Q. Please state your name, business address and present position with PacifiCorp dba Rocky Mountain Power ("the Company").

A. My name is Andrea L. Kelly. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am employed by PacifiCorp as Vice President of Regulation.

Qualifications

Q. Briefly describe your educational background and business experience.

A. I hold a Bachelor's degree in Economics from the University of Vermont and an MBA in Environmental and Natural Resource Management from the University of Washington. After graduate school, I joined the Staff of the Washington Utilities and Transportation Commission. In 1995, I became employed by PacifiCorp as a Senior Pricing Analyst in the Regulation Department and advanced through positions of increasing responsibility. From 1999 through 2005, I led major strategic projects at PacifiCorp including the Multi-State Process and the regulatory approvals for the MidAmerican-PacifiCorp transaction. In March 2006, I was appointed Vice President of Regulation.

Q. Have you been personally involved in the negotiations related to the Klamath Hydroelectric Settlement Agreement ("KHSA")?

A. Yes. I was part of PacifiCorp's core negotiating team for the KHSA.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes, I have appeared as a witness on behalf of PacifiCorp in the states of California, Idaho, Oregon, Utah, Washington, and Wyoming.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony presents the Company's rate-related requests in this proceeding associated with the relicensing and settlement process costs for the Klamath Hydroelectric Project ("Project") and implementation of the KHSA. In support of the Company's request, my testimony explains the Federal Energy Regulatory Commission ("FERC") relicensing and settlement process the Company followed for relicensing the Project, demonstrates that the Company's decision to enter into the KHSA was a prudent business decision as compared to the costs and risks of relicensing alternatives, supports the use of the Rolled-In allocation methodology for allocating the costs of the KHSA to Utah customers, and explains why it is in customers' best interest for the Commission to address these issues in this proceeding.

Q. How is your testimony organized?

A. My testimony is organized into the following seven sections:

- First, I present the cost elements that the Company is proposing to recover in this proceeding from Utah customers;
- Second, I describe the Project and the benefits customers have derived and will continue to derive from the operation of the Project;
- Third, I provide an overview of the process to obtain a new operating license from the FERC;
- Fourth, I describe the relicensing and settlement process undertaken to date to resolve the expiration of the Project license;

- Fifth, I explain the significant activities related to the relicensing and settlement process costs for which PacifiCorp seeks recovery in this case;
- Sixth, I provide an overview of the KHSA and present the Company's economic analysis demonstrating that the Company's decision to execute the KHSA is in the best interest of customers; and
- Seventh, I describe the progress to date related to implementation of the KHSA.

KHSA Cost Elements Allocated to Utah Customers

Q. What cost recovery related to the KHSA is being proposed by the Company in this case?

A. There are three cost elements that the Company has included in this proceeding associated with the KHSA. First, the Company is seeking to add to rate base and begin amortization of the relicensing and settlement process costs. Second, the Company is seeking the Commission's approval of a depreciation schedule that would depreciate the Klamath facilities on a straight-line basis such that the net book value reaches zero by December 31, 2019, prior to possible dam removal. Third, the Company seeks to recover Utah customers' allocated share of the $172 million capped customer contribution towards dam removal costs. Mr. Steven R. McDougal's testimony and exhibits present and discuss the revenue requirement impact of each of these elements in this proceeding.

Q. Have issues around cost recovery of these KHSA-related cost elements been discussed in prior Utah regulatory proceedings?

A. Yes. In the Company's last rate case, Docket 10-035-124, the parties entered into a Stipulation which included an agreement to defer consideration of these issues until a future proceeding. Issues related to the KHSA were also addressed in Docket 02-035-04, in which the Commission adopted the 2010 Protocol subject to the terms of an Agreement among parties.[1] That Agreement expressly preserved the rights of parties with respect to KHSA-related costs.

Q. Please discuss the Company's ratemaking proposal related to the relicensing and settlement process costs.

A. The Company proposes to add the process costs to Utah's rate base and to amortize these costs on a straight-line basis through December 31, 2019. This will allow the costs to be fully amortized prior to the target date for dam removal. Adding these costs to rate base will also cause the accrual of Allowance for Funds Used During Construction ("AFUDC") to cease. As a result of the Stipulation in Docket 10-035-124, an additional year of AFUDC has accrued on this asset in Utah.

Q. Have other state commissions reviewed the process costs and included them in the Company's rate base?

A. Yes. These costs have been included in rate base in rate case proceedings across all six states in which the Company serves. The costs have been explicitly included in rate base in California, Oregon, and Wyoming.

[1] The Commission adopted the 2010 Protocol subject to the terms of the Agreement by oral bench order on November 8, 2011. A final written order is pending.

Q. Why is it in Utah customers' best interest for this Commission to adopt a new depreciation schedule for the Klamath-related rate base in this proceeding?

A. Adoption of a new depreciation schedule in this proceeding will mitigate the impact on Utah customers. If the Commission waits to adopt a new depreciation schedule and the dams are removed beginning in 2020, the burden on customers could be substantial. It is also an action that can be reviewed and revised in the future if circumstances related to the Project change.

Q. Have other state commissions adopted the proposed depreciation schedule?

A. Yes. The new depreciation schedule has been included in rate case proceedings across all six states in which the Company serves. The new depreciation schedules have been explicitly adopted in California, Oregon, and Wyoming.

Q. What allocation methodology has the Company applied to the costs associated with the Project, including the costs associated with the KHSA?

A. The Company has applied the Rolled-In allocation methodology to all cost elements. The system generation ("SG") factor has been applied to the rate base related to the Project, including the process costs. The system energy ("SE") factor has been applied to operations and maintenance costs. Finally, the SG factor has been applied to allocate the funds related to dam removal.

