Stephen F. Mecham (4089)
Callister Nebeker & McCullough
Gateway Tower East Suite 900
10 East South Temple
Salt Lake City, Utah 84133
Telephone: 801 530-7300
Facsimile: 801 364-9127
Email: sfmecham@cnmlaw.com
Attorneys for Desert Power LP

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 AN ORDER APPROVING AVOIDED COST RATES	Docket No. 03-035-14

PREFILED DIRECT TESTIMONY OF ROGER J. SWENSON

Petitioners Desert Power LP and US Magnesium LLC hereby jointly submit the Prefiled Direct Testimony of Roger J. Swenson in this Docket.

DATED this 9th day of April, 2004.

Callister Nebeker & McCullough

/s/______________________________
Stephen F. Mecham
Attorneys for Desert Power LP

HATCH, JAMES & DODGE

/s/____
Gary A. Dodge
Attorneys for US Magnesium LLC

PREFILED DIRECT TESTIMONY

Of

ROGER J. SWENSON

On behalf of Desert Power LP and US Magnesium LLC

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AN ORDER APPROVING AVOIDED COST RATES

Docket No. 03-035-14

April 9, 2004

<u>Background</u>

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 a principal in the firm E-Quant Consulting, LLC. E-Quant Consulting, LLC is a private consulting firm specializing in energy matters.

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.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is sponsored by Desert Power LP ("Desert Power") and US Magnesium LLC ("US Mag").

Q. What is the purpose of your testimony?

A. My testimony will provide the basis for an appropriate methodology for setting prices for Qualifying Facilities ("QFs"). It will also respond to PacifiCorp's proposed methodology and explain why my proposed methodology is superior, both from a ratepayer perspective and from the perspective of a QF developer.

Q. Has the State of Utah taken an official position on QF development?

A. Yes. Utah Code Section 54-12-1 outlines the State's Policy as declared by the Utah Legislature:

> (1) The Legislature declares that in order to promote the more rapid development of new sources of electrical energy, to maintain the economic vitality of the state through the continuing production of goods and the employment of its people, and to promote the efficient utilization and distribution of energy, it is desirable and necessary to encourage independent energy producers to competitively develop sources of electric energy not otherwise available to Utah businesses, residences, and industries served by electrical corporations, and to remove unnecessary barriers to energy transactions involving independent energy producers and electrical corporations.
>
> (2) It is the policy of this state to encourage the development of small power production and cogeneration facilities, to promote a diverse array of economical and permanently sustainable energy resources in an environmentally acceptable manner, and to conserve our finite and expensive energy resources and provide for their most efficient and economic utilization.

It is thus the declared policy of this state to promote the development of independent power sources in order to provide new sources of energy, maintain economic vitality, enhance production of goods, encourage employment and conserve the state's finite resources.

Q. How does the state code attempt to encourage this policy?

Utah Code Section 54-12-2 provides the following means of accomplishing the declared state policy:

> (1) Purchasing utilities shall offer to purchase power from independent energy producers.
>
> (2) The commission shall establish reasonable rates, terms, and conditions for the purchase or sale of electricity or electrical generating capacity, or both, between a purchasing utility and an independent energy producer. In establishing these rates, terms, and conditions, the commission shall … devise an alternative method which considers the purchasing utility's avoided costs. The capacity component of avoided costs shall reflect the purchasing utility's long-term deferral or cancellation of generating units which may result from the purchase of

power from independent energy producers.

(3) Purchasing utilities and independent energy producers may agree to rates, terms, or conditions for the sale of electricity or electrical capacity which differ from the rates, terms, and conditions adopted by the commission under Subsection (2).

(4) The commission may adopt further rules which encourage the development of small power production and cogeneration facilities

Accordingly, Utah utilities are required to purchase QF power and energy at the purchasing utility's full avoided costs, specifically including a capacity component that reflects the possible deferral or cancellation of generating units.

Q. Have other State entities weighed in on this issue?

Yes, for example, the Utah Energy Office has confirmed the State policy to encourage development of co-generation and to overcome barriers to combined heat and power (cogeneration) systems. [See Memorandum from Jeff Burks to Stephen F. Mecham, Chairman, Utah Public Service Commission, dated April 1, 2003, attached as Exhibit USM 1.1 to the Direct Testimony of Roger J. Swenson in Docket 03-035-38]

Q. How does an appropriately constructed avoided cost pricing methodology advance the legislature's intent?

A. If the pricing is structured correctly, ratepayers should remain indifferent; PacifiCorp witnesses Mark Tallman and Dr. Rodger Weaver both recognize that ratepayer indifference should be the standard (Tallman, pg. 2, lines 14-15; Weaver, pg. 8, lines 11-16). Purchases from a qualifying facility should provide neither a cheaper nor a more expensive source of power for the electric utility. A clear pricing signal that represents true deferrable cost and pricing based on actual avoidable costs, as opposed to projections that may or may not prove to be accurate, will both ensure ratepayer indifference and encourage the development of these efficient resources. The state will benefit from more economically viable industrial and commercial entities that contribute to the local economies and tax base, employ people, and produce economical products. The state will thus gain a stronger, more vital economic industrial base. This economic benefit comes at no additional cost to ratepayers, but with an overall net efficiency gain in the use of finite natural resources.

Q. Who is responsible for carrying out the state's policy directives in Utah Code Section 54-12-1?

A. Ultimately, only the Commission has both the directive and the ability to ensure that these state policies are fully put into effect. Also, Utah Code Section 54-4a-1(1)(a) suggests that the Division should be an advocate for these state policies. In addition, the State Energy Office, which has clearly weighed in on the issue and is supportive of encouraging independent power production in the state, plays a role. Finally, the Committee of Consumer Services, which also seems supportive of these state policies, should play a role, although its main interest may be to ensure ratepayer indifference by supporting reasonable and accurate QF pricing methodologies.

