Gary A. Dodge (0897)
HATCH, JAMES & DODGE
10 West Broadway, Suite 400
Salt Lake City, Utah 84101
Telephone: (801) 363-6363
Facsimile: (801) 363-6666
Email: gdodge@hjdlaw.com
Attorneys for US Magnesium LLC

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PACIFICORP for Approval of an IRP Based Avoided Cost Methodology for QF Projects Larger than 1 Megawatt	DOCKET NO. 03-035-14

PREFILED DIRECT TESTIMONY OF ROGER J. SWENSON

US Magnesium, LLC hereby submits the prefiled Direct Testimony of Roger J. Swenson in this Docket.

DATED this 29th day of July, 2005.

/s/________________________________
Gary A. Dodge,
Attorney for US Magnesium LLC

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email this 29th day of July, 2005, to the following:

Edward A. Hunter
Jennifer Martin
STOEL RIVES LLP
201 South Main Street, Suite 1100
Salt Lake City, UT 84111
eahunter@stoel.com
jehoran@stoel.com
Attorneys for PacifiCorp

Michael Ginsberg
Patricia Schmid
ASSISTANT ATTORNEY GENERAL
500 Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84111
mginsberg@utah.gov
pschmid@utah.gov
Attorneys for Division of Public Utilities

Reed Warnick
Paul Proctor
ASSISTANT ATTORNEY GENERAL
160 East 300 South, 5th Floor
Salt Lake City, UT 84111
rwarnick@utah.gov
pproctor@utah.gov
Attorneys for Committee of Consumer Services

Roger Swenson
238 North 2200 West
Salt Lake City, UT 84116
Roger.Swenson@prodigy.net

Stephen F. Mecham
Callister Nebeker & McCullough
10 East South Temple Suite 900
Salt Lake City, UT 84133
sfmecham@cnmlaw.com

James W. Sharp
ExxonMobil
800 Bell Street
Houston, TX 77002-2180
James.W.Sharp@ExxonMobil.com

Richard S. Collins
Gore School of Business
Westminster College
1840 South 1300 East
Salt Lake City, UT 84105
rcollins@Westminster College.edu
Representing Wasatch Wind

/s/______________________________

PREFILED DIRECT TESTIMONY

Of

ROGER J. SWENSON

On behalf of US Magnesium, LLC

In the Matter of the Application of PACIFICORP for Approval of an IRP Based Avoided Cost Methodology for QF Projects Larger than 1 Megawatt

Docket No. 05-035-14

July 29, 2005

Background

Q. Please state your name and business address.

A. Roger J. Swenson , 1592 East 3350 South, Salt Lake City, Utah 84106.

Q. By whom are you employed and in what capacity?

A. I am an independent utility and energy consultant.

Q. Please summarize your educational and professional experience.

A. I have a BS degree in Physics and a MS degree in Industrial Engineering from the University of Utah. I have worked in the energy industry for over 20 years. Prior to working as a consultant I was the Vice President of Energy Marketing for an oil and gas production company that was affiliated with a cogeneration development company. Prior to that I worked for Questar Corporation in various positions including some time spent on rate making matters. I have also testified before this Commission on various matters including maters involving QF rates.

Q. What is the purpose of your testimony?

A. My testimony will analyze and discuss alternatives to PacifiCorp's proposed methodology for calculating avoided cost rates. In addition, I will propose alternative contract terms and conditions for Qualifying Facilities ("QF").

