IDAHO PUBLIC UTILITIES COMMISSION

REPORT TO THE GOVERNOR AND THE IDAHO LEGISLATURE

ON THE COSTS OF ELECTRIC SERVICE IN IDAHO

EXECUTIVE SUMMARY

Idaho Code §§ 61-338 and 61-339, as enacted by 1997 House Bill No. 399, direct the Public Utilities Commission to obtain information from utilities operating in Idaho concerning the costs of supplying electric energy to their customers separated among utility functions.

The information collected reflects existing utility cost structures in which rates are set to recover actual costs and a reasonable rate of return on investment, and costs are fully allocated among the various services provided.  Calendar year 1996 or a comparable fiscal year were used for the embedded cost data.

Because a number of existing classes of service such as “industrial” and “irrigation” include customers with widely differing demands and usage, costs have been separated at the voltage level rather than the customer-class level.  All costs have been expressed in terms of cents per kilowatt hour because that is the way electric consumers have traditionally been billed for the bulk of their power costs.

In addition to the categories required to be used by House Bill No. 399 -- generation, transmission, and distribution -- the Commission has required separation of demand and energy costs associated with generation, as well as the contribution received from secondary sales and miscellaneous revenue.  Fish mitigation, demand-side management and alternative energy costs that are also associated with generation have been identified.  In addition to transmission and distribution facilities costs, the Commission has chosen to separate metering, meter reading, billing, uncollectible accounts expense, “other” costs, and public purposes including universal service and low-income assistance.

Appendix III of the report details the average costs by category for all the reporting electric providers.  Costs are broken into the categories of generation, transmission, distribution facilities, metering, meter reading, billing, uncollectible accounts expense and other expenses.  Detailed information for each provider supplied by voltage level can be found in Appendix IV.

At the request of Intervenors FMC and Potlatch, the Commission has opened Case Nos.

IPC-E-98-2, UPL-E-98-1, and WWP-E-98-1 to further investigate the separated cost data filed by Idaho Power Company, PacifiCorp d.b.a. Utah Power and Light Company, and the Washington Water Power Company and formal audits have been scheduled.  In these

proceedings the Commission will address a number of issues raised by these and other parties that were too complex and contentious to be resolved before the 1998 legislative session.  No further proceedings have been scheduled to review the cost information provided by publicly-owned utilities not under the jurisdiction of the Commission.  The Commission will report the results of the investor-owned utility investigations when the results become available.

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BACKGROUND

Idaho Code§§ 61-338 and 61-339, as enacted by 1997 House Bill No. 399, direct the Public Utilities Commission to obtain information from utilities operating in Idaho concerning the costs of supplying electric energy to their customers.  The Commission was required by July 1, 1997 to begin proceedings to acquire cost information separated among utility functions, consisting at a minimum of generation, transmission, and distribution, but including other categories the Commission might deem relevant.  All investor-owned, cooperative, and municipally-owned utilities operating in Idaho, with the exception of any investor-owned utility serving less than 1000 customers and any cooperative serving less than 1000 customers and also serving consumers in other states, must report cost information in the form and manner requested by the Commission.

There are three major investor-owned utilities (IOUs) and 26 publicly-owned utilities that are required to report cost information in accordance with House Bill No. 399.  Two utilities, Inland Power and Light and Atlanta Power Company, are exempted.  Appendix I contains maps showing the service areas and a chart of residential rates for all IOUs and publicly-owned utilities in Idaho.

Following enactment of House Bill No. 399, Governor Philip Batt expressed his interest in public purpose investments made by utilities and urged the Commission to include public purposes as a separate component of electric costs, and furthermore, to separately identify costs associated with universal service, fish mitigation, low-income assistance, conservation and alternate energy sources.

