BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

LC 42

In the Matter of PACIFICORP'S 2007 Integrated Resource Plan	)))	COMMENTS of the **NW Energy Coalition**

The NW Energy Coalition (NWEC) Coalition recommends that the Commission not acknowledge Pacificorp's 2007 Integrated Resource Plan (IRP) without substantial modification of the Company's Preferred Portfolio. PacifiCorp has not made the case that it should acquire two conventional coal plants. Faced with: (a) an increasing certainty of restrictive CO_2 regulation; (b) the asymmetrical risk related to under-estimating the future economic and environmental cost of greenhouse gas emissions (see opening UM 1302 comments of CUB, RNP, EMO and NWEC); and, (c) the minimal rate benefit of taking on this risk (at most a quarter of a mill/kWh[1]), the Company's analysis does not justify moving forward with two long-lived, capital intensive, base-load, unsequestered coal plants. NWEC believes that the GHG Emissions Performance Standard Portfolio introduced at the end of Chapter 7 is a much better alternative, having comparable costs but significantly lower long-term risk, than the Company's preferred alternative.

The big question is why PacifiCorp's Preferred Alternative relies mostly on fossil-fuels—including two conventional coal plants—in the face of existing and imminent legislation restricting greenhouse gas emissions. Oregon, Washington and California have already passed renewable energy standards, with the Governor of Utah proposing the same in that state, not to mention probable federal legislation in the next few years. How did the utility's sophisticated modeling come up with this counter-intuitive result?

Modeling Nightmare

Pacific's approach can best be characterized as "Computers on steroids." The utility uses an enormous, sophisticated "black box" model to analyze hundreds of possible resource portfolios against thousands of alternative futures. This approach is

[1] IRP Fig. 7.19, p. 187

supposed to make decisions more objective, but it has the opposite effect. That is because the policy choices are hidden in the *assumptions* that drive the results and in how factors are *weighted*. Often as not, the Company changed more than one important input per run, so it is impossible to tell which factor drove the result. And since the assumptions and decisions on how much importance to give various interim results are difficult to parse out from the hundreds of pages of charts and graphs the computer generates, one is simply left with the impression that the company didn't ask the right questions. Deliberately or not, the result is lots of numbers, but little understanding.

What is most troubling about this approach is that the Company has failed to apply a measure of common-sense skepticism to the results. It has not questioned why its modeling came up with counter-intuitive results, much less changed its assumptions as those concerns became clear.

Questions and concerns with the modeling and analysis

1. Why does PacifiCorp choose unsequestered pulverized coal even with high CO_2 adders?

Even under the \$61 CO_2 adder, Pacific doesn't choose sequestered coal. If one looks at Table 5.3 (and 5.4), pp 95 & 96, which lists the model's resource choices, the last column provides a cost comparison. The environmental adder in the second-to-last column is mainly due to a CO_2 adder of \$8/ton. If one now applies a \$61 adder, wind is, of course still lowest cost. But now sequestered coal (~\$76/MWh) is much cheaper than either conventional coal or gas CTs. However there is no portfolio tested that chooses sequestered IGCCs.

The probable reason for this failure to choose sequestration is that the model's "high" adder value isn't very high. It is \$37.9, *not \$61*, as it is in the rest of the IRP. Also the model phases in the adder fairly slowly; and, it used a very high discount rate for the carbon adder. These three factors, together with a relatively short run period (20-years), produce this illogical result. While this issue may seem to be a little on the fringe, given the technological hurdles to sequestration, we use it as an illustration of why we must call into question *all* of the CEM Group 1 runs We discuss this more in #6 below.

2. For higher carbon adder scenarios, conventional coal plants should be modeled with shorter economic lives.

If higher carbon adders are adopted, it will be in order to meet the longer term carbon-reduction targets adopted by Oregon, California and Washington (and needed to attempt to head off climate catastrophe, according to most scientists.) Under those circumstances, conventional coal plants will either need to be shut down or, if possible, retro-fitted with expensive carbon capture and sequestration technology. This fact was not incorporated into the IRP modeling.

