SURVEY OF ELECTRIC UTILITY
EMBEDDED COST METHODS FOR
GENERATION AND TRANSMISSION
IN NORTH AMERICA

Prepared for Manitoba Hydro

by

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December 22, 2003
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I. INTRODUCTION AND SUMMARY

At the request of Manitoba Hydro, NERA surveyed a number of electric utilities in the US and Canada in order to determine generation and transmission embedded cost of service (COS) methods currently employed, or methods used in the past where embedded cost studies for generation are no longer prepared. The utilities chosen for the survey are those with one or more of the following characteristics similar to Manitoba Hydro’s:

- significant hydroelectric capacity;
- active participation in a competitive wholesale market;
- significant off-system sales.

US utilities with retail operations in more than one state first separate costs by state in a jurisdictional study before doing a COS study for rates to be implemented in a particular state. Those utilities with wholesale transactions regulated by FERC also do a jurisdictional COS study first, where wholesale firm/long-term transactions are allocated costs as a separate jurisdiction. The table below summarizes the classification and allocation methods of the utilities in the survey.
<table>
<thead>
<tr>
<th></th>
<th>BC Hydro</th>
<th>Bonneville Power Administration</th>
<th>Hydro Quebec</th>
<th>Idaho Power</th>
</tr>
</thead>
<tbody>
<tr>
<td>% of Hydro Capacity &amp; Off-System Sales</td>
<td>Over 87% of capacity is hydro. 30% of total sales in FY2001 were off-system.</td>
<td>67% of firm energy comes from hydro. 79% of FY 2001 sales were off-system.</td>
<td>97% of capacity is hydro. In 2001, off-system sales represented 15% of total sales.</td>
<td>58% of capacity is hydro. 15.5% of total sales were for resale in FY2001.</td>
</tr>
<tr>
<td>Classification Method</td>
<td>Specific Facilities Approach:</td>
<td>Based on marginal costs.</td>
<td>Load factor method.</td>
<td>System load factor for own generation fixed costs.</td>
</tr>
<tr>
<td></td>
<td>- Hydro: Cap Sub method.</td>
<td>The delta above average market price is used to approximate marginal demand costs.</td>
<td>Transmission (including transformers and transformation substations): 100% demand.</td>
<td>Purchase costs: 100% energy-related.</td>
</tr>
<tr>
<td></td>
<td>- Thermal: 100% demand.</td>
<td>Load variance costs are estimated using an option price.</td>
<td></td>
<td>Transmission: 100% demand</td>
</tr>
<tr>
<td></td>
<td>Purchase costs: 100% energy-related costs.</td>
<td>Energy costs are the residual revenue requirement after deducting demand and load variance costs.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Water rental fees: 84.7% energy, 15.3% demand (reflecting variable and fixed components)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Transmission: 100% demand; even generation-related transmission is functionalized to transmission</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Time-Differentiation?</td>
<td>No</td>
<td>12 seasons for energy and demand.</td>
<td>No</td>
<td>Two seasons (summer and non-summer) based on marginal cost relationships. No daily-time differentiation.</td>
</tr>
<tr>
<td>Allocation Method</td>
<td>Demand-related: Average of 12 CP</td>
<td>Allocation of generation costs among classes of service is based on priorities set by federal legislation, with a cost-benefit test used as a final check on reasonableness.</td>
<td>Allocation of generation demand costs based on the relationship between class load factors and the total distribution load factor. Energy-cost based on annual class kWh share. Allocation of transmission costs based on 1 CP.</td>
<td>Demand-related: 12 CP, each month weighted according to marginal monthly demand cost. Energy-related: class kWh share in each month, weighted by monthly marginal energy costs</td>
</tr>
<tr>
<td></td>
<td>Energy-related: class kWh share</td>
<td></td>
<td>Allocation of transmission costs based on the relationship between class load factors and the total distribution load factor. Energy-cost based on annual class kWh share. Allocation of transmission costs based on 1 CP.</td>
<td></td>
</tr>
<tr>
<td>Treatment of Off-System Sales/Revenue</td>
<td>Revenues from long-term contracts credited as generation (100% energy); short-term sales credited as transmission (100% demand-related).</td>
<td>Surplus energy sale revenues are first used to offset transmission costs associated with these sales. Residual revenues are classified as 100% energy-related and credited to the generation revenue requirement.</td>
<td>No information available.</td>
<td>Contracts &gt;1 year are treated as a class for allocation purposes. Company keeps excess revenues from the class. Revenues from short-term sales are credited to all jurisdictions and classes based on kWh.</td>
</tr>
<tr>
<td></td>
<td>Newfoundland &amp; Labrador</td>
<td>Ontario Hydro</td>
<td>Pacificorp</td>
<td></td>
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<tr>
<td>--------------------------------------</td>
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<td></td>
</tr>
<tr>
<td><strong>% of Hydro Gen &amp; Off-System Sales</strong></td>
<td>66% of capacity is hydro.</td>
<td>31% of total capacity is hydro; 2% were off-system sales.</td>
<td>15% of capacity is hydro; 32.4% of total sales in 2002 were off-system.</td>
<td></td>
</tr>
<tr>
<td><strong>Classification Method</strong></td>
<td>System load factor for hydro plants</td>
<td>89 COS study: Classification of all generation costs based on negotiated percentage factors (42% demand-related, 58% energy-related).</td>
<td>Fixed costs: arbitrary percentages: 75% demand, 25% energy.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Plant-specific load factor for oil-fired plant</td>
<td>Currently: 100% generation costs classified as energy-related (market prices).</td>
<td>Variable costs: all demand-related except for fuel.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>100% fixed costs are demand related for Gas Turbine and Diesel</td>
<td>Transmission: 100% demand</td>
<td>Firm purchases: 75/25</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Variable costs: energy-related except for diesel and gas turbine fuel cost in the Island Int. and Labrador Int.</td>
<td></td>
<td>Non-firm purchases: 100% energy.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Purchase costs: system load factor.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Transmission: 100% demand; transmission connecting remote generation is functionalized to generation.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Time-Differentiation?</strong></td>
<td>No.</td>
<td>89 COS study – Two seasons: Winter/Summer and two daily periods (peak/off-peak). Energy and generation capacity costs are time-differentiated based on an analysis of hourly system incremental energy costs.</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Currently: Customers not subject to rate freeze pay hourly market prices.</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Allocation Method</strong></td>
<td>Demand-related costs: Single CP</td>
<td>89 COS study: Demand-related generation costs: average of 6 NCP method within season; Energy-related generation costs: class kWh share within period and season</td>
<td>Demand-related costs: Average of 12 CP</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Energy-related costs: class kWh share</td>
<td>Currently: Customers not subject to rate freeze pay hourly market prices.</td>
<td>Energy-related costs: class kWh share</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Transmission:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Networks: Monthly CP or 85% NCP during peak</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Transformation and Connection: monthly NCP</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Treatment of Off-System Sales/Revenue</strong></td>
<td>Newfoundland serves energy to an IOU utility, that is considered as a separate customer class in the COS.</td>
<td>89 COS study: Revenues from external sales credited proportionally to fixed and variable generation costs, before classification.</td>
<td>Revenues are credited to generation:</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Currently: not applicable.</td>
<td>Firm-sales: 75% demand, 25% energy</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Non-firm sales: 100% energy</td>
<td></td>
</tr>
<tr>
<td>% of Hydro Gen &amp; Off-System Sales</td>
<td>Salt River Project</td>
<td>Tennessee Valley Authority</td>
<td>Northern States Power Co.</td>
<td></td>
</tr>
<tr>
<td>-----------------------------------</td>
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<td></td>
</tr>
</tbody>
</table>
| 5% of generation capacity is hydro.  
Sales for resale were 38% of total sales in 2002. | 8% of TVA’s energy comes from hydro plants.  
84.2% of TVA’s total sales in FY2002 were for resale. | Hydro represents 5% of the total capacity. Off-system sales are 27% of total sales in MN, ND, SD, WI and MI. |
| Classification Method | System-load factor to classify fixed generation costs. Variable O&M and fuel are energy-related. Purchase power costs classified based on fixed/variable contract charges.  
Transmission: Step-up and switching facilities at generators are functionalized to generation; all other transmission costs are classified as demand-related. | Transmission and all generation costs are demand-related except for fuel, purchased power, corrective maintenance and a portion of research and development. | In WI, MI: 100% of fixed generation costs are treated as demand-related. In MN, SD and ND: classification based on Cap-Sub method.  
All transmission costs are treated as demand-related. |
| Time-Differentiation? | No | No | In MN, SD and ND demand costs are allocated to 2 seasons using factors derived from average level of demand in excess of annual minimum demand. Energy costs are time-differentiated within the day (see below). There is no time-differentiation in WI, MI. |
| Allocation Method | Demand-related based on average CP in 4 summer months.  
Energy-related based on class kWh share. | Demand-related costs: A range of CP allocators (1CP, 2CP, 12CP, S/W CP; Hybrids: 1CP/12CP, 2CP/12CP). Lower hydro costs allocated to residential customers only.  
Energy-related costs: class kWh share. They are considering allocation based on hourly load-weighted market energy prices. | Demand-related cost: MN, SD and ND: 1CP in each season;  
WI, MI: 12 CP.  
Energy-related costs: Peak and off-peak usage, weighted by system marginal energy cost in MN, SD and ND. Annual class’ kWh share in all other states. |
| Treatment of Off-System Sales/Revenue | Resale is a separate class, costs allocated based on the methods outlined above. The demand component of purchases is not assigned to resale class. Revenues in excess of costs allocated to resale class are not credited back to retail classes. | Revenue credited to generation costs. Classification in the same proportion as total generation costs. | In MN, SD, ND, WI, MI: revenues credited to native customers; classification based on contract charges. |
II. BC HYDRO