Q. Do you believe that past policies and practices of PacifiCorp and Utah agencies have facilitated and encouraged the development of efficient QF

resources as contemplated by the Utah legislature?

A. No. Even though there is clear state policy encouraging the development of these types of efficient resources, my perception is that there is an institutional mind set against QF development. There appears to be a suspicion that QF developers are trying to take advantage of federal and state laws mandating utility purchase in a manner that puts ratepayers at risk.

Q. Is there an unfair advantage for these types of independent generators?

A. No. There is clearly an advantage over other independent generators in that QF projects have a built-in market for their power production. This advantage is hardly unfair, however, and it is prudent, so long as pricing is correctly set. If QF facilities did not have this right, the existing monopolistic market structure would continue to create a very low probability of development of any QF resources. The right of a QF to obtain a long-term contract at prices that make ratepayers indifferent may be -- and in the current environment, clearly is -- the *only* reasonable way for a facility to obtain necessary financing. Creating a pricing structure that reflects what the utility itself would ask for in rate recovery proceedings levels the "playing field" for the QF, while the state gains the societal benefits of less energy usage and a healthier economy in return.

Q. What happens if the pricing methodology does not track what the utility is likely to actually avoid?

A. Then either ratepayers or the development of QFs would be harmed. I believe this is the source of many of the negative perceptions concerning QFs. If avoided cost rates are set based on long-term fuel price projections which are little more than guesses -- however sophisticated the methodology used to produce the guesses -- avoided costs are certain to diverge from actual avoidable costs. Sometimes, the market fuel projections will be higher than will actually occur. In this case, QF pricing will be set too high and there will inevitably be overcharges to ratepayers. Other times, the fuel projections will be low. If avoided cost rates are set based on low, unrealistic long-term fuel cost projections, then developers will not be able to fund projects.

The pricing methodologies that have been used in Utah in the past for QF rates, and the methodology proposed by PacifiCorp in this docket, necessarily involve a guess as to future fuel prices. At times in the past, these guesses have led to high avoided cost payments to QF projects, reinforcing the negative attitude towards QF projects. At other times, the guesses have been unrealistically low, stifling the development of QF projects in this State. Neither outcome is desirable, either for ratepayers or for QF developers. A better approach is needed to further the state policy of encouraging efficient resource development, while simultaneously protecting ratepayer interests. The approach that I am suggesting in this testimony will accomplish both of these essential goals.

Q. Has the Commission made any attempt to facilitate QF development?

A. Yes. Years ago, the Commission approved Schedule 37, which sets rates and terms for the purchase of QF power and energy from small -- less than 1 MW -- QF projects. Unfortunately, small QF projects are almost never economical.

More recently, the Commission approved Schedule 38, which was intended to create a process by which larger QF projects could obtain "indicative pricing" in order to determine economic feasibility, and then proceed to contracting without facing never-ending negotiations with and stonewalling by the utility.

Q. How has the Schedule 38 process worked so far?

A. Unfortunately, not well at all. Even though a procedure was approved over a year ago to permit potential QF developers to provide specific detailed operating information in order to receive indicative pricing, there is still no meaningful basis for determining indicative prices.

The Commission directed PacifiCorp on February 24, 2003, in Docket 02-035-T11, to file a methodology to develop avoided costs within ninety days. No methodology was provided. On September 24, 2003, in Docket 03-035-14, the Commission ordered PacifiCorp to file a revised avoided cost methodology within sixty days. Again, nothing was filed by the utility. A working group was established and met sporadically in 2003 to try to come to some conclusions on approaches to structuring a methodology, but little came of the group's efforts. No consensus was reached as to an appropriate methodology. Finally, in February of 2004, PacifiCorp made a filing with a proposed avoided cost pricing methodology for QFs over 1 MW.

PacifiCorp's proposed methodology continues to perpetuate many of the mistakes of past methodologies. For example, the energy prices are based upon long-term natural gas projections that will inevitably prove to be inaccurate, leading either to excessive payments to QF developers or (more likely) the continued frustration of QF development in Utah. In addition, while a capacity payment is proposed, PacifiCorp's methodology will almost certainly ensure that no new QF projects will be developed because it includes short-term projections that would unreasonably deny a developer recovery of most of its capacity costs during the first few years. Also, PacifiCorp's proposal would convert a significant component of the capital costs into a variable payment, skewing economic dispatch of the QF facility and frustrating financing efforts. PacifiCorp's proposal also incorporates a number of ill-defined, subjective adjustments to QF payments in a manner that would continue to leave QF developers at the mercy of PacifiCorp. If PacifiCorp's proposal is accepted, Utah will continue to see limited or no QF development and statutorily mandated state policies and ratepayers' best interests will continue to be thwarted.

Probably the best indication that the current (and PacifiCorp's proposed continued) process will not meet the objective of encouraging the development of efficient independent generation in this state is the dismal results we have seen so far. Even though PacifiCorp has made an overwhelming demonstration of its urgent need for new power resources in the immediate future, and despite a clear, statutorily-mandated policy to encourage independent generation, new QF development in this State has been virtually non-existent. In an environment where numerous new generation resources are being developed (by the utility), it is incredible, and ludicrous, that there has been no significant QF development. It is one thing when QF development does not occur during periods when the utility has excess capacity. It is inexcusable when efficient cogeneration projects are not occurring in periods when the utility is actively building new resources.

Q. Why do you believe that the recently adopted Schedule 38 process for larger QFs to obtain indicative pricing and a contract has not worked well?

A. Schedule 38 still gives way too much discretion and leverage to the utility. PacifiCorp has no reason to encourage the development of independent power sources in this State, or to pay true avoided costs. Desert Power and US Mag both followed all of the Schedule 38 procedures in a vain effort to obtain meaningful avoided cost pricing and contracts, and have done everything in their power to expedite the process. Yet neither has received a reasonable or defensible pricing proposal or a proposed contract. All of the information specified in Schedule 38 or requested by PacifiCorp was provided many months ago. While we have received some proposed prices, they have never been adequately supported and do not make sense. Although we have asked PacifiCorp many questions about the proposed avoided costs and how they were determined, the questions remain unanswered.