3. Why was only one low-CO_2 portfolio analyzed? (Furthermore, it was only introduced at the end, so it was not directly compared to the others.) And, why was it rejected?

Given all the discussion about global warming and carbon regulation, and the existence of emissions requirements in WA and CA, (and introduced, though not passed, in Oregon) that prevent new unsequestered coal-fired electricity from being acquired or purchased by most utilities, it is surprising that the Company only added a portfolio without conventional coal plants after most analysis was completed—almost as an afterthought. In addition, it ran the CEM which chose the portfolio under only an $8/ton adder—even though the whole reason for such a portfolio is to react to a strict carbon regulation regime. So we do not know what the portfolio would look like under a more reasonable assumption.

Interestingly however, despite this drawback, the GHG Emissions Performance Standard portfolio (GHG portfolio) produced the lowest emissions and also the lowest costs under the $38 and $61 adders. We believe that were the modeling fixed to more logically treat carbon in sales and purchases, as discussed in the next bullet, this portfolio would have compared even better to the preferred portfolio (RA14) eventually picked by PacifiCorp.

We also find it disturbing that the Company gives no rationale for rejecting the GHG portfolio as compared to RA14. We can guess that the reason might be the portfolio's high stochastic risk, but it is disappointing that there is no discussion. Given the GHG portfolio's *risk-reducing* scenario-risk advantages—lowest cost under $38 and $61 adders; lower stranded cost risk; increased likelihood of meeting a Utah RPS if passed; and, most important, an actual reduction in emissions over the study horizon—this portfolio is in our view markedly superior to the Company's current preferred portfolio.

4. In the context of the Company's preferred portfolio serving growing loads by adding two conventional coal plants and some gas plants, some questions arise.

(a) Why does PVRR *decrease* under higher CO_2 adders (Table 7.37, Cap and Trade); (b) why does CO_2 intensity *decrease* over time and under higher adders? (Fig. D.2 p.120 appendix D); (c) why do CO_2 emissions *decrease* over time (Figure (7.27, p. 196); and, (d) why are emissions costs *negative* under a cap-and-trade scenario? (response to NWEC DR #8, attachment A)

The explanation given by the Company to (a), (b) and (c) is that,

> Because the IRP models account for the CO_2 cost adder in their unit dispatch solutions, a simulation can result in sizable annual emission credits due to ramping down of coal generation and ramping up of other resources with lower CO_2 emissions. (*ibid.*)

The answer to (d) is in the same data response:

> [T]he CO_2 cap-and-trade modeling framework assumes that PacifiCorp can sell as well as purchase allowances priced at the CO_2 allowance cost. Consequently, if system CO_2 emissions are below the CO_2 cap in a particular year, the Company receives a CO_2 emissions credit….

In simple terms, even though the Company's loads are growing, and it has added two coal plants and other fossil fueled resources to serve those loads, it will have sufficient resources to dispatch down its coal generation enough to lower total emissions; and so much so that it can even make money by selling excess emissions allowances.

But this strategy leads to some inevitable questions. First, if PacifiCorp has enough resources to be able to shift enough generation away from coal so as to actually lower its emissions after years of load growth, why does it need to build more coal plants? Second, if this strategy causes its existing fleet of coal plants—plus two more—to be used so much less, their capacity factor must go way down, making them quite a bit less economic.

So could it be that PaciCorp's model chooses base-load coal plants to meet its growing summer peak need, *and then doesn't run them the rest of the time*—instead running gas plants and thus resulting in lower emissions? That strategy would result in quite high per-kWh costs for those coal plants, so we are doubtful that the model would choose coal over gas.

More likely, we believe, is that the model executes a "carbon laundering" scheme. That is, it doesn't actually turn off the coal plants. It probably dispatches them to price, not the utility's retail load. If the retail load isn't there the plants don't shut down, they sell into the market. The trick is that PacifiCorp's dirty surplus power is sold with its high carbon content into the market with no cost consequences. And when Pacific purchases power from that same market, the power comes with a carbon content of the much lower western system mix. Thus the utility can essentially offload its dirty power, at a hefty profit, onto others, and purchase cleaner power when it needs to with price not reflecting carbon content. What makes this scheme especially profitable is higher CO_2 adders! That's because a higher adder will raise the market price, resulting in even higher profits for sales.