A. Background

BC Hydro serves more than 1.6 million customers in an area containing over 94% of British Columbia’s population. BC Hydro has constructed an integrated system of close to 11,500 megawatts of generating capacity – over 87% of which is hydroelectric. It generates between 43,000 and 54,000 GWh of electricity annually from 32 hydroelectric facilities, 2 gas-fired thermal power plants and 2 combustion turbine stations. BC Hydro generates and distributes electricity, while BC Transmission Corporation provides transmission service on behalf of BC Hydro and other power providers. Off-system sales represented about 30% of total kWh sales in 2001.\(^1\)

The company’s last official embedded COS study was undertaken for FY 1996/97. The description below reflects the approaches followed in that study.\(^2\) BC Hydro has been under a rate freeze since then. However, a review of their COS study will be undertaken within the next 18 months, as part of a comprehensive regulatory review by the BC Utilities Commission.\(^3\)

The British Columbia Transmission Corporation (BCTC) is a provincial government-owned company under the Company Act. The company began operations on August 1, 2003. BC Hydro continues to own the core transmission assets while BCTC manages, maintains and operates BC Hydro's transmission assets, which include 18,000 kilometers of transmission lines. The BC transmission system is interconnected to Alberta by two 138 kV lines and one 500 kV line and to the United States by two 500 kV and two 230 kV lines.

By late 2004 BCTC will have its own tariff and be fully independent of BC Hydro. At the time of the latest COS study (1998) transmission was integrated into BC Hydro and therefore part of the study.

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\(^1\) BC Hydro 2002 Annual Report.


\(^3\) Source: email from Trudy Kwong, Senior Regulatory Advisor at BC Hydro. November 17, 2003.
B. Generation and Transmission Embedded Cost Methods

1. Classification Method

BC Hydro’s classification of generation costs between demand and energy components varies with the type of plant. The aim is to reflect the degree to which plant was built to meet demand and energy needs. The classification factors are as follows:

- Hydro plant was classified as 50% demand- and 50% energy-related. The demand-component of hydro plants was estimated based on the “equivalent peaker method” (also known as Capacity Substitution). Based on B.C. Hydro’s estimated peaker value of $65 per kW and comparing that to the annual carrying cost of the hydro facilities (valued at replacement cost) produces a demand component of approximately 50%.

- The baseload natural-gas plant, Burrard Thermal Station, was classified entirely to demand\(^4\) because the plant provides firm capacity and contributes significantly to the operation of the transmission system (which is entirely demand-related).

- Other thermal plants (gas combustion turbines and diesel turbines) were classified as 100% demand-related because they were installed to provide peaking capability and peak day reliability to certain areas of the integrated system.

The associated O&M expenses were classified between demand and energy in the same proportions as the classification of generation plant. The only exception was the fuel costs (natural gas) associated with Burrard thermal plant, which was classified 100% as energy. Other generation costs were classified as follows:

- Water Rental fees: classified 84.7% to energy and 15.3% to demand, reflecting the variable and fixed cost components of these fees.

- Purchases for domestic use, including purchases from Independent Power Producers (IPPs) were classified as 100% energy-related.

\(^4\) This classification changed from the 91/92 and 92/93 COS studies, in which Burrard Thermal Station was classified as 60% energy related.
Generation-related transmission plant and substation plant are functionalized to the transmission function. Transmission costs are classified 100% to demand, including variable costs (O&M, depreciation, administrative, finance charges and others).

2. Time-Differentiation

Generation and transmission costs were not time-differentiated.

3. Allocation

In its 1993/94 Fully Allocated COS study, BC Hydro used a 12-month weighted CP approach. The weights reflected the relative “probability of unserved energy” during the high-demand hours in each month. In the most recent study, demand-related costs were allocated using the 12-CP method (equal monthly weightings). The reason stated in the 97/98 COS study for this change is that the unweighted 12 CP is consistent with the method employed to determine the BC Hydro WTS (Wholesale Transmission Service) tariffs.

The energy-related costs were allocated by share of energy sales (adjusted for losses) to each class.

4. Treatment of Revenues from Off-System Sales

Revenues from off-system sales were credited as follows:

- revenues from long-term “Electricity Trade” (about 62% of total off-system sales revenues) were credited to the generation function and classified as 100% energy-related;
- revenues from sales to Seattle City Light (about 27% of total sale revenues) were credited to all functions (generation, transmission and distribution) on the basis of rate base;

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5 Generation-related transmission consists of portions of transmission lines connecting the generation in the North and South Interior Regions to other portions of the BCH transmission grid. Specific generation-related transmission assets functionalized to the transmission function include line, substations and general assets.
revenues from short-term sales (11% of the total) were credited to the Transmission function and classified as 100% demand.

C. Pros and Cons and Expected Changes

According to BC Hydro, the main advantage of their approach is its simplicity. The disadvantage is that some of the allocations are arbitrary. With the exception of demand-related cost allocation approach, the method has basically remained unchanged. However, BC Hydro will likely change its COS methods in the future to reflect utility and market changes. No specific plan for review of COS methods has been developed.
III. BONNEVILLE POWER ADMINISTRATION

A. Background

Bonneville Power Administration (BPA) is a federal agency under the US Department of Energy that markets wholesale power at cost from 31 federally owned dams (67% of firm energy), one nuclear plant (10% of firm energy), and firm contracts and other resources (23% of firm energy), primarily to Pacific Northwest publicly- and investor-owned utilities and to some large industrial customers. It provides 45% of the electric power used in the Pacific Northwest. BPA also sells to or exchanges power with utilities in Canada and other parts of western United States. BPA’s sustained peak capacity is over 17 GW. BPA’s sales for resale were about 80% of total kWh sales in 2002.6

BPA’s Transmission Business Line (TBL) operates and owns one of the nation’s largest high voltage transmission systems with 15,397 circuit miles. The system connects the Northwest to Canada, California and the inland Southwest. The following table shows BPA’s transmission lines by voltage level:

<table>
<thead>
<tr>
<th>Operating voltage</th>
<th>Circuit miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,000 kV</td>
<td>264(^7)</td>
</tr>
<tr>
<td>500 kV</td>
<td>4,476</td>
</tr>
<tr>
<td>345 kV</td>
<td>570</td>
</tr>
<tr>
<td>287 kV</td>
<td>125</td>
</tr>
<tr>
<td>230 kV</td>
<td>5,319</td>
</tr>
<tr>
<td>161 kV</td>
<td>46</td>
</tr>
<tr>
<td>138 kV</td>
<td>69</td>
</tr>
<tr>
<td>115 kV</td>
<td>3,920</td>
</tr>
<tr>
<td>below 115 kV</td>
<td>608</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>15,397</strong></td>
</tr>
</tbody>
</table>


---

7 BPA’s portion of the PNW/PSW direct-current intertie. The total length of this line from The Dalles, Ore., to Los Angeles is 846 miles.
BPA is a self-funding agency that recovers its costs through power and transmission sales. Both power and transmission are sold at cost, and BPA repays any borrowing from the U.S. Treasury with interest.

