Electricity System Study
ESSB 6560

Prepared by:
Washington Utilities and Transportation Commission
Department of Community, Trade, and Economic Development

Executive Summary

This report was prepared by the Washington Utilities and Transportation Commission (UTC) and the Department of Community, Trade and Economic Development (CTED) under the provisions of ESSB 6560. The report provides information about Washington's electric utility industry, identifies trends affecting the industry and consumers, and identifies strategies for achieving policy objectives. It does not provide recommendations or reach conclusions as to the advisability of the changes described or the strategies discussed. The report is organized into nine sections:

1. Washington's Electricity Landscape

Washington's electric power system is unique. The state relies heavily on hydropower and federally owned generation and transmission facilities. The majority of retail electricity service is provided by consumer-owned utilities, with only about one-third of retail sales accounted for by investor-owned utilities regulated by the Washington Utilities and Transportation Commission (UTC). No utilities are granted exclusive territorial franchises in Washington. In contrast, most of the nation is served by fossil-fired generation delivered over investor-owned transmission lines. Retail service is dominated by investor-owned utilities regulated by the states. Most other states grant monopoly franchise service territories.

Average electricity rates in Washington are 4.19 cents/kWh, 40 percent below the national average. While rates vary across the state's 60 or more utilities, even the most expensive of Washington's utilities fall below the national average. Rates in the residential and commercial sectors have increased over the last 9 years, but at a pace substantially less than inflation. Some industrial customers, particularly those choosing non-traditional services that involve market-based pricing, have seen rate decreases over the last three years, while residential and commercial rates have generally been flat.

Utilities surveyed for the report serve approximately 90% of Washington's electricity customers. Among these customers, fewer than 1000 consume more than one average megawatt of electricity per year or have an annual peak demand greater than one megawatt. Less than one percent of customers have time of use electric meters.

Review of costs by category (generation, transmission, and distribution) suggests that the major reason for Washington's low electric rates is low-cost generation supplies. These relatively low-cost supplies are due to a variety of factors, including the Federal Columbia River Power System, the prevalence of hydropower generally, and the age and ownership characteristics of resources used to serve Washington consumers.

2. Trends Affecting Electric Service Costs

Trends are described in six categories: wholesale markets, retail markets, supply adequacy and reliability, environment, technology, and fuel cost.

Federal policy changes, including the Energy Policy Act of 1992 and subsequent FERC orders 888 and 889, are transforming wholesale power markets. Active short-term power markets have developed. These markets may reduce costs by increasing utilization of low-priced resources. They also exhibit volatility and may increase some environmental costs. Increasing wholesale competition may increase pressures to distribute the benefits of low-cost federal power more broadly.

All 50 states have at least examined the prospect of restructuring their retail markets, and mandatory retail competition is underway in at least 13 states. In Washington, utilities have experimented with pilot retail access programs and most offer some form of market-based rates to large customers. Many utilities are involved in corporate realignments and new partnerships. Uncertainty regarding future retail market structure seems to have shortened planning horizons and led to reduced investment in energy efficiency, renewable resources, and resource development generally. This uncertainty makes it unclear who can or should take actions to reduce the growing likelihood of supply and capacity shortages.

Declining salmon populations, global climate change, and increasing competition in electric power markets are trends that may affect the environmental cost of electricity production. At least in the case of declining salmon runs, more environmental costs are being “internalized” in power rates, reflecting the cost of salmon recovery measures. Internalization of environmental costs does not necessarily increase or decrease total costs, but it does increase prices. These price impacts may be offset by reduced environmental costs.

Improvements in the efficiency of electricity-generating and electricity-using technologies have reduced electric service costs. Renewable technologies and “distributed” technologies such as fuel cells may reduce the cost and change the nature of electric service in the future. New communication and information technologies may present significant opportunities to reduce electric service costs and expand product and service diversity.

Coal and gas prices have generally declined since the early 1980s, though gas prices have climbed since 1995. The cost of these fuels in Washington is below national averages.

3. Strategies to Minimize Electric Service Costs

Strategies to minimize electric service costs are grouped in the same categories as trends affecting electric service costs: wholesale market, retail market, supply adequacy and reliability, environment, technology, and fuel cost. Stakeholder comments on the first draft of this report revealed a tension between maintaining desirable characteristics of the existing system and a desire to respond to changes in the market that may render existing policies and strategies ineffective. Discussion of strategies does not imply that any change is recommended or endorsed.

The wholesale market is not under state jurisdiction. However, actions taken within the state and region may help to minimize the cost of wholesale power. Potential strategies to minimize wholesale power costs include reinforcing the connection between Washington consumers and the benefits of the Federal Columbia River Power System (FCRPS) and promoting more effective wholesale competition through more efficient operation of the high-voltage transmission grid.

ESSB 6560 did not call for a comparison of alternative retail market structures, and the evidence concerning the effects of market structure on costs is inconclusive. Some strategies may help minimize costs in the presence of competitive pressure by: 1) reinforcing the connection between Washington customers and low-cost resources; 2) mitigating incentives to either shift or increase total costs; and 3) removing barriers to efficient market operation.

The likelihood of supply and capacity shortages in the Northwest in the winter is growing. These shortages may occur under adverse hydropower conditions, due to power demands that exceed the region's combined capability to generate and import power. The prospect of shortfalls is exacerbated by market uncertainty. Utilities may be increasingly reluctant to develop and execute plans to meet future loads reliably when those loads may be served by other power suppliers. Other resource developers may also face obstacles associated with uncertainty.

Potential strategies to reduce environmental costs of electric service are described in three categories: salmon recovery, global climate change, and aligning competitive markets with environmental objectives. "Internalizing" environmental costs in energy prices may decrease or increase total costs, depending on whether the value of the resulting environmental improvement exceeds the cost of the measures undertaken. Some strategies, including cost-effective energy efficiency, may reduce both economic costs and environmental costs of electric service.

New and developing energy technologies hold significant promise for reducing electric service costs. Private firms, the federal Department of Energy, universities, national laboratories, and other research institutions are typically the leaders in energy technology development. However, the state can play a supporting role through policy initiatives and technology development partnerships. Periodic technology assessments may help to identify needs and opportunities.

Fuel costs are generally outside of the state's control. However, strategies discussed elsewhere in the report may affect the state's exposure to changes in fuel costs.

4. Electricity Rates and Equity: the Potential for Cost-shifting

Electricity rates in Washington are generally set by state or local regulators. These rates are based on an analysis of "cost of service" and regulators' assessments of fairness. For the limited purposes of this analysis, "cost shifts" are defined as decisions by rate regulators to change the distribution of costs. Changing political, regulatory, and market conditions can affect the way state and local regulators make these judgments.

Much of the power generation that serves Washington customers is likely to cost less than its market value. If the value of these low-cost resources is not preserved for Washington customers, power costs could rise significantly. Such an increase could put great pressure on state and local rate-setters to shift costs among customers and customer classes.

Changes in transmission regulation and in the way Bonneville Power Administration markets power may influence the probability of cost shifts in the wholesale market. Small rural utilities and residential and small farm customers of investor-owned utilities may be particularly exposed to these cost shifts. Strategies to discourage cost shifts in this sector focus on efforts to influence the decisions of the Federal Energy Regulatory Commission and BPA.

Cost shifts may also develop because of changes in retail electricity markets. By gaining access to market-based rates, some customers could leave behind power costs that local or state regulators may shift to other customers. Analysis in this report estimates the potential magnitude of such cost shifts under a range of market price forecasts and other assumptions. Under medium market forecasts, the estimated statewide average potential for cost shifts to the residential and commercial classes is estimated to be 1 to 2 percent of retail rates. Estimates for individual utilities range from 0 to 5 percent. The potential is greater under low market price scenerios.

Cost shifts could also result from utility system "bypass" – construction of generation or delivery facilities to serve large customers directly. Across a range of market-price forecasts, the statewide average potential for cost shifts due to bypass varies from 0.6 percent to 1.2 percent on retail rates of remaining customers. Estimates for individual utilities range from 0 to 3.4 percent.

A substantial proportion of industrial and large commercial load is already being served under "non-traditional" and market-priced tariffs. The average rate for this service is substantially lower than traditional industrial tariffs. There is no evidence that commercial and residential rates have increased as a result of these discounts. We do not know whether or how the benefits of lower-priced power would be distributed among customers in the absence of these tariffs.

A number of additional circumstances in the retail market could lead to cost shifts including: insufficient metering accuracy for competitive retail loads, unequal collection of funds for system benefit programs, avoidance of state and local revenue taxes, and technology change in “distributed generation” such as fuel cells, microturbines, and some renewable resources.

A wide variety of both market structure and administrative strategies are available to discourage or prevent the occurrence of cost shifts. Perhaps the most important of these is preservation of the value of low-cost generation resources for Washington customers. Additional structural strategies include clarification of service territory obligations and boundaries, and establishment of competitive retail customer classes, including clear terms and conditions for this service. Administrative strategies address rate setting by state or local utility regulators. These strategies include rate-freezes, rate caps, performance-based rates, clarification of stranded-cost issues, and clarification of system benefit program charges.

5. Utility Service Territory Agreements

Unlike most states, Washington does not issue state level “franchises” or “certificates” to provide electric service. While they may need local permits to construct facilities, most electric providers may serve any customer in the state, regardless of their historic service territory. Providers are allowed by state law to enter into voluntary, contractual “service territory agreements” that define service territories and obligations. These agreements must be approved by the WUTC. Over time there have been 28 such agreements; 17 remain in effect and a number that have formally expired are still being observed.

State law has no provision requiring electric companies to deliver power for other electric providers. However, state law does discourage the construction of duplicate facilities for energy service. Currently, there appears to be little duplication of facilities. However, duplication of facilities may increase, particularly if more customers seek energy supplies from providers other than their traditional distribution utility. State-level certificates could uniformly define the rights and responsibilities of distribution utilities without restricting the ability of new consumer-owned utilities to form. Proponents of establishing state certificates for distribution territories argue such a step could allow increased competition while maintaining the state policy against duplication of facilities. Opponents suggest that exclusive service territories would insulate distribution utilities from competition and decrease pressure to minimize distribution costs.

6. Consumer Protection Policies and Procedures

The UTC establishes consumer protection rules for investor-owned utilities and local governing boards establish consumer protection rules for consumer-owned utilities. Policies tend to be uniform for investor-owned utilities. There is more variation among consumer-owned utilities, with smaller utilities tending to have more informal means of establishing credit, collecting past due amounts, and handling customer complaints.

All covered utilities have complied with the disclosure requirements of ESSB 6560. The UTC and CTED surveyed utilities on their policies in a number of general categories including: credit and deposit requirements; methods of informing customers of rates and terms of service; metering, billing, and adjustment policies; payment arrangements, such as due dates, late fees, budget plans, and financial assistance; disconnection procedures; confidentiality of customer information; complaint procedures; protections for contract customers; and customer survey methods.

Increased competition may lead to increasing consumer complaints. Additional consumer protection may be needed if competition increases, along with consumer education designed to alert consumers to their new rights and choices. Some issues that may arise include: protecting consumers from fraudulent providers; ensuring adequate disclosure of product information so customers can compare offerings; allocating stranded costs among customers and shareholders; clarification of metering requirements; disconnection policies; protecting against market power abuses; registration and licensing of service providers; and ensuring that basic service remains affordable.

7. Utility Service Quality

Service quality encompasses items such as customer access to the utility; responsiveness to customers; restoring power after outages; the time required to establish new service or make repairs; and the process for handling customer complaints.

The UTC oversees service quality standards for investor-owned utilities while local governing boards oversee standards for consumer-owned utilities. Rules governing service quality are not uniform or comprehensive. In one case, as a condition of a utility merger, the UTC has developed a detailed service quality index (SQI), establishing targets and monetary sanctions.

Existing and prospective competition may begin to put pressure on service quality performance. Experience in other industries indicates that customers with more competitive choices tend to see improved service quality, while monopoly customers see a decline. A survey of state utilities shows that many do not routinely measure service quality and that the elements that are measured vary from utility to utility. Lack of common data makes it difficult to draw general conclusions.

If the Legislature decides that minimum service quality standards should be established, it has at least two alternative strategies. It could set general principles and let state and local regulators establish specific standards consistent with the principles. This would allow local decision-making, and would likely lead to more variation in policies. Alternatively, the Legislature could set uniform statewide standards. This would ensure consistency throughout the state, but may not recognize unique local conditions. If retail competition is broadly implemented, the Legislature could establish a service quality “floor,” but allow individual companies to provide a higher level of service as a way to compete.

8. Electric Service Reliability

Major dimensions of system reliability include power interruption, power quality, and generation supply adequacy. Available survey and engineering data tentatively show that Washington consumers are generally satisfied with the reliability of the electric power system, and that system outage statistics are comparable to national averages.

Most utilities measure power interruptions, though precise methods vary. Equipment failure, trees and branches, animals and accidents are the cause of most power interruptions. Storms are often the immediate cause of such interruptions.

Power quality refers to the voltage and frequency characteristics of delivered power. While power quality has long been a concern for industries with sophisticated production equipment, it is a growing concern for other business and residential customers because of the proliferation of microprocessors, which are sensitive to power fluctuations.

Reliability also depends on adequate power supply capacity. In our hydroelectric based system, supply varies substantially with precipitation and snowpack. Transmission capacity can affect the ability of utilities to meet peak loads reliably, particularly in Western Washington. With growing competition and uncertainty regarding future market structure, utilities' ability to plan for and invest in adequate power supplies may be impaired. Increasingly, power supply may be provided by independent producers that are not subject to state or local regulation. The ability of these independent entities to deliver power reliably under a range of weather and market conditions is not known.

Competitive pressures and market uncertainty may also affect utility investment in distribution systems, where storm response, system maintenance, system expansion and vegetation management are keys to reliability. Utilities may also face pressure to help customers protect themselves from power quality fluctuations and to ensure their systems are Y2K compliant.

Additional challenges to system reliability may be found in the transmission system, which handles transfers of bulk power. Historically, the system has been managed by regional utilities that voluntarily comply with industry standards. Increasing competition in wholesale power markets makes voluntary compliance more difficult to maintain. Discussions are taking place at the national and regional levels to develop new models designed to maintain transmission system reliability.

Strategies that address reliability in distribution, generation, and transmission are discussed. Distribution strategies are further categorized into those that involve performance standards, program standards, and institutional and market issues.

9. Electric System Benefits

State and federal governments have adopted a variety of policies in support of conservation, renewable resources, and low-income service ("system benefits"). Policy goals underlying these purposes include: minimizing total costs of energy service; ensuring affordable service; environmental quality; affordable housing; efficiency in government and industry; diversification of energy supplies; minimizing waste; and others.

Trends: From 1979 to 1995, the region's utilities acquired over 800 average megawatts of energy savings in cooperation with state and local governments and consumers. The Northwest Power Planning Council estimates that 1500 average megawatts of cost-effective savings are available at an average cost of 1.7 cents per kWh. Capturing these savings would reduce the region's electricity bill by an estimated $1.7 billion. Investment in energy efficiency in Washington has declined from nearly $155 million in 1993 to an estimated $44 million in 1998 and is projected to continue to decline to $24 million in 2000. Competitive pressure to minimize prices, lower wholesale energy prices, uncertainty regarding future market structure, and programmatic changes have contributed to this decline.

Non-hydro renewables represent less than 1% of utility sales in Washington. Declining wholesale power prices and market uncertainty have dampened renewable resource development below what was planned in the early 1990s. Utility-scale wind projects came on line in Oregon and Wyoming in 1998. However, a planned project in southern Washington was cancelled.

Low-income energy services include home weatherization and various forms of assistance in paying bills. While need appears to be increasing, funding for these services has declined, due in large measure to reductions in federal and BPA funding. There are some indications that low-income bill assistance by utilities may be increasing.

Electric system benefits have been accomplished with a mixture of public and private investment. Public investment in these functions has come primarily from electric service revenues and been administered by utilities and BPA. Public investment may be necessary in order to remove market barriers to energy efficiency, or to achieve other policy goals including environmental quality and universal service. Most of the states that are restructuring retail markets have included provisions for funding energy efficiency, renewable resources, low-income services, and/or research and demonstration.

Strategies: Opinions vary widely on how to pay for, administer, and achieve electric system benefits. However, there appears to be relatively broad support for approaches that: encourage rather than replace private investment in these functions; maximize the ratio of achievement to investment; and distribute the costs and benefits of these investments equitably.

Sources of public investment include electric service revenues and tax revenues. Electric service revenues may be collected through a "system benefits charge" – a competitively neutral charge on delivery of electricity that applies to all consumers. A variety of program approaches and administrative options for public investment in energy efficiency, renewable resources, and low-income services are discussed, with an emphasis on how these approaches can complement and encourage private investment while minimizing costs.

Other strategies for accomplishing these purposes may require little or no direct public investment. These include: improved energy codes and standards; developing markets for "green" resources; a renewable portfolio standard; "internalizing" environmental costs through environmental standards or fees; and flexible payment arrangements for low-income customers.

Achievement of electricity system benefits over time may be improved by establishment and tracking of performance objectives, and through periodic review of investment levels and program strategies.

0.0 INTRODUCTION

This report provides information about Washington's electric utility industry, state and local regulation, and a number of issues that may require consideration in any policy changes affecting essential electricity services. The 1998 Legislature commissioned the Washington Utilities and Transportation Commission (UTC) and the Department of Community, Trade and Economic Development Energy Division (CTED) to study seven issues:

(a) Variations in retail electricity rates within the state and in comparison with national averages, trends affecting the electricity service costs for all customers in the state, and strategies available to minimize those costs in the future;
(b) Demographics of retail electric customers in the state to include the distribution of customers by size of load;
(c) The potential for cost-shifting among customer classes and among customers within the same class, and strategies available to minimize inappropriate cost shifts;
(d) The consumer protection policies and procedures of electric utilities, including areas of consistency and inconsistency among the utilities in those policies and procedures;
(e) The status, number, and primary characteristics of service territory agreements between electric utilities;
(f) The current level of service quality and reliability as measured by available statistics, trends affecting quality of service and the integrity and reliability of the distribution system, and ways to ensure high service quality and reliability in the future; and
(g) Current levels of investment in conservation, non-hydro renewable resources, and low-income energy assistance programs, trends affecting such investment, and ways to fairly, efficiently, and effectively foster future achievement of the purposes of such investment.

A number of these areas directed the agencies to study strategies available to accomplish identified objectives. In these areas, we have described strategies, policies or actions that might be considered or adopted. In many cases, we have described arguments for and against these strategies. Based on our understanding of the Legislature's expectations, the agencies have not made specific recommendations regarding any strategy. Rather, we focused the study on presenting relevant information and discussing a range of policy options. In no case do these discussions of policies and strategies represent recommendations or conclusions as to the advisability or necessity of implementing such policies or strategies.

Discussions of policy options and strategies also do not imply that any particular action is necessary. Some stakeholders feel that Washington currently enjoys a relatively low-cost, reliable electric power system and that the best strategy may be to minimize change. Others suggest that economic forces have already changed the electric power market, such that existing strategies for accomplishing policy goals may no longer be effective or appropriate. This tension between preserving the desirable characteristics of the existing system and responding to market changes that are already occurring was a recurring theme throughout the stakeholder discussions on the development of this report. Without implying that policy change is necessary, the agencies have provided information documenting the changes that are taking place, indicated how those changes may affect achievement of policy goals, and discussed alternative strategies for achieving policy goals in light of those changes. Again, describing changes and outlining alternative responses does not imply endorsement of either.

Summary of Report Organization

This report is organized into nine major sections.

1. **Washington's Electricity Landscape.** Fundamental characteristics of retail electric utility service in Washington, including:
    - ❖ Retail electric utilities serving the state
    - ❖ Utility load demographics
    - ❖ Retail rates and how they vary across the state
    - ❖ How rates and electricity costs compare with national averages.
    - ❖ Costs associated with different components of service (generation, transmission, and distribution)
2. **Trends Affecting Electric Service Costs.** These include wholesale and retail market development, the adequacy of the region's electricity supply and capacity, environmental trends, technology, and fuel cost.
3. **Strategies to Minimize Electric Service Costs.** Describes alternative strategies for minimizing electric service costs in light of the trends discussed in Section 2.
4. **Electricity Rates and Equity: The Potential for Cost-Shifting.** Examines the potential for cost-shifting among customer classes and among customers within rate classes. This potential is described qualitatively along with some simple quantitative estimates. Major trends affecting the potential for cost-shifting are described and strategies available to minimize cost-shifting are discussed.
5. **Utility Service Territory Agreements in Washington.** Describes state policy regarding utility service areas and the status of contractual service territory agreements.
6. **Consumer Protection Policies and Procedures.** Describes policies and practices employed by Washington utilities that establish terms and conditions of utility service and consumer rights.
7. **Utility Service Quality.** The way in which consumers are able to interact with their utility, and utility survey results regarding customer satisfaction.

8. **Electric Service Reliability.** A summary of information regarding:

    - Performance data for local distribution systems, such as service interruption and frequency data
    - Consumer survey results concerning satisfaction with electricity delivery performance reliability
    - Trends in distribution system reliability and major factors affecting distribution system performance
    - Strategies available to maintain high levels of distribution system performance.

9. **Electric System Benefits.** Conservation, renewable resources and low-income weatherization and energy assistance, including:

    - History of these programs and utilities' roles in undertaking them
    - Investment and performance trends
    - Factors affecting utility and other investment in these purposes
    - Strategies available to foster efficient use of electricity, renewable resource development and low-income programs.

Summary of Study Process and Data Collection

The study included data from published and other sources, utilities, and stakeholders. It included compilation of information and analyses rather than generating new forecasts, economic analyses or computer models. The only original quantitative analysis is in the cost-shifting discussion, in which simple estimates are presented of the magnitude of cost-shifting that might occur under a set of described conditions.

Washington's utilities were a major source of information for the study. They were requested to complete a survey pertaining to the seven study areas. The survey instrument is included in the appendix. Eighteen utilities responded to some or all of the survey, including four cooperatives and one small public utility district that were exempted from the provisions of ESSB 6560. Utilities responding to the survey represent more than 2.3 million, or 88 percent, of Washington's customers. For the most part, utility survey responses were thorough and provided information critical to the study's completion. The agencies recognize the substantial amount of work completing these surveys required of the utilities and thank them for their willing cooperation. Table 0.1 includes a list of utilities that responded to the survey.

Table 0.1. Utilities Contributing Data to the Study

Public Utility Districts: Benton County PUD Chelan County PUD Clark County PUD Cowlitz County PUD Franklin County PUD Grays Harbor County PUD Snohomish County PUD Grant County PUD **Investor-Owned Utilities:** Puget Sound Energy PacifCorp Washington Water Power	**Cooperatives:** Benton Rural Electric Association Inland Power and Light Parkland Power and Light Nespelem Valley Electric Orcas Power and Light **Municipal Utilities:** Seattle City Light Tacoma Power

The study also included a process for stakeholders and interested parties to contribute information, participate in discussions, and review the draft report. In June 1998, notice was sent to more than 700 interest groups, utilities and other parties announcing the study and requesting responses to simple questions regarding preference for level and forum for participation. The agencies received 184 responses to these questions and from this information designed a stakeholder consultation and participation process consistent with the general preferences of stakeholder groups. This process included:

- A general orientation and study introduction meeting in early July
- Surveying utilities and collecting information through mid-September
- Discussion and input on the study's major areas at four meetings in August.
- A meeting and opportunity to comment on the draft report in November.
- Extensive written comments on the draft report that contributed to substantial improvements in the final report.

Participation in this stakeholder process was enthusiastic and constructive. The agencies appreciate the time individuals and organizations committed to attending meetings and reviewing the draft report.

1.0 Washington's Electricity Landscape

Washington's economy and quality of life share with the rest of the nation a great dependence on the availability of high quality, reliable and affordable electricity service. However, Washington's electricity industry differs from the rest of the nation's in some important respects. While electricity service in most of the nation is dominated by relatively large investor-owned utilities with state-certified monopoly service territories, Washington's utilities are a diverse mix of both size and ownership, none of which have a state-certified monopoly service territory. The majority of electricity service is provided by utilities that are owned by consensus and locally controlled.

Figure 1.1 Kilowatt-Hours sales by Utility Type - Washington, 1996

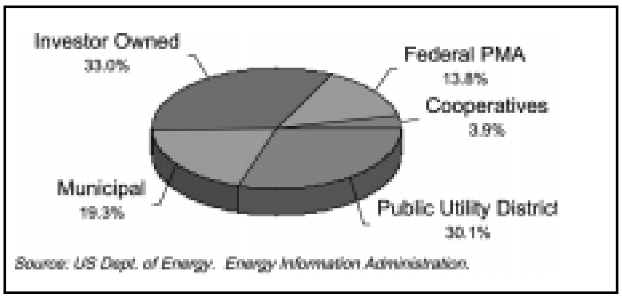
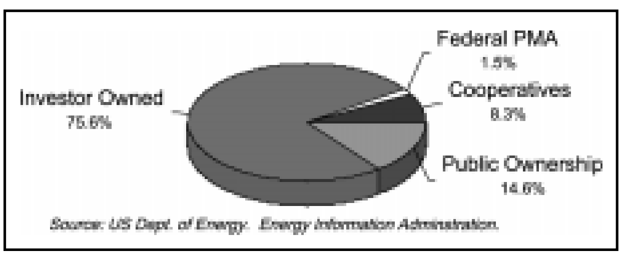


Figure 1.2 Kilowatt-Hours sales by Utility Type - USA, 1996



While most of the nation is served by electricity generated from fossil fuel or nuclear sources, Washington's electricity industry is dominated by hydropower, which accounts for roughly a third of the nation's total hydropower generation. While this is a benefit of our geography, it comes with a cost. Hydropower development on the Columbia, Snake and other rivers is marked by one of the nation's most controversial environmental problems: survival and restoration of salmon populations. Our reliance on hydropower also complicates energy planning and policy because water, the fuel for power generation, is not only unpredictable in supply, but is also a multiple-use resource important for irrigation, transportation, recreation, and other uses.

Figure 1.3 Electricity Generated in Washington

Percent of total: 1996 Data

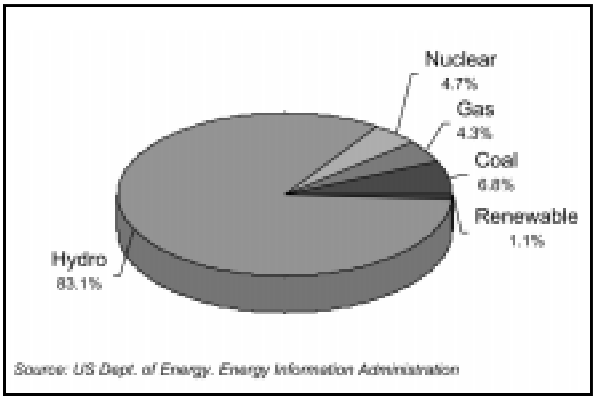
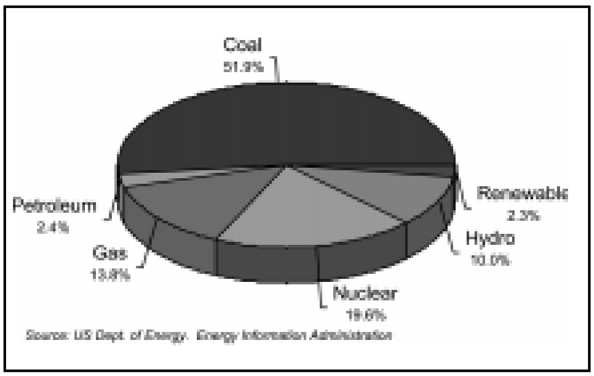


Figure 1.4 Electricity Generated in USA

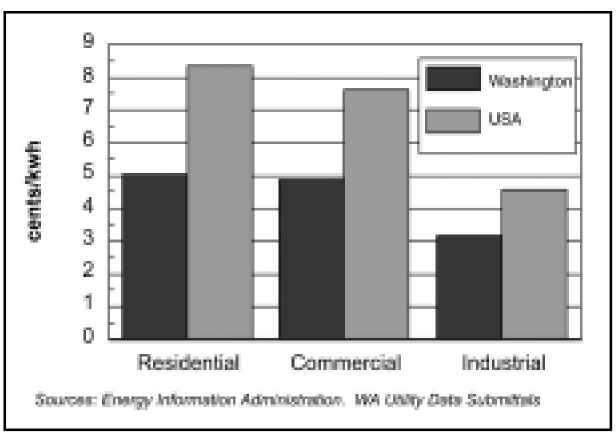
Percent of total: 1996 Data



Few other states in the nation are as dependent as ours on federal facilities that generate and transmit electricity. More than half of the power generation and 80 percent of the high-voltage transmission serving Washington comes from the Bonneville Power Administration (BPA).

Figure 1.5 Average Rates Compared

Washington vs. United States



Finally, perhaps the most important distinquishing feature of Washington's electric power system is our low power rates. Our reliance on hydropower, federal power resources, and a diverse mix of public and private utilities produces among the lowest electricity rates in the nation.

1.1 Washington Utility Demographics

1.1.1 Utility Organization and Ownership

In 1996, Washington had more than 2.5 million electricity customers served by more than 60 utilities. These utilities vary greatly in size, ranging from Northern Lights Cooperative (an Idaho-based cooperative) which serves 14 customers in Pend Oreille County, to Puget Sound Energy which serves 864,462 customers in the Puget Sound area. The dozen largest utilities, together with the BPA's 10 direct service industries, account for about 85 percent of the state's customers and electricity use.

Figure 1.6 Customers By Utility Type - Washington, 1996

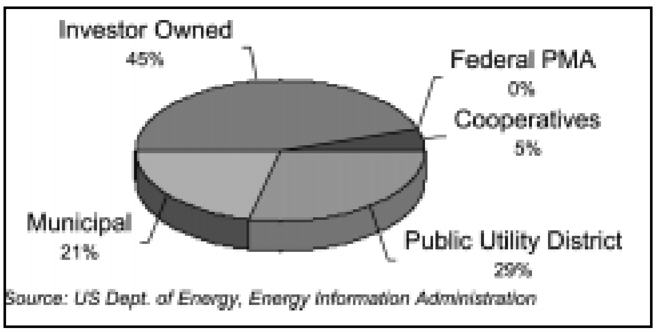
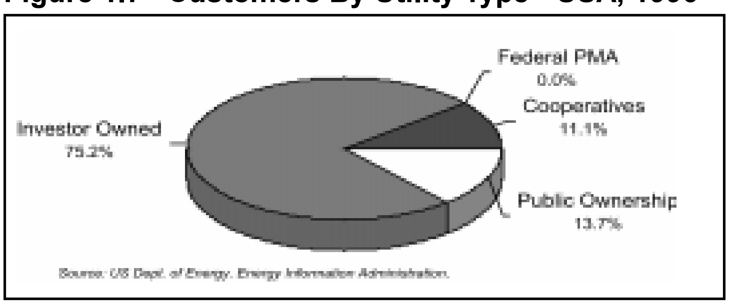


Figure 1.7 Customers By Utility Type - USA, 1996



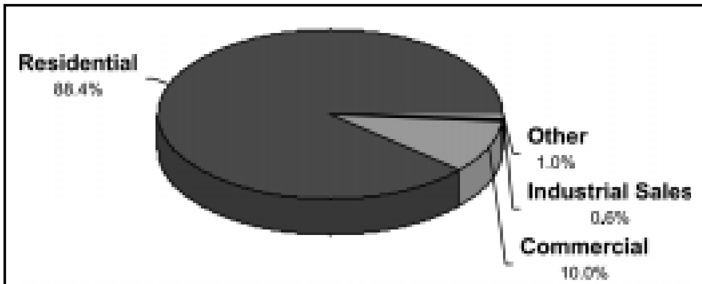
Except for the Bonneville Power Administration, the various retail utilities in Washington are authorized and governed by a number of sections of state law. General service requirements and standards for the three investor-owned electric utilities are set out in chapter 80.28 RCW. These are the only utilities whose rates, terms and conditions of service are regulated by the state under jurisdiction of the Washington Utilities and Transportation Commission (UTC). Municipal utilities, public utility districts, cooperative and mutual corporation utilities, irrigation districts and port districts are governed by combinations of the provisions of Title 80 RCW and specific enabling legislation. The municipal utilities are locally regulated as functions of city government authorized by Title 35 RCW. Public Utility Districts are locally regulated by elected county officials as authorized by Title 54 RCW. Cooperative and mutual corporations are locally regulated by membership boards and governed by chapters 23.86, 24.06, or 87.03 RCW. Fifty-five percent of Washington's electricity customers and sales are served by locally-controlled and regulated utilities.

Washington also has the largest number of utility control areas of any state in the Western U.S. A utility "control area" is the technical term for a geographical area of the electricity grid that is managed closely to ensure that all loads and generation are kept in balance at all times. These areas are components of the management framework by which the Western System Coordinating Council (WSCC) monitors and maintains electricity reliability throughout 14 Western states. To understand Washington's utility landscape, the technical details of control area operation are not as important as the fact that the state contains 9 such areas. These areas may contain a number of individual utilities, or they may contain only one. Current technology and practice requires that scheduling of transmission between these control areas be for transfers of no less than 1 MW. Under current technology and practice, individual customers or aggregations of customers seeking competitive electricity supply would need to represent at least 1 MW of load in any control area. Control areas are operated in Washington by Seattle City Light, Tacoma Power, Puget Sound Energy, PacifiCorp, Grant County PUD, Chelan County PUD, Douglas County PUD, Washington Water Power, and BPA.

1.1.2 Customer Characteristics

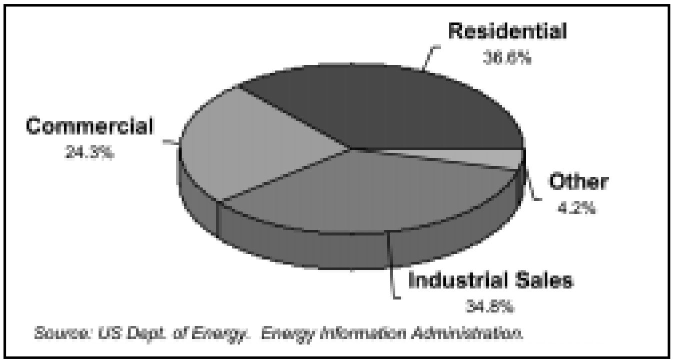
Washington's utilities serve approximately 2.6 million customer accounts. Of these, residential homes and apartments represent 88 percent of the total. Commercial customers (including medium-sized businesses, schools, hospitals, offices and retail stores) make up 10 percent of accounts, and large industrial customers, street lighting and irrigation make up the remaining 2 percent. The proportion of sales to commercial and industrial customers exceeds their share of the customer base, reflecting higher electricity usage levels of these customers. These customer class proportions are especially influenced by the 10 large industrial accounts served directly by BPA or over BPA transmission.

Figure 1.8 Washington Customers by Sector
Washington - 1996



Source: US Dept. of Energy. Energy Information Administration.

Figure 1.9 Proportion of Washington Electricity Use by Customer Class
Washington - 1996



The wide variation in per-customer electricity consumption among the customer classes is further described in Table 1.10. Based on data reported by utilities, the table depicts the number of customers whose annual electricity usage (kWh) or electricity demand (kW) falls within the specified range. The majority of electricity customers (65 percent) use fewer than 10,000 kWh annually. Some proposals recently discussed for introducing competition in retail electricity service establish a threshold of 1 aMW. Table 1.10 indicates that about 300 customers use more than 1 aMW of electricity annually. Among customers metered and billed on the basis of peak demand, the utilities report that 765 register an annual peak demand of 1 MW or more. The figures in this table represent a sample of more than 90 percent of Washington's electricity customers. So, while the figures in Table 1.10 capture the pattern of customer electricity use, they do not represent complete state totals.

Table 1.10 Distribution of Customers by Annual kWh and Annual Peak kW.

KWh (000)	# of Customers	Cumulative %	Peak KW	#of Customers	Cumulative %
0 to 9	1,460,749	64.98	0 to 99	12,981	52.2
10 to 49	739,478	97.88	100 to 149	3,958	68.2
50 to 99	18,699	98.71	150 to 199	2,079	76.5
100 to 200	11,621	99.23	200 to 249	1,234	81.5
200 to 499	10,129	99.68	250 to 299	852	84.9
500 to 999	3,617	99.84	300 to 349	645	87.5
1000 to .5 aMW	2,749	99.96	350 to 399	496	88.5
.5 to 1 aMW	477	99.99	400 to 449	414	91.2
1 to 2 aMW	166	99.99	450 to 499	310	92.4
2 to 4 aMW	78	100.00	500 to 999	1,118	96.9
> 4 aMW	70	100.00	> 1 MW	765	100.0
Total in Sample	**2,247,833**			**24,852**	

Source: 6560 Utility Data Survey
Note: Customers reported by peak kW demand are only those metered and billed for demand.
Note: Does not include BPA direct service industrial customers.

1.1.3 Metering

For billing purposes, utilities install many types of meters to keep track of customer usage. Most meters measure only total accumulated electricity use and peak electricity demand for commercial and industrial accounts. They do not typically record when electricity is used. The capability of installed metering to provide time-of-use information is a key consideration when utilities offer new kinds of service, such as time-of-use pricing or competitive access to alternative electricity providers. According to data provided by utilities for this report, fewer than 2,000, of more than 2.2 million, meters installed in Washington are capable of recording time-of-use to at least an hourly level of precision. Table 1.11 indicates that the majority of these meters are in the commercial and industrial sectors.

Table 1.11. Distribution of Standard and Time-of-Use Meters, by Customer Class.

