Q. Please state your name and business address.

A. My name is Jeffrey K. Larsen. My business address is One Utah Center, Suite 2300, 201 South Main Street, Salt Lake City, Utah, 84111.

Q. What is your position at Rocky Mountain Power (the Company) and briefly describe your employment history with the Company?

A. I am currently employed as Vice President of Regulatory Affairs. I joined the Company in 1985, and I have held various accounting, compliance and regulatory-related positions prior to my current position. I have testified on various matters in the states of Utah, Idaho, Wyoming, California, Washington and Oregon.

QUALIFICATIONS

Q. Briefly describe your educational and professional background.

A. I received a Master of Business Administration degree from Utah State University in 1994 and a Bachelor of Science degree in Accounting from Brigham Young University in 1985. I have also participated in the Company's Business Leadership Program through the Wharton School and an Advanced Education Program through the J.L. Kellogg School of Management at Northwestern University. In addition to formal education, I have also attended various educational, professional and electric industry-related seminars during my career at the Company.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. Between December 16, 2006 and March 22, 2007, Rocky Mountain Power filed three separate applications for accounting orders. These applications requested authority to: 1) defer the costs of loans made to Grid West (Docket No. 06-035-163), 2) defer the severance costs related to the MidAmerican Energy Holdings Company (MEHC) transaction (Docket No. 07-035-04), and 3) defer costs related to the flooding of the Powerdale hydro facility (Docket No. 07-035-14). The purpose of my testimony is to describe the essential elements of each of these applications and to explain why the requested deferred accounting treatment is appropriate and consistent with standard utility practice. Specifically, I will address the following topics:

1. Explain what deferred accounting is.
2. The purpose for deferred accounting.
3. The generally accepted standards surrounding the establishment of regulatory assets.
4. The authoritative basis for deferred accounting.
5. Why the applications are not barred by the rule against retroactive rate making.
6. Deferred accounting and its relationship to test periods and rate setting proceedings.
7. The background and essential details of each deferred accounting application and why deferred accounting is appropriate in each case.
8. How Rocky Mountain Power's proposed treatment of the requested deferrals is consistent with Public Service Commission of Utah (Commission) precedent for deferring and amortizing costs.

9. The implications of deferred accounting and the “stay out” commitment from Docket 06-035-21.

PURPOSE OF DEFERRED ACCOUNTING

Q. What is deferred accounting?

A. Deferred accounting is an accounting mechanism used to properly match a current period expense or revenue with potential future events such as a revenue stream that covers a cost in the future or the matching of a cost with units of output achieved as a result of the current period expense. Deferred accounting is a well-recognized regulatory tool in the utility industry for the proper matching of costs and benefits and addressing cost recovery issues. Accounting for regulated utilities allows for costs or revenues that would normally be booked as a current period cost or revenue by an unregulated enterprise to be deferred and spread (amortized) over several periods. As such, deferred accounting is simply a financial accounting adjustment made by a utility that has no impact on customer rates until the costs associated with the deferral are included in a general rate case or other cost recovery mechanism such as a surcharge. Deferred accounting allows for the recovery of prudent costs in a reasonable manner because the costs are spread over several periods instead of resulting in spikes in a utility’s cost of service.

Q. What is a “regulatory asset”?

A. The Uniform System of Accounts (USOA) provides the following definition:

> Regulatory Assets and Liabilities are assets and liabilities that result from rate actions of regulatory agencies. Regulatory assets and liabilities arise from specific revenues, expenses, gains, or losses that would have been

> included in net income determination in one period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services. 18 CFR 101, Uniform System of Accounts, Definition No. 30.

DEFERRED ACCOUNTING STANDARDS

Q. What is the authoritative basis for the deferral of expenses?

A. Regulatory assets are governed by statements of financial accounting standards (FAS) No. 71. Statement 71 recognizes that in many cases a regulated company may have the rationale or the requirement to capitalize certain costs, while generally accepted accounting principles (GAAP) may require the cost to be expensed. The provision for deferred accounting is captured in the USOA, which contemplates the deferral of expenses through the creation of regulatory assets, or in the case of income items, regulatory liabilities.