The transmission revenue requirements includes: recovery of the federal investment in transmission and transmission-related assets; the operations and maintenance (O&M) and other annual expenses associated with transmission and ancillary services; the cost of generation inputs for ancillary services and other inter business-line services necessary for the transmission of power; and all other transmission-related costs incurred.

BPA’s Transmission Business Line conducted its own rate proceeding apart from BPA’s Wholesale Power Rate case. In the 2004 Transmission Rate Case transmission rates were increased by 1.5%.

B. Generation and Transmission Embedded Cost Methods

BPA’s 2002 Wholesale Power Rate Development Study contains BPA’s latest embedded COS study for generation. The study apports BPA’s revenue requirement among classes of service based on priorities of service defined in Federal legislation. Costs are allocated to three resource pools:

1) The Federal Base System (FBS), which includes costs from Federal Columbia River Power System and long-term contracts signed on the date of the Northwest Power Act (1980).

2) The Residential Exchange (RE), which includes resources belonging to participating IOUs.

3) The New Resource (NR) pool, which includes any additional resources.

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8 2002 Final Power Rate Proposal Wholesale Power Rate Development Study (WP-02-FS-BPA-05), May 2000.
BPA assigns its transmission facilities and corresponding costs to segments according to the types of services they provide. Various technical sources, such as one-line diagrams and plans of service and the existing contracts provide a basis for classification. Currently, segments include:

- **Generation Integration**: includes all facilities that connect the Federal generating plants to the integrated transmission network. This segment is assigned to generation.

- **Network**: consists of the transmission facilities that transfer bulk power between utility service areas in the NW and the Delivery, Southern, and Eastern Intertie segments.

- **Utility Delivery**: consists primarily of substation facilities required to step down from transmission voltages to voltages below 34.5kV for delivery to the transmission customer's distribution system.

- **Industry Delivery**: consists of facilities required to deliver power to Direct Service Industrial customers. The facilities consist of substations that reduce transmission voltage to delivery voltages below 34.5-kV.

- **Southern Intertie**: it is a system of transmission lines that interconnect the PNW to California power systems at the Oregon border.

- **Eastern Intertie**: consists of the Garrison-Townsend 500 kV line and the associated substation facilities at Garrison.

- **Ancillary Services**

1. **Classification Method**

BPA classifies and time-differentiates its generation costs on the basis of the demand and energy components of generation marginal costs. Its generation marginal costs estimates are derived from an electric market model that simulates wholesale energy transactions in a competitive pricing system for a five-year period (FY 2002-2006, in its 2002 COS study). The methods used to compute the three elements of marginal costs are described below:

   a) **Marginal Energy Costs**: BPA simulates hourly market prices for each of the five years. These hourly prices are then averaged for peak (“Heavy Load Hour”- HLH) and off-peak (“Light Load Hour”- LLH) periods within each month in each year.
b) **Marginal Demand Costs**: BPA calculates monthly marginal demand cost (in $/kW) as follows:

- First, for each of the five years for which market price estimates have been developed, BPA computes the delta between each hour’s market price and the annual average market price; the hourly deltas are then averaged monthly, then annually, yielding a $/kWh value for each year;

- This annual value is multiplied by the number of HLH (peak hours) in a year, resulting in a $/kW-year value for each of the five years;

- The resulting value is divided by 12 to obtain a $/kW-month value for each year. These values are then averaged over the five-years;

- Finally, this average monthly value is shaped to each month of the year based on the pattern of 5-year averaged monthly HLH market prices. The result is a different demand charge for each month, in $/kW-month.⁹

   

c) **Load Variance Cost**: The load variance cost is the estimated incremental cost associated with the risk BPA must bear in standing ready to serve an unknown quantity at an unknown cost, but at a fixed price. BPA uses the value of options to approximate the cost of standing ready to serve uncertain deviations in loads. The load variance charge is capped at 0.80 mills/kWh.

 generation costs classified as energy-related are the residual of total generation costs not classified to demand or load variance. Once BPA has estimated the annual revenues that would result from the monthly demand and load variance charges, these revenues are subtracted from BPA’s total generation revenue requirement. The monthly HLH and LLH energy rates are adjusted proportionally until estimated revenues from the energy charges equal the balance of BPA’s power revenue requirement.

 Transmission costs are classified 100% as demand-related (capacity).

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⁹ In its 2002 COS study, BPA capped the monthly demand values (at $2.50/kW-month) and the annual average at $2.00 per kW-month) to mitigate bill impacts relative to the lower demand charges from its 1996 COS study.
2. Time-Differentiation

The time-differentiation of the generation costs classified as energy, demand or load variance are embedded in the process described above. Since the marginal cost study shows substantial monthly differentiation in predicted energy and capacity costs, the 2002 BPA COS study uses twelve seasons.\(^{10}\)

3. Allocation

Allocation of generation costs is performed by determining the relative sizes of resource and rate pools. There are four rate pools: \(^{11}\)

- “Priority Firm” (PF): preferential customers including publicly-owned and municipal utilities
- “Priority Firm Exchange”: small farms and residential customers of IOUs under exchange program
- “Industrial Firm” (IF)
- “Residential Load” (RL): residential load under subscription contracts.

The process for allocating energy costs begins with an examination of firm loads and resources during a critical period to determine the amount of monthly firm energy surplus or deficit. From this ratemaking load and resource balance, service to each of the rate pools from each of the resource pools is determined for the rate test period. When service from each resource pool to each class of service has been identified, the amount of such service is the allocation factor for the resource pool. Resource pool costs are allocated to classes of service based on the proportions of a class’ identified use of the resource pools.

The FBS pool is allocated to the PF pool. If there are not enough FBS resources, BPA allocates exchange resources until it covers the PF pool’s requirements. The remaining

\(^{10}\) This is a change from 1996 where BPA used six seasons.

\(^{11}\) Rates from the study were designed to be in place from October 2001 to September 2006.
exchange resources and new resources are allocated to the PF Exchange pool, the IF pool and the RL pool, in that order.

Once these costs are allocated, BPA performs a cost-benefit analysis and reallocates costs according to the results. In 1996 costs to the publicly-owned customers (i.e., municipal utilities, coops and public utility districts) were higher than benefits and BPA re-allocated some costs to other loads.

Transmission segment costs are first credited for revenues from non-general rates; the remaining segment costs are allocated to products and services based on contributions to monthly peaks.

Most of the transmission revenue is collected from monthly demand charges applied to annual contract demands--i.e., the customer must nominate an amount that covers its maximum needs during the year. Other revenue (about 15%) comes from a different product for which demand charges are based on monthly-metered amounts. These readings are taken at the time of the monthly network system peak.

BPA also sells weekly and daily products, which are take-and-pay and demand-based. Hourly products recover about 3% of BPA’s transmission revenues.

The costs of Industry Delivery and Eastern Intertie segments are directly allocated to the corresponding customers.

**4. Treatment of Revenues from External (Off-system) sales**

BPA sells its surplus non-firm energy in the regional market. Surplus energy is all generation beyond the critical-period estimated energy used for allocating purposes. BPA estimates the quantities and prices of surplus sales and subtracts forecast surplus energy revenues from the revenue requirement before the allocation process starts. Projected surplus energy revenues are used to first offset transmission costs associated with sales of surplus energy, with the remainder credited to firm power customers. These residual excess revenues are functionalized to generation and classified to energy. They are then allocated to loads served with Federal system resources (FBS and NR). The generation-related surplus energy
revenues are allocated in this manner on the grounds that the expenses incurred to generate this surplus energy are Federal Resource costs only.

C. Pros and Cons and Expected Changes

BPA’s method follows the steps required by the 1980 Regulatory Power Act. There are no expected changes.\textsuperscript{12}

\textsuperscript{12} Based on email sent by Gabrielle Foulkes, BPA Power Business Line. October 16, 2003.
IV. HYDRO QUEBEC

A. Background

Hydro Quebec is a major producer, transmission provider and distributor of electricity in Northeast America. About 97% of total Hydro Quebec generation capacity (32,516 MW) is hydro-based. Electricity sales outside Quebec reached 54.2 TWh in 2001, about 15% of total energy sold.