Q. Why is it appropriate for the Commission to apply Rolled-In allocation factors to the cost elements listed above?

A. The KHSA was entered into by PacifiCorp because doing so is in the best interest of all customers compared to the alternative of relicensing, under a range of possible outcomes. I present the economic analysis supporting the Company's decision later in my testimony. This Commission has consistently endorsed the Rolled-In allocation methodology, and viewed any departure from Rolled-In with a critical eye. The Company's decision to enter into the KHSA was no different than any other business decision – it was the best decision for customers. In addition, if the Company relicensed the Project, the Rolled-In methodology would apply to those costs. Under the Rolled-In methodology, the costs associated with a system resource are allocated system-wide. Since the Project is a system resource, system allocation of its costs is both appropriate and reasonable as it is no different than any of the Company's other hydroelectric generation facilities on the system.

Q. Are there circumstances where costs associated with state-specific policy preferences should be assigned to the state that caused those excess costs?

A. Yes. The 2010 Protocol explicitly acknowledges that principle.

Q. Are there any excess costs related to the KHSA?

A. No. As demonstrated by the Company's economic analysis, the KHSA is preferable in terms of cost and risk over the alternative of relicensing.

Q. Should the fact that Oregon and California customers are contributing funding towards dam removal costs cause the Commission to move away from Rolled-In allocations for that cost element?

A. No. The costs the Company recovers in rates in other states is irrelevant to the costs that are allocated to Utah under a multi-jurisdictional allocation methodology. Although it is generally accepted by most states that the Company should be afforded the opportunity to recover its prudently incurred costs, there are numerous examples where the Company's costs are both over-allocated and under-allocated. For example, the Washington Utilities and Transportation Commission adopted the West Control Area allocation methodology in 2006. This has the effect of over-allocating the costs of west side resources and under-allocating the costs of east side resources. No Utah party has ever argued that the over-collection of costs in Washington should somehow be credited to Utah customers, or that the under-collection of costs in Washington should somehow be collected from Utah customers. For Utah parties to isolate the potential over-collection of the dam removal surcharge and seek a credit to Utah customers would be a significant departure from past practices and could have unintended consequences. The dam removal costs related to the KHSA are no different than any other costs under a Rolled-In allocation methodology; they are system costs that are appropriately allocated to Utah customers using the SG factor.

Overview of the Project

Q. Please describe the Project.

A. The Project is a 169 megawatt hydroelectric facility on the Klamath River in southern Oregon and northern California. It consists of eight developments including seven powerhouses, five mainstem dams on the Klamath River (Iron Gate, Copco No. 1, Copco No. 2, J.C. Boyle, and Keno), as well as two small diversion dams on Spring Creek and Fall Creek, tributaries to the Klamath River. The Project as currently licensed includes the East Side and West Side generating facilities, which use water diverted by the Link River Dam, a facility owned by the Bureau of Reclamation that regulates the elevation and releases of water from

Upper Klamath Lake and which is not included in the Project. The Project also includes Keno Dam, which has no hydroelectric generation facilities, but which serves to regulate water levels in Keno Reservoir as required by the Project license. The Company operates all eight developments under one FERC license (FERC Project No. 2082). The Project is partially located on federal lands administered by the Bureau of Land Management and the Bureau of Reclamation. The first hydroelectric development, Fall Creek, was completed in 1903 and Iron Gate, the last hydroelectric development, was completed in 1962. Keno Dam was completed in 1968. A map of the Project is provided as Exhibit RMP___(ALK-1).

Q. Generally, what benefits does the Project provide PacifiCorp's customers?

A. Since its completion, the Project has provided customers with reliable, low-cost power. As currently operated in compliance with the limitations of the existing license, the Project is a source of energy, capacity, and reserves. Unlike most other sources of generation, hydro projects also provide an additional environmental benefit because they are emissions-free. In addition, the generating units of the Project located in California qualify as renewable energy resources for the California Renewable Portfolio Standard.

Overview of Federal Relicensing

Q. Please provide an overview of the federal relicensing process.

A. Under the Federal Power Act ("FPA"), FERC has the exclusive authority to license nonfederal hydropower projects on navigable waterways. Original licenses are issued for a term of 50 years, after which a licensee may seek relicensing. FERC issues subsequent licenses for a term of not less than 30 years or more than

50 years with FERC deciding the length of the license. FERC regulations require that a licensee file a Notice of Intent to apply for a new license five and a half years prior to license expiration. On average, licensing takes eight to 10 years, and some applications have taken as long as 30 years. During the relicensing process, FERC typically allows projects to continue operating on annual license extensions under the same terms and conditions once the old license has expired. Such is the case with the Project at this time, as the original project license expired in 2006. The licensing process requires FERC to consider the economic, engineering, environmental, and socioeconomic aspects of the project. In issuing licenses, FERC must give "equal consideration" to environmental values and adequately protect and mitigate the effects of the Project based on environmental and other concerns. In doing so, FERC attaches conditions to the license.

Q. What roles do state and federal resource agencies play in the process?

A. State and federal fish and wildlife agencies review applications and submit comments to FERC regarding the impact the Project may have on the environment. Based on those impacts, state and federal agencies recommend conditions to FERC to place on the license to mitigate the potential impacts. The FPA gives certain federal agencies authority to require FERC to include the agency's conditions on the license. For example, the Secretaries of Commerce and the Interior have the authority to require applicants to install fishways (ladders and screens) at projects, and to require applicants to reduce variability of in-stream flows.

