Witness CCS – 6
Witness DPU-10

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Rate Schedules and Electric Service Regulations	:	**Docket No. 01-035-01**
	:	**PREFILED DIRECT TESTIMONY OF PHILIP HAYET FOR THE COMMITTEE OF CONSUMER SERVICES AND DIVISION OF PUBLIC UTILITIES**

June 4, 2001

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Philip M. Hayet, 215 Huntcliff Terrace, Atlanta, GA, 30350.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a utility rate and planning consultant and I am the owner of the firm Hayet Power Systems Consulting, which provides utility rate, planning, and economic consulting services. I am appearing in this proceeding as a witness for the Committee of Consumer Services ("Committee") and the Division of Public Utilities ("Division").

Q. PLEASE DESCRIBE BRIEFLY THE NATURE OF THE CONSULTING SERVICES PROVIDED BY HAYET POWER SYSTEMS CONSULTING.

A. Hayet Power Systems Consulting provides consulting services in the electric utility industry. The firm provides expertise in system planning, load forecasting, resource analysis and utility industry policy issues.

Q. PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. Exhibit PMH/1 describes my educational background and work experience within the utility industry. Briefly, I received my Bachelor's degree from Purdue University and my Master's degree from the Georgia Institute of Technology, both in Electrical Engineering. I have more than twenty years of experience in the electric utility industry in the areas of generation resource planning, economic analysis, and rate analysis.

Following the completion of my graduate work, I was hired by Energy Management Associates ("EMA"), an Atlanta based utility consulting firm.[1] During my employment with EMA I worked with numerous software packages including probabilistic production cost and reliability analysis, rate and financial analysis, and

[1] EMA has since been sold and is now known as NewEnergy Associates. For purposes of my testimony, I

maintenance optimization tools. During the period of 1980 – 1988, I worked on numerous consulting assignments that involved Multi-Area/Multi-Company systems similar in many respects to PacifiCorp's System, using EMA's PROMOD IV software system. Some of these assignments included studies for the New York Power Pool and the Pennsylvania/New Jersey/Maryland Interconnection ("PJM"). PROMOD IV is a detailed probabilistic production costing tool that is widely used throughout the United States as well as internationally.

In 1991, I moved to the PROSCREEN II department as a Lead Consultant with the responsibility to provide support for EMA's PROSCREEN II clients[2]. PROSCREEN is an integrated resource planning tool with much less modeling detail than PROMOD's, used for studies that cover a much longer time horizon. My role was to provide expertise in the production costing area, particularly to assist clients in the development of Integrated Resource Plans. Between 1994 and 1996 I led a team of people responsible for providing client support and consulting services to approximately half the PROSCREEN client base. Some of the consulting projects we conducted included benchmark analyses, resource planning studies, avoided cost studies, demand side management analyses, system benefit studies, and multi-area production cost studies.

In 1996 I left EMA, and began my own consulting firm, Hayet Power Systems Consulting. I have conducted numerous consulting studies in the areas of competitive electricity market price forecasting, generation resource analysis, rate case support, new generation technology analysis, and ISO market development analysis. My clients have included global power plant developers, multinational oil and gas exploration and power development companies, State Energy Offices, Staffs of Public Utility Commissions, Consumer Advocate Offices, law firms, and international consulting firms.

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will continue to refer to it as EMA.

[2] Recently this model was renamed Strategist, however, for purposes of my testimony, I will continue to refer to it as PROSCREEN.

Q. HAVE YOU PARTICIPATED IN ANY REGULATORY PROCEEDINGS THAT INVOLVED PACIFICORP?

A. Yes, I testified in PacifiCorp's (Company) Docket No. 97-035-01. In that case I testified in support of the Net Power Cost Stipulation ("1997 Stipulation") on behalf of the Division and the Committee. I also assisted Mr. Randy Falkenberg, who testified in PacifiCorp's most recent Utah rate proceeding (Docket No. 99-035-10), in which Mr. Falkenberg addressed net power cost issues. Mr. Falkenberg will also be a witness for the Division and the Committee in this case.

Q. HAVE YOU APPEARED AS AN EXPERT IN OTHER PROCEEDINGS?

A. I recently testified on behalf of the Louisiana Public Service Commission ("LPSC") in front of FERC (Dockets EL00-66-000, ER00-2854-000, EL95-33-002) in a case in which Entergy filed to modify its System Agreement between its member companies in each of the states that Entergy serves, as a result of the introduction of retail competition in some of the states.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. In this proceeding PacifiCorp utilizes a new method for deriving net power costs. Net power costs are the variable production costs that result after subtracting power sales revenue from fuel costs plus purchased power expense. For many years prior to this, PacifiCorp relied on its in-house developed PD/Mac model to determine estimates of net power costs. The purpose of my testimony is to explain the evaluation that I conducted of the new spreadsheet model that PacifiCorp used in this proceeding. My goal was twofold; first, to determine if the spreadsheet model was a reasonable tool for PacifiCorp to use in evaluating its net power costs in this case; and second, to identify improvements that I would recommend PacifiCorp make to its method of deriving net power costs in the future. My testimony also addresses two additional adjustments to net power cost modeling that need to be included in this case, which result from a significant deficiency in PacifiCorp's spreadsheet model and from an error related to the use of wrong load data in the spreadsheet model.

