

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

In re deferred energy filing of NEVADA POWER)
COMPANY and Application to change fuel and)
purchased power rates.)
_____)

Docket No. 03-11019

At a general session of the Public Utilities
Commission of Nevada, held at its offices
on March 24, 2004.

PRESENT: Chairman Donald L. Soderberg
Commissioner Adriana Escobar Chanos
Commissioner Carl B. Linvill
Commission Secretary Crystal Jackson

ORDER

The Public Utilities Commission of Nevada (“Commission”) makes the following
findings of fact and conclusions of law:

I. Procedural History

1. On November 17, 2003, Nevada Power Company (“NPC”) filed an Application, designated as Docket No. 03-11019, with the Commission to change fuel and purchased power (“F&PP”) rates.
2. The Application is filed pursuant to the Nevada Revised Statutes (“NRS”) and Nevada Administrative Code (“NAC”), Chapters 703 and 704, including but not limited to NRS 704.100 - 704.110 and 704.187, and NAC 704.023 - 704.195.
3. The Commission issued a public notice of the Application in accordance with state law and the Commission’s Rules of Practice and Procedure.
4. Petitions for Leave to Intervene were granted to: Chemical Lime Company (“Chemical Lime”), Kroger Co. (“Kroger”), MGM Mirage (“MGM”), the Nevada Independent Energy Coalition (“NIEC”), the Southern Nevada Water Authority (“SNWA”), the United States

Department of Energy (“DOE”), and the Utility Shareholders Association of Nevada, Inc. (“USAN”). NIEC’s intervention was limited to standby Deferred Energy Accounting Adjustment (“DEAA”) and Base Tariff Energy Rate (“BTER”) rates only. The Regulatory Operations Staff of the Commission (“Staff”) and the Attorney General’s Bureau of Consumer Protection (“BCP”) participate as a matter of right in this matter.

5. On November 21, 2003, a Procedural order was issued in this matter setting forth a procedural schedule.

6. On January 20, 2003, Kroger filed a letter stating it would not actively participate as an intervener and would postpone association with in-state counsel.

7. On January 26, 2004, NPC filed a Motion to Associate Julia Sullivan as Counsel (“Motion to Associate”).

8. On January 28, 2004, MGM filed a Stipulation among the parties via facsimile that allowed MGM to late-file its direct testimony and NPC to late-file its rebuttal testimony with regard to MGM’s testimony. An original Stipulation was filed with the Commission on February 3, 2004.

9. On January 30, 2004, DOE filed a Motion to Appear as Counsel (“Motion to Appear”).

10. On February 6, 2004, Procedural Order No. 2 was issued in this matter, granting the Motion to Associate.

11. On February 10, 2004, Chemical Lime filed a letter withdrawing its intervention.

12. On February 11, 2004, the BCP filed a Motion to Compel. The BCP alleged that NPC had not adequately responded to a BCP discovery request for presentations, reports, memos, and/or analysis performed by the Boston Consulting Group (“BCG”) for NPC relating to

the F&PP activities of NPC.

13. On February 11, 2004, Procedural Order No. 3 was issued in this matter, granting the Motion to Appear.

14. On February 17, 2004, NPC filed a Response to BCP Motion to Compel.

15. On February 17, 2004, a duly noticed hearing was held in this matter. The hearing continued on February 18 and concluded on February 19, 2004.

16. On February 17, 2004, at the hearing in this matter, the BCP withdrew its Motion to Compel.

II. Base Tariff Energy Rate

NPC's Position

Mr. Yackira

17. NPC witness, Mr. Michael Yackira, Executive Vice President and Chief Financial Officer, supports the rate mitigation plan proposed in this docket. (Ex. 2 at 2.) Pursuant to the NPC's plan, wherein a deviation from the current regulations is required and requested, the BTER would increase by approximately \$80 million, rather than \$171 million if the Commission's regulations were followed. (Id. at 5.) Additionally, the proposed BTER, if implemented on April 1, 2004, would remain in effect for approximately thirteen and one-half months. (Id. at 6.) Mr. Yackira is confident that the proposed BTER will provide sufficient cash flow for NPC. (Tr. at 15-16.)

Mr. Denis

18. Mr. Roberto Denis, Vice President of Energy Supply and witness for NPC, testifies that the more accurate the BTER the less of a deferred balance there will be. Consequently, the proposed BTER is based on the estimated cost of executing NPC's 2004

Energy Supply Plan. (Ex. 3 at 14.)

Mr. Branch

19. NPC witness, Mr. William Branch, Principal Strategy and Policy, reports that he used forecasted costs and sales for the fourteen-month period from April 2004 through May 2005 to estimate the requested BTER. (Ex. 4 at 16.) The proposed BTER is \$0.04577 per kilowatt hour (“kWh”) for residential customers and \$0.04738 / kWh for non-residential customers. (Id.) Mr. Branch did indicate, however, that the projected cost had increased to about 49 mills from the current application’s estimate of 46.73 mills. (Tr. at 67.) Mr. Branch indicates that the PROMOD production cost model was used to forecast costs for the April 2004 through May 2005 period, partly based on forecasted natural gas rates from Tradition Financial Services (“TFS”) in Exhibit 1 at Exhibit E-3. (Id. at 16-18.) Mr. Branch further indicates that the proposed method of calculating the BTER requires a waiver of NAC 704.130. (Id. at 17.)

Mr. Meehan

20. NPC witness, Mr. Eugene Meehan, Senior Vice President at National Economic Research Associates and Co-chair of its energy practice, examined the appropriateness of using TFS forward power quotes to set the BTER in this case. (Ex. 7 at 4.) Mr. Meehan concludes that the use of broker quotes to develop market price estimates for the currently proposed BTER is appropriate because the New York Mercantile Exchange (“NYMEX”) market is very liquid and reliance on NYMEX forward prices is appropriate.

Ms. Franklin

21. Ms. Patricia Franklin Manager, Federal Energy Regulatory Commission (“FERC”) & California Regulatory and witness for NPC, provides testimony supporting the calculation of the BTER rate. (Ex. 15 at 5-6.)

SNWA's Position

22. SNWA's witness, Dr. Dennis Peseau, President, Utility Resources, Inc., believes that NPC has included excessive costs in the calculation of the BTER related to call option premiums. (Ex. 26 at 2.) Dr. Peseau, however, does not propose an adjustment to NPC's proposed BTER. However, he recognizes that NPC's cash requirements are higher for 2004. (Tr. at 314.) According to Dr. Peseau, he desires to highlight the cost assumptions made by NPC in order to reduce the risk that future deferred costs will be disallowed. (Ex. 26 at 7.) The risk that Dr. Peseau perceives is related to NPC's plan to hedge in excess of its physical gas requirements through the purchase of call options, which is a change from the previous strategy of buying long-term contracts and hedging with fixed-for-floating and basis swaps. (Id. at 8.) The proposed \$40.3 million premium for the options, according to Dr. Peseau, will increase the cost of gas by \$.62 to \$.92 per MMBtu. (Id. at 9.) Dr. Peseau compares this cost to the current price listed in the *Wall Street Journal* of \$.17 to \$.46 MMBtu. (Id.) Dr. Peseau's recommendation is that NPC reconsider its hedging methodology. (Id. at 10.)

Staff's Position**Mr. Buck**

23. Mr. Fred Buck, Financial Analyst and witness for Staff, indicates that Staff is not opposed to NPC's request to institute a BTER with a thirteen and one-half month duration. (Ex. 23 at 2.) Mr. Buck also recommends an increase in the BTER based on forecasted sales data, and he also recommends a deviation from the current regulation be permitted. However, Mr. Buck's recommendation of \$0.04887 and \$0.5050 per KWh for residential and non-residential, respectively, exceeds NPC's request. (Id. at Attachment FCB-12.) His recommendation is based on the premise that the DEAA rate will be adjusted downward and that the expected energy cost

will be higher. (Id. at 2-3.) Additionally, Mr. Buck believes that it is beneficial to ratepayers to have a BTER that accurately reflects energy costs. (Id. at 3.)

Mr. Knecht

24. Mr. Ron Knecht, Economist and witness for Staff, opines that Staff's proposals will allow reasonable improvement in NPC's key financial indicators over the time period that the rates are in effect. (Ex. 24 at 6.)

NPC's Rebuttal Position

25. NPC witness, Mr. Branch, states that the level of costs in the BTER proposal is consistent with NPC's 2004-2006 Energy Supply Plan which was approved by the Commission in Docket No. 03-7004. (Ex. 5 at 8.) Additionally, he states that the hedging costs included represent a 14- month period, but for a 12-month period the costs amount to \$34.9 million rather than Dr. Peseau's \$40.3 million. (Id.) Mr. Branch also reports that the hedging costs approved in Docket No. 03-7004 are within several hundred thousand dollars of the costs used to calculate the BTER. (Id.) Mr. Branch also indicates that the current cost was slightly above the requested BTER. (Tr. at 68.)

Commission Discussion and Findings

26. Although Dr. Peseau has reservations about the proposed BTER based on proposed costs for hedging, Staff supports an increase in the rate. Unfortunately, the BCP offered no testimony on this topic. The testimony of Mr. Yackira and Mr. Branch indicates that, although costs have risen slightly, the requested rate will be sufficient to provide NPC enough cash to fund its F&PP requirements. Additionally, Mr. Branch points out that the BTER request is consistent with NPC's Energy Supply Plan. The Commission allowed NPC to utilize a similar methodology in the last Deferred Energy case. Given the continued volatility in the energy and

natural gas markets together with the continued high price of natural gas, it is appropriate to attempt to estimate what the actual cost of fuel and purchased power will be in the next Deferred Energy period. More stable rates will result from a closer match of the BTER to the actual cost, and the Commission believes that the proposed methodology will provide a closer match. Therefore, the Commission finds that a deviation from NAC 704.130 is appropriate and approved. The Commission also finds that the requested BTER rate of \$0.04577 / kWh for residential customers and \$0.04738 / kWh for non-residential customers is appropriate and approved.

27. Staff also supports the request that the BTER rate for residential and non-residential customers be in effect for thirteen and one-half months beginning April 1, 2004. Therefore, the Commission finds that pursuant to NAC 704.0097, good cause exists and it is in the public interest to grant a deviation from NAC 704.116 regarding the term of the BTER. The Commission finds that the requested term of the rate is appropriate, given the April 1, 2004, implementation date, and is approved.

III. Deferred Energy Accounting Adjustment (“DEAA”)

A. Amortization Period

NPC’s Position

28. Mr. Yackira, witness for NPC, indicates that the rate mitigation plan proposed in NPC’s application includes the DEAA rate, as well as the BTER. (Ex. 2 at 2-3.) The rate mitigation plan calls for an asymmetric amortization of the DEAA balance, wherein 15 percent is recovered the first year and the remainder is recovered equally over the remaining two years.

(Id. at 5.)

29. Mr. Yackira states that for the test period of October 1, 2002, to September 30,

2003, the costs of purchasing fuel and power exceeded the revenues generated by the BTER set in NPC's last deferred energy case in Commission Docket No. 02-11021. He noted that the difference between costs and revenues for purchased fuel and power has been calculated monthly and accumulated in DEAA3, the current Deferred Balance. (Id. at 3.)

30. A balance of \$93,031,494 in the DEAA3 is the amount NPC proposes to be recovered over a three-year period. Further, a straight-line amortization of the DEAA3 balance would result in recovery of \$31,919,498 each year, with a DEAA3 rate for residential customers of \$0.00235 per KWh and \$0.00128 per KWh for nonresidential customers. (Id. at 3.)

31. Mr. Yackira explained that, due to NPC's proposed general rate change in its pending Docket No. 03-10001, NPC proposes to implement a schedule to reduce the number of times rates will change this year, together with an asymmetric amortization of DEAA3. If accepted, this will result in recovery of about 15 percent of the balance starting April 1, 2004, and about 42.5 percent of the balance each following year for the next two years, commencing May 15, 2005. (Id. at 4.) Mr. Yackira also noted that the DEAA1 balance, the amortization rate from the Commission's decision in Docket 01-11029, will be fully collected by the end of this year. (Tr. at 12.)

SNWA's Position

32. SNWA's witness, Dr. Peseau, recommends that NPC's rate mitigation proposal be modified to collect no dollars in the first of the three year amortization periods to further reduce customer rate shock, with the total remaining balances collected equally in the following two years. (Ex. 26 at 2.) Dr. Peseau also recommends that the DEAA1 rate be reduced to ensure that the amortization period extends to April 1, 2005. (Id.) Dr. Peseau states that customer rate continuity and stability are better served with this proposal. (Id. at 4.) His proposal results in a

reduction to NPC's request from an increase of 5.74 percent down to an increase of 2.4 percent, or a reduction of \$50.6 million in the first year. (Id. at 7.)

BCP's Position

33. BCP witness, Mr. Phil Williamson, BCP's Manager of Technical Staff, believes that the asymmetrical amortization proposal should be denied. (Ex. 27 at 8.) He believes that the three-year amortization occurring evenly throughout the period should be the outside limit on rate mitigation because, he believes, an equal proportional amortization is what was contemplated by the legislature. (Id. at 7.)

34. Mr. Williamson does not support NPC's asymmetrical amortization proposal for several reasons. First, Mr. Williamson believes that the proposal is unnecessary and notes that the Nevada Legislature addressed rate mitigation and extended the amortization period of the deferred energy balance from one year up to three years. He asserts that symmetrical amortization reduces the annual impact of rate increases by two-thirds which provides significant and appropriate mitigation of rates. Mr. Williamson believes that further mitigation is simply counterproductive and, when viewed with other potential consequences of the proposal, should not be allowed since total costs to consumers will increase. (Id. at 5.) For instance, if prices exceed the projected costs used to set the BTER, as they did in NPC's last deferred energy filing, the back loaded proposal of NPC will exacerbate a rate increase request in NPC's next deferred energy filing. (Id. at 7-8.)

35. Mr. Williamson also believes that the asymmetrical amortization would give an improper price signal to the customer by further obscuring the true impact of the costs incurred. He explains that accurate price signals are important to customers and, when given accurate pricing signals, they can adjust usage levels and to some extent control their energy bill.

Furthermore, proper price signals lead to reduced consumption, reduced demand for the commodity and lower prices. Mr. Williamson states that the greater the effort to mitigate rates by spreading costs over time, the less accurate the price signal; therefore, this reduces the customer's price awareness and the ability to take steps to reduce consumption during high cost periods. This, Mr. Williamson believes, would keep demand artificially high, which in turn supports high price levels. (Id. at 6.)

36. In addition, Mr. Williamson also believes that this proposal would cause an increase in costs to ratepayers through additional carrying costs on the deferred energy balance because it back loads the recovery of the balance, meaning that the carrying charge is applied to higher average balances over the amortization period. (Id.)

37. Lastly, Mr. Williamson believes that the asymmetrical amortization would postpone a long overdue rate decrease or possibly have the opposite impact and exacerbate a rate increase in the second year of amortization. Specifically, rates from this proposal will automatically increase by a proposed \$25,500,000 in the second year of amortization from \$14,000,000 to \$39,500,000. (Id. at 7.)

38. All in all, Mr. Williamson believes that balance is needed between rate mitigation, the cost that mitigation adds, accurate pricing signals, and the impact of increasing rates for years two and three of the amortization period. He believes that the hypothetical benefits of the asymmetrical proposal are outweighed by the potential detriments; therefore, the proposal should be denied. (Id. at 8.)