Q. What options does an applicant have if the mandatory conditions make the project uneconomic?

A. The applicant has limited options. The applicant may accept the uneconomic license, decommission and remove the facility, or pursue litigation and challenge the mandatory conditions. The applicant has the option of selling the facility as well. Because of the potential risks of removal of facilities and the uncertainty of litigation, those options are seldom favored. Consequently, applicants often try to manage uncertainty by settling issues among the various stakeholders before licensing is completed or by negotiating acceptable decommissioning and removal outcomes.

Q. Other than the FPA, what other laws must FERC take into consideration when granting licenses?

A. Because licensing is a "federal action," FERC must evaluate the application under a host of federal laws: the Clean Water Act ("CWA"), the Coastal Zone Management Act, the National Environmental Policy Act ("NEPA"), the Endangered Species Act ("ESA"), the Fish and Wildlife Coordination Act, and the National Historic Preservation Act, among others. These laws add significant time and expense to the application process.

The Company has sought CWA Section 401 certifications for the Project from both Oregon and California. In addition, ESA considerations are present at the Project due to the presence of threatened coho salmon in the Klamath River below Iron Gate dam, and endangered Lost River and shortnose suckers that predominantly reside in Upper Klamath Lake and its tributaries but utilize habitat within the Project boundary.

Q. Does FERC offer more than one relicensing process?

A. Yes. At the time the license application for the Project was developed and filed – the final license application was submitted to FERC in February 2004 – applicants could use either traditional or alternative licensing processes. During the process of developing the license application for the Project, FERC developed an additional licensing process called an integrated licensing process, which became the default process for relicensing in 2005. Applicants may also enter into a negotiated settlement at any time. The Company initiated licensing under the traditional approach for the Project, and has pursued settlement to resolve the issues related to the Project relicensing.

Q. Please provide a more detailed description of the traditional FERC relicensing process.

A. The traditional process involves three stages of consultation. In the first stage, the applicant distributes an Initial Consultation document, which explains the project and its operation and environmental setting to federal and state agencies, tribes, non-governmental organizations ("NGOs"), community interest groups and other stakeholders. Following the consultation document, the stakeholders meet and visit the site. Thirty days after the meeting, comments and additional study recommendations are due to the applicant. Stage one ends when a set of resource-by-resource study plans and stakeholder consultation documentation have been completed and provided to FERC.

Q. What takes place in the second stage of consultation?

A. In the second stage, the applicant conducts the proposed studies and prepares a draft license application, which it distributes to FERC and to interested agencies, tribes and stakeholders for review and comment. At this stage, agencies routinely request additional studies, which can be costly and time-consuming. The applicant may refer such requests to FERC for dispute resolution and FERC may request additional information. The applicant must provide FERC with a written summary of how the Company resolved any disagreements with agencies and others. The second stage ends when FERC accepts a final application for filing.

Q. Please describe the third stage.

A. In the third stage, FERC solicits initial comments and preliminary terms and conditions from resource agencies, tribes, and stakeholders, and gives notice that the project is ready for environmental analysis under NEPA. FERC may require additional information from the applicant to address those comments. FERC next initiates its detailed environmental and engineering review and solicits final comments, recommendations, terms and conditions, and mandatory prescriptions. From all of this information, FERC prepares an Environmental Assessment or Environmental Impact Statement taking into account comments, responses and conditions. Ultimately, FERC issues a license order describing both how the project will be operated during the next license term, and what environmental and other enhancement obligations the licensee must fulfill. Those obligations include the mandatory terms and conditions provided by the Secretaries of Commerce, Agriculture and Interior. In addition, if relevant, FERC appends any conditions associated with CWA Section 401 water quality certifications that have been issued by state agencies.

Overview of Project Relicensing and Settlement Process

Relicensing Process

Q. Please describe the relicensing process to date for the Project.

A. PacifiCorp filed a Notice of Intent to relicense and issued its First Stage Consultation Document on December 15, 2000. In an attempt to arrive at consensus-based approaches to the licensing process with the various stakeholders involved, PacifiCorp pursued a "traditional-plus" licensing approach in which the traditional process was followed with a concerted effort to solicit stakeholder input and agreement on study plans before they were submitted to FERC for review. This "traditional-plus" approach resulted in a significant number of stakeholder meetings to review proposed study plans, gather input, and attempt to achieve consensus.

Q. Please explain stakeholder participation in the relicensing process for the Project.

A. Public meetings for the relicensing process began in January 2001 and continued through 2002 and 2003. The final license application was submitted to FERC in February 2004. FERC issued its first scoping document for the environmental review process in April 2004 and scoping was completed in May 2005. FERC issued notice that the project was ready for environmental analysis on December 28, 2005. The original FERC license expired February 28, 2006, and annual licenses have been issued by FERC since that time.

Federal agencies – the National Marine Fisheries Service, U.S. Fish and Wildlife Service, Bureau of Reclamation, and Bureau of Land Management – issued draft terms and conditions for a new license in March 2006. The draft terms called for full volitional fish passage at all Project developments as well as other license conditions to benefit environmental resources that would reduce power generation and increase the costs of a new license. That same month, the Company submitted applications to California and Oregon for CWA Section 401 water quality certifications of the Project. As a result of the Energy Policy Act of 2005, the Company had the opportunity to challenge the underlying facts behind the draft agency terms and conditions and propose alternative licensing conditions. The Company filed alternative license conditions with FERC that the Company believed provided similar environmental benefits as the draft agency terms and conditions but at less cost and loss in power production from the Project. The Company's filing also challenged material facts relied upon by the agencies. A trial-type hearing was conducted on these issues of material fact underlying the agency terms and conditions in August 2006 and a decision was issued by an administrative law judge in September 2006. Also in September 2006, FERC issued a draft Environmental Impact Statement for Hydropower License.