(Number of meters. [Fraction of meters in class])

	Residential	Commercial	Industrial	Total
Standard (Cumulative kWh/kW)	1,967,735	213,852	9,191	2,190,778
Time of Use (site or remote read)	642 [<.04%]	875 [.4%]	412 [4.3%]	1,929 [.09%]
Total Meters	1,968,377	214,727	9,603	2,192,707

Source: 6560 Utility Data Survey

While the preceding figures and tables capture the statewide character of utility demographics, they do not capture the diverse character of Washington's electric service providers. Table 1.12 demonstrates that the smaller utilities, mainly cooperatives, serve predominantly residential customers and customers categorized as "other" (often irrigation loads). The investor-owned utilities and PUDs also show a high proportion of residential loads, but have substantial industrial load as well. The municipal utilities demonstrate the most even pattern across the classes. Finally, BPA's retail service in Washington is almost exclusively industrial, the remainder going to federal agencies.

Table 1.12 Proportion of Retail Sales (kWh) by Customer Class for Each Type of Utility.

Utility Type	Residential	Commercial	Industrial	Other	Total
BPA	0.0%	0.0%	93.1%	6.9%	100%
Cooperatives	57.3%	21.4%	3.6%	17.7%	100%
Investor-Owned	45.7%	34.5%	19.4%	0.4%	100%
Municipal	35.4%	25.4%	29.4%	9.8%	100%
P.U.D.	41.5%	24.0%	32.5%	2.0%	100%
Total WA sales	36.6%	24.3%	34.8%	4.2%	100%

Source: Energy Information Administration. 1996.

1.2 Washington Electricity Rates

Electricity rates in Washington are set for investor-owned utilities by the UTC, and by city councils, boards, or other local governing bodies for public utilities. In both cases, rates are fundamentally based on the average cost of providing electricity service. A more detailed discussion of the way in which rates are developed is included in Section 4.0, Electricity Rates and Equity. Before comparing rates among utilities and between the state and the nation, two clarifications are necessary.

First, the *structure* of utility rates — the way in which individual utility bills are calculated — varies significantly among utilities. This variation includes how much revenue is collected from basic charges, capacity demand charges and energy charges. Decisions about how to structure rates in a fair and equitable way are made by state or local regulators based on the nature of the customer-base being served. We have focused our analysis on the average rate. This is the revenue collected from customers divided by customers' electricity usage. The average rate is not affected by variations among utilities in the way customer bills are structured to include basic charges, seasonal energy rates, capacity charges and energy block charges.

Second, utility costs vary depending on the nature of the territory the utility serves. For example, many small rural utilities must maintain distribution systems to serve very dispersed customer loads. This may lead to higher service costs per customer than would be the case for an urban utility. Utility costs also depend on the age of the utility system, which can affect capital costs and the degree of maintenance required. While we have not attempted a detailed study of these differing cost circumstances, it is important to keep them in mind when comparing average rates among utilities.

Two sources of information are used for examining utility average rates. The first is information reported by utilities in response to the 6560 information survey. These data include utility revenue, customer counts and electricity use for each customer class for 1993 to 1997. The utility-reported data were provided by those utilities not exempted from the 6560 legislation, and therefore only covers 12 utilities plus six others that volunteered information. These utilities make up approximately 88 percent of total state utility sales. The remaining utilities include relatively small cooperatives, mutuals, public utility districts, municipal utilities, irrigation districts, and BPA service to a limited number of direct service industries. For these utilities, we have relied on data collected and reported by the United States Department of Energy's Energy Information Administration (EIA). EIA data are reported annually for all utilities based on information reported by the utilities to EIA and other federal agencies. For both the 6560 data and EIA data, utilities categorize information into the basic customer classes: residential, commercial, industrial and other (including street lighting, irrigation and unclassified uses). Based on these two sources, Appendix 1.1 includes average rates for each utility and for each customer class for the years 1993 through 1997. In the following sections, we examine statewide average rates by customer class and utility category, how these rates compare with national averages, and trends in both state and national rates. Table 1.13 presents statewide average rates for each of the customer classes for each of the years 1993 through 1997.

Table 1.13. Average Rate to Washington Customers 1993-1997, Cents per Kilowatt-Hour

Sector	1993	1994	1995	1996	1997
Residential	4.63	4.95	5.01	5.08	5.01
Commercial	4.50	4.70	4.81	4.92	4.82
Industrial	2.97	3.16	3.25	3.19	3.07
Other	4.03	3.96	4.27	4.21	4.49
All Sectors	4.14	4.38	4.47	4.53	4.44

Sources: Utility Data Reported to 6560 Study.

Taking 1996 as a year for comparison, Table 1.14 compares Washington average rates with national averages for each customer class. For all customer classes, Washington is not only substantially below the national average, but when all states are ranked, Washington is the lowest or near the lowest in all categories.

Table 1.14 Washington Electric Rates Compared to National Average - 1996

(Ranked by statewide rates, where 1=lowest; 50 states + District of Columbia)

Category	Washington Rank	WA average rate (cents/kwh)	US average rate (cents/kwh)
Residential	1	5.0	8.4
Commercial	2	4.9	7.6
Industrial with BPA	2	2.9	4.6
Industrial without BPA	2	3.0	4.6
All Sectors	3	4.5	6.9

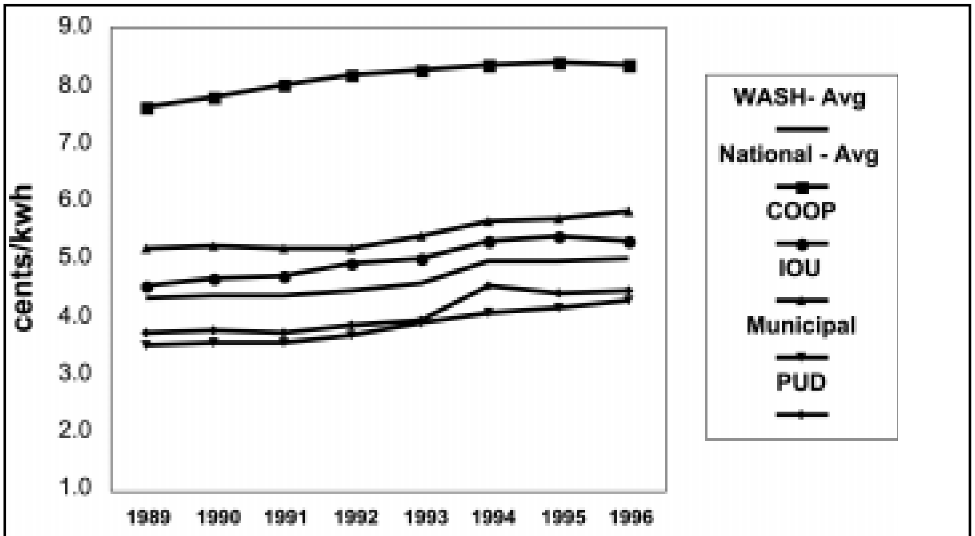
Source: Electric Sales and Revenue 1996, DOE/EIA-0540.

EIA data includes all customers, so is more complete than data reported for 6560.

1.2.1 Residential Rates

All utilities reporting information in our study offer a basic residential rate to homes and apartments for standard domestic uses. A few utilities offer more than one residential rate depending on such factors as electric space and water heating, but, in general, a single tariff covers utility service to the residential class. Figure 1.15 compares statewide residential average rates with the national average for the years 1989 through 1996. During this period, the national average rate increased by 0.71 cents/kWh or about 9.3 percent. For comparison, during the same period the Consumer Price Index measurement of inflation increased by nearly 35 percent. The Washington residential average rate also increased over this period by 0.70 cents/kWh. On a percentage basis this increase is 16.3 percent. The percentage increase may be higher for Washington than the nation because our average rates started at a lower level.

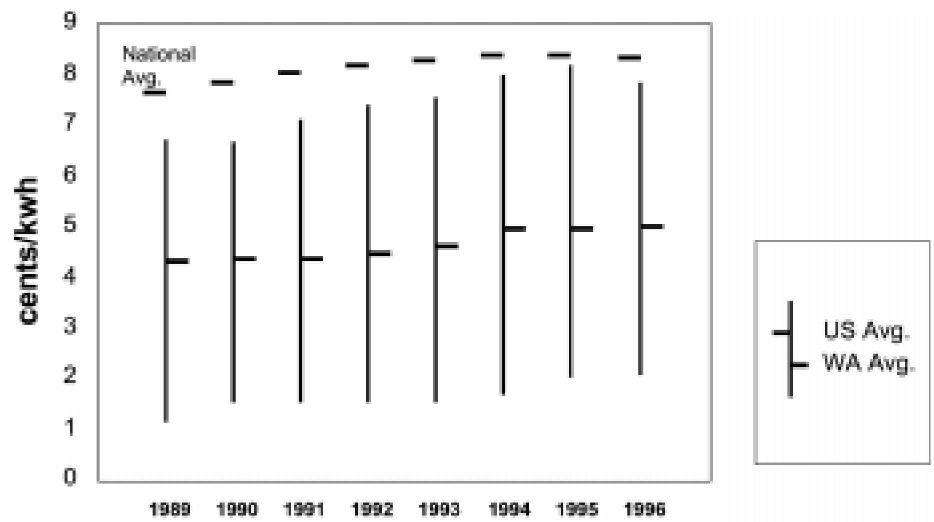
Figure 1.15 Residential Rates



Sources: Energy Information Administration. 6560 Survey of WA Utilities.

Figure 1.16 Range in Washington Residential Rates

Compared to National Average



Source: Energy Information Administration and 6560 Survey Utility Data.

Figure 1.15 also plots statewide averages for each major category of utility. Differences in these rates reflect not only differences in utility costs related to type of ownership, but also the nature of the areas being served. Typically, cooperatives and relatively small public utilities serve rural areas and the municipals serve urban areas. The investor-owned utilities serve a mix of urban and rural areas as do many of the public utility districts. While there is variation in average rates among the utility types, all show modest upward trends in average rates; all are substantially below the national average.

Figure 1.16 takes a more detailed look at variation among the state's 60-some utilities by plotting the full range of average rates in comparison to the national average. This figure demonstrates that even those utilities having the highest residential rates in Washington are still lower than the national average.

The average rate paid by residential customers does not reveal very much about the average customer's actual electricity bill. Table 1.17 examines average annual electricity usage for Washington residential customers in 1996, as well as the average annual bill. Both of these figures are compared with national averages. This comparison points out that the average annual electricity bills of Washington residential customers are also below the national average, but not by as much as our rates. This is because customers in Washington use about 33 percent more electricity per year than the national average, probably as a consequence of our low rates, and possibly because of a lack of natural gas availability for some utility customers in rural areas.

Table 1.17 Average Annual Residential Electricity Use and Bill.

	Annual Use (kWh)	Annual Bill ($)
Washington Average	14,000	710
National Average	10,300	859
WA Investor-owned	12,900	750
WA PUD	17,000	756
WA Municipal	12,200	521
WA Cooperatives	16,900	900

Source: Energy Information Administration

Commercial rates serve a very diverse customer sector. Customers in this sector vary from small offices, restaurants, gas stations and grocery stores to high-rise office buildings of millions of square feet. The sector also includes schools, hospitals and government buildings, as well. Most Washington utilities offer a range of rates that include at least a small and large commercial tariff. Some others offer a greater range of services. Eligibility for commercial service tariffs is typically determined by load level, either connected kW load or minimum energy use, or both. Commercial rates typically include both an energy charge and a kW demand charge. Figure 1.18 tracks the total number of commercial tariffs offered by the 18 utilities reporting data to the 6560 study. The number and variety of service tariffs offered in the commercial sector remained relatively constant over the period 1993 to 1997.

Figure 1.18 Commercial Tariffs Offered
As reported for HB 6560 Study

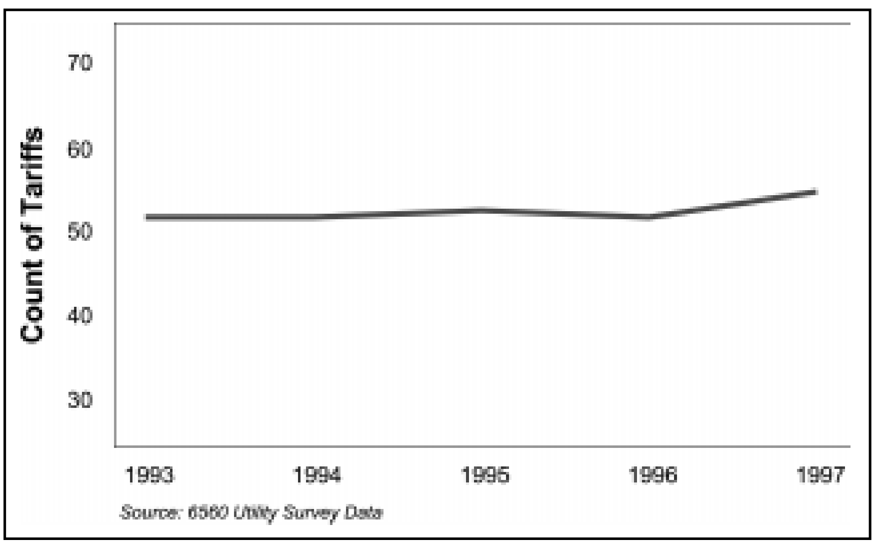
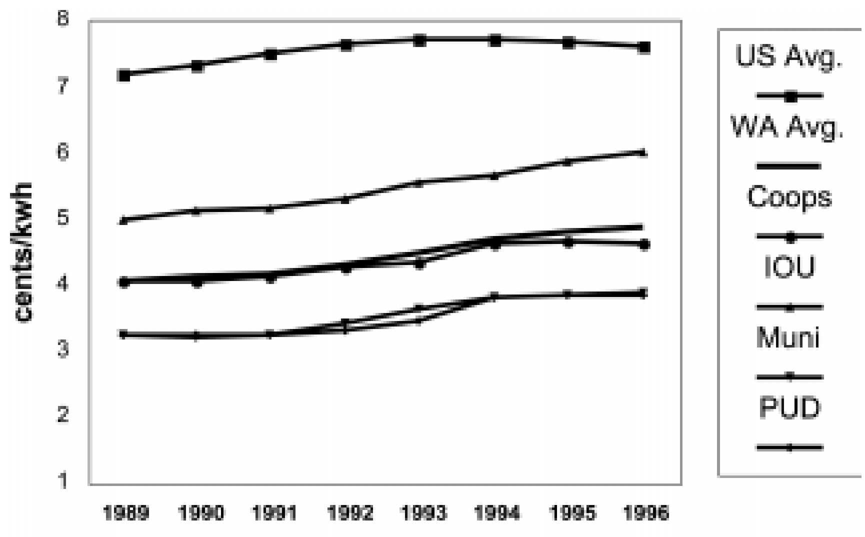


Figure 1.19 compares statewide commercial average rates with the national average for 1989 through 1996. During this period, the national average rate increased by 0.45 cents/kWh or about 6.2 percent. The Washington commercial average rate increased over this period by 0.82 cents/kWh, or 20.0 percent. About half of the difference in percentage increase is again explained by rates starting at a lower level.

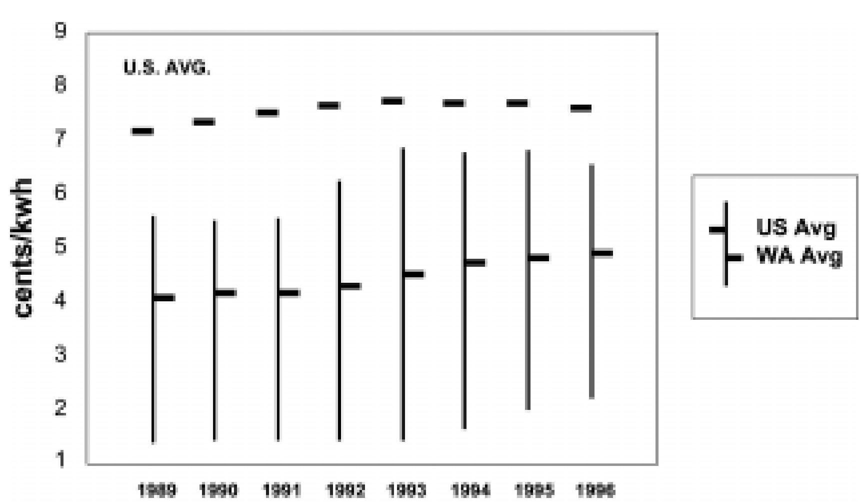
Figure 1.19 Commercial Rates



Source: Energy Information Administration and 6560 Utility Survey.

Figure 1.20 Range in Washington Commercial Rates

Compared to U.S. Average



Source: Energy Information Administration and 6560 Utility Data Survey.

Figure 1.19 also plots the statewide average rates for each major category of utility. Again, the differences in these rates reflects not only the differences in utility costs related to type of ownership, but also the nature of the areas being served. Typically, cooperatives and relatively small public utilities serve rural areas and the municipals serve urban areas. The investor-owned utilities serve a mix of urban and rural areas as do many of the public utility districts. While there is variation among the utility types, all show modest upward trends in average rates and all are substantially below the national average.

Figure 1.20 provides a more detailed look at variation among the state's 60 plus utilities by plotting the full range of average commercial rates in comparison to the national average. This figure demonstrates that even those utilities having the highest commercial rates in Washington are lower than the national average.

1.2.3 Industrial Rates

Industrial class rates present some data interpretation and analysis problems. While utilities traditionally have provided one or more average cost-based tariffs for industrial and other large service loads, recent years have seen an increasing variety of services and pricing in the industrial sector. These include special customer-specific contracts, market-based pricing, and unbundled delivery service. The 6560 study information provided by utilities reported all of these tariffs, contracts and other services separately. We have included all of these categories of service in the overall industrial class averages to reflect what affect they have had on overall industrial class rates. In addition, we have attempted to break these "non-traditional" services out for separate examination later in this section. In the case of unbundled services (retail wheeling) we have not included revenue and delivered kWh in the averages for industrial rates because the data do not include the energy component of service. This portion of service is provided by entities other than the utility based on negotiated prices and, as such, is not reported to either the federal agencies or to the utilities. It is unavailable and therefore cannot be included. This complication was encountered only for Washington Water Power's pilot program.

We have tracked rates charged by BPA to the direct service industries separately. These 10 large industrial customers are the only industrial customers in Washington served directly by the federal government without a state utility intermediary that is regulated either by the UTC, or by a local jurisdiction.

Figure 1.21 presents the total number of industrial class service tariffs reported by the 18 Washington utilities submitting information to the 6560 Study. The number of services offered has grown over the period 1993 through 1997, reflecting the efforts of utilities to tailor services more closely to the specific circumstances of industrial customers.

Figure 1.21 Industrial Tariffs Offered

As reported for HB 6560 Study

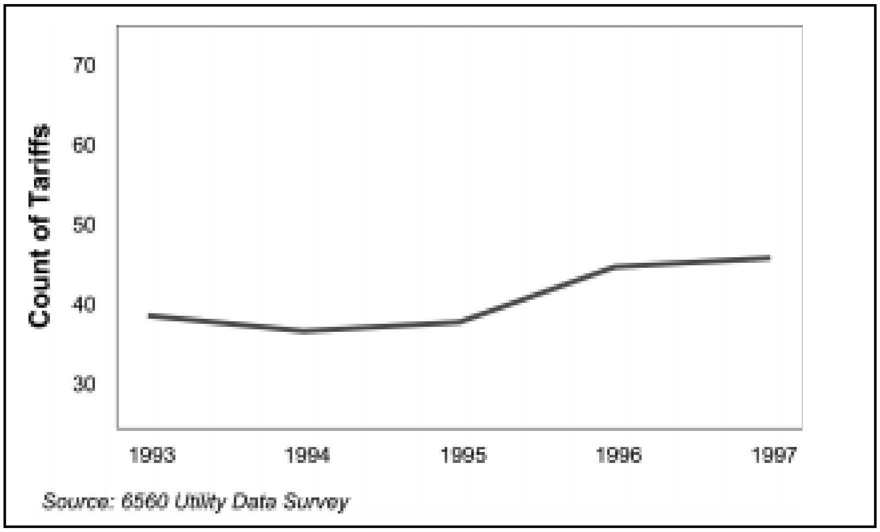


Figure 1.22 compares statewide industrial average rates with the national average for 1989 through 1996. During this period, the national average rate *decreased* 0.12 cents/kWh or 2.6 percent. The Washington industrial average rate, excluding BPA's direct industrial sales, increased over this period by 0.52 cents/kWh, or 19.3 percent. Figure 1.22 also plots the statewide averages of industrial customer rates for each major category of utility, including BPA. The figure demonstrates variation among the utility types due at least in part to the factors cited above for residential and commercial rates. The average rates for all the utility categories show upward trends, but all of the averages remain below the national average.

Figure 1.22 Industrial Rate Comparisons

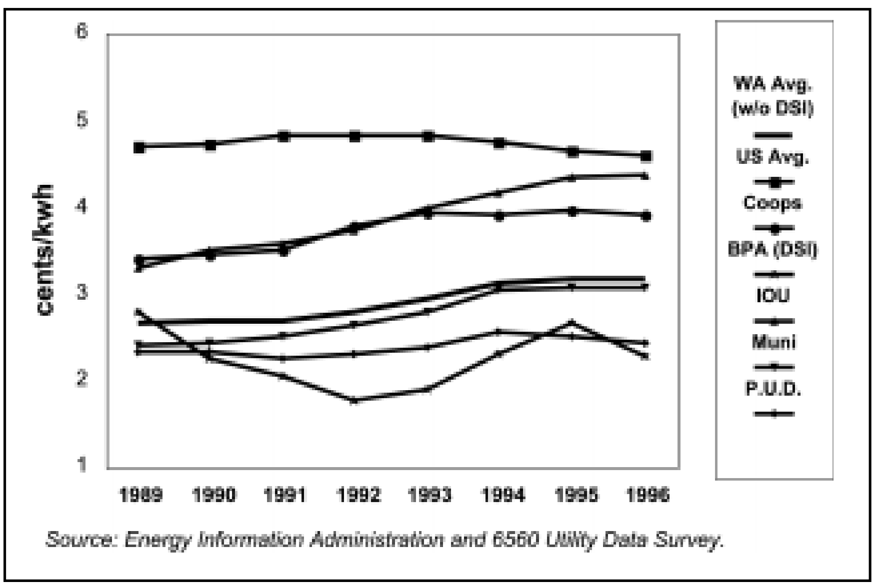
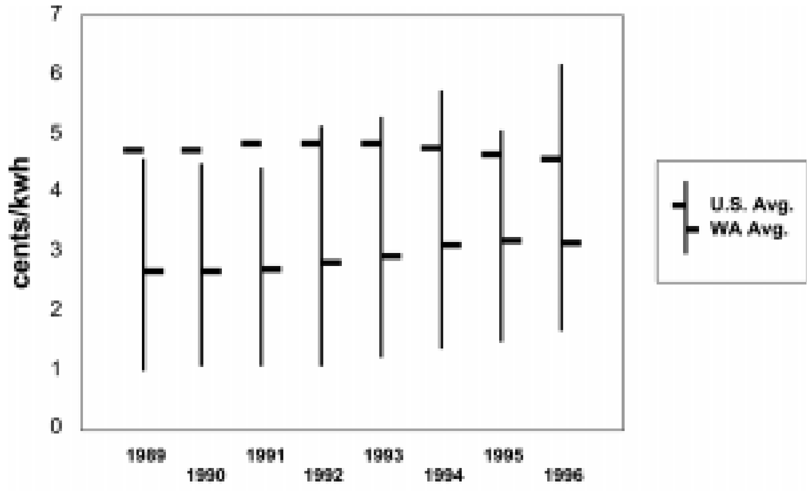


Figure 1.23 Range in Washington Industrial Rates



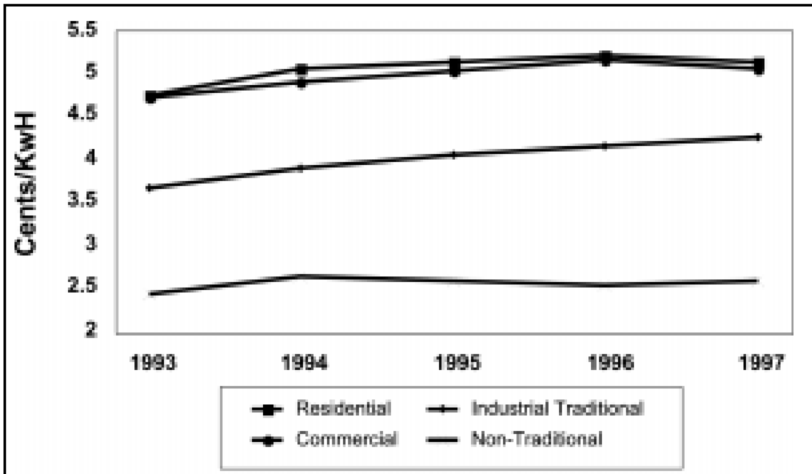
Source: Energy Information Administration and 6560 Utility Data Survey.

Figure 1.23 provides a more detailed look at variation among the state's 40 plus utilities that offer industrial rates by plotting the full range of average industrial rates in comparison to the national average. This figure demonstrates that, while the average industrial rate is lower than the comparable figure for the nation, the national figure has been declining and the state average increasing. Over the last several years some utilities in Washington are shown to have average industrial rates that exceed the national average.

To examine the trends in services reported by the utilities as non-traditional, Figure 1.24 plots the average rates for service under these tariffs along with average rates for industrial services not characterized by utilities as non-traditional. The term non-traditional tariff was defined in the 6560 survey instructions as "…any departures from bundled service priced at embedded cost including market-based electricity rates, unbundled services, or customer specific special contract pricing."

Figure 1.24 Comparative Rates by Sector

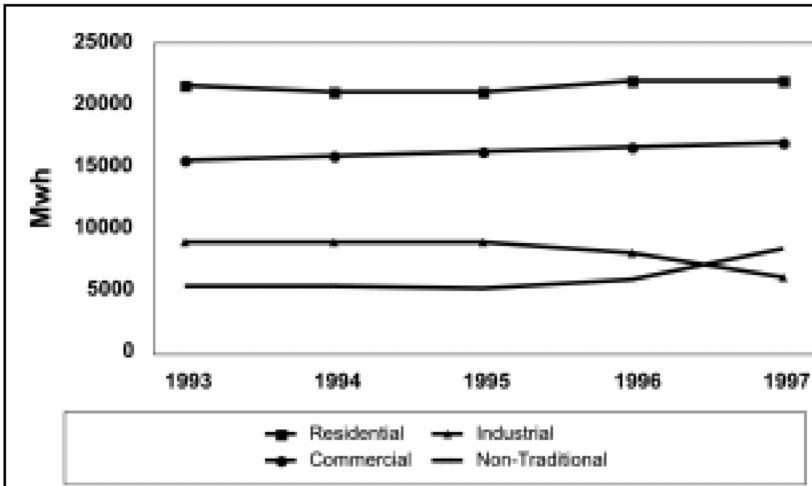
Utilities with Non-tradional Rates



Source: 6560 Utility Data Survey

Figure 1.25 Annual MWH Delivered by Sector

Utilities with Non-tradional Rates



Source: 6560 Utility Data Survey

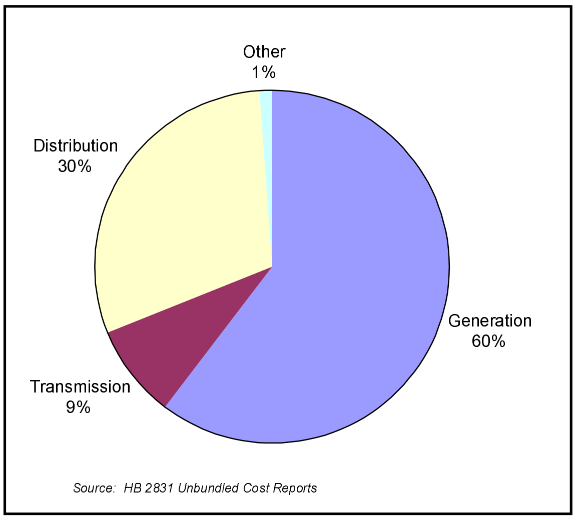
Several trends are apparent from these figures. First, a clear shift from traditional, embedded cost tariffs to non-traditional service began in 1995 (Figure 1.25). Second, the average rate for non-traditional service is significantly lower than for traditional industrial service. A pattern of increasing rates for the industrial loads not served under the non-traditional rates is also clear. This trend may represent a cost-shift within the industrial class; it may reflect that loads remaining on traditional service are fundamentally different from those taking non-traditional services, or it may have been due to a BPA rate increase in this time period which was passed through to these customers. The trend towards non-traditional service represents a fundamental change in the way utilities allocate costs and risks among customers and customer classes. Figure 1.24 does not provide evidence that the trend towards non-traditional service has caused rates to *increase* for the commercial and residential classes. However, these classes have not experienced either the rate *decreases* or any changes in risk that customers taking non-traditional service may have over the last three years. This issue is further explored in Section 4.0, Electricity Rates and Equity.

1.3 Costs for Generation, Transmission, and Distribution

The following subsections characterize Washington's costs of electric power service, broken down by generation, transmission, and distribution. These costs underlie the rates discussed above. Most of the data for these characterizations are drawn from the data that utilities reported for the HB 2831 study. In keeping with that study's cost categories, generation costs include demand-side management and control area services. Distribution costs include customer account services and metering and billing.

The pie chart below shows the share of total (internal) costs in each category for the utilities reporting under HB 2831. While all three of these components represent significant costs, generation is both the largest and perhaps the most susceptible to changes associated with recent trends toward competition.

Figure 1.26 Internal Costs by Category for HB 2831 Reporting

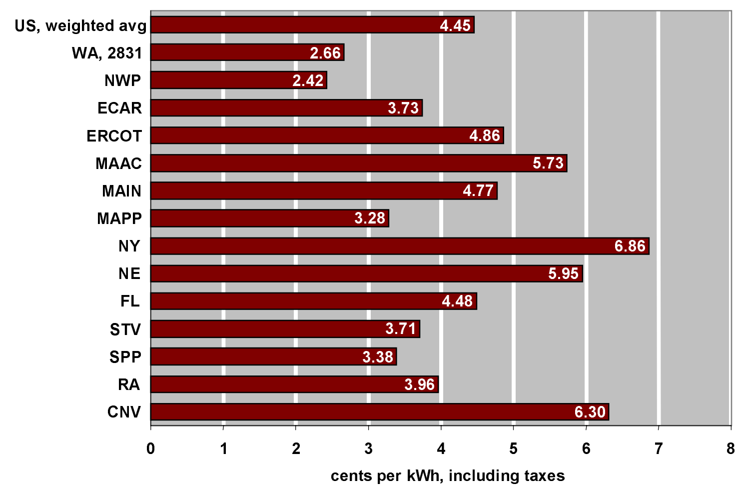


1.3.1 Generation

1.3.1.1 Average Generation Cost for Washington Compared to Other Regions

The most significant factor distinguishing the existing cost profile of Washington's electric power system is the predominance of relatively low-priced electrical generation. The average cost of electrical generation as reported by the utilities submitting unbundled cost data under HB 2831 is 2.66 cents per kWh. The US Energy Information Administration estimates that average cost of electric generation for utilities nationally is 4.45. (EIA figures are derived from National Energy Modeling System modelling runs, rather than actual survey data. We do not know whether EIA groups costs into generation, transmission, and distribution in exactly the same manner as the HB 2831 study.) The average cost of generation in Washington and the Northwest are compared to average costs for generation in other regions in Figure 1.27.

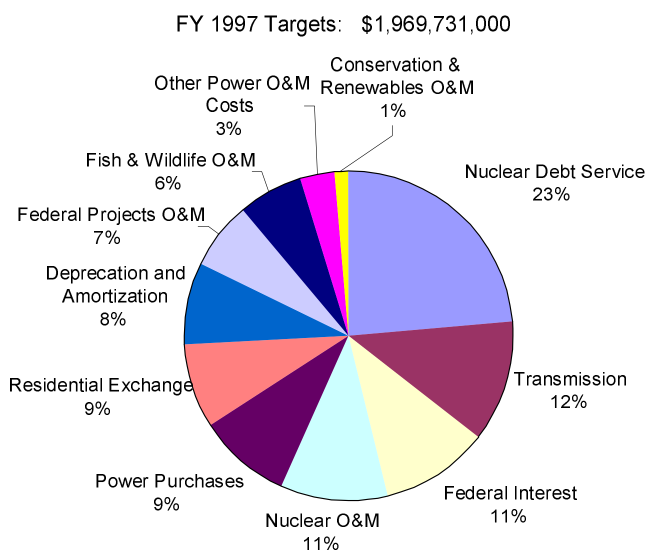
Figure 1.27 Comparison of Generation Costs



1.3.1.2 Preferential Access to Federal Generation Resources at Cost-Based Rates.

Approximately half of Washington's electric power comes from the Federal Columbia River Power System. The price of power from the FCRPS is approximately 2.3¢ per kWh. The FCRPS consists primarily of hydropower. However, while nuclear generation accounts for only 7% of FCRPS output, it represents about one third of the cost of power from the system (including debt service on terminated plants). The costs of the FCRPS also include costs associated with accomplishment of BPA's statutory missions, including the costs of serving low-density rural systems; the costs of mitigating damage to fish and wildlife; and the cost of investments in energy efficiency and new renewable resources. Figure 1.28 shows the breakdown of Bonneville's costs among various categories.

Figure 1.28 Bonneville Power Business Line Expenses

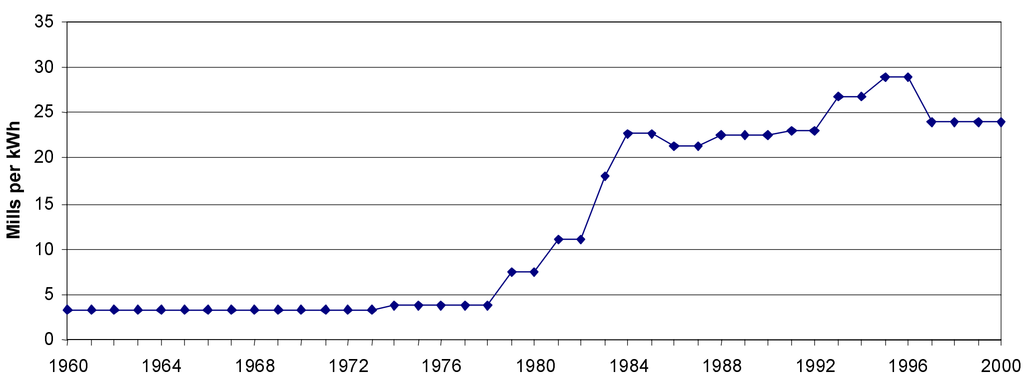


Source: Bonneville Cost Review

The price of power from the FCRPS has remained relatively low and stable since the system was put into service, with the exception of a dramatic increase in wholesale prices from 1979 to 1983, when the costs of the WPPSS nuclear plants were absorbed in BPA rates. Today's rates are very close to their 1983 level in nominal terms. In real terms, they have declined since 1983.

The difference between the cost of power from the Federal system and its value historically has been quite large. That difference accrues to the beneficiaries of cost-based rates from BPA: Northwest public agencies, the residential and small farm customers of investor-owned utilities, and BPA's Direct Service Industrial customers, primarily aluminum smelters. It is difficult to evaluate how large this difference is likely to be in the future. However, according to the Northwest Power Planning Council, it appears to be substantial under a fairly wide range of assumptions about future market conditions and federal system costs (See Figure 1.29). Intense interest in securing allocations of FCRPS power in the current BPA subscription process confirms the growing perception that the value of this power will continue to exceed its cost.

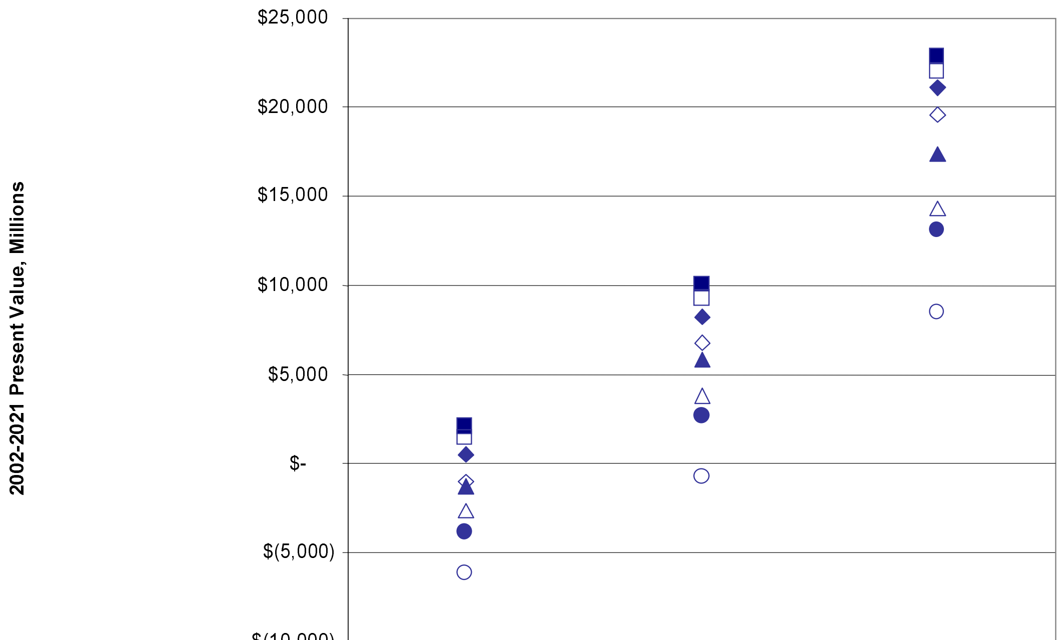
Figure 1.29 Bonneville Rates, 1960-2000



Source: Bonneville Power Administration

Figure 1.30 shows the long-term value of the FCRPS under a variety of scenarios for salmon recovery strategies and market conditions. As indicated in the chart, market price is probably the most significant uncertainty in assessing the value of the federal system over the next 25 years. In the low market scenario, the real price of power climbs from 17 mills/kWh in 1998 to approximately 19 mills in 2007, before beginning a gradual decline to 13 mills by 2021. In this scenario, the net present value of the federal system is negative for five of eight salmon recovery scenarios studied by the Council. In the high market scenario, where prices climb to 35 mills by 2005 and remain there through 2021, the system is worth several billion dollars under all salmon recovery scenarios. The medium market scenario foresees real prices of 23-25 mills from 2000-2021. Only the most expensive fish cost option, involving a five dam drawdown, flow augmentation, and modification of remaining dams for Clean Water Act compliance, results in a net present value for the system of less than $2.5 billion.