Staff's Position

Mr. Buck

39. Mr. Buck, witness for Staff, recommends that the DEAA balances be recovered

over two years, commencing in April 2004. (Ex. 23 at 10.) Mr. Buck states that this method liquidates all three period balances over two years, rather than three, at a lower rate than NPC's proposal. (Id.)

Mr. Knecht

40. Staff witness, Mr. Knecht, utilizes Staff's new financial and cash-flow simulation model of NPC, ("FinSim"). With this model he compares and analyzes the adoption by the Commission of NPC's deferred energy cost proposals in this docket and in NPC's revenue requirement increase requested in Docket No. 01-10001. He also compares and analyzes Staff recommended levels in these two dockets. (Ex. 24 at 1.)

41. Staff's proposals permit reasonable improvement in NPC's current financial condition over the periods the proposed rates in this docket and in the general rate case, Docket No. 03-10001, would be in effect. Mr. Knecht states that for cash-flow reasons, NPC's rate "phase-in" proposals should be denied. He adds that Staff does find NPC's use of future market prices in its forecasted energy costs to be reasonable; therefore, Staff adopts it. (Id.)

42. The new financial FinSim model of NPC utilized by Staff in this case allowed Staff to independently evaluate the forecasted financial position of NPC. FinSim consists of three interrelated modules addressing energy costs, revenues, and finances. The modules include the following:

- a) The energy module calculates future BTER, deferred fuel costs, and the DEAA, and also tracks the deferred energy deferral and amortization, as well as end-of-period accumulated balances.
- b) The revenue module calculates forecasted period non-F&PP revenue. Forecasted revenues from this module are then included in the monthly and

annual summary of revenue, which is then inputted into the finance module.

c) The finance module produces the forecasted period's financial results based on data flowing from the revenue and energy modules, along with forecasted data produced within the finance module itself. (Id. at 2.)

43. The FinSim has only recently been operational; therefore, it has not received the full range of testing and verification exercises Staff has planned. However, Mr. Knecht contends that based on his knowledge and use of the model, FinSim is a sound tool for the purpose for which it was used herein. (Id. at 3.)

44. Mr. Knecht submits that overall NPC's and Sierra Pacific Power Company's ("SPPC's") balance sheets and cash-flow coverage ratios are weakened, their costs of capital are increased, and they are grappling with capital spending and refinancing needs for the next two years. He notes that the companies have made progress in shoring up their liquidity. (Id. at 5.)

45. Staff's proposals will allow reasonable improvement in NPC's key financial indicators over the time rates adopted in Docket Nos. 03-10001 and 03-11019 (see RLK-2 and RLK-3) remain in effect. Mr. Knecht adds that NPC's proposals will modestly improve those indicators. (Id. at 6.)

46. The main reason for improvement in NPC/ Sierra Pacific Resource's ("SPR's") financial condition starting in 2004 is the current amortization of NPC's large deferred energy cost. Further, Mr. Knecht opines that in view of the key role of the deferred energy amortizations, particularly in NPC's cash flow, it is not advisable to defer collection of revenue requirements or deferred energy costs, especially in the event Staff's proposed ratemaking costs, rate base, and expenses are adopted. Additionally, the phase-in is not needed, and it would burden ratepayers and the public interest. (Id. at 7.)

NPC's Rebuttal Position

47. NPC witness, Ms. Franklin, disagrees with Mr. Buck's recommendation to blend DEAA 1, DEAA 2 and DEAA 3 and to set a single, new DEAA going forward. Ms. Franklin contends that there are several impediments to Mr. Buck's approach including statutory restrictions, regulations and prior Commission orders. For example, if Mr. Buck's position were accepted, DEAA 1 would not clear for four years, contrary to NRS 703.110(7)(a), which requires that a debit balance must be cleared over a period not to exceed three years. Ms. Franklin explains that NPC began amortizing the Period 1 balance authorized in Docket No. 01-11019 [sic] on May 1, 2002. Its three-year amortization period is complete on March 31, 2005; however, the impact of Mr. Buck's proposal would extend the amortization of period 1 for a full year until March 31, 2006, a four-year amortization. (Ex. 16 at 3-4.) Ms. Franklin also notes that the Commission must follow the plain meaning of the statute, which, in this case, allows for a three-year amortization period. Furthermore, Ms. Franklin contends that Mr. Buck's recommendation is contrary to the Commission's regulations, as amended, which prescribe the methodology for accounting and clearing the DEAA balances when up to three DEAA accounts were open at one time. Also, the provision in NAC 704.111 (b) indicates that a balance, once set for amortization in excess of 12 months, is segregated for the duration of its designated amortization period which also supports her argument that Mr. Buck's recommendation is inappropriate. (Id. at 5.)

48. With regard to Dr. Peseau's recommendation, Ms. Franklin states that it has the same defects as Mr. Buck's. She explains that the impact on cash flows aside, Dr. Peseau's recommendation that DEAA 1 be reset using the current balance and current revenues is contrary to NAC 704.111 (b), which was developed by the Commission to manage the complications

stemming from overlapping multi-year amortizations. (Id.)

49. All in all, Ms. Franklin contends that both Mr. Buck and Mr. Peseau's recommendations are contrary to the approach eventually adopted by the Commission, statutes and regulations; thus, the Commission should reject these recommendations. (Id.)

Commission Discussion and Findings

50. In summary, NPC proposes an asymmetric amortization with 15 percent collected the first year and the remainder split between the last two years. Dr. Peseau proposes no recovery for the first year, with a decrease in the DEAA1 amortization rate to ensure rate stability. Mr. Williamson opposes the concept of an asymmetric amortization, while Mr. Buck recommends a two-year amortization beginning in April 2004.

51. The Commission believes that the ratepayers will be better served by a straightforward amortization. And, given the size of the DEAA3 balance, the Commission believes that a 27-month symmetric amortization period is appropriate. The Commission believes that the ratepayers will receive more stable rates, as well as less of an increase in rates in summer 2004, if recovery of the DEAA3 balance is delayed until January 1, 2005, when the DEAA1 balance will be eliminated. The deferred energy mechanism ensures over time collection of only the authorized F&PP costs with appropriate carrying charges. Therefore, this delayed commencement of the amortization of the unrecovered costs from this case can appropriately be done. Upon elimination of the DEAA1 rate, the DEAA3 may be implemented, and the net effect will still be a significant reduction to rates in January 2005.

52. Accordingly, the Commission finds that a 27-month symmetric amortization for the DEAA3 balance is appropriate. The Commission also finds that rate stability is important to ratepayers and that both rate stability and rate increase mitigation will be best achieved by

delaying recovery of the DEAA3 balance until the DEAA1 balance is fully amortized by the end of this year. Finally, the Commission finds that upon elimination of the DEAA1 balance and DEAA1 rate, NPC shall implement a DEAA3 rate on or after January 1, 2005, that amortizes the balance, as adjusted by the Commission in this Order, equally over the remainder of the three-year amortization period of approximately 27 months.

B. NPC's Energy Supply Strategy

NPC's Position

Mr. Denis

53. Mr. Denis, witness for NPC, testifies regarding: 1) the primary elements of NPC's approach to managing the energy supply function with a full requirements load service obligation; 2) the capability and organization in place to manage the energy supply portfolio and underlying risks; and, 3) NPC's execution of the 2003 Energy Supply Plan costs are reflected in the proposed DEAA, and approach and progress in formulating an Energy Supply Plan for the summer of 2003 (with estimated costs reflected in the proposed BTER). (Ex. 3 at 4.)

54. With regard to managing the energy supply function, Mr. Denis described the approach in three parts: 1) established set of management guidelines; 2) energy risk management and risk control approach; and, 3) ongoing regulatory involvement and acknowledgment of the resource portfolio management plans. (Id. at 5.)

55. The guidelines used by the Energy Supply organization in developing the Energy Supply Plan include:

- a) developing an Energy Supply Plan that balances costs, risks, price, volatility, reliability and predictability of supply;
- b) investigation of options to execute against the Energy Supply Plan;

- c) application of quantitative techniques and diligence commensurate with risk to evaluate and execute each transaction;
- d) implementation of the Energy Supply Plan that manages ratepayer risk regarding reliability, volatility and cost; monitor the portfolio regarding evolving market conditions and managing the resource optimization options; and,
- e) ensuring simple, transparent and well-documented decisions and execution processes. (Id. at 5-6.)

56. Mr. Denis states that with regard to NPC's approach to energy risk management and risk control, the Energy Supply organization is responsible for risk management and that it is separate from the Risk Control organization. He emphasized that this is a clear differentiation between planning (setting policy) and execution. (Id. at 6.)

57. Further, Mr. Denis states that, within the Energy Supply function, NPC must maintain ongoing energy supply and risk management plans to systematically evaluate supply portfolio alternatives against a set of specific criteria set by Risk Control. He stated the risk management approach includes: 1) the Electric Resource Plan, which covers the long-term resource and infrastructure needs and the plans to meet those needs; and, 2) the Energy Supply Plan, which details the intermediate-term resource requirements and plans to fulfill those requirements. (Id. at 6.)

58. Mr. Denis states that the execution approach includes adherence to the approved supply plans and the ongoing tactical execution of the plans, which includes monitoring and managing the costs and risks associated with the energy supply portfolio. (Id. at 7.)

59. Mr. Denis explains that his department is charged with managing the cost,

reliability and volatility risks for NPC's customers regarding the approved resource and supply plans. He noted that to that end, a set of limits has been placed on his department's execution of the approved plans that are monitored by a separate arm of the organization, the Risk Control group. Mr. Denis also notes that these limits are flexible enough so that his team can do their jobs, while operating within a set of parameters. He states that these limits define and help to manage the overall risk of NPC and its customers, while the Enterprise Risk Oversight Committee ("EROC") sets the risk control limits and parameters, which is under the responsibilities of the Enterprise Risk Management and Control Policy. (Id. at 7-8.)

60. Mr. Denis states that NPC has identified five "core competencies" that are required to manage the energy supply portfolio of a regulated utility with full requirements load service obligations. These core competencies are: operational, analytical, execution, regulatory interface, and back office. (Id. at 8-10.)

61. The Energy Supply organization is staffed with four separate and distinct functions that complement the core competencies as follows:

- a) Vice President of Generation manages internal generation;
- b) Director of Resource Procurement performs resource procurement and optimization and oversees fuel, power and transmission buyers;
- c) Director of Planning and Analysis leads economists, planners, modelers, and analysts who perform the analysis to support supply strategies and facilitate ongoing communication of the status of the supply plans an portfolio; and,
- d) Director of Business Services and Controls oversees contract administration and accounting group. (Id. at 10-11.)

62. The Energy Supply group is responsible for setting the energy supply strategy, inclusive of the mix of resources, terms, and structures, to be used to fill the approved Energy Supply Plan. The Planning and Analysis groups, Mr. Denis states, is responsible for the preparation of the regional outlook for supply, demand and transmission of electric and natural gas, daily and long-term price forecasts for power and fuels, and load forecasting. (Id. at 11.)

63. Mr. Denis also states that the Energy Supply organization is not limited to a planning role. He stated that this group is also responsible for the implementation of the Energy Supply Plan and for the strategy set at the policy level. Specifically, the Resource Procurement group is responsible for the procurement of fuel and power resources on the short, intermediate, and long-term bases. (Id. at 11-12.)

64. Further, Mr. Denis notes that analysts in the Planning and Analysis group also provide support for the work of the Resource Procurement group. He explained that an independently derived analysis and approval process from the Planning and Analysis group supports material transactions from the Resource Procurement group. (Id. at 12.)

65. With regard to the execution of the 2003 Energy Supply Plan, Mr. Denis testified that it has essentially been completed. NPC completed execution of its gas hedging strategy for the winter 2003-2004 (November 2003 to March 2004) in October. He stated that with less than two months remaining in calendar year 2003, NPC's focus had been on short-term and real-time procurement activities. (Id.)

66. NPC filed its 2004-2006 Energy Supply Plan with the Commission on July 1, 2003. The Energy Supply Plan was part of NPC's 2003 Resource Plan filing, wherein NPC requested Commission approval of its recommended gas hedging strategy for the summer of 2004 and the winter of 2004-2005. Mr. Denis states that the procurement phase for the summer

of 2004 was set to commence after the Commission issued its final decision regarding the Resource Plan. NPC issued a Request for Proposals (“RFP”) for long-term resources consistent with the resource plan and the Energy Supply Plan in July and a second RFP as contemplated in the Energy Supply Plan for intermediate-term resources has been issued. (Id. at 13.)

67. Mr. Denis explained that most of the costs reflected in the DEAA rate (in this filing) were incurred in the last year pursuant to NPC’s 2003 Energy Supply Plan. NPC’s energy procurement practices for the current test period were reviewed by the Commission in NPC Energy Supply Plan filing in January 2003 (Docket No. 03-1037) and in NPC’s previous deferred energy filing (Docket No. 02-11021). In Docket No. 03-1026, the Commission approved long-term contracts for the test period purchases. (Id. at 13.)

Mr. Branch

68. Mr. Branch, witness for NPC, describes and supports the power and gas procurement strategies in place during the test period. In addition to the BTER, he testifies regarding: the Energy Supply Plan process; intermediate resource assessment for power; intermediate resource assessment for natural gas; and the monthly resource assessment for power and natural gas. (Ex. 4 at 3.)

69. There are three groups within the Energy Planning and Analysis Department responsible for analyzing resource requirements, with each group differentiated by the time horizon it is responsible for analyzing. The groups are:

- a) Long Term Resource Analysis Group – responsible for the analysis used to support electricity and fuel commitments of three years or longer;
- b) Intermediate Term Resource Analysis Group – responsible for analysis used to support resource requirements from greater than one month to

three years; and,

- c) Short Term Resource Analysis Group – responsible for the analysis of short-term resource options, which usually consist of one month or less in length.

70. Mr. Branch states that he focuses on the process, analyses, and strategies formulated by the Intermediate and Short-term Resource Analysis groups and their roles in the execution of transactions for the delivery of power and fuel during the test period in this filing. (Id. at 4-5).

71. Mr. Branch states that the 2003-2005 Energy Supply Plan is a guide for filling the intermediate-term resource requirements and consists of an intermediate-term resource procurement plan for power and natural gas and a risk management strategy to reduce price volatility. Additionally, the plan outlines NPC's approach for meeting its load obligations and supports portfolio decision-making for 2003. (Id. at 5.)

72. Further, Mr. Branch describes the process used to develop the 2003-2005 Energy Supply Plan as including the following:

- a) NPC identified the outlook for load and existing resources and the resulting new resource requirements;
- b) Regional market fundamentals including the pricing variables and historical and implied price volatilities were summarized and analyzed;
- c) NPC identified alternative energy supply portfolio options to meet the intermediate-term resource requirements; and,
- d) The potential supply portfolios were evaluated based upon a range of quantitative and qualitative criteria that included: cost to serve; ratepayer

value at risk; reliability; commercial viability; and financial implications.

(Id. at 5-6.)

73. Mr. Branch explained that the analytical process resulted in the recommended energy supply portfolio. He stated that the 2003-2005 Energy Supply Plan includes a recommendation regarding the types and mix of products to acquire, and summary of underlying risks and steps to mitigate such risks. (Id. at 7.)

74. The power procurement strategy selected weighted the intermediate portfolio mix heavily towards peaking and seasonal capacity, or synthetic tolling agreements (i.e., a purchase power agreement with the energy component based on a natural gas index). This strategy was selected due to the expected cost to serve and ratepayer risk profile of the portfolio. Also, this strategy had the highest rating on the commercial viability criteria. (Id. at 7.)