Q. Please summarize your testimony and recommendations.

A. I discuss the pros and cons of the various approaches to calculation of avoided cost rates proposed by various parties. I conclude that the proxy plant method is the preferred method because of its simplicity and transparency, particularly for purposes of calculating avoided costs for a tolling arrangement for a QF plant that is willing to be dispatched. Energy pricing for such a QF should be based upon the heat rate of the deferrable proxy plant times a gas index price. The capacity price should be based upon demonstrable capital and O&M costs for the proxy plant. If the plant operates outside of dispatch hours it should be paid 93% of the Palo Verde index price. I suggest that, for a QF who wants fixed prices, we could use the energy output of the DRR model, once certain artificial modeling constraints are removed, and then add capital and O&M costs. The DRR model can determine fixed pricing for all hours in the future by using a resource the size of the next deferrable plant. The calculation can be rerun at regular intervals or when a specified level of new resources is under contract. Potential QF developers could rely on the published prices until the amount of QF power under contract reaches the capacity of the next deferrable plant. Under these approaches, QFs will receive pricing closely tied to what the utility would actually have paid in the future.

Q. Why should we continue to take up this matter?

A. Federal law requires that QFs be paid rates based on avoided costs. Utah law requires that efficient cogeneration projects be encouraged and that barriers be removed to the development of this type of power production. We are still trying to identify the rates, procedures, terms and conditions that will accomplish those purposes.

Q. Why do you think these statutes were adopted?

A. The statutes concerning avoided cost rates were adopted as it was becoming more and more apparent that the energy supplies that the country was relying on were diminishing and that we must have policies in place to encourage more efficient use of resources. They are also designed to promote renewable resources so that future generations may continue to have access to precious natural resources such as natural gas. The requirement that utilities purchase this power at avoided cost rates provides a necessary outlet for the power from these type of projects, as there was (and is) no true market to sell this output.

Q. Are you aware of any illustrations of the types of energy savings that result from these types of projects?

A. Yes. The US Environmental Protection Agency's Combined Heat and Power ("CHP" also known as cogeneration) Web Page (http://www.epa.gov/chp/what_is_chp.htm) illustrates the savings as follows:

> [T]he CHP system can produce the same electrical and thermal output at a 75% fuel conversion efficiency as compared to 49% for separate heat and power. This is a 50% gain in overall efficiency resulting in a 35% fuel savings.

Also, renewable energy projects such as wind, solar or geothermal provide additional benefits in that they reduce dependence on fossil fuel inputs for power generation.

Q. Are there even more reasons today to promote this type of technology?

A. Yes. Prices for natural gas have increased dramatically in the past two years. Prices are signaling a market shortfall of natural gas relative to supply. Price is allocating supplies of natural gas and is driving many energy intensive companies out of business or offshore.

Q. Are there any reasons to be cautious about promoting QF and small power development?

A. No. Some parties have consistently expressed the fear in task forces and hearings that have occurred over the past several years that the utility might end up paying too much for QF power or might encourage more generation than is needed. However, these concerns are overstated and manageable. There are always risks, of course, that a different approach or decision might have produced a different outcome. These risks exist with approval of power projects proposed by the utility, power purchase contracts and QF projects. Failure to set QF rates at a sufficient level also has risks, as it will block the development of QF projects and deprive Utah ratepayers of the benefits of these highly efficient resources. Risks associated with QF pricing are very manageable since the Commission must approve contracts larger than 3 MW. If this Commission has before it a contract or contracts that are not in the public interest, it can adjust the terms or limit the amount of capacity available under specified terms and conditions.

Q. What are the key issues associated with pricing?

A. The key pricing issues that have been stressed numerous times in hearings before this Commission are (i) setting rates at full avoided costs and (ii) maintaining ratepayer indifference. The payment for power produced by a QF or Small Power Producer should reflect all of the costs that are likely to be avoided by QF purchases, but should not cause utility ratepayers to incur more costs than if the

QF power had not been purchased.

Q. How have Parties proposed to create pricing that accomplishes this?

A. Various parties have suggested different concepts to deal with the methodology to determine pricing. The three main methodologies that have been proposed are: (i) a "proxy" method; (ii) a differential revenue requirements method ("DRR"); or (iii) a competitive bid method. The Proxy method uses the capital costs and operating costs associated with a specific plant or type of plant as a guide to determine prices. The DRR method attempts to use a least cost model to determine costs avoided when a zero cost resource is added to the stack of available resources. A competitive bidding approach requires a QF developer to bid its resource into an RFP process if and when the utility desires to procure new resources for inclusion in rate base.