Incorporating the findings of the trial-type hearing, the agencies issued modified terms and conditions for a new license in January 2007. FERC then initiated ESA consultation for a new license in March 2007 and the National Marine Fisheries Service and U.S. Fish and Wildlife Service issued final biological opinions in December 2007. To initiate analysis of the project under the California Environmental Quality Act ("CEQA") pursuant to obtaining CWA Section 401 certification, the Company signed a memorandum of understanding with the California State Water Resources Control Board in September 2007. FERC completed its environmental analysis of the project and released its Final Environmental Impact Statement ("FEIS") for Hydropower License in November 2007.

Q. Please describe the relicensing process after the Company filed its applications for CWA Section 401 certification of the Project.

A. Since filing its applications in March 2006 for CWA Section 401 certification with California and Oregon, PacifiCorp has been implementing water quality studies and monitoring in order to improve water quality conditions in the Project reservoirs and in the Klamath River downstream of Project facilities. The result of these study and planning efforts will help the states of California and Oregon assess whether the Project can meet applicable water quality standards. In June 2009, the California North Coast Regional Water Quality Control Board issued a draft Total Maximum Daily Load ("TMDL") report for the Klamath River and in February 2010, the Oregon Department of Environmental Quality released its draft TMDL for the Klamath River in Oregon. The TMDLs prescribe nutrient, temperature, and dissolved oxygen requirements in the river that must be attained by Project facilities. PacifiCorp has been actively involved in reviewing the TMDLs since they will ultimately inform the conditions that may be imposed on the Project through the CWA Section 401 certification processes.

Q. Absent the settlement under the KHSA, what steps remain to be completed in the relicensing process?

A. In order for FERC to issue a new Project license, CWA Section 401 water quality certification must first be completed by the states of California and Oregon. The conditions of the CWA Section 401 certification would then be incorporated into the new FERC license for the Project. PacifiCorp has CWA Section 401 water quality certification applications pending in both states. However, pursuant to the KHSA, CWA Section 401 certification of the Project will be held in abeyance while the Secretary of the Interior makes a determination as to whether the four main stem Klamath River dams owned by PacifiCorp should be decommissioned and removed or relicensed.

Settlement Process

Q. Please describe how settlement is used in FERC relicensing process.

A. Due to the complex nature of relicensing proceedings and the many issues and stakeholders involved in the process, many relicensing proceedings are resolved by settlement. As mentioned before, a settlement between the parties to a relicensing proceeding can be entered at any time while the relicensing process is ongoing. Settlements are encouraged by FERC and recent changes to the relicensing process alternatives have been made to encourage applicants and stakeholders to reach consensus on the issues related to project relicensing so the parties can reach settlement. Indeed, PacifiCorp has pursued settlement for the majority of its recently completed hydro relicensing proceedings including the North Umpqua, Bear River, and Lewis River projects. In addition, settlements have been entered among PacifiCorp, agencies and stakeholders to decommission the Condit, American Fork, and Powerdale hydro projects after those projects began the traditional FERC relicensing process.

Q. Please describe the settlement process to date for the Project.

A. For the Project, PacifiCorp initiated settlement discussions in October 2004 with stakeholders, following submittal of the license application. These settlement discussions were entered into by the Company to identify the interests of the stakeholders such that those interests could be addressed in a settlement that would preserve the economic value of the Project under a new long-term FERC license to operate the facilities. The first mediated settlement meeting was conducted in January 2005. Settlement meetings proceeded through 2005 and mid-2006. At that point, Project stakeholders decided that they wanted to turn their attention to resolving basin-wide natural resource issues between themselves without PacifiCorp's involvement. PacifiCorp then discontinued its participation in settlement discussions while those stakeholders continued to meet. PacifiCorp did not participate in these negotiations because resolution of these broader issues was beyond the scope of the relicensing proceeding and did not relate directly to operation of the Project. This group of stakeholders, after months of negotiations, released the draft Klamath Basin Restoration Agreement ("KBRA") in January 2008. The KBRA is intended to resolve issues of water allocation in the Klamath Basin and provide for habitat restoration and called for removal of PacifiCorp's main stem hydroelectric dams.

Q. Is PacifiCorp a signatory to the KBRA?

A. No. PacifiCorp is not a party to the KBRA. PacifiCorp has no responsibilities under the KBRA and customers will bear no costs associated with the KBRA.

Q. Please describe settlement efforts related to the Project subsequent to the release of the KBRA.

A. Following release of the KBRA, active settlement negotiations were resumed among PacifiCorp, the federal government, and the states of California and Oregon. Other key stakeholders joined the settlement negotiations, resulting in an Agreement in Principle ("AIP"), which was released on November 13, 2008. The AIP laid out a framework for resolution of the issues related to relicensing of the Project including the potential decommissioning and removal of PacifiCorp's four main stem dams on the Klamath River – J.C. Boyle, Copco No. 1, Copco No. 2, and Iron Gate. As a result of discussions with the National Marine Fisheries Service and the U.S. Fish and Wildlife Service, PacifiCorp also developed an Interim Conservation Plan to provide benefits to ESA-listed aquatic species during the period of interim operations prior to potential dam removal or the re-establishment of fish passage through the Project pursuant to project relicensing.