FAS 71 provides for deferring costs that would otherwise be charged to expense if it is probable that those specific deferred costs are subject to recovery in future revenues.

Q. Do deferred accounting standards require that an expense be an extraordinary amount to be considered for deferral?

A. No, it is more dependent upon the extraordinary nature of the event leading to the cost than it is the magnitude of the cost. As indicated in general instruction no. 7 of the USOA, to be considered extraordinary an event or transaction must be of an unusual nature and be abnormally different from the ordinary and typical activities of the company, and which would not reasonably be expected to recur in the foreseeable future. It is important to bear in mind that the USOA's uses the term "extraordinary" in an accounting sense and not in the common sense of remarkable.

The Commission has followed this approach in its deferred accounting rulings related to the Y2K and the Noell Kempf Climate Action Project in Docket No. 99-035-10, where both deferrals were less than $4 million and $1 million (Utah allocated amounts), respectively, where the Commission did not limit the application of deferred accounting to high dollar or significantly material cost items.

Q. Is assurance of cost recovery required before a cost can be deferred from the income statement to the balance sheet?

A. No. A deferral does not assure future cost recovery and does not bind a regulatory agency to a level of recovery unless or until that agency addresses the cost recovery in a rate setting process. The condition is that it is "probable that such items will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services".

Also, it is important to remember that there is a fundamental difference between a case dealing with cost recovery such as a general rate case or a surcharge request and a case involving only accounting procedures. An order for deferred accounting is not a ratemaking decision. It is improper to assume that having met the criteria for recording deferred charges that the utility is automatically entitled to recovery of the deferred costs. A deferred accounting order only affords the utility the opportunity to present the cost for recovery in a future rate case. Such an order does not foreclose any discussion or presentation of evidence that would normally occur when the commission conducts the ratemaking hearing for the expense. In further recognition of the difference between a deferred accounting order and a ratemaking decision, the USOA provides specific accounting procedures if rate recovery of all or part of a deferred amount is disallowed.

Consistent with the USOA, Rocky Mountain Power has only requested approval for the accounting treatment of the deferrals and has not requested a determination of ratemaking treatment. The ratemaking treatment of these costs will be addressed in Rocky Mountain Power's next general rate case.

Q. Why doesn't the rule against retroactive rate making prohibit the company from deferring the costs that it has requested be deferred?

A. The rule against retroactive ratemaking only applies to a rate setting proceeding in which the utility is attempting to recover past expenses or in which it is being required to refund past revenue that were contemplated in setting rates in the prior proceeding. When the estimates of costs and revenues prove to be inaccurate and costs are either higher or lower than predicted, the rates cannot be changed to correct for the error. As such, the rule prohibits refunds when rates were set too high and surcharges when rates were set too low.

The rule is not applicable to deferred accounting because the very purpose of allowing a deferred expense is to provide an opportunity for the future recovery of an expense that was not considered in the prior rate proceeding. Furthermore, deferred accounting applications are not requests to reset current rates, but rather, simply requests for the approval to make an accounting adjustment and preserve an expense (or revenue) on the balance sheet until a future period when it can be presented and addressed in the context of a rate setting proceeding.

Q. Why should the Commission defer and amortize an extraordinary expense that occurs outside of a test period?

A. The criteria for deferring an expense or revenue and establishing a regulatory asset or liability are the same whether the extraordinary expense is incurred during a rate case test period or outside a rate case test period. As previously stated, the deferral process is a mechanism used to maintain stable utility rates and to allow the Company an opportunity to recover it's prudently incurred costs in providing utility service. Extraordinary costs should be deferred and amortized over a period of time so that when rates are set, they are set on the basis of the Company's normalized cost and revenue streams. A normalized level of costs includes not only the deferral of unusual expenses incurred during a given year, but also the amortization of unusual costs that occurred in previous years.