Figure 1.30 Projected Value of Federal System Under Various Scenarios



	Low Market Price	Medium Market Price	High Market Price
■ Reduced Flow Augmentation	$2,045	$9,995	$22,770
□ 95 BiOp	$1,450	$9,201	$21,944
◆ Transportation Plus	$474	$8,253	$21,061
◇ Transportation Plus, Clean Water Act (CWA)	$(994)	$6,784	$19,593
▲ Lower Snake Drawdown	$(1,244)	$5,834	$17,346
△ Lower Snake and John Day Drawdown (Five Dams)	$(2,663)	$3,832	$14,317
● Five Dam Drawdown, CWA	$(3,896)	$2,599	$13,084
○ Five Dam Drawdown, Flow Augmentation, CWA	$(6,219)	$(763)	$8,470

1.3.1.3 The Prevalence of Hydropower in Washington's Resource Mix, and Particularly the Prevalence of Large Hydro Projects

Because Washington is part of an integrated regional grid, it is not possible to determine exactly how much of the electricity generated for Washington consumers is hydropower. However, we can get a good indication by looking at the power generated in a slightly larger region. In the four Northwest states (Washington, Oregon, Idaho and Montana), hydropower accounted for 85% of electric generation in 1996. Of this amount, projects larger than 300 MWa accounted for 77%. For a variety of reasons including scale, these larger projects tend to produce lower-priced power.

1.3.1.4 The Age of Washington's Resource Mix

Very little electric generating capacity has been added in the region in the last decade. As a general rule, older projects tended to have lower construction costs, were financed at lower interest rates, have already amortized much or all of their capital costs, and may have internalized fewer environmental costs.

1.3.1.5 The Prevalence of Publicly-Owned Generation

Publicly-owned generating resources account for nearly three-fourths of total electric generation serving Northwest consumers (again, it is impossible to calculate a mix of resources serving Washington customers alone). These resources were financed with tax-exempt debt and the cost of power from these resources to consumers does not include return on equity (where that power is delivered by publicly-owned distribution utilities). As a result, and all other things being equal, the price of power from these resources is lower. (The extent to which these price advantages represent cost advantages may be arguable; for example, different tax treatment for public resources may affect the distribution of costs and benefits as well as the magnitude of costs and benefits.)

1.3.1.6 The Environmental Cost Profile of Washington's Generation

Most conventional forms of electrical generation carry significant environmental costs. Some of these costs are internalized in the form of pollution controls or fish and wildlife mitigation requirements, for example. Others, such as health impacts due to air emissions, remain external to the price of power, but are significant costs nonetheless. In Washington, significant environmental costs of the existing system include:

- Damage to fish and wildlife, particularly to threatened and endangered anadromous fish, associated with hydropower development
- Air quality, human health, and ecosystem impacts associated with extraction of fossil fuels and emissions from fossil-fueled generating resources.
- Prospective or current changes to local ecosystems (including hydrology, forests, ocean temperatures, sea levels, etc.) and human health impacts associated with climate change.
- The risk of health impacts associated with radioactivity released from nuclear power plants or their waste products.

Environmental costs are generally difficult to estimate in economic terms. However, the magnitude of these costs can have a significant impact on the overall cost-effectiveness of some resources.

1.3.1.7 Variations in Generation Costs Among Utilities in Washington

Generation costs among Washington utilities reporting data for the HB 2831 study range from a low of .96 cents per kWh to a high of 3.49 cents per kWh. Figure 1.31 below depicts reported costs for generation, transmission, and distribution for each of the utilities reporting under HB 2831.

Figure 1.31 Unbundled Cost Summary by Utility

Utility	Generation [1]	Transmission	Distribution [2]	Total Cost
		cents per kWh		
PacifiCorp	2.50	0.72	1.65	4.88
Puget	3.49	0.55	1.50	5.54
Wash. Water Power	2.82	0.38	1.60	4.80
Benton	2.10	0.53	0.96	3.59
Chelan	0.96	0.06	0.74	1.75
Clark	3.01	0.11	0.77	3.89
Cowlitz	1.98	0.01	0.29	2.29
Grant County	1.38	0.30	0.82	2.51
Grays Harbor	2.53	0.32	1.72	4.57
Snohomish	2.75	0.20	1.88	4.84
City of Richland	2.65	0.01	1.07	3.74
Seattle City Light	1.86	0.36	1.70	3.92
Tacoma Utilities	2.55	0.14	0.84	3.53
Washington State (Surveyed Utilities)	2.66	0.36	1.33	4.34
Low	0.96	0.01	0.29	1.75
High	3.49	0.72	1.88	5.54

Source UTC. *Washington Electric Service Quality, Reliability, Disclosure and Cost Report.* December 1, 1998 ("2831 Study")

1) Includes demand side management, non-hydro renewables, fish & wildlife mitigation, and control areas services as per 2831 study.

2) Includes customer account services, metering and billing, and "other" costs as per 2831 study.

1.3.2 Transmission

1.3.2.1 Transmission System Characteristics

The West, and particularly the Northwest, is more dependent on the transmission of power over the interstate, high-voltage grid than is the rest of the country. Much of the Northwest's generating capacity is located along the Columbia and Snake Rivers in eastern Washington and Idaho, or at coal fields in Montana or Wyoming, far from load centers in the Puget Sound area and the Willamette Valley.

The region's generation is tied to load by an extensive high-voltage transmission network that is dominated by the federal system. Bonneville was authorized by the Bonneville Project Act of 1937 to "set rates to extend the benefits of an integrated transmission system and encourage the widest possible diversified use of Federal power." This authority was broadened by the Transmission System Act of 1974, which directed the BPA Administrator to build transmission facilities "within the Pacific Northwest as [s/he] determines are appropriate and required to: (a) integrate and transmit the electric power from existing or additional Federal or non-Federal generating units; (b) provide service to the Administrator's customers; (c) provide interregional transmission facilities; or (d) maintain the electrical stability and electrical reliability of the Federal system."

Bonneville has used this authority to construct an extensive federally-owned transmission system, including some transmission facilities that are only marginally connected to the FCRPS such as the 500 kV lines that connect Montana Power's Colstrip lines to the Northwest. As a result, the federal system accounts for some 80% of the region's high-voltage transmission wire.

1.3.2.2 Variations in Transmission Costs among Washington Utilities

On average, transmission accounts for around 10% of total costs for Washington utilities. However, costs for transmission vary greatly among Washington utilities. Transmission costs reported by utilities in the unbundled cost report for HB 2831 ranged from .72 to .0089 cents per kWh. (Using the uniform cost allocation methodology developed for the IndeGO proposal, transmission costs for these same utilities ranged from a high of .3795 cents per kWh to a low of .1918 cents per kWh. Transmission costs by utility are included in Figure 1.31.)

Variations in transmission costs among Washington utilities may be attributable to a variety of factors, including but not limited to: the extent to which they own their own transmission and/or generation; distances between loads and generation; load factor (the relationship of peak demands to average consumption); and geographic factors.

1.3.2.3 External Costs of Transmission

Environmental costs associated with the transmission system are primarily related to siting concerns. High-voltage transmission facilities require wide rights-of-way from which all vegetation must be cleared and along which roads must be maintained. Typical issues that would be raised in an environmental impact statement therefore include the impact on wetlands, wildlife, and wilderness areas. Visual impacts and cultural impacts are often of concern to communities affected by high-voltage transmission lines. Some studies suggest that prolonged exposure to electromagnetic fields (EMFs), such as one would experience living near a high-voltage transmission line, may cause cancer. Other studies have found no link between electromagnetic fields and cancer. Research continues into whether such a link exists.

1.3.3 Distribution

1.3.3.1 Variations in Distribution Costs among Washington Utilities

Differences in density are commonly cited as the primary reason why distribution system costs vary among utilities. Utilities with a large proportion of their customers in rural areas have more miles of line to construct and maintain on a per customer basis. This makes costs higher for utilities that are predominantly rural. The data collected for the 6560 and 2831 studies show that there is a strong countervailing factor, however. Constructing and maintaining distribution lines is more expensive in urban areas than in rural areas on a per mile basis, due to higher costs for rights of way, higher percentage of wires underground, more expensive labor, and a number other reasons. Cost per mile shows a strong inverse relationship to density.

The result is that the cost per kWh doesn't vary nearly as much as one might expect, at least among the utilities that reported data for the unbundling study. Distribution costs reported under 2831 ranged from .72 to 1.85 cents per kWh. However, distribution costs per mile of line ranged from $7,241 per mile to $81,290 per mile.

Another way to compare distribution system costs is to look only at the distribution system costs that are allocated to residential customers. This should correct for the fact that some utilities have higher concentrations of industrial customers, which would result in lower system-wide costs on a per-kWh basis. Residential distribution costs vary from a low of 1.26 cents per kWh to a high of 2.39 cents per kWh. Rural, eastside utilities generally show lower costs on a per kWh basis. However, customers of these utilities consume more electricity per year than customers in more urbanized areas, in part because they may have less access to natural gas for heating. The result is that customers in those areas often pay more, on an annual basis, for distribution services despite the lower unit price. Annual residential distribution costs ranged from $206 to $480 per customer. Distribution costs by utility are presented in Figure 1.31.

1.3.3.2 External costs of distribution

The environmental costs associated with the distribution system are similar to those described above for transmission wires. Concerns about visual impacts, in addition to reliability considerations, have caused many utilities to begin putting wires underground, at least for new developments. Concerns about EMFs have generated resistance to siting facilities such as substations in neighborhoods.

2.0 Trends affecting electric service costs

Overview

This section of the report describes trends affecting electric service costs for Washington consumers in six broad categories:

1. **Wholesale markets**
2. **Retail markets**
3. **Supply adequacy and reliability**
4. **Environment**
5. **Technology**
6. **Fuel cost**

This section will primarily address trends that affect total electric service costs. Trends and strategies that concern distribution of costs are covered more fully in Section 4, Electricity Rates and Equity: The Potential for Cost-shifting.

2.1 Wholesale markets

2.1.1 Federal Policy Changes and the Introduction of Wholesale Competition

Perhaps the most important and far-reaching trend affecting electric power costs is the change taking place in the market structure for power generation. Beginning in 1978 with the passage of the federal Public Utility Regulatory Policy Act (PURPA), non-utility generators have played a growing role in developing new power supplies. PURPA required investor-owned utilities to purchase power from non-utility generators if the price was less than the utility's own cost to build new generation. Although PURPA had a limited impact on most Washington utilities, it opened the door for companies other than utilities to build and own generation.

This change was accelerated by the passage of the federal Energy Policy Act in 1992. EPACT was intended to create a fully competitive wholesale market for generation, and spurred a number of developments that furthered that goal. One of these developments is the formation of regional transmission associations (RTAs) in the western interconnection to facilitate access to the regional transmission grid.

In 1996, the Federal Energy Regulatory Commission (FERC) issued its Order 888, "Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities". Order 888 requires transmission owners to offer transmission services to other companies under the same terms and conditions that they offer it to themselves. It also encourages the formation of independent system operators (ISOs) to provide open access to the transmission system under a grid-wide tariff that would apply to all eligible users. All jurisdictional utilities are required to file open access transmission tariffs with FERC that meet the specifications in the order, and to provide service to themselves and to other companies under the terms of those tariffs.

These developments have greatly increased the ability of generators to gain access to the transmission grid. The combination of these regulatory changes and low natural gas prices has resulted in increasingly active short-term markets for electric energy. Power is now traded on an hourly basis at trading hubs such as the Mid-Columbia bus, on a day-ahead basis on the California Power Exchange, and in the form of futures contracts on the New York Mercantile Exchange. Utilities now have a ready market in which to sell surplus generation to other utilities or to purchase power from other utilities or non-utility generators.

The development of active short-term markets, in conjunction with enhanced access to the transmission grid, may tend to lower the price of electric generation by maximizing the aggregate efficiency of the existing bulk power system. That is, an efficient market should help to ensure that whenever a low-cost resource and a high-cost resource are both available, the low-cost resource is called upon first. There is some evidence to suggest, however, that active short-term markets have increased utilization of resources with relatively high environmental costs.

One of the features of these markets is price volatility. Volatility may occur as prices continuously adjust to balance supply and demand at any given time. Electricity markets are likely to be particularly volatile, especially on an hourly basis, because electricity cannot be stored; so supply and demand must balance instantaneously. This means that utilities have very little time to arrange for alternate supplies in the event of an emergency. One such emergency occurred in the Midwest during June of 1998, when market prices soared to over $7.00 per kWh. This extreme volatility was caused by a series of extraordinary events including a heat wave, generating unit outages, transmission constraints, and defaults on power supply contracts by two power marketers. The combination caused confidence in the market to wane, leading to panic buying of whatever power was available.

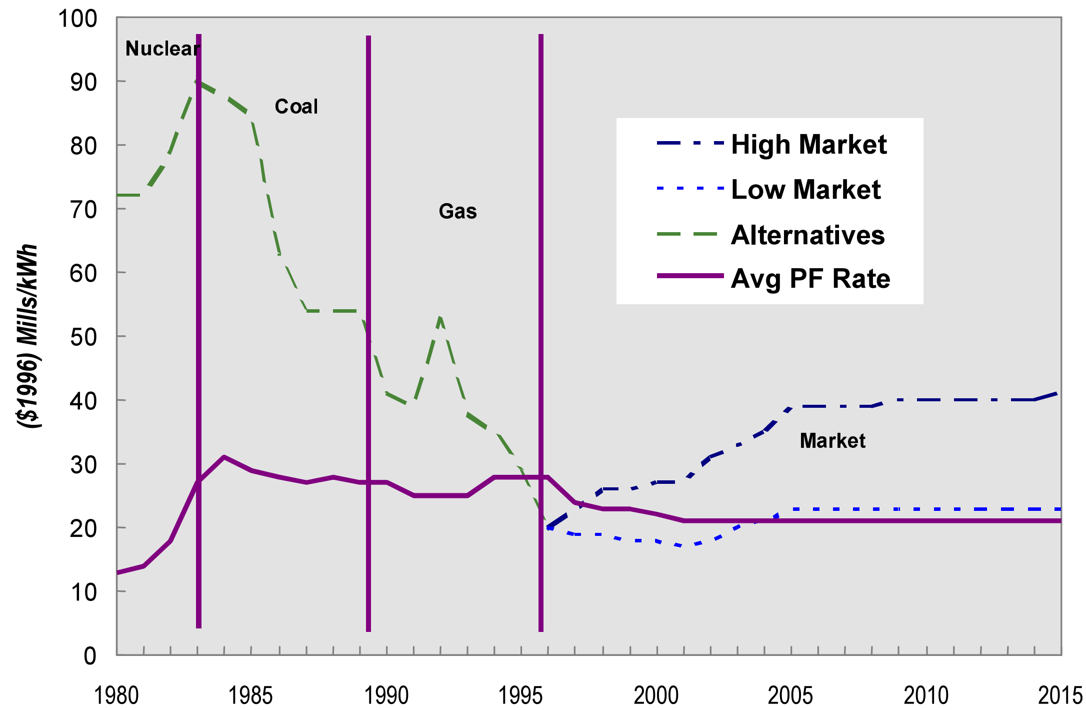
Volatility does not mean that power markets necessarily result in higher costs than traditional utility planning, in which enough capacity is built to meet an administratively determined probability of being able to meet all loads. Indeed, market volatility might result in capacity savings if price-sensitive customers (those that have the ability to modify their consumption based on price) purchase power on the open market. These customers would be free to make whatever arrangements they wished to hedge their risk against price volatility, while the utility would be freed from the obligation to manage the risk on behalf of those customers. On the whole, this may be a less costly way to balance supply and demand in peak periods than the traditional practice of building utility capacity to meet infrequent peak demands. It does, however, allow for conspicuous price swings.

2.1.2 Effects of wholesale competition on BPA and Federal Columbia River Power System

Although Washington has not initiated any significant changes in its retail market, Northwest states were among the first to experience significant effects from the introduction of wholesale competition. This is due to the tremendous importance of the Bonneville Power Administration in the region. BPA is a federal power marketing agency that operates exclusively at the wholesale level (with the exception of its Direct Service Industrial customers, to whom BPA provides retail service). The agency provides approximately half of the power consumed in Washington and operates 80% of the high voltage transmission in the State.

The effects of wholesale competition on BPA have been significant. As the graph below shows, the price of alternative power sources plummeted in the early 1990s, reaching and briefly falling below BPA's price in 1995. It is worth noting that this challenge to BPA's competitiveness does not appear to have been caused by increasing costs at BPA. BPA's prices have stayed virtually flat in nominal terms and declined somewhat in real terms since the dramatic increases associated with the WPPSS projects in the early 1980s. Competitive pressure was induced primarily by reductions in the price of alternative power sources.

Figure 2.1 Avoided Cost of Generation and Future Market Price Projections vs. BPA Average Rate



Sources: BPA Business Plan and 1996 Rate

When the price of alternative resources approached BPA prices, BPA embarked on a series of controversial changes in an effort to improve its competitive position. These changes included:

- ❖ Seeking a cap on fish and wildlife expenses and an exemption from any Endangered Species Act or other environmental requirements that would push fish and wildlife expenses higher.

- ❖ Terminating its contract to pay for construction and operation of the Tenaska gas-fired generating project.
- ❖ Reversing its preliminary commitment to British Columbia to purchase the "Canadian Entitlement" – power that returns to Canada under the terms of the Columbia River Treaty.
- ❖ Eliminating most of its energy efficiency investments.
- ❖ Large reductions in staff and contractors.
- ❖ Curtailing the Residential Exchange agreements through which BPA extended the benefits of the FCRPS to the residential and small farm customers of investor-owned utilities, including Puget Sound Energy.
- ❖ Developing new marketing strategies that were viewed by some as inappropriate competition with the private sector.
- ❖ Signing transmission contracts and power contracts with the Direct Service Industries that may preclude future recovery of stranded costs from those customers.

Each of these steps met with strong opposition from one or more stakeholder groups. With growing frequency throughout 1995, this opposition was brought to the attention of Congress and executive agencies in Washington, D.C.. Sensing that growing discord in the region was undermining the region's ability to retain the benefits of the federal system for Northwest consumers, the Northwest Congressional delegation and the Department of Energy urged the four Northwest Governors to develop a plan for the future structure of the regional power system. In response, the Governors convened the Comprehensive Review of the Regional Energy System in 1996. The Steering Committee for the Comprehensive Review recommended a variety of changes with respect to the federal power system as a part of a package designed to balance competing interests. These changes included a strategy for marketing the output of the FCRPS to Northwest customers by subscription; formal separation of BPA's transmission and generation functions; and formation of an independent system operator for the transmission system.

Since those recommendations were issued:

- ❖ The Northwest Power Planning Council convened a cost review panel to recommend further reductions in BPA's costs. BPA has agreed to try to implement most of these recommendations. The final recommendations of the Cost Review are included as Appendix 2.1.
- ❖ The Governors appointed a Transition Board to oversee implementation of the Comprehensive Review's recommendations. The Transition Board has focused on the recommendations with respect to BPA's power and transmission operations. It has developed a proposal for recovering stranded costs in the event that BPA's costs exceed market rates and a proposal for subjecting BPA's transmission rates to review by the Federal Energy Regulatory Commission essentially equivalent to the review applied to investor-owned transmitting utilities.

- ❖ BPA will begin the process of offering subscriptions for cost-based power, according to the terms of a proposal issued in December of 1998.
- ❖ BPA is scheduled to begin a rate case that will further define the terms and conditions of those subscription contracts in 1999.

Another important trend affecting the region's ability to sustain the legal right to preferential access to cost-based power from the federal system is the growing pressure to redistribute the benefits of the FCRPS more broadly. This pressure has existed for decades. However the pressure may have intensified in recent years[1] due to a variety of factors, including:

- ❖ The evolution toward competition in wholesale, and, to a lesser extent, retail power markets. With power prices increasingly subjected to market forces, the rationale for continuing to constrain marketing of federal power at cost to a particular geographic region may appear to be eroding.
- ❖ The general trend in other countries and the U.S. away from large public enterprises and toward privatization.
- ❖ Growing concern over how to pay for the large federal entitlement programs as the population ages and the consequent pressure to convert federal assets to cash and/or increase the return to taxpayers from those assets.
- ❖ The increasingly organized advocacy of the Northeast-Midwest Coalition, a large group of members of Congress who call for selling federal power at market rates.
- ❖ The increasingly open nature of transactions throughout the Western power grid and the proliferation in the number of buyers and sellers seeking access to the lowest cost alternatives.
- ❖ The growing frequency with which regional power issues are debated in Washington, D.C. and the perception that federal taxpayers may be exposed to nuclear debt, fish costs, or other costs that BPA fails to recover in its rates.
- ❖ Recent improvement in BPA's market position, due in part to rising western wholesale market prices.

If these pressures converge in a way that allows redistribution of the benefits of the FCRPS, Washington's power prices could rise substantially. These pressures will almost certainly come to bear in the context of a national restructuring bill. They are likely to persist even in the absence of such a bill.

2.1.3 Effects of both wholesale and retail competition on the connection between existing generation and "native loads"

Historically, electric generating resources were built or purchased to serve a particular set of consumers. Those consumers had few, if any, options for electric service and their utilities were required to serve their loads. In this environment, consumers could generally expect to pay the costs and receive the benefits of a specific set of electric generating resources that were built to serve them.

With growing competition in both the wholesale and retail markets in the Western grid and major realignments of some vertically integrated utilities, this connection between customers and resources is becoming increasingly tenuous. Typically, the erosion of this connection has manifested itself as a "stranded cost" issue: When the connection between customer and resource is broken by competition, and the resource is worth less than it costs, who bears the portion of the costs that cannot be recovered through market rates ("stranded costs")? In Washington, the more significant issue may be on the other side of the coin: When the connection is broken, who reaps the benefits that accrue to resources that are worth <u>more</u> than they cost ("stranded benefits")?

Resolution of these questions may substantially affect the cost of electric service in Washington. These questions may have somewhat different implications for investor-owned and consumer-owned utilities, since the latter have no shareholders to bear stranded costs or reap stranded benefits. However, the prospect of redistribution of the benefits of low-priced resources is a concern for both types of utilities and their customers. Insofar as resources used to serve Washington consumers are below market, erosion of the connection between "native resources" and "native loads" will tend to increase costs for Washington consumers, unless measures are taken to preserve the financial benefits of those resources for those customers.

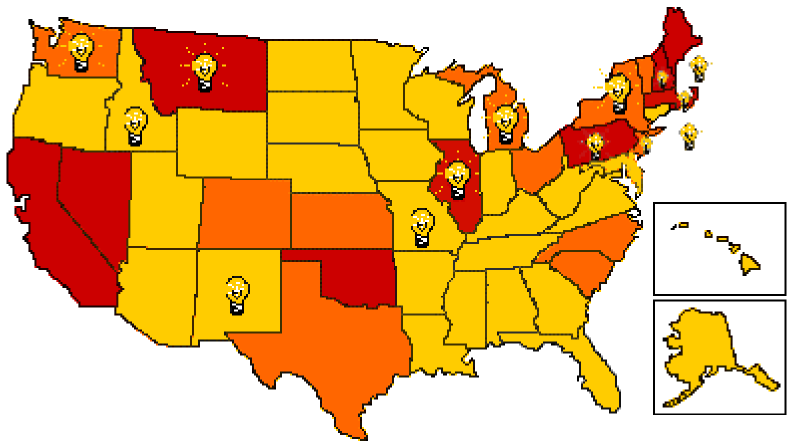
2.2 Retail market developments

2.2.1 Federal and state restructuring initiatives

Congress considered mandating retail access in its deliberations on the 1992 Energy Policy Act, but elected to defer the issue pending state action. Subsequently, federal restructuring legislation in various forms has been introduced but not yet seriously debated in Congress. Appendix 2.2 provides a comparison of some of the major features of the federal electric restructuring bills that have been introduced to date.

According to the Edison Electric Institute, all 50 states and the District of Columbia have initiated "legislative or regulatory processes examining retail competition, deregulation, restructuring, and/or alternative forms of regulation for the electric utility industry."[2] The National Regulatory Research Institute also confirms that all states have engaged in some restructuring-related activity.[3]

Figure 2.2 Status of Electric Utility Restructuring Activities



Retail Wheeling Legislation Passed
Retail Wheeling Legislation Proposed
Legislative or Regulatory Activity
Indicates states where pilot programs have been initiated or approved

Source: Strategic Energy Limited, http://www.sel.com/retail.html
This site includes links to detailed information on each state

The impetus for retail restructuring came largely from industrial customers in states with high power prices, like California and the New England states.[4] Seeing the growing disparity between retail power rates and the price of power in wholesale markets, these customers sought direct access to lower cost power supplies. Gaining this access generally meant changing state laws and/or regulatory requirements to compel utilities to deliver power from the provider of the customer's choice.

Even the first states to restructure are still in the early stages of implementing their restructuring laws or administrative orders. (A detailed comparison of state electric restructuring legislation provisions is provided in Appendix 2.3.) No meaningful conclusions can yet be drawn from the experience in these states with respect to the effect of retail restructuring on electric service costs. The prospects for future federal and state restructuring efforts and the pace of those efforts remain unclear.

It should be noted that Washington's electric power system is unique in its mix of federal, state, and local institutions and in the mix of authorities and responsibilities among those institutions. These unique features suggest that a model of restructuring that may work for states with less complicated systems may not be applicable in Washington. This is not to suggest that retail restructuring is impossible or undesirable, but rather that it raises a variety of unique issues that make it difficult to generalize from experience elsewhere. Washington is also unique in its mix of investor-owned and consumer-owned utilities. Most of the states that have restructured their retail markets have adopted different requirements for COUs and IOUs. Many of these states require IOUs to offer direct access but permit COUs to do so. However, COUs that do not elect to offer direct access are generally not permitted to sell to customers of utilities that do offer direct access.

Most of the arguments about whether retail restructuring will reduce electric service costs remain inconclusive. These arguments are briefly characterized in Section 3.2.

2.2.2 Retail market developments in Washington and the Northwest

At the end of 1996, the Comprehensive Review of the Regional Energy System recommended that the four Northwest states restructure their retail electric markets by July of 1998.[5] Montana is the only state to have enacted restructuring legislation and has begun to implement retail choice. Restructuring bills were considered by the Washington and Oregon Legislatures in 1997. (The Oregon Public Utility Commission is currently considering a restructuring plan filed by PGE/Enron.) The issue was considered again by the Washington Legislature in 1998, but no comprehensive restructuring bills were introduced. Bills requiring large utilities to account separately for the different components of electric service (HB 2831) and requiring state agencies to study various aspects and trends in the industry (ESSB 6560) were passed. This study is the product of the latter bill.

Although the Washington Legislature has not initiated any action to restructure Washington's retail electric market, that market is changing substantially. While utilities have not been compelled to deliver power from alternative providers, they are nevertheless experiencing and responding to significant competitive pressures and opportunities. Some of these changes, and some of their potential implications for electric service costs, are described below:

2.2.2.1 Pilot retail access programs

Several utilities have conducted pilot retail access programs, including Puget Sound Energy, Washington Water Power, and Clark PUD. Prices offered in pilots may bear very little relationship to prices in a system-wide retail access environment. Pilots have generally been structured to test operational issues, rather than to test the effects of competition on costs or prices.

2.2.2.2 "Non-traditional" rates

Most utilities have provided some form of either direct access or market-based rate schedule to their largest industrial customers. These have resulted in substantial recent declines in industrial rates. However, some customers are opting out of market-based rates and returning to conventional regulated service as wholesale market prices turn upward. We cannot judge whether this retail market activity has resulted in either cost reductions or cost shifts. To the extent that these customers enjoyed lower rates, this may be due to lower costs in the wholesale market that would have ultimately flowed through to retail customers even in the absence of market-based rates for industrial customers.

In response to the data survey for this study, fifteen utilities provided data on "non-traditional" rate offerings. These rates generally reflect either a market-based price or an agreement by the utility to purchase market power on behalf of the customer, as opposed to the traditional practice of charging rates based on the average cost to serve the customer class. The data indicate that cost pressure due to declining wholesale market prices can have a direct impact on utility rates, even in the absence of mandatory retail access.

Seven of these fifteen utilities offered "non-traditional" service to large customers in 1997. Five of the seven have seen participation in non-traditional service grow rapidly since 1995. A total of 418 customers were taking "non-traditional" service in 1997, accounting for nearly half the industrial load of the reporting utilities.

Figure 2.3 Share of Large Customer Load

	Share of Large Customer Load Taking Service Under "Non-Traditional" Rate Schedule
1995	*19%*
1996	*25%*
1997	*47%*

Source: ESSB 6560 Data Request

The average price at which "non-traditional" service was offered was 2.8¢ per kWh, more than half a cent lower than the average of the lowest industrial rate. This represents an average discount of 17% off the lowest reported industrial rate. The largest reported discount was 36% off the lowest industrial rate. The power products sold at these discounted rates may carry some price and supply risks.

Including these non-traditional rates, large customers have seen an average rate decrease of around 5% since 1995, while residential rates have remained relatively flat. Of the fifteen utilities reporting, thirteen reduced rates for their industrial customers between 1995 and 1997, and eight reduced the rates of their residential customers. Many of these were consumer-owned utilities that lowered rates following BPA's 1996 wholesale rate reduction. Industrial rates declined relative to residential rates for thirteen of the fifteen utilities. (The distributional impacts of non-traditional rates are discussed in Section 4.)

Figure 2.4 "Non-Traditional Service" Rate Information (Average of Reporting Utilities)

Average rate for "non-traditional" service(¢/kWh)	2.79
Average of lowest reported industrial rate (¢/kWh)	3.39
Absolute difference from lowest industrial rate (¢/kWh)	-0.60
Percent difference from lowest industrial rate	-17%

Source: ESSB 6560 Data Request

2.2.2.3"Diversification" of consumer-owned utility purchases

Many consumer-owned utilities took advantage of BPA's offer to "diversify" their resources by reducing their reliance on BPA in 1996. In some cases, they used this opportunity to offer market access or market-based rates to industrial customers. This was a way to pass through the benefits of low market prices without formal retail access. Diversification was also used by some utilities to make wholesale market purchases on behalf of all their customers.

2.2.2.4 Variations in tax exposure

By contracting directly with out-of-state suppliers, a few customers may avoid paying state and local taxes associated with utility service. We do not know how this may affect costs, since it either results in shifting of the tax burden or reduction in public services funded through taxes. Since the taxing jurisdiction presumably judges the benefits of those services to exceed the cost, reductions in those public services do not equate with reductions in cost. The present magnitude of this cost issue does not appear to be very large, unless and until more customers gain access to out-of-state suppliers. (See Section 4. See also Appendix 4.1 "Briefing Paper on Tax Policy and Restructuring the Gas and Electricity Industries," Washington Department of Revenue, November, 1998.)

2.2.2.5 Aluminum companies diversify supplies

The state's aluminum companies have diversified their resources and now purchase roughly 25% of their power from sources other than BPA. Like their BPA purchases, most of these purchases are untaxed at the state and local levels, as they do not flow through a retail electric utility. Since these purchases generally replace untaxed BPA purchases, they do not reduce tax revenues. These companies also have relatively new transmission contracts with BPA that give them direct access to the wholesale power market. The effect of this diversification on total costs, if any, is not known.

2.2.2.6 Declining achievement of energy efficiency, renewable resources, and low-income weatherization

Utility investment in energy efficiency, renewable energy, and low-income weatherization is declining rapidly. (See Section 9). While lower wholesale power costs explain some of this decline, much of it is due to competitive pressure on utilities to minimize rates. The rapid decline in BPA funding for these initiatives has generally not been offset by increased funding from retail utilities. Insofar as these investments secure cost-effective resources or otherwise produce benefits that exceed their costs, declining investment may raise total costs. For example, the Northwest Power Planning Council estimates that failing to capture cost-effective energy efficiency improvements that market forces will not capture would cost the Northwest region roughly $1.7 billion over the next 20 years.[6]

2.2.2.7 Competition and cost-cutting pressure raises concerns with respect to reliability

Reliability-related trends are discussed at length in Section 8 of this report. One concern is that pressure on integrated utilities to cut generation costs may cause underinvestment in maintenance and operation of delivery systems and thereby compromise their reliability. These utilities may also face uncertainty regarding their ability to recover the cost of reliability-related investments. We have no data on trends in reliability-related investments.

2.2.2.8 Transition costs

Some information suggests that utilities are experiencing costs associated with preparing for the possibility of greater competition in the future. For example, enhanced billing and metering technology, software changes, and the costs of compliance with HR 2831 and ESSB 6560 were all cited by utilities as costs related to competition or the prospect of competition. Data from California and the UK suggest that these transition costs may be significant in retail markets that have been legally restructured to provide open access.[7] We have no data on these costs in Washington, nor have we assessed what additional benefits may come from these investments.

2.2.2.9 Corporate realignment and reintegration

Investor-owned and consumer-owned utilities are engaged in a variety of mergers, acquisitions, realignments, and new partnerships to position themselves to take advantage of strengths, shore up vulnerabilities, and compete in new markets. Some large utilities appear to be focusing primarily on their wholesale marketing activities, while others are selling or plan to sell their generating assets to concentrate on expanding their range of activities in the retail market. Consumer-owned utilities including Chelan PUD and Snohomish PUD have formed marketing partnerships with investor-owned utilities or their affiliates. Public utilities are also beginning to provide and/or seeking authority to provide a wider range of services, including gas and telecommunications.

The effects of these trends on costs are far from clear. In general, mergers and acquisitions are nominally motivated by economies of scale or scope and the potential for cost reductions through the integration of complementary services. However, they may also be formed to take advantage of opportunities to exert horizontal market power. Some have expressed concern (and others have expressed hope) that partnerships formed for wholesale marketing may lead to wider access of consumers across the western grid to the benefits of low-priced resources that currently serve Washington consumers. (From a Washington perspective, this could raise costs; from a west-wide perspective, it could shift costs and benefits. Also, it should be noted that increased wholesale marketing of Northwest resources does not by itself redistribute the *benefits* of those resources. Unless existing laws and regulation that link Washington utilities and consumers to those benefits are changed or weakened, Washington consumers may benefit from increased wholesale marketing, insofar as wholesale revenues are credited against revenue requirements to lower retail rates.) Expansion of the range of services offered by consumer-owned utilities may lower costs for some services in some areas, but also raises concerns about competition between public and private service providers.

2.2.2.10 Uncertainty regarding cost recovery and market structure

Uncertainty regarding future market structure has consequences that may affect electric service costs as much as actual changes in market structure. For example, in the face of substantial uncertainties about their future customer base, utilities are generally disinclined to make long-term investments. To the extent that this disinclination is a considered response to uncertainties regarding such factors as technological change, it could tend to help minimize costs. (Washington has ample experience with long-term power investments that turned out to be unnecessarily costly.) However, to the extent that aversion to long-term investment reflects uncertainty about the legal and regulatory framework in which utilities will do business in the future, it may tend to increase costs over time. Such uncertainty could drive costs up and increase volatility by making it difficult to find capital for projects that ensure adequate supply, efficiency, and reliability in the future (See Section 2.3). Such uncertainty also tends to produce a bias against strategies with high proportions of capital costs to operating costs, even when those strategies are the least costly ones available. Without rendering judgement on how these trends will ultimately affect costs, it is worth noting that the concerns above are a function of uncertainty about future market structure rather than any particular change in market structure.