75. Mr. Branch states that the Energy Supply Plan also made recommendations regarding the preferred method of meeting NPC's intermediate-term resource requirements, which included:

- a) Adoption of a 12 percent planning reserve margin for capacity;
- b) Management of off-peak and shoulder month energy price risk;
- c) Utilization of competitive procurement practices to meet load obligation;
- d) Documentation of the planning, analysis, and procurement activities. (Id. at 8.)

76. With regard to the power transactions that resulted from this strategy, Mr. Branch explains that the 2003 - 2005 Energy Supply Plan identified a capacity requirement for the 2003 summer peak of 5,408 MW, based on a 12 percent planning reserve margin. An additional 2,171 MW would then be needed to meet the planning reserve margin, with existing resources of 3,237

MW. After completion of the Energy Supply Plan, NPC revised its load forecast, which increased the capacity requirement to 5,460 MW and the additional capacity requirement to 2,223 MW. (Id. at 8.)

77. NPC acquired electric transmission capacity for summer 2003 because, as Mr. Branch states, it was reasonably priced, served to increase the diversity of resources at its disposal, and increased reliability in that it made NPC less dependent on a single point to fill the marginal requirements (Id. at 9.)

78. With regard to monthly resource assessment for electric and natural gas, Mr. Branch explained that the Short Term Resource Analysis group determines the timing and scope of the monthly requests for proposals. Representatives from Resource Procurement and Credit Risk Management and, when necessary, Power and Fuel Contract Administration also participate. (Id. at 14.)

79. The responses to the RFP are reviewed and evaluated by Short Term Resource Analysis, Resource Procurement, Fuel and Power Contract Administration, and Credit Risk Management. These groups come to a decision regarding what action, if any, to take on an RFP. Resource Procurement then contacts the parties whose RFP had been selected. Any energy or capacity position remaining is then filled by the preschedule and real-time system dispatch and trading functions. (Id. at 15.)

80. The Short Term Resource Assessment group determines how to meet monthly resource requirements by inputting data into a unit commitment model that simulates the system for a particular month. The input data includes: generating unit availability, secured transactions, hydro energy and capacity allocation, estimated load requirements, estimated reserve levels, fuel price estimates, and market price estimates. The simulations are conducted along with a

spreadsheet analysis to determine the capacity position, energy position, estimated natural gas burn, and spot purchase profile. (Id. at 15.)

Mr. Hill

81. NPC witness, Mr. Jeffrey Hill, Director of Resource Procurement, describes the role of the Resource Procurement department along with NPC's purchased power and fuel procurement activities during the test period, and attests to the procurement costs reflected in the DEEA balance. He also addresses electricity term purchases, coal purchases, natural gas purchases, and resource optimization. (Ex. 6 at 2-3.)

82. According to Mr. Hill, the Resource Procurement department implements the Energy Supply Plan developed by the Planning and Analysis group and approved by the Energy Risk Committee. The Resource Procurement department has responsibility for electricity term purchases, coal purchases, natural gas purchases, and resource optimization. (Id. at 3.)

83. Mr. Hill testifies that NPC used a combination of company-owned generation and purchased power to meet its load responsibility during the test period, and purchased 47 percent of its capacity requirement on the peak day and 34 percent of its energy needs to supplement company-owned generation, Qualifying Facility, Independent Power Producer, and Hoover Dam resources to meet customer demand. (Id. at 4.)

84. NPC's 2003 - 2005 Energy Supply Plan provided the process by which it acquired its purchase power term contracts. The Energy Supply Plan identified a need, or open position, for the summer of 2003 of approximately 2,200 MW to be filled through the issuance of RFPs. NPC issued an RFP on July 29, 2002, February 24, 2003, and on April 14, 2003, and each was issued to members of the Western Systems Power Pool ("WSPP") Agreement. Energy products NPC requested in these RFPs were intermediate and long-term summer and annual products,

peak and off-peak products, and Palo Verde-to-Mead transactions. (Id. at 5.)

85. Mr. Hill also noted that NPC issued RFPs for Utah and Colorado coal during September 2002 for deliveries beginning January 2003. The RFP requested a one-year term and/or a three-year term. Seven suppliers submitted bids for one-year terms, with three of those suppliers submitting three-year term proposals. (Id. at 10.)

86. With regard to the Gas Supply Plan, Mr. Hill stated that traders procured product volumes identified by the Planning and Analysis and/or Power Trading groups from contracted parties. The lowest price buying option was then determined through market surveys. (Id. at 12.)

87. The Gas Supply Plan was met by using a combination of term and spot products. Mr. Hill explains that term supplies were solicited through the RFP process, and bids were evaluated based on price, flexibility of delivery points, quantity available, reliability of supplier, and creditworthiness. Term products were delivered to the system at indexed prices, according to Mr. Hill. Spot supplies were usually procured as day-ahead or day-of-flow, and spot prices were negotiated daily based on prevailing market prices by traders. (Id. at 12.)

88. Economic implementation of the Gas Supply Plan consisted of swaps and options. Mr. Hill testifies that the purpose of the financial hedges was to manage the cost of the procured gas supplies and the gas price component of electric power agreements for the test period. (Id. at 12.)

89. For this test period, NPC solicited approximately 50 gas suppliers in five different RFPs for summer and winter seasonal bids. Products were acquired from the solicited bids. A total of 67 term transactions were active in the October 2002 through September 2003 period. (Id. at 13.)

90. The summer 2002 hedge program had a mixed portfolio of approximately one-third swaps, one-third options, and one-third at market prices, and concluded in October 2002. The winter 2002-2003 hedge program consisted of approximately 50 percent swaps and 50 percent options. For the summer of 2003, the hedge program called for the exclusive use of call options. (Id. at 14.)

91. Financial transaction activity occurred between 18 and 24 months prior to the settlement periods. Mr. Hill states that each of the term transactions was executed at market prices consistent with an Energy Supply Plan monitored according to the Risk Control Process. He noted that the products purchased pursuant to these transactions were consistent with the requirements of competitive solicitations, and the prices paid compared favorably with other responses received during that time. (Id. at 14-15.)

92. NPC's resource optimization group optimizes its available resources through a real-time trading function, a real-time generation economics function, a pre-scheduling function, and a short-term power trading function. Mr. Hill explained that short-term power trading refers to trades with durations of one month or less. (Id. at 15.)

93. NPC's resource optimization group strives to mitigate the costs of term contracts with internal generation and short-term trades, according to Mr. Hill. With regard to day-ahead and real-time trading, the market is surveyed to locate opportunities to make sales above the incremental cost to generate energy in excess of the needs of NPC's native load. The sale of excess generation priced above the incremental cost of producing such energy reduces the average price per megawatt hour ("MWh") of the energy supplied to native load customers. Further, day-ahead and real-time mitigation efforts and economic dispatch of system resources result in the lowest net electrical production cost for NPC and its customers. (Id. at 17.)

C. Risk Management and Control

NPC's Position

Mr. Coyle

94. NPC witness, Richard Coyle, Vice President of Finance and Chief Risk Officer, testifies that he serves as the independent officer responsible for monitoring the operation of NPC and SPPC to ensure compliance with risk policies and procedures of the companies. He addresses NPC's DEAA rate and BTER with regard to NPC's risk control process and operation during the test period, and supports NPC's request to calculate the carrying charge applicable to the DEAA balance to capture the total cost of funds borrowed to pay for purchased fuel and power. (Ex. 11 at 3.)

95. The risk policies NPC has implemented are:

- a) Enterprise Risk Management and Control Policy – standards for monitoring and controlling integrated enterprise risks, including energy supply risks;
- b) Energy Risk Management and Control Policy – applicable to all physical and financial transactions related to Sierra Pacific Resource's ("SPR") energy procurement activities and its energy supply portfolios; and,
- c) Credit Risk Management and Control Policy – outlines SPR's philosophy toward the management and control of the credit risks of normal business operations. (Id. at 4.)

96. Primary objectives of Enterprise Risk Management and Control Policy include:

- a) identification of risks;
- b) qualitative or quantitative assessment of risks;
- c) evaluation of costs and merits of risk mitigation options; and,

d) identification of risks to be retained by the Companies. (Id. at 5.)

97. The primary purpose of the Energy Risk Management and Control Policy is:

a) provide preset limits and guidelines for employees authorized to legally bind the Companies to transactions covered by the policy;

b) establish sound guidelines for the management and control of risks attributable to those transactions; and,

c) define the responsibilities for managing and monitoring those risks. (Id. at 5-6.)

98. The primary purpose of the Credit Risk Management and Control Policy is:

a) provide guidelines for employees authorized to legally bind SPR and its subsidiaries to procurement and sales, service delivery transactions;

b) establish sound guidelines for the management and control of risks attributable to those transactions; and,

c) define the responsibilities for managing and monitoring those risks. (Id. at 6.)

99. Mr. Coyle states that the Credit Policy applies to all of the physical and financial transactions at SPR and its subsidiaries. He identified three main areas of credit risk address in the policy as energy supply, large customer accounts, and supply chain management (non-fuel). (Id. at 6-7.)

100. NPC controls and manages energy risk primarily through organization and governance, energy risk management programs, and energy risk control practices. (Id. at 7.)

101. Six areas affected by SPR's risk management process are:

1. Enterprise Risk Oversight Committee ("EROC")

2. Energy Risk Committee (“ERC”)
3. Vice President, Finance and Chief Risk Officer
4. Risk Control
5. Credit Risk Management
6. Energy Supply (Id. at 7-8.)

Mr. Thompson

102. Mr. Rick Thompson, Manager of Risk Control and witness for NPC, discusses NPC’s Risk Control and states that Risk Control has the following four key responsibilities:

- a) Monitoring compliance with approved policies, limits, and procedures;
- b) Reporting;
- c) Managing limit exceptions; and,
- d) Assisting the Chief Risk Officer on special projects. (Ex. 13 at 2.)

103. Mr. Thompson explains that monthly risk control reports are prepared by Risk Control for the ERC and EROC usually completed by the third week of each month and include data through the end of the previous month.

104. Mr. Thompson states that market data includes information such as historical spot prices and forward price curves for natural gas and power. Portfolio data includes counter-party ratings and current exposure. The ERC and EROC utilize the data to monitor current and expected future economic conditions, and assess their effect on the general business environment and on NPC. (Id. at 3-4.)

105. The EROC approved an Energy Risk Management and Control Policy on January 6, 2003, that set limits for the energy supply portfolios of NPC and SPPC. Three sets of limits that applied to energy transactions and the energy portfolio that were approved are: Transaction

Approval Limits, Portfolio Risk Control Limits, and Credit Risk Limits. (Id. at 4.)

106. Transaction Approval Limits control the values of contracts and the length of the terms of contracts. Risk Control reviews energy transaction, on a weekly basis, for compliance with transaction approval limits. The two limits are: contract value – the total dollar value of a contract; and contract term – the term length of a contract. (Id. at 4.)

107. Risk Control Limits constrain the energy supply portfolio, and limits are monitored monthly and more frequently based on market trends. Three limits measured are: Test Period Mark-to-Base; Value-at-Risk (“VAR”); and, Supply Plan Parameters. (Id. at 5.)

108. Credit Risk Limits help to ensure that SPR is not overly exposed to suppliers and other counter-parties with unacceptable credit profiles, according to Mr. Thompson. Credit risk is monitored and measured on a combined basis (Transaction Approval Limits and Portfolio Risk Control Limits are monitored and measured for NPC and SPPC individually) to assess risks by each counter-party. Four credit limits monitored monthly are: portfolio below investment grade; portfolio weighted average credit rating; counter-party credit limit–on-going transactions; and, counter-party credit limits–large transactions. (Id. at 6-7.)

109. Mr. Thompson also explains that a set of metrics was established that are monitored by Risk Control on a period basis. These metrics provide transparency of the corporate credit portfolio to the EROC. An Arrears Balance Metric and Uncollected Deposits Metric were established to monitor the credit exposure attributable to large retail customers. To control the credit exposure attributable to Supply Chain Management, a Counter-party Credit Metric was also established. (Id. at 7.)

///

///

D. Electric**1. Forward Contracts and Basis Swaps****NPC's Position****Mr. Meehan**

110. NPC witness, Mr. Meehan, evaluates the prudence of NPC's forward power purchasing activities for the test period of October 1, 2002, through September 30, 2003. The deferred balance for which NPC seeks recovery includes these purchases. (Ex. 7 at 3.)

111. Mr. Meehan addresses all purchases of forward electricity products and risk management products bought on a forward basis. Forward electricity products refer to electricity purchases at least one month prior to delivery, according to Mr. Meehan. He does not consider week-ahead, day-ahead, and other short-term purchases in his analysis. (Id. at 3.)

112. Mr. Meehan notes that risk management products refer to financial transmission products, tolling agreements, and electricity options. He considered all risk management products purchased at least one month in advance in his analysis. (Id. at 3-4.)

113. Mr. Meehan considered NPC's short-term purchases that were entered into to optimize the use of its existing generation assets. (Id. at 4.)

114. NPC's forward electricity purchases for the test year are characterized in four phases:

- a) Phase 1 – purchases made in the period prior to and surrounding the FERC's June 2001 order on Western price caps;
- b) Phase 2 – purchases made in the fall of 2001, when the market for test year deliveries had declined substantially. NPC accelerated test year purchases at this point;
- c) Phase 3 – purchases made subsequent to 2001, including but not limited to

purchases made pursuant to the development and implementation of NPC's Energy Supply Plan of January 31, 2003.

- d) Phase 4 – purchases made for economy energy reasons, including Q1 of 2003 purchases made in December 2002, month-ahead purchases made at various times during the Test Period, and 324 MW of off-peak purchases for June and July 2003 made in May 2003. (Id. at 4.)

115. Mr. Meehan testifies that in each of the four phases NPC's procurement practices were prudent. He states that in Phase 1, relying on the forward market was the only reasonable choice available to NPC. In Phase 2, Mr. Meehan submits that it was prudent to utilize the standard block as a way of trading power in the WECC and relying on block purchases and the broker market. He states that in Phase 3, NPC returned to practices it had used successfully in the past and were available again. Mr. Meehan asserts that this was a prudent reaction to the changes in the market. In Phase 4, he states that practices were also prudent and NPC made low risk purchases to provide energy cost savings. (Id. at 10.)

116. Mr. Meehan stated that the standard for what constitutes prudent managerial action is well established in regulatory practice. He noted that prudence is best characterized as whether NPC's actions are generally consistent with what a reasonable person would have done given the information reasonably available at the time. (Id. at 11.)

117. To assess the prudence of NPC's transactions, Mr. Meehan developed a series of questions that provide the framework for evaluating whether the transactions were reasonable. He then evaluated these questions based on objective information available at the time the transactions were entered into. (Id. at 12.)

118. Mr. Meehan submits that the four questions he developed to provide an objective

means of determining whether NPC's purchases were prudent focus on the following main issues:

- a) the reasonableness of the need for the relatively large volume of purchases;
- b) the reasonableness of the decision to begin purchasing small quantities of power in early 2001 for the Test Year and accelerated quantities in late 2001;
- c) the reasonableness of the Phases 3 and 4 purchase strategy; and,
- d) the reasonableness of the execution of the purchases. (Ex. 7 at 13-14.)

