

**MEMO**  
**April 17, 2006**

**To:** Carbon Allocation Technical Working Group

**From:** Phil Carver, ODOE

**Subject:** Utility Specific Cost Estimates

**INTRODUCTION**

This memo provides utility specific estimates of the cost of the straw proposal for capping CO<sub>2</sub> emissions for PGE, PacifiCorp and a example consumer-owned utility (COU) that buys all of its power from the Bonneville Power Administration (BPA). There are continuing efforts to refine the estimates of the costs of conservation and renewable resources beyond those included in the Northwest Power Planning Council's *5<sup>th</sup> Power Plan*. Even so, the ranges provided below are firm estimates because the design of the straw proposal effectively caps the cost of compliance at \$40 per metric ton of CO<sub>2</sub> (real 2004 dollars). All estimates assume that all free allowances are allocated based on 2004 load-serving entity (LSE) emissions and 5 percent of allowance are auctioned. (In the straw proposal historical emissions would be for the period 2003-2005. These numbers based on 2004 are illustrative of using the longer base period, for which we don't yet have data.)

Also attached to the same e-mail are three Excel spreadsheets. Page 1 of the 2020 tab of "Renew-displ-fossil-gen.xls" and the top part of "COU allowance cost example.xls" have already been distributed. The whole spreadsheet "rough-base-emission-12-02-05.xls" is unchanged from what was distributed in December.

**ESTIMATES OF OREGON COST FOR 2020**

Rows 8-10 of page 2 of "rough-base-emission-12-02-05.xls" spreadsheet show that the average Oregon 2020 total compliance costs range from 1.7 to 5.2 percent of 2004 retail electric retail revenues if the costs of reductions range from \$10 to \$30 per metric ton of CO<sub>2</sub>. These cost increases are the total impact in 2020 from the straw proposal. This assumes that all load growth is met by cost-effective conservation and renewable generation. This is consistent with the Northwest Power and Conservation Council's (NWPPCC) *5<sup>th</sup> Power Plan*, which indicates that in most scenarios all load growth can be met with cost-effective conservation and renewable generation.

The *5<sup>th</sup> Power Plan* indicates that spending to achieve the risk-adjusted cost-effective amount of conservation would be about 3 percent of electric utility revenues. (CATF staff is working with the Energy Trust of Oregon to refine this value for PGE and PacifiCorp.) This conservation plus cost-effective renewable generation can meet load growth with little or no growth in CO<sub>2</sub> emissions, depending on the level of load growth. This indicates that there should be little or no extra costs to keep CO<sub>2</sub> emissions at the

2004 level. There should be no extra cost from the CO<sub>2</sub> cap until the cap is lowered below the 2004 level.

Conservation beyond the level included in the 5<sup>th</sup> *Power Plan* for the Northwest would include new technologies for cost-effective conservation that emerge during 2006 to 2020 and conservation that is more expensive than market power but is a low-cost source of CO<sub>2</sub> reductions. Renewable generation that costs more than market-priced power would be the other major source of CO<sub>2</sub> reductions after the CO<sub>2</sub> cap is ramped down.

If load growth is in the low range of 5<sup>th</sup> *Power Plan* scenarios, there would be cost-effective conservation and renewable generation to reduce loads and emissions below the 2004 level. In this case the CO<sub>2</sub> reduction would occur at no additional cost. Also, if Oregon acquires cost-effective Northwest renewable generation more quickly than other Northwest states, it could reduce fossil-fueled generation and costs by acquiring cost-effective renewable generation ahead of need. CO<sub>2</sub> reductions in this case also would impose no additional costs.

If all cost-effective conservation and renewables are acquired, it is unlikely the total Oregon increase in 2020 costs will be outside the range of 2 to 5 percent of 2004 revenues (in real 2004 dollars). The actual cost of CO<sub>2</sub> reductions is capped by the \$40 per tonne alternative compliance option. This would be highest compliance cost per tonne that a utility should pay. Even if a utility paid \$40 per tonne for some of its allowances, the cost of its own reductions should always be less than this.

#### **UTILITY COST ESTIMATES FOR 2020**

The other spreadsheets show examples of the range of costs for an Oregon consumer-owned utility that purchases all of its power from the Bonneville Power Administration (“COU-allowance-cost-example.xls”) and for PacifiCorp and Portland General Electric (PGE) (the second page of the “2020” tab of the spreadsheet “Renew-displ-fossil-gen.xls”). These spreadsheets use assumptions that are consistent with “rough-base-emission-12-02-05.xls.”

All these estimates assume that load growth can be met with cost-effective conservation and renewable generation. The increases in cost shown below are the total impact on 2020 costs. Costs for years between 2009 and 2020 would be less.

**COUs.** For the Oregon COU example the cost of achieving a 17 percent reduction for 2020 from 2004 emission levels would range from 0.1 to 0.7 percent of 2004 retail revenues as the cost of purchasing allowances ranges from \$5 to \$35 per tonne of CO<sub>2</sub>. It is highly unlikely costs will be outside this range, given the \$40 per tonne cap on compliance costs.