Hydro Quebec TransÉnergie operates one of North America's largest power transmission systems, including some 32,000 km (20,000 miles) of lines, 20 interconnections and over 500 substations. The following table shows Hydro Quebec’s lines by voltage level:

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Substation (number)</th>
<th>Lines (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>765 kV and 735 kV</td>
<td>37</td>
<td>11,280</td>
</tr>
<tr>
<td>±450 kV DC</td>
<td>2</td>
<td>1,218</td>
</tr>
<tr>
<td>315 kV</td>
<td>59</td>
<td>4,942</td>
</tr>
<tr>
<td>230 kV</td>
<td>50</td>
<td>3,081</td>
</tr>
<tr>
<td>161 kV</td>
<td>40</td>
<td>1,869</td>
</tr>
<tr>
<td>120 kV</td>
<td>216</td>
<td>6,535</td>
</tr>
<tr>
<td>69 kV or less</td>
<td>101</td>
<td>3,389</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>505</strong></td>
<td><strong>32,314</strong></td>
</tr>
</tbody>
</table>


In June 2000, the Government adopted Bill No. 116, which introduced major amendments to the “Act Respecting the Régie de L’énergie” regarding rate determination. Under this Act, Hydro-Quebec Production supplies to the Quebec market up to 165 TWh of

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energy per year (the so-called “heritage pool”), at a fixed price of 2.79 cents per kWh. Beyond the heritage pool volume, Hydro-Quebec Production competes with other generators in response to Hydro-Quebec Distribution’s calls for tenders, which determine the cost of electric power other than heritage pool.

B. Generation and Transmission Embedded Cost Methods

The description below focuses on the Hydro Quebec’s most recent classification and allocation approach, adopted as part of its 2002 rate filing. The purpose of this rate case was to translate the 2.79¢/kWh heritage pool price to Hydro Quebec customer classes in a way that reflected each class’ contribution to heritage pool costs.

1. Classification Method

Hydro Quebec classified the 2.79¢/kWh between demand- and energy-related components by using the distribution system load factor (67.3%). As a result, the energy cost component of the heritage pool price was set as 1.87¢/kWh, with the remainder being the demand cost component (0.92¢/kWh).

The transmission revenue requirement is classified as 100% demand-related. In the Act Respecting the Régie de L'énergie, the transmission network is described as follows:

“electric power transmission system” means a network of installations for the transmission of electric power, including step-up transformers located at production sites, transmission lines at voltages of 44 kV or higher, transmission and transformation substations and any other connecting installation between production sites and the distribution system. (Chapter 1, paragraph 2, page 2)

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14 On February 7th, 2000, Charles A Trabant, of Merrill Lynch, presented to the Minister of Natural Resources a report titled "Le tarif de fourniture d'électricité au Québec et les options possibles pour introduire la concurrence dans la production d'électricité." In that report, Merrill Lynch calculated the total generation cost of Hydro-Québec for 2001, based on the embedded cost and a rate of return on equity.

15 These costs do not include any generation-related transmission assets or generation outlet costs. Source: Myriam Hudon Direction Affaires réglementaires et tarifaires at Hydro Quebec Distribution. November 17, 2003.

2. Time-Differentiation

In the past, Hydro Quebec has done analysis using the Base, Intermediate and Peak (BIP) method, by which peaking plant costs were assigned to defined peak hours of the year, intermediate load plants to defined peak and shoulder hours, and base-load plants to all 8760 hours. We found no evidence that Hydro Quebec used this method for rate design.

In its 2001 rate design case, Hydro Quebec did not time-differentiate its generation or transmission costs. (The starting point of its COS study was the single per-kWh heritage pool cost.) The utility did, however, define a peak period made up of the 300 highest load hours (which take place in winter), as the reference period to determine the contribution of each class to the demand-related generation and transmission costs. This is explained in more detail below.

3. Allocation

The method adopted for allocation of the demand-related component (0.92¢/kWh) to classes was the relationship between class load factors and the total distribution load factor. For this purpose, class load factor is defined as the ratio of class annual consumption to the product of class non-coincident peak within the 300-hour peak period and the number of hours in the year. Under this approach, if a class had a load factor equal to the distribution system load factor, the demand component for the class would be 0.92¢/kWh. With a lower load factor, the class would face a higher demand per-kWh charge, and vice versa.

The underlying assumption was that a lower load factor reflects a stronger relative presence in the peak period and is associated with a higher unit cost, while a high load factor means that electricity is used in a stable way during the year, which reduces the unit cost.

The energy-related portion of the bulk-power rate (1.87¢/kWh) did not vary by customer class.

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TransÉnergie has three wholesale electricity market customer categories: native load, network integration service (no subscription) and point-to-point service. The transmission revenue requirement is allocated to native load and to point-to-point service on the basis of their total capacity needs. These capacity needs are defined as follows:

**Native load:** The distributor establishes the aggregated peak load of all customers. The transmission provider supplies the capacity at a price fixed at the beginning of the year. Residual capacity becomes available to other transmission customers.

**Point to point:** The capacity is defined as the capacity reserved or scheduled between specific points of injection and delivery. Point-to-point customers have to pay for this capacity whether they use it or not.

The share of revenue requirement assigned to native load (retail market customers) is allocated among rate classes on the basis of their coincident peak demand (1 PC).

4. **Treatment of Revenues from External (Off-system) sales**

No information on how revenues are credited was available.

C. **Pros and Cons and Expected Changes**

The existing arrangements involve an effort to allocate higher demand-related costs to those classes that contribute more to the peak demand, using load factor measures. Intervenors did not challenge this method.

According to the utility, its transmission rates take into account the fact that the annual peak demand has an immediate bearing on the cost incurred by the transmission provider in planning its system. And because the rates are based on the cost of service incurred by the transmission activities, the postage-stamp rates reflects the fact that the system is integrated and used to render all transmission services. Hydro-Quebec’s OATT has been in force since the opening of the competitive wholesale electricity market. The tariff was inspired by FERC’s pro forma OATT but reflects Quebec’s context.18

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18 Myriam Hudon, Hydro Quebec.
V. IDAHO POWER

A. Background

Idaho Power (IP) is an investor-owned utility serving customers in Idaho and eastern Oregon. IP is one of the nation's few investor-owned utilities with a predominantly hydroelectric generating base. It owns and operates 17 hydroelectric plants (58% of its generating capacity) and 2 thermal plants, and shares ownership in 3 coal-fired plants. Off-system sales represented 15.5% of total kWh sales in 2002.\(^{19}\)

Idaho Power has a service territory of 22,000 square miles, with nearly 5,000 miles of transmission lines. Along with major transmission owners in the Northwest, the company is moving forward on the development of a Regional Transmission Organization (RTO) as required by the FERC. Idaho Power is part of RTO West.

On October 16, 2003 IP filed an application with the Idaho Public Utilities Commission (IPUC) to increase the company’s general rates an average of 17.7%, the first overall change in its rates since 1994.\(^{20}\) The COS methods described below were used in this recent filing.\(^{21}\)

B. Generation and Transmission Embedded Cost Methods

1. Classification

The energy portion of the steam and hydro production fixed cost is determined by IP’s load factor of 55.26%. The balance of the steam and hydro fixed cost is then classified as demand-related. All variable generation costs, such as fuel costs, are classified as energy-related.

\(^{19}\) 2002 Idaho Power Annual Report.


\(^{21}\) Description is based on 2003 IP’s Application (In the Matter of Application of Idaho Power for Authority to Increase its Rates and Charges for Electric Service to Electric Customers in the State of Idaho. Direct Testimony of Maggie Brilz. Case No. IPC- E-03-13-A) and on follow-up conversations with Maggie Brilz, Director of Pricing at Idaho Power.
All transmission investment and expenses are functionalized as transmission and classified as demand related.

2. Time-Differentiation

Idaho Power defines two seasons: summer (June, July and August) and non-summer (all other months), and computes the monthly marginal generation capacity and marginal energy costs within each season. This information is used to allocate the demand-related and energy-related portion of generation costs to each of the seasons, based on each season’s respective marginal cost proportions. Costs are not differentiated by time of day.

Similarly, in the development of transmission allocation factors, Idaho Power weights monthly peak coincident demand by marginal costs and has identified transmission marginal costs only for the months of June, July, and August. Costs are not differentiated by time of day.

The Idaho Commission has stated in previous cases that the use of monthly marginal costs to weight peak demand and energy in the allocation step, but exclusion of marginal cost information in the classification step, strikes a balance between backward-looking costs and forward-looking costs. No party, including the Commission, has expressed an interest in using marginal costs for anything but weighting the allocation factors.\(^{22}\)

3. Allocation

Demand-related generation costs are allocated to customer classes based on 12 weighted coincident peaks, where the weights are based on the relative monthly marginal generation capacity costs. This approach takes into account class contribution to peaks all year round, but the weighting process gives greater emphasis to the months when marginal capacity costs are high. IP has transmission-related marginal costs only during the summer (June, July and August), when there are transmission deficits. Consequently transmission costs are allocated only on the basis of transmission-marginal-cost-weighted coincident peaks in the three summer months.