Q. Are the requirements for deferred accounting different when the utility uses a forecast test period?

A. No. These principles associated with deferred accounting are applicable regardless of whether a historic forecast test period is being utilized. As I just mentioned, extraordinary costs that are prudently incurred on behalf of customers and thus legitimately recoverable from customers, are deferred and amortized over a period of years. This properly reflects the ongoing normalized costs of the utility. The creation of the regulatory asset has no impact on current rates.

Rather, the amortization expense and the remaining unamortized balance of a deferred expense or revenue that carry through any test period (whether it is an historic or forecast test period) to the utility's next general rate case will be included in the revenue requirement filing at that time.

ROCKY MOUNTAIN POWER DEFERRED ACCOUNTING POLICY

Q. What are the primary reasons the Company defers costs or revenues?

A. Some of the primary reasons the Company will defers costs or revenues on its books and in its regulatory filings (i.e. capitalizes or records items on the balance sheet rather than recording expenses or revenues) include the following:

1. <u>A deferral provides the proper matching of costs or revenues with asset utilization or associated costs or benefits of providing service</u>. An example of this situation is the set up costs associated with moving longwall mining equipment. For as long as the Company has operated longwall mining equipment, it has deferred longwall set up costs. When a longwall coal mining machine finishes mining a section of coal, known as a "panel", it is necessary to move it to a new panel. The cost of setting up the longwall machine to mine the new panel is capitalized and amortized based on the tons of coal produced from the new panel. Thus, by deferring costs and spreading (amortizing) them over a period of time, the costs are properly matched with the coal produced as a result of the longwall move and the resulting accounting of these costs better reflect the ongoing normalized operations of the Company.

2. <u>A regulatory commission has already approved the cost or revenue for both deferral and rate treatment</u>. An example of this situation is when the Company

has requested approval to sell a plant and or mine, regulators have prescribed the amount of gain to be recorded on the balance sheet and how that gain will be amortized and returned to customers through rates. In this instance, the Company records a book liability that is amortized over the specific recovery period set forth in the order. Similar to the first example, this treatment of the revenue better reflects the ongoing normalized revenue of the Company.

3. <u>The cost or revenue is extraordinary test period expense or revenue for which deferral and amortization rate treatment are sought within the context of a rate case</u>. During general rate case proceedings parties routinely identify costs within a test year (whether its historic or forecast) that were prudently incurred on behalf of customers but because the costs were extraordinary they should not be reflected in rates as ongoing period expenses, but rather, the costs should be spread (amortized) over time to better reflect the ongoing normalized cost of service of the Company. In these cases the costs are deferred and amortized over a period of time with only the annual amortization reflected as a period expense in new rates. An example of this situation is when the Company has received approval or has been directed to defer and amortize test period expenses such as computer hardware costs, software costs, reengineering costs, Y2K costs, mine closure costs, and pension costs. Additionally, various commissions have allowed deferral and amortization of more remarkable extraordinary costs associated with ice storms, flood damage, generator outages, or high winds and rain, and less remarkable extraordinary items such as costs for computerized financial models, special studies, acquisition adjustments, or early termination of coal supply

contracts. Accordingly, the accounting of these costs and any subsequent recovery of the costs better reflect the ongoing normalized operations of the Company.

4. <u>A regulatory commission has approved a deferred accounting order for costs or revenues, but has not ruled on their rate treatment.</u> These costs or revenues generally did not occur during or were not reflected in a rate case test year. These costs are deferred, however, because they exhibit the same extraordinary criteria as for those costs just described. An example of this situation is the deferral of the reduction in the West Valley Combustion Turbine lease cost that occurred prior to the test period in the last Utah general rate case. As noted above, this treatment of the costs or revenue better reflects the ongoing normalized revenue of the Company.