Following the release of the AIP, PacifiCorp pursued further negotiations with the parties to the AIP – the federal government, California and Oregon – as well as an expanded group of stakeholders, agencies, and other interested parties to complete a final settlement agreement for the Project. On February 18, 2010, the KHSA was executed by over 30 parties, including PacifiCorp, the Secretary of the Interior, governors from the states of Oregon and California, Native American

Tribes, and parties representing counties, irrigation districts, fishermen, environmentalists and other organizations. I have provided a detailed chronology of key points in the Klamath relicensing and settlement process as Exhibit RMP___(ALK-2).

Q. Did PacifiCorp enter settlement discussions for the sole purpose of pursuing dam removal?

A. No. As described above, PacifiCorp entered into settlement discussions to find an outcome that would meet the interests of Project stakeholders while also preserving the value of the project for customers so that it could operate economically under a new long-term license. While engaging in settlement discussions, PacifiCorp at the same time also robustly engaged in the traditional licensing process to achieve a similar economic outcome for the Project under a new license.

Costs and Benefits of Relicensing

Q. Please describe how pursuing relicensing and settlement has provided customer benefits.

A. PacifiCorp has pursued relicensing to preserve economic benefits to its customers from the Project. Had the Company not elected to pursue relicensing of the Project, it would have been required to submit an application to FERC for surrender of the Project license and decommissioning/removal of the facilities. Doing so would have exposed PacifiCorp's customers to the uncertainties related to potential decommissioning and removal of the facilities, while necessitating that PacifiCorp's customers pay for the immediate replacement of the energy provided by the Project. Throughout the relicensing and settlement process, PacifiCorp has taken the position that decommissioning and removal of the Project without sufficient protections against the associated costs, risks and liability is not in the best interests of the Company or its customers. To that end, it has pursued settlement in a manner that will provide those protections. In addition, the relicensing and settlement process has provided benefits by allowing customers to continue to benefit from the Project during the period between the expiration of the Project license in March 2006 and continuing until the potential removal of the facilities.

Q. How much has the Company incurred in the relicensing and settlement process?

A. The project was completed at a total cost of approximately $74.1 million on a system-wide basis as of December 31, 2010. Mr. McDougal's testimony and Exhibit RMP___(SRM-3) provides a breakdown of the share of these costs that have been allocated to Utah customers. A cost breakdown for the Project relicensing and settlement process is provided as Confidential Exhibit RMP___(ALK-3).

Q. Do the relicensing and settlement costs include costs to implement the KHSA?

A. No. The relicensing and settlement costs only include costs related to pursuing the traditional relicensing process and the costs necessary to pursue settlement of the Project relicensing. Costs related to implementing the KHSA will be recovered as they are incurred prior to potential removal of the facilities through normal operations and maintenance costs and, where applicable, specific capital projects related to KHSA implementation.

Q. What are the major cost categories for the process costs?

A. For total-company costs through 2010, approximately 36 percent of the costs ($26 million) derive from outside expert consulting services. These services included the development of the detailed scientific information necessary to prepare the first stage consultation document and the costs to consult with stakeholders and prepare detailed study plans for the various resource areas investigated as part of the relicensing process. These services included the execution of the vast array of technical studies required and the costs to prepare the license application. Examples of the studies and data collected include:

- Complete aerial photography and mapping of the Project,
- Bathymetric and sediment studies of Project reservoirs,
- Environmental resource investigations,
- Wildlife and vegetation surveys,
- Geomorphology studies,
- Biological and engineering studies of various fish passage alternatives, fisheries modeling and habitat assessment,
- Studies of potential Project operational enhancements,
- Historic and cultural resources investigations,
- Socioeconomic studies,
- Recreation surveys and planning,

- Extensive water quality monitoring, and development of a Project water quality model and associated water quality modeling studies,
- Development of cost estimates for potential protection, mitigation, and enhancement ("PM&E") measures likely to be required in a new license.

These costs, plus an additional $9 million of legal costs, also included license application preparation, CWA Section 401 applications costs and related studies, ESA consultation and documentation costs, legal review and legal costs associated with the Company's challenge to agency terms and conditions, responses to comments in relation to the license application and required analysis of the Project pursuant to the California Environmental Quality Act. Finally, this included costs associated with the settlement process, facilitator and mediator services, communications and other services.

The amount of information necessary to be developed for the preparation and support of hydroelectric license applications is very significant. The Project license application and associated study documentation and filings produced by the Company require in excess of eight feet of shelf space. This is similar to the shelf space devoted to the Company's license application for the recently relicensed North Umpqua project.

Materials, labor and associated expenses accounted for approximately $11 million – or approximately 14 percent of total costs. These costs included labor and associated costs for the Company's project management, technical leads, environmental scientists, and administrative staff. The remaining costs are related to property taxes paid against accrued relicensing costs, and AFUDC.

Q. What controls does the Company put in place to ensure that the expenditures made in the relicensing process were required, necessary, and prudent?

A. First, the Company appoints a Project Manager for each relicensing project. The Project Manager works with Hydro Resources and PacifiCorp Energy management to coordinate all efforts related to the process and project cost management. The Company also assembles a project team, which is comprised of technical leads who are subject matter experts in the various relicensing areas. Examples of technical leads include: fishery and wildlife biologists, cultural and recreation specialists, engineering, etc. The team develops a relicensing strategy to address likely required studies and potential PM&E measures. The technical leads assist the Project Manager is overseeing work tasks within their area of expertise. Consultants have been generally selected through a formal bidding process unless specific expertise was needed, in conformance with general PacifiCorp procurement policy.