\(^{22}\) E-mail response by Maggie Brilz, Director of Pricing. November 15, 2003.
Energy-related costs are allocated based on each class’ share of marginal energy costs, computed as the product of monthly weather-normalized class energy consumption and monthly marginal energy costs.

4. Treatment of Revenues from Off-System Sales

The basic approach in Idaho Power studies is to treat each state served (Idaho and Oregon) and each wholesale contract greater than one year as a jurisdiction. Costs are allocated to each jurisdiction using the classification and allocation methods outlined above. If the revenues from the long-term wholesale contracts exceed allocated costs, the utility keeps the difference. At times this methodology results in a higher or lower return in the wholesale jurisdiction than in the retail jurisdictions. The revenues from short-term sales are credited on a per-kWh basis to all classes.

C. Pros and Cons and Expected Changes

Idaho Power has not changed its COS method for more than 20 years and it does not have plans to change it. According to Idaho Power, classifying transmission as demand-related is appropriate since transmission is capacity driven. The company’s method of allocating transmission costs to customer classes provides a higher cost allocation to those customers whose usage places a higher burden on the transmission system.\textsuperscript{23}

\textsuperscript{23} Maggie Brilz, Idaho Power
VI. NEWFOUNDLAND & LABRADOR HYDRO

A. Background

Newfoundland & Labrador Hydro (NFH) is principally a wholesaler of electricity and sells the bulk of its power to an investor-owned utility, Newfoundland Power (NP), and several industrial customers. It also sells directly to over 34,000 customers living in rural communities in Newfoundland and Labrador. NFH has 938 MW of hydroelectric capacity and 490 MW of thermal capacity.\(^{24}\)

B. Generation and Transmission Embedded Cost Methods

NFH uses an embedded COS study internally and for official rate filings with their regulatory commission. In August 2003, NFH submitted to the Public Utilities Board a General Rate Application that included an embedded COS study.\(^ {25}\) The approaches used for cost classification and allocation in the 2003 filing are described below.

1. Classification

Because of the geography of Labrador and Newfoundland, NFH is a combination of Isolated and Interconnected systems:

- In Labrador, an interconnected system sharing generation and transmission facilities is located in the south, while numerous communities with isolated systems are located along the coastline;

- In Newfoundland, an interconnected system covers most of the island (including Newfoundland Power’s service area), while a few isolated systems with their own generation are located along the coast.

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\(^{24}\) 2002 Newfoundland Labrador and Hydro Annual Report.

Transmission assets that connect remote generation to the grid are functionalized as generation and classified according to the type of generation they interconnect. The rest of the transmission assets are functionalized as transmission.

The COS study contains five subsets, related to five geographic areas of Newfoundland & Labrador, with methodological differences among the five areas.

**a. Fixed Costs**

The approach used by NFH to classify fixed generation costs varies according to the type of generation and its location:

1. Island Interconnected System:
   - Hydraulic Generation: *System load-factor*
   - Thermal Generation (Oil-Fired): *average plant load-factor* for preceding 5 years
   - Gas Turbine/Diesel: 100% demand-related

2. Isolated Systems (two isolated diesel systems):
   - Island Isolated: *System load-factor*
   - Labrador Isolated: *System load-factor*

3. L'Anse au Loup System (Isolated system w/ secondary supply purchased from Hydro-Quebec, all diesel capacity): 100% demand-related.

4. Labrador Interconnected: (Primary supply purchased from Churchill Falls). Gas Turbine/Diesel: 100% demand-related.

All transmission costs are considered 100% demand-related.

**b. Variable Costs**

Generally, all variable costs are treated as energy-related. The exceptions are diesel and gas turbine fuel costs in the Island Interconnected and Labrador Interconnected systems. These costs (which represent a very small portion of the total revenue requirement) are classified
100% to demand. NFH did not explain the rationale for this. However, it is possible that these diesel and gas units are mostly used for system support, rather than to supply energy.

c. Purchase Costs

The classification of purchase costs depends on the system:

- For the Island Interconnected and Labrador Interconnected: System load factor is used for classification purposes.
- For L'Anse au Loup: costs are classified as 100% energy-related

2. Time-Differentiation

No time-differentiation process is used.

3. Allocation

Demand-related costs are allocated on the basis of single CP and energy-related costs are allocated on the basis of annual kWh share.

4. Treatment of Revenues from External (Off-system) sales

NFH treats its wholesale customer, Newfoundland Power, as a single-customer class.

C. Pros and Cons and Expected Changes

No changes have been made to the COS model recently. However, in the current proceeding, a report has been filed by EES Consulting (hired on behalf of the Public Utilities Board) containing recommendations on changes to NFH methods. EES recommends the use of a “peak-credit” (or Cap-Sub) for classification of fixed generation costs.

Transmission classification has been relatively free from controversy. One of the main transmission issues in recent rate cases has been the assignment of radial transmission lines.

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26 Responses to Questionnaire by Anne Dwyer, Senior Financial Analyst at NFH.

serving a small amount of thermal generation and customers from only one or two rate classes. The issue is whether costs should be assigned to only those rate classes served from the radial transmission lines, or whether the small amount of generation warrants the sharing of costs among all customers. NFH anticipates a ruling in the current rate application on this issue.\textsuperscript{28}

\textsuperscript{28} Anne Dwyer, Newfoundland and Labrador Hydro
VII. ONTARIO HYDRO

A. Background

The Energy Competition Act No. 35 authorized the restructuring of Ontario Hydro (OH) and the eventual opening of wholesale and retail electricity markets in Ontario. In April 1999 OH was restructured into Hydro One Inc. and Ontario Power Generation (OPG) Company. Hydro One Inc. is in charge of transmission and distribution, through its subsidiary Hydro One Networks. The Ontario Energy Board regulates rates for the transmission and distribution of electricity and natural gas.

OPG produces more than 60% of the province's power and exports energy to other Canadian cities and the US. OPG’s electricity-generating portfolio has a total capacity of 22.2 GW, consisting of nuclear, fossil and hydroelectric stations, with hydro representing 31% of total capacity.

The former OH served around 300 distributors (municipal utilities), and large and rural customers through a distribution subsidiary. In 2000, under the new legislative framework, Hydro One acquired 88 municipal utilities, increasing its end-use customer base by 25 per cent. Hydro One now distributes electricity to 41 small municipal utilities that are not connected directly to the Hydro One transmission system, and to about 1.2 million end-use customers, including residential users, farms, small business and large industrial customers (above 5 MW), in urban and rural areas.

Hydro One is responsible for 97% of Ontario's electricity transmission system. The 28,400-kilometer high-voltage system transmits electricity from generating facilities across the province to the local distribution utilities and large industrial consumers.

Prior to May 1, 2002, OPG’s revenues were earned primarily through the direct sale of electricity to wholesale and large industrial customers in Ontario and to interconnected markets. The wholesale electricity prices charged to Ontario customers were billed on a bundled basis including transmission and other related charges. OPG received the bundled

29 Source: “2002 Hydro One Annual Information Form”.
payments and distributed funds to Hydro One under the terms of revenue allocation arrangements.\footnote{The allocation arrangements were designed so the undistributed balance of funds would provide OPG with planned revenue of 4.0¢/kWh based on forecasted demand and customer mix, together with a fixed amount for ancillary services.} On May 1, 2002, the wholesale and retail electricity markets in Ontario opened to competition, and unbundled rates for Hydro One’s end-users came into effect.

Since the inception of the spot market in May 2002, all of OPG’s electricity generation is sold into the real-time energy spot market administered by the Independent Market Operator (IMO).\footnote{OPG also sells electricity purchased from the IMO into the interconnected markets of other provinces and the U.S. Northeast and Midwest.} The generation costs to Hydro One are those reflected in the hourly competitive market prices. As a result, there is no need to classify or allocate generation costs—the current market pricing system implies 100% energy classification and generation costs that vary hourly. However, a large part of Hydro One’s end-users are currently under a rate freeze. In November 2002, the legislature passed Bill 210—Electricity Supply, Pricing and Conservation Act, under which residential, small commercial customers with annual usage below 250 MWh and some designated users (institutions, community service organizations and farms) pay a frozen generation charge of 4.3¢/kWh during the period 2002-2006.\footnote{The rate freeze is retroactive to May 2002. In addition, transmission and distribution rates are capped at levels in effect on November 11, 2002 until at least April 30, 2006.}

In addition, large customers who do not qualify for the frozen rate and as a result face hourly spot market prices, are eligible for a price rebate, currently fixed at 50% of the difference between 3.8 cents per kWh and the average spot market price in each quarter. This measure was intended to address price volatility concerns faced by business.

