Witness CCS – 1

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Petition of Spring Canyon For Approval Of A Contract For The Sale Of Capacity And Energy From Its Proposed QF Facilities	:	**Docket No. 05-035-08**
In the Matter of the Petition of Pioneer Ridge, LLC and Mountain Wind, LLC For Approval Of A Contract For The Sale Of Capacity And Energy From Their Proposed QF Facilities	:	**Docket No. 05-035-09**

DIRECT TESTIMONY OF

PHILIP HAYET

MARCH 18, 2005

TABLE OF CONTENTS

INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Philip Hayet, and I am President of Hayet Power Systems Consulting ("HPSC"), 215 Huntcliff Terrace, Atlanta, GA 30350.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an electric utility industry consultant and I am testifying on behalf of the Utah Committee of Consumer Services ("Committee").

Q. WHAT CONSULTING SERVICES DOES HPSC PROVIDE?

A. HPSC provides consulting services related to electric utility system planning, load forecasting, resource analysis, production cost modeling, and utility industry policy analysis.

Q. PLEASE SUMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in CCS Exhibit No. 1.1 attached to my testimony.

SUMMARY AND RECOMMENDATIONS

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The Commission has asked three questions concerning the Schedule 38 Avoided Cost Stipulation ("Stipulation") it approved on June 28, 2004, which I will respond to on behalf of the Committee.

Q. WHAT ARE THE THREE QUESTIONS THAT THE COMMISSION HAS ASKED?

A. The questions are as follows:

1. Does the Stipulation approved in Docket No. 03-035-14 ("Stipulation") still reflect PacifiCorp's avoided costs such that it remains the applicable interim method for determining avoided costs?

2. If the answer to question (1) is yes, how many megawatts are remaining under the cap contained in Paragraph 10 of the Stipulation?[1]

3. If the answer to question (1) is yes, how should the order of eligibility for the remaining megawatts be determined and what is the order?

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION'S THREE QUESTIONS.

A. Concerning the Commission's three questions, the Committee has these three recommendations:

- Commission Question one - The Committee recommends that the Stipulation avoided cost methodology continue to be used until a permanent method is developed. As such the Committee would like to see a permanent method be developed and implemented as quickly as possible. The Committee has consistently advocated for the use of the Differential Revenue Requirement ("DRR") approach. The Committee believes that the Stipulation avoided cost method has a tendency to overstate avoided costs. Using the most current data assumptions, the updated Stipulation method produces significantly higher avoided cost rates compared to the Stipulation results, while the Company's DRR analysis produced avoided cost rates that were very close to those in the Stipulation. Because the DRR results are so close to the Stipulation results, the Committee finds it reasonable for now to continue to use the Stipulation methodology.
- Commission Question Two - Based on the Committee's review of the existing QF contracts, 100.4 MWs remain under the cap. The Committee rejects the idea that non-firm QF energy should not be counted as far as the cap is concerned.
- Commission Question Three - The Committee has two concerns in responding to this question. Since it believes the Stipulation methodology has a tendency to overstate avoided costs, the Committee prefers to minimize the length of time that Stipulation pricing will be in effect. Second, the Committee believes the QF

[1] In my copy of the Stipulation, Paragraph 9 is the one that discusses the 275 megawatt cap.

that has the least construction risk should be preferred. As such, the Committee recommends that ExxonMobil should be selected as the next QF.

Q. DOES THE COMMITTEE WANT TO PROVIDE ANY OTHER RECOMMENDATIONS TO THE COMMISSION?

A. Yes. The Committee makes the following additional recommendations.

- Spring Canyon has asked the Commission to consider increasing the cap above the 275 MW limit specified in the Stipulation, and asking the Commission to extend the deadline when a QF resource must be online beyond June 2007. The Committee strongly urges the Commission to reject those requests as the interim pricing method was only intended to be a short-term solution until a permanent approach is implemented. Any attempt to increase the cap or extend the length is completely inconsistent with the objectives of the parties that designed the methodology and entered into the Stipulation agreement.
- The Committee is concerned by the fact that it has found numerous data inconsistencies, that became evident as the Committee compared the results of one power cost model to another. Given the importance that the Company places on these models for planning and ratemaking purposes the Committee recommends that the Commission order PacifiCorp to conduct a thorough audit of the models it uses, review data assumptions employed by those models, and ensure that net power cost results produced by the different models are consistent.
- The Committee recommends that the Commission should require the Schedule 38 Task Force ("Task Force") to complete its work in as short an amount of time as possible, in order to implement a long-term avoided cost methodology.