119. With regard to deferred energy carrying charges, Mr. Coyle explains that when the utility pays more for the fuel and power it purchases than it recovers through the BTER, an under-collection occurs. These under-collections are placed into a deferred account and eventually recovered through the DEAA. In order to pay for the energy purchased on behalf of customers, the utility must then raise capital (borrow money and sell stock). The cost of that capital (debt and equity) is carried until the full cost of purchased power is recovered from customers. The carrying charge, in under-collections, is designed to reimburse the utility for the cost of the capital associated with funding the full cost of the purchased power. (Id. at 24-25.)

120. An over-collection occurs when the utility pays less for the fuel and power it purchases than it recovers in its BTER. In this instance, the over-collection is treated as a loan to the utility and the carrying charge is designed to compensate customers for the use of their funds during the over-collection period. (Id. at 25.)

MGM's Position

121. MGM's witness, Mr. Mark E. Garrett, an attorney and consultant specializing in

utility regulation, recommends an adjustment, with respect to NPC's purchased power purchases, in the amount of \$38,147,165. Mr. Garrett explains that his adjustment restates the transactions entered into during the early months of 2001 using the prices available during the fall of 2001, as a proxy for reasonable prices. He has also removed the losses incurred on buy/sell arrangements made for the Fourth Quarter ("Q4") of 2002 and calendar year 2003 during this same period. More specifically, his adjustment includes imprudent power purchases and trading losses for six 6x16 transactions that NPC sold for a cumulative loss of \$9,983,878, also referred to by Mr. Meehan under the heading "Basis Swaps." Also included is the difference between what NPC paid for power purchases in early 2001 versus what he believes NPC should have paid had it followed its own policies at points in time closer to when they were actually needed. (Ex. 28 at 10-11 and Attachment DLB-01.)

122. Mr. Garrett explains that his proposed adjustment uses the same reasoning articulated by the Presiding Officer's Draft Opinion in NPC's last deferred energy case, Docket No. 02-11021. The Draft Opinion proposed to disallow \$62,261,800 of forward purchases for 2002 made by NPC in early 2001. Furthermore, Mr. Garrett states that in the Final Opinion of Docket No. 02-11021, the Commission believed that, "NPC failed to analyze the available market data on price while over-purchasing power at extremely high prices 12-17 months before it was needed," and it disallowed purchases made by NPC during the period of December 16, 2000, through May 30, 2001, for deliveries in the summer of 2002. Mr. Garrett states that the purchases proposed in his adjustment for the 2003 test year are imprudent because they also violated the Timed Procurement Strategy since they were made some 18 to 30 months prior to their need. (Id. at 8.) Mr. Garrett also notes that the Commission found that NPC did not follow "its policies in effect at the time the purchases were made." Additionally, Mr. Garrett also states

that the purchases proposed in his adjustment for the 2003 test year are imprudent because they violated the Timed Procurement Strategy by being made some 18 to 30 months prior to their need. (Id. at 8.)

123. In addition, Mr. Garrett states that a review of NPC's purchased power contracts in this Application reveals that NPC also made purchases at excessively high prices in early 2001 for the test period here, some 18-30 months before the power was actually needed. He believes that these purchases were made as a result of NPC's failure to "analyze the available market data on price" and its further failure to follow its own Risk Management Committee ("RMC"), "policies in effect at the period of time the purchases were made." Mr. Garrett also notes that in his review of NPC's RMC meeting minutes, he failed to find any authorization of such purchases by the RMC. (Id. at 8-9.)

124. Mr. Garrett also reviewed NPC's 2001 purchased power contracts for the test year in this docket and found that NPC entered into one transaction, Number 1137, with a start date of January 1, 2002, and an ending date of December 31, 2002, at a price of \$162.00 per MWh. Given the fact that the December 15, 2000, order of FERC has a \$150.00 per MWh soft price cap, any costs that NPC incurred above the \$150.00 per MWh soft price cap are clearly imprudent. (Id. at 9.) However, Mr. Garrett believes that there is substantial evidence for disallowing more than the costs above FERC's \$150.00 per MWh associated with Transaction Number 1137; in fact, he would restate, to a reasonable level, all of the purchases made for the 2003 test period that were entered into during that extremely volatile period in early 2001. (Id.) He believes that these transactions violated NPC's purchasing strategy at the time and were made in an extremely volatile market where prices had soared to unprecedented levels. He further believes that, while NPC might be able to articulate reasons for purchasing power for its 2001

summer, or even 2002, requirements during this volatile period, it cannot justify making purchases at these prices for 2003, some 18-30 months in the future. Mr. Garrett reiterates that not only did NPC have no authority from its RMC to make purchases to satisfy its 2003 requirements, but there wasn't any valid reasons to accelerate the 2003 purchases. He explains that the strategy in place at the time only called for filling Second Quarter ("Q2") and Third Quarter ("Q3") requirements for 2001 and 2002. Additionally, there was no mention made of any such approval for filling open positions for 2003.

125. In conclusion, Mr. Garrett states that because of: the extremely high and volatile market prices; the FERC actions that set a wholesale soft price cap; the lack of studies to quantify NPC's financial risks or guide NPC in its power purchasing strategy; and the fact that there was no authorization from its own RMC, he believes that the several transactions to purchase power that NPC entered into for 2003 were imprudent. (Id. at 5 and 9.) He notes, however, that prices paid in 2001 were paid during a dysfunctional market. (Tr. at 376.) This results in a recommendation for an adjustment in the amount of \$28,255,060, which is the difference between what NPC paid for imprudent power purchases in an early 2001 highly volatile and dysfunctional market versus what NPC should have paid if it had followed its stated policies. (Id. at 10-11.)

BCP's Position

126. BCP witness, Mr. Williamson, recommends that the Commission deny NPC recovery of \$20,557,344 in purchased power costs resulting from transactions that were undertaken and performed imprudently by NPC. (Ex. 27 at 16 and Attachment JPW-2.)

127. Mr. Williamson states that NPC purchased 25 percent of its purchased power needs for Q3, 2003, and 125 MW of forward products for calendar year 2003 from late January

2001 through the end of June 2001. He claims that these purchases are imprudent for the following reasons:

- a) They were made with minimal investigation, minimal planning and were basically entered into on the “spur of the moment.” (Id. at 14.)
- b) They were made at a time when Western energy markets were still in crisis, even though the energy would not be needed for another two years. (Id. at 13.)
- c) NPC violated its own purchasing policy when it filled 25 percent of its purchased power needs for Q3, 2003, and an additional 125 MW of forward products for calendar year 2003, approximately two years in advance. Under the “Timed Procurement Strategy,” which was the policy at the time, NPC should have gradually filled its open position with no more than 30 percent filled more than two or three months in advance. (Id. at 15.)

128. Therefore, Mr. Williamson believes that the increased costs of these transactions are costs resulting from transactions that were undertaken and performed imprudently by NPC; thus, ratepayers should not be responsible for these increased costs. (Id.) Mr. Williamson, however, recognizes that NPC did acknowledge that NPC had issued an RFP which was included in the CEP and that that proposal extended to 2010. (Tr. at 344-346.)

Staff’s Position

129. Staff witness, Arturo Vivar, presents recommendations on behalf of Staff on issues relating to NPC’s power purchases and associated risk management activities. In Mr. Vivar’s review of NPC power contracts, he found that the Commission should consider several

contracts for disallowance. (Ex. 18 at 3.)

130. In September and October of 2001, NPC entered into a series of 6x16 and 7x24 forward power contracts. In the Minutes of the PLR Energy Risk Management-Exposure Management Committee meeting dated October 17, 2001, NPC noted the following contracts:

- 300 MW (Mead) 7x24, 2004-2012 @ 35.50
- 50 MW (Mead) 7x24, 2003 @ 36.00
- 150 MW (Palo Verde to cover previously executed Mead/Palo Verde spread) 6x16, 2003@ 39.75
- 300 MW (Mead) 6.16, Q2/Q3 2003-2005 @ 47.06 (average price)

131. Mr. Vivar notes that NPC acknowledged in the meeting's Minutes that, due to its poor credit position, a \$40 million cost to ratepayers resulted from these contracts. (Id. at 5-6.)

132. Further, Mr. Vivar contends that the issue is whether ratepayers should be responsible for this additional cost. He submits that maintaining financial health is the responsibility of NPC's management, and NPC should bear the burdens of its actions with regard to costs associated with poor credit, not the ratepayers. Hence, he states that at issue is how much of the \$40 million cost is applicable to purchases in the Test Period and subject to disallowance. (Id. at 7.)

133. Mr. Vivar submits that the resulting disallowance should be \$1,589,599 according to his calculations. He notes that given the fact that the \$40 million cost was not broken out by NPC and, given the lack of information for a calculation to allocate the cost among the several contracts, an estimate based on the weighted dollar value of the Test Period contract volumes to the total dollar value of the full volume of the contracts was made. Hence, his calculation is the dollar value of the contract volumes that were delivered into the Test Period divided by the total

value of all of the contract volumes. (Id. at 7.)

134. With regard to a second proposed adjustment, Mr. Vivar also takes note of a February 2001 Forward Power Contract, listed as Transaction Number 1137 in NPC's Bookrunner report. The contract has the following characteristics:

- Term: Calendar 2002 (for purposes of this analysis only the Q4 of 2002 portion of the contract relevant to Test Period)
- Type: 6x16 Firm Energy
- Delivery Point: Mead
- Price: \$162 per MWh
- Quantity: 50 MW

135. Mr. Vivar notes that this transaction is a remnant of the type of power contract that was disallowed in NPC's previous deferred energy rate case, and this contract was entered into more than six weeks after FERC issued its soft price cap of \$150 per MWh. He contends that this is a high-priced purchase power transaction executed when NPC did not follow its own policies. Mr. Vivar concludes that, based on the findings and precedence in the prior deferred energy case (Docket No. 02-11021) with the same methodology applied therein, Transaction Number 1137 should be adjusted downward. (Id. at 9.)

136. Mr. Vivar contends that the calculation to determine the disallowance of costs related to this contract is straightforward and that he applied the same methodology as the Commission applied in Docket No. 02-11021. Hence, the fixed price in the remnant contract is compared to the forward prices at a more proximate date to the Test Period. The disallowance is \$7,639,632 based on this methodology. Mr. Vivar states that the timeframe used to set the market price that NPC would otherwise have paid is the average of the forward power prices for

Mead delivery in Q4 of 2002, as quoted in July, August, and September of 2002. (Id. at 9-10.)

137. Mr. Vivar's Exhibit AV-2 illustrates that forward power prices in 2002 during any month of the period leading up to Q4 of 2002 period were relatively low. He opines that purchases made for Q4 of 2002 during any month of the period leading up to Q4 of 2002 would have been beneficial to the ratepayers as compared to the actual prices NPC paid for the contract in questions. Mr. Vivar states that Mead forward prices are used to match the delivery point of the contract, and a credit risk premium of 8 percent is used to be consistent with the Commission's approved methodology. (Id. at 10.) However, on cross-examination Mr. Vivar states that he was not involved in the Western energy markets during the energy crisis. (Tr. at 187.) Additionally, his involvement in this case was limited to a review of some documents, and he exhibited limited knowledge of the RMC, as well as NPC's strategy. (Tr. at 189-193.)

138. Based on his analysis, Mr. Vivar concludes that a total of \$9,229,231 should be deducted from the DEAA amount sought by NPC.

NPC's Rebuttal Position

139. NPC's witness, Mr. Meehan, disagrees with Mr. Garrett's proposed disallowances regarding "Basis Swaps". He argues that the transactions that Mr. Garrett identifies as "speculative trades" (Attachment DLB-01), do not represent speculation or an attempt by NPC to buy and sell power in the market in order to realize a profit; rather, these transactions are basis trades. (Ex. 9 at 2.)

140. Mr. Meehan explains that basis trades are used to secure the delivery of power from one distinct trading hub to another delivery point. For instance, in the case of Palo Verde and Mead, Mr. Meehan explains that these hubs are not directly connected electrically; however, the markets are linked through basis trading. The cost of transmission between two distinct

trading hubs is the difference between the cost of power delivered at Palo Verde, a more liquid trading hub, and the cost of power delivered at Mead. Mr. Meehan explains that this difference, called basis, represents the cost of transmission between Palo Verde and Mead. Therefore, Mr. Meehan states that Mr. Garrett's calculation of the cost of transmission between Palo Verde and Mead of \$9,983,878, is incorrect because he has mischaracterized transmission costs as "trading losses". (Id. at 2-3.)

141. With regard to identifying basis trades, Mr. Meehan explains that they are easily identified according to their pattern. For instance, in the case of Palo Verde and Mead, the basis trades would be identified for the following reasons:

- a) The sale and purchase of identical products occurred on the same day.
- b) The sale is at a point remote from NPC's system (Palo Verde) and the purchase is at a point deliverable into NPC's system (Mead)

(Id. at 3.)

142. Mr. Meehan also notes that NPC's use of electric basis trades in 1999 and 2000 was reviewed and accepted by independent auditors Price Waterhouse Coopers ("PWC"). In addition, NPC's use of electric and gas basis trades in 2001 and 2002 has been reviewed by the Commission in each of the last two deferred energy dockets, in SPPC's deferred energy dockets and in its purchased gas adjustment proceedings. The Commission has never found the practice of using basis trades to be imprudent. (Id. at 3-4.)

143. Mr. Meehan states that Mr. Garrett's analytical approach to his recommended disallowance of \$28,255,600 for the 2001 forward contracts for 2003 delivery is not appropriate. Mr. Meehan argues that Mr. Garrett relies on hindsight methodology and inappropriate proxy prices in "adjusting" transactions due to timing. (Id. at 4.)

144. Mr. Meehan states that Mr. Garrett's testimony is hopelessly flawed with regard to the facts in and around FERC-imposed price caps. (Id. at 5.) For instance, Mr. Garrett mischaracterizes facts with respect to price caps in the West because the FERC Order, which set the so-called "soft" cap on prices at \$150/MWh, was not applied outside of California. Furthermore, as experience showed in the weeks following the imposition of the \$150/MWh cap, the California soft cap was not effective and prices climbed far above the soft cap not only through the West, but also in California. (Id. at 4-5.) Lastly, Mr. Meehan notes that the prevailing thought in the period February to April 2001 was that additional price caps would not be imposed. (Id. at 5.)

145. With regard to the analysis performed by NPC and the consistency with its policies in force at the time, Mr. Meehan believes that Mr. Garrett ignores the fact that NPC prepared and filed the Comprehensive Energy Plan ("CEP") in January of 2001, which called for purchases to be made for 2003 and 2004. Mr. Meehan argues that the assertion that purchases were made without study and without authorization is simply wrong. He explains that the CEP is a clear, unequivocal and very public explanation of NPC's response to the energy crisis, the cancellation of divestiture and unavailability of the Transitional Purchase Power Agreements, as well as its intention to begin closing its open positions for 2002-2004. He also notes that the CEP is authorized at the highest levels of NPC; therefore, the assertion that these purchases were contrary to NPC's policies because they were not approved by the RMC is simply untenable. (Id. at 5-6.) Furthermore, Mr. Meehan contends that Mr. Garrett justifies his position by pointing to the reasoning reflected in the Commission's Draft Opinion, which was rejected in and eliminated from the Final Order. (Id. at 6.)

146. In addition, Mr. Meehan argues that Mr. Garrett mischaracterizes the market

conditions because, while recognizing volatility, the testimony fails to recognize that the prices NPC paid for 2003 products reflected very reasonable implied heat rates that were consistent with a balanced or even surplus market. Mr. Meehan contends that Mr. Garrett's testimony presents no analysis to demonstrate why such a purchase was unreasonable given the market conditions at the time; in fact, the market volatility mentioned by Mr. Garrett justifies closing some open positions. (Id. at 6-7.)

