs/HAC/um1208hac14636.pdf

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catastrophe was due primarily to poor dike construction and maintenance, it is a sample of future impacts from a business-as-usual policy."

The overall question before the Commission in this docket is how should the integrated resource plans consider the likelihood that future federal or state policy will cap and then reduce CO_2 emissions from the power sector.

The CO_2 risks of different utility strategies are not symmetric. New coal plants are unlikely to operate for their assumed 40-year lives. If shut down before their amortization life the costs of these plants would become stranded assets. Disallowing these costs would likely raise the cost of capital, raising rates to customers. This would be a serious problem for future Commissioners. If instead, the construction of a new coal plant is delayed a few years, future costs and resource choices can be clear enough to avoided stranded assets.

As discussed below state climate policies are rapidly evolving. The November 2008 federal and state elections and the ensuing 2009 legislative sessions are likely to significantly clarify federal and state CO_2 policies. As a minimum, the Commission's order in this case should require that utility IRPs evaluate irreversible utility commitments to standard coal plants based on an assumption that Oregon's CO_2 goals will be met for the electric sector.

Recent CO_2 Actions by Western States

This year has seen a significant increase in actions on climate change by western states.

On February 26, 2007 the governors of Arizona, California, New Mexico, Oregon and Washington signed the Western Regional Climate Action Initiative.

The initiative includes:

> "Setting an overall regional goal, within six months of the effective date of this initiative, to reduce emissions from our states collectively, consistent with state-by-state goals;
>
> Developing, within eighteen months of the effective date of this agreement, a design for a regional market-based multi-sector mechanism, such as a load-based cap and trade program, to achieve the regional GHG reduction goal; …"

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Since February, British Columbia, Manitoba and Utah have joined the western climate initiative.

California is in the process of implementing its greenhouse gas cap of 1990 emissions by 2020 for all sectors as required by AB 32 (passed in Sept. 2006). California has completed its rulemakings on its emissions performance standards (SB 1368, passed Sept. 2006).

To date, eight of the eleven western states, including Oregon, have adopted renewable electricity standards. The three remaining states are Idaho, Wyoming and Utah. (see http://go.ucsusa.org/cgi-bin/RES/state_standards_search.pl?template=main). The governor of Utah has announced he will seek to implement a renewable electric standard. The final report from the Utah Renewable Energy Initiative Focus Group is due October 15.

Washington is implementing a greenhouse gas emission performance standard under SB 6001 passed this April. This bill also includes statutory emissions goals for 2020, 2035 and 2050. Section 4 requires the governor to make recommendations to the 2008 session including a recommendation on "How market mechanisms, such as a load-based cap and trade system, would assist in achieving the greenhouse gases emissions reduction goals;"

The 2007 session of the Oregon Legislature passed 25 bills and resolutions related to energy. Most of Governor Kulongoski's pre-session initiatives passed including SB 838 (renewable electric standards), HB 2210 (biofuels), HB 2211 (expanded business energy tax credits) and HB 2212 (expanded residential energy tax credits). SB 3543 (global warming actions) also passed. This bill sets greenhouse gas reduction goals for 2020 and 2050, and establishes the Global Warming Commission and the Oregon Climate Change Research Institute. HB 3543 states in Section 2:

> "(1) The Legislative Assembly declares that it is the policy of this state to reduce greenhouse gas emissions in Oregon pursuant to the following greenhouse gas emissions reduction goals:
>
> (a) By 2010, arrest the growth of Oregon's greenhouse gas emissions and begin to reduce greenhouse gas emissions.
>
> (b) By 2020, achieve greenhouse gas levels that are 10 percent below 1990 levels.

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(c) By 2050, achieve greenhouse gas levels that are at least 75 percent below 1990 levels."

Responses to Issues

Issue 1. What CO_2 regulatory cost stream should utilities use in their IRP base case, and what assumed CO_2 regulatory future, e.g., a fixed carbon adder or a carbon policy modeling constraint, should serve as the basis for the base case cost stream?

<u>Summary of Recommendation</u>

The base-case CO2 regulatory cost stream should be based on the midrange estimate of the IPCC Working Group III contribution to the Fourth Assessment Report (AR4) with induced technological change. This results in costs per short ton of CO_2 of $32 in 2030 and $66 in 2050 (all values in 2007 dollars). The 2013 value should be $20 per short. Values for other years should be interpolated.