On June 30, 1997, the Commission issued a Notice of Inquiry opening Case No. GNR-E-97-1,

In the Matter of the Commission’s Own Investigation into the Costs Incurred by Idaho’s Electric Utilities in Providing Electric Service, and announcing a workshop on August 6, 1997.  The workshop was held for two reasons.  First, it was to provide direction to utilities on the appropriate cost categories to be separated and analytical methods to be used.  Second, the workshop was to educate the general public and interested stakeholders without technical backgrounds on the key issues associated with cost separation to permit them to be better informed participants in future restructuring debates.  The Commission hired a consultant to give a formal presentation and to moderate several panel discussions on the subject of cost separation.  The workshop was well-attended by persons representing a wide variety of interests including, among others, publicly-owned utilities, investor-owned utilities, customer groups and environmental organizations.

Following the workshop, the Commission issued a Notice of Scheduling and Proposed Order

No. 27134 generally endorsing a methodology presented by Idaho Power as a model for Idaho’s other electric providers to use in providing separated information; establishing cost categories and ground rules for studies; finding that strandable costs are beyond the scope of the proceeding; and asking for comment.  The order also scheduled a technical workshop for the Commission Staff and representatives of electric providers to resolve technical issues.

Participants in the workshop included Idaho Power Company, PacifiCorp, the Washington Water Power Company, and the Idaho Consumer-Owned Utility Association (ICUA) representing 21 of the 26 publicly-owned utilities required to provide cost information.

On November 18, 1997, the Commission issued Order No. 27211 adopting the conclusions and recommendations from the technical workshop and addressing comments in opposition to the Commission’s proposed order.  The Commission found some of the issues raised by Intervenors FMC and Potlatch to be on point but too complex and contentious to be resolved before the 1998 legislative session.  The Commission stated its intention to open, upon receipt of cost information from investor-owned utilities, three new dockets to address the issues raised by FMC and Potlatch and examine in detail the cost data provided.  It indicated, however, that no further proceedings would be held to review the cost information provided by publicly-owned utilities who are not under the jurisdiction of the Commission.  Electric providers were given until December 18, 1997 to file their cost information.  Four small non-profit providers were given an extension until January 18, 1998 to file their information and permitted to make abbreviated filings that satisfy the minimum requirements of House Bill No. 399.

GROUND RULES FOR COST STUDIES

The directions given to the electric providers were based on the underlying assumption that the information provided should reflect the existing cost structure inherent in regulated utility rates today.  In today’s regulated environment, utilities are allowed to charge rates to recover their prudently incurred actual costs and a reasonable rate of return on investment, and costs are fully allocated among the various services provided.  The separated costs may or may not reflect prices that would be charged in an unregulated market.

Basic Data

All studies use calendar year 1996 or comparable fiscal-year embedded-cost data.  No reconciliation of costs and rates or revenues has been required.  In the case of investor-owned utilities, the cost data has been normalized for weather and stream flows.  Normalization adjustments reflect the mix between hydropower and other generation as well as what loads would be under normal weather conditions.  Because publicly-owned utilities purchase most of their power rather than generating it themselves, their per-kilowatt-hour costs are not as sensitive to weather and stream flows as those of generating utilities.  Therefore, they were not required to file normalized data.

Utilities have used their authorized or other reasonable cost of capital in determining return on investment.  Neither PacifiCorp nor Washington Water Power has had a recent case before the Commission in which its cost of capital was determined; therefore authorized rates of return may not reflect current costs of capital.  In its study, PacifiCorp used a hypothetical weighted cost of capital of 9%, while Washington Water Power filed using its authorized rate of 11.02% as well as its more appropriate current actual regulated return of 9.58%.  The Washington Water Power numbers in this report are from the 9.58% filing.  Idaho Power used the 9.306% agreed to in Case No. IPC-E-95-11.  ICUA members used their actual margins or 11%.

Use of the Idaho Power Format

In July 1997, Idaho Power filed its report Unbundled Cost Information with the Commission. The basic methodology, described as a modified revenue requirement approach, used by Idaho Power in preparing this report was adopted by the Commission as a model for other utilities to use in preparing their own information.  The study was based on historical accounting information allocated using methods accepted by its regulatory agencies.  Idaho Power presented its approach at the August workshop.  In Order No. 27134, issued following the workshop, the Commission indicated agreement with the Idaho Power approach and urged other electric providers to use it as a guide for their own studies.  In general, utilities have followed the Idaho Power approach.