Q. What do you see as the primary pros and cons of each of the proposed methodologies?

A. The Proxy method is very simple and straightforward and the calculations are all transparent. One shortfall of the Proxy method is that the pricing of avoided costs is most accurate if the QF and the avoided resource operate in the same manner. For example, if the Proxy resource is a CCCT and will be dispatched 45%-60% of the time, then the QF Proxy pricing approach will be extremely accurate for that 45%-60% of the time, in the dispatch hours. If the QF operates outside the dispatch hours, some other pricing mechanism must be applied to find the ratepayer indifference price, such as one that relies upon a market index.

The DRR Method is very cumbersome and complicated and hardly what I would call transparent. The adapted GRID-based model that PacifiCorp uses to attempt a DRR calculation takes roughly 8-hours for a single run on a dedicated computer. The operation of the model is complex and intimidating to all but the most computer savvy among us. Even a computer nerd would require hundreds of hours of dedicated analysis to fully understand and analyze the model and verify its output. Understanding and analyzing the output and results of any one computer run to determine specific cause and effect relationships require a robust effort. The hardest issue is ensuring that all of the assumptions and logic lead to results that are consistent with how a system would actually be operated. The clearest advantage of this type of pricing approach is, assuming all of the many complicated inputs, assumptions and formulae are correct, it provides a means to determine energy pricing in all hours.

A competitive bid alternative has been proposed but none of the details has ever been clearly identified or worked out. A competitive bid process would likely provide a clear understanding of market value, but it is unlikely that any but the very largest potential QFs would participate in an RFP process or absorb the costs and commitment required for an RFP response. A 5 or 10 MW QF simply cannot and will not bear the hundreds of thousands of dollars in likely costs of an RFP process, particularly given the likely outcome that the resource size requested will make the QF unsuitable for winning the RFP. The bid process may or may not be reasonable for much larger QF projects. In the absence of a well-developed proposal, it is hard to comment on its likely utility. We should, however, use the results of any recent utility competitive bid process to provide inputs to pricing determinations for QF prices.

Q. Do you have any specific preference for one of the approaches?

A. The Proxy method is the method that I prefer, using the next deferrable plant as the pricing determinant. I like the simplicity and transparent nature of that method. I do, however, believe that a DRR method may be useful to predict certain things, such as the hours that a Proxy plant may operate and alternative resources that a QF may displace, based on assumed input prices for fuel and purchase power cost and system load. My primary reservations with the DRR method are its complexity and the dramatic impact that certain artificial modeling assumptions can have in driving the derived pricing.

Q. Can you provide examples of artificial modeling assumptions in the DRR approach that can have a substantial impact?

A. Yes. For instance, one assumption used in PacifiCorp's proposed DRR approach is that the market for power in many off-peak periods is too shallow for any sales of excess power to be made. Therefore, when the DRR model assumes a QF project with a 100% capacity factor that runs full out in all hours, it turns down coal plants with variable operating costs of roughly $10-$11/MWH. It is hard to understand how off peak prices can consistently be reported in the $30-$40 range if there is too shallow of a market for sales. If that were the case, prices would generally be down in the $10-$11 range in off-peak hours, reflecting the variable cost of the last economic unit satisfying the markets needs.

Q. **What does this artificial modeling assumption do to the avoided cost calculation?**

A. It drives avoided energy costs dramatically lower than realistic levels. Each MWH of coal plant output reduction weights the avoided cost calculation with that very low variable cost of coal production.

Q. **Can you provide another example of how artificial modeling assumptions in the DRR approach make the results questionable?**

A. The issue of how power may be transferred between bubbles in the model becomes a very important limiting assumption. The model assumes that there is no non-firm transmission available in any hours and that there will be no additional firm transmission available from upgrades in the future. By limiting power transfers to existing firm transmission rights, coal plants are again shut down.