This CO_2 cost scenario should also be analyzed by natural gas utilities. Attaining the percentage levels of reductions for climate stabilization by the 2050 from natural gas users is unlikely without substantial use of low-emissions electric sources. Even so, most cap and trade proposals have CO_2 allowance trading at market-clearing prices between the electric sector and natural gas direct use sector. If this is the case, natural gas utilities would face the same CO_2 allowance prices as electric utilities.

Discussion

The most comprehensive assessment of the cost adders needed to stabilize atmospheric concentrations at a level of 550 part per million CO_2-equivalent is set out below. (The CO_2 cost adders in the IPCC reports are in 2007 dollars per metric ton. Divide these values by 1.102 to convert to dollars per short ton.)

From http://www.ipcc.ch/SPM040507.pdf

IPCC, Summary for Policymakers: *Climate change 2007: Mitigation. Contribution of Working group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change,* May 2007, page 29.

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"23. Policies that provide a real or implicit price of carbon could create incentives for producers and consumers to significantly invest in low-GHG products, technologies and processes. Such policies could include economic instruments, government funding and regulation (*high agreement, much evidence*).

• An effective carbon-price signal could realize significant mitigation potential in all sectors [11.3, 13.2].

• Modeling studies (see Box SPM.3) show carbon prices rising to 20 to 80 US$/t$CO_2$-eq by 2030 and 30 to 155 US$/t$CO_2$-eq by 2050 are consistent with stabilization at around 550 ppm CO_2-eq by 2100. For the same stabilization level, studies since TAR that take into account induced technological change lower these price ranges to 5 to 65 US$/t$CO_2$-eq in 2030 and 15 to 130 US$/t$CO_2$-eq in 2050 [3.3, 11.4, 11.5].

• Most top-down, as well as some 2050 bottom-up assessments, suggest that real or implicit carbon prices of 20 to 50 US$/t$CO_2$-eq, sustained or increased over decades, could lead to a power generation sector with low-GHG emissions by 2050 and make many mitigation options in the end-use sectors economically attractive. [4.4,11.6]"

For its base case CO_2 cost adder the Commission should use the mid-range value for an economy-wide policy with induced technological change ("5 to 65 US$/t$CO_2$eq in 2030 and 15 to 130 US$/t$CO_2$-eq in 2050"). In formal comments to the Congress, most parties have advocated for consistent economy-wide policies to minimize the cost of CO_2 reductions. Converting from dollars per metric ton yields mid range costs adders per short ton of CO_2 of $32 in 2030 and $66 in 2050 (all values in 2007 dollars). Studies performed for the Carbon Allocation Task Force indicate an expected trading price for CO_2 allowances below $20 would not meet Oregon's 2020 goal, except in the low-load growth case (see page 8 of http://www.oregon.gov/ENERGY/GBLWRM/docs/CATF_Report-HalNelson-Final.pdf). The first date for implementation of legislation passed in 2009 would be 2011. A more likely date for implementing federal or state regulations is 2013, given a possible lags in policy adoption and implementation. This indicates a mid-range starting cost of $20 per short ton in 2013. Values for years between 2013 and 2030 and between 2030 and 2050 should be interpolated.

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Issue 2. What alternative CO2 regulatory cost streams should utilities use in their IRP scenario analyses, and what assumed CO2 regulatory futures should serve as the bases for these alternative cost streams?

Summary of Recommendation

The lower case should be the lowest power sector value considered in the Working Group III contribution to the IPCC Fourth Assessment Report (AR4). This is a levelized CO_2 cost of $18 per short ton. This value reflects a separate CO_2 adder for the power sector and is the lowest value in that range. This value is unlikely to achieve the Oregon CO_2 goal for the power sector.

The higher case should be the high end of the IPCC Working Group III contribution to the Fourth Assessment Report (AR4) with assumed technological change. This results in costs per short ton of CO_2 of $59 in 2030 and $118 in 2050 (2007 dollars). The 2013 value in the high case should be $25 per short ton of CO_2. Values for other years should be interpolated. As discussed in response to Issue #1, these CO_2 regulatory cost streams should also be used in natural gas utility IRPs.

Discussion

These proposed low and high values provide a wide range of CO_2 adders. The IPCC AR4 ranges represent the most comprehensive assessment available and are current. Given the asymmetric risk of CO_2 regulation on utility commitments before 2010, this range appropriately balances high and low CO_2 cost risks. The low case $18 per short ton levelized value will have almost no impact on the cost of utility plans. The level of reductions that will be required by future regulations is uncertain, but it is extremely unlikely that future regulation will not require some reductions from the power section, one of the lowest-cost sources of reduction.