PENDING DEFERRED ACCOUNTING APPLICATIONS

GRID WEST LOAN

Q. Please review the Grid West loan deferred accounting application.

A. On December 19, 2006, Rocky Mountain Power filed an application to defer the costs of loans made to Grid West, the Regional Transmission Organization (RTO) which now appear will unlikely be repaid to Rocky Mountain Power (Docket 06-035-163). Rocky Mountain Power has been involved in the development of RTO for over five years. This activity was a result of meeting FERC requirements to develop regional transmission entities and competitive electric markets. In conjunction with other western utilities, Rocky Mountain Power, by and through Grid West, has been attempting to develop an independent regional electric transmission entity that would manage certain operational functions of the transmission grid and plan for necessary expansion. Grid West was established as a non-profit corporation to serve the public interest.

Rocky Mountain Power provided initial funding for the development of RTO West, the predecessor to Grid West, in June of 2000. From that date to the present, Rocky Mountain Power has loaned a total of $2.7 million to Grid West. All other regional utilities involved in the formation of Grid West have made similar loans to the organization. Grid West planned to repay the loans through surcharges to customers once it became operational. Unfortunately, Grid West is unable to repay Rocky Mountain Power's loan and the Company is requesting to defer the cost of these loans as of the date of this filing, so that it may account for the costs in a manner that better reflects the ongoing operations of the utility, and preserve an opportunity to request recovery of these costs in a subsequent rate setting proceeding.

Q. What is Utah's share of the $2.7 million?

A. Rocky Mountain Power estimates that the total amount of the deferred account will be approximately $1.1 million, which represents Utah's portion of Rocky Mountain Power's $2.7 million loan.

Q. How does Rocky Mountain Power propose to account for these costs?

A. Rocky Mountain Power proposes to account for these costs in the following manner: (1) Amounts currently recorded as a loan to Grid West will be transferred from Account 124, Other Investments, to Account 182.3, Other Regulatory Assets; and (2) The amortization of the balance will be accomplished by crediting Account 182.3 and debiting Account 560, Transmission Operation Supervision and Engineering, coincident with and subsequent inclusion of the amortization expense in rates.

Q. Why did Rocky Mountain Power not specify an amortization period in the application for deferred accounting?

A. The Company submits that such request is not necessary because the length of an amortization period and its start date can be determined by the Commission at the time of the Company's next general rate case. At the time of the next general rate case, in addition to determining whether the Company should be allowed to recover the expense in rates - whether it is a proper expense to be included in the Company's revenue requirement, the Commission would determine: (1) the appropriate amortization period and (2) when the amortization period should begin.

Q. Should the Commission deem it necessary to establish an amortization period for the Grid West Loan deferral in this docket, what would Rocky Mountain Power recommend?

A. Notwithstanding the above, to the extent the Commission determines that it would prefer to address amortization issues at this time, Rocky Mountain Power would propose a 3-year amortization period. The Company submits that a 3-year amortization period is reasonable and appropriate given the dollar amount of Utah's share of the defaulted loans. The 3-year period affords the Company with timely recovery of costs while not unduly burdening customers with the level of expense. Additionally, by the time the company receives a revenue stream to cover these expenses, it will have already been a significant length of time the Company has gone without a carrying charge or recovery.

Q. When does the Company propose that amortization begin?

A. As a general rule, as included in the description of account 182.3, the USOA provides that amortization should be charged concurrently with the recovery of the expense in rates. In this instance, however, the Company proposes to begin amortization on January 1, 2007, which is the beginning of the calendar year following the actual write-off of the defaulted loans.

Q. Why was the Grid West loan write off not included in the last rate case?

A. The notification of default on the Grid West loan was not received until April 2006, which was after the March 7, 2007, filing date (and well beyond the lockdown of results to complete the case filing) and therefore too late to be included in the revenue requirement in the general rate case, Docket No. 06-035-21.

Q. Does the request to defer the costs of the Grid West loans violate the "stay out" commitment from 2006 general rate case settlement in Docket 06-035-21?