Q. WHY DID PACIFICORP REVISE ITS METHOD OF CALCULATING NET POWER COSTS IN THIS PROCEEDING?

A. In its Order issued on May 24, 2000, based on the last PacifiCorp Utah rate case (Docket 99-035-10), the Public Service Commission ("Commission") required PacifiCorp to significantly alter the format of its net power cost model, and therefore, ordered PacifiCorp to provide a Microsoft Excel version prior to its next rate case. The Order also required an evaluation of alternative ways to normalize net power costs. To this, PacifiCorp responded by filing a request on June 13, 2000 asking for reconsideration of the Commission's Order requiring changes to PacifiCorp's method of deriving net power costs. The Commission agreed with PacifiCorp and stated,

> *"…the Company makes a reasonable point in that filing a new format for a model that may be replaced puts the cart before the horse."*
> (Commission Rehearing Order Docket No. 99-035-10, Issued October 6, 2000, page 4, paragraph 3)

The Commission decided that the alteration of model format should await the conclusions of the net power cost evaluation. However, the Commission stated,

> *"Should PacifiCorp file a rate case before this is complete, a reformatted production dispatch model (PD/MAC), or an alternative to that model, must be in its Application."*
> (Commission Rehearing Order Docket No. 99-035-10, Issued October 6, 2000, page 4, paragraph 3)

PacifiCorp has not completed its evaluation of alternative ways to normalize net power costs as required by the Commission, and therefore, for this rate case it had to derive net power costs using a reformatted production dispatch model. As a result, PacifiCorp built an Excel based spreadsheet model to calculate net power costs.

Q. PLEASE SUMMARIZE THE CONCLUSIONS AND RECOMMENDATIONS OF YOUR TESTIMONY REGARDING ADJUSTMENTS TO PACIFICORP'S NORMALIZED NET POWER COSTS THAT YOU SUPPORT.

A. My conclusions and recommendations regarding adjustments to PacifiCorp's net power cost filing are as follows:

1. An adjustment was made to correct an error that PacifiCorp introduced in using the wrong Utah load requirement in its modeling methodology. This error was identified by the Air Force and its consultant who are parties in this proceeding. Compared to PacifiCorp's normalized net power costs, this adjustment alone results in a reduction of $20.4 million on a total Company basis.

2. The reality of PacifiCorp's operation as an integrated system comprised of both a Pacific~~Western~~ and a~~n~~ Utah Division~~ Eastern division~~ was ignored in the spreadsheet model. Instead PacifiCorp treated the two divisions as being completely independent. I modified the spreadsheet model to correct this deficiency. This adjustment reduces net power costs by an additional $32.5 million on a total Company basis as compared to the Company's filed level of net power costs.

   In modeling net power costs, the magnitude of an adjustment depends on the order in which adjustments are applied, and what other adjustments have already been made. These two corrections were made after including all of Mr. Falkenberg's adjustments. Consequently, the magnitude of these corrections was smaller. When included in the results of Mr. Falkenberg's final case, the impact of adding my two adjustments reduced net power costs by $~~9.1~~8.9 million on a total Company basis.

Q. BASED ON YOUR REVIEW OF PACIFICORP'S NEW SPREADSHEET MODEL, WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A. They are as follows:

1. PacifiCorp has met the requirements set forth by the Commission for it to file net power costs using a reformatted production dispatch model in this rate case, and since the spreadsheet model was created in Excel it is very easy to use and understand.

2. If PacifiCorp continues to use its spreadsheet model, there are some additional modeling features, that at a minimum, should be incorporated into whatever model PacifiCorp uses. These features include dynamic treatment of forced outages, the ability to dispatch generating units at levels between the minimum and maximum capacity, the ability to model heat rates at different capacity levels, and time period modeling.

3. Despite the fact that PacifiCorp has already built a new model, it should still be required to complete a thorough evaluation of alternative ways to normalize net power costs prior to the start of any future rate case. While I am not opposed to the use of the spreadsheet model for this case, I find it to be highly structured towards the conditions at hand, and it needs to be evaluated for robustness across all potential system conditions. The results of such an evaluation should determine if the spreadsheet model should be continued, if PD/Mac should be resurrected, if some other model should be built or if a new model should be purchased from a commercial software vendor.

Q. HOW WILL THE REMAINDER OF YOUR TESTIMONY BE ORGANIZED?

A. First I will discuss two adjustments to PacifiCorp's modeling that I support in my testimony. The first adjustment corrects an error in PacifiCorp's spreadsheet model related to the input of the Utah Load Requirement. I also corrected a deficiency in PacifiCorp's model that does not allow PacifiCorp to be represented as an integrated utility with transmission capability between the two d~~D~~ivisions.

Next I will discuss other modeling issues that I believe should be addressed in this model or in any other model which PacifiCorp proposes to use for deriving net power costs in the future. This discussion leads to my ultimate recommendation that PacifiCorp be required to complete a thorough evaluation of ways to normalize net power costs, as the Commission had required in its Order on Reconsideration of Docket 99-035-10, issued October 6, 2000.

CORRECTION TO UTAH LOAD REQUIREMENTS MODELING

Q. WHAT MISTAKE DID PACIFICORP MAKE RELATED TO INPUTTING LOAD DATA INTO ITS SPREADSHEET MODEL?

A. In effect, PacifiCorp made a very simple mistake which had a very large impact. There are two worksheets in the PacifiCorp model that require the input of load data. On one of the worksheets PacifiCorp correctly input the total system load requirement for each month of the test-year period, but on the other, PacifiCorp made a mistake in specifying the Utah load requirements. The test-year period is October 1999 through

September 2000. On one of the worksheets ~~the correct PacifiCorp system load requirements were input for this test-year period. However, on another worksheet~~ PacifiCorp incorrectly used only 1999 data when it input the Utah load requirement. The net result was that ~~that~~ on that worksheet, PacifiCorp incorrectly input an energy requirement of 23,716 GWH for the test-year period in its modeling, while it should have input 24,852 GWH.

Q. WHAT WAS THE IMPACT OF THIS MISTAKE?

A. Intuitively, it would seem that after correcting this mistake and modeling a higher load requirement in the Utah Division, the net power costs would increase. However, just the opposite occurred.~~,~~ A~~A~~fter correcting this problem, net power costs decreased by $20.4 million on a total Company basis compared to PacifiCorp's normalized net power cost case. The savings resulted strictly from the cost and revenue associated with purchases and sales from/to the secondary market.