Q. **Do you believe that the assumptions of no non-firm transmission and no transmission upgrades are reasonable?**

A. No. I agree with comments submitted by the Committee of Consumer Services in reference to the 2004 IRP concerning non-firm transmission modeling: “PacifiCorp’s assumption that non-firm transmission capacity is not available limits the model’s ability to dispose of shoulder hour surplus capacity and therefore does not capture the benefits of coal.” The utility’s approach to DRR modeling does exactly the same thing and lowers the avoided cost price artificially and dramatically.

Q. **Do you have any evidence that transmission capacity is actually available when the DRR model says that none exists?**

A. Yes. I looked at specific hours on 7/17/05 through 7/25/05. I pulled up information from the PacifiCorp OASIS system for that period to look at transmission capacity. It reported the availability of off-peak firm capacity for PACE-PACEW, PACE-PATHC, PACE-REDB, PACE-GON and PACE-MPAC in aggregate for that same period of 1138 MW, as well as over 1000 MWs of non-firm transmission in many of the off peak hours from the PacifiCorp east transmission area. Clearly, the artificial modeling assumption in the model that says coal plants need to be turned down is wrong for this specific period. I suspect it is wrong for essentially every period.

Q. **Can we know what transmission will be available in the future?**

A. I believe we can reasonably assume that transmission systems will continue to be improved and that systems designed to meet peak load requirements will be unloaded during off peak hours. An article concerning PacifiCorp published in The Oregonian on July 16, 2005 states that the Company expects to spend more than $1 Billion upgrading power plants and transmission lines. The specific transmission improvements mentioned in the article include:

- $196 million to build a transmission line in Utah to boost capacity in the Salt Lake City area.
- $78 million to upgrade an Idaho-to-Utah transmission line, boosting

PacifiCorp's ability to move power in east-west directions.

- $88 million to establish a transmission link in Washington between Walla Walla and Yakima or Vantage to improve access to wind energy.

The article goes on to state that as much as 400 megawatts of new wind resources can be added after its transmission upgrades are completed.

Q. **Are there other assumptions in the DRR approach that seem questionable?**

A. Yes, another assumption that I question is the idea that if a 100% load factor QF resource displaced the 2009 CCCT, the utility would go ahead with developing a base load resource in 2011. This assumption simply provides more base load resource that, again, is turned down in the off peak hours, further depressing QF pricing.

Q. You have raised several problems with the DRR methodology used by PacifiCorp. Have you seen anything that gives you any level of comfort with the DRR methodology?

A. Yes, I have. In response to a data request, PacifiCorp ran a DRR model run that changed the hours of operation for the QF from 100% to those specific hours that the avoided proxy plant CCCT runs in the model. In other words, the assumed QF displaced the proxy CCCT in every hour that the model suggests the CCCT would run, and no more, over the 20-year period. The energy component of avoided cost pricing derived from that run is shown on Exhibit 1 (USM 1.1). The resulting price on a 20 year levelized basis is $60.36/MWH - almost exactly the same result as that derived from the proxy model using similar assumptions. This shows that the DRR model can produce an energy price (after 2009) that matches exactly with the assumed heat rate (7.6 Dths/MWH) and forecasted gas price of the proxy unit that would be displaced.

Q. **What does that tell you about the DRR and Proxy model?**

A. They both give similar results, assuming similar resource assumptions as to size and hours of operation are used.

Q. **What does that suggest to you?**

A. When I have two models that give me the same result, I prefer to use the simpler, more transparent model. QF projects that offer a similar operating profile to the CCCT that is the next deferrable plant should be priced in this manner. For a QF that offers a fully dispatchable resource, we can use the proxy plant operating characteristics and proxy model and be confident that we are capturing the actual avoided cost. The most recent RFP for comparable resources should be the basis for any other costs that are needed in the calculations and to bring a measure of validation to the pricing. For a QF plant that is non-dispatchable or that operates outside of the hours that the utility chooses to dispatch it, an additional pricing step would be necessary. A reasonable approach is to utilize a market index price for non-dispatch hours, as was used in the stipulation and as is currently being used in several contracts in place, including US Magnesium's.