COMMISSION QUESTION ONE

Q. PLEASE DISCUSS THE COMMITTEE'S POSITION REGARDING THE COMMISSION'S FIRST QUESTION?

A. The Commission's first question is as follows:

> Does the Stipulation approved in Docket No. 03-035-14 ("Stipulation") still reflect PacifiCorp's avoided costs such that it remains the applicable interim method for determining avoided costs?

Although I will provide a response to the Commission's first question below, I will first discuss the Committee's concerns about the avoided cost methodology that was developed for the Stipulation, as well as concerns about the reasonableness of the analyses that have been presented by the Company and other parties in support of their views. Based on these concerns the Committee adamantly opposes increasing the cap or extending the deadline for projects to be on line as requested by certain parties.

Q. WHY DOES THE COMMITTEE HAVE CONCERNS ABOUT THE AVOIDED COST METHODOLOGY THAT WAS DEVELOPED IN CONNECTION WITH THE STIPULATION?

A. While the Committee supported the interim Schedule 38 avoided cost methodology, it is important to understand that the interim methodology represented a compromise among all of the parties. The Committee has consistently recommended the use of a Differential Revenue Requirement ("DRR") Method for computing avoided cost rates. The Division of Public Utilities ("Division" or "DPU") also expressed its support for the use of the DRR approach. However, PacifiCorp, UAE, and two QF entities – US Magnesium and Desert Power supported the development of a proxy approach for developing avoided cost rates. While the Committee and the Division believed the DRR method was superior to any proxy approach, both agencies stated that we would be open to consider a proxy approach if one could be developed that produced reasonable avoided cost rates.

At the time that the Stipulation was under consideration in early 2004, there was significant pressure coming from various quarters to implement an avoided cost pricing methodology that could be applied to a few QFs that desired to supply power to PacifiCorp. The Committee supported the avoided cost rates contained in the Stipulation for a number of reasons:

- the interim avoided cost method was temporary and appeared to produce avoided cost rates that were reasonable;
- the Stipulation contained language that anticipated the Task Force would develop a long term avoided cost method by November 20, 2004 and submit it to the Commission for approval;
- the Stipulation contained a provision to limit the amount of capacity that PacifiCorp could purchase from QFs based on the interim avoided cost rates, and
- there was a deadline for when QFs had to be online in order to be eligible to receive the avoided cost payments.

The Task Force has been examining both Proxy and DRR methods and its work is incomplete. However, it appears that momentum is building for the use of a DRR method.

The Committee's major concerns regarding the Stipulation approach stem from the fact that it is a hybrid approach that relies partly on a DRR method and partly on a proxy plant method.[2] The Committee has always

[2] The proxy plant method is based on the capacity and energy costs of a combined cycle combustion turbine ("CCCT") unit.

objected to a proxy approach based on a CCCT resource because PacifiCorp serves its load requirements using a combination of coal, gas, hydro and other resources. Thus, it is unreasonable to assume that in every hour PacifiCorp's avoided costs would reflect only the costs of a CCCT unit.

Q. PLEASE EXPLAIN HOW AVOIDED ENERGY COSTS ARE DETERMINED UNDER THE DRR AND PROXY METHODS.

A. The DRR method relies on results from two production cost model runs: the first run models the base system as it is anticipated to exist in the future; and the second includes a zero-cost QF added to the base system. According to PURPA, QFs should be paid a rate that is no more and no less expensive than the cost the utility would incur if it had to serve load without the QF. The annual difference in production costs between the two production cost runs, divided by the annual amount of megawatthours ("MWhs") supplied by the QF, represents the annual average avoided cost that the QF should be paid.