Q. PLEASE EXPLAIN WHAT THE SECONDARY MARKET IS.

A. The secondary market is used for purposes of making spot-market purchases and sales. These purchases and sales are considered non-firm obligations that are made for the purpose of balancing PacifiCorp's system and they are dynamically determined by the model. These transactions are different than "Short Term Firm" ("STF") purchases and sales that PacifiCorp also models. Although STF purchases and sales also cover a short duration, they are still contracted for in advance and require a firm commitment on the part of the buyer and seller. As opposed to secondary purchases and sales, which are calculated by the model in a dynamic way, STF purchases and sales are input in the model with a specific amount of energy and cost. The magnitude of secondary purchases and sales is considerably smaller than STF transactions. For example in its normalized net power cost case, STF purchases totaled 15,610 GWH while secondary purchases totaled 2,404 GWH.

PacifiCorp estimates secondary purchases and sales in its model by dispatching all of its resources to meet its load requirements. If it is economic to do so, the model will run PacifiCorp's generating units to their maximum capacity levels in order to sell surplus energy to the secondary market. Likewise, the model will back down generation on units to their minimum capacity levels, if it is economic to purchase from the secondary market. Sales to the secondary market are determined if the sum of all resources exceed all load requirements. Purchases from the secondary market are made if sales are less than load requirements. A shortage is said to exist, or a company is short, if purchases from the secondary market have to be made. A surplus is said to exist, or a company is long, if it is able to make sales to the secondary market. The error in the Utah load requirement affected both the amount of purchases and sales in the Utah Division as well as the amount of purchases and sales in the Pacific Division.

Q. PLEASE EXPLAIN FURTHER HOW THE ERROR IN UTAH'S LOAD REQUIREMENT COULD IMPACT SECONDARY PURCHASES AND SALES IN BOTH DIVISIONS.

A. Essentially, net power costs decline as a result of increasing Utah load requirements because the calculation of the deficiency or surplus in one division is tied to the calculation of surplus or deficiency in the other division. A simple analogy might help to understand the way the model works. Suppose someone owns two rolls of pennies, and that person desires to know how many there are in each roll and how many pennies there are in total. The counting of the pennies can be performed in a couple of ways. One way is to count each of the rolls separately and then add the two numbers together to get the total number of pennies. Another way would be to count the pennies in one roll separately, and then put the pennies in the two rolls together in one pile and count them together. Since the amount of pennies in one roll is known and the total number of pennies is known, then the number of pennies in the second roll can be determined by subtraction. For example, suppose an independent count is performed and it is determined that there are 50 pennies in the first roll and 26 in the second. The sum of the pennies is 76. Next, let's assume the counting was done the other way. In other words, the first roll is counted and found to have 50 pennies. Then both rolls are counted together and found to have 76 pennies. Then by subtraction it is known that the second roll has 26 pennies. This is similar to the way in which secondary purchases and sales are computed in the model for the Pacific~~Western~~ and Utah~~Eastern~~ Divisions.

Q. PLEASE EXPLAIN THE WAY PACIFICORP'S SPREADSHEET MODEL DETERMINES SECONDARY PURCHASES AND SALES.

A. The model calculates the surplus or deficiency in the Pacific D~~d~~ivision much the same way as the pennies are counted in the second example. First, it determines the Utah D~~d~~ivision surplus/deficiency by summing up all of the loads in the Utah D~~d~~ivision plus wholesale sales (long-term firm plus short-term firm) in that division. It then subtracts all thermal generation, hydro and wholesale purchases (long-term firm and short- term firm) made in that division. If more generation exists than load, then a surplus occurs and the Utah D~~d~~ivision makes secondary sales to the wholesale market in the surrounding area. If the resources are insufficient to meet the load requirement in the Utah D~~d~~ivision, then secondary purchases are made from the wholesale market surrounding the Utah D~~d~~ivision.

Next, PacifiCorp determines the surplus/deficiency that exists in the Pacific D~~d~~ivision. PacifiCorp could have done this in exactly the same way as it computed the surplus/deficiency in the Utah region. That is, it could have computed the surplus/deficiency strictly based on the loads and resources in the Pacific D~~d~~ivision. Instead the spreadsheet model determines the entire PacifiCorp system surplus/deficiency, and then subtracts the Utah D~~d~~ivision surplus/deficiency to derive the Pacific D~~d~~ivision's surplus/deficiency. ~~When the Pacific division surplus/deficiency was calculated by subtracting the Utah division surplus/deficiency from the PacifiCorp system surplus/deficiency, s~~Since an error had been introduced in the calculation of the Utah D~~d~~ivision surplus deficiency, then the Pacific D~~d~~ivision surplus/deficiency was also calculated incorrectly.~~ However, in this case, the correct load requirement was used to compute the total system load.~~

Consider a simple example. After assessing the loads and resources in the Utah D~~d~~ivision, suppose the deficiency in that division was 744 GWH in a month. Similarly after assessing the entire system load and system resources, the deficiency on a total PacifiCorp system-wide basis was determined to be 1,744 GWH, then the Pacific D~~d~~ivision was determined to be deficient by 1,000 GWH (1,744 – 744). Knowing this, the model would then go to the Utah secondary market and purchase 744 GWH of secondary wholesale energy, and it would go to the Pacific market and purchase 1,000 GWH of energy.[3]

Now assume that it had been discovered that the Utah load requirement was incorrect and too low by 100 GWH and therefore the Utah deficiency based on the loads and resources in the Utah D~~d~~ivision should have been 844 GWH~~MW~~. Furthermore, assume that the correct loads and resources were used in computing the total system deficiency, which was still 1,744 GWH. Then the calculation of the Pacific D~~d~~ivision deficiency was incorrect. Instead of being 1,000 GWH, the correct Pacific D~~d~~ivision deficiency was 900 GWH. Again, the reason that there is a reduction in net power costs when Utah's load requirement increases has to do with the way the model calculates surpluses and deficiencies in both divisions. Since the Utah D~~d~~ivision load requirement was wrong, then both division's deficiencies were computed wrong. By correcting the load requirement input in the Utah D~~d~~ivision, the surplus/deficiency calculation in both divisions was then corrected.