Allocation of Costs Among Customer Groups

Because it is more expensive to serve some customers than others, costs have traditionally been allocated among customer groups with similar characteristics.  Customers whose demand for power is highest at the time of the system peak (for example, space heating and cooling customers) are more expensive to serve than customers who use a constant amount of power each day of the year.  Customers who take power at transmission-level voltages are cheaper to serve than customers for whom power must be “stepped down” to lower household-level voltages.  Billing and other customer-related costs must be spread over a smaller number of kilowatt hours for residential customers than for industrial customers.  Costs, therefore, must be separated not only among cost categories, but also among customer groups.

Customers have traditionally been grouped by classes such as residential, industrial, etc. However, a number of existing customer classes include customers with fairly large as well as small usage (for example, the irrigation class includes everything from small family farms to large corporate operations).  Therefore, for this report customers have been grouped according to the voltage levels at which they take service, and costs have been separated at the voltage rather than the class level to provide more accurate and useful information.  Also, because voltage level is more consistent among utilities, it is hoped that this grouping may foster comparability of information from utility to utility.  To make the information more useful to customers, the reports were required to include adequate descriptions to allow customers to understand how the voltage-level information relates to them.

All costs have been expressed in terms of cents per kilowatt hour because that is the way electric consumers have traditionally been billed for the bulk of their power costs.  In a restructured industry, this tradition might not survive and customers might find a larger portion of their bill does not vary with their usage.  For example, in its unbundling report Idaho Power points out that it is possible that customers using the distribution facilities of a utility may pay a fixed monthly fee for that usage because many distribution costs are not usage sensitive.

Currently, customer rates are based on the average costs of serving all the customers in a class such as “residential” even though the cost of serving individual customers can be quite different. This practice is referred to as “postage stamp” pricing.  Idaho Power also points out that its study maintains the postage stamp concept and does not consider line distances or population densities as a factor.  If these factors were taken into consideration, the cost of serving customers with similar load characteristics in the same class of service but living in different areas might be shown to be different.

Functionalization and Classification of Costs

Utility costs have traditionally been functionalized between production (or generation), transmission, and distribution.  Much of the functionalization of costs occurs directly as costs are incurred and recorded on the financial books of the utility in accordance with the Uniform System of Accounts (USOA) required by the Idaho PUC for investor-owned utilities under its jurisdiction.  Although municipal and cooperative utilities have not traditionally accounted for costs using the USOA, members of the Idaho Consumer-Owned Utility Association volunteered to present their cost information in conformance with the USOA, making their data comparable to data filed by investor-owned utilities.

Expenditures that relate to more than one function generally fall into the category of general and administrative costs.  These costs must be allocated among generation, transmission, and distribution.  In the past, utilities developed their preferred allocation methods for assigning administrative costs, and unless they were found to be unreasonable, these methods were accepted by the Commission.  Because there is no one correct method of allocating costs, allocation methods may differ between utilities.

To allocate functionalized costs among customer groups, they must first be classified as demand, energy, or customer-related.  Demand costs are those that are related to capacity, or readiness to serve.  Energy costs vary according to consumption, and customer costs vary with the number of customers, regardless of power consumption.  The classification of costs as demand, energy or customer-related also differs among utilities.  The methodology appropriate for each utility will depend to some degree on the operating characteristics of that utility.  Utilities were instructed for purposes of this report to use the method approved by the Commission for them.  ICUA members have individually chosen a method they believe is appropriate to reflect the operating characteristics of their utilities.

COST CATEGORIES

House Bill No. 399 requires cost information to be separated among utility functions, consisting at a minimum of generation, transmission, and distribution services, but including other categories the Commission may find relevant.  Governor Batt requested that the Commission also separately identify a number of cost categories related to “public purpose” expenditures.  As a result of the Governor’s request, comments received in writing and at the two workshops, the Commission has identified a number of cost categories that should provide information that will be useful in understanding Idaho’s current electric costs.