The proxy method that is used in the Stipulation relied on a DRR approach for the first part of the 20 year study period to determine avoided energy costs, and on the energy costs of a CCCT unit (proxy plant approach) for the remainder of the 20 year study period. The criterion of when to switch to the proxy plant method is when PacifiCorp first becomes completely capacity deficient in all twelve months of the year.

Q. WHEN DID THE STIPULATION SWITCH FROM THE DRR APPROACH TO THE PROXY PLANT APPROACH?

The Stipulation, based on the load and resource balance that existed in early 2004, indicated that the Company would be completely resource deficient in every month of the year beginning in 2007. Based on an updated load forecast, and a new supply and demand balance, PacifiCorp is now only resource deficient for all twelve months beginning in 2011. PacifiCorp filed an analysis with the Commission on February 28, 2005, in which it updated the Stipulation results by including its most current load and resource balance projections, market price forecast, and gas price forecast. The Company used its GRID model to compute production costs for the DRR method up to 2011, and then used the capital costs and energy costs associated with a CCCT unit for the remainder of the 20-year period.

Q. WHAT IS YOUR OBJECTION TO THE USE OF THE STIPULATION METHODOLOGY?

A. As mentioned previously, the Committee has consistently maintained that the DRR method should be used for the entire 20-year period for developing avoided energy costs, not just for the first six years when the Company believes it is in a resource sufficiency period. The Company is obligated to use a production cost model to conduct long-term resource planning as part of its Integrated Resource Planning (“IRP”) process and, therefore, the Company should rely on a similar approach to develop its avoided cost estimates. Of course, the IRP results must be reasonable and some concerns about the credibility of PacifiCorp's IRP results will be discussed later in my testimony.

Q. DOES THE COMMITTEE HAVE CONCERNS ABOUT THE COMPARABILITY OF THE ANALYSES THAT HAVE BEEN PRESENTED BY THE COMPANY AND OTHER PARTIES IN SUPPORT OF THEIR VIEWS REGARDING THE STIPULATION AVOIDED COSTS?

A. Yes, on February 28, 2005 three parties filed testimony that contained analyses supporting their positions regarding avoided cost rates. PacifiCorp performed two analyses; Roger Swenson, on behalf of the wind power developers, performed an analysis; and David Olive, on behalf of Spring Canyon also performed an analysis. Each of these analyses use information supplied by the Company that came from incomplete studies and relied on inconsistent data assumptions.

Q. PLEASE BEGIN WITH MR. SWENSON'S ANALYSIS.

A. Mr. Swenson compared the Stipulation avoided costs to two sets of alternative avoided costs computed for use by the Task Force, in which a 500 MW QF was analyzed. The Task Force attempted to overcome problems with the proxy approach by developing a "resource stacking" method. This method still relied on a production cost modeling run, but ultimately, it was a spreadsheet-based model that attempted to consider the influence of resources other than just gas-fired generation. The production cost model results provided weighting factors based on how much energy would be produced by coal, gas and other resources in PacifiCorp's resource plan. Those weighting factors were subsequently used to develop an avoided cost energy rate. The other results that Mr. Swenson provided in his testimony were from a 500 MW QF DRR analysis that the company conducted using the IRP model. Unfortunately, these two analyses didn't use consistent input data assumptions, which was one of the main goals of the Task Force.