Q. WHAT WAS THE RESULTING IMPACT ON NET POWER COSTS?

A. The impact on net power costs was strictly related to the calculation of secondary market purchases and sales. Exhibit PMH/2 shows the changes to PacifiCorp's normalized net power cost case. Since the Utah Division's load requirement increases by about 1,160 GWH, then Utah sales to the wholesale market are

[3] One additional problem with this, which will be elaborated on below, is that no consideration is given to the possibility of purchasing power from the other division's market. The Utah D~~d~~ivision's market is only used to serve the Utah deficiency and the Pacific D~~d~~ivision's market is only used to serve the Pacific deficiency.

eliminated completely and purchases from the wholesale market increase. Since the overall system deficiency was correct, and does not change (2,068 GWH), then the amount of sales in the Pacific Division actually increase, while the amount of its purchases decrease. The overall effect is that the Pacific Division sells more and purchases less secondary power over the ~~historical~~ test period, while the Utah Division does just the opposite. ~~-~~Since there is a difference in the market prices between the Pacific~~Eastern~~ and Utah~~Western~~ secondary markets, it is better to purchase from the Utah market and sell into the Pacific market. The overall net cost on a $/MWH basis declines from $115.5/MWH to $105.7/MWH when the data is corrected resulting in a savings of $20.4 million on a total company basis.

POWER FLOW BETWEEN DIVISIONS

Q. PLEASE EXPLAIN THE PROBLEM WITH POWER FLOWS BETWEEN THE PACIFIC~~WESTERN~~ AND UTAH~~EASTERN~~ DIVISIONS OF THE PACIFICORP SYSTEM.

A. This was touched on in the problem just discussed. In reality, PacifiCorp operates its system on an interconnected basis whereby loads can be served by generation located in either division, subject to certain operating constraints such as voltage considerations, transmission limitations, etc. In fact, part of the justification of any merger between companies such as Utah Power and Light and Pacific Power and Light are the cost savings resulting from integrated operations. Previously, using PD/Mac, PacifiCorp allowed for the transfer of power between the divisions, limited by transmission constraints. For some reason, which has not been clearly explained, PacifiCorp has ignored the transfer capability that exists between the divisions.

Q. WERE THE ASSUMPTIONS EXPLAINED CONCERNING THE DEVELOPMENT OF THE MODEL?

A. PacifiCorp witness, Mr. Widmer, provides virtually no discussion at all concerning the development of the spreadsheet model in his testimony. The only comments that Mr. Widmer makes concerning the development of the model is that the Commission ordered PacifiCorp to use a model other than PD/Mac in its last rate case (Docket 99-035-10), and he states, "The Company calculated net power costs on a normalized and adjusted basis using a spreadsheet model, as an alternative to PD/Mac." (Mark Widmer Direct Testimony, Page 5, line 17). The remainder of Mr. Widmer's testimony includes discussions of data inputs and output results which would apply to any model that PacifiCorp had chosen to use. However, no further explanation was provided as to the development of the spreadsheet model or how it compares to PD/Mac.

Q. WHY DO YOU CONSIDER THIS LACK OF EXPLANATION OF THE NEW SPREADSHEET MODEL TO BE IMPORTANT?

A. At the same time that PacifiCorp filed with the Commission for a rate increase, which it claimed to be necessitated by the extraordinary increase in net power costs, PacifiCorp also changed to a new methodology for computing net power costs. While I am not trying to imply that PacifiCorp should not have developed a new model (particularly in light of the Commission's recent Order), I believe that the Company should have provided a more thorough explanation of the development, configuration and attributes of the new model.

The Company is requesting a very sizable rate increase in this case, based on its input assumptions and modeling with its new spreadsheet model. In Utah, rates are set based on normalized net power costs for a historical test year calculated using a model to simulate the operation of the PacifiCorp system. Both Company witnesses, Messrs. Wright and Widmer, explain in their testimonies that the primary cause of the increase in net power costs was due to the skyrocketing price of power in the wholesale markets. Therefore, our goal was to determine whether the normalized net power cost results that PacifiCorp filed accurately reflected the increase in wholesale market prices, or whether the new model itself or the data input assumptions led to an overstatement of net power costs.

Given our task of examining the model and the data assumptions, we found the lack of documentation of the model to be a minor impediment to our analysis. We were able to understand the operation of the model and we determined that there are deficiencies in the model that lead to an overstatement of net power costs. I will discuss these modeling deficiencies at a later point in my testimony.

Q. WILL YOU BE ADDRESSING ANY CONCERNS ABOUT THE INPUT DATA?

A. No. Mr. Falkenberg will discuss problems with the data assumptions in his testimony.

Q. WAS ANY DOCUMENTATION REGARDING THE SPREADSHEET MODEL AVAILABLE OUTSIDE OF MR. WIDMER'S TESTIMONY?

A. In response to CCS Data Request 1.1, the Company explained that due to the short amount of time that it had to develop the spreadsheet model in order to include results in its filing, it simply did not have time to create any extensive documentation. Nevertheless, the Company did provide some very brief explanations of the spreadsheet model within its responses to data requests, and it also provided a two-page discussion outline, which briefly summarized features of the spreadsheet model.