Finally, due to the fluid and multi-disciplinary nature of the FERC relicensing process, which requires significant legal support, the Office of General Counsel reviews the relicensing project and works with the Project Manager and outside counsel to assure that legal services in support of the relicensing effort are necessary, prudent, and procured in conformance with Company policies that are intended to control costs.

Q. Please explain how outside services costs have been managed.

A. First, an overall budget was established for the project spanning the time through expected license issuance. Each year, as part of the annual budgeting and approval process, the portion of the Project budget to be expended in the upcoming year is thoroughly reviewed and approved by management. Throughout the year, a monthly break down of all Project expenditures is provided to department management and to the Project Manager. This process provides an opportunity to look at Project costs on an overall basis and make adjustments as may be necessary to stay within the overall Project budget if possible. The process also provides an opportunity to review all expended costs on a monthly basis to ensure they are proper and represent prudent expenditures to accomplish the relicensing and settlement objectives.

Q. Has the complexity of the Project impacted the overall level of process costs?

A. Yes. As detailed earlier in my testimony, the relicensing process is time-consuming, complex and requires the expenditure of significant staff labor, outside technical support, and legal services to prepare an application and defend and prosecute that application through the regulatory process. The Project has been the most complex and contentious relicensing proceeding the Company has undertaken for its many hydroelectric projects. Even so, the Project relicensing costs are comparable with another recent relicensing effort by the Company on the North Umpqua River. At the conclusion of that relicensing process in 2005, the total cost was approximately $55.1 million. In that case, the relicensing and settlement process spanned ten years, from 1991 to 2001. The settlement parties were fewer in number and included: U.S. Forest Service, National Marine Fisheries Service, U.S. Fish and Wildlife Service, Bureau of Land Management, Oregon Department of Environmental Quality, Oregon Department of Fish and Wildlife, and Oregon Water Resources Department.

The KHSA and Supporting Economic Analysis

Q. Please provide a more detailed description of the KHSA.

A. The KHSA provides for the transfer of the Project to a Dam Removal Entity ("DRE") no earlier than 2020. The KHSA calls for the Secretary of the Interior to conduct further studies and environmental review and to issue a determination as to whether dam removal should proceed. Prior to the Secretary's determination, key milestones called for in the KHSA must occur, including the passage of federal legislation to enact key provisions of the KHSA and to provide protection for the Company and its customers from liabilities related to dam removal. Prior to transfer of the Project facilities to the DRE, PacifiCorp will continue to operate the facilities and its customers will continue to benefit from the low-cost power produced by the facilities. Prior to dam removal, the KHSA requires the Company to implement a number of interim measures to mitigate impacts of the Project in the Klamath Basin.

Q. Please provide an overview of PacifiCorp's approach to the negotiations that led to the execution of the KHSA.

A. Relicensing the project has been a complex and challenging process that is interwoven into longstanding and contentious issues in the Klamath Basin. Throughout these negotiations, the federal government and the states of Oregon and California have expressed a strong policy preference that PacifiCorp's dams on the Klamath River be removed. In response, PacifiCorp outlined four core principles that guided its negotiation strategy related to a path that could lead to dam removal:

1. Protect utility customers from uncertain costs of dam removal;
2. Transfer dams to a third party for removal;
3. Protect utility customers from liabilities of dam removal; and
4. Ensure that utility customers continue to benefit from the low-cost power of the dams until the dams are removed

Q. Does the KHSA deliver the Company's four core principles?

A. Yes. The terms of the KHSA deliver each of these elements for the benefit of PacifiCorp's customers. As such, the KHSA provides a more certain and less risky path forward for customers.

Q. How does the KHSA protect customers from uncertain costs of dam removal?

A. The KHSA contains a $200 million cap on the customer contribution to the costs of dam removal and also provides, with the passage of necessary federal legislation conforming to the terms of the KHSA, liability protection that will shield customers from additional costs related to dam removal should ultimate costs exceed those laid out within the KHSA.

Q. Were there any other key considerations for PacifiCorp as it negotiated the terms of the KHSA?

A. Yes. PacifiCorp negotiated the terms of the KHSA in a manner that resulted in a fair and balanced outcome to customers and other stakeholders. As discussed in detail below, under relicensing, the status quo for the Project isn't an option. As such, the costs to customers under the KHSA were compared against a baseline relicensing scenario throughout the negotiations. This analysis ensured that customers would be expected to be no worse off under the KHSA as compared to a conservative estimate of relicensing costs. This analysis, combined with the significant risk-reducing elements of the KHSA, ensures that the KHSA is in the interest of PacifiCorp's customers.

Q. Please describe PacifiCorp's general approach to the economic analysis supporting its decision to enter into the KHSA.

A. Prior to entering into the KHSA, PacifiCorp compared the cost to customers of the KHSA with the costs to customers under a conservative relicensing scenario. The costs to customers of relicensing are highly uncertain. As such, the Company developed a relicensing case against which the economics of the KHSA were compared. The relicensing case relies heavily on the costs and data developed as part of the FERC FEIS.

Q. Please provide an overview of the Company's estimated costs to relicense the Project.

A. As detailed on page 2 of Confidential Exhibit RMP___(ALK-4), the Company's estimated costs to relicense the Project include in excess of $400 million in capital and in excess of $60 million in operations and maintenance (“O&M”) costs over a 40-year license term. Of these capital costs, the majority is related to implementation of aquatic resource PM&E measures. These costs are related to providing volitional upstream and downstream fish passage at all Project developments, which is required by the mandatory agency terms and conditions. Additional funding would be required for terrestrial resource PM&E measures, recreational resource PM&E measures, land use PM&E’s, and cultural resource PM&E measures. The remaining capital costs are for water quality improvements to address temperature and dissolved oxygen effects of the Project reservoirs and to address water quality concerns related to algae. Consistent with PacifiCorp’s license application, the East Side and West Side developments would be decommissioned and removed.