The 20 year levelized payment results that Mr. Swenson provided in his testimony comparing the Stipulation results to both the DRR and the Resource Stacking approach are summarized below:

Based on RJS Supplemental Exhibit 1	**Levelized Payment (1)**
2004 Stipulation 100 MW 85% load factor QF	$51.03
500 MW DRR 85% load factor (PacifiCorp Corrected Model provided to Task Force 2/16/05)	$49.02
500 MW Resource Stack 85% load factor (PacifiCorp Model provided to Task Force 2/9/05)	$58.40

(1) Discount rate used to levelize QF Payments is 7.2%

Q. WHAT DID MR. SWENSON CONCLUDE?

A. Mr. Swenson concluded that the avoided cost rates set forth in the Stipulation are still reasonable.

Q. WHAT DID MR. OLIVE'S ANALYSIS SHOW?

A. Mr. Olive basically provided the same analysis as Mr. Swenson, which is summarized below from his Exhibit DLO 2.

Based on David Olive Exhibit Spring Canyon DLO 2

	Stipulation All-in $/MWh[3]	PacifiCorp 500 MW QF DRR method (Corrected) $/MWh
2006-2025 Levelized Price	$48.86	$49.02

Based on a comparison of the Stipulation avoided cost rates to the DRR results that the Company provided to the Task Force, Mr. Olive concluded that the Stipulation avoided cost rates are within a reasonable range. Mr. Olive also expresses a concern that the Stipulation avoided cost rates may be understated, yet he provides no insight as to how much he believes they may be understated.

Q. WHAT ANALYSES DID PACIFICORP CONDUCT?

A. First, PacifiCorp updated the avoided cost proxy model that was used to derive the Stipulation avoided cost rates. The Company used a more current load and resource balance based on its 2005 IRP, an updated GRID production cost analysis for use during the sufficiency period, updated fuel cost and forward market price estimates, and updated proxy plant assumptions from the 2005 IRP. The load and resource balance is a calculation performed outside of GRID that is used to make a

[3] There is a slight difference between the Stipulation levelized value between what Mr. Olive computed and what Mr. Swenson computed, which I did not see the need to reconcile.

determination of when PacifiCorp would be in a resource deficiency period. This affects the level of capacity payments that are made in the Stipulation method and it determines when the switch occurs from a DRR method to a proxy method. While the load and resource balance was updated to reflect the current 2005 IRP, the GRID database was not changed. Specifically, the resource plan entered in GRID was not changed to reflect the fact the IRP determined that new units would be added during the study period. For consistency the loads and resources used in the 2005 IRP should have also been used in GRID.

PacifiCorp initially filed the results of this analysis with the Commission on February 28, 2005. However, PacifiCorp used a 10 MW QF resource and it was reminded that it should have used a 100 MW resource instead. PacifiCorp subsequently revised its analysis using a 100% available, 100 MW QF, and provided those results to the parties at the technical conference on March 9, 2005.

Q. EARLIER YOU MENTIONED PACIFICORP CONDUCTED TWO ANALYSES THAT WERE FILED ON FEBRUARY 28, 2005. WHAT WAS THE SECOND ANALYSIS?

PacifiCorp used the IRP model to conduct a DRR analysis based on an 85% available, 99 MW QF resource. The objective of this analysis was to determine whether the avoided costs that had been computed with the updated Stipulation model were reasonable when compared to results produced using the DRR approach. In addition to the fact that the updated Stipulation analysis used a 100% available, 100 MW QF, while the DRR analysis used an 85% available, 99 MW QF resource, I found numerous examples of other inconsistencies in PacifiCorp's data assumptions.

Q. BEFORE DISCUSSING THESE DATA INCONSISTENCIES, WHAT DID THE RESULTS SHOW AND WHAT WERE PACIFICORP'S CONCLUSIONS?

A. PacifiCorp's results are summarized in the table below.

Based on PacifiCorp's February 28 and March 9, Analyses

	2004 Stipulation Fixed Energy Pricing Approach All-in $/MWh	PacifiCorp February 28, 2005 100 MW QF DRR All-In $/MWH	PacifiCorp's Updated Stipulation Fixed Energy Pricing Approach (Corrected March 9, 2005) $/MWH	PacifiCorp's Updated Stipulation Variable Energy Pricing Approach (Provided February 28, 2005) $/MWH
2005-2024 Levelized Price	$50.03	$50.33	$59.08	$63.63