We attempted to clarify what the Company was doing with its sales through a number of data requests. In NWEC request #10 we asked, "What is PacifiCorp's assumption in this IRP regarding which party—buyer or seller-gets the emissions for sales and purchases?" PacifiCorp's answer was cryptic: "PacifiCorp **made no assumption** in this IRP regarding which party gets the emissions for sales and purchases." (Attachment A, emphasis added) This is remarkable, since either the model includes the emissions with sales and purchases, either to the buyer or seller, or it doesn't. It's impossible to have "no assumption."

The IRP states that "The indirect CO_2 emissions related to purchases are calculated by multiplying net purchased power generation by an average emissions factor of 0.565 tons/MWh which is **offset by emissions deemed to go with wholesale sales at the average system emission rate**…" (Chapter 6, p. 134 emphasis added) which, according to the response to our DR #9(c) and (d) (Attachment A), is either a much dirtier 0.822 or 0.862 tons/MWh (depending upon whether or not the mix is diluted by purchases). This statement seems to confirm the carbon laundering scheme we suspect is leading to the counter-intuitive results of larger loads, more coal plants, but less emissions.

At present, there is no regional or national accounting protocol for the emissions that accompany (or not) sales and purchases, especially non-specific market transactions. But one cannot reasonably believe that states will allow this end-around their greenhouse gas reduction goals to be tolerated for long. In most discussions of carbon regulation schemes we have heard about, this issue of "contract shuffling" and carbon "washing" is front and center. We do not know exactly how it will be solved, but Pacific should not assume it cannot, or will not, be solved.

However, whichever way the model treats this issue, there is an issue. Either the model is dispatching to <u>load</u> (actually running only during peaks) or to <u>price</u> (running when market prices are higher than variable costs). If the former, the model should not be choosing high capital cost base-load coal plants, because they will be operating at very low capacity factors, rendering them uneconomic. If the latter, the model should not allow sales to include emissions at greater then the west-side rate (0.565 tons/MWh), leaving the excess as the responsibility of the utility. (This solution is one commonly being discussed to deal with this issue under cap-and-trade mechanisms.)

Perhaps the Company is confusing the existing Emissions standards of CA and WA with a cap-and-trade regime. Under those states' standards, short term contracts *are* exempt from any carbon requirement. However the carbon content of those sales and purchases will very likely be captured by any realistic cap-and-trade scheme. Finally, even if non-specific sales *are* allowed to escape regulation, parties with relatively cleaner power will increasingly want to sell it only as unit contracts, so as to capture the value of the low carbon content. That will increase the average carbon-intensity of market sales, lower their value (price) and eventually eliminate most of the advantage of any laundering transactions.

5. <u>Why were renewables artificially capped?</u>

Wind and geothermal resources are clearly the lowest cost resources available (see 5.3 and, pp. 95 & 96), and much more so under higher carbon adders. At $61/ton, for example, wind is about 2¢/kWh less expensive than sequestered IGCC and 3¢/kWh cheaper than conventional coal or gas CTs. With this huge cost advantage, it is strange that PacifiCorp artificially capped the amount its model could pick. Certainly it should have investigated the possibility of building transmission access to mega-wind sites in Montana and Wyoming, and/or serving much of its projected new Wyoming load with wind plus some gas shaping. And, it is difficult to see why the Company is not much more aggressively pursuing its lowest cost resource, geothermal.

6. <u>The foundation for developing its portfolios, the initial "CAF" runs, is biased toward low-carbon adder futures.</u>

PacifiCorp built the basic foundation for all its portfolios by running its CEM against 16 alternative scenarios. Sounds good. But we have a number of specific problems with the Company's approach.

(a) The 16 futures were quite arbitrarily determined with no weighting for probability. It is assumed that all have equal probability. As we discussed in our UM 1302 comments, this approach is unwarranted, because the likelihood and cost impacts of these factors are quite asymmetrical.