The PM&E measures contained in the Company’s baseline relicensing scenario generally include those measures specified in the “Staff Alternative with Mandatory Conditions” alternative in the FERC FEIS. Because the CWA Section 401 water quality certification process for the Project is not yet complete, the water quality measures necessary to obtain a new license remain highly uncertain. Thus, the Company’s relicensing scenario includes measures that have been evaluated during the FERC process to address the water quality effects of the Project, as an estimate of what might be required.

In addition to the capital and O&M expenditures to implement the required PM&E measures, the relicensing scenario also reflects a 20 percent reduction in the energy that would be produced from the Project. This is due to the requirement to provide more water to bypassed reaches of the Klamath River, which makes less water available for generation. This most significantly impacts generation at the J.C. Boyle development, where compliance with agency terms and conditions on flows would reduce generation more than 40 percent. J.C. Boyle is by far the largest generation facility in the Project.

Q. What information sources were used to derive these costs?

A. The majority of the costs included in the Company's analysis are in the FERC record and contained or referenced in Appendix A of the FEIS. These costs have been escalated to current dollars since the costs contained in the FEIS were in 2006 dollars. Some costs were developed from PacifiCorp internal estimates and generation impact models. Given the uncertainty related to the costs to implement measures required to obtain CWA Section 401 water quality certifications from California and Oregon, water quality costs include measures explored during the relicensing proceeding to address project-related water quality effects.

Q. Please provide an overview of the Company's assumed costs of implementing the KHSA.

A. As detailed on page 3 of Exhibit RMP___(ALK-4), the Company's assessment of the costs of settlement includes approximately $9 million in capital costs and approximately $70 million in costs that would be characterized as O&M costs. The majority of the capital costs reflect the costs of interim water quality improvements and hatchery improvements. Increased funding for hatchery programs and ongoing hatchery production following dam removal represents approximately half of the O&M costs. Other funding requirements include restoration and study funding, lands and cultural resources funding, aquatic habitat enhancement, water quality monitoring and improvement costs. Implementation and management costs are also reflected in the O&M costs. Implementation costs also include the decommissioning of the East Side and West Side development at a cost of approximately $3 million, and the $172 million dam removal customer surcharge.

Q. How were these costs derived?

A. The majority of the costs included in the Company's assessment of settlement costs are derived from Appendices C and D of the KHSA. These appendices list the interim measures that the Company must implement prior to dam removal. Many of the interim measures consist of capped funding obligations for specific resource areas such as hatcheries, aquatic habitat enhancement, water quality monitoring, water quality studies and improvements, and land management activities. Other costs for specific interim measures are estimates of what might be necessary to fulfill the obligation spelled out in the interim measure based on the costs to develop certain infrastructure or implement specific projects. As with the relicensing case, some costs are developed from PacifiCorp internal estimates and generation impact models.

Q. How was the analysis structured?

A. The analysis evaluated the Present Value Revenue Requirement ("PVRR") of the stream of costs under the KHSA and compared it against the PVRR of the stream of costs under the relicensing scenario. The analysis covered a 44-year period beginning in 2010 – this equates to a 40-year license beginning in 2013.

Q. What did the analysis assume with respect to the costs of replacement power?

A. In both scenarios, the Company assumed that lost generation would be replaced with renewable, non-carbon emitting resources. This was accomplished through the use of a forward price curve that contained a “carbon adder” as a reasonable proxy for the cost of renewable replacement power. As noted above, there is also lost generation under the baseline relicensing scenario due to operating restrictions that were included in the FERC FEIS.

Q. How did the Company use the analysis to inform its negotiation strategy?

A. As mentioned above, the Company was willing to agree to a set of financial commitments under the KHSA that did not exceed the cost estimates in the relicensing scenario. However, it was also important to the durability of the KHSA that the other settlement parties viewed the overall result as fair and balanced. If the PVRR of the KHSA was significantly below the baseline relicensing case, this durability would have been threatened.

Q. Does the KHSA result in a fair and balanced outcome to PacifiCorp’s customers?

A. Yes. Based on the results of this conservative analysis, the KHSA results in a PVRR that is below the cost of relicensing. This is shown in a summary of the Company’s economic analysis included on page 1 of Confidential Exhibit RMP___(ALK-4). More importantly, customers are protected from the risks and liabilities that exist absent an agreement among the parties. The Company conducted additional sensitivity analyses related to these risks and customers were better off under a broad range of assumptions. In the end, the Company's decision to enter into the KHSA was no different than any other business decision – customers are better off in terms of costs and risks under the KHSA when compared against the range of alternate scenarios.

Q. What cost risks does relicensing present for customers?

A. The risk of increasing costs is one risk relicensing presents for customers. The PM&E measures included in the Company's assessment of relicensing costs are based on the best estimates available as developed during the relicensing proceeding several years ago. As such, there is always a risk that costs for PM&E measures will escalate as measures are fully designed and constructed. This represents a risk to customers since a new license would prescribe the construction of certain facilities to mitigate project effects and establish fish passage regardless of the ultimate cost of those measures. Consultation with agencies, as required by a new license, can also increase the scope and cost of PM&Es as design standards and agency criteria change.

The cost of additional PM&E measures is another risk relicensing presents for customers. Agencies have also reserved authority to require additional mandatory PM&E's to address changed environmental conditions or the potential ineffectiveness of required PM&Es to attain the desired benefits. Thus, additional PM&E measures could be required during the term of a new Project license that would result in costs to customers in excess of what is reflected in known relicensing costs at this time.