The lowest values in the IPCC ranges ($5/metric ton CO_2-eq in 2030 and $15 metric ton CO_2-eq in 2050) would have little if any impact on technological progress and therefore seem inconsistent with a scenario dependent on induced technological progress. Nor would cost adders at this level have a significant impact on utility decisions.

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Such low CO_2 adders are equivalent to a business-as-usual policy. While it is possible federal and state CO_2 policies will be completely ineffective, such a scenario should not receive more than a ten percent probability. Such a policy would have a place only if the Commission were to choose five scenarios with the lowest and highest CO_2 adder scenarios at a ten percent probability. If the Commission chooses three scenarios of equal weight, the three scenarios proposed above would provide a reasonable range of CO_2 cost adders.

Issue 3. How should the existing, and potential future, carbon or other greenhouse gas emission goals of the State of Oregon be included in utility IRPs?

All utilities should be required to estimate the range of costs for compliance to HB 3543 greenhouse reduction goals (see below) with and without the use of high quality offsets. The baselines and caps for utilities should include reductions in emissions of other greenhouse gases (GHGs). These are primarily sulfur hexafluoride (SF6) emissions by electric utilities and methane (CH4) emissions by both types of utilities. Emission limits for the years from 2010 to 2020 should be linear interpolations of projected 2010 emissions and the 2020 goal. Similarly, emissions limits for the years between 2020 and 2050 should be linear interpolations.

Issue 4. What probability weighting, if any, should utilities assign to the CO2 base case and scenario analyses?

Preliminarily, the three scenarios discussed in Issues #1 and #2 should be weighted equally. The risk analysis should be more sophisticated than a simple weighting of the three primary CO_2 scenarios, as discussed under Issue #6 below.

Issue 5. How should utilities vary the CO2 regulatory cost streams to identify the "trigger point" (or CO2 regulatory future) that changes the preferred resource portfolio, and should utilities vary other model inputs to achieve logical consistency and to test the sensitivity of the trigger point to the changes in other variables?

<u>Summary of Recommendation</u>

The appropriate analyses will depend on the kind of technology/strategy options being evaluated. Trigger point analyses should be conducted on decisions on the thermal efficiency of major new thermal plants in proposed action plans. The attached spreadsheet shows a simple

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trigger point analysis for pulverized coal vs. a bridging strategy with later construction of coal with carbon capture and sequestration (CCS). See Exhibit 1.

The renewable standards from SB 838 (2007 Or. Laws Ch. 301) should be adopted by the Commission as a minimum renewables scenario. Responding to carbon regulations will likely require higher levels of renewable generation than set in SB 838. (see http://www.oregon.gov/ENERGY/GBLWRM/docs/CATF_Report-HalNelson-Final.pdf).

The next IRP for PGE and PacifiCorp may be too early to do a trigger point analysis of whether they should exceed the minimum renewable standards in SB 838. When there is more experience implementing SB 838, utilities should assess what level of CO_2 cost adders would make it economic to pursue more renewable generation than required by law.

Discussion

The appropriate trigger-point analyses will depend on the kind of technology/strategy options being evaluated.

In the attached spreadsheet, the decisions being compared are a standard coal plant on-line in 2013 that cannot be retrofitted to capture CO_2 emissions vs. relying on purchased power between from 2013 through 2018 and an integrated gas combined cycle (IGCC) coal plant with carbon capture and sequestration (CCS) on-line in 2019. The path of CO_2 adders is set to yield equivalent present values (NPV) of costs for 2013-2052 for the two alternatives (row 5). This yields a real levelized CO_2 trigger point of $27.27 per short ton of CO_2 for the two alternatives (cell 51C; all values in 2006 $). All other values are from the draft PacifiCorp IRP. There are many such paths that yield equivalent NPVs for the two alternatives. These paths are set by varying the values of the escalation rate and base period value for the CO_2 cost adder (cells 3J and 10C, respectively). All CO_2 paths that equalize the NPV of the two alternatives would have similar real levelized CO_2 trigger points.

This analysis is slightly more sophisticated that the simple comparison of the levelized cost of the two alternative coal plants. Such an analysis would indicate a trigger-point CO_2 value

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of $30.65 per short ton, as shown in row 29. This indicates substantial value in the year-by-year analysis of this example.