**PGE.** The 2020 costs for PGE to meet the 17 percent emission reduction from 2004 would depend on whether it meets the requirement by changes on its own system or whether it purchases allowances. This discussion assumes that to meet the requirement

on its own system, PGE would acquire conservation or renewable generation beyond load growth with above-market-costs. These resources would reduce the amount of market purchases by PGE. These reduced purchases would reduce PGE's emissions at the net system mix's emissions rate (lb. of CO<sub>2</sub> per MWh), based on the straw proposal accounting methodology. Compliance cost to PGE would depend only on the net system mix emission rate and the cost of the conservation or renewable generation beyond load growth. As shown on lines 19-21 of page 2 of the "2020 tab" of the spreadsheet, the cost for this example would range from 1.6 to 6.5 percent of PGE's 2004 retail revenue for above-market costs of \$5 to \$20 per MWh. At the assumed net system emission rate, it is highly unlikely costs will be outside this range, given the \$40 per tonne cap on compliance costs,

In the example in the spreadsheet all of the extra conservation or renewable generation is assumed to displace purchases (cell I67 on line 6 of page 2 of the "2020" tab is set to zero). If instead, PGE found it cheaper to meet its CO<sub>2</sub> reductions by reducing gas-fired generation rather than purchases, the cost of the CO<sub>2</sub> reduction would be less. It could not be more if PGE minimized its costs. In this example, with the average heat rate of PGE's existing power plants, redispatch is not cheaper. For individual power plants with higher than average heat rate (e.g. Beaver) it may be to cheaper to reduce gas-fired generation rather than purchases.

Based on conditions in 2004 and assuming that the Port Westward plant is on line and running at full availability, PGE can meet the 2020 reduction of 17 percent below 2004 emissions solely by reducing purchases. This is shown on lines 14-16 of page 2 of the "2020" tab. If it could not, PGE would have to displace gas-fired power. This could slightly raise the costs of compliance, depending on the wholesale prices for gas and electricity and the CO<sub>2</sub> emissions rate for the displaced gas generation and the net system mix.

Instead of acquiring above-market conservation or renewable generation to reduce fossil-fueled power to meet load, PGE could meet its CO<sub>2</sub> requirements by buying allowances at auction or from other LSEs. If so, the cost would range from 0.8 to 5.4 percent of 2004 retail revenue if the cost of allowances ranged from \$5 to \$35 per tonne of CO<sub>2</sub> (see lines 23-25 of page 2 of the "2020" tab). In actual practice, the cost to PGE would be the lowest cost mix of extra conservation or renewable generation with above-market costs or the cost of purchasing CO<sub>2</sub> allowances.

**PacifiCorp.** The analysis of PacifiCorp costs is shown on lines 29-47 of page 2 of the "2020" tab of "Renew-displ-fossil-gen.xls." If PacifiCorp acquired conservation or renewable resources at above-market costs, Oregon customers would pay the above-market costs under the Revised Protocol of the Multi-State Agreement. Under the agreement the power associated with these resources also would be allocated directly to Oregon loads. The power from these resources would reduce the amount of PacifiCorp system resources allocated to Oregon. The displaced CO<sub>2</sub> would be based on the emissions rate (lb. of CO<sub>2</sub> per MWh) of the PacifiCorp's system mix.

The cost for PacifiCorp to meet the 17 emission reduction from 2004 would depend solely on the above-market costs of the extra conservation or renewables cost and its average system emissions rate. The cost for this method would range from 2.1 to 12.8 percent of 2004 retail revenue if the above-market cost ranged from \$5 to \$30 per MWh (see lines 40-42 of page 2 of the “2020” tab).

Alternatively, if PacifiCorp met its reductions through purchases of allowances, the costs would range from 1.9 to 13.1 percent of 2004 retail revenue if the cost of allowances ranged from \$5 to \$35 per tonne of CO<sub>2</sub> (see lines 44-46 of page 2 of the “2020” tab). As with PGE, the actual cost would be the lowest cost mix of the above-market conservation or renewable generation or the cost of purchasing CO<sub>2</sub> allowances.

#### **UTILITY COST ESTIMATES FOR 2009-2011 and 2012-2014**

**2009-2011.** For this estimate it is assumed that the cap for each utility for 2009-2011 is set equal to its 2004 emissions. If load growth can be met with cost-effective conservation and renewable generation, this cap would impose no extra costs on utilities.

The assumed reductions from 2004 emissions for the other three-year compliance periods of 2012-2014, 2015-2017 and 2018-2020 are 1, 8 and 15 percent, respectively. This is consistent with a 17 percent reduction in 2020, which is accounted for in the average 15 percent reduction from 2018-2020. Note that under the straw proposal there are no year-by-year costs. There are only costs for each compliance period.

**2012-2014** For the Oregon COU example the cost of achieving a one percent reduction for 2012-2014 from 2004 emission levels would range from 0 to 0.2 percent of 2004 retail revenues as the cost of allowances ranges from \$5 to \$35 per tonne of CO<sub>2</sub>. These costs are in the bottom box of the spreadsheet “COU-allowance-cost-example.xls.” It is highly unlikely costs will be outside this range, given the \$40 per tonne cap on compliance costs.

The “2012-14” tab of “Renew-displ-fossil-gen.xls” shows the costs of a one percent reduction for PGE and PacifiCorp. For PGE these costs range from 0.5 to 1.4 percent of 2004 retail revenues for above-market costs of \$5 to \$15 per MWh. The costs range from 0.2 to 1.5 percent of 2004 retail revenues for allowance costs of \$5 to \$35 per metric ton of CO<sub>2</sub>.

For PacifiCorp the cost of a one percent reduction for the 2012-2014 period ranges from 0.6 to 3.6 percent of 2004 retail revenues for above-market costs of \$5 to \$30 per MWh. The costs range from 0.5 to 3.7 percent of 2004 retail revenues for allowance costs of \$5 to \$35 per metric ton of CO<sub>2</sub>.

For both PGE and PacifiCorp the actual 2012-2014 cost would be the lowest cost mix of above-market conservation or renewable generation or the cost of purchasing CO<sub>2</sub> allowances.