A. No. Rocky Mountain Power submits that the proposed applications for deferred accounting do not violate the stay out commitment. As a purely technical matter, the stay out provision does not preclude the Company from filing an application for deferred accounting or establishing a new regulatory asset. Rather, paragraph 12 of the stipulation only prohibits the Company from filing a general rate case before December 11, 2007, with a rate effective date prior to August 7, 2008. An approval of the Company's application does not impact the rates that were agreed to by the settlement parties in the stipulation because the recoverability in rates of the cost of the Grid West loans will be decided in the Company's next general rate case.

The Company is simply requesting to defer and amortize costs that would normally be properly amortized over a period of time, as opposed to being absorbed in a single period. This accounting treatment results in the costs being accounted for in a manner that better reflects the ongoing operations of the utility, and preserves the opportunity to request recovery of these costs in a subsequent rate setting proceeding. Furthermore, by beginning the amortization in January 2007, amortization will occur while current rates are in effect so no current period expenses that are being incurred by the Company are being carried forward for future recovery. Only the remaining unamortized regulatory asset balance and remaining amortization expense will be reflected in the next rate case filing.

TRANSITION COSTS

Q. Please review the application to defer transition costs associated with the MidAmerican Energy Holdings Company transaction.

A. On January 24, 2007, Rocky Mountain Power filed an application to defer certain costs related to the MEHC transaction (Docket No. 07-035-04). The application specifically requests approval to defer certain costs pertaining to severance payments associated with the reduction in workforce ("Transition Costs" or "Severance Costs").

On March 21, 2006, MEHC acquired ownership of PacifiCorp. The Company has experienced both savings and costs related to the MEHC transaction. Among the cost savings is a reduction in labor expense reflecting workforce reductions associated with MEHC's ownership of PacifiCorp. However, in conjunction with the savings related to workforce reductions, the Company has also incurred additional costs related to payments for employee severance.

Pursuant to the recently completed severance program for non-union employees, employees who were involuntarily terminated, or who voluntarily terminated following a material alteration in their positions, were eligible for enhanced severance benefits consisting of severance pay, outplacement assistance and Company-subsidized health benefits. The specific severance benefits vary depending upon the compensation level for the impacted employee’s position and the employee’s length of service with the Company. As a result of the severance program 270 employees have been terminated resulting in $40 million in annual labor cost savings. Severance costs for these employees is approximately $46 million, of which only $6.4 was known by the Company and included in its revenue requirement filing as part of its general rate case in Docket No. 06-035-21. The remaining severance costs of $39 million have been incurred subsequent to that date, and were not considered as part of the revenue requirement filing in the last general rate case proceeding.

In order to match the benefits and costs of the severance program and to provide the Company an opportunity to recover its prudently incurred costs, Rocky Mountain Power requests to capitalize the costs and spread the recovery of those costs over time. This accounting treatment better reflects the ongoing operations of the utility, and preserve an opportunity to request recovery of these costs in a subsequent rate setting proceeding.

Q. What is Utah's share of the $46 million in severance costs?

A. Rocky Mountain Power estimates that the total amount of the deferred account will be approximately $18 million, which represents Utah's portion of the $46 million in severance costs. This amount also includes the $2,698,316 which is Utah's allocated share of the $6.4 that was included in Docket No. 06-035-21

Q. What is the Company's reasoning for requesting authority to defer and continue amortizing the Transition Costs that were included in Docket No. 06-035-21?

A. While the Company requested the amortization of $2,698,316 in Docket No. 06-035-21, the revenue requirement portion of the case was settled by the parties without reference to the specific treatment of these costs. As such, there was no Commission order authorizing deferral of the Transition Costs or to establish the amortization period. By including this amount in the application it does not impact rates that were set in the last general rate case, and it does not provide the Company with an opportunity for double recovery because the Company is requesting to amortize these costs from October 1, 2006, which is consistent with the Company's treatment of these costs in the rate case filing. This is also the date amortization would have begun if the Commission would have ordered the deferral and amortization of those costs in the last general rate case.