Note that a CO_2 cost of $62.09 per short ton would be sufficient incentive to shut down the new standard coal plant and replace it with a new CCS coal plant. This is shown in row 47 for year 2050. The analysis has not been adjusted to shorten the lifetime of the standard coal plant. This would have little impact on the trigger point. Nor has the incremental value of the CCS coal plant from 2052 through 2058 been included (assuming 40 year lives for both plants). Including these changes would lower the CO_2 trigger point.

A complete trigger-point analysis would examine uncertainties in major variables. This analysis assumes no cost reductions in the cost of a CCS coal plant between a plant started now and one completed in 2019. Lowering the cost of the 2019 CCS coal plant would lower the trigger point CO_2 cost adder. The availability of new renewable power plants in 2019 that cost less than the assumed CCS plant would also lower the trigger point. Sequestration of 90 percent of all western coal plant emissions would likely exhaust low-cost sequestration sites, raising CCS costs in later years. Other major uncertainties are the cost of purchased power 2013 through 2018 and the discount rate.

Other types of IRP actions should also be evaluated using trigger-point analyses. The renewable standards from SB 838 (2007 Or Laws, Chap. 301) should be adopted by the Commission as a minimum level of renewables. The next IRP for PGE and PacifiCorp may be too early to do a CO_2 trigger point analysis of whether should they should exceed the renewable standards in the years beyond 2020.

The near-term timing of renewable acquisition seems more dependent on short-term power prices and competition for good renewable projects. The timing may not be driven by alternative forecasts of CO_2 adders. When there is more experience implementing SB 838, PGE and PacifiCorp should assess what level of CO_2 cost adders would make it economic to pursue more renewable generation than required by law for the years 2020 and beyond.

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All analyses with CO_2 adders should use combined variations in CO_2 adders and natural gas prices. CO_2 cost adders increase the demand and price for natural gas for power generation so consistent CO_2 cost adders and natural gas prices should be used in all IRP analyses.

This sample analysis is not dependent on natural gas prices, except as they affect wholesale power prices 2013-2018. The difference in the $17.70 CO_2 adder assumed in this analysis for 2013-2018 and the PacifiCorp base-case adder of roughly $8 has a small impact on power prices relative to overall uncertainties in wholesale prices of natural gas and electricity. This impact could be incorporated in a more complete analysis.

Trigger-point analyses of this type can illuminate decisions without the Commission having to specify a value or range of CO_2 adders. The Commission order in this case should require IRPs to do such analyses for major action plan decisions. These decisions include whether more expensive but more efficient major thermal power plants are economic over their planned lifetimes.

Issue 6. Are the alternative futures used in the scenario analyses an adequate measure of the cost risk associated with choosing one portfolio over another? Should utilities use a different approach when considering the risk of future CO2 regulation?

The NW Power and Conservation Council has pioneered an innovative and useful assessment of the relative risks of alternative strategic approaches. (http://www.nwcouncil.org/energy/powerplan/plan/(06)%20Risk%20Section.pdf)

This type of analysis should be incorporated into electric IRPs, including but not limited to the risks from CO_2 regulation, fuel prices, load growth and variations in hydro generation.

Generally, the risks of underestimating CO_2 and GHG regulations are greater than overestimating them, if current regulation proposals are used as the basis to assess risks. As more is learned about climate change, the risks are more apparent. If serious consequences happen, political actions that seem unlikely now will become possible.

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The Fourth Assessment of the IPCC (*Working Group II, Summary for Policymakers,* April 2007) indicates serious climate change consequences lie ahead (http://www.ipcc.ch/SPM13apr07.pdf).

Likely impacts include:

"Warming in western mountains is projected to cause decreased snow pack, more winter flooding, and reduced summer flows, exacerbating competition for over-allocated water resources.

Disturbances from pests, diseases, and fire are projected to have increasing impacts on forests, with an extended period of high fire risk and large increases in area burned." (page 10).

"Coastal communities and habitats will be increasingly stressed by climate change impacts interacting with development and pollution. Population growth and the rising value of infrastructure in coastal areas increase vulnerability to climate variability and future climate change, with losses projected to increase if the intensity of tropical storms increases. Current adaptation is uneven and readiness for increased exposure is low." (page 11).

Actual occurrence of any of these events would likely to shift the political consensus to strong action on CO_2 emissions. The power sector is the most obvious target for regulation.

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The acknowledgement order of each IRP should discuss asymmetric risk. The Commission should acknowledge only proposed IRP actions if the IRP fully explores asymmetric risks of CO_2 regulations and the proposed actions reflect good judgment regarding these risks.

DATED this _*25*_ day of July 2007.