At this time PacifiCorp has not provided any testimony describing its conclusions. However, during the March 9, 2005 technical conference, PacifiCorp expressed concern about continuing to use the Stipulation avoided cost rates based on the updated Stipulation results. PacifiCorp was particularly concerned that the updated Stipulation avoided cost rates based on the variable energy pricing approach appear to be much higher than the 2004 Stipulation avoided cost rates. The variable pricing method, updated Stipulation avoided cost rates were computed by multiplying the annual heat rates that are in Appendix A of the Stipulation by the Company's December 2004 gas price forecast, and then adding in the avoided capacity costs that are also in Appendix A of the Stipulation. Those costs were levelized using a 7.2% discount factor, resulting in a $63.63/mWh levelized QF rate, which is 27% higher than the 2004 Stipulation avoided cost rate of $50.03/mWh. I share PacifiCorp's concern about the Stipulation methodology since the updated Stipulation avoided cost rate is significantly higher than the Stipulation rate. I find it unreasonable to assume that PacifiCorp's avoided costs would increase by this amount as a result of updating to current data assumptions, despite the increase in the current natural gas price forecast.

To validate the updated Stipulation results, PacifiCorp performed an additional analysis using the DRR method to ascertain whether the updated Stipulation proxy method results are reasonable. This DRR analysis showed that PacifiCorp's levelized avoided cost should be $50.33/mWh, which is well below the updated Stipulation proxy method result, but virtually identical to the Stipulation proxy method result that was developed last year. This implies that had PacifiCorp used the DRR approach at the time the Stipulation was developed a year ago, it is likely that avoided cost rates would have been lower than those developed using the proxy method.

Q. WHAT MIGHT EXPLAIN THE FACT THAT EVEN WITH MUCH HIGHER GAS PRICES THE DRR RESULTS ARE MUCH LOWER THAN THE UPDATED AVOIDED COST STIPULATION RESULTS?

A. In addition to the change in the gas price forecast, there are many other data assumptions that have changed, which should have been incorporated into both analyses. Based on a comparison of PacifiCorp's DRR and updated Stipulation proxy analysis I found many inconsistencies between the data assumptions used in the two methodologies. If consistent data assumptions were used, I would expect that the DRR approach would result in lower avoided costs compared to the Stipulation proxy approach, even when a higher gas price forecast is analyzed. The Stipulation proxy approach assumes that if gas prices were to rise 30% in a year, then avoided energy costs are assumed to rise by the same amount that year. However, the DRR approach recognizes that there are many hours in the year, particularly lower load hours, when PacifiCorp may not dispatch gas resources and a rise in gas prices would have no effect on the determination of avoided energy costs. In other words, PacifiCorp's avoided costs during those hours would be based on some other lower cost resource than a gas resource.

Q. WHAT OTHER DATA INCONSISTENCIES HAVE YOU IDENTIFIED BETWEEN PACIFICORP'S DRR ANALYSIS AND ITS UPDATED STIPULATION ANALYSIS?[4]

A. The list of inconsistencies include:

1. The DRR model uses an 85% available, 99 MW QF, while the updated Stipulation method uses a 100% available, 100 MW QF.
2. The DRR method determines that no avoided capacity costs should be paid for basically the same QF resource as modeled in the updated Stipulation approach, yet the updated Stipulation method includes annual avoided capacity payments.
3. The DRR method incorporates an expansion plan based on resources that were identified during the 2004 IRP. This includes a 525 MW CCCT unit that comes on-line in fiscal year 2010. During the sufficiency period, the updated Stipulation method includes a GRID production cost analysis that does not include this unit.
4. The DRR method includes new resources that were identified in the 2004 IRP, yet it includes capital cost assumptions based on the 2005 IRP. Some of the overnight cost-of-construction assumptions are as much as $100/kW more in the 2005 IRP compared to the previous IRP.
5. There are many differences in the categories of costs or revenues that are modeled in the GRID-based updated Stipulation method compared to the DRR method. For instance, GRID includes these costs that are not in the DRR method:
   - Wheeling Expenses;
   - Use of Facilities Charges;
   - Sales of Excess Gas;
   - Pipeline Reservation Fees.
6. There are differences in the categories of costs or revenues that are modeled in the DRR method that are not included in the updated Stipulation method. For instance the DRR method includes these costs that are not in the updated Stipulation method:

[4] Note that not all of the inconsistencies identified in this list will lead to differences in avoided costs. For something to affect avoided costs, it must be a variable cost that might be different in the base case versus the change case that includes the QF.