Q. How does Rocky Mountain Power propose to account for the new Transition Costs?

A. Rocky Mountain Power proposes to account for all of the MEHC Transition Costs, both the severance costs that were included in Docket No. 06-035-21 and the severance costs that have been incurred subsequent to that date, by charging them to Account 182.3 Other Regulatory Assets and amortizing these amounts to Account 930.2 Miscellaneous General Expenses.

Q. Why did Rocky Mountain Power not specify an amortization period in the application for deferred accounting?

A. Similar to the application pertaining to the Grid West loans, the Company requested that the Commission issue an order authorizing the Company to defer the Transition Costs, only, and did not specifically request a determination of the amortization period and related start date. Instead, the Company proposed to address amortization and recovery of these costs in its next general rate case.

Q. Should the Commission deem it necessary to establish an amortization period for the Transition Costs deferral in this docket, what would Rocky Mountain Power recommend?

A. To the extent the Commission determines that it would prefer to address amortization periods and start dates at this time, Rocky Mountain Power would propose a 3-year amortization period for Utah's share of the total severance costs. This includes the $6.4 million ($2.7 million Utah allocated share) of severance costs that were included in the last general rate case (Docket 06-035-21) and the new severance costs that were not included in setting rates in the last rate case. A

3-year amortization period for both costs is consistent with the amortization period proposed for the severance costs included in Docket 06-035-21 and ensures that there are net labor savings each year during the amortization period.

Q. When would the Company propose that amortization begin?

A. If the Commission determines it wants to identify the amortization period, the Company proposes that the amortization period begin October 1, 2006 for all of the Transition Costs because October 1, 2006 is the mid-point between March 21, 2006 and May 23, 2007, the applicable time frame that employees were severed as part of the change-in-control severance plan, and is arguably the proper time period for purposes of matching costs and savings.

Q. Does the request to defer the total Severance Costs violate the "stay out" commitment from 2006 general rate case settlement in Docket 06-035-21?

A. No. Similar to the Grid West application, Rocky Mountain Power submits that the proposed applications for deferred accounting do not violate the stay out commitment. The stay out provision does not preclude the Company from filing an application for deferred accounting or establishing a new regulatory asset and approval of the Company's application does not impact the rates that were agreed to by the settlement parties in the stipulation. Furthermore, by beginning the amortization in October 2006, amortization will occur while current rates are in effect so no current period expenses that are being incurred by the Company are being carried forward for future recovery. Only the remaining unamortized regulatory asset balance and remaining amortization expense will be reflected in the next rate case filing.

POWERDALE

Q. Please review the application for an accounting order for costs related to the flooding of the Powerdale hydro facility.

A. On March 21, 2007, Rocky Mountain Power filed an application to (1) transfer its undepreciated net investment of approximately $8.9 million in the Powerdale plant from Federal Energy Regulatory Commission (FERC) Account 101, Electric Plant in Service, to FERC Account 182.2, Unrecovered Plant and Regulatory Study Costs, (2) to record Powerdale decommissioning costs estimated to be approximately $6.3 million to FERC Account 182.2, and (3) to establish amortization periods for these amounts. Similar to the other applications, the issue of rate relief will be addressed in the Company's next general rate case.

Q. What were the events that lead to the filing of the Powerdale application?

A. On November 7, 2006, the 6-MW Powerdale generation facility (the "Powerdale Plant") was severely damaged by flooding and debris flow. The Company has analyzed the relative cost-effectiveness of repairing the flood damage to the Powerdale Plant or retiring the plant before its current FERC-mandated decommissioning date of April 1, 2010. This analysis is based on a comparison of the total costs required to retire the Powerdale Plant versus total costs to repair and operate it. The analysis demonstrates that the retirement of the resource is an overall lower cost-to-customers than the repair and continued operation of the plant by approximately $1.6 million. Therefore, the Company intends to retire the plant assuming the Commission approves the Company's petition. (A more detailed description of this analysis is contained in the application for the accounting order.)