Q. Can you envision approaches that incorporate the best aspects of both of the models?

A. Yes. As under the Stipulation, a QF developer should have the option of choosing either variable pricing (proxy heat rate times gas index) or fixed pricing. The Proxy model provides the most reasonable basis for calculating avoided costs for the variable pricing option. The DRR method can provide a means to determine fixed pricing. The shortcomings of the DRR model for this purpose can largely be overcome by using reasonable assumptions for the value of power produced in off peak hours instead of indulging the unreasonable assumption that coal plants will be turned down. We can identify the number of hours that the coal plant is reduced in the DRR model run to estimate the amount of power available for market opportunities.

Q. How can we revise the DRR method to set fixed QF pricing?

A. We can determine a fixed pricing basis by using the output from the DRR method and then adding the value of market opportunities for coal generation that the DRR model has artificially turned down by assumption.

Q. How can you value the market opportunities?

A. We could change the DRR model to permit market sales in each bubble at the price of the nearest market point using the forecasted market prices in the DRR model. Alternatively, we can make a conservative assumption that the quantity of coal displacement power could be moved to the lowest pricing point in the western markets and sold at 93% of the market price at that location.

Q. **Did you ask PacifiCorp to make the change to the DRR model to allow market sales based on the nearest market hub?**

A. Yes. I was told that the model could not be changed to handle that assumption. I am not certain why the model is so inflexible and I have not had time to try to make the necessary modifications myself. Instead, I have simply added to the DRR results the value of the energy of coal displaced in the model based on 93% of the lowest forecasted off peak market price from the western pricing hubs.

Q. **Why use 93% of the lowest pricing point in the forecast?**

A. Power generally moves from a low market price point to a higher market price point because market traders are trying to take advantage of the pricing difference. Parties with transmission rights try to maximize the value of their transmission rights. That natural movement of power creates opportunities for transmission path counter flow. For example, if prices are $30/MWH at Mid C and $40 at PV, there may well be no transmission available from north to south (Mid C to PV), but there should be ample transmission available the other way, from south to north. In this example, it is a reasonable assumption that we should be able to move power to the lower price $30/MWH market. I use 93% of the index forecasted price to account for the non-firm nature of the resource. The combination of using the lowest pricing point and the 93% factor provides a conservative estimate of the value of the coal power artificially turned down by the DRR model that can be sold using non-firm transmission.

Q. If you make this change to the pricing derived from the DRR model what is the result?

A. Exhibit 2 (USM 1.2) shows the resulting change to the DRR annual energy avoided cost runs with the 100% capacity factor operation of the 525 MW QF resource. The result, as shown in Exhibit 3 (USM 1.3), is a levelized avoided energy cost of $49.93/MWH, and a total levelized avoided cost price at an 85% load factor for a 20 year contract of $59.99/MWH.

Q. What explains the difference between this value and the value determined by PacifiCorp of $46.80?

The difference results solely from the assumptions used in PacifiCorp's model that turn down coal plants with no assumed market outlet for power that cost roughly $10/MWH to produce. Those assumptions are simply not reasonable. Also, my number is very close to the 85% capacity factor levelized price derived in PacifiCorp's most recent filing in Wyoming on June 14, 2005 of $59.49/MWH. Similarly, the latest Idaho avoided cost rates for PacifiCorp, effective December 4, 2004, for a 20 year contract is $61.33/MWH for a project that begins in 2006. My calculation falls comfortably within this relevant range of calculations. This shows that the methodologies used in the other states to derive avoided cost pricing are reasonable in comparison to the results of the DRR methodology used by PacifiCorp in Utah, but only if you remedy the artificial modeling constraints.