On July 15, 2003, US Magnesium made a request that also encompassed Desert Power's generation to finalize pricing and contract terms and conditions. This request was made pursuant to Schedule 38, section I.B.4., for a proposed contract, and it was accompanied by the updated information required by the tariff. Schedule 38 requires PacifiCorp to provide a draft power purchase agreement within 30 days of receiving all required information, and US Mag, in conjunction with Desert Power, specifically requested that contract negotiations be finalized by August 31, 2003. No contract was tendered and no meaningful negotiations were entered into. No specific or understandable basis for any pricing was offered. We were left with no alternative but to file our own proposed contracts with the Commission for approval. The Schedule 38 process does not work because PacifiCorp has the ability and the incentive to make it not work.

Q. In order to further the State's objective of facilitating QF projects, how should the process work for determining avoided cost rates for larger QF projects?

A. The process should be clear, transparent, timely and replicable, and should produce reasonable results. It should provide a potential developer with timely and accurate economic signals. The process should lead to similar results and pricing, whether the resource is built by the utility or by a QF developer. Ratepayers should be indifferent as to the cost/price because rates should be set at the utility's avoidable costs.

Q. What kind of economic signals would you expect to see from avoided cost calculations at this time?

A. PacifiCorp has announced a need for more than 4,000 MW of new resources over the next decade, with system growth projected primarily on the eastern side, particularly Utah. PacifiCorp also claims significant transmission limitations into the fast growing Wasatch Front "bubble." Given those projections, I would expect to see dramatic avoided cost price signals that would strongly encourage the development of new resources within the "bubble." Indeed, this Commission has found that PacifiCorp is and remains over 1,000 MW deficient during summer peak periods. Remarkably, however, the price signals we have received from PacifiCorp have been inconsistent with all of these factors, and have served to continue stifling the development of QF cogeneration projects. Indeed, PacifiCorp's practices appear to be designed to stifle the development of any resources other than those constructed or owned by PacifiCorp.

We have also seen a pattern of emergency requests for approval of plants to be built or owned by the utility. The Gadsby peakers were certificated on an emergency basis, followed by Currant Creek. These "emergencies" -- apparently based upon the sudden advent of crises -- have clearly underscored the need for development of new resources quickly. Yet QFs have been given quite a different message from the utility, one of indifference and delay. When we have made repeated requests for clear explanations of power pricing and for contracts, we have been systematically ignored and brushed aside into working groups that waste time and precious resources. We have not encountered any responsiveness from the utility and have received no real help from state agencies.

Q. What are your purposes in proposing a new methodology for determining QF prices?

A. We are trying to establish a clear basis for determining the economics for new QF projects that cannot be unreasonably delayed or manipulated by the utility. We are trying to implement a process that will encourage the development of this efficient and important resource. We are trying to promote precisely what the State Legislature has mandated, i.e., healthy and viable Utah businesses and more efficient use of Utah's precious and finite resources. What we want is a chance to push the efficiency of the processes, both economically and environmentally, and push new technologies that will enable US Mag, for example, to become more competitive on a global scale. The companies that I represent are trying to become more efficient in order to survive and -- hopefully for the state -- prosper and continue to employ people well into the future.

Q. You mentioned that the bias against independent power may be based on pricing methodologies that set purchase rates too high by using future pricing estimates. Do you have a better approach?

A. Absolutely. Both QF developers and ratepayers will see better results if avoided costs are set with reference to what I call the "Next Deferrable Plant" ("NDP") approach. The NDP approach is based on specific and verifiable costs associated with building and operating a specific type of plant with specific variable costs. The PacifiCorp methodology is based upon projections of costs and fuel prices for decades into the future. In contrast, the NDP methodology uses actual, verifiable costs as they occur and are incurred. For example, delivered fuel costs and the NDP's heat rate are used to set the variable energy payment. Similarly, actual O&M costs for the NDP, to the extent available, are used in setting QF prices, including both non-fuel variable costs and fixed costs. Capacity payments are based upon avoided investment costs, including any attendant transmission costs, associated with an actual, deferrable resource.

Q. Does this NDP approach follow the specifics laid out in the Utah Code in section 54-12-2?

A. Yes. The code requires that avoided costs must include a capacity component that reflects the potential long-term deferral or cancellation of generating units that may result from the purchase of power from the independent energy producer. When the capacity payment is set based on a specific resource, then the energy payments should reflect the value that the same resource would bring to the utility's purchasing options. A resource with a set capacity payment will have a set variable operating cost based on the operating cost of the NDP proxy unit. This approach takes away the problem of inappropriate pricing caused by guessing at future fuel prices.

Q. What is the most appropriate NDP for QF resources developed at the current time?

A. PacifiCorp's peaking plant at West Valley.

Q. Why is that plant the most appropriate NDP?

A. The lease for the West Valley plant has a termination provision that allows it to be dropped as a resource in 2006; therefore, it is potentially deferrable – as contemplated by the statutory definition in Utah Code Section 54-12-2. Also, we have clear and determinable variable and fixed operation and maintenance factors for that resource that provide actual, verifiable costs from a recent historic period, as well as a specific capacity payment that can be directly derived from the lease payment (or from the capital recovery schedule based on the approved capital structure of the company if the utility decides to buy the generation facility from its subsidiary).

Q. Please explain this NDP approach as applied to pricing in the proposed methodology.

A. Under the proposed NDP methodology, PacifiCorp will pay the QF a fixed capacity payment derived from PacifiCorp's current lease agreement for the West Valley units. PacifiCorp will also pay the QF a monthly payment for fixed operation and maintenance costs derived from PacifiCorp's actual operating costs for the same West Valley units used to set the capacity payments. Finally, PacifiCorp will pay an energy price for deliveries based upon actual fuel costs and the NDP's heat rate, plus a variable operation and maintenance cost.