Q. WAS ANY EXPLANATION PROVIDED FOR THE LACK OF POWER FLOW TRANSFER CAPABILITY MODELING BETWEEN DIVISIONS IN THAT DOCUMENTATION?

A. The CCS Data Request No. 1.4 f asked the following:

> *What methodology does the model use to monitor transmission limitations within the PacifiCorp system?*

Response:

> *It is assumed that there are no transmission limits between east and west sides of the Company's system.*

Furthermore, within the discussion outline, the only mention PacifiCorp makes of the transmission modeling is:

Transmission capability – Open access makes this less a constraint

These responses by the Company's witnesses are clearly wrong with regard to how the model works. By saying there are no transmission limits between the two sides of the PacifiCorp system, the Company is telling us that the model places no restriction on the amount of power that can flow between divisions. In fact, no logic exists to allow power to flow at all between the divisions.

Q. PLEASE BRIEFLY DESCRIBE THE OPERATION OF THE SPREADSHEET MODEL.

A. The overall objective of the spreadsheet model is to determine the cost of the operating resources to serve PacifiCorp's load obligations. Because hydro conditions can vary significantly from one year to the next, PacifiCorp develops estimates of net power costs based on normalized hydro conditions in the Pacific Division~~Western division~~. The spreadsheet model also dynamically determines the amount of purchases and sales that are to be made to the secondary markets in both the Pacific and Utah Divisions. Essentially, flows are calculated between PacifiCorp and the secondary markets, however, no flows are permitted between the Pacific and Utah Divisions.

The spreadsheet model operates on a monthly basis, and in each month each division has both a retail load requirement plus a wholesale sales load requirement. The wholesale load sales requirement includes both long-term firm and short-term firm transactions, whose volumes and prices are directly entered into the model. The spreadsheet model determines which resources are available to satisfy those load requirements. Only the resources located within a division are permitted to satisfy that division's total load requirements. So in each month, Utah's thermal, hydro, and wholesale purchase (long-term firm and short-term firm) resources are used to satisfy Utah's retail and wholesale sales load requirements. Likewise, the Pacific~~Western~~ D~~d~~ivision's thermal, hydro, and wholesale purchase resources are used to satisfy the Pacific~~Western~~ D~~d~~ivision's retail and wholesale sales load requirements. In the event that any surplus energy exists in a month, in either division, then that division is considered long for that month, and is permitted to make a secondary sale to its surrounding market. If instead one of the divisions is short, in other words the sum of its resources is less than its load requirement, then the spreadsheet model makes a purchase in that division from the surrounding market.

Q. WHAT IS THE PROBLEM WITH THIS LOGIC AS IT RELATES TO POWER TRANSFERS BETWEEN THE DIVISIONS?

A. In its new spreadsheet model, PacifiCorp does not provide for modeling logic that would allow transfer capability between the divisions. The spreadsheet model, therefore, gives no consideration as to whether one division's surplus could supply the other division's deficiency. Nor does the logic consider the possibility of using the transmission system to sell or purchase power from the other division's market to maximize efficiency.. The lack of these modeling considerations is problematic in that it inflates the normalized level of net power costs. [4]

Q. CAN YOU PROVIDE A NUMERICAL EXAMPLE SHOWING THE BENEFIT OF ALLOWING TRANSFER CAPABILITY MODELING? .

A. Yes. I revised PacifiCorp's spreadsheet model to incorporate logic that would allow for the transfer of power between PacifiCorp's divisions. Exhibit PMH/3 contains an accounting of the imports and exports that each of the divisions conduct for the historical test year, under PacifiCorp's method and my revised method

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[4] In its testimony PacifiCorp suggests that the primary reason for the large increase in net power costs is due to a sharp increase in wholesale market prices. It is notable, however, that PacifiCorp has incorporated modeling logic that forces uneconomic results regarding wholesale market purchases and sales.

After its evaluation of the resources that serve the loads is complete, PacifiCorp's normalized net power cost case shows that during the test-year period the Utah Division sells 877 GWH to the secondary markets during certain times of the year, and purchases 1,227 GWH from the secondary market at other times of the year. The results also show that the Utah D~~Eastern d~~ivision only purchases from the secondary market in the amount of 1,719 GWH, and it never sells to the secondary market.

The results show that PacifiCorp would have been much better off had it relied on Utah's market to supply some portion of each division's deficiency, rather than having each division rely on its own secondary market to supply its own deficiency. The cost to purchase power in Utah's secondary market on a weighted-average basis over the year is $87.3/MWH, while the cost to purchase power in the Pacific Division's secondary market is $102.9/MWH. While it is clearly cheaper, by an average annual amount of about $15/MWH for both divisions to purchase power from Utah's secondary market, PacifiCorp's modeling does not permit this. Had PacifiCorp allowed the Pacific Division to purchase power from the Utah Division's market and then allowed power to flow between the divisions, the overall cost to the Company would have been considerably lower. According to the new logic that I added, PacifiCorp would save about $32.5 million on a total company basis compared to PacifiCorp's normalized net power cost case.

Q. HAVE YOU DETERMINED THE IMPACT OF YOUR ADJUSTMENT AFTER INCLUDING ALL OF MR. FALKENBERG'S OTHER ADJUSTMENTS?

A. Up to now I have discussed the impact of my proposed modifications compared to PacifiCorp's normalized net power cost case. Compared to that case, the sum of my two adjustments reduce net power costs by $52.9 million on a total company basis. ~~original case.~~ My ultimate recommend~~ed~~ation is to include these two adjustments with all of Mr. Falkenberg's other adjustments. ~~In fact,~~ ~~is included with~~ Mr. Falkenberg's ~~'s shows an~~ E~~e~~xhibit RJF/2 ~~which not only~~ includes all of his recommended adjustments, and ~~but he includes the impact of~~ my two proposed adjustments as well (See ~~as well as my two modeling corrections. Exhibit PMH/4 is similar to~~ Mr. Falkenberg's Exhibit RJF/2). ~~which shows all of his adjustments to PacifiCorp's normalized net power cost case, and it includes my adjustments as well.~~ Compared to Mr. Falkenberg's final case, the addition of my two adjustments reduces net power costs on a total company basis by an additional amount of $~~9.2~~8.9 million ($5.~~8~~5 million + $3.4 million).