(b) There does not seem to be a logical consistency or correlation among all factors in each future. Thus we get a high carbon adder paired with a low electricity price—an extremely unlikely future without breakthroughs in new low-emission technology.

(c) As we mentioned, since the model never uses a high carbon adder (its high is $37.90), a high discount rate and short study period, it never chooses sequestered coal.

(d) $8/ton of CO_2 is considered the medium value, and the high value is truncated by not using $61 (the model considers $38 its high value). Since the low value is $0 and the range is $38, one would expect medium to be $17. It is unclear why Pacific doesn't include $61, since this value is used everywhere else in the IRP. If it had been used, a medium value of $30.50 would have been more realistic. This treatment of CO_2 adders is especially troubling given the limited "trigger point" discussion on p. 149. In that section it is seen that all the effects of raising the CO_2 adder come *above* $8/ton. And we also note that IGCC with sequestration is triggered above $38/ton, which is never even modeled. Thus 9 of the 15 alternative futures have carbon adders at or below the first small trigger point.

(e) The "carbon laundering" we mentioned above actually advantages coal plants in high carbon scenarios. The reason for this is that coal plants have lower non-environmental costs than the alternatives (except for renewables). However, even though the model builds to meet a capacity need, it chooses base-load coal plants because of their low cost. This works because more base load is not needed, except during peak periods, so the model is often selling surplus to the market at a profit, with no penalty for the fact that the power has high emissions. (Either that, or the model dispatches the coal plants to load, resulting in very low capacity factors, because they are initially chosen to meet a mainly summer load.) This profit is even greater under higher carbon adders. That's because market prices will rise with the adder. Pacific's model assumes no one will notice that the power it is selling is much dirtier than the market mix. So essentially, the utility is dumping low cost, but dirty power, into the market—and the more it can sell, the better.

Over and above these specific drawbacks is a large concern with how the preliminary analysis is used for the remainder of the process. The result of this initial resource screening is to set the base portfolio for further analysis. PacifiCorp basically used resources that appeared in most, or a majority of the CAF runs (e.g., Figure 7.3, p. 152). But since the majority (9 of 15) used only $8/ton or less, and none used more than $38/ton, these lower carbon adder futures drive the result.

7. <u>The IRP misses the whole point of "optionality."</u>

On p. 152, PacifiCorp has a very limited discussion of "optionality." The Company states that "…the CEM deterministic runs do not capture the optionality value of gas resources; consequently, testing them in a stochastic modeling environment is necessary to estimate their full value in a diversified portfolio."

We do not believe that stochastic modeling captures the option value of relatively easily sited, low-capital cost, and dispatchable resources, such as gas CTs or medium-term purchases. Coal plants will increasingly become more difficult to site and construct, given their size, environmental footprint, long lead time and rapidly increasing capital costs. And it is very unlikely that coal plants will be allowed to continue to operate for their full life in any carbon regulatory scenario that is serious about reducing—not just slowing the growth of—greenhouse gasses. While gas plants are also at risk due to carbon regulation and natural gas prices, the possible stranded cost is much less than a coal plant. Finally, gas plants may have a secondary value in helping to integrate the large amounts of wind that should be the Company's resource of choice.

The optionality for which NWEC has been advocating is the ability to "change horses in mid-stream" if the future changes drastically due to such factors as technology breakthroughs or the necessity for much stronger carbon regulation. Testing for this value requires a different approach than stochastic testing. It requires a dynamic approach such as performed by the NW Power and Conservation Council or being called for in the new UM1302 guidelines, where portfolios are tested against significant and permanent (not stochastic) changes in the future.

8. <u>PacifiCorp's modeling fails to account for elasticity of demand.</u>

We're not sure which way the inclusion of price elasticity of demand would tip the results, but it is an important consideration that should be included in any analysis. Under high carbon adder scenarios, for example, electricity prices will almost certainly increase, driving down demand. This effect was not analyzed.

9. The Company's assumptions regarding how its Plan will comply with the various state and possibly federal RPSs are questionable.