The avoided cost payments during the first year will be based upon the fixed and variable costs actually incurred by PacifiCorp in connection with the West Valley units over a recent 12-month period for which actual data is available. Actual gas usage and power production for the 12-month period ending December 31, 2003, would be used to calculate the actual heat rate of the West Valley units, and that value would be used for the NDP heat rate. Actual fuel costs as they occur will be applied to the NDP heat rate to calculate the monthly energy payment. PacifiCorp would have the ability to schedule the QF facility as though it were the NDP facility in the utility's resource mix. After the first year, the fixed and variable components (besides fuel) will be adjusted based upon inflation.

Although the unit is scheduled and paid for as though it were the NDP resource, there will be times when the QF facility supplies capacity and energy to the utility even though PacifiCorp did not schedule it. The price for unscheduled deliveries will be based upon the lower of the West Valley-based variable operating costs or firm or non-firm market prices, depending upon PacifiCorp's then-current resource position. Non-firm market prices would be used if PacifiCorp is a net seller in the market, while firm market prices would be used if PacifiCorp is a net buyer in the market. The specific costs, pricing factors and formulae used to calculate the monthly purchase price are detailed in Exhibit 2 (USM/DP Exh. 1.2).

Q. Please explain how the NDP approach is used to determine avoided costs.

A. By identifying the NDP, a specific type of deferrable resource can be used to calculate costs that may potentially be avoided. The NDP resource will have a variable operating cost profile that can be used to directly determine avoided costs, based on fuel consumption and attendant actual fuel costs (including transportation) and variable operating and maintenance costs. The NDP resource will also have a specific capital cost component, based on actual costs derived from contracts, estimated costs from the IRP process, or other relevant sources, as well as fixed operating costs.

Q. How should avoided cost payments be structured?

A. Capacity payments should be based on avoided revenue requirement impacts from the specific NDP resource capital costs, including any attendant transmission capital costs, using the existing approved capital structure and capital costs of the utility and the established tax rate or contract terms. To this should be added the fixed portion of the plant's operations and maintenance ("O&M") costs, including the fixed cost component of any fuel transportation costs.

The energy payment should be based directly on the known fuel consumption of the NDP resource times the "actual" delivered fuel price at the time of delivery, plus a variable O&M factor based on verifiable data. Transmission losses that are avoided should also be included in the calculation of avoided costs. The utility should then dispatch the QF resource in its planning just as though the resource is part of its resource mix with the contractually specified heat rate and variable operating costs (that is, as though it were the NDP). This approach will give the utility a resource with set variable operating costs that will justify the capacity payment to be made.

Q. Is this the way Schedule 37 avoided costs historically were calculated?

A. Not exactly. The historical Schedule 37 method used a future (non-specific) proxy plant and estimates of operational costs and heat rates. Significantly, however, it has always used a then-current best guess at future delivered fuel prices. The fuel price estimate accounts for the greatest component of avoided cost pricing. The NDP approach is thus far superior, and less risky, to the utility and its ratepayers. It is less risky in that pricing will follow the costs the utility can actually avoid, not projected costs that may bear little resemblance to actual avoidable costs.

Moreover, the NDP approach is much more flexible and understandable. Each new plant will naturally track identifiable needs as the NDP changes based on changing load and resource requirements.

The NDP approach also tracks actual energy market circumstances: if power prices are low compared to the variable component of avoided costs rates, the plant will not be dispatched because the plant is dispatched based on actual costs rather than projected costs made at some point increasingly distant in time.

The QF contract will be based on the specific NDP at the time the QF makes a commitment to supply the resource. As future resource requirements change, the NDP used to calculate avoided cost payments for new plants will also change. For a newly proposed QF plant, the NDP will be a plant that is potentially deferrable at the time the new facility is proposed, necessarily reflecting then-current circumstances. This approach avoids price forecasting and the attendant risks of locking in prices for future facilities that may prove to be extraordinarily high, particularly if locked in during periods of peak gas pricing forecasts. Instead, the NDP approach looks to the specific costs of the NDP that may be avoided, just as if the utility had acquired the NDP plant for its resource mix.

Q. What are the most significant differences between your proposed NDP

approach and the approach proposed by PacifiCorp?

A. PacifiCorp's approach is not tied to a specific deferrable resource. It utilizes projections rather than actual costs and operating characteristics of a specific, identifiable plant. The largest component of avoided cost rates is based upon very long-term natural gas price forecasts that historically have been notoriously inaccurate, and will undoubtedly continue to be inaccurate in the future. It also perpetuates the ability of the utility to stonewall a project by its use of subjective, ill-defined adjustments.

Q. Are there other differences between your approach and the approach proposed by PacifiCorp that cause you concern?

A. Yes, there are. For example, PacifiCorp includes the difference between the capital cost of a simple cycle and a combined cycle plant in the variable or energy component of the QF rate. That is an inappropriate treatment of capital costs; all capital costs should be recovered in the capacity portion of the rate.

Q. Why is that?

A. There is no rational economic basis for making this adjustment. If a combined cycle plant is the NDP, then avoided costs should be structured based on actual capital costs that may be avoided. If part of the capital cost is put into the variable cost element, it distorts the pricing signals. It pushes the plant much further down the dispatch queue compared to where it should be by artificially increasing its variable cost above actual costs. It would mean that the plant will not be dispatched appropriately, and the owner will be at a significant risk that the capital cost of the combined cycle installation will not be recovered. This inappropriate and unnecessary adjustment serves no legitimate purpose and simply creates another barrier to the development of independent power. In marked contrast, PacifiCorp includes all of the capital costs that it incurs in developing a combined cycle plant as capital costs, and does not include such costs in the variable cost determination for purposes of economic dispatch.