Q. CAN YOU PLEASE EXPLAIN WHY THESE ADJUSTMENTS ARE SO SMALL WHEN ADDED TO ALL OF MR. FALKENBERG'S OTHER ADJUSTMENTS?

A. ~~Exhibit PMH/4 contains two tables. The first shows the impact of my adjustments when compared to PacifiCorp's normalized net power cost case. In that case the sum of my two adjustments reduce net power costs by about $53 million ($20.4 million + $32.5 million). However, when my two adjustments are added after all of Mr. Falkenberg's adjustments the impact on net power costs is only $9.2 million. Thus, t~~The impact of my adjustments are more pronounced when the cost of purchasing from the wholesale market is higher. For reasons ~~which are~~ explained in his testimony, Mr. Falkenberg's adjustments effectively lower the cost of purchasing from the wholesale secondary market by going to actual test-period prices.

OTHER MODELING IMPROVEMENTS

Q. WHAT AREA DOES YOUR FIRST MODELING IMPROVEMENT RELATE TO IN THE SPREADSHEET MODEL?

A. In his testimony, Mr. Falkenberg discusses problems associated with generating unit availability input data itself. He explains PacifiCorp's method of developing availability rate inputs based on averaging availability data over a four-year rolling average period. Mr. Falkenberg's concern is over the use of a four-year rolling average period, and the fact that PacifiCorp shows dramatically declining availability rates over that period. Based on his analysis, Mr. Falkenberg recommends using a six-year period for averaging in order to smooth out any statistical aberrations that occur in the four-year period. He also discusses the possibility of using an even longer time period for averaging generating unit availability.

In addressing this issue, we also explored the possibility of including dynamic modeling of generating unit forced outages in the spreadsheet model. However, it became obvious that this modification was computationally difficult because it had to be simulated in a tedious manual procedure that would have to be repeated each time we ran a case. Our recommendation is that the six-year average adjustment that Mr. Falkenberg supports be adopted in this case, and then this method be implemented as a permanent modification to the spreadsheet program or whatever tool PacifiCorp adopts in the future.

Q. PLEASE ELABORATE ON THIS MODIFICATION.

~~A.~~A. The modeling of generator unit availability ~~levels~~ characteristics is a major driver in the determination of net power cost results. As such, I would like a feature added to the spreadsheet model that would allow for more dynamic treatment of generator outages, similar to the way that hydro units are treated in the spreadsheet model. In the simplest of terms, I recommend that a feature be added that would allow for an averaging of output results, as opposed to the averaging of input data that takes place right now. At present, PacifiCorp develops inputs to the spreadsheet model by averaging four-years worth of availability data to derive an average availability rate for each unit. This average availability data is entered into the model and a single run is made to ~~it is run to~~ derive net power costs. Based on the input availability data for each unit, the spreadsheet model derives monthly generation results for each unit by multiplying capacity times the average availability times the number of hours in the month.

As an example, consider the way PacifiCorp treats Huntington Unit 1 during January of the test year. During that month, PacifiCorp schedules no maintenance for the unit

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and it determines that it is economic to run the unit at its maximum capacity, which is 440 MW.[5] Based on Mr. Falkenberg' six-year availability calculation the average of the six years of data is 91.22%. I consider this to be the average of the input method because this six-years worth of data is averaged and the average values are input into the spreadsheet model. Then the spreadsheet model calculates generation by multiplying the capacity times the availability times the hours in the month. So for Huntington Unit 1, the generation in January is:

440 MW * .9122 * 31 * 24 = 299 GWH

Once the generation on this unit and all of the other units has been determined, the spreadsheet model continues the process to calculate the amount that each division is either short or long, based on the procedure that I described earlier in my testimony. Unfortunately, this process is not very dynamic because it calculates the net power cost results based on the one average availability condition.

A better approach, which should be incorporated into the spreadsheet model's logic, would be to allow the user to input each of the six availability rate values into the model, and then have the model evaluate the net power cost results for each of the availability rate conditions. In essence, one run of the spreadsheet model would be performed to evaluate net power costs based on the 1994 availability rate data, one run for the 1995 rate data, one run for the 1996 rate data, and so on until the spreadsheet model runs all six availability rate cases. When the six runs are completed then all results would be averaged to obtain the final net power cost results. Thus, I consider this to be the average of the output approach.

Q. WHAT IS YOUR BASIS FOR RECOMMENDING THAT AN AVERAGING OF THE OUTPUT APPROACH WOULD BE BETTER THAN THE AVERAGING OF AN INPUT APPROACH?

[5] The issue of how PacifiCorp determines that a generating unit should run at minimum or maximum capacity is another concern that will be addressed further below in my testimony.

A. Whenever a single data input item has a large impact on the results, then it is always preferable to conduct separate evaluations for each of the data items. PacifiCorp itself has long made use of this approach for evaluating the impact of hydro generation on PacifiCorp's net power cost results. For many years PacifiCorp ran PD/Mac to derive net power costs using an iterative procedure based on 50 hydro water conditions for both its Pacific Northwest Hydro resources, and for the Mid-Columbia River hydro resources. Now that PacifiCorp has moved to a new spreadsheet model, it has preserved the 50 water year logic in that separate iterations are performed for each hydro condition. In the past, PacifiCorp concluded that the impact on the results was so significant, that it made more sense to run separate iterations for each water condition and then average the output results, than it did to average the hydro input data and run only one model evaluation.