PacifiCorp assumes it will be able to apply almost all of its system-wide renewables to the states (OR, WA and CA) that have passed RPSs. In this way it only needs about 6% of its system to be renewable, even though those states' RPSs call for 15% or more over the IRP's study horizon.

When questioned about this, the Company said it is more of an allocation or MSP issue than an IRP issue. Presumably, Utah will get some money from the RPS states in order to give up its claim to its share of the system's renewables. While perhaps this issue is mostly an MSP issue, it is not entirely, and there is some customer risk in accepting the Company's strategy toward meeting its RPS obligations. For example, the longer PacifiCorp assumes Utah or the Federal government will not pass an RPS, the more likely it is that the best renewable locations for wind and geothermal will be taken by others. Also, Utah might very well decide it does not want to be saddled with a disproportional amount of "brown" power in anticipation or actual passage of its own or a federal RPS. It may be willing to sell its share of the utility's green power only for a short time. In that way it will not have to start at zero when a federal or Utah RPS is passed. This would cause Oregon to fail to meet its own standards if the Company was depending on that transfer to last. Finally, a long, drawn-out MSP negotiation will tend to freeze PacifiCorp management, at a time when smart decisions will be needed.

Therefore, the decision to low-ball its future renewables requirement is a risky decision not incorporated into the Company's IRP analysis.

10. The Company's methodology and results for DSM potential and deployment (especially Class 2 DSM) consistently shortchange the best opportunities for lowering customers' bills, regardless of whether the future is or is not carbon-constrained.

It is almost inconceivable that a thorough and comprehensive document such as the 2007 IRP could be released and so widely miss the mark on what is, in so many cases, the most cost-effective resource available to the company and its customers.

The decrements in the IRP load shapes are based on just six Class 2 DSM resources for each of the East and West regions. These are based on "studies such as the NWPPC 5th Power Plan". Even the Company acknowledges these estimates in the 2007

IRP are out-of-date for the Oregon portion of its service territory.[2] These shortfalls were identified as overlooked DSM resources in Oregon, in which the Company has the benefit of working with a statewide program administrator; one can only imagine the extent of DSM potential that has not yet been included in the company's plans for the Eastern region of its service territory.

The entire list of documents enumerating the Company's underestimation of the DSM potential in its service territory is too long to list here.[3,4,5] And the company's flawed analyses continue to this day to consistently underestimate DSM potential.[6] By not optimizing the use of DSM resources that reduce customer consumption and that obviate the need for baseload and peak generating resources, customers are paying higher bills than they need be.

And all of these shortcomings in the IRP occur even before one attempts to measure the benefits from DSM that are received immediately while also preparing for a carbon-constrained future.[7] Modeling suggests that significant deployment of DSM in meeting greenhouse gas reduction targets in California, Oregon, and the Northeast states will reduce customers' bills in most cases, but in all cases will be the most cost-effective approach to reducing carbon emissions in the electricity sector.[8,,910]

Conclusion

Probably one could find a number of errors in any utility's IRP. It is a complicated modeling problem. But the magnitude of errors and omissions in PacifiCorp's analysis is just too much to disregard. Compounding that problem, unfortunately, is the Company's over-reliance on this exercise to tell it what it should do.

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[2] Oregon Public Utility Commission staff data request 4, Docket LC 42, August 2, 2007.

[3] "The Potential for More Efficient Energy Use in the Southwest," SWEEP, 2002; savings potential in Utah: 17% in 2010, 31% in 2020; savings potential in Wyoming: 19% in 2010, 36% in 2020.

[4] "Energy Efficiency and Conservation Measure Resource Assessment," Energy Trust of Oregon, 2006

[5] "ACEEE's 3rd National Scorecard," ACEEE, 2005. State rankings of energy efficiency spending per capita identify significant potential, especially in the Eastern region: Oregon scored 6th (out of 51); Utah 19th (out of 51); and, Wyoming was the lowest in the nation (51st out of 51).

[6] Comments on PacifiCorp's DSM Potential Study, SWEEP, August, 2007.