Q. You propose that QF prices should be based on the NDP's heat rate and dispatched as such. What if a QF elects to operate for more hours than the economics of the resource would suggest?

A. If the QF plant desires to operate beyond the hours that would be economic given the utility's market price or the utility does not have a specific need for the plant to operate for system requirements (the dispatch hours), then the plant should receive a market-based price. That price should be the lower of market prices or variable operating costs for the NDP. The market price should be based on transparent published market prices, shaped hourly as is done in the PacifiCorp IRP. In that manner, PacifiCorp's ratepayers never overpay when PacifiCorp otherwise would not dispatch the plant, and the QF owner has certainty of the economic environment in which it operates.

Q. Would paying market prices to a QF for energy delivered during non-dispatch hours increase costs to ratepayers?

A. No, as long as the price paid to the QF avoids a PacifiCorp market purchase or PacifiCorp is a net seller in the market and receives the offsetting price at the time. Under either such circumstance, the price at which PacifiCorp is avoiding buying or is actually selling additional power is the same as the price being paid to the QF. Ratepayers under those conditions will be kept whole. If the utility is in the position of being a net seller and the utility needs the QF resource as operating reserve, then the QF should receive a non-firm market index price for avoided costs so that the QF can continue to provide its status as operating reserve. Under this approach, actual non-firm index pricing shaped by specific hourly pricing factors should be used and the specific hours that PacifiCorp is a net buyer and seller in the market should be tracked and verified by audit.

Q. What else is of concern in PacifiCorp's proposal?

A. Another very serious concern is PacifiCorp's proposal to use a capacity payment that allows just 25% of the capital cost recovery of a peaking resource until 2007. This sends a very clear message to project developers that they should not build these plants until at least after 2007. It creates a complete barrier to the development of this type of project. A plant that will only receive a return on its capital investment based on 25% of its true value will not be built. It is clearly not what Utah statutes contemplate, particularly when there is a clear and undeniable need for resources before that time. PacifiCorp's testimony in this case stands in marked contrast to its urgent plea for immediate resources in the recent Currant Creek case. Moreover, because US Mag and Desert Power filed their petitions and committed to build resources before the Currant Creek case was filed, the Currant Creek resource cannot properly be used to reduce capacity payments to those entities.

As PacifiCorp is well aware, just because a plant is only needed for three months per year based on load projections does not mean that it is not needed. A peaking plant is often used for only a few months per year, or 5-15% of the hours in a year. Projections made for the Currant Creek Plant before this Commission reflected that it would only operate about 18% of the available hours during the first year. Yet I doubt that PacifiCorp would agree to recover only 18% of its annual investment cost for the first year. If PacifiCorp's proposal is adopted, its recovery of capital costs for the West Valley peaking plant, the Gadsby peaking facilities and the early years of the Currant Creek plant should be similarly reduced. This is yet another example of PacifiCorp treating itself more favorably than another potential developer.

Q. Can you provide an example of how your proposed pricing structure would work?

A. Yes. I have provided an example in Exhibit 1 (USM/DP Exh. 1.1) of pricing calculations based on PacifiCorp's projections for gas and power market prices. I have used the best information available to me concerning West Valley pricing, and I have included my assumptions in Exhibit 2 (USM/DP Exh. 1.2). I want to stress that actual payments to the QF under this NDP methodology will not be set based on these types of projected costs, but rather based on actual costs and what the utility actually sees in the market. If market prices for power are lower, then the QF will be paid less. Similarly, if gas prices are lower than the projections, then the prices paid to the QF will be lower.

Q. How do your projected prices compare to the average prices proposed by PacifiCorp using Rodger Weaver' schedule 37 methodology over the 20-year period 2005-2024?

A. The average projected price for the 20-year period using my NDP method, without adjusting for transmission upgrades, is $55.79/MWH. The average price using schedule 37 over the same period is $50.64. My proposed methodology is superior, both from the perspective of a QF developer and from the perspective of ratepayers because actual pricing received by a QF is directly tied to actual cost, not the validity of either my 20-year projection or Dr. Weaver's. This avoids the debates of which of our hypothetical pricing projections are more accurate, the answer to which is unknown and unknowable. Under the NDP approach, ratepayers are protected from inaccurate projections and QF developers are provided reasonable revenue assurances that should permit the financing of projects.

Q. What are your primary objections to the price adjustments proposed by Bruce Griswold?

A. One of my primary objections to Mr. Griswold's list of adjustments is that there is no clear standard or basis to quantify many of the adjustments. They seem to allow for qualitative answers and thus provide additional uncertainty over what a QF will be paid. Even with the benefit of a formal discovery process in this docket, we have been frustrated in our efforts to understand the basis for these proposed adjustments, or precisely how they should be calculated. For example, US Mag Data Request 2.9a. asked the following question; "What should the monthly capacity factor be for a 100% dispatchable resource?" PacifiCorp's answer was that we did not provide sufficient information for PacifiCorp to answer the request. Any adjustments should be clear and understandable in this process.

Q. Are there better ways to deal with the issues that Mr. Griswold attempts to address?

A. Yes. For example, QF pricing for non-firm resources or variable production resources such as wind developments can easily be accommodated under the NDP approach. The non-firm resource should not receive a capacity payment and, correspondingly, should not be subject to remedies for non-performance or the same security requirements that a firm resource would face. When a non-firm facility would be dispatched based on the NDP plant's variable operating cost, the purchase price should be based on a 100% load factor price calculated with the NDP input variables. For the other (non-dispatch) periods, a non-firm resource should receive market prices like a firm QF. The non-firm resource should also have the right to provide its own operating reserves, if it so chooses. A resource willing to contract for some fractional portion of its operating deliveries on a firm basis should have the right to do so.

Q. How about adjustments for availability?

A. If the QF has a lower availability and does not provide an alternative resource to meet the dispatch needs of the NDP, then the capacity payment should be reduced accordingly on a percentage basis.