Generation

Generation includes the cost of power supply whether obtained through a utility’s own generation facilities or through power purchased from an entity such as the Bonneville Power Administration (BPA).  In Idaho, investor-owned utilities generate most of their own power, while publicly-owned utilities purchase the bulk of their power.  The cost data filed by Idaho utilities show that, on average, generation costs are the single major cost of providing power, accounting for between 50% and 60% of total utility costs.  These costs range from

2.31 cents per kilowatt hour for Idaho Power to 3.28 cents per kilowatt hour for PacifiCorp.

Care should be taken in comparing these numbers with prevailing market index prices.  These generation costs represent long-term power supplies complete with all ancillary services, whereas market index prices usually do not.

Because large-volume utility customers pay both demand and energy charges, electric providers were required to break generation charges into demand and energy categories.  Demand-related costs are incurred to ensure that power will be available when needed during peak-usage periods. They consist primarily of return on investment in generating facilities as well as related depreciation expense for generating utilities and demand charges for purchasing utilities.  Energy-related costs are those that vary with the output of electricity and include variable costs such as fuel, purchased power, and operating and maintenance expenses.  Purchasing utilities pay an energy or commodity rate per kilowatt hour of wholesale power purchased.  In practice, some fixed costs have been allocated to energy and some operation and maintenance expenses have been considered fixed and therefore allocated to demand.  The classification of these expenses will likely be one of the issues addressed in the cases opened to consider investor-owned utilities’ separated costs.

During non-peak periods and periods of excess capacity, a utility is frequently able to generate and sell excess power from facilities included in its rate base.  Because the facilities are supported by retail customers, these surplus sales and other miscellaneous utility revenue have traditionally been used to offset generation costs in setting retail rates.  The Commission has, therefore, required that this contribution be separately identified under the generation category.

Several commenters took exception to categorizing alternative energy sources, demand-side management (DSM), and fish mitigation as public purposes when in fact they are generation or power supply costs.  They argue that removing these costs from generation would be misleading and would understate generation costs.

While they may be imposed by public bodies, fish mitigation costs are incurred as a direct consequence of constructing hydroelectric projects.  There is no difference between these costs and other environmental mitigation costs such as scrubbers on fossil fuel generating stations. Finally, practically speaking, it is almost impossible to capture all fish mitigation costs embedded in a utility’s rate base and operating costs.  Utilities have agreed to break out those embedded costs that are most easily identifiable and to track these costs in the future.

Alternative energy sources may be the category that most clearly belongs under generation. While the costs associated with these plants may be slightly higher than more traditional generation, these resources generate power and produce revenue in precisely the same way other generating resources do.  Examples are Washington Water Power’s Kettle Falls Plant powered by wood waste and Idaho Power’s solar installations.  They exist not because they were required by a public agency, but because the utilities believed they were reasonable investments.

Since the early 1980s, the Commission has encouraged utilities to develop programs to reduce demand on their systems and thereby avoid building expensive new generating facilities. Amounts that were considered reasonable payments for DSM resources were based on the costs a utility could avoid if it did not have to acquire new generation.  Because DSM costs were incurred in lieu of adding generation and were based on avoided generating costs, they were traditionally considered to be “generating costs.”

Whether future DSM costs will be considered generation costs will depend on whether the electric industry is restructured.  If generation is deregulated as proposed, it is highly unlikely that future DSM expenditures will be considered generation costs.  For purposes of this report, they are shown as they have traditionally been considered, as generation costs.

Washington Water Power notes in its unbundling report that its DSM Tariff Rider, Schedule 91 is a revenue surcharge and is intended to be a non-bypassable distribution charge even though the Rider is applied to what may be considered generation costs.  Idaho Power has a filing before the Commission in which it proposes to allocate DSM costs incurred prior to 1994 as they have traditionally been allocated but to allocate costs incurred since 1994 based upon the ability of the customer class to participate in DSM programs.

Non-Generation

Transmission facilities transport energy at high voltage levels from generation sites to load centers and, in some cases, to large end-use customers.  Generally speaking, distribution facilities connect all but the very largest consumers to the electric system, with customers taking service at different voltage levels.  Although the use of the transmission system for wholesale sales and wheeling is regulated by the Federal Energy Regulatory Commission (FERC), the cost of transmission and distribution services to provide retail sales to IOU customers in Idaho is regulated by the Idaho Public Utilities Commission.  Purchasing utilities pay their wholesale

providers to have power delivered to their service areas.  Although many of the publicly-owned utilities included this cost under purchased power, it has been categorized as “transmission” in this report.