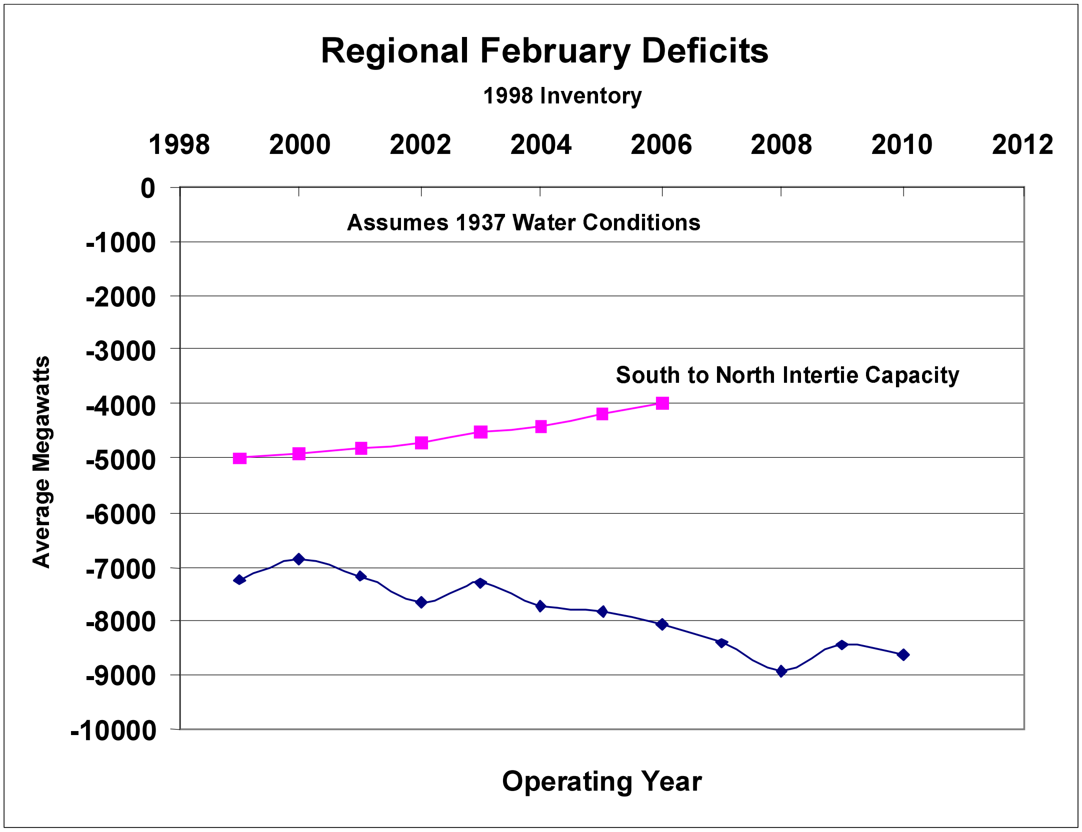
The changes described in 2.2.2 may affect not only the total cost of electric service, but also the distribution of costs, reliability, customer service, and environmental performance – many of the issues highlighted by the Legislature as sources of concern and study in ESSB 6560. This suggests that even if “restructuring” per se does not occur, many of the issues it raises are with us today.

2.3 Supply Adequacy and Reliability

Recent analyses of the Northwest’s power system loads and resources indicate that in some months, the demand for electricity could exceed the region’s current ability to generate and import power to meet regional loads. This analysis was presented in the Bonneville Power Administration’s “White Book.”[8] This issue is addressed as a reliability concern in Section 8. However, it is also a trend that may affect electric service costs, insofar as the means chosen to ensure supply adequacy and reliability may affect the cost of service.

Figure 2.5 provides a simplified view of the issue that was presented to the Northwest Power Planning Council. It shows the monthly regional deficits (current resources minus projected loads) that would occur in February with extremely adverse hydro conditions as represented by the conditions that existed in 1937. The bottom line depicts the region’s power generation shortfall under such conditions. The top line depicts the approximate transfer capability of the North-South intertie, the main source of imported power. Its capability decreases with time as a result of load growth in the Northwest, which affects the ability to move power from south to north on the intertie. The growing gap between the two lines depicts the size of the deficits the region would experience under these very adverse water conditions. A similar but somewhat more severe problem exists when considering the ability to meet sustained peak loads. Those are the average loads during the peak ten hours per day for a five day work-week. During such a period, loads increase and generating capability may decrease due to extreme weather conditions.

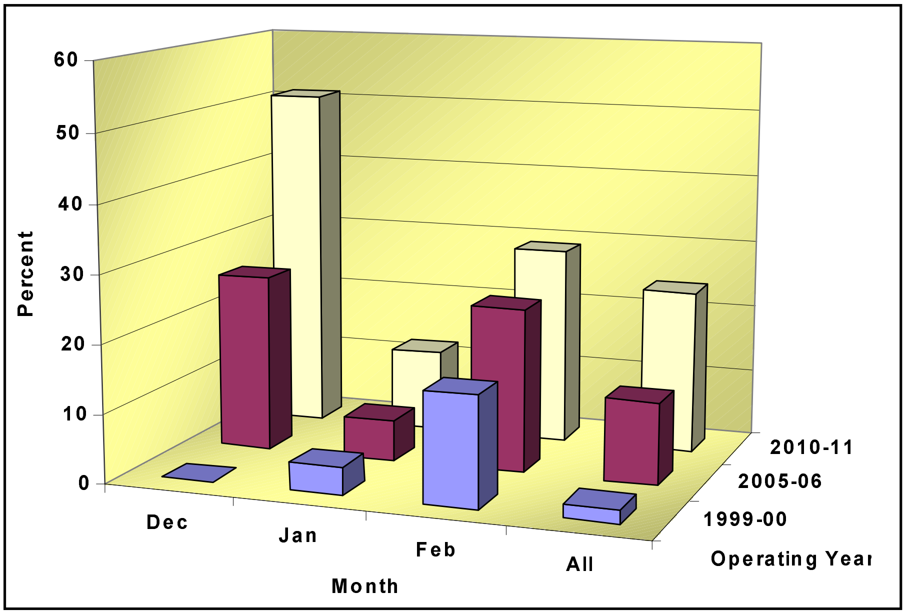
Figure 2.5 Regional February Deficits



The representation of the problem shown in Figure 2.5 is simplified in many respects. One of the most important is that it does not reflect the effects of year to year, month to month variations in hydro conditions. The Columbia River System cannot store the full annual runoff of the basin and the flexibility to use existing storage to maximize power production is increasingly limited. The difference in the hydro system's power capability from the driest to the wettest years is as much as 8000 average megawatts. These variations affect the probability that we will actually experience deficits in any given year.

To begin to assess the probabilities, Northwest Power Planning Council staff have looked at how frequently the regional deficit would exceed import capabilities in each of the winter months (December, January and February), based on the 50 water years in the historical record (1929-1978). This analysis was done for three different future operating years, assuming current regional resources and medium load growth. This is shown in Figure 2.6.

Figure 2.6 Probability of Monthly Energy Shortage



This figure indicates that for the 1999-2000 operating year, the likelihood of deficits in February is about 15 percent. By 2010-11, however, the likelihood of a deficit for December grows to roughly 50%. These deficits have been forecast for a few years now. But the magnitudes are increasing and the time available in which to take actions to avert a shortfall is becoming more limited.

In its preliminary look at this issue, the Northwest Power Planning Council reports that addressing these shortages is complicated by the changing nature of the utility industry. When utilities were less subject to competition, they acquired assets to provide an industry-standard level of reliability, including reserve generation and a robust transmission and distribution system. Regulators allowed investor-owned utilities to recover the cost of those assets in rates, even when some of those assets would be used very infrequently and cause increases in rates. With the prospect of competition, many utilities may be reluctant to include in their rates the cost of acquiring sufficient resources to serve loads that may have no obligation to remain on their system. To the extent that they are planning to meet future load growth, utilities increasingly rely on power purchases rather than constructing their own generation. Under the 1980 Regional Power Act, BPA has primary responsibility for meeting new regional loads when requested. However, many BPA customers no longer rely exclusively on BPA, and others question whether this is an appropriate role for a federal agency.

Additionally, a growing number of power suppliers are not regulated utilities but marketers or brokers who buy and sell power on the wholesale market without necessarily owning resources. Or they may be independent power producers without a captive customer base that assures them recovery of their fixed costs. Some utilities are selling off their generating assets. The result of these trends is increased risk for companies that acquire new generating resources.

This market risk may be compounded by the uncertainty associated with fluctuating output of the hydropower system. Developers have neither a stable market for the output of their resources, nor a guarantee that water conditions will be sufficiently unfavorable that their output is needed in any given month or year. This means that they may have to recover the costs of developing new resources over relatively short and highly unpredictable schedules of operation. The Northwest Power Planning Council has initiated an analysis to determine: 1) Whether existing market incentives are sufficient to bring about the development of new resources (generation, transmission or demand side); and 2) If market incentives are not adequate, what alternatives are there for ensuring the Northwest an adequate, reliable power supply?

The issue of generation adequacy and its affect on reliability is discussed further in Section 8.

2.4 Environment

Environmental costs are a significant component of the total cost of electric service. Power production of various types produces substantial air emissions, nuclear wastes, and significant impacts on water quality and quantity and river flow patterns. Since Washington relies primarily on hydropower, total air emissions from electric resources used to serve Washington consumers are relatively modest.[9] However, hydropower imposes other environmental costs, primarily in the form of damage to river ecosystems and particularly to anadromous fish. While it is difficult to quantify the economic value of hydropower's environmental impacts with precision, these costs are clearly a major factor in decisions about the region's existing and future electricity supplies. The financial cost and effectiveness of current and proposed measures to reduce these environmental costs are the subjects of intense debate.

In evaluating environmental trends that affect the cost of electric service, it is useful to distinguish between *internal* costs and *external* costs. Internal environmental costs are included in rates paid by consumers, such as the costs associated with installing air pollution control equipment or fish ladders. External costs are borne in the form of environmental damage such as habitat degradation or human health impacts.

This distinction between internal and external costs is important in order to clarify the difference between changes in the *amount* of environmental costs and changes in the *distribution* of environmental costs between internal and external categories. For example, measures required to support recovery of endangered salmon stocks may *shift* costs from the external category to the internal category. Prices may rise due to such internalization. However, such price increases do not generally reflect increases in total costs. Internalization of environmental costs increases total costs only if the cost of the mitigation measures exceeds the cost of the environmental damage mitigated. (This may be the case, for example, if the mitigation proves ineffective.)

It is often difficult or impossible to compare the cost of mitigation with the cost of environmental damage. However, when mitigation is required, society has implicitly made a broad, often political judgement that fixing or preventing the environmental damage is less costly than the damage itself. If we collectively do not accept this judgement, then pressure builds to change the laws or regulations that require mitigation. However, where we accept this judgement, then internalization associated with effective mitigation measures may tend to reduce costs, by sending price signals that more accurately reflect total costs.

The trends discussed below have implications for both the amount of environmental costs and the distribution of costs between external categories and internal categories. Many environmental trends may affect electric service costs. However, three trends seem most likely to have a substantial impact on the environmental costs of electric service in the foreseeable future: 1) declining populations and extinction of wild anadromous fish, 2) global climate change, and 3) increasing competition in electric power markets.

2.4.1 Declining populations and extinction of wild anadromous fish

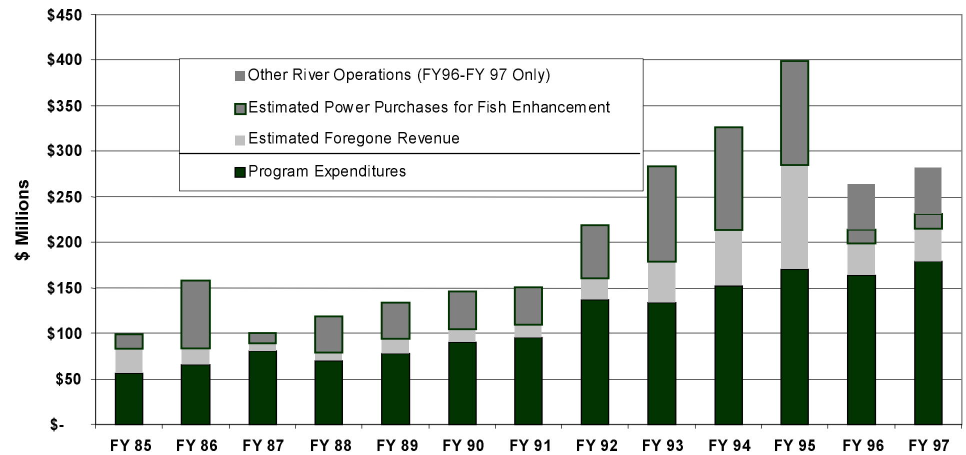
Many factors contribute to the decline of wild salmon and steelhead populations, including habitat destruction, recreational and commercial harvest, consumptive water uses, unfavorable ocean conditions, and competition between wild and hatchery stocks. On many rivers including the Snake and the Columbia, dams and hydropower production also appear to play a significant role in the decline of these populations. The trend in total environmental costs attributable to hydropower can be argued either way.

On the one hand, costs may be rising as genetically distinct stocks near extinction. When a run of fish approaches or falls below the threshold where it can continue to survive as a separate stock, additional costs are incurred in the form of lost genetic diversity, cultural values, and future economic opportunities.

On the other hand, improvements to fish passage facilities, flow regimes, hatchery practices, habitat management, and other biological conditions for fish in recent years suggest that some environmental costs have been mitigated. Many of these costs have been internalized in power rates. To the extent that these mitigation measures have been effective (a hotly contested issue), external environmental costs of hydropower production are presumably lower than they would have been without these measures. Whether the improved conditions attributable to these measures have been worth their costs is also a bitterly disputed issue, in light of continued decline of many wild stocks.

The dollar value of damage to fisheries from hydropower production cannot be assessed with precision. The cultural, biological, and esthetic values at stake are very difficult to quantify and value economically, and the precise affects of hydropower production cannot be definitively separated from other factors that adversely affect these stocks. However, it is clear that more environmental costs associated with anadromous fish decline are being internalized in power rates. The chart below shows the increases in BPA's fish and wildlife expenditures over time as reported in BPA's FY 1999 budget submittal.[10]

Figure 2.7 BPA Fish and Wildlife Costs



Sources: (1) 1985-1995 Data - Department of Energy, FY 1999 Congressional Budget Submittal, BPA, Fish and Wildlife Crosscut. (2) 1996-1997 Data - BPA White Paper, "What is BPA spending for fish and wildlife, March 1998. Available at http://www.efw.bpa.gov/Environment/EW/FISCAL/fiscal1.html
Notes: For FY85-FY 95: BPA Power Purchases for Fish Enhancement and "Foregone Revenues" from Source (1) For FY96 and FY 97: Power purchases, foregone revenue and other river operations from Source (2). FY85- FY 95 Program FY 85-For FY96 and FY 97: Power purchases, foregone revenue and other river operations from Source (2). FY85- FY 95 Program FY 85-FY95: Program expenditures include "Direct Fish and Wildlife Program,, "Reimbursable," and "Program Related Fixed Expenses" from Source (1) and FY96-FY97 "Direct fish and wildlife program,", "Reimbursables," and Debt service on capital investment" from Source (2).
Notes: Characterizing forgone revenue and power purchases as "fish and wildlife costs" is controversial. Such opportunity costs associated with irrigation, navigation, and flood control generally do not appear as budgeted "costs."

2.4.2 Global climate change

In 1995, the International Panel on Climate Change, a collection of 2000 of the world's leading climate scientists, concluded "the balance of scientific evidence suggests a discernable human influence on global climate."[11] While there is significant controversy about global climate change and its policy implications, the IPPC report documents a preponderance of scientific evidence on some aspects of the phenomenon, including the following:

- Global average temperatures have increased over the last century, with marked increases in the last decade;
- Concentrations of carbon dioxide and other heat-trapping gases in the atmosphere are increasing to unprecedented levels, due in part to human activities including burning of fossil fuels;
- Over the historic record, warming trends coincide with periods of high atmospheric concentrations of carbon dioxide.[12]

However, substantial uncertainty remains regarding the timing, magnitude, and local impacts of global climate change. This uncertainty cuts both ways: scenarios under which global climate could change dramatically and abruptly appear to be as likely as scenarios in which change is gradual and less disruptive.

Likely local impacts of climate changes are characterized in a 1997 report from the Joint Institute for the Study of Atmosphere and Oceans.[13] In the Pacific Northwest, the most significant effects may come from reduced snowpack due to warmer winter temperatures. More precipitation is likely to fall as rain in the winter and spring, causing more flooding early in the year and water shortages later in the year. Reduced snowpack means changes in the timing and reductions in the amount of hydropower production (which could be offset by reduction in winter space heating loads), reduced irrigation, warmer water temperatures and lower flows in the summer and fall. These conditions, along with higher ocean temperatures, may reduce the likelihood of salmon and steelhead recovery.[14] Significant impacts to forests, agriculture, coastal areas, and other ecosystems are also likely.[15] Some impacts from climate change may be beneficial. However, human systems are adapted to a relatively stable climate regime. Adaptations to rising sea levels, changed agricultural patterns, volatile weather, and other impacts may be costly.

Scientists indicate that global climate change is attributable to the increase in concentrations of various heat-trapping gases in the atmosphere ("greenhouse gases" or "GHG").[16] Emissions of these gases and their estimated relative contribution to global warming as a share of Washington's total contribution are depicted in the first chart below. The chart also depicts the relative contributions of different activities to GHG emissions in Washington. The following chart tracks GHG emissions by energy source over time.

Figure 2.8 Washington Greenhouse Gas Emissions

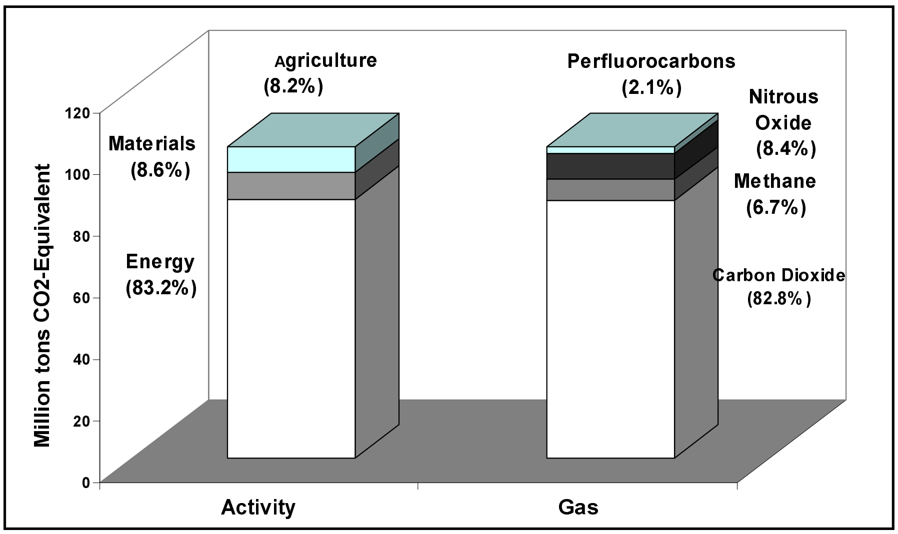
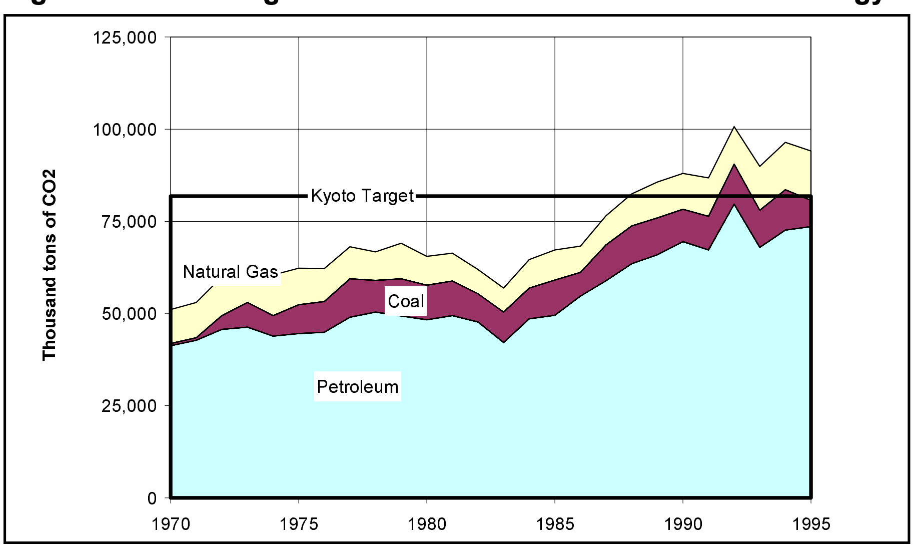


Figure 2.9 Washington Carbon Dioxide Emissions from Energy Use by Source



Transportation is by far the largest and fastest-growing source of greenhouse gas emissions in Washington. However, electricity production is a significant source of carbon dioxide. Most of the carbon dioxide produced by electric generators that serve Washington loads is produced by the Centralia and Colstrip coal-fired power plants in Washington and Montana, respectively. The 1997 Kyoto protocol, negotiated by more than 150 countries, would require the U.S. to reduce its GHG emissions to 7% below 1990 levels by 2008-2012. (Scientists indicate that substantially greater reductions [50-70%] would be necessary to stabilize the concentration of GHGs in the atmosphere.[17]) The U.S. Senate has not ratified the Kyoto Protocol. However, the agreement is a protocol to the United Nations Framework Convention on Climate Change ("Convention"), which President Bush signed and the Senate ratified in 1992. The non-binding U.S. commitment in the Convention is to reduce GHG emissions to 1990 levels by 2000.

Virtually all of the costs of climate change are presently external to electric power prices. Unlike other emissions, carbon dioxide is almost entirely unregulated, and few jurisdictions or utilities have incurred costs to mitigate it.[18] Even though most of our power comes from hydroelectricity, internalization of carbon costs in power prices could have a significant effect on prices in Washington, depending on how it is accomplished. (Here again, internalization of costs in prices does not equate to total cost increases, since higher power prices may be offset by lower external environmental costs.) For example, the Northwest Power Planning Council estimates that carbon taxes of $25 per ton would increase the price of electricity from coal and natural gas in the region by 2.3 cents per kWh and 1.2 cents per kWh, respectively.[19] Fuel switching away from carbon-intensive fuels may mitigate actual effects on power prices.

If and when the costs of carbon dioxide emissions are internalized, Washington's hydroelectric resources would become even more economically valuable relative to fossil-fueled resources. With some 85% of the region's electricity supplied by hydropower, internalization of GHG costs nationally or internationally could significantly decrease the price of power in Washington relative to other states and regions.

While global climate change is probably the most significant environmental trend related to air emissions from energy production, changing regulation of power plant emissions generally may also affect electric service costs. For example, compliance with tier 2 air quality standards of the Clean Air Act Amendments of 1990 will require some generators to reduce emissions of nitrogen oxides and fine particulates. Compliance may reduce health and environmental damages associated with these pollutants while raising the price of power from resources that must undertake mitigation measures.

2.4.3 Increasing competition in electric power markets

Growing competition in electric power markets can affect both the total environmental cost of electric service and the distribution of environmental costs between internal costs (included in power rates) and external costs (not included in power rates). Some of these potential effects are described below.

- *Insofar as competition focuses on minimizing electric power prices, it may increase pressure to increase external costs.* Since prices include only internalized environmental costs, price competition may tend to generate pressure to externalize environmental costs, or at least to avoid internalizing them. However, to the extent that environmental laws require mitigation of external costs, competitive pressure may lead to innovations that reduce the cost of complying with those laws.
- *Competition may tend to undermine utility investment in cost-effective energy efficiency and renewable resources.* Competitive pressure, along with other factors, appears to be reducing investment in and accomplishment of cost-effective energy efficiency and renewable resources. (See section 9). This may be due in part to the fact that conservation resources cease to be a utility asset if the customer in whose facilities the measures are installed switches to another provider. Also, while these resources may minimize total costs, they may not minimize rates, for two reasons. First, energy efficiency reduces consumption and thereby reduces the number of kilowatt-hours sold over which utilities spread their costs. Second, both energy efficiency and renewable resources tend to have lower environmental costs than conventional power sources. Since many of these costs are not included in rates, the environmental advantages of these resources do not improve their ability to compete on price.
- *Competition may increase the availability of "green power" for consumers willing to pay a premium for environmental quality.* "Green power" marketing has already begun in many places, including Washington. Some marketers use premium revenues from sales of "green power" for new investment in resources with low environmental cost or for mitigating environmental damage. This would tend to reduce environmental costs. Other green marketing programs redistribute the cost of existing resources to those consumers who express a willingness to pay more for them. This would not reduce environmental costs. Markets for green resources may tend to exhibit what economists call the "public goods" problem:[20] The environmental advantages of "green" resources are shared by everyone, regardless of whether they choose to pay more for those resources. And by the same token, those who pay more for "green" power must still bear the environmental costs of conventional resources. This public goods problem is the economic rationale for collective investments in military protection, transportation infrastructure, and other goods that cannot be secured in sufficient quantities through private investment alone.

2.5 Technology

Electric technology trends are discussed briefly below. While electricity technology has not been a major focus of legislative debate, it is a subject that may be worthy of somewhat more detailed analysis than the agencies have undertaken within the scope and time constraints of this study.

Technological innovations in both electricity-generating equipment and energy-using equipment have significantly reduced the cost of electricity over time. Ongoing technological changes are likely to include increases in the efficiency of generation, smaller and more distributed generating technologies, decreased production of criteria air pollutants, and growing interaction with information, communications and transportation technologies. These changes seem likely to decrease both internal and external costs of electric generation over time. New technologies are also likely to influence other costs of electricity operations through changes in metering and billing, load control, and greater utilization of infrastructure (e.g. cable or internet additions to power communications networks).

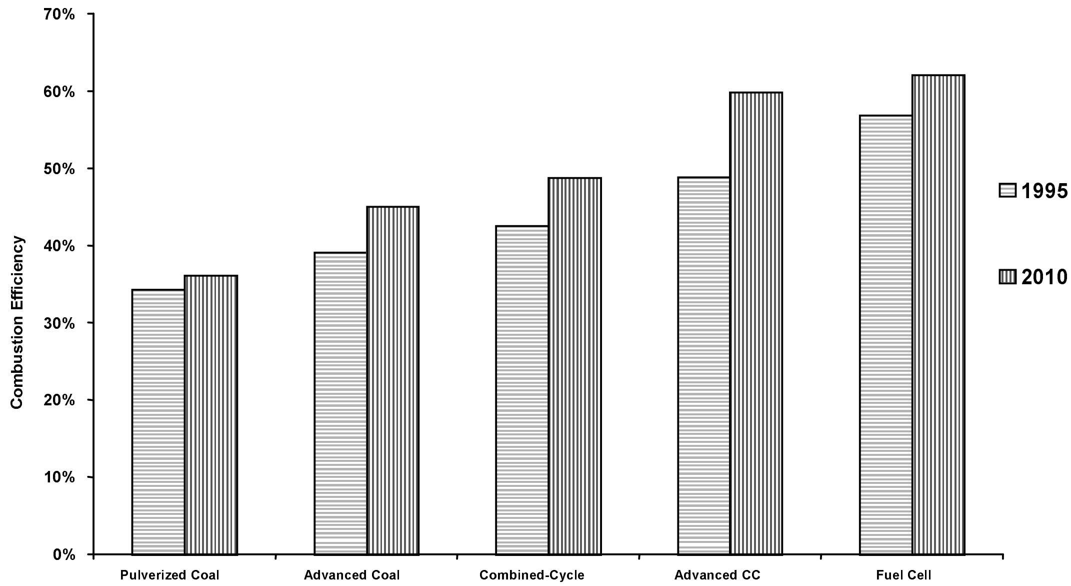
However, there are some indications that short-term competitive pressures may be squeezing out utility investments in research and development of energy technologies. (We have no data on trends in R & D expenditures for other electricity related industries, sulkch as equipment manufacturers.) One recent study finds that, "research and development funding by 80 of North America's largest investor-owned utilities fell by one-third between 1993 and 1996."[21] On average, industrial firms in the U.S. spend approximately 3.1% of sales on R&D. In 1994, US utilities, on average, devoted .3% of sales to R&D, and substantial reductions have occurred since then.[22] To respond to this situation, at least seven states with restructuring initiatives have included R&D among the categories of investment that are supported by a system benefits charge.

2.5.1 Natural Gas Combustion Turbines

The natural gas combined cycle combustion turbine is likely to remain the most common new generating technology for the immediately foreseeable future. The Energy Information Administration (EIA), in its 1998 Energy Outlook, estimates that 85% of new electricity generation from 1996 to 2020 will be combined-cycle or combustion turbine technology fueled by natural gas.[23]

Continuing advances in high temperature materials, coupled with improved turbine design and control technologies, will probably continue to push up the thermal efficiency of this equipment. The NWPPC uses a 0.5% per year increase in thermal efficiency for its resource projections. EIA reaches similar conclusions. Figure 2.10 illustrates EIA's projections for efficiency improvements for combustion turbines along with other comparable generating technologies. By 2010, the thermal efficiency of advanced combine cycle facilities is expected to increase from 49 % to 60%.

Figure 2.10 Combustion Efficiency of Electric Generating Technologies 1995 and 2010



Source: Energy Information Administration (EIA), Assumptions for the Annual Energy Outlook, 1997.
Note: Efficiency calculated based on actual (1995) and projected (2010) commercially available heat rates.

In addition to improved efficiency, the capital costs of new generating technologies are also likely to decline. EIA estimates that the capital cost components of advanced combined cycle units will decline from 7.5 mills/kWh ($1996) in 2005 to 7.2 mills/kWh ($1996) by 2020.[24] Capital costs represent about one-quarter of the total estimated cost of advanced combined cycle combustion turbines, so marginal reductions in capital cost will probably not be as important as fuel price trends in determining overall costs.

2.5.2 Distributed Technologies

Smaller scale distributed generation may assume a larger share of future electricity generation. Much research is underway on distributed technologies such as fuel cells, microturbines, photovoltaics (PVs), and advanced energy storage devices.[25] Advances in fuel cell technology are being driven rapidly by a number of factors, including the growing demand for clean transportation alternatives. Microturbines are likely to be sized at 25-75 kW, fuel cells from a few kW to a megawatt or more, and PV rooftop systems may be as small as a few kW each. Most of these technologies can be applied either as an additional component of the existing electricity grid or as stand alone, grid-independent systems. Estimates of the potential penetration of such technologies into the market range from as much as 20% of the new generation capacity additions over the next 10 to 12 years to only negligible contributions during that period.[26]

- **Microturbines:** Mass produced microturbines in sizes below 100 kW are now beginning to enter the market. Some of the likely applications include placement at the end of transmission and distribution lines to avoid high cost upgrades, installation as uninterruptible power supply units, and use as a dedicated prime mover for pumps, air conditioning, or process equipment. Many of the large manufacturers of conventional turbines and generators are developing microturbine product lines.
- **Fuel Cells:** Fuel cell technology is based on an electrochemical (rather than thermal) reaction between hydrogen and oxygen that produces direct current electricity and heat. The residual product from fuel cells is pure water. A wide range of feedstocks (including natural gas, coal, biomass) can subjected to a reforming process to extract hydrogen fuel for the cells. Successful development and production of fuel cells on a large scale could have major impacts on the costs and market structure of electricity production. Although currently too costly for most applications at 15 cents/kWh or more, they hold major promise for numerous future applications. Substantial research is underway on a wide range of fuel cell technologies including phosphoric acid, molten carbonate, alkaline, solid oxide, and proton exchange membranes.[27] Fuel cells are highly modular and can be manufactured in sizes from a few kW to several megawatts. Given the substantial investments in fuel cell research, it is likely that manufacturing cost and production costs will continue to decline.
- **Storage Devices:** Electric, chemical, and mechanical storage devices can serve as storage media in applications ranging from individual homes to utility systems. For utilities, new storage technologies can help increase utilization of transmission and distribution equipment, decrease reserve margins, allow for better integration of intermittent sources (such as wind and photovoltaics) into utility systems, and increase system reliability.[28] For electricity users, storage systems can increase power quality, provide uninterruptible power supply, provide storage and backup for intermittent renewable technologies, and reduce peak demand. Substantial research and development is under way to improve battery and flywheel technology. R&D is especially active in the area of low-cost, high power density batteries for transportation applications.[29] Flywheels offer the ability to store large amounts of energy at a high energy density. Improvements in materials, magnetic bearings, and vacuum chambers have reduced storage losses. Development of flywheels for utilities has focused on power quality applications.[30]

Figure 2.11 Distributed Generation Options

Technology	Size	Efficiency (%)	Cost Range
♦ Microturbines	25-100 kW	26-30	$300 - $400/kW
♦ Fuel Cells (numerous technologies)	200 watts – 5 MW	40 –65	$3000/kW
♦ Photovoltaic	<1 – 1000 kW	10-20	17-25 cents/kWh
Storage Devices			
♦ Battery Storage	500- 5000 kWh	70 –75	$400 - $1000/kW
♦ Flywheels	2-20 kWh	70 –80	$3000 - $6000/kW

Sources: EPRI Journal, March/April 1998. Cost range for U.S. DOE, Renewable Energy Technology Characterizations, "Overview of Energy Storage Technologies," 1997.

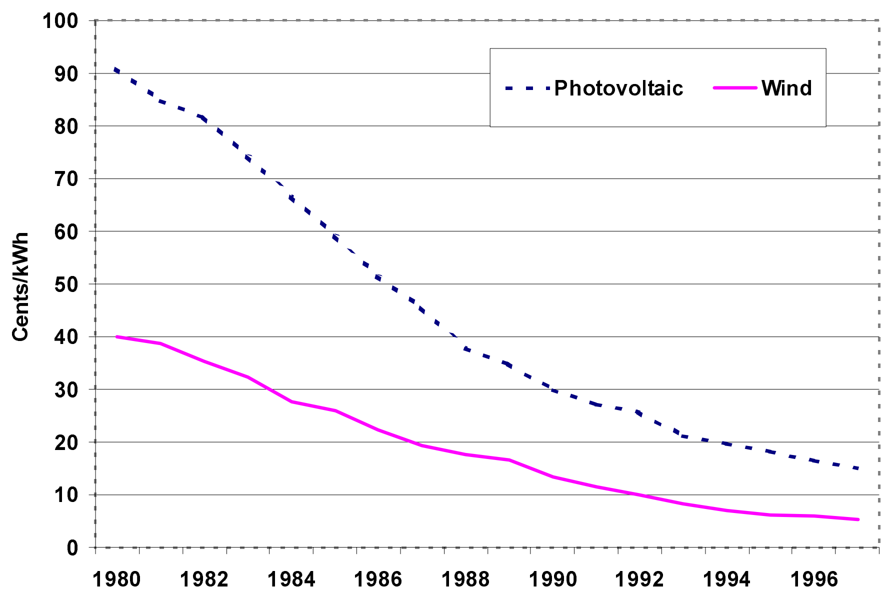
2.5.3 Hydroelectric generation

Hydroelectric generation is unlikely to increase in the U.S. overall and in the Pacific Northwest in particular. However, research and development are underway to improve the technology of hydroelectric turbines so that they are more "fish friendly" and can also operate more effectively under a wider range of water flow conditions. EPRI estimates that it will require 2 to 10 years for prototype development and testing of such improved turbines and development of variable speed, variable power turbines and controls.[31]

2.5.4 Renewable Technologies

Renewable energy technologies in addition to hydropower include wind, solar thermal, solar photovoltaic, geothermal, landfill gas and biomass. Currently the internal costs of these technologies are moderately to substantially higher than natural gas combustion turbines. Their external costs, however, are generally considered to be lower. The NWPPC's 1996 cost estimates range from 4.1 cents/kWh for wind to 17.8 cents/kWh for photovoltaic generation.[32] However, the costs of these technologies have declined significantly over the last two decades. Figure 2.12 illustrates this decline. Because some of these technologies lend themselves to distributed application, they are cost-effective in some remote applications now. For example, solar photovoltaics are a cost-effective option for pumping water for livestock in some areas.

Figure 2.12 Decreasing Costs of Renewable Energy Sources



Source: U.S. DOE, *Technology Opportunities to Reduce U.S. GreenhouseGas Emissions*, p. 2-37, 1998.

2.5.5 Cogeneration

Cogeneration or combined heat and power (CHP) is the simultaneous production of electricity and heat. Cogeneration allows for increased thermal efficiency through productive use of what would otherwise be waste heat from combustion. Cogeneration/CHP dates back to the early years of the electricity industry when small, localized power plants, predominately at industrial sites, produced both electricity and heat for industrial processes. As the size of generating plants expanded and large plants were often sited outside major population centers, cogeneration's share of electricity production waned. However, interest in cogeneration, both domestically and internationally, is again increasing. One factor driving this increase is the availability of small and clean distributed generation, which allows electric generators to be closer to heat-demanding processes or commercial loads. Overall efficiencies of 70 to 80 percent can make cogeneration very attractive to independent power producers and end users in some applications.[33] Because of the high thermal efficiencies it allows, cogeneration may contribute significantly to the achievement of carbon emission reduction goals. Washington currently has more than 680 MW of installed cogeneration capacity.

2.5.6 Energy-using equipment

Just as improvements in electricity generating technology have steadily increased the conversion efficiency of electricity production, technological improvements in electricity using equipment have significantly increased end use efficiency. Over the last 25 years, the development and adoption of building energy codes, implementation of large scale utility conservation programs, national appliance and equipment efficiency standards, and state conservation efforts have driven technological innovation. High efficiency motors, windows, electronic ballasts, and sophisticated energy management systems are a few of the many new electricity-saving devices. These technologies have reduced the cost of electric service by displacing the need for more costly new supplies and lowering operating costs for residential, commercial, and industrial equipment.

The NWPPC estimates that cumulative savings from energy efficiency programs in the region amounted to about 1,000 average megawatts in 1996. The Council estimates that the region still has approximately 1,535 average megawatts of cost-effective conservation potential available at an average levelized cost of 1.7 cents/kWh. Much of this potential involves increased commercialization of energy saving technology.

Figure 9.4 in Section 9 shows the decline in the electricity intensity of Washington's economy (the amount of energy used to produce a given amount of economic output) in real dollar terms. Technological improvement is one of the factors contributing to this decline.