Q. Your calculations are for a QF facility that operates at a 100% load factor. How can fixed pricing be determined for QF facilities with different operating characteristics?

A. Determining fixed pricing for projects with different operating characteristics is more complicated. The methodology should be fair and reasonable and should produce rational results. I believe that avoided energy costs can reasonably be tied to the energy prices derived from the DRR model. On and off-peak energy prices can be determined from the DRR model. The capacity component can then be added and spread across the on-peak hours. Exhibit 4 (USM 1.4) shows the fixed avoided cost pricing with the on peak and off peak hourly pricing derived in this manner. The fixed on peak and off peak prices should then be shaped using PacifiCorp's hourly shaping factors, as used in existing contracts. In months where there is a capacity payment, the energy pricing should be capped at the heat rate times the gas price for any given hour. As new QF projects come in for pricing, the most recently approved pricing can continue to be used until the quantity of QF resources under contract equals the utility's needs, as reflected in the DRR run that established prices. The model would establish a fixed price for every hour through the contract period. This approach utilizes a somewhat complicated, but transparent, approach, and it does not take eight hours to run the analysis each time someone wants to understand the effect of a change in operating characteristic for a proposed plant.

Q. Can you give an example showing why this method provides more reasonable fixed pricing than the company's method?

A. Let me use a simple example. Assume two identical QF plants, each with capacity of 262.5 MW (half of the assumed 525 MW avoided plant), each dispatchable and operating the same hours as the projected CCCT unit, but with one unit coming on line before the other. Under my approach, the avoided cost pricing for both units will be identical. Energy prices would be limited to the

CCCT heat rate times the gas price (because the DRR resource will run when it is in the money), producing a fixed energy price of $50.30 and a total avoided cost price of $60.36/MWH

Q. Using that same example, what would be the result using PacifiCorp's proposed methodology, as you understand it?

A. For the first plant, the rate would be determined by running the DRR model and would be based on the difference between the values for a 262.5 MW plant running only at the CCCT dispatch hours and an imaginary 262.5 MW plant running 100% of the time. The resulting blended energy rate -- based on both the actual plant and the 100% load factor imaginary plant -- would likely be roughly half way between the $36.73 100% load factor energy rate and the 2009 CCCT determined energy rate of $50.30, or $43.51/MWH. The total fixed price for the first plant, using PacifiCorp's methodology, would be about $54.38/MWH.

For the second 262.5 MW plant, the same model would be run using a 525 MW plant at the 2009 CCCT operating hours rather than any of the 100% load factor imaginary plant. The total fixed price for the second plant would be $60.36/MWH. The second plant would be paid more just because the imaginary 100% load factor plant had been removed from the assumptions in the DRR model. It does not make sense for two plants with exactly the same operating characteristics and size to receive such different treatment under the circumstances of the example. The method I propose, which uses the DRR method only to set a fixed price for a set quantity of power resources, does not discriminate in that manner.

Q. **What other specific terms and conditions for QF contracts need to be considered?**

A. One item that is very important for new QF development is the length of the contract term. A QF developer should have access to a contract term comparable to the term over which the utility would amortize a similar resource. Otherwise, the utility discriminates against QF projects and violates the concept of ratepayer neutrality.

Q. **Why is this important?**

A. New developments such as coal gasification or other clean coal technologies are very capital intensive. As capital becomes a larger share of total costs it becomes even more imperative to have capital recovery structures that mimic what the utility itself would use. If the contact term for such a project is artificially limited, it will create a significant barrier to the development of these important new technologies.

Q. **Why do capital intensive projects need this consideration?**

A. To be economic, these types of projects require the lowest possible capital structure. New clean coal projects such as coal gasification are projected to be able to produce synthetic natural gas for roughly $4.00/Dth under certain financial conditions. Those conditions will not exist if the critical off-take contracts that provide pricing certainty have artificially short contract terms. Maximum contract terms must be equal to the expected system life or it is likely that these projects will be impracticable for all but utilities that enjoy long term amortization allowed by regulated rate making.