- Thermal Variable O&M expenses;
- Emissions Allowance Costs.

7. The load requirement appears to be different between the two methods. For instance, the updated Stipulation GRID based load requirement in 2006 is 56,716 GWH. In that same year, the DRR load requirement is 61,823 GWH. This disparity in loads could result in differences in avoided costs.

Perhaps the most surprising result that I noticed in my comparison was the magnitude of the difference in system net power costs between the two methods for the same time period. In 2006, the base case run for the updated Stipulation method based on the GRID analysis shows a system net power cost figure of $786.7 million. For essentially the same time period, the DRR method IRP-based net power costs are $570.7 million. This is a dramatic difference in system net power costs. (What's even more perplexing is that the GRID net power cost results are higher by $216 million, yet the GRID model has a lower energy requirement by 5,107 GWH.)

Q. HAVE YOU PREPARED EXHIBITS THAT COMPARE THE NET POWER COST RESULTS PRODUCED BY EACH OF THE METHODS?

A. Yes, I have. Confidential CCS Exhibit 1.2 contains total costs, generation and average costs for the updated Stipulation (GRID-based) method covering the period 2005 through 2011, and Confidential CCS Exhibit 1.3 contains similar results for the period 2006 through 2011 for the DRR (IRP-based) method. The major differences in production cost results appear to be largely related to differences in gas generation and net purchases and sales energy.

Q. HAVING REVIEWED MR. SWENSON'S, MR. OLIVE'S AND THE COMPANY'S TWO ANALYSES, WHAT ARE YOUR CONCLUSIONS?

A. The models that PacifiCorp relies on are used in many important decision-making processes, and it is critical that they be as accurate as possible. PacifiCorp's GRID model is used for rate case studies and the model used for the DRR analysis is the same production cost model that PacifiCorp uses in the IRP to make important resource planning decisions. The Committee strongly recommends that PacifiCorp should be required to conduct a thorough audit of its modeling practices to ensure that when it relies on multiple models for important planning and ratemaking dockets that the models use consistent assumptions and data.

Q. WHAT IS THE COMMITTEE'S RESPONSE TO THE COMMISSION'S FIRST QUESTION?

Because of the data inconsistency problems that we have identified, the Committee was unable to determine whether the Stipulation reflects a reasonable estimate of PacifiCorp's actual avoided costs. However, we are convinced that the DRR approach should be used to develop a projection of PacifiCorp's avoided costs, and had the DRR method been available at the time of the Stipulation, we believe the DRR based avoided cost results would have been lower than what was determined using the Stipulation method. Now that the gas price forecast has increased, PacifiCorp's avoided costs should rise as well, but the question is by how much. Even with the higher gas prices, PacifiCorp's latest DRR results are fairly close to the Stipulation results. Therefore, the Committee recommends that the Commission should continue to rely on the Stipulation pricing, although in the interests of protecting the ratepayer's interests, the Commission should attempt to minimize the use of the Stipulation pricing to the greatest extent possible. Our recommendations regarding the Commission's other two questions provide suggestions as to how this may be accomplished.

COMMISSION QUESTION TWO

Q. PLEASE DISCUSS THE COMMITTEE'S POSITION REGARDING THE COMMISSION'S SECOND QUESTION.

A. The Commission's second question is as follows:

> If the answer to question (1) is yes, how many megawatts are remaining under the cap contained in Paragraph 10 of the Stipulation?

To date, four QF contracts have been approved by the Commission to receive payments based on the Schedule 38 Interim Tariff. Those QFs and the amount of megawatts associated with each of the contracts (with the information taken directly from the contracts) are:

- Desert Power – 95 MW;
- Kennecott – 31.6 MW;
- Tesoro – 12 MW;
- U.S. Magnesium – 36 MW

The sum of all of the capacity associated with these QF contracts is 174.6 MW, which means 100.4 MW remains for other QFs under the cap.