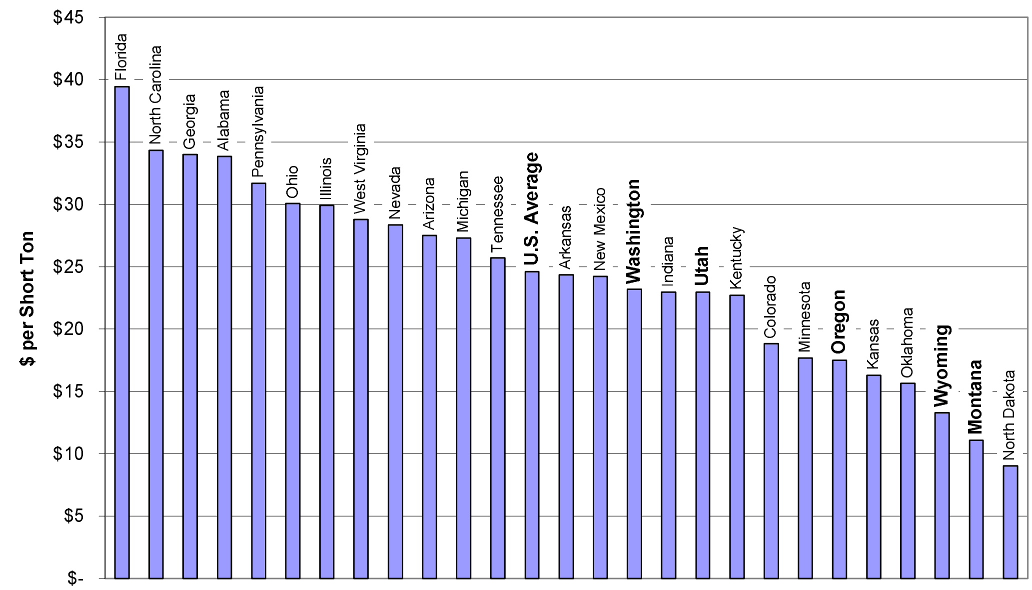
2.5.7 Communications and information technology

Communications and information technologies present substantial opportunities to reduce electric service costs and expand product and service diversity. These technologies allow for remote meter reading, real-time pricing, direct load management, and remote monitoring of energy efficiency or power quality.[34] Remote meter reading is likely to be the most significant near-term application, allowing utilities to decrease their operating costs while linking them more closely to their customer base. Such enhanced links also open up the opportunity for energy service providers to form new partnerships and to provide new services.

2.6 Fuel

Washington's primary reliance on hydroelectric power has tended to insulate it to some degree from trends in the price of fossil fuels. However, a significant portion of the power consumed by Washington citizens comes from large, coal-fired power plants that were built in the 1970s. Moreover, almost all new generating capacity that has been installed in the 1990s has been fired with natural gas, and gas appears to be the resource of choice for the foreseeable future. Fuel prices are likely to play a growing role in determining the price Washington consumers pay for electricity.

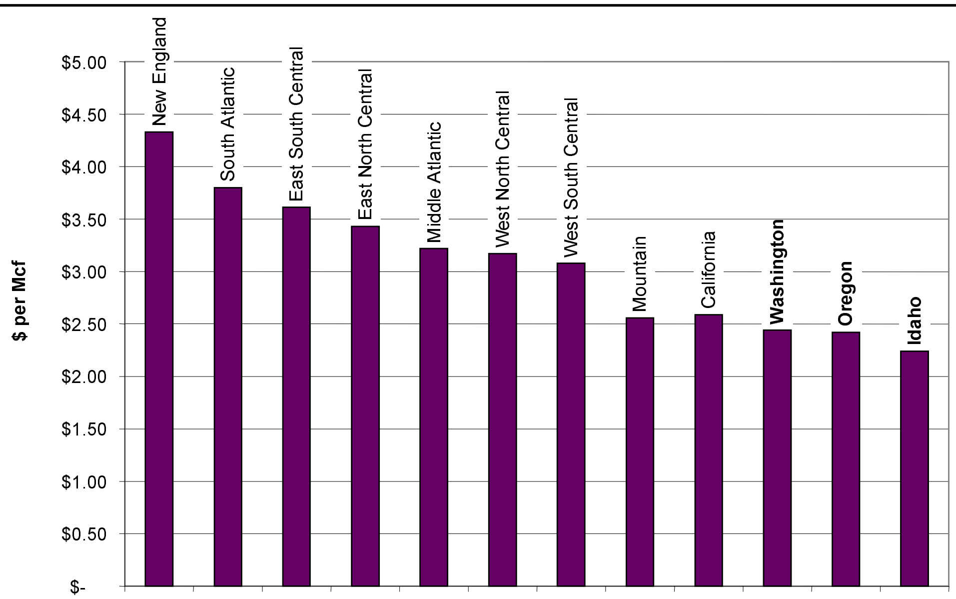
Figure 2.13 Coal Prices to Electric Utilities, Selected States, 1997



Source: EIA, Coal Industry Annual

Fuel prices in the Northwest tend to be lower than in the rest of the country. Figure 2.13 compares coal prices at electric utilities in selected states around the country. The boldface type indicates states in which coal plants owned by utilities serving Washington customers are located. Wyoming and Montana, where the bulk of the Northwest's coal-fired generating capacity is located, enjoy some of the lowest coal prices in the country. This is due both to the characteristics of the resource (the coal tends to lie close to the surface and be low in sulfur) and to the location of the generating plants at the minemouth, reducing the cost of transporting the fuel. Centralia coal is cheaper than the national average.

Figure 2.14 Natural Gas Prices at City Gate, Selected State and Census Divisions, 1996

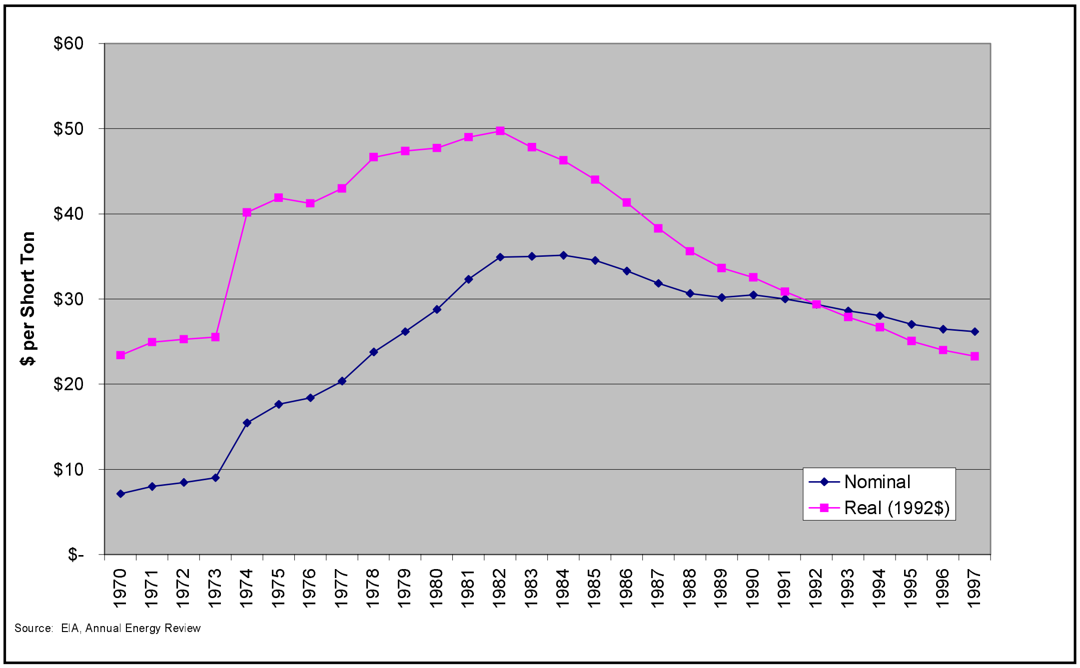


Source: EIA, Natural Gas Annual

Figure 2.14 compares city gate natural gas prices in selected states and census divisions. Washington, Oregon and Idaho enjoy some of the lowest natural gas prices in the country, even lower than in gas-producing regions like the West South Central (which includes Oklahoma, Texas and Louisiana). This is due primarily to the availability of cheap Canadian supplies, and secondarily to inexpensive production in Wyoming and northwestern Colorado. There is some question about whether this cost advantage will continue. Several projects are in the works that may decrease this cost advantage by increasing pipeline capacity from the Rocky Mountain region eastward, both in the U.S. and in Canada.

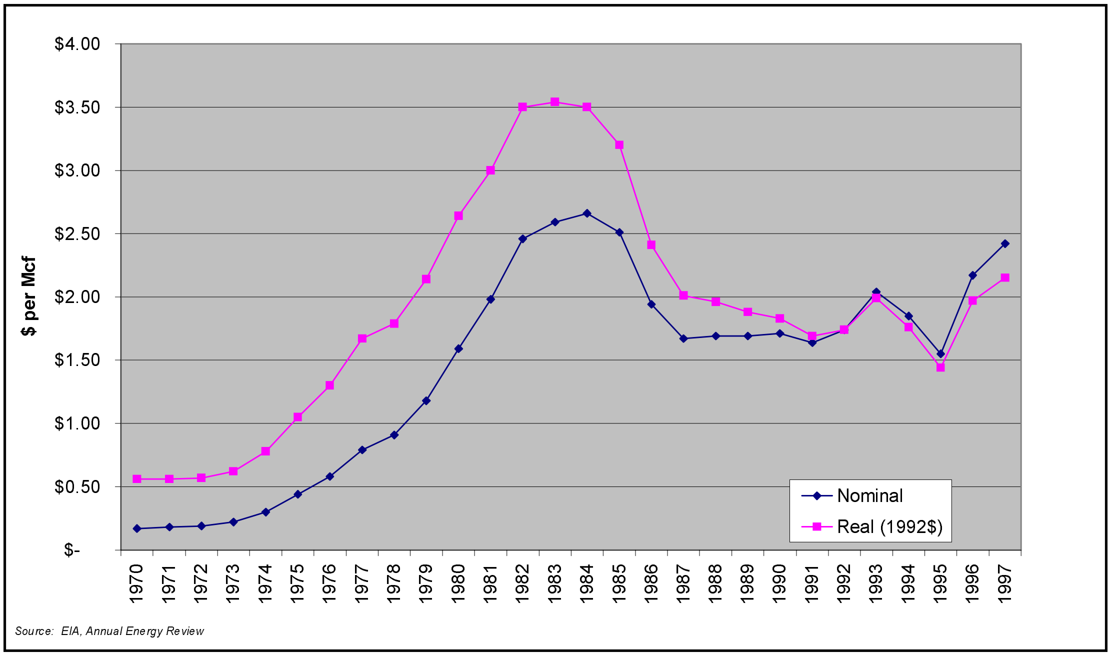
The next two charts examine the trend of fuel prices over time, both in real and in nominal terms. Prices for coal and natural gas have exhibited similar trends over the past thirty years or so. Both were cheap in real terms in the early 1970s, and both saw steep price increases throughout the 1970s. Coal prices across the country have declined steadily since, peaking at around $35 per ton in 1982-1984. The average price in 1997 was $26.16 per ton. In real terms, prices for coal delivered to electric utilities are less than half what they were fifteen years ago.

Figure 2.15 US Coal Prices to Electric Utilities, 1970-1997



The story is similar, though more pronounced, for natural gas. Gas prices skyrocketed in the 1970s, increasing over 500% in real terms between 1970 and 1983. Production increases, infrastructure improvements, and regulatory changes led to much lower prices by the late 1980s, and prices fell to less than half their former levels in the mid-90s. The last three years have seen gas prices drifting back upwards. It remains to be seen whether this becomes a long-term trend.

Figure 2.16 US Wellhead Natural Gas Prices, 1970-1997



Both natural gas and coal are fossil fuels with substantial environmental impacts, primarily in the form of air emissions. The costs of these impacts are not fully internalized. Burning coal produces harmful air pollutants including oxides of nitrogen (NO and NO_2, or NO_x), sulfur dioxide (SO_2), and carbon monoxide (CO), as well as ash, fine particulates, and heavy metals such as mercury and arsenic. Burning natural gas produces no particulates or heavy metals, but does produce NO_x and CO. Both fuels produce carbon dioxide, the most prevalent greenhouse gas. In general, and particularly in the case of carbon dioxide, coal-fired generators produce substantially greater emissions per unit of energy than do gas-fired units.

While some of these environmental costs have been internalized through fuel switching or the installation of pollution control equipment, increasing environmental liabilities are a factor that is likely to affect future fuel prices. For example, the coal industry is still in the process of complying with Phase I of the Clean Air Act Amendments of 1990, which require a 60% reduction in industry-wide SO_2 emissions by 2010. The Energy Information Administration has estimated that the cost to utilities of complying with Phase I of the 1990 CAAA has amounted to $836 million per year, in 1995 dollars.[35] Compliance with Phase II, which begins in 2000, will also be costly. Minemouth coal may continue to get cheaper, but burning it will probably continue to get more expensive.

Efforts to reduce greenhouse gas emissions may put upward pressure on fuel prices. The electric utility sector accounts for approximately one third of U.S. greenhouse gas emissions, and may be called upon to achieve a substantial portion of greenhouse gas emission reduction targets. Some internalization of carbon costs may be required in order to achieve significant greenhouse gas reductions. This internalization would increase the price of electricity in proportion to the carbon emitted by the generation source, with the greatest increases falling on coal-fired power. By the same token, it would increase the relative price advantage of renewable resources, including the hydropower that provides most of Washington's electricity supply.

Carbon emission reduction efforts would probably also affect natural gas prices. Electric utilities may substantially increase their use of natural gas in an effort to reduce emissions from coal plants. This would put pressure on gas supply and cause prices to increase. Natural gas also contains carbon and would presumably be subject to any policy that internalizes carbon costs.

Endnotes for Section 2

[1] See, for example, Senate Bill 2499 in the 105th Congress.
[2] "Retail Wheeling and Restructuring Report," Edison Electric Institute, June 1997.
[3] National Regulatory Research Institute "Electric Industry Restructuring Box Score"; http://www.nrri.ohio-state.edu
[4] The average price of electricity in the 17 states that had mandated retail competition as of May 1998 was 8.6 cents/kWh, compared to an average price of 6 cents/kWh in the other states. ("Creating Competitive Markets in Electric Energy: A Critical Analysis of H.R.655" *Electricity Journal,* May 1998)
[5] "Comprehensive Review of the Northwest Energy System Final Report: Toward a Competitive Electric Power Industry for the 21st Century," December 12, 1996.
[6] *Fourth Northwest Conservation and Electric Power Plan*, Northwest Power Planning Council, 1998
[7] On May 13, 1998, the *San Francisco Examiner* reported that California utilities would ask to recover $979 million for costs incurred to initiate retail competition through 2001. In the August/September 1998 issue of *Electricity Journal,* Alex Henney reports that the transaction costs for initiating competition in the U.K. exceed $1.5 billion.("Contrasts in Restructuring Wholesale Electric Markets: England/Wales, California, and the PJM")
[8] *1997 Pacific Northwest Loads and Resources Study,* the Bonneville Power Administration, December 1997.
[9] Nationally, however, electric power generation accounts for two thirds of total emissions of sulfur dioxide, one third of total emissions of nitrogen oxides, and one third of total emissions of carbon dioxide.
[10] The agencies did not collect comparable data on internalization of fish costs from other hydropower operators, but anecdotal evidence suggests significant increases in recent years for many hydropower facilities.
[11] IPCC Second Assessment, Climate Change 1995, Intergovernmental panel on Climate Change. United Nations
[12] D. Raynaud et al., "The Ice Core Record of Greenhouse Gases," *Science,* 259, 1993, pp. 926-34
[13] Snover, Amy, Edward Miles, and Blair Henry, OSTP/USGCRP Regional Workshop on the Impacts of Global Climate Change on the Pacific Northwest, NOAA Climate and Global Change Special Report No. 11, March 1998.
[14] See, for example, "Thermal Limits and Ocean Migration of Sockeye Salmon: long-term Consequences of Global Warming," *Canadian Journal of Fisheries and Aquatic Science*, Volume 55, 1998, D.W. Welch, Y. Ishida, and K. Nagasawa.
[15] Snover, et al
[16] IPCC Second Assessment Climate Change, 1995
[17] IPCC, Second Assessment
[18] Last year, Oregon began to internalize carbon dioxide costs when it incorporated carbon emission standards in its energy facility siting statute. Under the new law (HB 3283), electric generating facilities sited in Oregon must mitigate carbon emissions to a level 17% lower than the most carbon-efficient power plant operating in the U.S. at the time the new plant is permitted. This can be accomplished through emission reduction at the plant or payment of $0.57 per ton of carbon into a fund for carbon mitigation projects.

[19] Northwest Power Planning Council, *Draft Fourth Northwest Power Plan,* Table 6-3
[20] See Hardin, Garrett, "The Tragedy of the Commons," *Science*, 162 1968. pp. 1243-1248
[21] "Changes in Electricity-Related R&D Funding," US General Accounting Office, August 1996 GAO/RCED-96-203
[22] "US National Investment in Energy R&D: 1974-1996", JJ Dooley, PNNL-11788, December 1997
[23] Energy Information Administration, *Annual Energy Outlook 1998 with Projections Through 2020,* DOE/EIA-0380(98), December 1997, page 51.

[24] EIA, *Outlook 1998,* page 52.
[25] EPRI Journal, "Emerging Markets for Distributed Resources," March/April 1998
[26] EPRI Journal, "Emerging Markets…"
[27] See for example, Avista Labs of Spokane at http://www.avistalabs.com/home/index.html for information on fuel cell research.
[28] U.S. DOE, Renewable Energy Technology Characterizations, "Overview of Energy Storage Technologies," 1997 at http://www.eren.doe.gov/utilities/techchar.html.
[29] See for example, "Study Progress: Electric-Car Batteries Are on Track," Electric Power Research Institute, 1998.
[30] "Energy Storage Technologies," Appendix A, U.S. DOE, Renewable Energy Technology Characterizations, 1997.
[31] Electric Power Research Institute, *Powering Progress, The Electricity Technology Roadmap Initiative. Background Report: A Preliminary Vision of Opportunities,* August 1997, page 2-16.
[32] NWPPC, *1996 Plan,* Table 6-1, page 6-5.
[33] Tim Hennagir, "CHP's Promise," Independent Energy, January/February, 1998.
[34] Michael Kintner-Meyer, "Communication Technologies for Energy Management and Energy Services" ACEEE Summer Study, 1998, page 8.204
[35] EIA, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*, April, 1997, available on the EIA website: http://www.eia.doe.gov/cneaf/electricity/clean_air_upd97/exec_sum.html

3.0 Strategies to minimize electric service costs

Overview

This section describes strategies to minimize the cost of electric service to Washington consumers. For consistency, it groups these strategies into the same six categories as the trends in the preceding section:

1. **Wholesale market**
2. **Retail market**
3. **Supply adequacy and reliability**
4. **Environment**
5. **Technology**
6. **Fuel cost**

Many of the strategies available for minimizing electric service costs are not within the state's control. We include discussion of some strategies that may be outside of the state's purview in order to indicate where the most important decisions regarding future costs are likely to be made. Because the nature of the state's role and opportunities varies widely among the categories, the scope of strategies in each category also varies widely. As is the case throughout the report, we describe strategies and in some cases list arguments for and against them. However, no recommendations are implied.

Discussions of strategies also do not imply that any particular action is necessary. Some stakeholders feel that the best strategy for minimizing costs may be to minimize change. Others suggest that economic forces have already changed the electric power market in ways that make existing strategies for minimizing costs less appropriate. The tension between preserving the desirable characteristics of the existing system and responding to market changes that are already under way was a recurring theme in stakeholder comments on the draft report and in public meetings. Again, describing changes and outlining alternative responses implies no endorsement.

3.1 Wholesale market

For the most part, the wholesale electric power market is not under state jurisdiction. Wholesale power prices and wholesale transmission are generally regulated by the Federal Energy Regulatory Commission. However, the state may have a role in regional efforts to protect the benefits of the Federal Columbia River Power System (FCRPS) and in influencing policy development with respect to transmission grid operations.

3.1.1 Strategies to reinforce the connection between Washington consumers and the benefits of the Federal Columbia River Power System

Perhaps the single most important factor affecting the cost of electric service in Washington in the foreseeable future is the extent to which the benefits of the Federal Columbia River Power System remain with regional (primarily Washington) consumers. Retaining these benefits was the primary objective of the Comprehensive Review of the Regional Energy System. It is the main focus of the Governor's Transition Board. It is also the primary focus of efforts by members of the Northwest congressional delegation to craft a "Northwest Chapter" for federal electric restructuring legislation. The Bonneville Power Administration cited it as the overarching purpose of its December 1998 power subscription proposal. The value of these benefits depends on a variety of factors, most notably the future direction of prices in the wholesale power market. However, the Northwest Power Planning Council estimates that the 20-year value of these benefits exceeds $5 billion in all but the lowest market scenarios, and could exceed $20 billion in the highest market scenarios.[1]

Most of the strategies for retaining the benefits of the FCRPS proposed by the Comprehensive Review, the Transition Board, BPA, and others fall into three basic categories:

1. Paying for the system reliably;
2. Managing the system effectively and efficiently; and
3. Distributing the system's benefits equitably.

3.1.1.1 Paying for the system reliably:

If regional consumers fail to fully cover the costs of the FCRPS, federal taxpayers could be exposed to those costs. This could undermine the region's claim on the benefits of the system in the future. The Comprehensive Review and now BPA have proposed a system for "subscribing" to power from the FCRPS on terms that would maximize the likelihood that the costs of the system are fully covered by Northwest consumers. BPA and the Transition Board have recommended slightly different contingency plans for recovering costs from subscribers, should costs rise above those used to calculate rates. These contingency plans include: tapping a reserve fund for fish and wildlife recovery; a "cost recovery adjustment mechanism" that would raise power rates; additional cost reductions; and potentially a transmission surcharge to recover power costs. BPA has established a goal of reaching an 88% probability of making its annual payment to the U.S. Treasury on time and in full in every year of the five-year rate period beginning in 2001. High probability of Treasury repayment is widely regarded as an important index of the region's ability to pay for the FCRPS reliably.

A more direct strategy for covering the costs of the system would be for the region (probably meaning some combination of BPA's customers and the Northwest states) to purchase the FCRPS or its output. BPA customers have discussed this option. Members of Congress and representatives of federal executive agencies have also discussed this option as a way to reduce federal debt and reduce the presence of the federal government in power markets. We know of no active negotiations regarding purchase of the system.

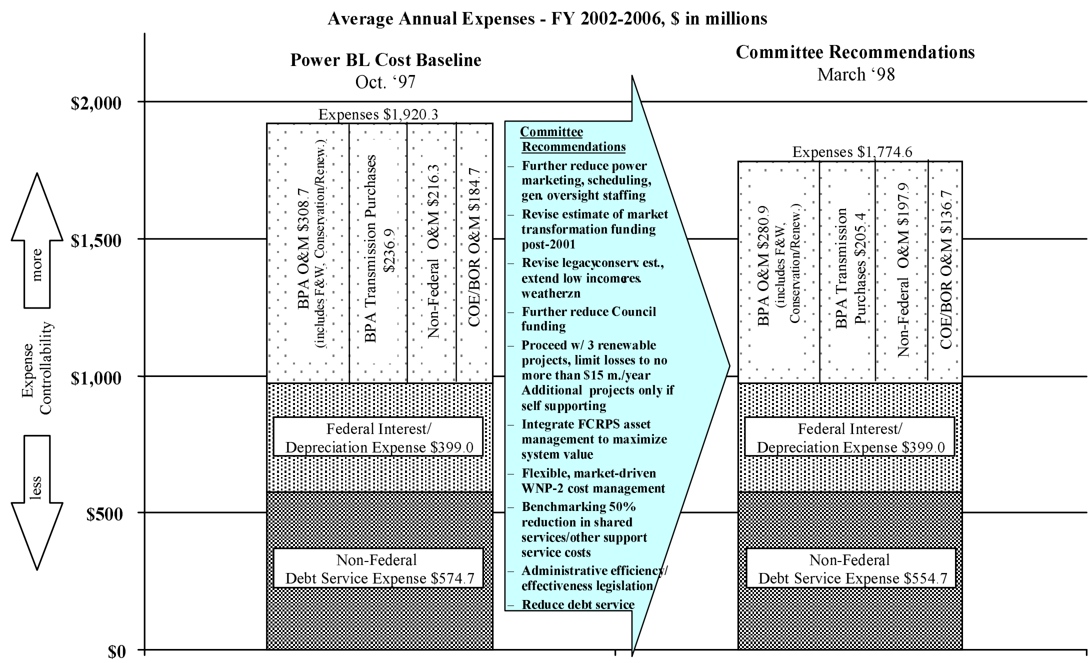
However, some BPA customers who have substantial generating capacity (the Public Generating Pool) have proposed that BPA offer a "Slice of the System" product for subscription. This product would consist of a proportion of the system's total output, rather than a fixed amount of power. Since the system's output is subject to substantial annual and seasonal fluctuation, the actual dimensions of the "slice" would vary. This would transfer some of the risks associated with precipitation and other variables from BPA to the customer. This transfer of risk is in some ways akin to ownership of a piece of the FCRPS. Insofar as this "slice" product increases the likelihood that regional consumers will bear the system's costs reliably, it may increase the likelihood that the system's benefits remain in the region. BPA proposes to offer the "slice" product in its upcoming subscription process.

3.1.1.2 Managing the system effectively and efficiently

The case for keeping the benefits of the FCRPS in the Northwest may be strengthened to the extent that the region can demonstrate that it is managing the system effectively and efficiently. Better management also increases the likelihood of paying for the system reliably. While effectiveness and efficiency are in the eye of the beholder, the following strategies for increasing the quality of FCRPS management are under consideration or being pursued:

- **Cost containment and production efficiencies:** In 1997, following the recommendations of the Comprehensive Review, the Northwest Power Planning Council established a cost control forum to assist BPA in controlling its costs. The recommendations of the cost management committee identify $146 million in reductions to planned power expenses for BPA's next rate period, Fiscal Years (FY) 2002-2006. These reductions are in addition to substantial cost cutting already undertaken. The effects of these recommendations on BPA's costs are depicted in the Figure below. The actual recommendations are included as Appendix 2-1. BPA plans to incorporate many of these recommendations in its upcoming rate proposal.

Figure 3.1 Cost review recommendations would reduce Power Business Line expense projections by about $146 million



Notes: Actual FY 1997 PBL expenses = $1,871.5 million
PBL cost baseline for FY 1997-2001 in the 1996 rate filing = $2,005.9 million
Committee recommendations for Corps, Bureau and WNP-2 are a combination of expense reductions and increased revenues. These are reflected here as a reduction in expenses only.

W:cm\fpr\coststud\DraftReport\comparison.ppt

- **End-use efficiency:** The case for keeping the benefits of the FCRPS may be stronger to the extent that the region maximizes the system's productivity by using system output efficiently. BPA has made substantial investments in energy efficiency over the years, saving roughly 690 average megawatts of power since 1982. However, due in part to competitive pressure at the wholesale level, BPA investments have been declining rapidly since 1994. As part of its package of recommendations, the Comprehensive Review suggested that states stem this decline by establishing a minimum investment standard in energy efficiency and renewable resources equivalent to 3% of total retail utility revenues. BPA proposes to provide rate discounts to its customers to support their energy efficiency investments and achievements. Other energy efficiency strategies are discussed in Section 9 of this report.
- **Improved environmental management:** The effectiveness of the region's efforts to restore endangered salmon and steelhead stocks may well affect the region's prospects for retaining the benefits of the system. Evaluation of alternative salmon recovery strategies in the Columbia Basin is well beyond the scope of this study. Landmark decisions with respect to recovery strategies for endangered Columbia River stocks are ex-

pected from the National Marine Fisheries Service in 1999. BPA has attempted to respond to the substantial uncertainty surrounding the costs of these strategies by adopting a set of "fish funding principles" and proposing to set power rates to accommodate a range of possible outcomes.

3.1.1.3 Distributing the system's benefits equitably

Members of the region's congressional delegation have frequently advised BPA customers and stakeholders to develop and support a regionally sanctioned way to share the benefits of the system or risk losing those benefits altogether. Some measure of regional agreement regarding the nature of BPA's role in competitive markets may also be an important component of a unified regional position.

The need to develop such a unified regional position was the impetus for undertaking the Comprehensive Review and for forming the Governors' Transition Board. It also underlies the attempts on the part of members of the congressional delegation to develop a "Northwest Chapter" for federal restructuring legislation. BPA's current subscription proposal[2] for sales of power starting in 2001 is an attempt to form the basis for such an agreement by accommodating the following claims on the system's benefits. (The following description outlines how BPA has attempted to structure a package that balances competing interests. No endorsement of any of these features is implied.):

- ❖ Public preference: The proposal allocates the substantial majority of the firm power from the FCRPS to public agencies.
- ❖ Extending the benefits to residential and small farm customers of investor-owned utilities: The proposal allocates 1800 aMW of power (and/or equivalent benefits in the form of cash payment) for residential and small farm customers of investor-owned utilities, with the prospect of more after 2006.
- ❖ Extending the benefits to Direct Service Industrial (DSI) customers: After meeting the requirements of its public and private utility customers, BPA expects to have enough power to meet the loads of the DSI customers.
- ❖ Preserving the Low Density Discount (LDD) and defraying transmission costs for remote systems: The LDD effectively allocates some of the benefits of the entire system to low-density rural systems, many of which are in Washington. BPA also proposes to absorb certain transmission costs for remote systems (the "General Transfer Agreements") in general power rates.
- ❖ Providing a discount for customers making qualifying investments in energy efficiency, renewable resource, and low-income weatherization.
- ❖ Adopting fish funding principles and rates that can accommodate a large range of costs associated with salmon and steelhead recovery.

- Offering a “slice of the system” product for customers with the ability and inclination to accept more of the risks and rewards of variations in system output and costs.

With respect to BPA’s position in competitive markets, the subscription proposal may reduce BPA’s role in acquiring new resources to serve customers, thereby lowering the agency’s profile in generation markets. The Transition Board has issued a set of recommendations that would subject BPA’s transmission rates and operations to oversight by the Federal Energy Regulatory Commission on terms comparable to FERC’s regulation of private transmission carriers. The Comprehensive Review proposed limits on BPA’s role in the energy efficiency marketplace by developing guidelines to prevent BPA from competing with private energy efficiency firms.

These efforts to reduce BPA’s presence as a federal agency in the marketplace may reduce BPA’s revenue-earning potential and/or conflict with BPA’s existing statutory obligation to acquire resources to serve loads. However, they may also reduce the potential for conflict with private competitors and thereby promote the achievement of regional consensus on the future of the FCRPS and BPA. There may be an inherent tension between reducing BPA’s competitive presence and ensuring that the agency earns sufficient revenue to cover its costs reliably while providing adequate supplies to serve regional customers.

3.1.2 Strategies to promote more effective wholesale competition through efficient, competitively neutral operation of the high-voltage transmission grid

Section 2 described changes in the regulation of the nation’s high-voltage transmission system designed to promote an efficient wholesale generation market. FERC’s Orders 888 and 889, issued in 1996 and revised in 1998, required jurisdictional (investor-owned) utilities to file “open access” tariffs, under which they are to treat competitors the same as they treat their own power marketing departments or subsidiaries. Order 888 also anticipated and encouraged the formation of regional Independent System Operators (ISOs) to enhance the development of competitive power markets.

During 1996 and 1997, a number of utilities held discussions about forming “IndeGO,” an independent system operator for the Northwest. One of the purposes of the IndeGO proposal was to remove “pancaked” transmission rates — the practice of charging a customer the embedded cost rate each time a transaction crosses a utility intertie. This practice results from multiple ownership of the transmission grid. Computer modeling done by the IndeGO pricing work group suggests that doing away with transmission “pancakes” could save the region $8-16 million a year in fuel costs alone due to more efficient dispatch of existing resources. Savings have been estimated to be as high as $40 million if pancakes were eliminated throughout the western interconnection.

Additional savings may be reaped from more efficient system expansion decisions. Eliminating pancaked transmission rates might allow the Northwest to make larger seasonal purchases of energy from California, delaying the need to invest in new capacity to meet winter peaks. Additional benefits cited by IndeGO supporters include: better reliability due to coordinated grid operation by an entity with a neutral position in the marketplace; reduced ability for large, transmission-owning utilities to exercise vertical market power; and more efficient use of the existing grid through transmission capacity rights that are easily tradable.

It is not clear, however, whether the benefits of forming an ISO outweigh the costs. Many stakeholders argue that the region already enjoys many of the benefits promised by an ISO due to the existence of the wide-reaching federal transmission network. Some IndeGO opponents argue that inefficiencies in the existing system are modest, so the potential for efficiency gains from independent system operation is small. Figure 3.2 displays detailed estimates of the costs and benefits developed for the IndeGO proposal. There is significant disagreement within the region about the magnitude of both the costs and the benefits displayed in this table.

Figure 3.2 Costs and Benefits of Forming IndeGO

Benefits

Estimated Annual Benefits from Forming IndeGO	***Value of Benefit to IndeGO Region***
Reduced Staffing	$14-18 million
Elimination of Multiple Control Centers	$2 million
Coordinated Main Grid Transmission Planning	$3-5 million
Eliminating Pancaking —Improved Generation Dispatch	$8-16 million
Eliminating Pancaking — More Efficient System Expansion [a]	$0-81 million
Total Quantitied Benefits	*$25-123 million*

Additional Benefits Claimed by Proponents

- More competitive power market — Less opportunity for “self-dealing” of transmission access or other ways to “game” bulk power markets
- More valuable use of existing facilities — tradable transmission rights increase chance of achieving “optimal” generation dispatch
- Improved reliability due to coordinated grid operation
- Improved dispatch due to better method of calculating losses

Costs

Startup Costs	
November, 1997 Estimate: Greenfield Facility	$89-164 million
February, 1998 Estimate: Dittmer Remodel [a]	$28 million
Operating Costs	
November, 1997 Estimate: 275 employees	$45 million
February, 1998 Estimate: 206 employees [a]	$24-32 million

Sources: IndeGO proposal, November 26, 1997; IndeGO Costs Paper, William Pascoe, February 26, 1998; IndeGO Benefits Report, IndeGO Benefit Analysis Work Group, September 2, 1998

Notes: [a] Estimates developed after the November proposal were not reviewed or endorsed by all IndeGO parties.

Additional concerns that parties in the region had about forming IndeGO include:

- The prospect of cost shifting among utilities and among states, as the IndeGO fixed cost recovery methodology would have resulted in some cost shifts.

- The ability and willingness of BPA to participate in an ISO;
- The potential transfer of jurisdiction over transmission rates from local boards and commissions to FERC; and
- Uncertainty about retail market structure in a number of states.

As a result of these concerns, the IndeGO proposal was shelved in the spring of 1998.

A number of utilities in the region are currently working on a more limited version of an ISO that they call an Independent Grid Scheduler (IGS). The IGS would take on a few of the functions envisioned for IndeGO, including calculating and posting ATC, hosting a short-term market for unused transmission capacity rights, and coordinating grid scheduling among existing control areas. The proposed entity would incur few of the estimated costs of a full-fledged ISO, but might also realize few of the estimated benefits. There is currently no timeline for IGS implementation.

FERC held hearings during the spring and summer of 1998 to examine whether and how it should require the formation of ISOs. Some FERC commissioners believe FERC already has the authority to order ISO formation.[3] FERC issued a Notice of Intent to Consult with states regarding ISO formation on November 24, 1998 (Docket RN99-2-000). This process will address such subjects as where the boundaries of these districts should be drawn, what the minimum functions of a regional transmission system operator should be, whether participation should be voluntary of mandatory, and what the role of states should be. It is unclear what meaning this would have for the Northwest, where more than three-fourths of the transmission is owned by BPA, which is currently subject only to limited FERC jurisdiction. It is also unclear how this would affect attempts to form an IGS.

3.2 Retail Market

3.2.1 Discussion of the relationship between retail restructuring and minimizing electric service costs

As noted in Section 2, most of the arguments about whether and to what extent retail restructuring will reduce electric service costs remain inconclusive. The record indicates that the Legislature's decision not to call for an explicit comparison of the effects of alternative retail market structures in ESSB 6560 was driven in part by a perception that such a comparison would be too speculative to be useful. Therefore, the agencies did not attempt to analyze the cost impacts of changes in retail market structure. Some of the arguments of proponents and opponents of retail restructuring are characterized briefly and crudely (though not analyzed or endorsed) below.

- **Arguments of proponents of retail restructuring**: Some proponents of retail restructuring maintain that retail choice is an effective strategy for minimizing electric service costs. They argue that the absence of competitive pressure allows regulated electric utility monopolies to build and earn profits on unnecessarily costly electric generation. Since conventional rate-of-return regulation links revenues to expenditures, regulated utilities generally earn more for spending more, to the extent that regulators approve these costs. They argue that average rates set by regulators can provide incorrect price signals, causing customers to consume more power when they should use less and less when they should use more. Proponents also argue that, since customers have no option but to purchase from their monopoly provider, utilities can load excessive costs into rates with impunity, so long as regulators approve. While regulators are charged with minimizing costs to consumers, this regulatory control is pitted against a powerful incentive for investor-owned utilities to include more costs in rates, since they earn a return on most costs. Furthermore, proponents argue that the "natural monopoly" rationale for rate regulation no longer applies to electrical generation in the same way it applies to distribution or transmission. Some proponents of restructuring legislation argue that, without such legislation, competitive forces will tend to erode important collective investments that are currently carried in utility rates, including taxes, energy efficiency, renewable energy investments, and low-income services. Others suggest that restructuring may result in greater demand for power generated from renewable resources and thereby decrease environmental costs. Proponents of retail restructuring point to the experience in wholesale power markets and other services such as telecommunications as evidence that competition not only lowers costs but also enhances service by providing more product innovation and responsiveness to customers. Finally, some argue for restructuring on the grounds that retail competition is already occurring and that some legal framework for that competition is necessary.