[7] "The Treatment of Carbon Risk in Western Utility Resource Plans: Preliminary Results and Analysis," Lawrence Berkeley National Laboratory, presentation April, 2007.

[8] "Climate Action Team Report to Governor Schwarzenegger and the Legislature", California EPA, March 2006.

[9] "Energy Efficiency's Role in a Carbon cap and Trade System: Modeling Results from the Regional Greenhouse Gas Initiative," Bill Prindle, ACEEE, May, 2006.

[10] "Modeling Electric Load-Based CO2 cap-and-Trade", report to the Oregon Carbon Allocation Task

Due to the multitude of discretionary assumptions that go into determining the inputs, what to test, and how to interpret the results, it is incumbent upon the utility to exercise more judgment—and to exercise that judgment in a transparent way so that the parties understand what is model-driven and what is a judgment call.

Most troubling, in our opinion, is the Company's failure to question and explain why serving larger loads with new coal and gas plants produces fewer emissions. This single counter-intuitive fact challenges the entire IRP and demands a thorough examination of the model. (Just imagine if all utilities came to the same conclusion. We could solve global warming with business as usual!) We have posited two possible flaws that could have lead to the result. Either the model allows for laundering carbon,—that is, dumping dirty power into the market with no penalty but large profit—or running the coal plants with very low capacity factors which would render them poor economic choices. Perhaps there is another explanation, but our questions in the workshops and data requests have not uncovered an alternate, benign, explanation. And if either of our explanations are true, they call into question the entire modeling effort and invalidate all of its results.

The IRP's other flaws we addressed are also substantive. They include:

- Initial CEM modeling tremendously biased toward low-carbon futures. The $61 adder was not used as its high value, and $8 should in no measure be considered the "medium" value.
- In higher carbon adder scenarios, conventional coal plants should be modeled with shorter economic lives.
- Only one lower-carbon scenario was even modeled, and it was rejected without explanation.
- Renewables were arbitrarily capped, which is especially flawed in high carbon scenarios. At such high prices, even expanding transmission to access mega-wind projects in Wyoming and Montana is probably economic.
- The optionality of a bridging type of strategy is not valued.
- PacifiCorp's modeling fails to account for elasticity of demand.
- The Company has minimized the difficulties it will face in attempting to apply almost all of its renewable resources to RPS states and should not assume this is a done deal.
- DSM potential, especially on the east side which does not have much of a history

Force, October 2006.

of conservation activity, was seriously underestimated.

Given these flaws, NW Energy Coalition urges the Commission not to acknowledge this IRP. The Company should correct the flaws noted above and rerun its analysis before seeking acknowledgment. In the alternative, we recommend that the Commission indicate it would accept the GHG Emission Performance Standard portfolio accompanied by a much more robust DSM program as an acceptable outcome.

Respectfully submitted,

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LC 42 Comments of the NW Energy Coalition

Attachment A

LC-42/PacifiCorp
September 17, 2007
NWEC Data Request 8

NWEC Data Request 8

(a) Please provide a detailed calculation of the "Total Emission Cost" in Table D.4 of Appendix D (p. 123) for portfolio RA14.

(b) Please provide the same calculation of the "Total Emission Cost" for the GHG Portfolio discussed in Chapter 7, beginning p. 213.

(c) Why are these negative?

Response to NWEC Data Request 8

(a) The response is provided as Attachment NWEC 8a.

(b) The response is provided as Attachment NWEC 8b.

(c) As shown in the spreadsheets provided as responses (a) and (b), the CO2 cap-and-trade modeling framework assumes that PacifiCorp can sell as well as purchase allowances priced at the CO2 allowance cost. Consequently, if system CO2 emissions are below the CO2 cap in a particular year, the Company receives a CO2 emissions credit (negative emission cost) equal to the difference between the actual emissions and the cap amount multiplied by the allowance cost. Because the IRP models account for the CO2 cost adder in their unit dispatch solutions, a simulation can result in sizable annual emission credits due to ramping down of coal generation and ramping up of other resources with lower CO2 emissions.