147. Mr. Meehan also argues that Mr. Garrett does not provide plausible reasons detailing why NPC should have adopted a *contrarian's* view of the market in February to April 2001, and assumed prices would drop, given that the market consensus was that prices were going to rise. (Id. at 7.) His testimony also does not provide any market analysis or rationale to explain when NPC should have known it should have bought power other than "later." Mr. Meehan questions why NPC should have waited three months, six months, or a year for the "market to clear" before buying, especially since prices continued to rise after FERC's December 15, 2000 Order. Mr. Meehan concludes that Mr. Garrett's testimony provides no evidence, just hindsight observations, as to how NPC could have known at the time that power prices would eventually collapse in June 2001. (Id. at 7-8.)

148. Further, Mr. Meehan argues that regardless of the false premises and historical disallowance recommendations of Mr. Garrett, his calculations are also inappropriate. For instance, the testimony uses two types of "Phase II" prices in his adjustment calculation in Exhibit DLB-01, which result in an apples to oranges adjustment. Specifically, the testimony proposes a \$50/MWh price for delivery at Palo Verde for Transaction 1137; however, this transaction was delivered at Mead, so using the \$50/MWh price is inappropriate. (Id. at 8.) Mr. Meehan also notes that Transaction 1137 was reviewed by the Commission and approved for

recovery in Docket No. 02-11021.

149. In addition, Mr. Garrett also miscalculates by “eyeballing” forward market price average and does not present precise or comparable prices for the period.

150. Mr. Meehan also argues that the methodology used by Mr. Garrett is inconsistent regarding Transaction 1407. Mr. Meehan explains that Transaction 1407 is a two-year product for delivery of power in 2002 and 2003, with a two-year blended price; however, Mr. Garrett treats this transaction as if it was a one-year product only. Consequently, the effective 2003 price would be much lower, thereby lowering the proposed disallowance. (Id. at 9.)

151. Lastly, Mr. Meehan notes that in Mr. Garrett’s testimony, the Phase II MW-weighted average prices include transactions with delivery both at Mead *and* Palo Verde and are again not appropriate to use as proxy prices with the transactions identified in the testimony. (Id.)

152. Finally, Mr. Meehan rebuts Mr. Garrett’s conclusion that Transaction 1137 was inconsistent with NPC’s stated purchasing strategy. Mr. Meehan argues that this strategy had been disclosed to the public in Docket No. 01-1045, the CEP. In the CEP, NPC specified its intent to contract for 6x16 firm energy for delivery in 2002 (Q1 500 MW, Q2 750 MW, Q3 1000 MW and Q4 500 MW); therefore, Mr. Meehan contends, Transaction 1137 is entirely consistent with this stated strategy. (Id. at 6-7.)

153. Mr. Meehan disagrees with Mr. Williamson’s recommendation regarding power purchases. (Ex. 8 at 7.) Mr. Meehan argues that Mr. Williamson’s three reasons for his adjustment rely entirely on his misapplication of the Commission’s prior order in Docket No. 01-11029. For instance, Mr. Williamson contends that NPC made purchases “with little or no analysis.” Mr. Meehan argues that Mr. Williamson’s use of paragraph 283 of the Commission’s

order in Docket No. 01-11029 as the basis of his conclusion, and also his attempt to paint purchases made for 2003 with the same broad brush, is a misapplication of the order and is at best disingenuous. (Id. at 7-8.) Mr. Meehan contends that the Commission is well aware that the order in the 2001 deferred energy case did not address purchases for delivery in 2003. As a matter of fact, Paragraph 283 in the prior order dealt with two specific categories of purchases made in February and April 2001 for delivery in the summer of 2001; therefore, this paragraph of the order has absolutely nothing to do with purchases made in 2001 for delivery in 2003. (Id. at 8.)

154. Mr. Meehan also argues that in addition to Mr. Williamson's misapplication of the Commission's prior order, his assertion that the purchases made for delivery in 2003 were made without analysis is incorrect. Once again, Mr. Meehan points out that these purchases were consistent with the CEP, and the analytical work behind it, provided to the Staff and BCP at the time, was substantial. Mr. Meehan argues that Mr. Williamson provides no evidence that the analysis of the transactions at question in this proceeding was not done and that his quote from the prior order deals with very different transactions. (Id. at 8-9.) Mr. Meehan also contends that, regardless of the work behind and in the CEP, such analysis is not required to realize that 25 percent of need is required or that the implied heat rate in a forward price is consistent with a return to a balanced market. Mr. Meehan notes that a specific contemporaneous analysis is not necessary when the results are obvious. (Id. at 9.)

155. In addition, Mr. Meehan believes that while the market was volatile, the purchases that NPC made in 2001 for delivery in 2003 were at prices that were consistent with a return to an equilibrium and even a capacity surplus market. Mr. Meehan argues that Mr. Williamson does not explain by any reference to NPC's need or by any reference to the market

conditions reflected by this purchase why these purchases were imprudent. (Id. at 9-10.)

156. With regard to Mr. Williamson's claim of volatility and reference to Mr. Meehan's testimony that markets were still in crisis, Mr. Meehan argues that the crisis was related to shorter-term markets and to gas markets. He then contends that the implied heat rates for the purchases made by NPC in 2001 for delivery in 2003 were very reasonable. Mr. Meehan argues that Mr. Williamson fails to recognize that it was, in fact, the crisis in the markets that made it prudent to buy 25 percent of the 2003 requirement in 2001, especially at the equilibrium prices NPC was able to obtain. (Id. at 10.)

157. Finally, in rebuttal to Mr. Williamson's contention that the purchases made "violated NPC's own purchasing strategy," Mr. Meehan states that this criticism is not valid for many reasons. First, Mr. Williamson bases his conclusion on minutes from a November 2000 RMC meeting, completely ignoring the effect that the events subsequent to November had upon NPC and its stated purchasing strategy. Mr. Meehan explains that these events were the most significant electric market crisis in the history of this country and were so significant that the state of Nevada did a complete about-face with respect to restructuring and divestiture. In addition, NPC was under a Commission order, which was consistent with the BCP's position at the time, to refile its resource plan to include longer-term power purchases. Mr. Meehan reiterates that the CEP, filed January 2001, clearly states NPC's intent to purchase for 2003 and beyond. In conclusion, Mr. Meehan contends that, in any case, non-conformance with a policy does not necessarily constitute imprudence; however, since it is clear that NPC had reasonably changed its policy in response to changing events, the Commission need not even broach the issue. (Id. at 10-11.)

158. NPC's witness, Mr. Meehan, disagrees with Mr. Vivar's proposed disallowance

of \$7,639,632 associated with the test year costs of Transaction 1137. Mr. Meehan argues that Mr. Vivar does not perform any independent analysis of the prudence of this transaction and disagrees with both the logic used as the basis of the proposed disallowance and his conclusions. (Ex. 8 at 2.)

159. First, Mr. Meehan contends that Mr. Vivar merely characterizes this transaction as being similar to transactions reviewed by the Commission in the last deferred energy proceeding when in fact, Transaction 1137 was *actually* reviewed by the Commission in Docket No. 02-11021 and was *not* identified as imprudent by any intervener or the Commission. (Id. at 2 and 3.) Mr. Meehan notes that the reason Transaction 1137 was not identified as imprudent in the last case is because it is *dissimilar* to those that were found to be imprudent. (Id. at 3.) Mr. Meehan explains that Transaction 1137 was not a typical “standard product” since it was for a 6x16 delivery pattern and was not purchased at a regional trading hub. Transaction 1137 was a purchase of power delivered all the way in to NPC’s control area, at the Mead substation. The price for Transaction 1137 of \$162 per MWh included the cost of transmission from Palo Verde into Mead. Mr. Meehan argues that Mr. Vivar makes no attempt to calculate what the cost of transmission into NPC’s control was at the time and thus fails to demonstrate that Transaction 1137 was priced in excess of FERC’s soft price cap of \$150 per MWh. (Id. at 3-4.)

160. As in his rebuttal to Mr. Garret, Mr. Meehan reiterates that the cost of transmission between two distinct trading hubs, such as Palo Verde and Mead, is the difference between the cost of power delivered at Palo Verde and the cost of power delivered at Mead. This difference, Mr. Meehan contends, is called the basis and represents the cost of transmission between Palo Verde and Mead. (Id. at 4.) Mr. Meehan explains that between January 2001 and May 2001, NPC entered into seven basis swaps to secure delivery of Calendar Year 2002 6x16

power from Palo Verde to Mead. The average price of transmission from Palo Verde into Mead during this period was \$19.86 per MWh. The lowest priced basis trade between Palo Verde and Mead that NPC was able to realize during this period was \$15.00 per MWh. Adjusted for the cost of transmission into NPC's system, Transaction 1137 was priced well below the soft price cap of \$150 per MWh. (Id. at 5.)

161. Mr. Meehan also contends that the transactions disallowed in the previous deferred energy filing were not for product delivered into Mead. He states that all of the transactions that were determined to be imprudent in the last case were purchases for delivery at Palo Verde. None of the purchases were for delivery into NPC's system. (Id.)

Commission Discussion and Findings

MGM's Proposed Adjustment

162. Mr. Meehan identifies a fundamental mistake in the analysis by Mr. Garrett in which the basis cost was confused with a trading loss. Mr. Meehan clearly explains that the difference in price calculated by Mr. Garrett reflects the cost of moving the electricity from the liquid trading hub at Palo Verde to NPC's hub at Mead. The Commission has been presented considerable testimony in prior cases concerning the problem NPC encounters in moving electricity from the liquid hub of Palo Verde to Mead and is well aware that there is, at times, a significant expense related to that transfer of electricity.¹ Therefore, based on Mr. Meehan's testimony, the Commission believes the proposed adjustment of \$9,983,878 is not appropriate and finds that Mr. Garrett's proposed adjustment should be rejected.

163. Mr. Garrett's proposed adjustment of \$28,255,060 is based on a restatement of NPC's actual cost to Mr. Garrett's estimate of a more reasonable level. As Mr. Meehan points

¹ This very issue was addressed in Docket No. 03-7004 wherein NPC was authorized to seek additional transmission capacity between Palo Verde and Mead.

out, this is based on a Draft Order of the Commission in Docket 02-11021, and, as such, carries no weight. Also, as Mr. Meehan also points out, the environment that existed in 2001 could not lead one to reasonably conclude that prices would drop to the level that Mr. Garrett considers reasonable a short time later. As Mr. Meehan reports, prices in fact continued to rise after FERC issued its December 15, 2000, order imposing price caps. Mr. Meehan clearly demonstrates that based on a reasonable analysis by NPC, at that time, the prices paid for 2003 products appeared to be reasonable based on the implied heat rates. Mr. Garrett did not do an analysis to determine whether the 2003 products were reasonable at the time NPC bought them. Additionally, Mr. Meehan points out two errors made by Mr. Garrett relating to Transactions 1137 and 1407. Further, Mr. Meehan relates that the Phase II prices used by Mr. Garrett are weighted averages, which include transactions with delivery at Mead and Palo Verde, thus basis costs are not considered.

164. The Commission believes that there are significant errors related to Mr. Garrett's proposed adjustment. Additionally, the Commission concurs with Mr. Meehan that Mr. Garrett's analysis was based on hindsight observations. Accordingly, the Commission finds that Mr. Garrett's proposed adjustment of \$28,255,060 is inappropriate and therefore rejected.

BCP's Proposed Adjustment

165. Mr. Williamson's proposed adjustment of \$20,557,344 is based on his assertion that the related transactions were imprudent. He states that NPC should have gradually filled its open position with no more than 30 percent more than two or three months in advance.

166. As Mr. Meehan indicates, the Phase II prices used by Mr. Williamson, as well as Mr. Garrett, are weighted averages which include transactions with delivery at Mead and Palo Verde. Therefore, the basis costs, which can be very substantial, have not been considered. As a

result, the Commission has concerns about the accuracy of Mr. Williamson's adjustments.

167. Mr. Williams makes an issue of the fact that NPC purchased 25 percent of its needs for Q3, 2002, between January and June 2001. Mr. Meehan points out that NPC's purchases were consistent with the CEP in Docket 01-1045. A review of this document, provided by Mr. Williamson's own counsel, indicates at pages 40-41 that in early 2001 NPC intended to purchase as much as 20 percent of its needs up to thirty-six months prior to the start of the period, with 10 to 40 percent purchased by 12 months before the start of the period.

168. Mr. Williamson asserts that the purchases were made with little or no analysis. However, Mr. Meehan rightly states that Mr. Williamson provided no evidence that NPC failed to conduct an analysis. In fact, in Docket 01-11029, the Commission found that NPC's practices in 1999 to 2000 were not imprudent and only made disallowances for purchases exceeding NPC's 107 percent strategy and for excess purchases. (Docket No. 01-11029 at 67.) Thus, the Commission believes that the evidence is that the purchases in 2001 for 2002 are prudent.

169. Since the purchase of power up to thirty-six months prior to use was clearly contemplated in the CEP, Mr. Williamson's assertion that the purchase of power in Phase I was "spur of the moment" is erroneous.

170. As in the case of Mr. Garrett, Mr. Williamson's use of Phase II prices as a reflection of reasonable prices appears to be a straightforward case of hindsight review and justification for his proposed disallowances.

171. Accordingly, the Commission believes that Mr. Williamson's proposed adjustment is not appropriate and finds that his adjustment is rejected.

Staff's Proposed Adjustments

172. Mr. Vivar states that PLR Energy Risk Management-Exposure Management

Committee Minutes indicate that ratepayers incurred a \$40 million expense on four contracts due to the poor credit condition of NPC. Mr. Vivar estimates that \$1,589,599 in improper expenses is related to the current test period, based on a ratio of the value of the contracts in the test period to the total contract volumes.

173. Mr. Vivar's proposal appears to be reasonable and apparently was not contested by NPC. Therefore, the Commission believes this is a reasonable adjustment and finds that NPC's Deferred Balance shall be reduced by \$1,589,599, which, when allocated and jurisdictionalized for Nevada by Mr. Buck, is a reduction of \$1,620,979.

174. Mr. Vivar proposes another adjustment in the amount of \$7,639,632 relating to a power contract on February 1, 2001, identified as Transaction No. 1137. According to Mr. Vivar, the proposed adjustment is based on Mr. Gildersleeve's theory in Docket 02-11021 where prices above \$150/MWh are considered unreasonable.

175. Mr. Meehan states that Mr. Vivar did no independent analysis of the prudence of this particular transaction. Mr. Meehan also correctly points out that this transaction is different from transactions that were deemed imprudent in the last Deferred Energy case. Transaction No. 1137 was for delivery at Mead, while the other transactions were for delivery at Palo Verde. The price of this contract, \$162/MWh, included the cost, or basis, of transmission into NPC's control area. Based on the lowest basis cost of \$15, the comparable cost of this contract fails to meet the criteria Mr. Vivar cites in making his adjustment. More importantly, however, Mr. Meehan reports that this transaction was reviewed and not found to be imprudent in Docket No. 02-11021. The Commission agrees with this statement. (See Docket 02-11021, Ex. 4 at 2.) Additionally, Mr. Vivar presents no evidence to cause the Commission to conclude that it should be disallowed or adjusted in this case.