- **Arguments of opponents of retail restructuring**: Some opponents of retail restructuring suggest that it will tend to level generation prices toward a system-wide average across the western power grid. Since Washington's prices are currently among the lowest, this will tend to shift costs in our direction. This is the conclusion of a number of studies of the effect of retail competition on prices. Opponents also argue that retail choice in some form already exists in Washington, insofar as consumers can choose to form public utilities. This choice, they contend, provides adequate competitive pressure on prices, while preserving local control that might be lost under retail restructuring. Some opponents of restructuring argue that the physical and operational characteristics of the power system lend themselves to vertical integration, and that restructuring may therefore cause cost increases and/or operational difficulties. Other opponents suggest that, since customers have dramatically different load characteristics and bargaining ability, competition will lead to cost shifting among customers rather than cost reductions. They suggest that marketing to small customers may be unprofitable and that these customers will not enjoy the benefits of competition. Some opponents suggest that unstructured competition leads to competitive pressures to reduce investments necessary to sustain reliability, customer service, and environmental protection. Opponents maintain that wholesale competition is already squeezing as much genuine efficiency as possible out of electric genera-

> tion, and that retail competition would bring no additional benefit. They, too, point to the experience in telecommunications as evidence: while long-distance rates are clearly lower, some contend that the cost savings are more than offset by greater confusion, intrusive marketing, and a proliferation of unwanted and expensive services.

We have no meaningful way of evaluating whether and to what extent retail choice will reduce total costs at this point. Data from other industries, countries, and states are sketchy. The data that do exist tend to focus on prices, with very little information on total costs of service. Even to the extent that these price trends are relevant, it is generally difficult to separate the relative impact of wholesale competition, technology changes, fuel cost fluctuations, and other factors from the impact of introducing retail competition. Also, Washington's unique mixes of federal, state, and local institutions and public and private power make it difficult to generalize from experiences elsewhere.

Retail competition may result in real increases in efficiency and reductions in cost. It may also result in increased product diversity and innovation. For some utility customers, the savings potential may be modest, particularly where existing rates are low. Other possible outcomes of retail competition include: redistribution of the costs and benefits of existing generating resources; shifting of tax burden; reduced investments in cost-effective conservation, renewable energy, low-income services, reliability, customer service, and other shared costs; and increased transaction costs.

These other possible outcomes generally do not represent reductions in the cost of energy service. Some of these outcomes may lead to lower prices for some consumers, but those price reductions may be accomplished by shifting costs or undermining investments necessary to minimize long-term costs and sustain a safe, reliable, environmentally sound system. These outcomes are not necessary products of retail competition or any particular market structure. They also do not reflect any unfair activity on the part of customers who take advantage of the opportunity for price reductions. Rather, these potential outcomes suggest that competitive pressures compel suppliers and price-sensitive consumers to seek competitive advantage wherever they can find it. These outcomes may frustrate the primary intent of competition: cost reductions generated by real efficiencies.

Again, we cannot conclude with confidence that any particular retail market structure will minimize costs, and ESSB 6560 did not call for such conclusions. However, regardless of future market structure decisions, competitive pressure exists and is likely to persist in the electric utility industry. The following three subsections describe strategies that may promote cost minimization in any market structure where competitive pressures exist by:

1. Reinforcing the connection between Washington consumers and existing low-priced resources.
2. Mitigating sources of competitive advantage that may either shift or increase total costs.

3. Removing market barriers and establishing or reinforcing the conditions for efficient market operation.

3.2.2 Strategies to minimize costs where competitive pressure exists by reinforcing the connection between Washington consumers and existing low-priced resources

With growing competition in wholesale and retail markets, the traditional connection between consumers and the electric resources built to serve them may be eroding[4]. The reasons for this trend are discussed in Section 2.

In much of the rest of the country, the most contentious issue in retail restructuring is: "Who will bear stranded costs?" In Washington, stranded costs are likely to be modest. In many instances, we may face the opposite issue. Insofar as electric generating resources used to serve Washington consumers are worth more than they cost, the animating issue here is how the positive difference between value and cost is distributed among Washington consumers, other consumers, and shareholders. This issue could be framed as "Who will reap the 'stranded benefits'?"[5] Stranded costs and stranded benefits are variations on the same issue: "When resources are sold at market, how is the difference between cost and market price distributed?"

This issue arises in conjunction with the transition to market prices. While Washington law does not mandate such a transition, data collected from utilities suggest that such a transition is at least partially under way in the retail market. (See 2.2.2.2) The transition is, of course, well under way in the wholesale market throughout the West. Corporate realignments and partnerships discussed in 2.2.2.9 also suggest that the traditional connection between consumers and the electric power resources that serve them may be becoming more fluid.

Because this issue concerns the distribution of the costs and benefits of existing resources, it may be a cost-shifting issue. (See Section 4.) We discuss it briefly here because, from a Washington-only perspective, it may well affect total electric service costs. The biggest part of this issue concerns the connection between Washington consumers and the resources of the Federal Columbia River Power System. Strategies to reinforce that connection are discussed in 3.1.1. However, Washington consumers are also served by a variety of publicly owned and privately owned non-federal resources that may be worth more than they cost. Strategies to reinforce the connection between Washington consumers and the benefits of those resources are discussed in Section 4, Electricity Rates and Equity.

3.2.3 Strategies to reduce costs where competitive pressures exist by mitigating other sources of competitive advantage that may either shift or increase total costs.

The premise of the strategies below is that costs may be minimized where competitive advantage is gained only by achieving genuine efficiency and cost reduction. (Another source of competitive advantage that may be consistent with cost-minimization is product differentiation. However, since this section focuses on strategies to minimize costs, it does not discuss product differentiation.) While each of these strategies is discussed more fully elsewhere in the report, they are listed here to indicate that they may reduce costs by focusing competitive pressure on the areas where it is most likely to result in real efficiencies.

3.2.3.1 Clarify and reinforce the distinction between components of electric service that are competitive and those that remain in monopoly service. Costs may be minimized where competition is focused on those portions of electric service that lend themselves to effective competition. (Power generation is generally acknowledged to be the component of service that is best suited to competition, though other functions including billing and metering may lend themselves to competition as well.) The purpose of competition may be frustrated, however, where competitive advantage can be gained by shifting or avoiding the costs of components of service that are not effectively competitive (such as local distribution). This suggests that cost-minimization may be more likely to occur where there is a clearly drawn line between the costs associated with competitive and monopoly components of service. Potential strategies for clarifying this line include:

- ❖ Encouraging or requiring separation of generation functions from transmission and/or distribution functions: Arguments for this approach suggest that competition will be enhanced and vertical market power will be reduced if the different components of electric service are provided by different businesses. Arguments against suggest that the physical characteristics of the electric system lend themselves to vertical integration and that efforts to "de-integrate" the industry raise property rights and local control concerns.
- ❖ Establishing geographically defined service territories for electric distribution: Proponents of this approach argue that it would both allow for equitable recovery of appropriate system costs and prevent construction of costly, duplicative, and poorly integrated distribution facilities. Opponents argue that eliminating the option of distribution bypass would allow distribution companies to arbitrarily load costs into rates for delivery service. They also argue that there may be simpler strategies such as exit fees to prevent cost shifting. This strategy is described in Section 4. The status of contractual service territory agreements is describe in Section 5.

3.2.3.2 Define appropriate system-wide costs and determine a fair way to collect them from all users without imposing competitive handicaps on any supplier. The "appropriate" level of such system-wide costs is open to debate. However, such costs may include:

- ❖ Unavoidable shared costs of the existing system that cannot be recovered in competitive power rates;
- ❖ Costs of investments that may be necessary to minimize long-term costs, preserve reliability, or protect the environment. Collecting the cost of such investments through non-bypassable distribution charges, as some states and utilities now do, reduces the likelihood that competitive advantage will be gained by bypassing these costs. This strategy is discussed more fully in Section 9.

- "Stranded" generation costs. Where price advantage is gained through redistribution of existing, unavoidable generation costs, no cost reduction has occurred. However, the method for recovering stranded costs can have important implications for total costs. Stranded cost recovery is most likely to support cost minimization where:
  - Recovery of sunk costs does not support or require continuing operation of uneconomic generation;
  - Owners of uneconomic generation have an incentive to mitigate stranded costs; and
  - Recovery procedures and formulas confer no undue competitive advantages on incumbent suppliers.

  Stranded cost recovery is discussed in Section 4.
- Utility taxes. Tax reforms such as shifting the Public Utility Excise Tax to a use tax may be designed such that suppliers do not gain competitive advantage or suffer competitive handicap based on differential exposure to taxes. (See Section 4. See also, "Briefing Paper on Tax Policy and Restructuring the Gas and Electricity Industries," Washington Department of Revenue, November 1998.)

3.2.4 Strategies to minimize costs where competitive pressures exist by removing market barriers and establishing the conditions for efficient market operation

To the extent that competition exists or is extended further into Washington's retail market, several strategies to provide the conditions for efficient market operation may be worthy of consideration, including:

3.2.4.1 Providing retail choice to those customers who are prepared and willing to accept and respond effectively to market risks: The Washington Legislature has debated various structural changes to the retail market in which some or all customers would gain direct access to the power market. Many utilities now offer some form of access to market-based rates for large customers. However, it is not clear which customers actually want direct access and are prepared to accept and respond to market risks and opportunities. For customers with the capacity to evaluate market risks, make informed choices from among a variety of suppliers, and adapt their purchasing to market volatility, genuine cost savings may be a real possibility. For customers who lack information, attract few alternative suppliers, and are unable to respond to risks and opportunities, genuine cost savings are less likely. Exposing consumers who do have these capacities to market opportunities and risks may help to increase the efficiency of the generation market (by increasing the number and diversity of buyers) and minimize the cost of responding to possible energy and capacity shortages. (See 2.3) Strategies for ensuring that consumers who choose alternatives to rate-regulated service bear the risks associated with such choices are discussed in Section 4 under "Terms and conditions for exit and reentry to average rates."

3.2.4.2 Strategies such as aggregation that allow small consumers to participate effectively in competitive markets. Experience from retail pilots in Washington and the early experience in states that have restructured suggests that effective markets do not evolve instantly or automatically to serve small customers. Public policies that facilitate aggregation of smaller loads into larger and more effective purchasing blocs may hasten the evolution of a more effective market for small consumers[6].

3.2.4.3 Information and disclosure: Markets function more effectively when consumers have accurate information. Lack of information may be a particularly troublesome obstacle for small consumers, since the cost of acquiring more information (measured in time and intrusiveness) may outweigh the benefits of informed shopping. However, to the extent that competitive options exist, public policies that increase the accessibility of accurate, objective, easy-to-understand and easy-to-compare information about those options are likely to promote cost minimization. Disclosure of information about generating resources is the subject of a study being delivered to the legislature pursuant to HB 2831.

3.2.4.4 Mitigating competitive advantages of "incumbent" suppliers. Where competition replaces monopoly service, a number of advantages may accrue to existing suppliers[7]. Insofar as these advantages do not reflect real efficiencies or cost savings offered by the incumbent, they may reduce the likelihood of cost reduction from competition. Where competition exists or is introduced, strategies to provide a level playing field for new entrants may help minimize costs.

3.3 Supply Adequacy and Reliability

Section 2.3 indicates that in some months, the region's demand for electricity could exceed the combined capacity of the region's power plants and the ability to import additional power. Without actions to prevent such shortfalls, the likelihood of deficits increases over time. The choice of strategies used to ensure adequacy and reliability of the region's power supply over time may have a significant impact on the cost of electric service.

Strategies to prevent such shortfalls include the variety of methods that utilities have used to meet growing demand in the past, including development of new generation resources, increasing transmission capacity, and demand-side measures including peak-shaving, distributed generation, and energy efficiency. However, as Sections 2.3 and 8.4.3 describe, implementation of these strategies is complicated by uncertainties regarding future market structure and the role of electric utilities with respect to meeting demand for power.

In the past, utilities could evaluate the range of supply and demand-side alternatives for providing adequate power supplies and capacity to serve a reasonably predictable customer base. However, with increasing competition in electricity markets and substantial uncertainty about the structure of those markets, utilities may be increasingly reluctant to assume full responsibility for meeting uncertain loads. (This trend is discussed more thoroughly in Section 2.3.) As a result, existing strategies for ensuring supply adequacy and reliability at the lowest cost appear to be less effective. New strategies may have to consider not only the cost and feasibility of supply-side and demand-side alternatives, but also the financial, legal, and institutional arrangements that will allow for timely development of those alternatives.

The Northwest Power Planning Council launched a study to address the adequacy and reliability of the region's power supply in December of 1998. The Northwest Power Pool is also conducting a study on the adequacy of power supply for the current winter. The Power Council has convened an external advisory group to help with the study. Given time and resource constraints and the fact that other agencies are conducting a more thorough examination of the issue, the UTC and CTED did not undertake an independent review of strategies to ensure supply adequacy and reliability.

Section 8 of this report addresses the issue of resource adequacy from the perspective of electric system reliability. In 8.5.2, it briefly discusses two power supply-related strategies to improve reliability: mandated minimum levels of generation reserves and deployment of "distributed generation," such as fuel cells, microturbines, and solar photovoltaic systems. An alternative to mandated reserve levels would be to create a market where generators can bid in emergency capacity and end-users can bid in demand reductions. This may improve the incentive to maintain some emergency reserves while providing a means for ranking and choosing alternatives for preventing supply shortages according to cost.

Like many issues discussed in this report, the issue of resource supply adequacy and reliability reflects the transitional nature of this period in the electric industry. There appears to be no consensus as to the future structure of Washington's electric power market. Yet the effectiveness of mechanisms used in the existing structure to ensure adequate, reliable, least cost energy service may be waning. Under the 1980 Regional Act, the Bonneville Power Administration bears significant responsibility for developing new resources for the region, and the Northwest Power Planning Council prepares a resource plan to guide BPA in that effort. In the current environment, it appears unlikely that BPA will perform this function to any significant degree. As a result, the Power Council's Regional Plan may be of limited applicability to the region's actual resource development activities. In response, the Council has initiated a formal examination of what new mechanisms may be needed to achieve one of the Regional Act's statutory purposes, "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply."

3.4 Environment

The discussion of environmental trends in Section 2 suggests that three trends are most likely to have a significant effect on the environmental costs of electric service in the foreseeable future:

1. Declining populations and extinction of wild anadromous fish.
2. Global climate change.
3. Increasing competition in electric power markets.

The strategies described below for reducing environmental costs correspond to these same three trends.

3.4.1 Declining populations and extinction of wild anadromous fish

Alternative strategies for promoting recovery of declining salmon and steelhead stocks are the subject of intense debate in Washington and the region generally. The costs and benefits of these strategies are also the subjects of considerable controversy. It is well beyond the scope of this report to suggest which strategies are the most likely to minimize environmental costs or minimize the total cost of electric service. However, fisheries advocates, utilities, and other stakeholders appear to be converging on at least two broad objectives. These objectives are not, in themselves, strategies. However, they may serve as evaluation criteria for choosing among strategies in such a way as to minimize internal and external costs.

- **Coherence:** The proliferation of divergent, uncoordinated, and sometimes competing salmon recovery plans tends to increase internal costs and limit the overall effectiveness of recovery efforts. Currently, at least three "sovereigns" have their own recovery plans. The federal government has a recovery plan for some endangered and threatened stocks developed under the Endangered Species Act by the National Marine Fisheries Service. (A more comprehensive federal plan is due to be issued in 1999). The states have the Northwest Power Planning Council's Fish and Wildlife Program, in addition to a variety of individual state plans. The Columbia Basin tribes have an anadromous fish restoration plan called "Wy-Kan-Ush-Mi Wa-Kish-Wit (Spirit of the Salmon)." These plans contain contradictory provisions and reflect different strategies. Unification (or at least effective coordination) of these plans may enhance the prospects for reduction of both environmental and economic costs.
- **Accountability:** The recovery effort may cost less and produce more if it has a clearer focus on intended results and accountability for achievement of those results. Given the scientific uncertainty associated with salmon and steelhead recovery efforts, results cannot be guaranteed. However, fisheries advocates and other river interests appear to agree that expenditures to date have not produced satisfactory results. Most interests agree that a more focused, less fragmented strategy with a stronger link to the best available science would be more likely to produce results.

Accomplishing these objectives may or may not reduce the costs of anadromous fish decline that are internalized in power rates. That is, a coherent, results-oriented strategy may result in higher prices to electricity consumers, but this increase in internal costs may be outweighed by a decrease in external costs if the strategy is significantly more effective. Conversely, strategies that are designed to minimize the internal cost of fish recovery measures, such as administrative or legislated "fish cost caps", may lower prices but may also increase external costs by precluding implementation of effective recovery measures. Evaluation of the costs and benefits of any particular set of fish recovery measures or cost control methods is beyond the scope of this report.

3.4.2 Global climate change

Reducing environmental costs associated with global climate change is an international challenge. In the absence of national and international efforts to reduce greenhouse gas (GHG) emissions, Washington strategies would be fruitless; even eliminating all of Washington's GHG emissions would have little effect on global climate if the State was acting in isolation. However, actions to reduce GHG emissions may have other benefits.

Some actions to reduce greenhouse gases, such as cost-effective energy efficiency improvements, offer net economic benefits in addition to their environmental benefits. Also, Washington is home to a variety of industries that anticipate substantial growth due to growing demand for low-carbon and carbon-free energy sources. These industries include: fuel cell development, energy efficiency firms, silicon crystal manufacturing, power inverters, efficient equipment manufacturing, light vehicle technology, and others.

Because so much of Washington's existing electric power base is renewable, the State may gain economic advantage from some strategies to reduce carbon emissions. The price we pay for energy may fall relative to other states and countries if federal or international actions internalize the cost of GHG emissions. Washington may also stand to gain from strategies to reduce carbon emissions that allow for tradable credits for emission reduction. Efforts are underway in Congress to ensure that early actions to reduce GHG emissions receive credit in any future emission reduction or trading initiative[8].

Strategies for reducing the external costs of electric service by reducing greenhouse gas emissions or storing carbon may be grouped broadly as follows:

1. Identifying and evaluating greenhouse gas emission reduction options.
2. Increasing efficiency of electricity production and use and developing renewable energy resources.
3. Offsetting or sequestering emissions in other sectors.
4. Internalizing the cost of carbon dioxide and other greenhouse gases.

3.4.2.1 Identifying and evaluating greenhouse gas emission reduction options.

States can examine the range of alternatives for reducing emissions and/or establish emission reduction targets. Oregon, for example, has established a "benchmark" of returning to 1990 emission levels by 2000.[9] The state has identified a series of actions to help meet that benchmark.[10] Alternative methods of emission reduction could be ranked according to economic costs and benefits to help policy-makers determine which if any strategies are appropriate.

3.4.2.2 Increasing efficiency of electricity production and use and developing renewable energy resources.

Strategies to increase energy efficiency and develop renewable resources may help reduce greenhouse gas emissions without reducing energy service levels. Some of these strategies are discussed at greater length in Section 9 of this report.

3.4.2.3 Offsetting carbon dioxide emissions through non-power related strategies

- **Emissions offsets:** The electric system may look to other sectors of the economy for cost-effective alternatives to emission reduction at power plants. In Washington, the largest opportunities appear to lie in transportation. Emissions from transportation are obviously not costs of electric service, so mitigating them does not directly reduce the environmental costs of electric service. However, if emission reduction strategies include a market for carbon dioxide emissions reduction under a cap and trade system, mitigating emissions in other sectors may be a cost-effective compliance strategy.
- **Sequestration of carbon:** Sequestration is a strategy for storing carbon to prevent it from accumulating in the atmosphere. Carbon sequestration efforts include forest conservation management (controlling deforestation) and storage management (increasing carbon storage in existing forests or establishing new forests). Independent power producers are gaining experience with sequestration through international forest management initiatives. More advanced, experimental sequestration strategies are also being researched[11].

3.4.2.4 Internalizing the cost of carbon dioxide and other greenhouse gases.
The economic rationale for internalizing environmental costs generally is discussed below in 3.4.3. Given continuing international negotiations aimed at reducing these emissions, it seems unlikely that carbon dioxide costs will remain completely external to energy prices. Some modest costs for programs such as tree planting have already been internalized in power rates for some customers. Other possible forms of internalization include:

- Siting or other air quality standards for greenhouse gas emissions[12].
- Carbon taxes (to replace other taxes or to fund carbon reduction efforts)
- “Cap and trade” (setting an emission ceiling and establishing a system of tradable credits to achieve the desired reduction at minimum cost, as the Clean Air Act does for sulfur dioxide. See 3.4.3)[13]
- Carbon emission reduction or sequestration activities by power providers who recover the cost of those activities in power prices[14].

Actions that internalize GHG costs to power prices may cause concern among price-sensitive customers, particularly the electricity-intensive industries that locate in Washington because of lower power prices. However, internalization of GHG costs at the national or international level may increase the price of power in other regions relative to Washington, because Washington relies primarily on hydropower.

3.4.3 Aligning competitive markets and environmental objectives

As noted in Section 2.4, competition in electric power markets can affect both the total environmental cost of electric service and the distribution of environmental costs between internal costs (included in power rates) and external costs (not included in power rates).

Strategies for minimizing environmental costs in a competitive environment are included in the discussion above on global climate change and in Section 9. The restatement of these strategies below focuses on the characteristics of these strategies that lend themselves to application in a competitive environment:

3.4.3.1 Universal System Benefits Charge for investment in energy efficiency and renewable resources.

This strategy is discussed more fully in Section 9. It is designed to reduce the competitive handicap associated with investments that may minimize environmental costs and/or total costs, but not rates.

3.4.3.2 Internalize environmental costs

To the extent that we rely on markets to minimize costs, strategies to ensure efficient market operation may become more appropriate. Economists have identified "externalities" as a significant cause of inefficiencies in markets, including energy markets[15]. Market forces are more likely to minimize costs where costs are internal to price. Even where internalization reduces costs, however, it may cause concern among price-sensitive customers. Examples of internalization strategies that might be pursued at state, federal, or international levels include:

- Introducing environmental standards concurrently with competition: Environmental standards, such as emission reduction targets, can be used to ensure that competition to minimize price occurs within environmental limits deemed appropriate by the jurisdiction that adopts those limits.
- Pollution taxes: A direct way to internalize environmental costs is to apply a tax that approximates the cost of the environmental damage or the cost of mitigation measures. Such taxes can be used to fund mitigation. Alternatively, they can be made "revenue neutral" by using them to reduce or replace other taxes[16].
- Cap and trade: An alternative to directly adjusting price to reflect environmental costs (through, for example, carbon taxes) is to set an overall limit on the amount of a pollutant and allow a market to develop that minimizes the cost of achieving that limit. This mechanism allows emitters of the capped pollutant to purchase credits from other emitters who can reduce emissions more economically. An informal market of this type has already begun to develop among some U.S. utilities who have voluntarily agreed to greenhouse gas reduction targets[17]. This is how sulfur dioxide is regulated under the Clean Air Act, and how the United States proposes to reduce carbon emissions to meet the Kyoto protocol[18].

3.4.3.3 Avoid and/or eliminate incentives to continue operation of older, less efficient sources of generation.

Competition may provide an incentive for innovations that reduce the economic and environmental costs of electric generation. However, depending on how it is structured, competition may also prolong the operation of older, less efficient generating facilities. For example, if terms for stranded cost recovery support or require continued operation of high-cost generation, opportunities for economic and environmental cost reductions may be missed. Strategies to avoid or compensate for these problems may include:

- ❖ Stranded cost recovery methodologies that do not require continued operation of facilities with high internal and/or external costs.
- ❖ Expedited siting for energy facilities that minimize environmental costs.

3.4.3.4 Facilitate development of markets for resources with low environmental costs.

The evolution of markets for "green power" could help to minimize environmental costs. Strategies to support evolution of such markets include:

- ❖ Direct access to resources with low environmental impacts: Even in the absence of a comprehensive retail access initiative, policy-makers could allow direct access to environmentally desirable alternatives[19]. It may, however, be difficult to sustain the administrative costs of providing access to "green" resources on such a limited basis.
- ❖ Disclosure of the environmental characteristics of electric generating resources and labeling of retail power products with environmental information: One of the requirements for efficient operation of competitive markets is clear, readily accessible information. Market research suggests that such information must be simple, objective, and somewhat standardized in order to be useful[20]. Disclosure and labeling of environmental information are discussed in Section 9 and at greater length by the UTC in its report prepared pursuant to HB 2831.
- ❖ Investing premium revenues associated with "green" resources toward development of additional "green" resources: "Green marketing" may reduce environmental costs if additional revenues from such marketing are invested in new resources with low environmental costs or in mitigation of environmental damage.

3.5 Technology

3.5.1 Background

Development and application of new technologies is generally a long-range, but nevertheless potentially important, strategy for reducing electric service costs. However, as discussed in 2.5, utility industry investments in electric technology R&D have declined dramatically in recent years, apparently due to short-term competitive pressures. As of 1994, U.S. utilities devoted about .03% of their revenues to R&D compared to an average of 3.1% for U.S. industrial firms[21]. We have no data on R&D trends for electricity-related industries other than utilities, such as equipment manufacturers. To mitigate competitive pressure to reduce R&D efforts, some states include R&D among the categories of investment that are supported by a system benefits charge.[22]

The private sector, USDOE, universities, national laboratories, and other research institutions are typically the leaders in energy technology research, development, demonstration, and commercialization. For example, the Federal government supports the introduction of new energy technologies by funding research at national laboratories and through the creation of many private/public partnerships to bring these new technologies to market.

The state can play a supporting role in technology development in a variety of ways. These roles can be loosely grouped into two categories: policy initiatives and partnerships. Policy initiatives may create a framework within which technology innovators have the necessary tools and incentives to conduct technology R&D. Partnerships may involve more active and ongoing participation by public agencies. These categories overlap substantially, since technology development often requires both policy support and collaboration among institutions with complementary capabilities.

3.5.2 Policy initiatives:

The discussion below focuses on some of the general strategies and institutional opportunities available for technology research, development, demonstration and commercialization rather than strategies to promote specific technologies.

- **Codes and standards**: Upgrade energy codes as cost-effective energy efficiency technologies become available. Technological innovation and expanding markets continue to drive down the cost of energy efficiency measures and products. Provisions for these new products could be incorporated in code as they become cost-effective during normal code review cycles. Washington can also support and participate in the development of federal appliance efficiency standards.
- **Market transformation and market development** initiatives to help commercialize new technologies: Market transformation is a relatively new approach to energy efficiency that concentrates on making structural changes to the markets for energy efficient goods and services. Market transformation frequently supports technological innovation[23]. It is discussed at greater length in Section 9. Market development strategies could include initiatives such as portfolio standards or public purchasing activities that expand the market for new technologies. (These are discussed in Section 9.) Alternatively, the state could target more conventional business development activities toward businesses engaged in energy technology development. Such strategies include: technical assistance, microloans, state administered federal grant and loan programs, retention and recruitment, business incubators, and trade assistance.
- **Increased linkages among energy services and information services**: The prospects for enhanced interaction between electricity technologies and information technologies appear to be growing. As new ventures linking these technologies are formed and the market develops, state policy-makers may wish to identify and/or remove barriers to cost-reducing integration of these technologies[24].

- **Public investment in technology research, development, demonstration and commercialization**: Technology research and development activities may exhibit the economic characteristics of "public goods:" since their benefits are shared widely, there may be inadequate incentives for any one party to bear the cost of producing those goods.[25] The combination of this public goods problem and growing short-term competitive pressures appear to have reduced R&D investment by utilities to a very low level. Alternative sources of public investment for such purposes are discussed in Section 9. At least seven states that have adopted system benefits charges direct or allow a portion of those revenues to be used for R&D.
- **Support for federal research and development**, particularly at NW institutions such as BPA, PNNL, and the state's research universities.

3.5.3 Partnerships

Washington State government has a long history of partnering with private and public sector entities for technology development. This history includes promotion of the state's leading technology industries and support of two premier research universities.

Washington firms and research institutions are already among the leaders in some of the most promising new electric power technologies being developed.[26] In addition to the many private firms in Washington with energy technology expertise, a variety of public institutions may bring valuable expertise to energy technology partnerships, including: the Bonneville Power Administration, Pacific Northwest National Laboratories, the US Department of Energy Regional Support Office, Washington State University Energy Program, the University of Washington, Spokane Intercollegiate Research and Technical Institute, the Washington Public Power Supply System, Conservation and Renewable Energy Systems, individual utilities, local governments, and others.[27] (PUD authorizing statues may limit their ability to enter into such partnerships.)

Energy technology partnerships with public and private institutions can take many forms. Existing partnerships include:

- A recently signed Memorandum of Understanding among the Washington Public Power Supply System, PNNL, and the WSU Energy Program to develop improved renewable and distributed energy technologies; and
- The Association of State Energy Research and Technology Transfer Institutions' effort to develop a "virtual lab" among the states.

Other possible examples include:

- Energy technology development enterprises may provide research funding to university faculty and staff using a wide array of contracting mechanisms and intellectual property rights allocations.
- Business incubators for energy technology industries.
- Application of distributed generation (photovoltaics, fuel cells, etc.) and other emerging technologies in public facilities to support development of

such technologies. Installation of solar-powered emergency telephones on bridges and freeways by the Department of Transportation is an example.

- ❖ Support for energy R&D by Washington state research institutions. This can be achieved by directly funding (from a systems benefit charge or other source) university-based energy R&D and/or clearly identifying research on energy technologies as part of the institutions' missions. This may also help attract federal and private support to R&D initiatives that address Washington needs and priorities.

3.5.4 Technology Assessment

Like all technology initiatives, energy technology R&D is by its nature a risky undertaking. Determination of which if any policy initiatives and/or partnerships would be beneficial to the state may require a thorough understanding of existing technology trends and initiatives and an assessment of the state's technology-related challenges and opportunities. Because of the vast scope of potential technology activities, the limited resources available, and the inherent risks, the choice of policy initiatives and/or partnerships should be a considered one. To inform such choices, the state may wish to consider periodic technology assessments to:

- ❖ Monitor progress of technology development and understand the trends that are likely to affect Washington's electricity system.
- ❖ Identify needs and circumstances that present specific, technology-related challenges and opportunities for the state's electric power system (for example, hydroelectric turbine modifications to promote juvenile salmon survival without increasing spill.)
- ❖ Identify private and public institutions in the state with complementary research and technology capabilities that could position the state to host federal R&D initiatives.
- ❖ Identify barriers to development and implementation of energy technologies that would be particularly beneficial to Washington.

3.6 Fuel Cost

Since Washington is not a significant fuel-producing state, most strategies for minimizing fuel costs per se are not applicable. Many of the other strategies discussed in this report may have the effect of reducing the state's exposure to fuel cost increases, including:

- ❖ Strategies to increase the efficiency of electric power generation.
- ❖ Strategies to increase the efficiency of electric power consumption.
- ❖ Strategies to maximize the thermal efficiency of gas consumption including cogeneration and replacing electric water and space heat with gas.
- ❖ Some of the strategies designed to reduce carbon emissions.
- ❖ Developing renewable energy resources.

- Strategies to accelerate the introduction of low-carbon or carbon free energy sources.

Strategies using market-based risk management techniques, such as hedging, options, and futures, may help suppliers and some consumers manage fuel cost uncertainties.

Endnotes for Section 3

[1]Northwest Power Planning Council, Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues, June 5, 1998, http://www.nwppc.org/98_11.htm.

[2]Bonneville Power Administration, Power Subscription Strategy Proposal, December, 1998.

[3] The Federal Power Act of 1920, §824a delegates to the Secretary of Energy the authority "to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy"

[4] For example PacifiCorp is divesting its distribution assets in Montana. PacifiCorp argues that, once they have no distribution business in Montana, they should not be allowed to recover any stranded costs from Montana consumers, nor should Montana consumers be entitled to any of the "stranded benefits" associated with PacifiCorp's below-market resources. With retail competition and divestiture, they contend, the link between Montana customers and the generating resources built to serve them is severed.

[5] The term "stranded benefits" may be a misnomer, since the issue arises not because the benefits are stuck, but rather because they are potentially unlinked from the traditional beneficiaries. Nevertheless, it is frequently used because it mirrors "stranded costs."

[6] See for example, Larry Alexander, et. Al, "Feasibility of Small Customer Aggregation for the Delivery of Comprehensive Energy Services in a Competitive Utility Environment," Proceedings from the ACEEE Summer Study, Washington, D.C. 1998.

[7] These advantages may include: Greater name familiarity; historical role in the community; scale of operations which would be prohibitive to duplicate; and potential ability to offer own supply subsidiary preferential access to distribution facilities.

[8] Senate Bill 2617, "Credit for Voluntary Early Action", October 1998

[9] "Oregon Shines II: Updating Oregon's Strategic Plan, A Report to the People of Oregon From The Oregon Progress Board and The Governor's Oregon Shines Task Force," January 21, 1997

[10] Oregon Office of Energy, Report on Reducing Oregon's Greenhouse Gas Emissions, December 18, 1996. Available at http://www.cbs.state.or.us/external/ooe/resource/finalrpt.htm

[11] More sophisticated and expensive sequestration strategies include capturing and sequestering carbon dioxide after combustion and decarbonizing fuel before combustion. Storage of carbon dioxide is proposed in the ocean or geologic formations. These approaches are technically feasible but the costs and the long-term environmental effects are largely unknown. Decarbonization involves removing some or all of the carbon from a fossil fuel and storing the carbon as a solid. This strategy faces economic obstacles because it substantially reduces the energy content of fossil fuels. Both technologies are considered long-term options.

[12] See, for example, Oregon HB 3823.

[13] "Greenhouse Gas Emissions Trading - Improved Compliance at Reduced Cost," Center for Clean Air Policy, Washington D.C., July 1997.

[14] For example, 650 utilities have signed Climate Challenge Participation Accords with USDOE in which they agree to reduce or limit greenhouse gas emissions. See "Early Action and Global Climate Change: An Analysis of Early Action Crediting Proposals", Pew Center on Global Climate Change, October 1998.

[15] See, for example, Hohmeyer, O., Social Costs of Energy Consumption, Springer-Verlag, 1989.

[16] For a complete discussion of this approach, see Tax Shift, Northwest Environment Watch, April 1998.

[17] Arizona Public Service is meeting its "Climate Challenge" commitment in part by purchasing credits from Niagara Mohawk Power Corporation, which were available because NMPC had reduced emissions by more than the amount necessary to meet its emission reduction commitment. Under the agreement, APS and NMPC jointly fund a renewable energy project in Baja Sur, Mexico. Source: APS online at http://www.apsc.com/power/96annual/releases.asp

[18] "Greenhouse Gas Emissions Trading - Improved Compliance at Reduced Cost," Center for Clean Air Policy, Washington D.C., July 1997.

[19] The Comprehensive Review, for example, recommended that access to "green" resources be allowed first, prior to general retail access.

[20] See, for example, "Uniform Consumer Disclosure Standards for New England: Report and Recommendations to the New England Utility Regulatory Commissions," November 13, 1997, prepared by The New England Disclosure Project, A Project of the National Council on Competition and the Electric Industry.

[21] JJ Dooley, "Unintended Consequences: energy R&D in a deregulated energy market." Energy Policy, 26 (1998), 551.

[22] Five states specifically allocate some SBC funds to r&d for energy efficiency and/or renewables. Two others encouraged r&d investment, but didn't earmark funds for it.

[23] For example, the Northwest Energy Efficiency Alliance is currently funding a project that would modify the furnaces used for growing silicon crystals to improve their energy and water use efficiency. This could represent a significant technological improvement in the process used for manufacturing photovoltaic cells and computer chips.

[24] For discussions of integration of communication, information, and energy technology, see Steven. R. Rivkin, "Co-Evolution of Electricity and Telecom. The Electricity Journal 11 (May, 1998), 71-76 and Paul A Centolella, "Energy Services in the Information Age: The Convergence of Energy, Communications, and Information Technologies." Proceedings from the 1998 ACCEE Summer Study on Energy Efficiency in Buildings. Washington, DC, 1998. Pp. 8.13-8.24

[25]"Strategic Options for Public-Interest R&D." Carl Blumstein and Stephen Wiel. September 19. 1997

[26] "The Next Generation of Energy: The Renewable Energy and Energy Efficiency Industries in Washington State,"" ECONorthwest for Washington DCTED, August, 1998.

[27] Washington public institutions currently focused on applied research development and demonstration of energy efficiency, renewables, and distributed energy technologies include but are not limited to:

1) Washington State University Energy Program with a broad focus on industrial (especially industrial motors), commercial, residential, energy distribution, and renewable technologies;

2) Pacific Northwest National Laboratory with a focus on a variety of specific energy efficiency and distributed energy technologies;

3) Spokane Intercollegiate Research and Technology Institute linked with Avista Lab with a focus on fuel cells;

4) The Washington Public Power Supply System's Applied Process Engineering Lab;

5) BPA with a focus on fuel cells and hydroelectric technology.

4.0 Electricity Rates and Equity: Potential For Cost-shifting.

ESSB 6560 directs the agencies to examine:

The potential for cost-shifting among customer classes and among customers within the same class, and strategies available to minimize inappropriate cost shifts.

This section addresses the issue of cost-shifting in four ways:

1) We discuss "cost-shifting" and average-cost rate-making in general. This discussion yields a working definition of the term "cost-shifting" and a scope for our examination of cost-shifting potential.
2) We describe a number of developments and circumstances in the electricity service industry in Washington that either could, or are, causing cost-shifts to happen.
3) We evaluate a subset of these circumstances to estimate what the potential magnitude of cost-shifting might be.
4) We examine a number of actions or policies that could affect and minimize the potential for cost-shifts.