LC-42/PacifiCorp
September 17, 2007
NWEC Data Request 9

NWEC Data Request 9

Chapter 6, p. 134, 2nd paragraph under the heading Carbon Dioxide Emissions.

(a) The second sentence apparently is a typo, because it is not a complete sentence. What was it supposed to say?

(b) It states that "The indirect CO2 emissions related to purchases are calculated by multiplying net purchased power generation by an average emissions factor of 0.565 tons/MWh which is offset by emissions deemed to go with wholesale sales at the average system emission rate." (emphasis added.) What is the average system emission rate used?

(c) Please provide a breakdown of how the average system emission rate was calculated. Specifically, how were system sales and purchases accounted for?

(d) If the answer to (c) is that sales and purchases were included in the calculation of average system emission rate, please calculate the rate if those sales and purchases were excluded.

Response to NWEC Data Request 9

(a) The entire sentence can be ignored; the sentence that follows the referenced sentence was meant to replace it.

(b) The average system emission rate is the annual pounds of CO2 emissions from company-owned resources and wholesale purchases per megawatt-hour of total system resources.

(c) The table below shows the derivation of the average system emission rate using 2007 as the representative year. The calculation includes wholesale purchases but excludes wholesale sales, since this rate is intended to reflect emissions attributable to meeting both retail and wholesale load.

LC-42/PacifiCorp
September 17, 2007
NWEC Data Request 9

Calculation of Average System Emission Rate

	Units	Formula	CY 2007
<u>Emissions</u>			
Thermal Generation	(Tons 000)		54,167
Wholesale Purchase [1/]	(Tons 000)		5,654
Total		(a)	59,821
<u>Energy</u>			
Thermal Generation	GWh		54,032
Wholesale Purchase	GWh		10,007
Other Energy [2/]	GWh		8,778
Total		(b)	72,817
Calculate Emission Tons per MWh	Ton / MWh	(a) / (b) = (c)	0.822
Conversion Tons to lbs	Ton to lbs	(d)	2,000
Average System Emission Rate	(lbs/MWh)	(c) * (d)	1643.1

[1/] includes Long Term Purchase Contracts, Front Office Transactions, and System Balancing Purchases
[2/] includes Wind Renewables, Owned Hydro, DSM Class 1, and Storage / Exchanges

(d) As mentioned in response c, the average CO2 system emission rate includes wholesale purchases but excludes wholesale sales. Using the calculation from response c above, the system emission rate excluding wholesale purchases is 1,725 lbs/MWh (Thermal Generation / Thermal Generation + Other Energy * 2,000).

LC-42/PacifiCorp
September 17, 2007
NWEC Data Request 10

NWEC Data Request 10

(a) What is PacifiCorp's assumption in this IRP regarding which party—buyer or seller—gets the emissions for sales and purchases.

(b) Is the answer different for short-term balancing transactions, front-office transactions, or long-term contracts?

Response to NWEC Data Request 10

(a) PacifiCorp made no assumption in this IRP regarding which party gets the emissions for sales and purchases. The company reported the emissions in the 2007 Integrated Resource Plan associated with serving retail loads as described in the Response to NWEC Data Request 9.

(b) No; the answer is the same for short-term balancing transactions, front-office transactions, or long-term contracts.

PacifiCorp System Emissions
RA14 Portfolio
Cap & Trade Method
($ 000)