However, the persistent gap between the market price and the frozen generation charge has lead to a growing budget deficit, now estimated at $700 million. As a result, the Ministry of Energy is expected to replace the rate freeze with alternative rate mechanisms aimed at better reflecting market conditions while limiting the price volatility in the market.\footnote{Sources: “The Toronto Start”, November 17, 2003; “Electric Utility Week”, November 17, 2003.}
B. Generation and Transmission Embedded Cost Methods

Hydro One Inc. has not developed an embedded generation COS study since 1989, i.e., before the restructuring of OH. The basic approaches used in that study by the former OH are described below.\textsuperscript{34} At that time, OH’s hydro resources represented about 30% of total capacity. Export sales represented about 2% of total sales.

OH used an embedded transmission cost of service study for official filings with its regulator, the Ontario Energy Board (OEB). The latest Transmission Cost Allocation and Rate Design proposal was submitted in October 1999 and approved in 2000.

1. Classification Method

OH used a number of alternative methods in order to see a range of possible classification results. The final percentage factors used in their 1989 COS study represented a compromise, taking into consideration intervenors’ positions. The generation classification factors were set at 45\% demand and 55\% energy for FY 1989 COS, changing by 1\% per year to reach a target of 42\% demand and 58\% energy by 1992. These factors were applied to total generation costs, including fuel.

Transmission assets are unbundled by function into three pools Network, Transmission Line Connection, and Transformation:

- The transmission Network pool consists of the costs of those electrical facilities that are used for the common benefit of all transmission customers.
- The Transformation Connection pool consists of the costs of all OH-owned transformation station facilities that step down voltage from above 50 kV to below 50 kV.
- The transmission Line Connection pool consists of the costs of assets that are radial parts of the high voltage transmission system.

\textsuperscript{34} Ontario Hydro was not required to file COS studies before the Ontario Energy Board. The description of the method employed in 1989 is based on a conversation with Mike Roger, a former member of Ontario Hydro.
OH separately identified the assets and costs related to generation connections that existed before Open Access on May 1, 2002 and assigned them to the Network Pool. The Network Pool revenue requirement is recovered from all load customers in Ontario.

Until May 2002 the generators did not pay transmission charges. Since May 1, 2002, new generation connections are provided by the beneficiaries, i.e. the generators self-provide the new generation connections to the transmission network. All transmission costs are considered demand-related.

2. Time-Differentiation

OH defined two seasons and two time-of-day periods based on an analysis of the hourly system incremental energy costs.\textsuperscript{35} The two seasons were winter (October to March) and summer (April to September). The peak period was defined as 7 am to 11 p.m. weekdays, with the remainder of the hours defined as off-peak. Demand-related generation costs were allocated to winter and summer based on each season’s relative marginal energy cost during peak hours. Energy-related costs were allocated to seasons and time-of-day periods according to each period’s relative incremental energy costs.

Transmission costs were not allocated to time-periods. However, the monthly charge determinant for Network Service is the higher of the customer’s coincident peak demand at the time of system peak or 85% of the customer’s non-coincident peak during peak period of 7 AM to 7 PM on working weekdays.

3. Allocation

The allocation of seasonal demand-related generation costs was done based on the 300 individual distribution utilities’ average seasonal NCPs, i.e., the average of the six monthly non-coincident peaks within the season.\textsuperscript{36} The demand-related costs allocated to OH’s

\textsuperscript{35} The analysis was undertaken in 1983/84. It looked at the fuel cost of the generating unit dispatched at the margin. No additional details of these studies were available.

\textsuperscript{36} Because of the large number of classes used in the study, the ratio of coincident to non-coincident demand was almost 1, meaning that there was not much difference between coincident and non-coincident demand.
distribution subsidiary (Power District) were then reallocated to customer classes based on their respective NCP within the season.

The energy-related costs were allocated using class kWh shares within the seasonal and diurnal periods.

The transmission allocation was as follows:

- **Network Service**: Charges were allocated on the higher of the hourly monthly coincident peak demand during the month, and 85% of the non-coincident peak demand in any hour during the peak period. Export and Wheel-Through (EWT) transactions are priced at a fixed charge per MWh. The revenue collected from the EWT Tariff Charges is used to reduce the revenue requirement for the Network Pool.\(^{37}\)

- **Transformation Connection**: Allocation was based on monthly NCP at the delivery point.

- **Line Connection**: Allocation is based on monthly Non-Coincident Peak demand at the delivery point of each line allocated to this pool (mainly radial lines).

4. **Treatment of Revenues from External (Off-system) sales**

Revenues from export sales were credited proportionally to the fixed and variable generation costs before the classification step. This is equivalent to classifying these revenues on the same basis as total generation costs.\(^{38}\)

C. **Pros and Cons and Expected Changes**

No information on pros and cons of the old embedded COS study was provided and there are no expected changes to the current transmission method or wholesale market pricing mechanism. However, as mentioned before, it is possible that the existing price freeze will be

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\(^{37}\) Generators do not pay transmission charges when they generate. When units are down and require service from the transmission network, they pay Network charges.

\(^{38}\) Source: Phone conversation with Mike Roger, Hydro One. October 21, 2003.
removed shortly. This will mean that a larger proportion of end-users will see time-
differentiated commodity rates, more reflective of market conditions.
VIII. PACIFICORP

A. Background

PacifiCorp is a multi-jurisdictional utility. It operates as Pacific Power & Light in Oregon, Washington, Wyoming and California; and as Utah Power and Light in Utah and Idaho. PacifiCorp has 53 hydropower facilities located in Washington, Oregon, Idaho, Utah and Montana, with a total generating capacity of 1,078 MW, or 15% of its total generation capacity. Off-system sales represented 32% of total kWh sales in 2002.39

PacifiCorp’s transmission network extends nearly 15,000 pole miles across 10 states in the western U.S. The system is interconnected with more than 80 generating plants and 15 adjacent control areas at 124 interconnection points. PacifiCorp has joined with Bonneville Power Administration and other utilities to create RTO West.

The transmission function includes the costs associated with the high voltage system utilized for the bulk transmission of power from generation sources and interconnected utilities to the load centers.

B. Generation and Transmission Embedded Cost Methods

PacifiCorp uses embedded studies for official rate filings in Utah, Wyoming, Idaho and Washington. Marginal cost studies are used in California and Oregon. Both marginal and embedded studies are also used internally.

The embedded cost method used by PacifiCorp for the classification and allocation of generation and transmission costs is consistent with the method agreed upon by the PacifiCorp Inter-jurisdictional Taskforce on Allocation (PITA).40


1. Classification

Classification of transmission and fixed generation costs follows arbitrary percentages: 75% Demand and 25% Energy-related. Fuel-related expenses and fuel costs are classified as 100% energy-related. All other generation-related costs are considered demand-related.

Firm purchases are classified as 75% Demand and 25% Energy. Non-firm purchases are classified as 100% Energy.

2. Time-Differentiation

Currently generation costs are not differentiated by time period. This may change in the future.

3. Allocation

Demand-related transmission and generation costs are allocated using class contribution to the 12 monthly system firm peaks. Demand costs are allocated in this manner because capacity is important to the company each month for meeting peak loads, load following, and plant maintenance. PacifiCorp's summer and winter peaks are very similar. The spring and fall monthly peaks are somewhat lower, with PacifiCorp’s lowest monthly peak generally around 80% of the annual maximum. Meeting peak load requirements, however, is also critical during the spring and fall months because that is when plants are taken out of service for maintenance. For these reasons, PacifiCorp supports the use of all 12 monthly peaks as the capacity allocation factor.

The energy portion is allocated using class MWh adjusted for losses to generation level.

4. Treatment of Revenues from External (Off-system) sales

All costs, including the costs associated with wholesale sales, are allocated to retail customers. Revenues from wholesale sales, FERC account 447 – “Sales For Resale” – are allocated to customer classes as revenue credits in a manner equivalent to the company’s treatment of firm and non-firm purchases:

• Firm Sales are classified as 75% Demand and 25% Energy.
• Non-Firm Sales are classified as 100% Energy.