4.1. Cost-shifting: Definition and Study Scope

Cost-shifting is a relevant issue when the price for a monopoly service is established as a cost-based rate through regulation or some other administratively or legislatively established directive. When prices are set administratively, the rate-setting body may have within its authority the ability to shift cost responsibility from one set of customers to another. Most electricity service in Washington continues to be priced through administrative or regulatory process at the state or local level. The changing context and factors affecting those processes will be the focus of this section. As a working definition of "cost-shifting" for the purposes of this analysis we will use:

> *An administrative or regulatory decision to change rates charged to customer classes or customers within a class that causes those customers to be responsible for costs they are not responsible for in rates today and which were formerly paid by other customers or customer classes.*

In a fully competitive market, prices are not set administratively. In theory, when a market is efficient and effective for all buyers and sellers there is no party that can cause costs to be shifted from one buyer to the detriment of another. For a market to be efficient and effective there must be multiple sellers competing for every buyer, and multiple buyers competing for every seller, and all parties must have reasonably equal access to capital and information. In practice, many markets are not fully efficient and competitive and prices can significantly diverge from underlying cost for individuals or groups of buyers. While this does not constitute administrative cost-shifting as we have defined it, the result could none-the-less be unfair price differentiation or price discrimination.

While we do not discount the potential for price discrimination or differentiation in markets that are not fully competitive, most retail electricity services in Washington have rates that are set administratively and not by markets. Consequently, we have confined our study to administrative cost-shifting. Moreover, we do not attempt to examine the validity of existing rates nor how prices and services might change in more competitive markets. The definition stated above is applied to administrative rate-setting decisions that are being made today about costs currently being recovered in rates, as well as to decisions that may be made in the future about costs that are yet to be incurred.

Some parties argue that the current level of rates may involve improper or inequitable allocations of cost and that these constitute cost-shifts that should require rates to be realigned with costs. This section does not examine or critique the past decisions of local rate-making authorities or the UTC that have led to the current distribution of cost-responsibility in rates. We believe this to be consistent with the statutory direction to study "the potential for cost-shifting."

The legislation also directs us to examine "inappropriate" cost-shifting. Rate-setting based on the average costs to serve a class of customers always involves the exercise of judgment in the translation of both common and direct costs into average rates. There are no uniform and objective criteria for determining whether cost-shifts, or discrepancies between rates and the costs to serve individual or classes of customers, are "appropriate". There is no state law that establishes how rates are to be based on costs, or that they be exclusively based on costs. Rates are directed by statute to be "fair, just, and reasonable" and one of the factors that must be considered is whether or not they are discriminatory or preferential. These are the criteria that are considered and balanced by state and local rate-setting bodies when judging whether rates are appropriate and whether any cost-shifting implicit within them is appropriate.

4.2. How are electricity rates based on costs?

Electricity rates in Washington have been, and by and large continue to be, based on a utility's aggregate costs to provide service to all of its customers. The revenue necessary to cover the utility's total costs is determined by either the UTC (for investor-owned utilities) or local commissions, governments, or cooperative boards for the consumer-owned utilities. This "revenue requirement" includes both <u>direct costs</u> — those that can be identified with particular categories of customers — and <u>common costs</u> — those that cannot be identified with any particular customer or category of customers.

The revenue requirement is assigned to the various customer classes to recover the common costs and the direct costs that are incurred by the utility to provide service to those customer classes. This is accomplished in a "cost of service study". Rates charged to the customers are developed based on this assigned revenue requirement such that the rate for each unit of service (kWh, kW of demand, or customer account) recovers the *average* cost of serving that customer class.

Calculation of the utility's overall revenue requirement (its overall cost of providing service) is a relatively straightforward matter. But, the assignment of costs to customer classes and ultimately to individual customers is more a matter of judgment than a matter of indisputable fact. Utility service involves a combination of power generation, power delivery, and administrative services that in many cases cannot be definitively assigned to a particular customer class, or particular customers within that class. No cost-of-service study can be totally accurate in its assignment to the customer classes of direct costs because the functions of utility service cannot be totally isolated (e.g. transmission and delivery services involve some aspects of generation services). And, common costs like administration and overhead can only be *allocated* to the customer classes because they are common to all the services. Even within customer classes, rates based on average cost mean that some customers pay more than their actual cost of service and some pay less. Consequently, rate-making based on average costs does not perfectly reflect the costs of service — either for the customer classes, or for individual customers within a rate class.

Recognizing these challenges in cost of service studies, rates are reviewed and approved based on the expert judgment of local officials, coop boards, or the Commissioners of the UTC. This judgment is exercised to achieve equity between customer classes and between customers within a class. However, whether they can be measured or not, average rates frequently involve some level of transfer, subsidy, or cost-shift between customer classes and among customers within a class. So long as rates are based on the average cost to provide service, some customers can argue justifiably that they are paying more than the actual cost to serve them and that other customers are paying less. Arguments about the size and fairness of these "inequities" generally make up a good portion of the debate that occurs during rate cases, at both the state and local levels.

The foregoing discussion makes clear that the issue of cost-shifting is not new. It has historically been a factor in, and a source of controversy surrounding, average-cost rate-making and will continue to be so for all electricity services for which rates are administratively set. Any time rates are changed the potential exists for cost-shifts to occur. The context in which these rate decisions are made *is* constantly changing, however. This changing context leads to change in the kind of pressures rate-setting bodies face when they make judgments about how and from whom costs should be recovered. The next sections describe these changing conditions and identify areas where pressure to shift costs might occur. It is important to recognize that cost-shifting pressures occur in both the wholesale power sector, including transmission, and in the retail local distribution utility sector. The latter category is clearly affected by the former. We have described these conditions separately because many of the issues at the wholesale level are not easily affected by state or local actions. Those at the retail level may be.

4.3. Developments and Trends Affecting Potential for Cost-Shifting: Wholesale Power and Transmission Sector

The most important and far-reaching factor affecting the conditions under which electricity rates are set and which might cause cost-shifts is significant change in the market structure for power generation. Beginning slowly in 1978 with the passage of the federal Public Utility Regulatory Policy Act (PURPA), and rapidly accelerating after passage of the federal Energy Policy Act in 1992, the power generation sector of the electricity industry has undergone a transformation. It has been transformed from a generally closed market dominated by utilities, to a much more open and competitive market involving both utility and non-utility generators, as well as commodity brokers and other market-makers. This has been accomplished primarily through changes in federal regulation of the wholesale power and transmission sectors. The implications of these changes for state and local utility rate-setting and the potential for cost-shifting are profound in the following areas:

- Services and pricing in a commodity market for electricity,
- Transmission access and pricing, and
- The policies of the BPA.

4.3.1. Commodity Market for Electricity

The advent of competition in the electric power generation sector was designed to lead to a commodity market for electricity generation. Since 1992, and particularly with the introduction of published price indices by national newspapers, futures contracts by the NYMEX, and the California Power Exchange in 1998, this commodity market has steadily grown. We noted in an earlier section the significant increase in the volume of bulk, generally wholesale, power transactions in this newly developed market. Competition among suppliers in the bulk power market may maximize the aggregate economic efficiency of bulk power generation. The average price of power from a more efficient power system may be lower, but it is likely also to be more volatile and could actually increase in some regions. While the development of a competitive bulk power market does not directly lead to any specific cost-shifting, it does change the conditions under which utility rates are set and these changed conditions could lead to cost-shifting in at least three ways.

First, the development of this market has led to better and more accessible information about the price at which bulk electricity is available — to utilities and to individual customers who have the means to purchase directly from the market or at market-based prices. It has also led to an expansion of the kinds of services and pricing options available to utilities and these customers. These prices and services may differ from the average cost of power supplied by utilities from plants built and contracts negotiated in the past to meet service obligations to customer loads. When coupled with wider access to the transmission system, the conditions exist for some customers to either leave the average cost system or to press for rates based on market prices rather than average costs. We will describe how these conditions might affect the retail market structure and retail cost-shifting in Washington in the section on retail market trends below.

Second, wholesale electricity price levels were quite low — less than 2 cents per kWh — early in the advent of a more open generation market in both the West and the rest of the country. This is the price for short-term “electricity commodity” before the costs of reliable transport, delivery, metering, billing and system management are included. Recently the market price of short-term electricity has become increasingly volatile with substantial price spikes. In the West, prices have been higher by a half to a full cent this year than those seen in 1995 and 1996 and have seen spikes of over a dollar per kWh. In the Eastern U.S. prices went as high as 7 dollars per kWh early in the summer of 1998. Price volatility is a normal characteristic of commodity markets and is a key factor necessary to attract new investment in production facilities. However, this volatility does represent a substantial risk, which could be distributed differently among customers in the future than resource cost risk is currently distributed in rates. [1]

The third issue involves the relationship between Washington's relatively low-cost power generation resources and Washington's electricity customers. Preceding sections have described how the generation resources now serving Washington customers are lower in cost than the cost of generation nationally, or more importantly throughout the rest of the West. Independent analyses also have shown that the cost of generation serving Washington also is likely to be lower than market clearing prices in California and other Western power marketplaces.[2] Washington's utilities might be able to command a higher price for power they generate if they were to sell in these markets at market price rather than to Washington customers at cost. If this value is not preserved for Washington customers, the potential exists for some, or perhaps all, Washington customers to see increased rates as power originally priced at cost is sold at market rates. This makes development of mechanisms to retain the value of these resources for Washington customers particularly important. A number of recent analyses have made estimates of the amount by which Washington's electricity costs might increase if power were simply market-priced with no provisions to benefits from low-cost resources for Washington customers. The Oak Ridge National Laboratory estimated that, in the absence of policies to retain the benefits of low-cost generation, the states in the Northwest Power Pool could see power generation prices rise 1.1 cents/kWh.[3] This translates to about 22 percent on average retail electricity rates in Washington. The Clinton Administration analysis of the effect of power market deregulation estimated that rates in the Northwest could decrease slightly (5.6 percent) by the year 2010, but only if policy makers took steps to capture the benefits of low-cost federal, public and private generation[4]. Other studies have made a similar point.[5] A recent study by the Northwest Power Planning Council identified that the regional value of cost-based federal power rates, when judged against market set power rates, is from 0 to 9 $billion over the next 20 years, depending on the measures undertaken to meet fish restoration obligations.[6]

4.3.2. Transmission Access and Pricing

The Federal Energy Regulatory Commission (FERC) issued new rules in 1996 (Order 888) to implement the direction of the Energy Policy Act to achieve open access to transmission services for all generation suppliers. These rules govern the transmission tariffs utilities must offer to anyone wishing to transmit power over their facilities. The rules require that all investor-owned utilities must make their transmission facilities accessible to all parties who may wish to use them on the same terms and conditions under which the utility itself uses the facilities. While the FERC rules do not apply directly to non-jurisdictional utilities such as federal, municipal or other publicly-owned utilities, reciprocity requirements are included which mean that a non-jurisdictional utility is not eligible to use the open access tariff of an IOU unless it offers a comparable open access tariff. The FERC also has established principles to govern the way in which rates for open access transmission tariffs are to be calculated. These transmission access and pricing policy developments could result in either direct or indirect pressure to shift costs in several ways.

4.3.2.1. Broadening of FERC Jurisdiction and Implications for Utility Bypass

The broadened access to bulk transmission systems, when coupled with a growing competitive generation market, establishes conditions that may encourage bypass of utility distribution systems. This is particularly true given the FERC's assertion in Order 888 that it has jurisdiction over the pricing, and terms and conditions of service for "retail transmission." These conditions could lead to some retail customers, even those served at relatively low voltage levels, gaining direct access to the bulk transmission system under terms and conditions established by FERC rather than the state or its local jurisdictions. This could lead to either retail distribution facility or power costs being left with the retail utility by departing customers that become FERC jurisdictional for much of their service. These costs could be shifted to other customers if the state or local regulators determine it is necessary to do so. The UTC has joined with ten other states and the National Association of Regulatory Utility Commissioners (NARUC) to appeal the FERC's Order in federal court to overturn what the states claim is an unauthorized jurisdictional incursion on state and local authority.

4.3.2.2. Implications of FERC Pricing Principles

Turning to transmission rates, the rates currently paid by the customers of Washington's investor-owned utilities include transmission and delivery costs that assign a portion of costs to customer classes based on the volume of use (throughput) over the transmission and delivery facilities serving those customer classes. FERC pricing principles assign all transmission and delivery costs to peak usage of the facilities and none to the volume of use. The difference between these two approaches is that customers whose usage varies through time (mainly residential and small commercial customers) are assigned a higher proportion of costs under the FERC method. This change in pricing methodology, coupled with FERC's requirement that utilities pay the same transmission rate to serve native load customers that they charge other users of their systems, means that a cost shift could occur between the industrial and residential classes over the next few years. Based on the transmission component of rates for Washington's largest investor-owned utility (Puget Sound Energy), the magnitude of this effect could be as large as $3 to 4 million annually.[7] This amounts to one-half to one percent of Puget Sound Energy's residential rates. This cost-shift may be difficult for the UTC to prevent given the FERC's jurisdiction over transmission pricing. In fact, the shift could be larger if FERC prevails in its jurisdictional claim noted above.

On the other hand, FERC jurisdiction over retail transmission could have the opposite impact for customers of Washington utilities that purchase a large share of their power or transmission from the Bonneville Power Administration. FERC jurisdiction over BPA's transmission system could shift costs among BPA customers in at least two ways. First, FERC's preferred methodology for pricing wholesale transmission service uses twelve monthly coincident peaks as a billing determinant for demand-based transmission charges. BPA has historically used fundamentally a single, non-coincident peak. Because the FERC methodology is much less favorable to high-load factor customers such as the direct service industries (DSIs), costs could be shifted to these customers from low load factor customers such as small utilities with a high proportion of residential load.

Second, FERC's preferred pricing methodology would allow BPA to include the costs of certain facilities in its transmission rates that have historically been recovered through power rates. These include facilities necessary to integrate generators into the regional grid (called "generation integration" facilities), as well as the Colstrip lines and the Southern Intertie. Rolling these costs into transmission rates would shift them from BPA's power customers to its transmission customers. It might also reduce the likelihood that BPA would have to rely on a transition cost-recovery mechanism such as a rate adjustment clause to cover a shortfall in power revenues.

Eliminating or limiting the application of "postage stamp" rates on the BPA system is another potential cause of cost shifting for BPA customers. "Postage stamp" rates means that transmission on the system is priced at the same rate regardless of the facilities used or distances involved. This is important to many small and rural utilities in the state because it keeps the cost of transmitting power to their systems low. While FERC's Order 888 principles call for "a single, unbundled, grid-wide tariff that applies to all eligible users", FERC has allowed a great deal of experimentation in order to promote the formation of Independent System Operators (ISOs). Eliminating postage stamp rates on the BPA system might better reflect the actual cost of transmission to individual utilities, but it could cause a significant shift of costs to small and rural utilities.

4.3.2.3. Formation of Independent System Operators (ISO)

As the FERC continues to restructure the wholesale power and transmission sectors, it has encouraged the establishment of ISOs. These organizations have many purposes, including: separation of utility power marketing commercial interests from transmission interests; establishment of more efficient access to transmission capacity; more organized control of transmission operation to enhance reliability; and the opportunity to improve the efficiency of transmission pricing. All of these have as an ultimate purpose the improved efficiency and effectiveness of a competitive power generation market.

One of the ways ISO formation might produce a more efficient power market is through elimination of the need to pay multiple transmission tariffs to cross multiple systems. This "pancaking" of transmission rates may restrain economic activity by raising the cost of transmitting power, simply because of dispersed ownership of the transmission grid. However, eliminating pancaked transmission rates would require broad scale transmission pricing changes to develop a single, region-wide tariff that recovers all the costs of each utility's transmission facilities. Such a uniform, single tariff may result in significant shifting of transmission costs. The implementation of an ISO in the Northwest could have the consequence of shifting transmission costs both to Washington from other states and shifting responsibility for transmission costs among Washington utilities.

Cost-shifting emerged as a significant issue during the discussions surrounding IndeGO (Independent Grid Operator), the proposal for an independent system operator for the Northwest and Rocky Mountain regions which was developed by a number of utilities during 1996 and 1997. A number of different pricing methodologies were considered during the IndeGO negotiations, each of which would have ramifications for cost-shifting. The greatest amount of cost-shifting would occur if transmission costs for all utilities in the region were simply averaged into a single, region-wide, postage stamp rate. This is the pricing methodology favored by FERC in the ISO principles that it laid out in Order 888. This methodology would result in costs being shifted to Washington utilities from states such as Montana, Colorado and Wyoming, in addition to costs being shifted among utilities within the state. Some Washington utilities could see their transmission costs increase by 50 percent, or 0.244 per kWh, under a region-wide, postage stamp rate, while others would see decreases of as much as 10%.

The IndeGO parties rejected a region-wide, postage stamp rate because this level of cost-shift was considered unacceptable by utilities participating in the negotiations. Instead, an alternative called the "Allocated Area Rate" pricing methodology was developed which averaged utilities' transmission costs with neighboring utilities within an "Access Pricing Area", instead of across the entire region. This method shifted fewer costs than a region-wide postage stamp rate, and largely eliminated the shifting of costs from one state to another. However, it still resulted in transmission cost increases of 25 percent, or 0.14 per kWh, for several Washington utilities, and cost decreases of a similar magnitude for others. These cost shifts played a large role in the decision by the region's utilities not to go forward with the IndeGO proposal at this time.

FERC has requested enhanced authority to require utility participation in ISOs, and a number of bills have been introduced in Congress which would grant such authority.[8] In recent speeches, FERC Commissioners have indicated they believe FERC already has the authority to order participation in ISOs by jurisdictional utilities.[9] FERC is likely to issue rules clarifying this issue at some point in the next few months. At this point it is not possible to predict what form of ISO may evolve in the Northwest, or how it will ultimately price transmission.

4.3.3. The Bonneville Power Administration

Aside from the transmission pricing issues already described, the BPA's rates for power have also been strongly affected by the development of a competitive wholesale power market. BPA is directed by the Pacific Northwest Electric Power Planning and Conservation Act — Public Law 96-501 (Regional Power Act) to establish its rates according to a very complex set of rules. Any change to BPA power rates, or to the distribution of costs among those rates is traditionally attended by protest from one regional interest or another. As BPA develops power rates and policies affecting access to federal power resources for the next five to twenty years the potential for costs and risks to be shifted are substantial. For purposes of this study we describe three areas: contingent cost-recovery mechanisms; availability of federal power sales; and the low-density discount. Other areas also present the potential for cost shifting including general transmission transfer agreements and BPA power rate structure changes.

4.3.3.1. Contingent cost-recovery mechanism

BPA is required to collect sufficient revenue to repay its debt to the federal Treasury (roughly $7 billion for power facilities) and its third-party debt of roughly $7 billion. The third-party debt is principally for the Washington Public Power Supply System nuclear projects Number 1, 2, and 3. The agency is also required to fund the operation of the power system and its responsibilities for fish and wildlife programs. If BPA's costs to fulfill all these responsibilities rise to a level that causes its rates to exceed the otherwise available price of power in the wholesale market it will begin to lose sales and fail to meet all its obligations. While recent projections made by the Northwest Power Planning Council indicate the probability of this situation occurring is relatively low, it is possible, particularly between 2001 and 2015, after which much of the WPPSS debt will have been repaid.[10] To plan for such a difficult situation, BPA will very likely need to establish a "contingent cost-recovery mechanism." This is a means for it to collect revenue from some source other than power sales to fulfill its obligations. A number of different approaches are currently under discussion. Any such mechanism could lead to cost shifts *if* it is ever implemented and *if* it fails to collect revenue equitably from all regional parties, including public and private utilities and direct service industries. The magnitude, probability, and distribution of these cost-shifts are impossible to predict at this point in time.

4.3.3.2. Availability of Federal Power

BPA will establish new contracts for power sales from the Federal Columbia River Power System (FCRPS) in 1999. These contracts will cover periods beginning in 2001. The amount of power available to be sold from the FCRPS is limited and BPA will establish the framework and criteria under which this limited power will be made available to Northwest utilities and direct service industries. Currently, FCRPS power is sold to meet the net-requirements of public utilities under the public preference provisions of the Bonneville Project Act and the Regional Act. Power is also sold, when requested, to meet the net-requirements loads of investor-owned utilities under the provisions of the Regional Act. And finally, the direct service industries purchase power under BPA's contracting authority granted under the Regional Act. Residential and small farm customers of the investor-owned utilities also receive benefits from the FCRPS through the Residential Exchange Program, authorized by the Regional Act. The only group of Northwest electricity customers who do not have access to some form of direct benefit from the federal power system are the industrial and commercial customers of investor-owned utilities.

Debate has occurred over the last year regarding how, under the Residential Exchange Program or otherwise, economic benefits of the FCRPS will be accessible to the residential and small farm customers of investor-owned utilities. Ultimate resolution of this issue will involve claims of cost-shifts by all parties. FCRPS benefits received by the residential customers of some of the investor-owned utilities (mainly Puget Sound Energy) are substantial, as much as $50 million/year. If actual power is allocated by BPA (rather than cash transfers) to these residential customers, insufficient FCRPS power will be available to serve the direct service industries.[11] Limiting the amount of federal power available to serve these industrial loads means that they will need to use their recently acquired access to BPA transmission services to purchase power on the market, perhaps at prices higher than FCRPS costs. If BPA arranges to provide benefits in the form of cash payments to the investor-owned utility residential customers, or purchases additional power to meet these loads, either the public utilities or the direct service industries will likely claim that new costs have been shifted to them. The nature of cost-shifts resulting from BPA's power allocation policies and rate making will not be known for certain before the end of 1999. BPA and the region are working hard to develop a framework for selling federal power that is principled and balances all interests.

4.3.3.3. Low Density Discount

Also as directed by the Regional Act, BPA has historically offered a discounted power rate to low-density utility systems (rural systems characterized by few customers per mile of distribution line). In 1996, this discount amounted to nearly $10 million for low-density utilities in Washington.[12] Depending on whether and how BPA decides to continue this rate discount, small rural utilities in Washington could see cost-shifts that, while not large in absolute magnitude, would none-the-less significantly affect rates on their relatively small systems.

4.4. Trends Affecting Potential for Cost-Shifting: Retail Power Sales and Distribution Sector

Given these major changes in the "upstream" sectors of generation and transmission, the nature of Washington's retail electricity market structure is undergoing change as well. New retail services and flexible pricing, as well as projects to bypass utility distributions can lead to potential cost shifts in a number of areas including:

- Average power costs embedded in utility rates;
- Average delivery system costs embedded in utility rates;
- Individual customer metering and system management;
- Taxes (both revenue and property) included in power rates;
- Conservation, renewable resource, and low-income program costs.

The following sections discuss trends and issues affecting potential cost-shifting in each of these areas. Where possible and practical we have provided an estimate of the potential magnitude of cost-shifts that might occur under a set of described circumstances and assumptions.

4.4.1. New Retail Services and Flexible Pricing: Power Supply

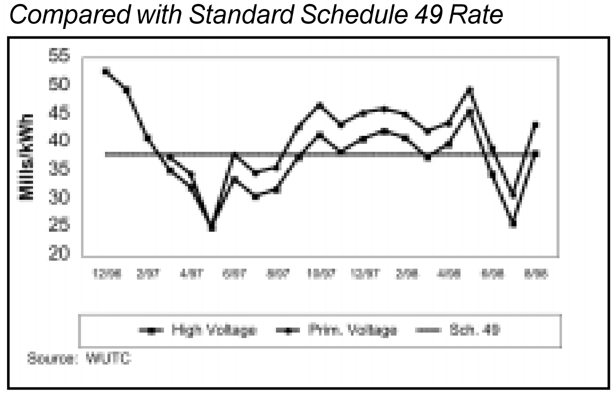
The development of a competitive generation market, accessibility of bulk power price information, and the broader availability of access to the transmission system have increased the level of interest among some customers and customer classes in obtaining power services at market rates rather than average cost utility tariffs. For the most part, these are large-volume-load industrial or commercial customers. Competitive power suppliers in the wholesale market are likewise eager to make retail power sales to these large loads. As a consequence, utilities have responded with a number of new services and pricing arrangements that vary from market based pricing of the energy component of service to fully separating delivery service and offering it apart from energy sales (retail wheeling or direct access). We noted increasing variety of service offerings and non-traditional tariffs in Section 1.0.

Data submitted by the utilities indicate that in 1997 roughly 8.4 million MWh of annual sales to industrial or large commercial customers were made under such “non-traditional” tariffs. These sales represent about ten percent of Washington’s non-DSI, total customer load and half of the state’s non-DSI industrial load. All of these arrangements depart, to some degree, from the average cost basis on which fully bundled utility service rates have historically been set. Consequently, offering these new services presents the very real possibility that costs may be shifted among or within customer classes. Even if the new service is based on a more accurate and precise measurement of the costs to serve a specific customer, the new rate will likely depart from the average cost of serving all customers in the class and therefore may result in some level of cost-shifting. However, the new service may enable the utility to retain an at-risk customer (an industrial customer considering plant closure or cogeneration) which could have beneficial cost or other societal consequences for other customers.

It is important to recognize that these pricing arrangements may also have a different set of risks than traditional utility service. In particular, market prices for electricity are volatile. Consequently, the total rate paid by customers served by market-based tariffs varies through time, where the traditional, average cost service tariff is much more stable. Recent experience with fluctuating market prices from late 1996 through 1998 led all of the customers who originally chose Seattle City Light’s market-rate tariff to return to traditional utility service. Washington Water Power’s recent Direct Access demonstration offers another case in point. Customers who signed up for alternative supplier service early in the program when market prices were low realized benefits. But those who either waited until the second year of the program, or who only signed initial

Figure 4.1 Puget Sound Energy Schedule 48 Rate

Compared with Standard Schedule 49 Rate



contracts for one year, found market prices to be much higher, and they consequently stayed with the utility. As a final example, Puget Sound Energy's Schedule 48 market -based rate includes a power component indexed to market prices for power. Figure 4.1 compares the average total rate paid by all Schedule 48 customers compared to the rate they would have paid under the traditional tariff.

Market pricing may provide a benefit to some, but this benefit does not always come at the expense of other customers, particularly if it is accompanied by an increase in exposure to volatile market prices. On the other hand, if customers are allowed to switch back and forth between average cost and market-based service, depending on which is cheaper at any given time, regulators may find it difficult to avoid shifting costs to other customers. Price risk and whether it is actually borne by those customers who enjoy the benefits of market prices is a key factor the UTC and local utility regulators must consider when the cost and equity implications of a new service or pricing policy are considered.

4.4.2 Potential Magnitude of Cost-Shifts from Market-access or Market-based Pricing: Power Supply

To examine the potential for cost-shifts resulting from new retail power services and market pricing, we have estimated the magnitude of costs that might be shifted under a range of scenarios. These estimates are intended to "bound" what could be a cost-shifting problem. They do not make a prediction of what cost-shifting could or would actually occur, or whether and how these costs might be recovered in the rates of other customers.

The bounding analysis estimates the magnitude of current electricity generation cost that might be shifted to other customers if large volume customers obtain service at market-rates, or are granted direct access to utility delivery systems. This analysis depends strongly on three key estimates:

1) The total <u>amount of load</u> that goes to market pricing. We will refer to this as "competitive load".
2) The <u>market price</u> for power.
3) The <u>cost for power embedded in utility rates</u>. The embedded cost includes the cost of generation, demand side management and related taxes; but it excludes the cost of transmission and distribution.

If market prices are higher than embedded utility cost, the potential for existing power costs to be shifted from one set of customers to another is zero. The utility is either recovering more than its embedded cost (in the case of market-based pricing), or it can sell power at a market rate higher than its embedded cost (in the case of retail wheeling). If market prices are lower than the utility's embedded cost, the magnitude of potential cost-shifting is estimated as the difference between market prices and embedded cost times the amount of affected load.

Only one of these three key values, the embedded cost of utility power supply, can be known with any certainty, and then only for a snapshot in time. This value has been reported by the state's 12 largest utilities in response to HB2831 based on current costs. The competitive load that would choose market-based pricing is strongly dependent on the market price of power. While we have forecasts of market price for power, these future values are only estimates. Consequently, the bounding analysis hinges on a range of values for market price.

The utilities are one source of information about the three key estimates. As a part of the 6560 Utility Data Survey, utilities provided estimates of:

1) The load that might chose market pricing;
2) The load already being served at market pricing;
3) Any forecasts they have made of market prices for electricity.
4) Embedded power costs (HB 2831 reports)

In addition, we have market price forecasts from the Northwest Power Planning Council and the recent history of actual market prices since the establishment of price indices at California/Oregon Border, Mid-Columbia, and the California Power Exchange.[13] Based on these sources we picked a low, medium and high value to bracket market prices. These values cover the range from $19/MWh to $31/MWh. Actual average prices during 1998 have generally fallen within this range, with some departures substantially above the $31/MWh during late summer and early fall.

Using this information we have estimated the potential magnitude of cost-shifts based on the following logic:

1. If embedded cost of power for a utility exceeds the forecast market price, the competitive load is assumed to choose market pricing.

2. The magnitude of potential cost-shift is estimated as the competitive load times the difference between market prices and embedded cost, where the embedded cost is a weighted average of the costs allocated to the customer classes that make up the competitive load. This measures the “unrecovered” cost.

3. The effect of this potential cost-shift on remaining customers is calculated as a percentage increase in average cost per mWh based on current total costs (power generation and delivery). To examine the potential impact of a cost-shift, the analysis makes the *assumption* that 100% of the unrecovered cost is shifted to the remaining customers and recovered in their rates. For purposes of calculating this *potential* no assumptions regarding stranded cost recovery have been made.

Tables 4.1 and 4.2 present these estimates under the three market-price forecasts and two scenarios estimating the size of potentially competitive load. The first table (4.1) presents Scenario 1 and is based on the utility-provided estimates of competitive load. The second table presents Scenario 2: a “worst-case” view based on the arbitrary assumption that all industrial and large commercial load is competitive. The column labeled “proportion of state industrial and large commercial loads” depicts the percentage of the state’s total industrial and large commercial load represented by the competitive load under each of the price forecasts.

In both competitive load scenarios, impact is measured both in terms of $/MWh and the percentage increase on total costs (power and delivery) that this would represent if it were shifted to the remaining load. These figures are averages for the state based on the 12 utility systems included in the analysis.[14] The "percentage increase" column also presents the range of utility specific figures around this average. Utilities fall within this range depending on the level of embedded power costs and the proportion of total load represented by the industrial and large commercial classes. For some utilities, the estimate of cost-shift potential is zero under all market price forecasts. For others, potential exists only under some of the forecasts, and for still others some potential exists across all of the market price range. Because of the number of assumptions involved and uncertainty about the actual size of competitive load, the statewide average estimates are more robust than are any estimates for individual utilities.

For Scenario 1, the proportion of industrial and large commercial load shifting to market-pricing ranges from 15 to 42 percent, depending on the market-price forecast. The statewide average impact of potential cost shifts ranges from less than 0.5 percent to 3.33 percent. The range around this estimated average impact is 0 percent to 13.1 percent. These impacts are relatively modest because of the state's relatively low-cost power generation. Based on market prices in the mid-$20/MWh range, the most likely impact is probably bracketed by the medium and high market-price forecasts, which represent the lower end of the ranges in these estimated impacts.

Table 4.1. Potential Magnitude of Cost-Shifts from Market-Based Pricing.
(Scenario 1. Utility estimates of competitive load)

Market Price ($/MWH)	Competitive Load (MWH)	Proportion of State Indust./Comm. Load	Unrecovered Cost (M$)	Impact ($/MWH)	Statewide Impact	Impact Range
19	10,708,640	42.4%	82.9	1.55	3.3%	0 to 13%
25	4,419,597	17.5%	30.5	.51	1.1%	0 to 3%
31	3,876,477	15.4%	6.0	.10	0.2%	0 to 0.5%

Estimate of competitive load from 6560 Utility Data Survey. Assumes no stranded cost recovery from competitive load. Total statewide industrial/large commercial load = 25,241 GWH. Does not include DSIs.

Table 4.2 presents Scenario 2. In this scenario, *all* industrial and large commercial loads are assumed to be competitive and to choose market-pricing if the market price is below utility embedded power cost. This is a larger estimate of potentially competitive load than in Scenario 1. Consequently, the estimated impacts are higher. This is particularly true for those utilities with a large share of industrial and commercial load. For Scenario 2, the proportion of industrial and large commercial load shifting to market-pricing ranges from 24 to 73 percent, depending on the market-price forecast. The statewide average estimate of impact on the costs for remaining customers ranges from 0.3 percent to 6.5 percent. The range around these averages is 0 percent to 25 percent. The higher end of this range occurs only in the lowest of the price forecasts and is driven by the effect of the arbitrary assumption that all industrial and large commercial loads choose market rates on utilities that have a large share of such loads. Again, because of the number of assumptions involved and uncertainty about the actual size of competitive load, the statewide average estimates are more robust than are estimates for individual utilities.

Table 4.2. Potential Magnitude of Cost-Shifts from Market-Based Pricing.
(Scenario 2. All Industrial and Large Commercial load assumed to be competitive)

Market Price ($/MWH)	Competitive Load (MWH)	Proportion of State Indust./Comm. Load	Unrecovered Cost (M$)	Impact ($/MWH)	Statewide Impact	Impact Range
19	18,395,455	72.9%	$137.5	3.00	6.4%	0 to 25%
25	8,443,155	33.4%	$50.4	.90	1.9%	0 to 5%
31	5,954,100	23.6%	$9.3	.16	0.3%	0 to 0.9%

Total statewide industrial/large commercial load = 25,241 GWH. Does not include DSIs.
Assumes no stranded cost recovery from competitive load.

Even beyond the preceding caveats to the analysis, several additional qualifications are necessary regarding the estimates in Tables 4.1 and 4.2.

First, it bears repeating that <u>these estimates are intended to bound the magnitude of cost that might be shifted – the potential for cost-shifting. They are not a prediction of what the magnitude will actually be, or whether any of these costs will actually be shifted. That is an issue in the hands of the utilities and their state and local regulators.</u>

Second, a number of factors could cause these estimates to be too high and a similar number could cause them to be too low. Some parties commenting on the draft of this report offered arguments for why they may be too high, and other parties offered arguments for why they may be too low.

Those who believe they are too high point out that mitigation of over-market power costs could be achieved through improved cost-efficiency, renegotiation of power purchase contracts, or other cost control measures. In addition, actions that capture the long-term market value of existing generation resources rather than their short-term value can reduce any gap between market-value and cost. The analysis is based on a “snapshot” of the difference between market value and cost. If costs are mitigated, the amount of cost that might be shifted is lower. In addition, one commentor noted that the average embedded power cost could actually decline if some customers choose to depart from bundled utility service. This could mean that, rather than costs being shifted, costs might be lowered for all customers. Finally, the analysis does not assume any provision for recovery of stranded costs from departing customers. If stranded costs are recovered from departing customers, there may be few if any costs left to be shifted. Snohomish County PUD commented that customers taking market priced power on its system were required to cover all costs. Consequently, the PUD states that market priced alternatives have produced no cost-shifting or cost-shifting potential in Snohomish County.

Finally, the estimates might be high because of data collection and analysis procedures. For example, when a utility provided a range of values for the possible competitive load, the analysis used only the highest value provided. If the market value of power is higher than estimated, or the average embedded cost for the competitive load is lower than reported, the load choosing competitive service may be smaller.than estimated and this would produce a smaller estimate of cost-shifting potential.

Those who believe that the estimates are too low also offered an impressive array of reasons. Many transmission and power purchase contracts, particularly those with BPA, contain a "take or pay" provision. When coupled with restrictions on the resale of power made excess by departing retail load, these take or pay provisions could leave utilities with power or transmission costs for which they cannot recover a market value. The analysis assumes that the potentially shifted costs are measured by the difference between the utility's embedded costs and market value. If the utility is prohibited by contract or law from recovering the market value it may be left with more costs to shift. Other commentors point out that the embedded cost of power reported by the utilities may in fact be erroneously low, and that this might lead to a larger estimate of both competitive load and a larger difference between embedded costs and market prices. The cost-basis for the power costs used in the analysis may not include all of the cost assigned to the power portion of rates and, consequently, some portion of distribution costs, A&G costs, or other overhead costs could be left with the utility to shift.[15]

Both sets of arguments have merit, but there is no way to judge whether considering all of those factors that might drive the estimates higher and all of those that might drive the estimates lower would lead to estimates that differ markedly from those we have made. Instead, we reiterate that this is an analysis intended to shed light on the potential magnitude of cost-shifting under the assumptions we have laid out. It is not statistically precise. It does suggest that under the assumptions we have used, the magnitude is modest: statewide less than 6 percent on the rates of remaining customers.

4.4.3. Loads Already Served With Non-Traditional Tariffs

The utilities also reported how much of their customer load was already served under market-based pricing or other non-traditional tariff service. Table 4.3 contains the loads reported by utilities as served by non-traditional tariffs as well as the proportion these loads represent of total industrial load.[16] This proportion is calculated for the utilities with non-traditional tariffs and for the state as a whole.