Q. Please describe the Powerdale Plant and the status of the decommissioning process?

A. Powerdale is located in north-central Oregon on the Hood River, south of its confluence with the Columbia River, in Hood River County. Constructed in 1922 and 1923, the major components of Powerdale include a small diversion dam ("Powerdale Dam") and reservoir (with less than 5 acre-ft of storage capacity), a 3-mile-long water conveyance system, and a single-unit, 6,000-kW powerhouse. Additional components include five vertical traveling fish screens located at the intake structure of the conveyance system at the west abutment of the dam And a 19-pool fish ladder is located at the east abutment of the dam.

The Company initiated the federal relicensing process for Powerdale in 1995. On February 27, 1998, the Company filed an application with FERC for a new license to continue operating the project. In December 2001, FERC released an Environmental Assessment ("EA") discussing the effects of the project. On February 1, 2002, the Company filed a Motion to Abey License Proceedings with FERC, because operation of the project under terms and conditions set forth in the EA would not be economical. In July 2002, the Company released a draft decommissioning plan.

In 2003, the Company filed with the FERC a settlement agreement addressing the interim operation and decommissioning of Powerdale. In November 2005, FERC adopted this settlement agreement and issued a removal order ("Removal Order") for Powerdale, which (1) amended the project's annual license to permit continued generation and incorporated proposed protection, mitigation, and enhancement ("PM&E") measures for a period lasting until April 1, 2010; (2) required the Company to cease generation of power on April 1, 2010; (3) provided for the removal of the project and implementation of associated PM&E measures by February 29, 2012; and (4) dismissed the application for relicensure. Copies of the Removal Order and the Settlement Agreement Concerning the Interim Operation and Decommissioning of the Powerdale Hydroelectric Project (the "Settlement Agreement") are attached as Exhibit 2 to the Company's application.

Pursuant to the Removal Order, the Company now has a plan to commence decommissioning of Powerdale in April 2010. Section 5 of the Settlement Agreement approved in the Settlement Order, however, addressed the possibility that a catastrophic event (such as the November 7, 2006 flood) could render continued operation of the plant uneconomic before that date. Under Section 5, entitled "Early Cessation of Generation; Early Decommissioning," upon the occurrence of a catastrophic event, the Company may cease generating power with notice to the parties and necessary FERC approvals. Such a decision limits the Company's interim operation responsibilities under the Removal Order and permits the Company to commence decommissioning prior to April 2010. On February 1, 2007, the Company sent its letter to the FERC describing the flooding event, requesting to cease generation immediately, and affirming that it will defer consideration of beginning formal decommissioning activities prior to April 2010 until it has consulted with the settlement parties identified in Exhibit 2

Part 2. On February 8, 2007, the FERC issued its approval letter stating, “In light of the reasons stated in your letter, your request to cease generation at the Powerdale Project is granted.”

Q. Why is an accounting order necessary?

A. The Company’s decision to retire the plant will result in the potential impairment of the Powerdale Plant physical and intangible assets in accordance with FAS 90, "Regulated Enterprises-Accounting for Abandonments and Disallowances of Plant Costs." In the absence of the requested accounting treatment from the Commission, this accounting treatment will require the Company to write-off its undepreciated plant investment as a period expense, as opposed to spreading (amortizing) the investment over a period of time.

Q. How does Rocky Mountain Power propose to account for the undepreciated portion of Powerdale’s plant assets?

A. The Company proposes to account for the costs by recording the decommissioning costs and the undepreciated portion of Powerdale’s plant assets in FERC Account 182.2, Unrecovered plant and regulatory study costs. The net book value of the tangible and intangible Powerdale Plant assets at December 31, 2006, equals approximately $8.9 million. The actual amount transferred to FERC Account 182.2 will be the remaining undepreciated net book value as of the date of the transfer.