Q. How should failure to dispatch be handled?

A. If a QF does not meet the dispatch requirements and does not provide an alternative source of electricity, then the QF should pay the net difference between the NDP variable production cost and the market cost for that period. That cost should be based on the contracted capacity that the utility had dispatched. The total net difference should be subtracted from the monthly payment that the QF receives.

Q. How about unscheduled maintenance?

A. If the QF has an unscheduled outage and does not provide an alternative source of electricity, then the QF should pay the net difference between the NDP variable production cost and the market cost for that period. That cost should be based on the contracted capacity that the utility had dispatched. The total net difference should be subtracted from the monthly payment that the QF receives.

Q. Should there be an adjustment based on rating agency debt imputations?

A. Not without further analysis of the issue and a clear demonstration that there is no other reasonable way to deal with the issue and that it imposed actual costs on the utility. If the specific contractual arrangement used for a QF contract actually forces the utility to incur extra costs that can be demonstrated and calculated, then there should be an appropriate adjustment in order to maintain ratepayer neutrality. However, given the newness and uncertainty of this issue, and particularly given the state's policy to encourage the development of QFs resources, there should be extraordinary efforts to avoid pushing unnecessary or unrealistic costs onto QFs. Only when all other avenues have been pursued and specific identifiable costs can clearly be assigned should any adjustment to revenues be made. The Commission should require the utility to be very flexible in addressing this issue in order to eliminate it as a potential barrier to the development of independent power production in this state. Also, it appears from literature provided by PacifiCorp that the treatment of QF purchase contracts, given the federal purchase mandate and relative confidence in cost recovery, that a lower risk factor should be assumed. All of these issues should to be examined in much more detail before an adjustment to QF prices should be imposed.

Q. What else should be considered in connection with this issue?

A. If debt imputation is used to reduce QF prices, similar imputation issues should be carefully examined and similarly treated with respect to PacifiCorp's parent company and unregulated affiliates. If consolidation with non-regulated entities may impact the potential development of needed resources in this state, then unregulated operations that may rely to any extent upon PacifiCorp's balance sheet for financial support should also be carefully examined and ratepayer indifference should be assured. For example, if leasing large power plant facilities to a subsidiary or delving into gas storage projects could contribute to the imputation issue, PacifiCorp's shareholders, and not QF projects, should bear any such costs.

Q. Can you summarize your position concerning the process for developing avoided cost rates and the pricing terms you have included in this filing?

A. I strongly recommend that the Commission use the Next Deferrable Plant as a proxy for capital costs, fixed cost and variable operating costs for purposes of setting avoided cost rates. That is the only way to give the utility and its ratepayers the equivalent of the specified deferrable resource. The QF should be paid a capacity payment equal to the actual revenue requirement costs that ratepayers may avoid, based on the capital cost of the NDP. Fixed and variable O&M costs should also be based on the NDP. Similarly, energy costs should be based on actual delivered fuel costs, using the NDP's heat rate.

During non-dispatch hours, if PacifiCorp is a net seller in a given hour when the QF is operating, the QF should be paid at non-firm market prices. If PacifiCorp is a net buyer in a non-dispatch hour, the QF should receive the lower of firm market cost or the variable operating cost of the NDP. Under this approach, PacifiCorp and its ratepayers will be protected against erroneous market projections and QFs will receive reasonable and verifiable avoided cost payments. This approach follows the specific intent of the statutes that call out using the purchasing utility's avoided costs.

Q. Why is this approach better than PacifiCorp's historical methods?

A. This alternative removes the element of long-term energy price projections that lead to inaccurate pricing signals. Also, it allows the facility that is hosting the cogeneration project to have a better understanding of economic alternative circumstances under different operating scenarios. For example, an operation can shift from a baseload 3 shift per day/24 hour operation to a 2 shift/16 hour per day operation and be able to understand the economics of making that shift. Such changes can occur without re-pricing the entire contract, as long as the change does not impact dispatch hours. Significantly, this method does not require non-quantifiable adjustments, since the capacity payment is based on performance standards.

Q. Do you believe your proposed QF pricing methodology is in the public interest?

A. Yes, very much so. The NDP approach will encourage and facilitate the use and development of independent power facilities and help alleviate projected capacity shortfalls along the Wasatch Front. QFs will receive prices based on costs actually avoided by comparable utility resources instead of prices that are based on a guess as to future values. QFs will receive the pricing certainty they need in the form of capacity payments that will allow revenue stability sufficient to justify investment and secure financing. Ratepayers will be indifferent from a rate perspective, but will benefit for all of the reasons outlined by the Utah legislature in adopting Utah's strong policy of encouraging independent power projects.

Q. Does this conclude your prefiled direct testimony?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was mailed, postage prepaid, this 9th day of April, 2004, to the following

Edward Hunter
John Eriksson
STOEL RIVES
201 South Main Street, Suite 1100
Salt Lake City, UT 84111

Michael Ginsberg
Patricia Schmid
ASSISTANT ATTORNEY GENERAL
Division of Public Utilities
500 Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84111

Reed Warnick
ASSISTANT ATTORNEY GENERAL
Committee of Consumer Services
160 East 300 South, 5th Floor
Salt Lake City, UT 84111