176. Consequently, the Commission finds that this proposed adjustment of \$7,639,632 is improper and rejected.

177. Mr. Meehan indicates in his testimony that certain purchases did not require a specific contemporaneous analysis “when the results are obvious.” While the Commission is not finding that NPC did not do an analysis in this case, the Commission believes it important to state unequivocally for future consideration that NPC is expected to conduct an analysis in each and every situation where decisions are made that could materially affect NPC, its ratepayers, or its shareholders, even if the results are obvious.

E. Natural Gas (Fuel)

NPC’s Position

178. Mr. Branch explains that the Gas Supply Plan implemented for the test period of October 1, 2002, to September 20, 2003, consisted of months in three different gas seasons:

- a) Summer 2002 season consisted of October 2002 only;
- b) Winter 2002-2003 season consisted of November 2002 through March 2003; and,
- c) Summer 2003 season consisted of April through September 2003.

179. For each of these seasons, a Gas Supply Plan was implemented. The Gas Supply Plan for the winter 2002-2003 included a combination of approximately 50 percent fixed price and 50 percent options; and, the Gas Supply Plan for the summer 2003, part of the 2003-2005 Energy Supply Plan, called for the exclusive use of call options. (Ex. 4 at 10-11.)

180. For the winter 2002-2003, the Gas Supply Plan was to hedge 50 percent of the gas requirements using fixed price financial swaps and 50 percent using options. (*Id.* at 11.) Mr. Branch states that the Gas Supply Plan is a component of the Energy Supply Plan, which

articulates NPC's approach to controlling gas price risk and describes its physical procurement strategy. Further, the Gas Supply Plan specifies the physical and financial requirement by month and by supply basin. It also includes a description of the hedging strategy selected and an analysis of the various hedging strategies considered. The detailed implementation scheduled for the Gas Supply Plan lists the volumes and locations for each week of the hedging period. (Id. at 12.)

181. The Gas Supply Plan is developed using monthly forecasted physical gas requirements and financial gas exposure. Mr. Branch also notes that NPC constructed various gas supply strategies to fulfill seasonal resource requirements. The options included variants of product mix in the portfolio and variants in the degree to which the portfolio is hedged. He states that the potential strategies were evaluated based on criteria similar to those used to evaluate the Energy Supply Plan portfolio that included cost-to-serve, VAR, cost of hedge, collateral, and potential collateral. (Id. at 13.)

182. Mr. Branch explains that the summer 2003 Gas Supply Plan was consistent with previous strategies. He stated that all of NPC's physical gas requirements were filled by acquiring gas at index at either the SoCal or Rockies markets and that both points are sufficiently liquid to insure that all of NPC's needs could be met with index purchases. Also, NPC's financial gas requirements were hedged by acquiring \$0.50 out-of-the-money call options. (Id. at 14.)

BCP's Position

183. BCP witness, Mr. Williamson recommends an adjustment of \$11,592,180 to reduce the cost of natural gas recorded in the deferred account balance for NPC's failure to implement its approved strategy and hedge its April to October 2003 gas costs at a time when

gas prices were depressed. (Ex. 27 at 17 and Attachment JPW-5.)

184. Mr. Williamson explains that, at the December 10, 2001, RMC meeting, a recommendation was made that NPC should execute transactions to protect it from upward movements in market price because NPC recognized that power and gas prices were depressed. The recommendation was to secure up to 40,000 Decatherms (“Dth”)/day for the period April-October 2003 and was approved by the RMC without rejection. However, the approved plan was not implemented; in fact, there were zero option, swap, or fixed price transactions entered into in order to secure the price of natural gas, at depressed levels, for the period April-October 2003, or from the date the December 10, 2001, strategy was approved through January 24, 2003. (Id. at 17 and Attachment JPW-4.) Therefore, Mr. Williamson contends, the proposed adjustment removes the cost associated with NPC’s failure to prudently follow its own strategy to lock in gas prices at a time when they were depressed. (Id. at 17.)

Staff’s Position

185. Mr. Paul Wielgus, Managing Director with GDS Associates, Inc., submits testimony on behalf of Staff regarding NPC’s energy risk management activities and its natural gas and associated risk management activities. (Ex. 19 at 2.)

186. Mr. Wielgus contends that NPC’s actions of not complying with its own risk controls, actions that resulted in well-defined negative consequences that were supported by its own reports, are not only inappropriate and unreasonable, but imprudent as well. As a result, Mr. Wielgus submits that NPC should not be able to recover the identified imprudent natural gas costs of between \$13.7 million and \$30.1 million associated with its noncompliance of its risk controls. (Id. at 6.)

187. Mr. Wielgus’ understanding of NPC’s energy risk controls is based on material

provided by NPC. He notes that the BCG assisted NPC in developing adequate risk management controls, and he points to BCG's report, "Risk Management Initiative Summary," which notes that NPC's energy risk control did not meet the capabilities required. (Id. at 6.)

188. NPC did put in place new energy risk policies during the Test Period. Mr. Wielgus notes that the Risk Manual put into place included a clear description of the manual's application and purpose, an energy risk definition, a description of the energy risk management control and framework, and a specific compliance section. (Id. at 7.)

189. Mr. Wielgus believes the energy risk control policy NPC put into place during the Test Period to be adequate. However, he adds that the mere establishment of risk policies, controls, and limits by itself does not result in compliance. NPC must execute accordingly. (Id. at 8.)

190. The key aspects of NPC's energy risk control policy that are relevant to Mr. Wielgus' review are the VAR limits, VAR reporting, and resulting compliance. NPC's Risk Manual clearly states the purpose of having control limits by identifying that the required procedures outlined in the manual not only balance the need for reliable supply but also control the risks inherent in the process. (Id. at 9.)

191. Mr. Wielgus states that NPC's VAR limit according to its Risk Manual is \$100 million. Further, he contends that NPC did not comply with its VAR risk control limits, and that it grossly exceeded its \$100 million VAR limit. Consequently, NPC is not compliant with its own risk controls for a least six of the twelve months of the Test Period. (Id. at 10.)

192. Mr. Wielgus submits that some of these noncompliance months had a noncompliance level of approximately 150 percent of the limit. He asserts that while NPC's VAR limit was \$100 million, the actual VAR was closer to \$150 million. According to the Risk

Control Reports that were provided, Mr. Wielgus states that the VAR remained high for the remaining months. NPC had a target VAR of \$70 million. Mr. Wielgus contends that from the information provided by NPC, it never met its target VAR during the Test Period. (Id. at 10.)

193. Mr. Wielgus opines that NPC experienced additional costs as a result of its noncompliance with its energy risk controls, and that these additional costs were a result of NPC's natural gas activities. He states that in the Test Period, these unreasonable risks resulted in additional natural gas costs of at least \$13.7 million. (Id. at 13.)

194. During the Test Period about 90 percent of NPC's natural gas costs were left unhedged. This, according to Mr. Wielgus, was during the time period leading up to the Test Period and through the first three months of the Test Period. Further, he notes that the cost hedges that were put in place during the Test Period were exclusively prepaid above-market cost hedges. (Id. at 14-15.)

195. According to Mr. Wielgus, as a result of NPC's prepayment for the short-term above-market cost hedges, it paid over \$13 million more in natural gas costs than if it had just bought at market or spot prices. (Id. at 15.)

196. Mr. Wielgus asserts that NPC's prepaid above-market cost hedges were not purchased at one time, rather they were purchased months later, near the middle of the Test Period. He contends that had the valuation been performed consistent with what actually occurred, the expected VAR for this alternative would have been higher and very close to the expected VAR for the no hedge, buy at market alternative. (Id. 17-18.)

197. NPC should have entered into fixed-price transactions to protect itself and ratepayers from the increasing risks associated with the market exposure, according to Mr. Wielgus. He points out that according to BCG, NPC was not calculating nor reporting VAR

even though it had the capability to do so, and he notes that not using the required capability to calculate VAR was unreasonable and imprudent. (Id. at 27.)

198. Mr. Wielgus notes that between March 2002 and the beginning of the Test Period, NPC entered into physical natural gas contracts covering approximately 30 percent of its total physical requirements. During this same time period, NPC financially hedged about 12 percent of its natural gas, and by the end of 2002, NPC entered into additional physical natural gas contracts resulting in coverage of about 40 percent. (Id. at 27.)

199. The majority of the hedges transacted were late in the Test Period. Mr. Wielgus submits that this was during a time of upward price movement, which caused the prices hedged to move up along with the dollar prepayment required, thus resulting in the negative financial consequences of NPC natural gas hedging activities. (Id. at 28.)

200. Mr. Wielgus contends that in the event NPC had entered into fixed-price financial swaps at the time when physical arrangements were entered into between March 2002 and March 2003, the natural gas cost savings would have been \$30.1 million. He states that if NPC had entered into fixed-price financial swaps when the prepaid cost hedges were entered into between March 2002 and March 2003, the savings in natural gas supply costs would be \$19 million. (Id. at 29-30.)

201. Mr. Wielgus contends that NPC's actions cost ratepayers approximately \$13 million more than if it had done nothing but buy natural gas at index or market. Included in this \$13 million is the premium or prepayment NPC paid to acquire the options during this period. (Id. at 30.)

202. Mr. Wielgus concludes that, due to NPC's imprudently incurred natural gas costs, it should not recover between \$13.7 million and \$30.1 million. (Id. at 36.)

203. However, Mr. Wielgus' counsel indicated that his schedules 1,3, and 4 were no longer reliable. (Tr. at 174.) During cross-examination, Mr. Wielgus further stated that his indicated range of an adjustment, from \$13.7 million to \$31.3 [sic] million, is no longer reliable. (Tr. at 182-183.)

NPC's Rebuttal Position

Ms. Reid

204. NPC's witness, Ms. LoreLei Reid, disagrees with Mr. Williamson's proposed disallowance for summer 2003 gas costs because his assumptions that the RMC intended staff to purchase 40,000 Dth per day for the summer of 2003 immediately and that staff took no action to implement the RMC's December 10, 2001, decision are incorrect. Ms. Reid also contends that Mr. Williamson's calculation is incorrect. Ms. Reid recalculated Mr. Williamson's proposed adjustment and contends that NPC saved ratepayers \$22,400 by pursuing the strategy that it did. (Ex. 17 at 3 and Attachment LLR-6.)

205. With regard to the implementation of the RMC's Gas Procurement Strategy, Ms. Reid states that at its December 10, 2001, meeting, it did not require the immediate purchase of 40,000 Dth per day of gas for the summer of 2003. She explains that the RMC *authorized* a purchase of "up to" 40,000 Dth per day; however, it did not *require* that staff purchase the *entire* 40,000 on the same day that the RMC met. Ms. Reid states that the recommendation that was approved by the RMC recognized that, "the amount of credit that our counter parties will extend to us is limited," and that NPC should allocate what credit it had available to securing power and gas related to its near-term needs first. (Id. at 4 and Ex. 27 at Attachment JPW-3 at 4.) Ms. Reid contends that NPC appropriately used what credit it had available to fill its near term requirements first; therefore, NPC was not inconsistent with the direction of the RMC. (Ex. 17

at 4.)

206. Ms. Reid also explains that on November 2, 2001, the RMC authorized purchase of 30 percent of the 2002 requirements. (Id. at Attachment LLR-2 at 11.) On December 4, 2001, the RMC authorized acceleration and completion of the summer 2002 requirements. (Id. at Attachment LLR-2 at 30.) Also, at the December 10, 2001, meeting, the RMC authorized purchases for “up to 40,000” for summer 2003 and “up to 20,000” for summer 2004. (Ex. 27 at Attachment JPW-3.) Ms. Reid contends that the gas buyers were transacting all of these requests in order and priority that was in accordance with the authorization and approved parameters that were provided. (Ex. 17 at 4-5.) Ms. Reid also notes that no fixed price bids were received, but the physical requirements for the summer of 2002 were secured, as were winter 2002-2003 and a portion of summer 2003. (Id. at 5.)

207. In addition, Ms. Reid explains that staff had been working on a proposal to enter into a full requirements contract with a third party for all of NPC’s native load for July 1, 2002, through December 31, 2007. Under this proposal, the third party would have been responsible for supplying all fuel required to run NPC’s generation units through December 31, 2007. An RFP to provide NPC’s full requirements through December 31, 2007, was issued on December 31, 2001, and an award was expected by February 8, 2002. (Id. at 6 and Attachment LLR-2 at 63.) Ms. Reid also notes that on numerous occasions subsequent to December 10, 2001, the RMC was advised that the summer 2003 position remained open, and that the full requirements negotiations were ongoing. She then emphasizes that at no point did the RMC indicate that failure to immediately purchase hedges for the authorized 40,000 Dth per day for the summer 2003 was in any way inconsistent with its policy. (Id. at 6.) In fact, the February 21, 2002, RMC meeting minutes state, “The utilities electric and gas purchases are currently on track or

slightly ahead of the targets under the strategy.” (Id. at Attachment LLR-2 at 129.)

208. Similarly, the RMC minutes for April 12, 2002, indicate that NPC is “on target” with its “buy over time” strategy. (Id. at Attachment LLR-2 at 181.)

209. With regard to NPC’s efforts to enter into a full requirements contract for July 1, 2002, through December 31, 2007, Ms. Reid states that NPC worked diligently to secure a full requirements contract. She explains that on March 20, 2002, NPC entered into a Memorandum of Understanding (“MOU”) with Williams Energy Marketing and Trading Company (“Williams”) pursuant to which the parties agreed to negotiate in good faith on an exclusive basis for up to 90 days to complete a full requirements contract; however, the MOU was terminated on April 9, 2002. (Id. at 7-8.) Ms. Reid contends that NPC continued to negotiate with other counterparties to secure a full requirements contract; however, on June 19, 2002, the RMC decided that, “NPC’s situation and the nature of the markets have changed substantially since the full requirements efforts were initiated. A reevaluation is clearly warranted. Consequently, NPC will notify all of the prospective full service providers of its intention to defer further efforts until NPC has had an opportunity to reevaluate its situation.” (Id. at 8 and Attachment LLR-2 at 275.)

210. Lastly, Ms. Reid contends that Mr. Williamson’s calculation contains several errors:

- a) Mr. Williamson’s actual weighted cost of gas for NPC includes the options premiums paid for call options used to hedge power contracts that are tied to natural gas costs; thus, he overstated the actual average cost of gas. (Id. at 9.)
- b) Fixed price contracts do not allow the buyer to “participate in the event of a declining market;” therefore, Mr. Williamson is wrong to include fixed

cost contracts in his analysis. The strategy suggested by the December 10, 2001, minutes is to purchase calls, not fixed price volumes. (Id. at 10.)

- c) Mr. Williamson acknowledged that he did not have call option pricing information; however, he went on to assume that a \$.30 per Dth call option premium would result in a strike price of \$3.71, which is only \$.50 above the then-current market. Mr. Williamson's unsupported assumption is incorrect; in fact, as of December 10, 2001, a \$.30 per Dth call option premium would have resulted in a strike price of \$4.64. (Id.)

211. All in all, Ms. Reid states that although NPC does not agree that any disallowance should be made, simply correcting Mr. Williamson's errors shows that there was a small benefit in not purchasing call options on December 10, 2001, at a \$.30 premium. (Id. at 11.)