Q. WHAT EVIDENCE DO YOU HAVE THAT MODELING AVAILABILITY RATE DATA IN SEPARATE CASES WOULD ALSO HAVE A LARGE IMPACT ON RESULTS?

A. We simulated the logic that I discussed above using a manual approach. First, we ran a case in which we modeled availability rate data using the average of the input technique. In this case, we averaged the availability rate inputs using a six-year rolling-average period. In fact, the basis for one of Mr. Falkenberg's adjustments calls for the averaging of the input availability rates on the basis of a six-year rolling-average period. -(Refer to Mr. Falkenberg's Case 3) For instance, Huntington Unit 1 had the following annual availability data between 1994 – 1999 based on data supplied by PacifiCorp.

	Availability Rates (%)
1994	96.1%
1995	91.9%

1996	89.3%
1997	87.8%
1998	90.1%
1999	92.2%
Average	91.2%

Similarly, data for each of the generating units was available and six--year average calculations were performed for each unit. We conducted seven separate spreadsheet model evaluations, one for each of the availability years, and one for the case with the six -year average availability rates. Mr. Falkenberg discusses this same evaluation and presents an exhibit that provides the net power costs under each of the evaluations. (See Exhibit RJF/8) The runs for each year of availability data yielded the following results:

	Net Power Costs ($millions)
1994	$498.9
1995	$572.6
1996	$640.2
1997	$866.4
1998	$807.5
1999	$816.5
Average	$700.4

When an analysis is performed in which separate model runs are performed for each year of availability data, then a net power cost value is obtained for each year. The average of these output results is $700.4 million on a total Company basis. This results in a reduction in net power costs results of $112.2 million ($812.6 million - $700.4 million) compared to PacifiCorp's normalized net power cost case.

We also ran a case in which we calculated the average of the six years of availability data and input that to the program. The net power cost result in that case amounted to $721.3 million on a total Company basis compared to PacifiCorp's normalized net power cost case. As a result, net power costs were reduced by $91.3 million ($812.6 million - $721.3 million).

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION FOR FUTURE MODELING REGARDING AVAILABILTY RATE DATA.

A. While the average of input method resulted in a smaller adjustment, we chose to support it because the average of the output approach is extremely tedious to develop as a manual adjustment, and needs to be refined using an automated procedure in a future version of the spreadsheet model.

In summary, the Commission should adopt the recommendation that PacifiCorp be required to use a six-year rolling-average calculation at this time (Refer to Mr. Falkenberg's Adjustment Case 3). Furthermore, the Commission may want to investigate the reasons why the availability rates for the PacifiCorp units have declined so dramatically over the six-year period of 1994 through 1999. Finally, we would also recommend that PacifiCorp revise the new spreadsheet model to adopt the average of the output methodology for treating availability rates in a dynamic manner.

Q. PLEASE DISCUSS YOUR NEXT MODELING IMPROVEMENT RECOMMENDATION.

A. The next modeling improvement recommendation relates to deriving the amount of generation by unit. The spreadsheet model determines the amount of energy that any unit dispatches based on whether it operates at minimum capacity or at maximum capacity, without considering the possibility of operating at any level in between. For cases in which there is such a disparity between the price of the wholesale secondary market and the cost of generation, then PacifiCorp's approach to modeling units at either their minimum capacity or maximum capacity is not unreasonable because most units generate close to their maximum capacity anyway. In PacifiCorp's normalized net power cost case, the annual average cost for its plants ranges from $5.21/MWH for the Dave Johnston plant to about $42/MWH, for the Gadsby plant, while the cost of purchasing from the wholesale market is over $100/MWH. This is quite a disparity, and effectively results in the PacifiCorp units operating at the maximum capacity all of the time. However, this case is somewhat unusual in that market prices are extremely high. In other cases in which market prices are lower PacifiCorp might be inclined to operate their units at levels between minimum capacity and maximum capacity more frequently.

I recommend that the spreadsheet model be changed to allow units to operate between their minimum and maximum capacity levels. To accommodate this change, PacifiCorp would need to be able to break up the capacity of each unit into blocks. For example Hunter 3 is listed as a 403 MW unit and could be broken up into three blocks having characteristics such as: [6]

Capacity Block	Capacity (MW)	Heat Rate (MBTU/MWH)	Heat Rate (as a Ratio of Max Heat Rate)
1	165	12.52	1.197
2	347	10.57	1.01
3	403	10.46	1.00

The current version of the spreadsheet model does evaluate the operation of a unit at either the minimum or maximum capacity; however, it only considers the unit as having a single heat rate which is the average full load heat rate. As can be seen

[6] The data used here is for illustration purposes and while realistic for the Hunter 1 unit, they were not obtained from

from the table above, the minimum heat rate can be 20% greater or more than the full load heat rate.

Q. PLEASE SUMMARIZE YOUR PROPOSAL REGARDING MULTI-SEGMENT MODELING.

A. Not only should the logic be changed to allow for more capacity states to be modeled between the minimum and maximum capacity levels, but also different heat rates should be considered at each capacity level. The multi-segment enhancement would result in the model evaluating each capacity block at its specific heat rate.

This capability currently exists within the PD/Mac model and Mr. Falkenberg and I recommended its use in an earlier proceeding, which was agreed upon by PacifiCorp in the Settlement Agreement in Docket 97-035-01. At a minimum two capacity states should be used for each unit, along with corresponding heat rates at each capacity state. Certain units may show a greater variation in heat rate between the second and third capacity states, and therefore at least a three capacity blocks for those units would be warranted.