Q. **Have you had discussions with PacifiCorp concerning developing a clean coal demonstration project at US Mag?**

A. Yes. I have had discussions for over 4 years in regards to using the US Mag site to develop a coal gasification plant. We have asked for the utility's support in going to the DOE for funding, but have received very little interest. US Mag also made PacifiCorp's support for such a process a condition to the settlement of last fall's electric supply agreement. We believed that we were going to get a letter of support, but to date we have received nothing.

Q. **What has been your perception of PacifiCorp's reluctance to support such an endeavor?**

A. PacifiCorp appears to have reservations concerning the economics and risks for this type of resource. They have stated that they believe it would involve too much risk from a cost recovery perspective. Apparently, since the utility has the ability to pass higher costs on through rate making mechanisms, it has less incentive than industry to try to move to more cost effective technology.

Q. **If the utility is unwilling to purse such a resource, why do you think non-utility developers can make this technology work?**

A. The utility has a very structured capital cost. The economics that will likely be established if the new energy legislation before congress is adopted will provide loan guarantees that may afford coal gasification projects a lower capital cost structure, with up to 80% debt. If a project has a long-term off-take contract in place for gas or power production that has been approved by the Public Service Commission, the very lowest cost of capital can be acquired. (National Gasification Strategy Gasification of Coal & Biomass as a Domestic Gas Supply Option, William G Rosenburg; http://bcsia.ksg.harvard.edu/BCSIA_content/documents/gasification_2005.pdf).

Q. **Are you saying that all entities should automatically have access to 35 year contracts?**

A. Not necessarily. What I am asking is for the elimination of artificial contractual barriers that will preclude the development of critical projects that our society needs. I am asking that QF projects be afforded an opportunity to amortize their project costs over a period similar to what a utility would use. If controls are needed, the QF developer can be required to demonstrate a need for a longer term. I am simply asking the Commission not to foreclose the potential for development of these high capital cost projects out of hand.

Q. **Do you have anything to say concerning the impact of accounting standards on PacifiCorp's financial statements?**

A. Yes. The more I hear about this matter, the more it appears to be a matter that needs to be taken up between rating agencies and utility regulators. It is very hard for me to understand how a QF contract that has been approved by the Public Service Commission can reasonably be thought of as creating a significant risk of non-recovery. The risk of cost overruns on a plant built by a utility seems much higher. The proposed imputation of "virtual debt" may be an interesting theoretical issue, but identifying and allocating costs to specific contracts seems arbitrary and unreasonable. The only documented analysis on this issue that I have seen, a study by the Energy Information Administration in 1994, states "there is no conclusive evidence that power purchases from non-utility generators raised the cost of capital to the utilities that were purchasing the electricity." There is simply no credible evidence at this time to establish the amount of costs that can reasonably be imputed to QF contracts. The proposal to impose virtual debt on a QF project appears to be little more than another artificial barrier to QF development.

Q. Are there other adjustments to the avoided cost rates that should be considered?

A. Yes, there should be location adjustments if a QF or small power producer helps avoid specific transmission costs and line losses or other identifiable and quantifiable costs.

Q. **Can you sum up your proposal?**

A. Yes. Capacity payments should be based on the capital and O&M costs of a deferrable proxy plant. For a plant willing to be dispatched, the heat rate of the Proxy plant times a gas index price should be used for the variable energy pricing option. Generation outside of dispatch hours should receive 93% of the Palo Verde index price. Fixed energy prices can be based on the output of the DRR model, assuming proper adjustments are made to reflect a realistic value of power in hours that the DRR model artificially turns down coal plants. QFs should be permitted to enter into contracts for up to 35 years. No accounting adjustments should be allowed.

Q. Does this conclude your testimony?

A. Yes it does