Mr. Branch

212. NPC's witness, Mr. Branch, disagrees with Mr. Wielgus' calculation or rationale for a disallowance where he attempts to compare the cost of natural gas acquired for NPC's generation (including hedges but not transportation) to the cost of the same quantity of natural gas at market prices. (Ex. 5 at 2.) Mr. Branch believes the calculation is inappropriate because:

- a) It is not an accurate representation of the intended comparison and must be corrected;
- b) Mr. Wielgus includes a disallowance for October 2002, ignoring the fact that the Commission already reviewed the hedging strategy for the summer of 2002 (April-October) in the last deferred case and found no imprudence; and
- c) Mr. Wielgus completely ignores the value of the hedges acquired by NPC

and simply does a hindsight comparison of experienced cost versus market cost.

(Id. at 3.)

213. Mr. Branch then describes the necessary corrections to Mr. Wielgus' Attachment PJW-1 that he believes should be made. First, the Column "Total Purchase Cost Less Transportation" includes costs of hedges executed for some of the summer tolling agreements that NPC entered into in January 2003. Thus, this column includes more than the cost of natural gas for NPC's generation. Mr. Branch believes that Mr. Wielgus used data from an NPC data response (Staff 23) that adjusted these costs for hedges related to the Reliant tolling agreement; however, he did not make the necessary adjustment for other tolling agreements, such as Mirant, Calpine and Panda Gila. Mr. Branch notes that a supplemental response to Staff 23 has recently been provided showing the corrected numbers for May through September. Consequently, the hedge costs are removed and the "Unit Purchase Cost Less Transport" is less. Mr. Branch has corrected this in his attachment Branch-Reb-1. (Id. at 3-4.)

214. In addition, Mr. Branch removed October 2002 from the table because the summer 2002 (April-October) hedging strategy was reviewed by the Commission and the parties in the last deferred case. He says that since the Commission found no imprudence in the April-October hedging strategy and made no disallowances for the portion of the strategy period applicable to the prior test period, through September 30, 2002, Mr. Wielgus' recommended disallowance for October 2002 is contrary to the Commission's prior order and is inappropriate. (Id. at 4.)

215. Mr. Branch concludes that the results of these corrections, which show the appropriate comparison of NPC's actual costs to market price, is \$4.6 million, not the \$13

million calculated by Mr. Wielgus. Mr. Branch notes that this doesn't mean the Commission should disallow \$4.6 million for imprudence; in fact, doing so would ignore the value provided by the hedges executed by NPC. (Id.) For instance, the hedges acquired by NPC for the summer 2003 period provided significant customer value and protection. Mr. Branch explains that his attachment, Branch-Reb-2, illustrates the value provided by the hedges executed by NPC for gas burn at its plants and for all hedges, including toll agreements, for the summer period. Mr. Branch points out that, as shown in the graph, had prices continued to increase, the hedges provided substantial protection. (Id. at 5.)

216. With regard to Mr. Wielgus' attachments PJW-2 and PJW-3 where he presents alternative scenarios that he uses to suggest disallowances of either \$18 million or \$30 million, Mr. Branch contends that Mr. Wielgus' calculations are flawed. First, Mr. Branch asserts that Mr. Wielgus calculates the difference between NPC's actual cost versus two hypothetical scenarios assuming that NPC had purchased fixed price products. Mr. Branch contends that as with Attachment PJW-1, and for the reason discussed above, October 2002 should be removed. Also, NPC's actual costs need to be revised to remove the hedge costs related to tolling agreements. (Id.) Furthermore, Mr. Branch argues that anyone can concoct a lower cost alternative hedging strategy with the benefit of hindsight. With the benefit of hindsight, Mr. Wielgus knows that prices increased during the test period; thus, he was able to select an alternative "better" strategy than NPC's use of call options. Mr. Branch believes that this is not the exercise that Mr. Wielgus should be undertaking in determining the prudence of NPC's chosen hedging strategy; therefore, Mr. Branch contends that Mr. Wielgus' hindsight analysis should be rejected. (Id. at 6.)

217. Mr. Branch also notes that with regard to Mr. Wielgus' statements regarding

NPC's capabilities to analyze and execute the Energy Supply Plan, his central theme is that NPC lacked a crystal ball. Mr. Branch reiterates that Mr. Wielgus' basis for disallowance is based on pure hindsight. (Id.)

218. In conclusion, Mr. Branch comments that Mr. Wielgus' testimony in this case regarding NPC's gas hedging strategy for the summer 2003 is contrary to the feedback that NPC has received from Staff during the last year. For instance, on February 11, 2003, NPC put on a full-day presentation for Staff on its 2003 Energy Supply Plan, including the gas hedging strategy for the summer 2003. Not only did Staff not provide any negative feedback, they also did not express any concern regarding the use of call options instead of fixed prices. Mr. Branch also points out that with the exception of the schedule now proposed by Mr. Wielgus, Staff expressed no concerns about acquiring hedges during the period January through April. Mr. Branch further notes that this was also the case in July 2003, when NPC filed an update to the Energy Supply Plan with its 2003-2022 Resource Plan calling for hedging gas exposure with 100 percent call options. Not only did Staff review the proposed Energy Supply Plan and filed testimony in support of it, but the Commission also approved the plan in its November 12, 2003, order. (Id. at 7.)

Mr. Coyle

219. NPC's witness, Mr. Coyle, argues that Mr. Wielgus recommends disallowances based on a hindsight perspective on gas price evolution. In addition, he uses peripheral arguments related to capabilities, risk controls and credit to challenge a prudent, well-planned gas hedging program. (Ex. 12 at 4.)

220. Mr. Coyle explains that NPC invested significant resources and senior management attention to improving the risk management capabilities between the Commission

Order in Docket No. 01-11029 and the beginning of the test period. Additional initiatives were implemented by the end of 2002, and, since then, NPC has worked continuously to improve its capabilities on an on-going basis. Mr. Coyle concludes, as shown in the high quality of NPC's supply plan filed January 31, 2003, that NPC's progress has had a positive impact on the overall Energy Supply Plan and the summer 2003 gas hedging plan that Mr. Wielgus is challenging. (Id. at 3.) Furthermore, Mr. Coyle argues that, contrary to Mr. Wielgus' testimony, NPC had already improved its capabilities related to energy supply risk management and risk control, in such areas as its organization, processes, staffing, analytical capability and policies when BCG was retained to help NPC meet or exceed "best practices" levels. In fact, in Docket No. 02-11021, BCG's Vice President and the project leader, Mr. Rick Peters, stated, "With respect to the Energy Supply Plan, we determined that even before our assignment had started, the Companies had begun to outline an approach that incorporated attributes of 'best practices.'" (Id. at 6.)

221. In addition, Mr. Coyle asserts that, from the time of the Commission's order in Docket No. 01-11029 through the end of the summer of 2002, the following improvements occurred:

- a) The risk management and risk control functions were separated, with the establishment of an officer-level position of Chief Risk Control Officer.
- b) A new senior level officer position was filled to manage the Energy Supply organization.
- c) A new organization charged with energy supply planning and analysis was created.
- d) A new intermediate-term analysis function was created to take a lead role in the assessment and analysis of intermediate term markets.

- e) NPC solicited, reviewed and acquired the Henwood suite of models for evaluating broader regional power market fundamentals and price analysis.
- f) NPC developed and implemented a long-term RFP process to procure capacity, both existing and newly built, within and beyond the control area.
- g) NPC undertook a critical review of Risk Control policies and drafted a revised policy for executive review.

(Id. at 7-8.)

222. In addition to these improvements, NPC achieved additional significant milestones that resulted in several key filings and transactions in early 2003. Mr. Coyle explains that during the course of 2003, NPC has continued to invest in improvements in its risk management and risk control capabilities, from selecting a permanent risk management software solution, to filing the 2004-2006 Energy Supply Plan, to continuing implementation and refinement of the monthly risk control report and exception logs. Mr. Coyle contends that as a management philosophy NPC will continue to implement additional capabilities and improvements over time to keep pace with the evolving business, economic, and regulatory environment. (Id. at 9-10.) Finally, Mr. Coyle disagrees with Mr. Wielgus' argument that NPC did not fully improve its capabilities well into the test period. Mr. Coyle contends that the most significant capability improvements were in place well before the planning season for the summer 2003 gas supply plan, the period upon which Mr. Wielgus' adjustment is aimed. (Id. at 11.)

223. Next, Mr. Coyle contends, as documented in the monthly risk control reports, that

NPC identified, tracked and addressed the VAR limit exceptions pursuant to NPC's policies and procedures. He explains that management review indicated a mismatch in timing between the authorized VAR limit (rolling 12-month VAR) and the test period VAR. Mr. Coyle explains that during the month of February 2003, natural gas prices spiked to above \$10 per Million British Thermal Units ("MMBtu") and, with that occurrence, the rolling 12-month VAR went up to \$145 million, exceeding the existing limit of \$100 million. (Id. at 12.) Options for addressing the VAR exceptions were discussed including:

- a) Continue gas procurement practices that matched to gas seasons and increase the rolling 12-month VAR limit.
- b) Accelerate procurement in advance of buying seasons.
- c) Change the VAR limit definitions to more seasonal limits.

(Id. at 3-4.)

224. Mr. Coyle notes that the reasons and results of this analysis were shared with Commission Staff. As indicated in response to Staff data request 275, NPC's Risk Management and Risk Control policy specifies that, in measuring compliance with the existing limits, the Risk Control Group will measure VAR based on a rolling 12-month basis. The review of the VAR limit exceptions indicated that when measured on a rolling 12-month basis, the VAR will normally increase during the calendar year. Mr. Coyle explains that based on this analysis, NPC was able to determine that unless procurement timing is significantly accelerated, use of a 12-month rolling measure of VAR is likely to result in exceeding preset limits toward the end of a calendar year. (Id. at 13.)

225. Mr. Coyle concludes that NPC chose to revisit these issues after a full 12-month cycle of implementing the risk management and risk control programs was complete. He states

that NPC determined that changing risk control limits, VAR measurement techniques or the timing procurements would be inappropriate, knee-jerk reactions. (Id. at 15.) Mr. Coyle also contends that NPC's decision not to make these changes did not create additional risks to be borne by customers during the test period. In fact, the monthly VAR for the key summer months was steadily declining as NPC faithfully executed the summer gas hedging plan outlined in the January 31, 2003, Energy Supply Plan that was filed with the Commission. (Id.) Mr. Coyle contends that NPC's disciplined execution of the approved summer 2003 gas hedging plan continued to reduce risks for the test period. (Id. at 4.)

226. With regard to NPC's credit position, Mr. Coyle explains that it was only one of three broad criteria that NPC used in selecting a gas hedging plan. He further explains that based on these criteria, the recommended gas supply plan formed on call options. Mr. Coyle contends that, if the Energy Supply function had instead determined that fixed price gas was required in the portfolio, NPC's credit function would have arrived at feasible credit terms with potential suppliers to enable such transactions. (Id.) In addition, Mr. Coyle argues that Mr. Wielgus fails to distinguish between potential and actual limitations. Mr. Coyle contends that NPC's credit position has and will continue to have the potential to limit its ability to transact in the market. Further, except for minor alterations in credit/payment terms, NPC's actual ability to transact in the market has not been impaired. (Id. at 16.)

Commission Discussion and Findings

227. Mr. Williamson recommends an adjustment of \$11,592,180 for NPC's failure to implement its approved strategy and hedge its April to October 2003 gas costs at a time when gas prices were depressed. He maintains that NPC was required to purchase up to 40,000 Dth/day as the result of an RMC recommendation in December 2001.

228. Ms. Reid, however, points out that the 40,000 Dth/day was an authorization and not a requirement. Of more importance, however, is the fact that NPC was working on a full requirements proposal that would have covered its gas requirements from July 1, 2002, through December 31, 2007. This alone would have dictated that NPC should be careful in committing to gas supplies, at least until February 8, 2002. According to Ms. Reid, the February 21, 2002, minutes of the RMC meeting indicate that gas purchases were on track or slightly ahead of the targets. Ms. Reid also points out significant errors in Mr. Williamson's calculations which, when corrected, actually show a small benefit in not purchasing call options.

229. The situation recounted by Ms. Reid clearly indicates that NPC acted in a reasonable manner under the circumstances. There is no evidence that indicates NPC should have locked up such a substantial quantity of gas, especially since NPC was looking for a full requirements contract.

230. In sum, Mr. Williamson failed to demonstrate that NPC did not follow its gas purchase strategy or that the strategy it did follow led to a detriment to ratepayers. Accordingly, the Commission finds that Mr. Williamson's proposed adjustment should be rejected.

231. Mr. Wielgus asserts that the failure of NPC to comply with its own risk controls resulted in negative monetary consequences in an amount between \$13.7 and \$30.1 million. Although he recognizes that adequate control policies were in place, he maintains that NPC failed to execute those policies. As a result of that failure, according to Mr. Wielgus, NPC purchased above market hedges which cost \$13 million more than if the gas was purchased at market or spot. Further, he contends that the failure to enter into fixed-price financial swaps instead of the prepaid hedges between March 2002 and March 2003 cost ratepayers about \$30.1 million.

232. Mr. Branch notes that Mr. Wielgus made computational errors that reduce his lower range to \$4.6 million. Additionally, had prices continued to rise, the hedges that were purchased would have provided substantial protection to the ratepayers. Mr. Branch further notes that Mr. Wielgus also failed to remove hedge costs relating to tolling arrangements, thus rendering his upper limit suspect. Mr. Branch also asserts that Mr. Wielgus' basis for a disallowance is based on hindsight. Of greater concern is the fact that Mr. Branch indicates that Staff was given a one-day presentation on NPC's Energy Supply Plan in February 2003, but expressed no concerns regarding NPC's hedging plans. While the Commission does not interpret this to mean that Staff agreed with NPC, the Commission would expect Staff to provide some guidance to NPC.

233. Mr. Coyle contends that NPC had significant capability improvements in place before planning for the summer 2003 period. Mr. Coyle notes that exceptions to the VAR were identified and addressed. This too was apparently shared with Staff.

234. The errors identified by Mr. Branch give the Commission reason to discount the testimony of Mr. Wielgus. Additionally, the Commission notes that Mr. Wielgus specifically recognizes that NPC put into place a satisfactory energy risk control policy. Although he takes exception to the implementation of the policy, no evidence was presented that such implementation was inadequate. Further, Mr. Wielgus takes issue with the purchase of certain hedges, which he asserts were above market. However, the Commission must give consideration to the fact that the sole purpose of the hedges is to provide upside protection to ratepayers. The Commission does not expect such measures to come at no cost. Also, the Commission agrees with Mr. Branch that Mr. Wielgus' proposed adjustment is largely based on hindsight since Mr. Wielgus selected a set of circumstances that inexorably led to a better outcome.

235. Of particular importance in this matter, however, is the fact that three of Mr. Wielgus' schedules are not reliable. Mr. Wielgus also states that his range is no longer reliable. Accordingly, based on all of the above evidence, the Commission can give no weight to Mr. Wielgus' testimony and finds that Mr. Wielgus' proposed adjustment should be rejected.²

F. Other

1. Deferred Energy Carrying Charge Gross-up

NPC's Position

236. Mr. Coyle states that since the reinstatement of deferred energy accounting in April 2001, NPC's costs of purchasing fuel and power have exceeded the level of recovery in the BTER in most months. For the months when NPC has under-collected its F&PP costs, the cumulative balance for the open period is a debit. In those months when the cumulative balance for the open period is a credit and NPC has over-collected its F&PP costs, a carrying charge is also applied to the cumulative balance. However, Mr. Coyle states that in this instance, it is in the customer's favor. Further, he stated that in both instances, the carrying charge applied to the cumulative balance is equal to NPC's last authorized rate of return or its net after-tax return. (Ex. 11 at 25-26.)