Base Line Allowances	NPV (2007 to 2026)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Allowance Value ($/ton)																					
CO2		-	-	-	53,002	53,002	53,002	53,002	53,002	53,002	53,002	53,002	53,002	53,002	53,002	53,002	53,002	53,002	53,002	53,002	53,002
SO2		157	157	157	64	64	64	64	64	64	64	64	43	43	43	43	43	43	43	43	43
NOX		-	-	-	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69
Hg		-	0.000696	0.000696	0.000377	0.000377	0.000377	0.000377	0.000377	0.000377	0.000377	0.000377	0.000218	0.000218	0.000218	0.000218	0.000218	0.000218	0.000218	0.000218	0.000218
Tons Actual from PaR (1000s)																					
CO2		54,167	53,971	52,914	50,354	48,668	46,045	45,517	47,276	47,630	48,557	49,331	50,462	52,204	52,620	52,311	52,724	52,676	53,512	54,132	54,874
SO2		92	78	64	54	41	33	31	29	29	30	31	32	30	30	27	28	27	27	27	27
NOX		86	80	74	67	61	52	50	48	48	49	49	51	49	49	47	47	45	46	46	46
Hg		0.0006	0.0005	0.0004	0.0003	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Percentage Emitted above Cap																					
CO2		0.0%	0.0%	0.0%	-5.0%	-8.2%	-13.1%	-14.1%	-10.8%	-10.1%	-8.4%	-6.9%	-4.8%	-1.5%	-0.7%	-1.3%	-0.5%	-0.6%	1.0%	2.1%	3.5%
SO2		-41.2%	-50.3%	-59.1%	-16.4%	-36.3%	-48.8%	-51.0%	-54.4%	-54.5%	-53.3%	-52.4%	-25.9%	-28.8%	-29.2%	-36.0%	-35.3%	-37.8%	-36.4%	-37.1%	-37.0%
NOX		0.0%	0.0%	0.0%	-3.0%	-10.8%	-24.3%	-26.7%	-29.9%	-29.4%	-29.1%	-28.2%	-26.0%	-28.7%	-29.2%	-31.9%	-32.2%	-34.8%	-33.1%	-33.6%	-33.4%
Hg		0.0%	-29.6%	-46.2%	-24.8%	-53.5%	-67.6%	-69.0%	-67.6%	-67.5%	-67.1%	-66.5%	-40.7%	-39.5%	-39.1%	-39.2%	-38.8%	-39.2%	-38.1%	-37.5%	-37.3%
Allowance Value ($/ton)																					
CO2		-	-	-	4.15	6.34	8.62	8.78	8.94	9.10	9.26	9.43	9.60	9.77	9.95	10.13	10.32	10.52	10.72	10.92	11.13
SO2		788	962	1,087	609	637	666	696	727	531	549	568	587	607	627	638	651	663	676	688	701
NOX		-	-	-	-		1,145	1,167	1,188	1,209	1,231	1,253	1,276	1,299	1,322	1,346	1,371	1,397	1,424	1,451	1,479
Hg		-	-	-	14,394	15,290	16,256	17,268	18,324	19,446	20,698	22,032	23,454	24,966	26,574	27,052	27,566	28,090	28,624	29,168	29,722
Net Emission Cost		(PaR Tons less Allowance Tons Multiplied by Allowance Value)																			
CO2	(210,871)	-	-	-	(10,991)	(27,476)	(59,970)	(65,723)	(51,196)	(48,889)	(41,168)	(34,618)	(24,390)	(7,796)	(3,804)	(7,000)	(2,871)	(3,431)	5,467	12,340	20,833
SO2	(309,661)	(50,906)	(75,749)	(100,668)	(6,407)	(14,810)	(20,832)	(22,766)	(25,343)	(18,537)	(18,743)	(19,056)	(6,486)	(7,466)	(7,819)	(9,812)	(9,804)	(10,714)	(10,498)	(10,898)	(11,062)
NOX	(165,563)	-	-	-	-	-	(19,112)	(21,358)	(24,380)	(24,400)	(24,549)	(24,236)	(22,741)	(25,541)	(26,443)	(29,494)	(30,247)	(33,321)	(32,313)	(33,434)	(33,916)
Hg	(1)	-	-	-	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**(686,096)**	(50,906)	(75,749)	(100,668)	(17,399)	(42,286)	(99,915)	(109,848)	(100,919)	(91,826)	(84,459)	(77,910)	(53,617)	(40,803)	(38,065)	(46,306)	(42,922)	(47,466)	(37,345)	(31,992)	(24,145)

CERTIFICATE OF SERVICE

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I certify that on the 19th day of September, 2007 I served the foregoing document (Comments of the NW Energy Coalition) upon all parties of record in this proceeding by e-mail.

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