There are also other process-related risks that licensing presents for customers. As one example, if the State of Oregon or California denied a CWA Section 401 water quality certification, FERC would be unable to issue a new license, yet maintains that it has the authority to require the owner to decommission and remove the project facilities at the owner's expense.

Q. Do you believe that the costs assumed in the baseline relicensing scenario are conservative?

A. Yes. Absent a settlement among parties, it is clear that the Company would continue to face significant opposition to relicensing. My observation is that on balance the stakeholders would attempt to drive the costs of relicensing as high as possible in an effort to make relicensing uneconomic. As discussed above, there are also significant risks related to the Company’s ability to secure state CWA Section 401 water quality permits.

Q. How do these risks compare to the risks under the Company’s settlement scenario?

A. Continuation down a path of relicensing presents far greater risks to customers than settlement under the KHSA. Under the KHSA, cost obligations are well–defined and largely capped. For the interim measures that do not have a cost cap, the relative cost risk is much less than under relicensing given the extensive scope and costs associated with measures required under relicensing. Additionally, transferring the dams prior to removal, along with other key protection measures outlined in the KHSA further minimize cost risk.

Q. Has the Company undertaken a comprehensive analysis of the costs of Project removal?

A. No. PacifiCorp has not attempted to complete a comprehensive analysis of the costs of Project removal given the many risks and uncertainties. Large uncertainties include the costs of sediment management, minimizing and mitigating environmental impacts related to removal, water quality and endangered species impacts, infrastructure impacts, and site re-vegetation and restoration costs. Many of these uncertainties can only be better defined through the removal design and permitting process. The KHSA is designed to shield customers from the risks and liabilities of dam removal while ensuring that a comprehensive science-based review is undertaken prior to the Secretarial Determination of whether removal of the dams is in the public interest.

Q. Have any credit rating entities commented on the benefits of the KHSA?

A. Yes. In an October 7, 2010, credit report for PacifiCorp, Standard & Poor's cited the KHSA as a "Major Rating Factor" providing strength to PacifiCorp's credit rating. The Standard & Poor's assessment stated that "A settlement reached in February 2010 regarding the contentious Klamath hydro relicensing case has the potential to adequately address the company's financial exposure if the project is decommissioned, which will not occur before 2020."

Q. What does this rating agency comment mean with respect to customer benefits?

A. This means that PacifiCorp's execution of the KHSA pursuant to the relicensing and settlement process has favorably impacted customers already by strengthening PacifiCorp's credit rating. This ultimately translates to a lower cost of debt which benefits customers.

Progress on KHSA Implementation

Q. Since the KHSA was signed in February, 2010, what progress has been made in implementing the KHSA?

A. Significant progress has been made by the Company in implementing its obligations under the KHSA and progress in implementing the regulatory and legislative actions necessary for the agreement to proceed has occurred as well.

As required by the KHSA, the Company has petitioned both the California State Water Quality Control Board and the Oregon Department of Environmental Quality to hold in abeyance its applications before those agencies to certify the Project under Section 401 of the Clean Water Act. Both agencies, acting in an independent capacity, have granted this abeyance in the recognition that successful implementation of the KHSA will resolve the relicensing proceeding for the Project.

Q. What implementation actions has the Company taken directly as a result of the KHSA?

A. Since the execution of the KHSA, the Company has made adjustments to Project operations consistent with its obligations under the KHSA and has taken actions to fulfill its requirement to implement interim measures to protect and enhance environmental resources in the Klamath basin. These interim measures include providing increased funding to support and enhance hatchery operations at the Company's fish hatchery located at the Project, actions to fund and implement habitat enhancement and conservation actions for salmon and fish species protected under the ESA, and actions to fund and implement water quality monitoring and enhancement measures.

Q. Have other parties to the Settlement made progress in implementing their obligations?

A. Yes. Since the Settlement was signed, the U.S. Department of the Interior ("Interior") and the California Department of Fish and Game ("CDFG") have undertaken the necessary environmental review and analysis consistent with the requirements of NEPA and CEQA, which must be completed prior to the Secretarial Determination. Scoping for the NEPA/CEQA process began in June 2010 and a Draft EIS/Environmental Impact Report for Klamath facilities removal was released by Interior and CDFG for public comment on September 21, 2011. Interior has completed numerous studies and technical reports over the past two years in fulfillment of its commitment in the KHSA to conduct relevant environmental studies and analysis to ascertain the impacts of potential dam removal.

Q. Is there progress with federal legislation that would advance the KHSA?

A. Yes. Legislation that would endorse and authorize the KHSA and the KBRA was introduced in the U.S. Congress on November 10, 2011. Senator Merkley from Oregon introduced the measure (S. 1851) in the Senate along with Senator Barbara Boxer from California. In the Senate, the bill has been referred to the Committee on Energy and Natural Resources. Representative Mike Thompson of

California introduced the measure (H.R. 3398) in the House of Representatives, along with 15 Representatives as co-sponsors.

Q. Now that legislation has been introduced, what legislative activity is anticipated?

A. Since the legislation was introduced, Senator Ron Wyden of Oregon has announced that the subcommittee of the Energy and Natural Resources Committee that he chairs will hold a hearing on the legislation early this year. Hearings such as this will be necessary for the legislation to be vetted in Congress such that it can be marked up by the relevant committees and eventually referred to the full House and Senate for passage.

Q. Does this conclude your direct testimony?

A. Yes.