237. Mr. Coyle believes the current deferred energy carrying charge mechanism does not adequately reimburse NPC for the capital costs associated with funding under-collected deferred energy balances. Mr. Coyle states this is because NPC is carrying these balances for three full years, rather than the 12 months provided for under the pre-2001 deferred energy mechanism, and the carrying charge rate does not reflect the cost of income taxes paid on the common equity portion of the authorized rate of return. (Id. at 26.)

238. Mr. Coyle testifies that the carrying charge should reflect the cost of income taxes

² Although the Commission has found in this order that the proposed disallowances for natural gas hedges are not appropriate for the periods in question, it is imperative that NPC continually reassess its hedging strategy to insure that the cost of the costs do not out-weigh the strategy's benefits to rate payers. NPC should not construe this finding or any other portion of this order to constitute precedent that the allowed level of hedging shall be found prudent in future deferred energy decisions.

on the common equity portion of the authorized rate of return. NPC does not segregate debt and equity capital when funding its deferred energy balances or rate base. NPC funds its rate base and deferred energy balances with a combination of debt and equity. The carrying charge is designed to reimburse NPC for its whole cost of all capital on an after-tax basis and is set based on NPC's authorized rate of return. (Id. at 26-27.)

239. Due to the fact that NPC cannot deduct the cost of equity used to fund purchased power and energy on its income tax return, Mr. Coyle explained that the equity portion of the authorized rate of return must be grossed-up. He added that unless the carrying charge applied to deferred energy balances provided for the collection of the income taxes on the equity portion of the capital used to fund the deferred balance, the carrying charge does not compensate NPC for the full costs of the capital raised to fund the deferred energy balance. (Id. at 27.)

240. Mr. Coyle submits that NPC does not earn its authorized carrying charge if the equity portion of the cost of capital is not grossed-up for taxes. He stated that if the carrying charge is not grossed up for income taxes on the equity used to fund the deferred balance, it is mathematically impossible to earn a carrying charge that reflects NPC's cost of financing purchased fuel and power. Further, he added that without the tax gross up on the equity used to fund purchased fuel and power, NPC will not be able to earn its authorized return on common equity of 10.1 percent. (Id. at 27-28.)

SNWA's Position

241. Dr. Peseau suggests that NPC is indifferent to the level of DEAA3 amortization because of the carrying charge on the Deferred Balance. (Ex. 26 at 4.)

BCP's Position

242. BCP witness, Mr. Williamson, disagrees with NPC's proposal to gross-up the

deferred energy carrying charge for federal income taxes and recommends that the Commission deny the request. (Ex. 27 at 12.) However, he states that if the Commission were to make a change to the carrying charge rate, it should be to lower the rate, potentially to zero, until the balances in the deferred accounts are reduced to zero. (Id. at 13.)

243. Mr. Williamson explains that deferred energy accounting was established by the Legislature to provide NPC with dollar for dollar recovery of only prudently incurred energy costs. He believes that NPC's proposal to gross-up the carrying charge for federal income tax obliterates the concept of a dollar of recovery for each dollar spent, by providing profit at the full rate of return for shareholders, plus a profit incentive for management to maintain large deferred balances in the account. (Id. at 9.) Mr. Williamson states that it is very important to maintain the dollar-for-dollar premise. Increasing the profit to NPC shareholders through increased carrying charges creates a monetary incentive that increases as the deferred balance rises, and decreases as the deferred balance falls. This, Mr. Williamson believes, is exactly the wrong incentive to provide when dealing with deferred energy costs. He states that this gives NPC the incentive to allow balances to build and to clear balances over a longer period of time. Mr. Williamson believes that this monetary incentive created by NPC's proposal could lead to unintended consequences such as reduced attention to risk management, longer amortization periods, asymmetrical amortization proposals, and BTER calculations that understate going forward costs. Mr. Williamson concludes that the consequences of these factors all promote the carrying of unnecessarily inflated deferred account balances to the detriment of consumers. (Id. at 9-10.)

244. In addition, Mr. Williamson states that if a grossed-up rate of return is granted to NPC, then in order to save ratepayers from incurring such high carrying charges, the BCP would

have an incentive to recommend a BTER at the high end of the range of projected future costs, and to shorten the amortization period under consideration in this and future cases. He further states that the average consumer does not receive 12.43 percent interest on account balances of financial instruments, and it is possible that such a high rate could be viewed as significant enough to strive for negative balances in the deferred accounts so that ratepayers could enjoy a 12.43 percent rate of return on their money. (Id. at 11.)

Staff's Position

245. Mr. Buck recommends no change in the present methodology. (Ex. 23 at 6.) Mr. Buck believes that NPC's proposal violates existing regulations, ignores the fact that NPC pays no tax on the deferred balance, violates Commission precedent, and is not in accord with NPC's position regarding recovery of deferred balances. (Id. at 6.) Further, Mr. Buck states that NPC has specifically indicated that energy costs are, "...passed through to the customer on a dollar-for-dollar basis." (Id. at 9.)

NPC's Rebuttal Position

246. Mr. Coyle disagrees with Mr. Williamson's suggestion that NPC receives a "profit" from carrying charges on deferred energy. Mr. Coyle explains that an economic profit can only be realized if NPC's return is greater than its costs incurred, including the opportunity cost of capital that the shareholder has invested. Mr. Coyle states that NPC incurs a capital cost, the cost of funding the DEAA balance over one, two, or three years. Mr. Coyle points out that NPC agrees with Mr. Williamson that NPC should be allowed, "a dollar for a dollar of prudently incurred cost with no additional profit." Mr. Coyle concludes that NPC is asking for nothing more in this case; rather, NPC is asking only to be reimbursed for its cost of capital, including income taxes. (Ex. 12 at 17.)

247. With regard to Mr. Williamson's assertion that allowing NPC to fully recover its cost of capital invested in deferred energy will incent NPC to build large deferred balances, Mr. Coyle disagrees. He argues that NPC has limited capital to invest in the business and would much prefer investing capital in rate base to serve customers rather than in funding deferred energy balances for up to three years. (Id. at 18.)

248. Mr. Coyle also disagrees with Mr. Williamson's suggestion that the customers are paying for contracts that were entered into prior to reestablishment of the deferred energy accounting and customers should not bear the carrying charges on deferrals related to these contracts. Mr. Coyle explains that the Commission has reviewed all of NPC's purchased power contracts for prudence, including contracts entered into prior to the reestablishment of deferred accounting. The costs reflected in the DEAA balance are the costs of only those contracts that the Commission has determined to be prudent. Mr. Coyle concludes that the carrying charge is only applied to the costs of contracts in the DEAA balance, not to the costs of contracts excluded from the DEAA balance. (Id. at 19.)

249. With regard to Dr. Peseau's statement that because of the carrying charge mechanism, NPC doesn't suffer any adverse financial consequence if recovery of the deferred energy balance is delayed, Mr. Coyle contends this is untrue. Mr. Coyle argues that if the carrying charge applied to the deferred balance is grossed-up for income taxes, as NPC has requested, then, Dr. Peseau is correct. However, NPC is not currently recovering the cost of capital associated with financing the deferred balance, because customers are not paying the income taxes on the equity portion of the return. (Id. at 19-20.)

250. Mr. Coyle also rebuts Mr. Buck's point that NAC 704.150 makes no mention of any gross-ups of any sort. Mr. Coyle states that although the regulation is silent on the issue,

such as the case of the Commission's determination on the treatment of deferred taxes, the question isn't going to be decided by the regulation. Mr. Coyle contends that the Commission must determine whether it intends the carrying charge on deferred energy balances to recover NPC's after-tax cost of capital. (Id. at 20.)

251. Mr. Coyle agrees with Mr. Buck that to be technically correct when calculating the carrying charges, the deferred energy balances should be reduced by the amount of deferred taxes per the Commission's orders. (Id. at 20-21.) Mr. Coyle does, however, disagree with Mr. Buck's comments about press releases where NPC mentions dollar-for-dollar recovery of deferred energy costs and does not mention carrying charges or recovery of income taxes. Mr. Coyle argues that financing costs are a part of deferred energy and that NPC is requesting recovery of all deferred energy costs including income taxes related to the equity return. Mr. Coyle then contends that this is consistent with dollar-for-dollar recovery of costs. (Id. at 21.)

Commission Discussion and Findings

252. The Commission recognizes that the concept of a tax gross-up negates the concept of dollar-for-dollar pass-through. A tax gross-up would allow NPC to recover more than one dollar for each dollar in fuel and purchased power expense. As Mr. Buck indicates, among other things, this would violate Commission precedent and is clearly not in accord with NPC's oft-stated position that it receives no profit on these amounts. Therefore, the Commission rejects NPC's proposal and finds that carrying charges on the Deferred Balance shall be calculated at NPC's last rate of return, after appropriate consideration of any Commission ordered Deferred Tax offset.

///

///

2. Deferred Tax Offset

BCP's Position

253. Mr. Williamson notes that, in Docket No. 01-11029, the Commission addressed reducing the deferred balance by deferred federal income taxes before calculating the carrying charge, calculating the interest on average monthly balances and limiting the carrying cost to the cost of debt. He argues that the Commission accepted the premise that the deferred balance should be reduced by deferred federal income taxes before calculating the carrying charge; however, it rejected calculating the carry on the average balance of the account for the month and also rejected limiting the carrying cost rate at the cost of debt to NPC. (Ex. 27 at 11.)

Staff's Position

254. Mr. Buck, in allocating Staff's adjustments between jurisdictions, utilized monthly calculations. (Ex. 23 at 4.)

255. Mr. Buck notes that NPC did not use a Deferred Tax offset for Period Three, the amortization period for the Deferred Balance at issue in this proceeding. (Id. at 8.) Had NPC followed this methodology as prescribed by the Commission in the last two Deferred Cases, the related Accumulated Deferred Federal Income Tax ("ADFIT") would have been deducted from the balance prior to computing a carrying charge. (Id.) Failure to deduct the ADFIT would result in NPC enjoying a source of tax-free capital. (Id. at 7.) Mr. Buck recommends that the Commission adopt Staff's recommended methodology. (Id. at 1.) The net result between the effect on Residential and Non-Residential classes is an increase to the Deferred Balance of \$288,588. (Id. at FCB-2 and Attachment FCB-7.)

NPC's Rebuttal Position

256. NPC's witness, Ms. Franklin, agrees with Mr. Buck with regard to his allocation

methodology and states that, while the adjustments change the percentages somewhat, the change is not material. (Ex. 16 at 2.)

257. However, Ms. Franklin disagrees with Mr. Buck's adjustment to carrying charges on the current balance because she believes that to the extent that new amounts have been accrued in addition to the balances authorized in Docket Nos. 01-11029 and 02-11019 [sic], NPC has calculated carrying charge in accordance with NAC 704.150. Further, Ms. Franklin states that if the Commission wishes to grant an additional deviation in this docket, NPC believes it is appropriate to grant such a deviation prospectively if the amortization period established exceeds one year, as was stated in Docket No. 01-11029. (Id. at 3.)

Commission Discussion and Findings

258. The relatively large Deferred Balance and the extended amortization period for DEAA3 give rise to the same circumstances that were present in the last two cases. It would not be reasonable for ratepayers to pay interest on the full balance while NPC enjoys tax-free capital. Therefore, the Commission finds that pursuant to NAC 704.0097, good cause exists and it is in the public interest to grant a deviation from NAC 704.150. Additionally, the Commission finds that Staff's methodology of deducting the ADFIT related to DEAA3 is appropriate and approved. However, to be consistent with the prior Orders, the Commission finds that NPC shall apply this on a prospective basis, with no current adjustment as proposed by Staff. The prospective carrying charge shall be applied in accordance with NAC 704.150.

3. Billing Dispute with Southwest Gas

Staff's Position

259. Mr. Rex Bosier, Financial Analyst and witness for Staff, identifies a continuing dispute with Southwest Gas Corporation ("SWG") concerning a gas penalty imposed by SWG

on NPC related to a volumetric imbalance. (Ex. 22 at 2.) NPC thus far has refused to pay this disputed amount. This issue has been brought to the Commission on two separate occasions. Mr. Bosier indicates that the Commission recognized only a portion of the proposed disallowance in Docket 02-11021, but it should have recognized a larger amount as indicated in Mr. Bosier's prior testimony. (Id.) In this case since the amount remains unpaid, Mr. Bosier recommends that the amount of \$688,041 be accrued, or transferred as appropriate, to a sub-account of Account 186, or in the alternative, kept below the line until the matter is resolved. (Id. at 2-3 and RAB-2, Ex. 23 at Attachment FCB-2, Tr. at 264.)

Commission Discussion and Findings

260. NPC did not rebut this item. Given that the amount recommended by Staff is relatively small, and the recommendation is for deferral, rather than disallowance, the Commission finds that it is appropriate to accrue the amount of \$688,041 in a sub-account of Account 186, without a carrying charge, until this matter is resolved. The Commission will reserve any consideration of the prudence of this amount until funds have been actually expended and the complete circumstances have been presented to the Commission.

4. BTER and DEAA Revenues

Staff's Position

261. Mr. Buck reports that, due to issues related to cycle billing, rates and the resulting revenues from Docket 02-11021 were not properly calculated. (Ex. 23 at 4-5.) As a result, revenues for May and June 2003 were understated. (Id.) Mr. Buck indicates that NPC agrees with his proposed adjustment of \$1,708,204. (Id. at 5 and FCB-6, Tr. at 99-100.)

Commission Discussion and Findings

262. NPC agrees with Mr. Buck. Therefore, the Commission finds that an adjustment

to the DEAA balance, a reduction of \$1,708,204, is approved.

5. Compliance Items

Staff's Position

263. Mr. Bosier reports that, in conformance with the Order in Docket 02-11021, NPC gas purchase authority levels are clearly stated and easily understood. (Ex. 22 at 4.) Although there were instances of non-compliance in this docket, corrective action has been taken. (Id.)

Commission Discussion and Findings

264. The Commission accepts Staff's report and finds that no further compliance action is required relating to gas purchase authority.

G. Commission Overall Findings and Conclusions

265. A summary of the Commission's disallowances and deferrals is attached hereto and incorporated herein as Schedule 1.

266. The Commission finds that NPC shall implement the Commission findings in this Order, develop appropriate rates, and submit appropriate documentation to Staff for review prior to placing the rates into effect.

267. The Commission also finds that, once the tariffs have been verified by Staff, NPC shall place the rates into effect concomitantly on April 1, 2004, with the rates developed from the General Rate Case (Docket No. 03-10001) and related dockets as appropriate such as the Depreciation docket (Docket No. 03-10002).

THEREFORE, based upon the foregoing findings of fact and conclusions of law, it is hereby ORDERED that:

1. The Application of NEVADA POWER COMPANY is GRANTED-IN-PART and DENIED-IN-PART as detailed in paragraphs 26-27, 50-52, 162-177, 227-235, 252, 258, 260,

4. All arguments of the parties raised in these proceedings, including but not limited to arguments raised in the hearing, not expressly discussed herein have been considered and either rejected or found to be non-essential further support for this Order.

By the Commission,

DONALD L. SODERBERG, Chairman and
Presiding Officer

ADRIANA ESCOBAR CHANOS, Commissioner
(Dissenting to Section E. Natural Gas Fuel
paragraphs 178-235 above)

CARL B. LINVILL, Commissioner

Attest: _____
CRYSTAL JACKSON, Commission Secretary

Dated: Carson City, Nevada

3-29-04
(SEAL)