/s/________________________________

Exhibit 1

Fixed Cost Calculation

	Capital ($/kw-yr)	Other Fixed ($/kw-yr)	Total ($/kw-yr)	($/MWH) 85% LF
2004	$ 78.11	$ 19.69	$ 97.80	$ 13.13
2005	$ 78.11	$ 20.18	$ 98.29	$ 13.20
2006	$ 78.11	$ 20.69	$ 98.80	$ 13.27
2007	$ 78.11	$ 21.20	$ 99.31	$ 13.34
2008	$ 78.11	$ 21.73	$ 99.84	$ 13.41
2009	$ 78.11	$ 22.28	$ 100.39	$ 13.48
2010	$ 78.11	$ 22.83	$ 100.94	$ 13.56
2011	$ 78.11	$ 23.41	$ 101.52	$ 13.63
2012	$ 78.11	$ 23.99	$ 102.10	$ 13.71
2013	$ 78.11	$ 24.59	$ 102.70	$ 13.79
2014	$ 78.11	$ 25.20	$ 103.31	$ 13.88
2015	$ 78.11	$ 25.83	$ 103.94	$ 13.96
2016	$ 78.11	$ 26.48	$ 104.59	$ 14.05
2017	$ 78.11	$ 27.14	$ 105.25	$ 14.14
2018	$ 78.11	$ 27.82	$ 105.93	$ 14.23
2019	$ 78.11	$ 28.52	$ 106.63	$ 14.32
2020	$ 78.11	$ 29.23	$ 107.34	$ 14.42
2021	$ 78.11	$ 29.96	$ 108.07	$ 14.51
2022	$ 78.11	$ 30.71	$ 108.82	$ 14.61
2023	$ 78.11	$ 31.48	$ 109.59	$ 14.72
2024	$ 78.11	$ 32.26	$ 110.37	$ 14.82

2.50% Inflation Factor
Capital cost and starting Fixed O&M from RS Exhibit 2

Exhibit 1

Total Avoided Energy Price

	Gas Price	Fuel $/MWH (10.233*Gas$)	O&M $/MWH	Losses $/MWH	Total $/MWH
2005	$ 4.53	$ 46.36	$ 3.90	$ 1.99	$ 52.24
2006	$ 4.34	$ 44.41	$ 4.00	$ 1.91	$ 50.32
2007	$ 4.36	$ 44.62	$ 4.10	$ 1.92	$ 50.64
2008	$ 4.30	$ 44.00	$ 4.20	$ 1.90	$ 50.11
2009	$ 4.27	$ 43.69	$ 4.30	$ 1.90	$ 49.90
2010	$ 4.09	$ 41.85	$ 4.41	$ 1.83	$ 48.09
2011	$ 4.09	$ 41.85	$ 4.52	$ 1.83	$ 48.21
2012	$ 4.17	$ 42.67	$ 4.64	$ 1.87	$ 49.18
2013	$ 4.26	$ 43.59	$ 4.75	$ 1.91	$ 50.25
2014	$ 4.34	$ 44.41	$ 4.87	$ 1.95	$ 51.23
2015	$ 4.45	$ 45.54	$ 4.99	$ 2.00	$ 52.53
2016	$ 4.58	$ 46.87	$ 5.12	$ 2.05	$ 54.04
2017	$ 4.71	$ 48.20	$ 5.25	$ 2.11	$ 55.55
2018	$ 4.84	$ 49.53	$ 5.38	$ 2.17	$ 57.07
2019	$ 4.97	$ 50.86	$ 5.51	$ 2.23	$ 58.60
2020	$ 5.12	$ 52.39	$ 5.65	$ 2.29	$ 60.33
2021	$ 5.27	$ 53.93	$ 5.79	$ 2.36	$ 62.08
2022	$ 5.43	$ 55.57	$ 5.93	$ 2.43	$ 63.93
2023	$ 5.57	$ 57.00	$ 6.08	$ 2.49	$ 65.57
2024	$ 5.74	$ 58.74	$ 6.23	$ 2.57	$ 67.54
2025	$ 5.91	$ 60.48	$ 6.39	$ 2.64	$ 69.51

Gas Price from RW-3 page 2 of 4 and IRP update for 2004 & 2005

Heat Rate	10.233	Mmbtu/MWH from RS Exhibit 2
Variable O&M	$ 3.90	from RS exhibit 2
Inflation	2.5%	from RS exhibit 2
Losses	3.8%	IRP page 151

Exhibit 1

	Market Prices From IRP Update	On peak	Off peak	Super Peak	Non Firm Shoulder	Non-Firm Off peak
		117%		120%		
2005	$ 39.96	$ 46.75	$ 30.90	$ 56.10	$ 30.40	$ 23.90
2006	$ 40.47	$ 47.35	$ 31.30	$ 56.82	$ 30.88	$ 24.30
2007	$ 39.98	$ 46.78	$ 30.92	$ 56.13	$ 30.42	$ 23.92
2008	$ 40.84	$ 47.78	$ 31.58	$ 57.34	$ 31.23	$ 24.58
2009	$ 41.85	$ 48.96	$ 32.36	$ 58.76	$ 32.17	$ 25.36
2010	$ 42.73	$ 49.99	$ 33.04	$ 59.99	$ 33.00	$ 26.04
2011	$ 43.30	$ 50.66	$ 33.49	$ 60.79	$ 33.53	$ 26.49
2012	$ 43.48	$ 50.87	$ 33.62	$ 61.05	$ 33.70	$ 26.62
2013	$ 44.42	$ 51.97	$ 34.35	$ 62.37	$ 34.58	$ 27.35
2014	$ 45.62	$ 53.38	$ 35.28	$ 64.05	$ 35.70	$ 28.28
2015	$ 47.23	$ 55.26	$ 36.52	$ 66.31	$ 37.21	$ 29.52
2016	$ 48.21	$ 56.41	$ 37.28	$ 67.69	$ 38.12	$ 30.28
2017	$ 51.59	$ 60.36	$ 39.90	$ 72.43	$ 41.29	$ 32.90
2018	$ 53.44	$ 62.52	$ 41.33	$ 75.03	$ 43.02	$ 34.33
2019	$ 55.76	$ 65.24	$ 43.12	$ 78.29	$ 45.19	$ 36.12
2020	$ 57.06	$ 66.76	$ 44.13	$ 80.11	$ 46.41	$ 37.13
2021	$ 57.21	$ 66.94	$ 44.24	$ 80.32	$ 46.55	$ 37.24
2022	$ 58.92	$ 68.94	$ 45.56	$ 82.72	$ 48.15	$ 38.56
2023	$ 60.69	$ 71.01	$ 46.93	$ 85.21	$ 49.81	$ 39.93
2024	$ 62.51	$ 73.14	$ 48.34	$ 87.76	$ 51.51	$ 41.34
2025	$ 64.38	$ 75.32	$ 49.79	$ 90.39	$ 53.26	$ 42.79