C. Pros and Cons and Expected Changes

According to PacifiCorp, most criticism of the COS methods stems from the 75% demand / 25% energy classification of generation fixed costs. Large industrial intervenors generally want a 100% demand classification and residential intervenors want a higher energy classification.

PacifiCorp filed a cost-allocation proposal in Oregon, Idaho, Utah and Wyoming in early October in conjunction with its Multi-State Process docket, in progress since April 2002. The company will file the proposal later with Washington and California, in coordination with rate case activity in those states.

The proposal, "The MSP Protocol," outlines an interstate allocation method for the company’s generation, power supply, transmission and administrative costs for retail customers, which has been the subject of intensive meetings with utility regulators during the past two years. If the MSP Protocol is adopted, it may be used for class cost of service as well. The proposed effective date is November 1, 2003.

The MSP Protocol changes the current allocation method. However, most generation fixed costs are still classified as 75% Demand and 25% Energy. The exception will be the fixed costs of peaking plants (simple-cycle combustion turbines), which would be classified as 100% demand related.

The proposal distinguishes between seasonal and non-seasonal generation resources. Seasonal resources would include simple-cycle combustion turbines and seasonal contracts. These would be allocated using seasonally-weighted allocation factors. The proposal does not provide the details of these seasonal factors. However, PacifiCorp indicated that the basic approach implies assigning the costs of these seasonal resources entirely to the months with

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41 PacifiCorp Inter-Jurisdictional Cost Allocation Protocol (the “MSP Protocol”).
higher peak demands (probably 3 months)\textsuperscript{42} and allocating these costs to classes on the basis of their contribution to the average CP within that period.

\textsuperscript{42} Phone conversation with Richard Cowan, PacifiCorp. October 29, 2003.
IX. SALT RIVER PROJECT

A. Background

Salt River Project Agricultural Improvement and Power District (SRP), a political subdivision of the state of Arizona, provides electricity to nearly 800,000 retail customers in the Phoenix area. It operates or participates in generation totaling 4,800 MW, including thermal, nuclear and hydroelectric sources in Arizona and elsewhere in the Southwest. SRP operates several dams along the Salt River and the canal system, which represent about 5% of a total generation capacity. SRP also invests in renewable energy technologies such as solar power and landfill gas projects.

SRP serves 62 wholesale customers. In 2002 its annual “sales for resale” amounted to 13,703 GWh, which represented about 38% of total kWh sales.

B. Generation and Transmission Embedded Cost Methods

SRP uses an embedded COS study for internal purposes, and for rate filings with its elected Board of Directors. The description below is based on the approaches followed in their latest COS study (2002).43

1. Classification Method

The average system load factor is used to classify generation fixed costs. In FY 96-97, the system load factor was 52.3%. This percentage is used to classify generation costs as energy-related. The remainder of generation costs is defined as demand-related.

Fuel, water for power, steam, nuclear and hydraulic expenses are considered energy costs, as they vary directly with the volume of production. Of the remaining O&M costs, 50% were considered demand-related and 50% energy-related, as recommended by Power Operations. A&G costs allocated to generation were classified as 40% demand-related and 60% energy-related.

43Description based on SRP responses to NERA questionnaire (October 24, 2003) and follow-up phone conversations with Ronn Rodgers, Principal Analyst at SRP.
Purchased power costs were classified as energy or capacity according to the energy and demand charges in these transactions.

Transmission plant investments are categorized by function. The original accounting records are adjusted to functionalize all step-up and switching facilities at production plants as generation (transferred from transmission). Plant percentages are used to functionalize the costs of depreciation expenses, voluntary contributions in-lieu of property taxes, and out of state ad-valorem taxes. All transmission costs are classified as demand-related.

2. Time-Differentiation

No time-differentiation step.

3. Allocation

SRP allocated energy-related costs based on the energy consumption of each retail customer class. Demand-related costs were allocated based on the four-month average coincident peak demand (including losses) for each class (June through September). SRP uses the four-month average coincident demand allocator because it best reflects how decisions on additions to generation and transmission capacity are made.

4. Treatment of Revenues from External (Off-system) sales

Resale is considered a separate class, which is allocated a share of capital investment costs, using the same allocation process as per the remaining classes. The demand-related portion of purchased power costs is not allocated to the resale class. In its embedded cost studies, SRP does not allocate the resale mark-up (i.e., revenues in excess of allocated costs) back to the retail classes, although this revenue is taken into account in the rate-setting process.

C. Pros and Cons and Expected Changes

SRP’s embedded COS method has been applied consistently over time. SRP does not have plans to change it in the near term. Regarding transmission, the main advantage of their
method, according to SRP, is that it is consistent with the company’s Open Access Transmission Tariff (OATT), which was reviewed by FERC.\textsuperscript{44}

\textsuperscript{44} Source: Response to NERA survey by Ronn Rodgers, SRP
X. TENNESSEE VALLEY AUTHORITY

A. Background

The Tennessee Valley Authority (TVA) is the US’s largest public power producer. Wholly owned by the U.S. government, TVA was established by Congress in 1933 primarily to provide navigation, flood control and agricultural and industrial development and to promote electrification in the Tennessee Valley region. Sixty-three percent of TVA’s energy comes from fossil power plants, 29% from nuclear power, 8% from hydro, and a small amount from green power and wind turbines. Through 158 public power utilities, TVA supplies electricity to 8.3 million people in the TVA service area. Only 16% of total sales are made to ultimate customers.45

TVA owns and operates one of the largest transmission systems in North America, serving some 8.3 million residents in an 80,000 square-mile area spanning portions of seven states. TVA’s system has 17,000 circuit miles of transmission line and 973 individual delivery and interchange points.

TVA is not regulated by a commission but is governed by a three-member board of directors. TVA’s Board sets rates through negotiation with power distributors.

B. Generation and Transmission Embedded Cost Method

For many years TVA has conducted embedded COS studies to allocate costs to its directly served customers and the distributors of TVA power. The studies are usually done using both actual and projected costs and allocation factors. TVA recently used such a study for the rate change for fiscal year 2004.46

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45 2002 TVA’s Annual Report.
46 Description of TVA methods is based on TVA responses to NERA questionnaire (October 23, 2003) and follow-up phone conversations with Steve Summers, TVA Manager of Product Costing.
1. Classification

All transmission and fixed generation costs are classified as demand-related on the basis that utility plant investment is largely a function of the total system capacity required to meet peak demand. Fuel, purchased power, corrective maintenance and a portion of research and development costs are considered energy-related. Hydro costs are allocated to the residential class, in conformance with TVA’s Hydro Preference Policy (see below). No transmission costs are functionalized as generation.

2. Time-Differentiation

There is no time-differentiation step.

3. Allocation

The energy-related costs are allocated based on kWh sales adjusted for losses. Demand costs are allocated in proportion to class contribution to a chosen number of peaks.

TVA reviews a range of allocation methods (based on various CP approaches) as a starting point for its rate change negotiation with distributors. As a result, there is not one specific allocation method that determines the final revenue allocation.\(^{47}\) The latest FY 2003 COS study computed class revenue requirements using the following options:

- **Single CP Case** – Demand costs are allocated on the highest coincident peak projected to occur during FY 2003.
- **WS CP Case** – Demand costs are allocated on the average of the highest summer and winter coincident peaks projected to occur during FY 2003.
- **12 CP Case** – Demand costs are allocated on the average of the 12 monthly coincident peaks projected to occur during FY 2003.

\(^{47}\) The latest rate negotiation process (2003) resulted in an increase to residential and commercial users of 1.7%, and a decrease to manufacturing users of -7.7%. These percentages reflected: 1) the desire by distributors to hold down the increase to residential rates, and 2) the desire by TVA to reduce manufacturing rates to retain load.
• **2CP/12CP Case** – Demand costs for directly served classes and distributor classes in total are allocated on the average of the summer and winter coincident peaks projected to occur during FY 2003. The distributor total is then reallocated to their end-use classes on the basis on the 12 monthly coincident peaks projected to occur during FY 2003.\(^{48}\)

• **1CP/12CP Case** – Demand costs for directly served classes and distributor classes in total are allocated on the single coincident peak projected to occur during FY 2003. The distributor total is then reallocated to their end-use classes on the 12 monthly coincident peaks projected to occur during FY 2003.