Because of environmental and economic considerations, it is assumed that the actual transmission of energy over electric transmission and distribution wires will continue to be a monopoly service and therefore regulated.  Some ancillary services such as scheduling, load following, load shaping, voltage support, and system reserves, as well as distribution and customer services such as metering, meter reading, billing, and other customer services may not be considered monopoly services.

While they are needed to facilitate transmission, most ancillary services are actually generation-related.  Although these services related to wholesale transmission have theoretically already been unbundled, costs for them are still being developed at the federal level.  Utilities have not, therefore, been required to separate retail costs for these services.  The average cost of transmission is .49 cents per kilowatt hour.

The Commission believes that it is appropriate to separately identify the costs of potentially competitive distribution and customer services.  For purposes of this report, metering, meter reading, and billing services have been identified as potentially competitive and listed separately from distribution facilities and other customer-related costs.  These categories average .27 cents per kilowatt hour.  Distribution facilities costs include return on distribution plant including poles, wires and transformers, as well as expenses such as depreciation, tree trimming, etc.  Distribution facilities costs average 1.73 cents per kilowatt hour.  Uncollectibles, or bad debt expense, has been separately identified because it relates to all other services for which bills have been rendered.  It averages .02 cents per kilowatt hour.  An appropriate method of allocation has not been developed, but will be necessary in the future if restructuring occurs.

Public Purposes

After moving demand-side management, fish mitigation and alternative energy sources to generation, there remain two categories of public purposes.  These are universal service and low-income assistance.  At the technical workshop the utilities indicated they spend very little on low-income assistance at this time.  (Project Share, a low-income assistance program, is financed through voluntary contributions from utility customers.  LIHEAP, or Low Income Home Energy Assistance Program, is a federal program that also provides heating assistance to low-income individuals.  Neither program is financed through utility rates.)  There also does not appear to be any universal service costs that can be identified.  Nevertheless, because there may be future costs incurred by utilities in these categories, it seems reasonable to retain the categories for future use.

STUDY RESULTS

For a number of reasons, the separated costs for a customer group will not equal that group’s current rate.  One reason is that costs may have changed since rates were last set, and even if, overall, rates still produce reasonable levels of revenue, individual rates are no longer cost-based. Another reason is that not all rates were strictly cost-based to begin with.  For investor-owned utilities, the Commission has traditionally considered cost important, but recognized that cost-of-service studies are not precise and that cost is only one among a number of factors to be considered in setting rates.  Other factors include the ability of a customer group to pay and how large an increase would be required to move a class to its cost-of-service.  The Commission has for a number of years been moving rates that were clearly not cost-based toward cost-of-service, but has tried to minimize the resulting economic hardships on classes that had previously been subsidized.

The separated costs reported by electric service providers in Idaho have been summarized and presented as follows:

Appendix I contains maps showing the service areas and a chart of residential rates for all IOUs and publicly-owned utilities in Idaho.

Appendix II contains charts showing national average utility costs as well as the average costs of generation, transmission, distribution, and other for the three Idaho investor-owned and the publicly-owned utilities.

Appendix III contains a summary of the cost data by category for each reporting provider.

Appendix IV contains a detailed chart for each provider showing separated costs per kilowatt hour by voltage level.

FURTHER PROCEEDINGS

The Commission has opened Case Nos. IPC-E-98-2, UPL-E-98-1, and WWP-E-98-1 to investigate the cost data filed by Idaho Power Company, PacifiCorp d.b.a. Utah Power and Light Company, and the Washington Water Power Company.  The Commission has scheduled audits of the underlying data of each of these investor-owned utilities.  Intervenors in these cases may conduct formal discovery.  In addition to verifying the data presented, it is expected that the issue of whether and how traditional cost allocation methods may have to change in a competitive environment will be addressed.

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