Q. How does Rocky Mountain Power propose to amortize the undepreciated plant balance?

A. In the near term, the Company proposes to amortize this balance at a rate equal to the present depreciation rate used for the Powerdale balance in FERC Account 101, or 4.2 percent. The Company anticipates requesting a change in this rate with the approval of a new depreciation study to be filed in September 2007 with an anticipated effective date of January 1, 2008. The Company anticipates requesting a three-year amortization period for the remaining balance of the unrecovered net plant balance in that study.

Q. How does Rocky Mountain Power propose to account for the projected Powerdale decommissioning costs?

A. The Company requests authority to record approximately $6.3 million of decommissioning costs, with provision for final reconciliation for final actual expenditures. This amount represents the Company's current best estimate of the costs of complying with FERC's Removal Order in light of the Powerdale Plant flood.

If this application is approved, Powerdale decommissioning costs will be accounted for as follows (all dollar figures are approximate):

- An additional liability of approximately $6.3 million will be recognized on the Company's books reflecting the Company's best estimate of the total costs to be incurred in complying with FERC's Removal Order in light of the Powerdale Plant flood.
- The $6.3 million expense associated with the recognition of the liability will be deferred as a regulatory asset in FERC account 182.2, rather than being recognized as a current period expense.
- As decommissioning occurs, the costs will be accounted for as a

reduction in cash and a corresponding offsetting reduction in the decommissioning liability.

Q. How does Rocky Mountain Power propose to amortize the Powerdale decommissioning costs?

A. The Company proposes a three-year amortization of the decommissioning cost regulatory asset. By deferring the cost and requesting inclusion in rates over a three-year period will better reflect the ongoing normalized cost of service of the Company and will allow the Company to collect the funds necessary to pay for the decommissioning of the plant when it begins in 2010.

Q. How will the Powerdale costs be handled under the multi-state Revised Protocol?

A. It is the intent of Rocky Mountain Power that all costs associated with the Powerdale will continue to flow through the Owned Hydro Embedded Cost Differential (ECD) Adjustment. Because Powerdale related costs will be charged to some accounts that are not currently included in the ECD calculation, the calculation will be modified to include the necessary accounts.

Pursuant to the Revised Protocol, the Company's inter-jurisdictional cost allocation methodology, hydro-related costs are initially allocated ratably to each jurisdiction served by PacifiCorp. Under the Revised Protocol allocation method, the Utah-allocated share of the undepreciated investment in the Powerdale Plant is approximately $3,549,000, and the Utah-allocated share of the decommissioning costs is approximately $2,505,000. These estimates are calculated based on conditions as of the Company's March 2006 semi-annual filing and will change over time as allocation factors change.

Under the Revised Protocol allocation method, subsequent to the initial system-wide allocation, hydroelectric generation-related costs are included in the calculation of the ECD, which assigns the majority of hydroelectric costs to the western side of the Company's system. In order to align cost responsibility with benefits received, the costs for which this Application seeks an order would be included in the calculation of the ECD for future rate-making purposes based on the continued use of the Revised Protocol.

Q. Does the Powerdale accounting application violate the "stay out" commitment from 2006 general rate case settlement in Docket 06-035-21?

A. No. As previously discussed, the stay out provision does not preclude the Company from filing an application for deferred accounting or establishing a new regulatory asset, and the rates that were agreed to by the settlement parties in the stipulation will not be impacted by the requested deferral.

DEFERRED ACCOUNTING APPROVALS IN OTHER STATES

Q. Has the Company filed and received approval of deferred accounting applications for these three items in other states?

A. Yes. In each of the states that the company has filed an application for deferred accounting for the costs related to Grid West loans and MEHC Transition Costs the Company has received commission approval to defer the costs. The applications for deferred accounting for the coast related to the flooding of Powerdale have been approved in California and Idaho and are presently pending before the Oregon, Washington and Wyoming commissions.

Q. Does this conclude your direct testimony?

A. Yes.