**TVA’s “Hydro Preference” Policy**

TVA has a policy of allocating the benefits of low-cost hydroelectric power to residential customers, commonly called “hydro preference.” All hydro-related generation costs are assigned directly to the residential class.\(^{49}\) Since the costs associated with the hydroelectric system are lower than TVA’s overall average costs, the result is lower residential costs.

TVA determines the amount of the hydro allocation benefits within the COS study. The study computes one set of allocated costs where all the costs, including the hydroelectric costs, are allocated to all customers (called the no-preference case). The study also computes another set of allocated costs where the hydroelectric costs are assigned to the residential class only (called the preference case).

The allocation of hydro generation benefits is achieved by adjusting residential demand and energy loads. The dependable capacity of the hydro system is subtracted from the projected residential summer and winter peak demands. Additionally, the normalized annual hydro energy production is subtracted from projected total residential usage. The remaining portion of the residential peak demand and the energy consumption is considered to be supplied from

\(^{48}\) “Distribution Total” includes 158 distributors of TVA power. This hybrid approach reduces the effect on directly served industrial customers by using 1 CP in splitting costs between directly served customers and distributors.

\(^{49}\) Only TVA hydro dam production costs and the costs of hydro generation purchases from the Southeastern Power Administration’s Cumberland River are considered in the calculation of the hydro preference.
the thermal system. These steps reduce the demand and energy allocators for the residential class and correspondingly raise the demand and energy allocators for the other firm classes.

The amount of capacity installed by TVA includes a reserve requirement to ensure continued service in the event of unexpected outages. In the no-preference-case portion of the COS study, equal reserve requirements are allocated to each class. However, no reserve requirements are associated with the hydro system. Since the hydro system benefits are allocated to the residential class in the preference case, the residential class requires a lower overall reserve margin and therefore receives a lower cost allocation. The difference in residential revenue requirements between these two cases is the value of the hydro allocation.

The preference energy and coincident peak demand allocators apply only to thermal production costs. Non-production costs such as transmission and system control costs utilize standard no-preference allocators and are unaffected by the assignment of hydro system benefits.

4. Treatment of Revenues from Off-system Sales

Off-system sales revenues are credited to generation costs prior to the allocation step, on a dollar-for-dollar basis (one dollar of cost for each dollar of projected revenue). The revenues from off-system sales are classified as demand/energy-related in the same proportion as total generation costs (approximately 65% demand, 35% energy).

C. Pros and Cons and Expected Changes

According to TVA, one of the disadvantages of the method is that off-system and non-firm sales costs are removed prior to allocation step. These costs have grown significantly over the past decade. Another disadvantage of its method is that there is considerable disagreement over the number of coincident peaks that should be used for allocating demand costs. The advantage is that energy sales and contribution to peak methodologies allocate costs to those customers who most contribute to each.\textsuperscript{50}

\textsuperscript{50} Source: Steve Summers, TVA. December 2, 2003.
TVA is exploring the possibility of using market energy prices for allocation of energy-related costs (demand-related costs would be allocated on the basis of 12 CP). Energy costs would be allocated using a “Resource Cost Allocation” (RCA) approach, which assigns costs to hours based on load-weighted hourly market energy prices, then allocates costs to classes based on their individual contribution to hourly load. The goal is to assign costs in a manner more reflective of competitive markets. However, generation classification would not change.
XI. NORTHERN STATES POWER COMPANY

A. Background

Northern States Power Company (NSP) is a wholly owned subsidiary of Xcel Energy.\(^{51}\) NSP operates in the states of Minnesota (MN), North Dakota (ND), South Dakota (SD), Wisconsin (WI) and Missouri (MI). NSP uses a variety of generation types including coal, natural gas, nuclear, hydro, oil and renewables. Its total generation capacity is 6,805 MW, of which about 5% is hydroelectric. Overall off-system sales are relatively large, about 27% of total kWh sales.\(^{52}\)

B. Generation and Transmission Embedded Cost Method

The methods employed by NSP in the various states are described below.\(^{53}\)

1. Classification Method

   a. Fixed costs

   NSP’s most recent electric COS study (1993 test year for MN, ND and SD) functionalizes Generation Step-Up to transmission. Because of the gradual move toward deregulation and the new FERC seven-factor test, the definition of generation step-up would probably change for a new rate case.

   In all states transmission costs are treated as demand-related. In the states of WI and MI, 100% of the fixed generation costs are treated as demand related. In MN, ND and SD, NSP classifies fixed generation costs using the “capital substitution” method, which the company

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\(^{51}\) Xcel Energy is a holding company formed by the merger of Denver-based New Century Energies (NCE) and Minneapolis-based Northern States Power Co. (NSP). The former NCE operated in the states of Colorado, Kansas, New Mexico, Oklahoma, Texas and Wyoming. We did not include the COS methods used in these states as NCE subsidiaries do not have any hydro resources.


\(^{53}\) The description of the methods is based on Xcel Energy responses to NERA questionnaire by Marx Gerald, Senior Price Analyst (October 22, 2003) and follow-up phone/email conversations with: Phil Zins (Manager of Pricing and Planning, Minnesota), Jim Gilroy (Principal Pricing Analyst, Minnesota), and Marx Gerald (Pricing Analyst, Wisconsin).
calls “stratification.” The fixed cost of the least expensive plant source, gas turbine or diesel peaking generation, is compared to fixed costs of the other sources (nuclear, fossil steam, hydro). The percentage that the peaking capacity cost represents of other capacity resource costs is the amount of each capacity source’s cost that is classified as demand related. The remainder is classified as energy-related.

The stratification method in MN, ND and SD results in the following classification of generation plant costs:

<table>
<thead>
<tr>
<th>Production type</th>
<th>% Base Load (energy-related)</th>
<th>% Peaking (demand-related)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro</td>
<td>67.5</td>
<td>32.5</td>
</tr>
<tr>
<td>Nuclear</td>
<td>74.7</td>
<td>25.3</td>
</tr>
<tr>
<td>Steam Fossil</td>
<td>59.4</td>
<td>40.6</td>
</tr>
<tr>
<td>Gas Turbine and Diesels</td>
<td>0.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>

b. **Variable generation costs**

All variable generation costs are classified as energy-related.

c. **Purchase costs**

In WI and MI, the fixed cost of purchased power is all considered demand-related. In MN, ND and SD, the fixed cost of purchased power is split in the same way as the fixed costs of company-owned generation (i.e., with Cap-Sub or “stratification”). Each purchased power agreement is analyzed to determine which capacity source it most closely represents. These purchased power expenses are then stratified using the appropriate production type percentage noted above.

2. **Time-Differentiation**

In MN, ND and SD, the demand-related component of fixed generation and transmission costs is separated into summer and winter seasons, with summer given the larger share. The portion of the demand-related component dedicated to serving a specific season is
computed by applying a seasonal demand-weighting factor. The weighting factor is derived from test-year monthly system peak demands, which have been reduced by the annual minimum demand. The summer and winter monthly net peak demands are averaged separately to determine each season’s portion of the averaged annual total. The current factors used in the class cost study are 72% summer and 28% winter. In MN, ND and SD, the energy-related costs are time-differentiated within the day through the use of a weighted energy allocator (see below).

There is no time-differentiation in the states of WI or MI.

3. Allocation

a. Demand cost allocation

In MN, ND and SD, the allocation of the seasonal demand-related costs to classes is based on class contribution to the system’s seasonal single coincident peak in each season. In WI, MI, the demand allocator is the average class demand contributions to the 12 monthly coincident peaks (12 CP) plus losses for each class.

b. Energy cost allocation

In MN, ND and SD, energy-related generation costs are allocated to classes based on an energy allocator that reflects each class’s on- and off-peak usage, with the on-peak usage “scaled up” by the ratio of the system on- to off-peak marginal energy costs.

In WI and MI the energy allocator is the customer class’ sales plus losses.

4. Treatment of Revenues from External (Off-system) sales

In MN, SD, ND, WI, MI, all off-system revenues are credited to native customers before the allocation process; the classification of these revenues is generally based on the structure of contract charges.
C. Pros and Cons and Expected Changes

Xcel Energy indicated that the company is very comfortable with the method applied in MN, ND and SD. It is conceptually sound and, although numerous interveners have challenged this method over many rate cases, the PUCs have sustained it. It has remained fundamentally the same for at least thirty years. Xcel Energy is also comfortable with the methods employed in the remaining states. Their fairness has been considered and approved by the state regulators.