Q. DO YOU AGREE WITH SPRING CANYON'S CONTENTION THAT THE CAP DOES NOT APPLY TO QFS THAT PROVIDE NON-FIRM CAPACITY?

A. No. Paragraph 9 of the Stipulation discusses the cap and states, "The parties agree that the Appendix A Prices should be available to any QF contract approved during the Interim Period so long as power from the QF project will be available to PacifiCorp by no later than June 1, 2007, up to a cumulative cap of 275 MWs for all QF projects approved during the Interim Period combined." This paragraph was clearly intended to include all QF contracts, not just firm QF contracts. I also recall that when we discussed the cap during settlement talks parties identified the potential QFs (and the attendant MWs) that might be interested in the interim avoided costs and the cap was set at 275 MW. In those conversations, I specifically recall that Tesoro and Kennecott, which are non-firm QFs, were included in the count that led to the 275 MW cap. Therefore, the Committee firmly rejects the notion that the cap should only be applied to firm QFs.

COMMISSION QUESTION THREE

Q. PLEASE DISCUSS THE COMMITTEE'S POSITION REGARDING THE COMMISSION'S THIRD QUESTION.

A. The Commission's third question is as follows:

> If the answer to question (1) is yes, how should the order of eligibility for the remaining megawatts be determined and what is the order?

The Committee is not aware of the existence of any specific rules associated with the Stipulation that establishes the order in which QFs are to be accepted when more QFs have applied than the cap will allow. Certain parties suggest a logical approach would be to set the order based on the date that the QF files with the Commission for approval of a QF contract. However, the Committee does not believe it is in the public interest to strictly decide which QF to take based solely on the order in which QFs file. Instead, the Committee believes that the public interest would be better served if the Commission were to apply a second test. That is, the Commission should make a selection among multiple candidates by selecting the one that presents the least risk of meeting its obligations of coming online by a certain deadline to supply power to serve PacifiCorp's load. Based on this selection criterion, ExxonMobil should be considered to become the next QF resource selected. ExxonMobil is already online and operating in Wyoming, and it would like to operate as a 75 MW QF resource in Utah beginning in 2006 based on transmission rights that it says it can acquire to deliver power to the Mona substation in Utah. Assuming no transmission upgrades would be required to deliver its power into Utah, the Committee recommends that ExxonMobil should be the next QF resource that should be selected.

Q. WHY DOES THE COMMITTEE BELIEVE THAT EXXONMOBIL WOULD BE A LESS RISKY ALTERNATIVE COMPARED TO SPRING CANYON, PIONEER RIDGE, OR MOUNTAIN WIND?

A. ExxonMobil is already online and operating and Spring Canyon and the two wind projects have many hurdles to overcome to be built and to come online by June 2007. Each year numerous potential QF and merchant projects are dropped because of the cost and complexity associated with financing and completing the projects. Spring Canyon, Pioneer Ridge and Mountain Wind all have significant development hurdles to overcome in order to construct their projects. Spring Canyon, for example, not only requires the construction of its own generating plant, but it also requires the construction of a third party “steam host” industrial facility that does not exist today, in order for it to become a QF. Even if Spring Canyon has the ability to construct its generating plant, if the industrial facility owner at some point decides not to go forward, then Spring Canyon would most likely have to cancel or delay its project. Even if a project isn’t cancelled, but delayed, that would present another dilemma for the Commission, because the Stipulation established June 2007 as the absolute deadline when the QF must be online. The delay of a project beyond June 2007 would imply that the deadline requirement wasn’t really a firm requirement at all, but instead more of a guideline. The Committee recommends that if a selected QF is in fact delayed beyond the June 2007 deadline, then it should be subjected to severe penalties that are built into the contract.

Q. DOES THIS CONCLUDE YOUR PREFILED TESTIMONY?

A. Yes, it does.