Respectfully submitted,

HARDY MYERS
Attorney General

/s/ *Janet L. Prewitt*

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CERTIFICATE OF SERVICE

I hereby certify that on the 25th day of July, 2007, I served the foregoing OREGON DEPARTMENT OF ENERGY'S INITIAL COMMENTS, electronically upon, the persons named on the attached service list. All parties have waived paper service.

DATED: This 25th day of July, 2007.

/s/ *Janet L. Prewitt*

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Janet L. Prewitt, #85307
Assistant Attorney General

Row **SAMPLE CO2 TRIGGER-POINT ANALYSIS: Non-CCS coal vs. Delayed CCS Coal**

2 (for evaluation of unsequesterable coal plants in draft PacifiCorp 2007 IRP)

Row									
3	**All values in 2006$**		Real Escalation of CO2 Cost after 2018 =					4%	
4	Yellow cells for inputs	Discount Rate (Real) 5.2%	**NPV Non-CCS**	**vs.**	**NPV Delayed CCS**				
5	Other costs from	For years 2013-2052	**$1,211**		**$1,211**				Cost of Coal plants
6	Draft IRP		**Unsequestered Coal**			**Purchase then Sequestered Coal**			from pages 89-92

Row	Year	CO2 Adder ($/ton)	Unsequestered Coal Non-Env. Op. Cost ($/MWh)	Unsequestered Coal Capital Cost ($/MWh)	Unsequestered Coal Tot. Cost w/Env. Add ($/MWh)	Purchase then Sequestered Coal Non-Env. Op. Cost ($/MWh)	Purchase then Sequestered Coal Capital Cost ($/MWh)	Purchase then Sequestered Coal Tot. Cost w/Env. Add ($/MWh)	
9	2012	$ 5.29	$ 19.57	$ 26.49	$ 51.45	$ 50.00		$ 52.64	used only to check
10	2013	**$17.70**	$ 19.57	$ 26.49	$ 63.14	$ 48.97		$ 57.82	purchase @ 0.5 TCO2
11	2014	$17.70	$ 19.57	$ 26.49	$ 63.14	$ 52.05		$ 60.90	
12	2015	$17.70	$ 19.57	$ 26.49	$ 63.14	$ 55.01		$ 63.86	
13	2016	$17.70	$ 19.57	$ 26.49	$ 63.14	$ 57.85		$ 66.70	
14	2017	$17.70	$ 19.57	$ 26.49	$ 63.14	$ 60.56		$ 69.41	
15	2018	$17.70	$ 19.57	$ 26.49	$ 63.14	$ 63.17		$ 72.02	
16	2019	$18.41	$ 19.57	$ 26.49	$ 63.80	$ 24.84	$ 47.25	$ 74.07	
17	2020	$19.14	$ 19.57	$ 26.49	$ 64.50	$ 24.84	$ 47.25	$ 74.14	
18	2021	$19.91	$ 19.57	$ 26.49	$ 65.22	$ 24.84	$ 47.25	$ 74.22	
19	2022	$20.71	$ 19.57	$ 26.49	$ 65.97	$ 24.84	$ 47.25	$ 74.30	
20	2023	$21.53	$ 19.57	$ 26.49	$ 66.75	$ 24.84	$ 47.25	$ 74.38	
21	2024	$22.40	$ 19.57	$ 26.49	$ 67.56	$ 24.84	$ 47.25	$ 74.47	
22	2025	$23.29	$ 19.57	$ 26.49	$ 68.40	$ 24.84	$ 47.25	$ 74.56	
23	2026	$24.22	$ 19.57	$ 26.49	$ 69.28	$ 24.84	$ 47.25	$ 74.66	
24	2027	$25.19	$ 19.57	$ 26.49	$ 70.19	$ 24.84	$ 47.25	$ 74.76	
25	2028	$26.20	$ 19.57	$ 26.49	$ 71.14	$ 24.84	$ 47.25	$ 74.86	
26	2029	$27.25	$ 19.57	$ 26.49	$ 72.12	$ 24.84	$ 47.25	$ 74.97	
27	2030	$28.34	$ 19.57	$ 26.49	$ 73.15	$ 24.84	$ 47.25	$ 75.08	
28	2031	$29.47	$ 19.57	$ 26.49	$ 74.22	$ 24.84	$ 47.25	$ 75.19	
29	2032	$30.65	$ 19.57	$ 26.49	$ 75.33	$ 24.84	$ 47.25	$ 75.31	cheaper new w/seq.
30	2033	$31.88	$ 19.57	$ 26.49	$ 76.48	$ 24.84	$ 47.25	$ 75.44	
31	2034	$33.15	$ 19.57	$ 26.49	$ 77.68	$ 24.84	$ 47.25	$ 75.57	
32	2035	$34.48	$ 19.57	$ 26.49	$ 78.93	$ 24.84	$ 47.25	$ 75.70	
33	2036	$35.86	$ 19.57	$ 26.49	$ 80.23	$ 24.84	$ 47.25	$ 75.84	
34	2037	$37.29	$ 19.57	$ 26.49	$ 81.58	$ 24.84	$ 47.25	$ 75.99	
35	2038	$38.78	$ 19.57	$ 26.49	$ 82.98	$ 24.84	$ 47.25	$ 76.14	
36	2039	$40.33	$ 19.57	$ 26.49	$ 84.44	$ 24.84	$ 47.25	$ 76.30	
37	2040	$41.95	$ 19.57	$ 26.49	$ 85.96	$ 24.84	$ 47.25	$ 76.46	
38	2041	$43.63	$ 19.57	$ 26.49	$ 87.54	$ 24.84	$ 47.25	$ 76.63	
39	2042	$45.37	$ 19.57	$ 26.49	$ 89.19	$ 24.84	$ 47.25	$ 76.81	
40	2043	$47.19	$ 19.57	$ 26.49	$ 90.89	$ 24.84	$ 47.25	$ 77.00	
41	2044	$49.07	$ 19.57	$ 26.49	$ 92.67	$ 24.84	$ 47.25	$ 77.19	env op cost
42	2045	$51.04	$ 19.57	$ 26.49	$ 94.52	$ 24.84	$ 47.25	$ 77.39	of non-seq
43	2046	$53.08	$ 19.57	$ 26.49	$ 96.44	$ 24.84	$ 47.25	$ 77.60	$ 69.95
44	2047	$55.20	$ 19.57	$ 26.49	$ 98.44	$ 24.84	$ 47.25	$ 77.81	$ 71.95
45	2048	$57.41	$ 19.57	$ 26.49	$ 100.52	$ 24.84	$ 47.25	$ 78.04	$ 74.03
46	2049	$59.70	$ 19.57	$ 26.49	$ 102.68	$ 24.84	$ 47.25	$ 78.27	$ 76.19
47	2050	$62.09	$ 19.57	$ 26.49	$ 104.93	$ 24.84	$ 47.25	$ 78.51	$ 78.44
48	2051	$64.58	$ 19.57	$ 26.49	$ 107.27	$ 24.84	$ 47.25	$ 78.77	$ 80.78
49	2052	$67.16	$ 19.57	$ 26.49	$ 109.70	$ 24.84	$ 47.25	$ 79.03	$ 83.21
50	NPV	$458							
51	**Real level. CO2 Adder**	**$27.27**	**2006 $ per ton**						
52									