Q. WHAT IS YOUR NEXT MODELING IMPROVEMENT?

A. Just as additional capacity segments would improve the modeling of the PacifiCorp system, so too would the ability to model the system in different time periods. While I am not suggesting that PacifiCorp should move to an hourly model for purposes of net power cost modeling, I do think that PacifiCorp should increase the amount of detail in its modeling methodology by making use of data associated with three different time periods, weekday, weeknight, and weekend. Given the level of importance placed on purchases and sales from the wholesale power markets, PacifiCorp should implement improvements to its modeling methodology that would better account for the different costs that occur at different times of the day. For

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any source in this case.

purposes of running its spreadsheet model, PacifiCorp inputs one cost value and one energy value per month for each transaction. To derive these inputs, PacifiCorp ignores the time period when the energy is scheduled and just specifies the total monthly values. It is very common in arranging wholesale transactions for the characteristics to be different during the 16-hour on-peak period versus the 8-hour off-peak period. By specifying the energy in different time periods, PacifiCorp's model would better capture the amount of generation shortage or surplus that exists and would determine its own generation results more accurately.

Q. HOW WOULD THE SPREADSHEET MODEL LOGIC WORK WITH THIS SUB-PERIOD DATA?

A. PacifiCorp would have to allow the ability to input data items by sub-period. This would include both energy and price data for each of the long-term and short-term firm purchases and sales, market prices used to determine secondary purchases and sales, load requirements and hydro energy which would have to be allocated to each sub-period. There may be some others that would have to be specified by sub-period as well. The model would then go about its calculations in the same manner as it does now, except it would evaluate each sub-period separately. The sub-period generation and costs for each of the resources should be summed up to derive the monthly result at the end.

Q. WHY DO YOU BELIEVE THIS WOULD IMPROVE THE RESULTS?

A. Schedules of energy, as well as the cost of that energy, are typically very different depending on the time period. Presently, PacifiCorp has to derive rough averaging procedures to develop average monthly values to input into the model, and this averaging process leads to problems. Although one could argue for going to hourly modeling, I don't think that it is necessary to do this for purposes of net power cost modeling based on a historical test year. While data typically differs by time periods, generally the energy and cost data during on-peak periods, or the energy and cost data during off-peak periods are very similar, and so sub-period modeling would be reasonable to use for this purpose.

EVALUATION OF ALTERNATIVE WAYS TO NORMALIZE NET POWER COSTS

Q. WHAT ARE YOUR FINAL RECOMMENDATIONS REGARDING THE EVALUATION OF NET POWER COSTS IN THE FUTURE?

A. I recommend that PacifiCorp complete its evaluation of alternative ways to normalize net power costs in advance of the start of any future rate case. This is consistent with the Commission's Rehearing Order in Docket 99-035-10. Part of this evaluation should be to justify whatever model is finally settled on and to provide appropriate documentation so that all parties can evaluate the reasonableness of the model for themselves. I have no objection to PacifiCorp deciding to continue to use the spreadsheet model in the future, if the evaluation also justifies the use of the model. However, if that is the final outcome, then I recommend that the Commission require the implementation of the modifications that I identify in my testimony, or at least require the Company to thoroughly examine these recommended modifications and provide detailed documentation of the reasons my recommended features are found to be objectionable. If PacifiCorp decides to build another model, then again, they should implement the same features that I discussed in my testimony.

Q. SHOULD PACIFICORP BE STEERED TOWARDS AN HOURLY MODEL?

A. This question has come up a number of times and in a number of jurisdictions where PacifiCorp operates, and I am sure that it will be evaluated as part of PacifiCorp's evaluation. In fact, for much of my work, I make use of hourly models. However, at this point I see no reason why PacifiCorp should be necessarily steered away from its spreadsheet model. Effectively, a model that is used to develop net power costs for the purposes of regulatory proceedings, such as this one, is a benchmark tool with the added complexity that some normalized data is used instead of actual data. PD/Mac was designed with this in mind and yet it became apparent that because it runs on an Apple computer it was difficult for intervenors to make use of the model. The model also was criticized for the fact that it was burdened with customized logic that today is no longer used. When some parties in PacifiCorp's previous rate case attempted to analyze the actual program code, they found that the extraneous logic made it difficult to understand all of the calculations, which largely turn out to be unnecessary anyway at this point in time.

Q. WHAT GOALS SHOULD PACIFICORP HAVE IN EVALUATING NET POWER COST MODELS?

Whatever model that PacifiCorp settles on in the future, I think it should meet the following goals:

- Is it capable of benchmarking to actual historical results? In the past when the issue of benchmarking came up, PacifiCorp always skirted the issue and claimed that it was difficult to use PD/Mac to benchmark because the model is a normalization tool. However, I would argue that unless the new model can demonstrate that it can accurately reflect actual historical operations, there is no way to know that when normalized data is added if the normalized model outputs are accurate.
- It should be built to accommodate normalization procedures that PacifiCorp has been accustomed to using in the past such as hydro normalization as well as the availability rate normalization that I recommended in my testimony.
- Documentation needs to be clearly developed so that all parties can understand the model and the reasons for any assumptions that were made. At a minimum, this documentation should include design documentation, a user's manual, and a report of the evaluation used to justify the use of whatever model that PacifiCorp settles on.
- Whatever model is settled on needs to be readily available for all parties to run and examine. The trouble with some commercially available software is that it is expensive and this can effectively deny staff and intervenors access to the model. I recommend that whatever model is used, it should continue to be available to all parties at no cost.
- As part of the evaluation of any new model, the robustness of the model needs to be considered. In the present case, the spreadsheet model adequately assessed conditions as they existed during the historical test period, which included very high market prices. As a result, most of PacifiCorp's thermal generating units were operated to their full availability. However, there may be times when the price of the external markets are lower and generating units would not run at as high levels. For this reason I propose that PacifiCorp implement segment dispatch modeling. Furthermore, PacifiCorp should fully evaluate the model to make sure

that it is robust given any conditions, not just a specific set as occurred in this case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.