2003 average difference on peak to daily is 117%
Assumed difference from on peak to supper peak is 120%
Assumed difference between firm and non-firm price is $7.00/MWH

Exhibit 1

Total Avoided Cost

	Avoided capacity Cost ($/kw-yr)	Dispatch energy ($/MWH)	Shoulder energy (non-firm mkt w/losses) ($/MWH)	Off Peak energy ($/MWH)	Average Energy ($/MWH)	85% LF Avoided Fixed cost ($/MWH)	Total rate @ 85% Load Factor ($/MWH)
2005	$ 97.80	$ 52.24	$ 31.60	$ 24.85	$ 35.90	$ 13.13	$ 49.04
2006	$ 98.29	$ 50.32	$ 32.10	$ 25.26	$ 35.56	$ 13.20	$ 48.76
2007	$ 98.80	$ 50.64	$ 31.62	$ 24.86	$ 35.38	$ 13.27	$ 48.65
2008	$ 99.31	$ 50.11	$ 32.46	$ 25.55	$ 35.71	$ 13.34	$ 49.04
2009	$ 99.84	$ 49.90	$ 33.44	$ 26.37	$ 36.23	$ 13.41	$ 49.63
2010	$ 100.39	$ 48.09	$ 34.30	$ 27.07	$ 36.14	$ 13.48	$ 49.62
2011	$ 100.94	$ 48.21	$ 34.85	$ 27.53	$ 36.51	$ 13.56	$ 50.07
2012	$ 101.52	$ 49.18	$ 35.03	$ 27.68	$ 36.94	$ 13.63	$ 50.57
2013	$ 102.10	$ 50.25	$ 35.94	$ 28.43	$ 37.85	$ 13.71	$ 51.56
2014	$ 102.70	$ 51.23	$ 37.11	$ 29.40	$ 38.87	$ 13.79	$ 52.66
2015	$ 103.31	$ 52.53	$ 38.68	$ 30.69	$ 40.24	$ 13.88	$ 54.12
2016	$ 103.94	$ 54.04	$ 39.63	$ 31.48	$ 41.32	$ 13.96	$ 55.28
2017	$ 104.59	$ 55.55	$ 42.92	$ 34.20	$ 43.80	$ 14.05	$ 57.85
2018	$ 105.25	$ 57.07	$ 44.72	$ 35.68	$ 45.39	$ 14.14	$ 59.52
2019	$ 105.93	$ 58.60	$ 46.98	$ 37.55	$ 47.25	$ 14.23	$ 61.48
2020	$ 106.63	$ 60.33	$ 48.24	$ 38.59	$ 48.59	$ 14.32	$ 62.91
2021	$ 107.34	$ 62.08	$ 48.39	$ 38.71	$ 49.26	$ 14.42	$ 63.67
2022	$ 108.07	$ 63.93	$ 50.05	$ 40.09	$ 50.87	$ 14.51	$ 65.39
2023	$ 108.82	$ 65.57	$ 51.77	$ 41.51	$ 52.46	$ 14.61	$ 67.07
2024	$ 109.59	$ 67.54	$ 53.54	$ 42.97	$ 54.17	$ 14.72	$ 68.89

$ 55.79 average 2005-2024

Analysis assumes all non super peak hours Pacificorp is net seller based on IRP market exposure assumption
Analysis also assumes that plant is dispatched 8 hrs per day 7 days per week
Dispatch hours 365 X 8 = 2920 hrs per yr
Shoulder hours 52 X 6 X 8 = 2496
Offpeak non-dispatch hours = 3344
Loss adjustment = 3.8% based on IRP pg 151

$ 5.15
10.2%

Exhibit 1

	Total Avoided Cost at 85% load factor
2005	$ 44.07
2006	$ 41.89
2007	$ 42.71
2008	$ 45.86
2009	$ 45.97
2010	$ 44.90
2011	$ 45.25
2012	$ 46.23
2013	$ 47.25
2014	$ 48.25
2015	$ 49.44
2016	$ 50.86
2017	$ 52.19
2018	$ 53.61
2019	$ 55.05
2020	$ 56.63
2021	$ 58.21
2022	$ 59.81
2023	$ 61.41
2024	$ 63.12
Average	$ 50.64

Data from RWeaver exhibit (RW-3) page 3 of 4

Exhibit 2

USM/DP Exhibit 1.2
Roger J. Swenson
UPSC Docket 01-035-14

West Valley Based Avoided Cost

Line #				
1	Lease Expense	$	14,983,000.00	
2	(Data request 1.14 answer)			
3	Property Tax Expense	$	2,000,963.00	
4	(Data request 1.14 answer)			
5	Labor	$	927,759.00	
6	(Data request 1.14 answer)			
7	Other Fixed O&M	$	848,006.00	
8	(Data request 1.14 answer)			
9	Total Fixed O&M	$	18,759,728.00	
10	(sum of Line 1-9)			
11	Average monthly max net output		199400	kw
12	(Data request 1.14 answer)			
13				
14	Annualized Lease Expense	$	78.11	/kw-yr
15	(line 1 divided by line11)			
16				
17				
18	Other Fixed Cost	$	19.69	/kw-yr
19	(sum of line 3-7 divided by line 11)			
20				
21	Total Fixed cost per kw-yr	$	97.80	
22	(line 14 plus line 18)			
23	Adjusted for losses			
24				
25				
26	Variable O&M	$	3.90	
27	(Based on IRP update Table C18)			
28				
29	Fuel		10233	Btu/kwh
30	(Based on IRP update Table C18)			
31				
32	Losses (IRP page 151)		3.8%	