53 From Figure A.3 on page 17 of the Appendix (p. 251 of 265 of the Draft IRP)

Row	Wholesale Prices	2013	2014	2015	2016	2017	2018
55	Nom. LLH ($/MWh)	$ 50.00	$ 54.00	$ 58.00	$ 62.00	$ 66.00	$ 70.00
56	Nom. HLH ($/MWh)	$ 60.00	$ 65.00	$ 70.00	$ 75.00	$ 80.00	$ 85.00
57	Nom Weight (flat gen)	$ 55.71	$ 60.29	$ 64.86	$ 69.43	$ 74.00	$ 78.57
58	2006 $/MWh	$ 48.97	$ 52.05	$ 55.01	$ 57.85	$ 60.56	$ 63.17

59 Inflation Values from page 1 of appendix (p. 235 of 265)

Estimate of PAC Base Case Environmental Adders

Assumed CO2 Adder	$	5.287	$/ton
Coal CO2 Content		205.35	lb per MMBtu

Technology	heat rate MMBtu/MWh	Environ. Adders (pages 89 & 91) CO2-Only $/MWh	PAC Est. $/MWh	Non-CO2 $/MWh	Non-CO2 Ratio to heat rate
UT Pulv. Coal	9.169	$4.98	$5.39	$0.413	22.22
UT IGCC non-sequest.	8.732	$4.74	$4.83	$0.090	97.13
UT IGCC Sequest.	9.917	$0.54	$0.64	$0.102	97.55
WY Pulv. Coal	9.427	$5.12	$5.54	$0.423	22.31
WY IGCC non-sequest.	8.915	$4.84	$4.93	$0.091	98.45