Table 4.3. Utility Industrial Load Served Under Non-Traditional (NT) Tariffs

(GWH)	1993	1994	1995	1996	1997
6560 Total	16,605	16,873	16,541	16,254	17,059
NT Utility Total(1)	14,398	14,419	14,155	14,120	14,647
NT Load	5,457	5,404	5,187	6,013	8,406
% State	32.3	32.0	31.4	36.9	49.3
% NT Utility	37.9	37.5	36.6	42.6	57.4

Does not include DSIs. Data from 6560 Data Survey covering 18 utilities and 89% of state total industrial load . (1) Seven utilities reported non-traditional industrial service: Cowlitz PUD, PacifiCorp, PSE, Seattle, Snohomish PUD, Tacoma Power and WWP.

The growing proportion of service under non-traditional tariffs suggests that some of the potential identified in Tables 4.1 and 4.2 may already have happened. However, the pressure to shift costs to other classes or customers implied by these existing pricing arrangements does not mean that costs have actually been shifted.

A record that rates have increased coincident with these pricing arrangements would provide at least circumstantial evidence of actual cost-shifting. The rate trends reported in Section 1.0 indicate that in Washington average industrial rates have increased over the last five years, as have average residential rates. For those utilities that offer non-traditional services tariffs, industrial rates are lower (under those tariffs) and the percentage of industrial load served under those tariffs has increased from 38 percent to 57 percent since 1993. The bulk of the increase in non-traditional service took place since 1995.

Table 4.4 examines the trends in rates between 1995 and 1997, for the state as a whole and for those utilities offering non-traditional pricing for industrial service. These figures include only those customers served by utilities and do not include the direct service industries served by BPA. Residential and commercial rates have remained virtually unchanged over this period, based on the statewide average and for the set of utilities offering non-traditional service. Industrial rates *declined* by an average of 5.5 percent for the state as a whole, but increased by a like percentage for those industrial customers taking traditional service from utilities that also offer non-traditional service.[17] As we noted in Section 1.0, this may represent increasing costs for the kind of industrial loads taking traditional service.

Table 4.4. Rates Statewide vs. Utilities with Non-Traditional Industrial Tariffs

	1995 Rate (c/kWh)	1997 Rate (c/kWh)	Change (c/kWh) (-)	Change (%) (-)
Statewide Rates				
Residential	5.01	5.01	0	0%
Commercial	4.81	4.82	.01	0.2%
Industrial	3.25	3.07	(.18)	(5.5%)
Utilities W/ NT:				
Residential	5.14	5.16	.02	0.4%
Commercial	5.05	5.06	.01	0.2%
Industrial (Trad.)	4.07	4.28	.21	5.2%
Industrial (NT)	2.61	2.60	,01	(0.4%)

Source: 6560 Utility Data Survey. Does not include DSIs.

Recent analyses covering the nation as a whole indicate that industrial rates have declined – in part due to new pricing arrangements – while residential rates have increased.[18] Table 4.4 demonstrates that, in contrast to national trends, there is little evidence that costs have been shifted to the residential or commercial classes in Washington. This comparison does not address the question of whether rates for these classes should have gone down at the same pace as the industrial class. Nor does it address the differences in risk between non-traditional service and traditional service to the industrial, commercial and residential classes.

4.4.4. Potential Magnitude of Cost-Shifts from Market-access or Market-based Pricing: Distribution and Delivery Services

Development of a competitive generation market and broad accessibility to price information from that market is also putting pressure on the distribution facility side of the retail electricity system. Some customers, again mainly large load customers, are showing growing interest in exercising their opportunities to bypass the local utility entirely.[19] This is not a new alternative; construction of redundant power delivery lines to access service from another utility has always been an option for customers who have practical opportunities to do so. The attractiveness of this option has increased, however, with transformation of the high voltage transmission system into an open-access common-carrier. Some utilities are also demonstrating growing interest in offering a competitive option to customers of neighboring utilities. Washington has no formally established utility territory boundaries other than those that the utilities themselves work out by contract (see Section 5.0). While there have yet to be significant examples of physical utility bypass and duplication of facilities, some examples are reportedly under consideration. In comments on the draft of this report Puget Sound Energy indicates that one of its large loads may be considering a project to interconnect with another utility.

The practicality and feasibility of distribution system bypass is very dependent on case-specific circumstances and subject to a variety of obstacles, including local land use, siting authorities, and the cost of bypass. One consequence of the threat of bypass is that utilities often attempt to discourage it by offering special pricing terms designed to retain the customer. Another is that it imposes discipline on the utility to keep its power *and distribution* rates low and to avoid customer class cross-subsidies. This competitive pressure can be beneficial if it lowers service costs to all the utility's customers. It can have adverse consequences if it discourages needed investment in distribution facilities, or discourages line extension investments to hook-up new customers in the utility's customary service area that would otherwise be justified by scale economies.

The consequence of a physical bypass is that some utility distribution facilities are duplicated. The embedded cost of these duplicated facilities is a cost that might be shifted to other customers. We have examined the potential magnitude of cost-shifts associated with physical bypass.

Similar to our estimates of the potential magnitude of power cost-shifts, we have relied on information provided by the utilities. As part of the information survey, the utilities were asked to estimate the amount of industrial load on their systems that might be able to exercise a physical bypass of distribution facilities. As with the power cost estimates, we have considered a range of market rates and assumed that bypass alternatives would only be exercised if the embedded power costs were greater than the otherwise available market price. This is an oversimplification for a number of reasons. But, it permits us to develop a rough estimate of the cost-shift potential from bypass.[20]

Based on the estimated bypass load potential and the embedded costs reported for power and delivery services reported by the utilities under HB 2831, Table 4.5 estimates the potential for distribution system costs to be shifted due to bypass. As with the power cost estimate, the purpose of this estimate is to provide an upper-bound on the size of the potential. And, as with the power cost estimates, no assumptions have been made regarding cost-mitigation or stranded cost charges. Because utilities and their regulators have it within their power to accomplish cost-mitigation and require stranded cost fees, <u>this is not a prediction or an estimate of what costs will actually be shifted.</u>

While the estimate is for delivery costs (i.e. wires cost), the load involved is also a subset of the power estimate. Those customers likely to exercise a bypass option are included in the set of customers who would choose market-base pricing alternatives. Consequently, the sum of the power cost estimates from Table 4.1 (or 4.2) and the wires cost estimates from Table 4.5 represents an upper-bound estimate for cost-shifting potential if customers choose market-pricing and those with bypass options exercise them. Table 4.5 presents the information and estimates on a statewide basis. Again, we have included the range of impacts across all 12 utilities included in the analysis. The statewide figures and average impact is a more meaningful and robust estimate than are estimates for individual utilities.

Table 4.5 presents estimates under the three market price forecasts used earlier. The column titled "Bypass Load" is the estimate supplied by the utilities of load that could build a bypass to another system. Impacts are presented in both \$/MWh and the percentage increase on the total cost for the remaining customers if the costs not recovered are shifted to their rates. The column labeled "Proportion of State Industrial/Commercial Load" represents the proportion of the state's total industrial and large commercial load that exercises bypass under each of the market price forecasts.

The estimated average statewide impact is small under all market price forecasts, ranging from 0.6 percent to 1.2 percent. The largest impact happens under the low price forecast, where nearly a quarter of industrial and large commercial load is affected. Under this case, the estimated impact on the costs for remaining customers ranges from 0 to 3.4 percent.

Table 4.5. Potential Magnitude of Cost-Shifts from Bypass.

Market Price ($/MWH)	Bypass Load (MWH)	Proportion of State Indust./Comm. Load	Un-recovered Cost (M$)	Impact ($/MWH)	Average Impact	Impact Range
19	5,961,689	23.6%	$33.5	.58	1.2%	0 to 3.4%
25	2,571,371	10.2%	$22.1	.36	0.8%	0 to 2.6%
31	2,127,000	8.4%	$17.7	.29	0.6%	0 to 1.6%

Estimate of bypass load from 6560 Utility Data Survey. Does not include DSIs,
Total statewide industrial/large commercial load = 25,241 GWH

4.4.5. Individual Customer Metering and System Management

This area covers a combination of power and delivery system issues. As new services including direct access are offered to customers, it becomes increasingly important to measure accurately both the magnitude of electricity usage and the timing of this usage for customers taking these services. It is important because these customers are either paying prices that are not based on average utility costs, or are receiving service from generation sources that are not the utility's or under the utility's direct control.

Traditional, average cost, utility service is provided through a local utility distribution system that is energized by the collective output of all of the utility's generation sources. The utility ensures that all use of electricity is matched with sufficient generation to keep all the lights on. Generation must be perfectly matched with load every second. This job is done by either the utility itself or a combination of utilities by operating a "control-area". Oversimplifying, traditional, average cost, utility service works because the average customer can be charged the average cost of all of the generation resources used to keep total generation in balance with total load. In reality, the utility's generation sources do not all cost the same and they are not all used all the time. But the utility does not need to match which generating unit was running with the electricity use of any particular customer so long as the average customer pays the average cost of all the generating units.

If competitive power suppliers serve some customers, and the utility does not closely track the usage of customers that are being served by these suppliers, cost-shifts could result in two ways. First, if the power supplier fails to deliver to the control-area the total amount of electricity that the open access customer actually used, the difference is automatically made up by the utility — since it, or its control area operator must keep generation in balance with load at all times. This is called an “imbalance” and if the utility is unable to determine through metering who caused an imbalance to occur it will be unable to charge the open access customer for the generation it supplied and the cost of this generation could be shifted to other customers. Second, the timing of any imbalance is very important because the cost of electricity generation as well as its market value varies depending on time of day. If an energy supplier delivers more power to the control area than its customer uses when the market value of power is low, and less power when the market value is high, the potential cost-shift from an imbalance is magnified. In fact, when calculated over a day or more the total customer use and total supplier deliveries could be in balance. But, if the time pattern is not metered, the utility may have been required to supply power during hours of imbalance when it is expensive and absorb excessive deliveries when it is cheap. The net cost to the utility may fall on other ratepayers if metering is not sufficient to identify these time patterns of imbalance.

These metering requirements are important regardless of the size of the customer usage. Deliveries of power into a control area over the transmission system can only be scheduled and tracked for transfers of 1 MW or more. Therefore, for any open access load to be accounted for within a control-area it must be at least 1 MW. If the 1 MW threshold is met with a number of aggregated sites, each must have metering sufficient to match usage of the aggregation with deliveries to the control-area boundary. Metering equipment is readily available to meet this need, but traditional utility meters are not sufficient because the measure only total energy usage and, in some cases, peak demand, not time of usage. Data are presented in Section 1.0 on the distribution of meter types and capabilities in Washington.

We have not attempted to estimate the potential magnitude of cost-shifts that might be caused by insufficient or inaccurate metering. However, it is revealing to note that the price of on-peak electricity sales at the Pacific Northwest trading hubs is often 50 to 100 percent higher than the price of off-peak sales.

4.4.6. Technology Change and Customer-Owned Generation

The opportunity for customers to construct their own generation facilities and displace most or all services provided by the utility has existed for decades. Customers make decisions to self-generate based on their costs to finance and construct generation facilities and purchase fuel. For the most part, examples of self-generation have been limited to large volume, usually industrial customers, who have their own source of fuel. Self-generation is relatively common in the pulp and paper industry where industrial by-products provide a fuel source and waste heat from generation can be used in on-site industrial processes. Technology development has improved the efficiency of self-generation and co-generation equipment, but because the customer must cover the full capital cost of such an installation it is unlikely that these opportunities will be as attractive as opportunities to gain access to market pricing through unbundled delivery services or physical bypass. Consequently, we do not believe that large scale self-generation adds greatly to the potential for cost-shifting in the state.

However, technology development in the area of small scale, localized generation, has advanced considerably in the last few years — particularly in the area of small fuel cells. Recent announcements of prototype equipment nearing commercialization indicate that fuel cell applications for small businesses, apartment buildings and even homes may only be a few years away. For example, both AVISTA Corporation and General Electric have recently reported research advances in small-scale fuel-cells and plans for commercialization of residential sized units in the next few years. BPA is reportedly also working on the demonstration of small-scale applications of fuel-cells. This is an important development for electric utilities because these small scale applications could mean that customers in the future will be able to replace utility service with their own, probably natural gas fueled, generation equipment. This would permit customers to completely disconnect from the utility grid leaving investments in utility generation, transmission and distribution that might be shifted to remaining customers. The timing of this technology development is not clear and the breadth of use of fuel cells or other small-scale local generation is today only a matter of speculation. However, widespread application could lead to significant cost pressures on local utilities and their regulators. Whether and how such costs might be shifted between customers is also unclear. But, it is nonetheless wise to consider that such a major shift in technology could undermine much of the justification and practical application of administratively established, average cost rates for utility distribution systems.

4.4.7. State and Local Taxes

State and local taxes are applied to utility sales as a gross revenue tax levied on the utility based on the gross revenue generated from retail electricity sales. The state tax is the Public Utility Excise Tax the revenues from which flow into the general fund. Local taxes are imposed by the municipality inside city limits and flow to the general-funds of the cities. Sales of electricity by out-of-state entities that are not otherwise engaged in the light and power business as an electric company in Washington do not generate taxable revenue at either the state or the local level. If utility services are unbundled and used to deliver power sold by out-of-state, non-taxable parties, both the state and affected local governments will lose tax revenue. This is potentially a cost shift if the lost revenue must be made up with charges or other taxes to other customers. Whether or not this would occur is uncertain and would be left to legislative decisions at the state or local levels.

The Department of Revenue (DOR) has prepared a briefing paper that examines tax-policy-related issues relevant to the electricity industry. DOR did not include any estimates of the potential lost tax revenues, in part because of the number of assumptions that would be necessary to make about the way power will be bought and sold and the location of customers and suppliers that may negotiate contracts. Faced with the same array of issues, we have not tried to make a tax-revenue-related estimate either. The DOR briefing paper offers a number of policy options for redesign of utility tax structure to fit with changes that may occur in the electricity industry. The paper describes the advantages and disadvantages of each. A copy is included in Appendix 4.1 of this report.

4.4.8. Conservation, Renewable Resource, and Low-income Program Costs

Most Washington utilities operate public purpose programs including conservation and low-income programs. These programs and their funding is the topic of another major section of this report (Section 9.0). For purposes of equity in utility rates and cost-shifting we have noted them here because they are a component of current utility rates that may not be included in special pricing arrangements, or that may be avoided altogether through open access or utility bypass. To the degree the programs are continued, their cost could be shifted between customers or customer classes.

4.5. Examination of Strategies Available to Minimize Cost-Shifts

This section describes an inventory of strategies and actions that may affect the potential for cost-shifts to occur. As noted earlier, there are no fully objective criteria for assessing whether cost-shifts are appropriate. So long as rates are set administratively, the responsibility to make judgements about whether rates are fair, just, reasonable and not unduly discriminatory or preferential will rest with the local rate-setting governments or boards, and with the UTC. For purposes of this evaluation we have assumed that some continuation of administrative rate-setting will persist even if policies to make retail electricity service competitive (open access) are adopted. This is because the delivery services will remain regulated and it is likely that some form of “default” or universal service options will need to be made available for customer classes for whom competitive options do not develop.

The strategies are organized into two categories. First, are those that may reduce the impact of some of the circumstances facing Washington’s retail utilities, the UTC, and the local jurisdictions responsible for rate setting that may lead to cost-shifting pressure. These strategies are categorized as <u>structural</u>. They include strategies affecting the wholesale and transmission sectors, as well as those affecting the introduction of competition to the retail service sector.

Second, are strategies addressing retail service rate-setting. These strategies are categorized as <u>administrative</u>. They include conditions or other requirements that might be placed on the rate-setting of the UTC and/or the local utility boards and commissions to prevent or reduce the likelihood of cost-shifting. In each case our purpose is to describe the strategy and the arguments for and against it, rather than to recommend a particular strategy or set of strategies.

4.5.1. Structural Strategies: Actions Affecting the Wholesale, Transmission, and Retail Service Sectors

1. Influence Development of Transmission ISOs to Minimize Cost-shifting in Transmission Pricing.

Description: Representatives of the state should participate in regional processes aimed at structuring management, access and pricing of the transmission system to prevent implementation of region-wide transmission tariffs that would result in cost-shifting.

<u>*Rationale:*</u> State interests are directly affected by the development of an ISO. The objective of participation is to add, where necessary, organizational improvements to our existing transmission system that further a competitive and reliable wholesale power market while avoiding transmission related cost-shifts.

Arguments For: If any ISO is ultimately proposed for the region, it will require approval from the FERC. The state will need to demonstrate that it participated actively in development of the proposal in order to be credible in defending state interests regarding cost-shifting and other issues in the FERC review process. In addition, state participation in regional transmission policy and organizations will bolster the case that state and regional interests should be included in ISO and reliability policy and not preempted at the federal level. Finally, some analyses indicate that the Northwest wholesale power market is already competitive and reliable under the current rate structure. Changes to this structure to accomplish a region-wide, average pricing could cause shifting with little or no additional benefit.

Arguments Against: State participation does little to add to the interests already well represented by the utilities. These interests may not be consistent since transmission affects different parties in different ways. The state could not establish a position that would avoid “choosing sides” among the utilities and other interest groups.

2. Influence Development of BPA Policy Regarding Allocation of Power and Pricing of Services.

Description: Representatives of the state participate in BPA processes with the objective of maintaining a financially viable federal power system that benefits the state and region, fulfills its environmental responsibilities, fulfills its public purpose responsibilities including affordable service in rural communities, and complements a competitive bulk power market, while at the same time minimizing pricing policies that result in cost-shifts.

Rationale: BPA’s policies regarding pricing and terms and conditions for access to federal power and transmission resources are a critical component of electric power service costs in Washington. Changes in these policies will invariably have the affect of raising some parties’ costs while lowering others.

Arguments For: The state can most effectively balance the competing interests of the various stakeholding parties within the state by influencing BPA on a government to government basis.

Arguments Against: There is no clear demonstration that BPA rate-making will necessarily result in retail cost-shifts. Participation by utilities and other interested parties is sufficient to represent state interests.

3. *Preserve low-cost generation benefits for Washington customers.*

Description: Actions include: strong defense in Washington D.C. of continued regional preference in access to cost-based power from the federal system, and preservation of the benefits of the low-cost generation of investor-owned and public utilities for the Washington customers of those utilities. The benefits can be kept in the region by having utilities retain ownership of the low-cost assets, or the net benefits can be assigned to customers after an asset sale. For investor-owned utilities, this can be accomplished by preserving the authority of the UTC to review, condition and approve "transfers of property" [Chapter 80.12 RCW] in the instance of sales of generation or utility mergers. For public utilities, the objective could be met with a clearly stated policy requiring that the net proceeds from the sale of publicly-owned generation assets or generation therefrom must be credited to utility customers.

Rationale: Washington's electricity generation base is, by most projections, lower in cost than would be its value if sold at market prices. In the absence of actions to preserve this benefit for Washington electricity customers, future developments could see these resources command prices based on market value with the consequence of increased electricity rates for Washington customers.

Arguments For: Preserves the benefits of the state's low-cost generation for Washington consumers regardless of the ultimate path of electricity wholesale and retail restructuring.

Arguments Against: No changes to current state law are necessary. Current law requires that the regulatory bodies of consumer-owned utilities review and approve any proposed sale of a generating asset and the disposition of proceeds from such a sale. The same provisions apply to the investor-owned utilities through the review and approval of the UTC in transfers of property.

4. *Certification of distribution service territories.*

Description: Establish geographically defined certificates describing the area in which an electric utility has the responsibility to provide distribution services to retail customers. As is the case in the local distribution gas industry, a certificate would be necessary to provide retail service. Certificates for a competing distribution company could be granted on demonstration that existing service is inadequate or that the competing service is otherwise in the public interest. Certificates apply only to electrical companies and do not prohibit private individuals from constructing facilities. Certificates do nothing to change the authority of municipalities or counties to choose to municipalize service through the establishment of a government-owned utility, or to condemn property for this purpose. Certification of distribution service territories would require new legislation.

Rationale: As described elsewhere in this report, Washington does not have distribution service territories established by certificate or franchise. This makes it difficult to establish who is responsible for serving a given customer, particularly where utility boundaries established by custom or history intersect. State policy discourages competition in utility wires and delivery service (RCW 54.48.020). Yet in the absence of defined service territory responsibilities duplication of facilities can occur and lead to facility costs being stranded if bypassed and potentially shifted to other customers.

Arguments For: Establishment of distribution service territories clarifies service obligations and provides for an orderly examination of circumstances where one utility can more cost-effectively provide service to the customer of another. This examination can identify any costs or compensation due between utilities, or the utility and a customer, and avoid some pressures to shift distribution facility costs.

Arguments Against: Reducing the uncertainty and risk associated with bypass (for the utility) reduces the competitive pressure to keep distribution costs low. Establishment of distribution service territories does not address all bypass or self-generation issues and, in fact, does not even apply when connection or generation facilities are privately constructed. State approval of service certificates or franchises would adversely affect the ability of municipalities and other public entities to exercise statutory authority to expand or create new service territory through condemnation or annexation. State authority to repeal a certificate threatens the local control of utility service. Finally, it would be inconsistent for the state to be creating new monopolies for service territories as the electric utility industry begins to face competition.

5. Establish a Competitive Class of Service (Partial Open Access)

Description: Based on size-of-load or other characteristics establish that some customers have access to use of the distribution system as a common carrier for delivery of power from whatever power supplier they choose. Metering standards would be necessary to ensure that the usage of such competitive access customers could be distinguished from the remainder of the utility's loads. Such competitive service is similar to the "transportation tariffs" available for natural gas customers who wish to purchase their own natural gas supplies. As is the case with these natural gas tariffs, the terms and conditions for competitive service and "re-entry" to utility service would be clearly established. Utilities could offer such services under current law, but new legislation would be necessary to require that the service be offered.

Rationale: Some customers are equipped and prepared to accept the risks and reap the benefits of arranging their own power sources. Clearly establishing the terms and conditions for these customers to arrange for market-based power supplies and conditions for the use of utility delivery systems provides for a more orderly treatment of costs that might otherwise be shifted to other customers or customer classes.

Arguments For: Responds to the desire of some customers to take responsibility for resource supply and price risk in return for potential benefits of market access. Provides for a more orderly allocation of risks, responsibilities and obligations between the utility and its customer classes. Prevents risk from being shifted from competitive customers to core customers of the utility. Allows for a focused calculation of any responsibility for past utility investments and any qualifications necessary to the utility's future obligation to provide service.

Arguments Against: May be difficult to control customers migrating back and forth between competitive and non-competitive service in order to capture the lower of market or cost-based pricing. This can lead to political pressure to breach protections against cost-shifting, particularly when the customer loads are large and economically important. Requires either a prohibition on utilities providing both cost-based, bundled service and competitive power services, or a difficult to enforce regulatory "fire-wall" between these services.

6. Establish Open Access to Competitive Power Supplies for All Customer Classes (Full Open Access)

Description: Establish that all customers have the opportunity to make their own selection of power supplier with the power delivered over the utility's, common-carrier distribution system. This is full retail wheeling and would transform the utility's current "obligation to serve" to an "obligation to connect". Terms, conditions, and rates for the use of the distribution delivery services would continue to be regulated. Full open access requires metering sufficient to separately account for every customer's usage pattern. Utilities could offer open access tariffs on their own decision, but legislation would be necessary to require that all utilities offer such service.

Rationale: If all customers have access to competitive power services there is no administrative pricing for these services and therefore no opportunity for administrative pricing decisions to shift costs.

Arguments For: Removes any possibility of administrative cost-shifting, at least for power services, and eliminates the complication of regulating the boundary between competitive and non-competitive services that can be a problem in partial open access. Permits all customers to choose power supplier, services, price and risk based on individual preferences. Clarifies utility role as "obligation to connect" with no obligation to provide power services. Provides for focused determination of customer responsibility for past utility investments.

Arguments Against: Competitive markets may not develop to serve all customer classes. Power marketers may concentrate efforts on larger load customers. Some universal or "default" service might be necessary to require of the utility and shifts in risk and cost between this service and competitive service would be similar to the boundary problems described for partial access. Customers may not have equal access to the information and capital necessary to make effective market choices and they may not be interested in understanding or taking on the responsibility to make these choices. Additional costs would likely be incurred by the delivery utility (or some other body) to maintain individual customer metering and necessary accounting to allow for billing settlements. Allocation of these costs to customers could involve cost-shifts or other inequities.

7. Maintain current regulatory system including UTC regulation of investor-owned utility retail rates and local regulation of consumer-owned retail utility rates with a legislative policy statement that discourages cost-shifting and utility distribution bypass.

Description: Maintain cost-of service regulation of retail utility service with flexibility for the UTC and local regulators to approve and implement utility services and rate structures, including unbundled or other competitive services as appropriate and if in the public interest.

Rationale: Establishes a state policy discouraging cost-shifting and distribution bypass while maintaining the capability of the UTC and local regulators to manage utility service consistent with the public interest and local utility circumstances.

Argument For: Maintains the flexibility of the current well-functioning system to adapt to local circumstances and local values. Does not impose a "one-size-fits-all" solution on utilities and customers. Requires no major structural reforms. Does not put the utility tax base at risk and does not force customers into undeveloped new markets.

Arguments Against: Does not guarantee that UTC or local regulators will not cause costs to be shifted inequitably. Does not establish a common and uniform set of rules for competitive electricity services and utility obligations. Does little to remove the uncertainties and risks that may cause utilities to make decisions that shift costs or risks among customers.

4.5.2. Administrative Strategies: Strategies and Actions Affecting Retail Service Rates

1. Legislative prohibition of cost-shifting.

Description: The legislature could prohibit any regulatory decision to change rates charged to customer classes or customers within a class that causes those customers to be responsible for costs they are not responsible for in rates today and which were formerly paid by other customers or customer classes. The prohibition would apply to the UTC as well as the public utility rate-setting bodies. This strategy would require new legislation.

Rationale: Cost-shifting is the result of administrative decisions to shift the responsibility for cost recovery from the rates of one customer or customer class to the rates of another. Prohibiting the rate-setting bodies from doing this prohibits cost-shifting.

Arguments For: Establishes a clear, unequivocal policy that cost-shifting is not permitted by the utility or by its rate-setting regulator.

Arguments Against: The complexity and imprecision of cost-of-service studies makes it unlikely that all but the most egregious incidence of cost-shifting could be identified definitively. This approach assumes that all current cost allocations are perfect and removes the flexibility to respond to changing circumstances from the regulator or local jurisdiction whose responsibility is also to ensure that sufficient revenue is generated to maintain reliable service. Such a one-size-fits-all approach represents a significant infringement on local rate setting and control by locally elected utility boards.

2. Rate Freeze.

Description: Prescribe that residential and small commercial rates must be frozen, or rise at no more than some established rate of increase, over some period of time. This approach was taken in California (for investor-owned utilities) as part of the state's industry restructuring. This strategy could be implemented by the UTC and local jurisdictions, but a uniform state policy would require new legislation.

Rationale: Freezing rates prohibits the utility, or its rate-setting body, from increasing the rates of one customer or class in order to lower the rates of another.

Arguments For: Provides protection against rates being raised for one customer or class of customers in order to lower rates for another. Straightforward to administer — rates don't change from what they are today.

Arguments Against: Removes flexibility from regulator and local jurisdictions to respond to changing circumstances including costs and other issues that may be out of their control. This approach assumes that all current cost allocations are perfect. May discourage needed investment in infrastructure, new generation resources, and public purpose programs, and lead to deterioration in service quality or reliability. Such a one-size-fits-all approach represents a significant infringement on local rate setting and control by locally elected utility boards.

3. Relative Rate Gap Caps

Description: Prescribe that the current relative comparison between residential, commercial, and industrial rates remain fixed regardless of how overall rates for all classes change in the future. For example, if residential rates for a utility are 50% higher than industrial rates, this percentage is held constant if industrial rates change. This strategy would be difficult to implement in legislation because the circumstances of each utility are different. The strategy could be implemented by the UTC or local jurisdictions without new legislation.

Rationale: Cost of service studies have established rates for the various customer classes that bear a proportional relationship to one another. So long as this relationship is maintained, no matter what changes are made to the rates charged to one or another of the classes, costs have not been shifted to one class in order to reduce them for another.

Arguments For: Provides the same kind of protection as the rate freeze, but allows for flexibility for the utility, regulator, or local jurisdiction, to respond to changing cost circumstances that affect the utility's overall revenue requirement.

Arguments Against: The "gap caps" must assume that the components of service cost remain constant between the customer classes and that all current cost allocations are perfect. Cost increases could be associated more with one class than another (for example, undergrounding of residential class distribution lines). Maintaining a strict "gap cap" could result in unfair distribution of costs between the classes. In addition, if industrial or other large load rates are indexed to competitive power prices, a strict implementation of the gap cap introduces significant price volatility and risk to residential rates. Gap caps will not be consistent between utilities because of differing customer base and cost structure and these differences could lead to confusion and controversy. Finally, a one-size-fits-all approach represents a significant infringement on local rate setting and control by locally elected utility boards.

4. Performance Based Rate-Making

Description: Prescribe that utility rates be based on performance standards rather than strictly on cost of service. So long as utilities achieve the specified performance standards, permit pricing to individual customers or classes of customers to be flexible within a ceiling and a floor. For example, rates could be set no higher than a ceiling set at historical cost adjusted for inflation and a floor no lower than the long run marginal cost of providing the service. This strategy would be difficult to implement in legislation because the circumstances of each utility are different. The strategy could be implemented by the UTC or local jurisdictions without new legislation.

Rationale: So long as the cost-basis for the rate ceiling for any class is fair, just and reasonable, the utility's ability to flexibly price below the ceiling for some customers does not shift costs to others or constitute undue discrimination. This approach is similar to the rate-freeze except that in provides the utility with downward pricing flexibility and an incentive to improve cost-efficiency, and the regulator with the flexibility to establish other performance requirements like service quality or cost-efficiency targets.

Arguments For: Allows both the utility and regulator the flexibility to respond to changing circumstances and to include a focus on performance standards other than rates. Diminishes the "cost plus" inefficiencies of traditional cost-based rate-making by mixing cost-based pricing principles together with incentives for the utility to capture cost-efficiencies in serving any of the classes. Capturing these cost-efficiencies permit it to either enjoy better earnings or compete with price discounts to more price sensitive customers.

Arguments Against: Pricing flexibility may lead to claims of price discrimination tantamount to cost-shifting. Determining the floor for pricing flexibility may be difficult. Pricing and performance standards could be complex, difficult and expensive to develop and monitor for the regulator or local jurisdiction. If not set high enough, a ceiling on rate levels could discourage or prevent needed investment for power supplies or reliability. A one-size-fits-all approach represents a significant infringement on local rate setting and control by locally elected utility boards.

5. Specify and Define Uniform Stranded Cost Recovery Responsibility

Description: Costs for power or delivery services not recoverable by a utility that offers services at market rates or that loses a customer to open access service are calculated and recovered from customers choosing non-embedded cost based services. Stranded costs could be evaluated using administrative calculations based on market price projections, or via a market valuation based on auction sale of the power or delivery facilities. Whichever approach is used, the cost recovery is limited in time and the costs to be recovered should be mitigated through cost-efficiencies, or contract reformation. The later is the approach taken in the gas industry when federal regulation of the interstate pipelines was changed to no longer require the pipelines to maintain dedicated reserves. This is an administrative step that would have to accompany the structural alternatives of partial or full open access listed above. It may also require clarification of distribution service territory issues. The UTC and local jurisdictions have the authority to implement stranded cost recovery on wires delivery services administratively. The authority to implement "exit fees" where wires service is no longer taken is problematic for both the UTC and the local jurisdictions.

Rationale: The utility incurred costs in order to provide service to all customers. If some customers choose to leave service in favor of another source of power supply or in favor of market pricing, the utility can recover its investment from these customers rather than shifting the cost to others, or to the utility shareholders.

Arguments For: Ensures that, if all historical costs embedded in utility revenue requirements are collected, they are not disproportionately collected from some customers or customer classes via a cost-shift. In the event that stranded costs are negative (a benefit), uniform treatment across customer classes ensures that these benefits are returned equitably to all customers. Policy providing for the equitable recovery of stranded costs also ensures that the security interest in public debt issued by public utilities is not undermined.

Arguments Against: The magnitude of stranded costs to be recovered is not simple to calculate — at least not for power costs. It depends on the relationships among market prices for power, existing fixed and operating costs of utility power, potential cost mitigation and assumptions about discount rates. If calculated based on an *administrative* estimate, the value is vulnerable to the inevitable errors in forecasting these factors. Stranded costs could be determined to be a large value based on forecasts made today and turn out to actually have been smaller or zero if the forecast undershot the actual market price. The reverse is true if the forecast overshoots the actual market price. Alternatively, an auction sale of power resources can establish a true *market valuation* of their worth. However, this is also a snapshot in time and could similarly lead to customers being made responsible for stranded costs when there actually were none, or no stranded costs when they actually prove to have been large. Finally, contract reformation as a cost mitigation may result in legal disputes regarding the statutory context within which the contracts were established (e.g. PURPA contracts). This could undermine the credibility of power contracts in the future.

6. Terms and conditions for exit and reentry to average rates.

Description: Establish terms and conditions that customers must meet in order to leave average rate service and in order to return to such service after having left. Such terms and conditions might include: sufficient metering capability to separate a customer's load shape from the remainder of the utility's loads; payment of stranded costs; customer willing to provide or compensate the utility for back-up service; customer responsible to pay any incremental costs to re-enter averaged rate service. Some Washington utilities including Grant County PUD have established such terms and conditions. This is an administrative step that would have to accompany the structural steps of partial or full open access listed above. This strategy would likely benefit from legislation to clarify service territory issues and obligation to serve issues.

Rationale: Removing a customer from the pool of customers served at the average cost to serve the pool has both cost and operational implications. Clearly establishing terms and conditions will ensure that existing costs are not left with the remaining customers and that new costs are not incurred by the remaining customers.

Arguments For: A clear set of rules and requirements for open access, or some other form of competitive pricing, makes it clear for those who might choose such service what they need to consider. And, it makes matters clear for those remaining on traditional utility service how they are being protected from cost and risk shifts.

Arguments Against: May be administratively, legally and politically complex. Administrative difficulties might include such issues as change of ownership, or change of site functions. Legal difficulties may involve clarification of obligation to serve issues. Political sustainability of these terms and conditions could be difficult if adverse economic or employment impacts result from poor market decisions by the customer.

7. Establish Uniform Responsibility for Conservation, Renewable Resources, and Low- income Programs

Description: For those public purpose programs to be accomplished through collective funding and action (e.g. low-income weatherization, bill assistance, some forms of conservation and renewable resources, universal service, etc.) a charge is placed on electricity service that applies to all customers. This strategy is further discussed in Section 9.0.

Rationale: Public purpose programs are undertaken to achieve enunciated state policy objectives. In the absence of a non-avoidable charge which applies to all customers, the cost of achieving the programs — many of which are currently included in utility rates — could either be shifted to, or fall disproportionately on one customer group or another.

Arguments For: Ensures that all customers contribute equally to programs that are deemed to be important to be funded collectively from utility services. Ensure that programs are funded in a competitively neutral way.

Arguments Against: These objectives and policies could more appropriately be supported through general tax revenues. To the extent one customer class might pay more for public purposes than the benefits they receive, a cost-shift will occur.

Endnotes for Section 4

1 This risk is not really a new cost. In the past, utilities have been responsible for building new generation capability adequate to meet growing demands. The cost of ensuring that demand was met under all load conditions is included in average utility rates. This means that rates are higher than the cost of producing electricity when loads are not near peak levels. The consequence of average-cost rates is that all customers contribute to the cost of ensuring adequate resources are available to meet all customer loads at all times — that is, the risk of new resource costs is shared by all customers.]

2 Possible Effects of Competition on Electricity Consumers in the Pacific Northwest. Hadley, Stan and Hirst, Eric. Oak Ridge National Laboratory. January, 1998. ORNL/CON-455. Power Markets in the U.S. Resource Data International. Boulder, Colorado. January 1997.

3 Possible Effects of Competition on Electricity Consumers in the Pacific Northwest. Hadley, Stan and Hirst, Eric. Oak Ridge National Laboratory. January, 1998. ORNL/CON-455.

4 Comprehensive Electricity Competition Plan. Rate estimates for the WSCC/NWPP in 2010. U.S. Department of Energy. March 25, 1998

5 See Are customers of Northwest utilities likely to pay higher electricity rates due to competiton? Northwest Power Planning Council.

6 Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues. Northwest Power Planning Council. June 5, 1998. No. 98-11.

7 Analysis done by UTC staff.

8 See for example H.R. 4432 entitled Electric System Reliability Act of 1998 introduced by Representatives Delay and Markey August 6, 1998.

9 See for example, Electric Competition Revolution: The Sequel". Remarks of James Hoecker, Chairman, Federal Energy Regulatory Commission. Sixth Department of Energy and National Association of Regulatory Utility Commissioner's National Electricity Forum. Houston, Texas, September 17, 1998.

10 Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues. Northwest Power Planning Council. June 5, 1998. No. 98-11.

11 These ten or so large industrial plants are predominately aluminum smelters. In the past, they have accounted for as much as 25 percent of total FCRPS sales.

12 Washington Rural Electric Cooperative Association.

13 Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues. Northwest Power Planning Council. June 5, 1998. No. 98-11.

14 The estimates were compiled for the state's twelve largest utilities only because these are the only utilities from whom current data on power costs are readily available from HB 2831 reports. These utilities comprise roughly 85% of the state's total electricity sales and more than 90% of the non-DSI industrial and large commercial sector sales.

15 For example, some public utilities are debt-free, but none-the-less recover new distribution facility costs in power rates. This situation could be remedied by assigning and recovering these costs on distribution.

16 Non-traditional service to applies generally to "large loads". These are not necessarily synonymous with "industrial loads". In some cases large commercial class loads qualify for non-traditional service.

17 Had we been able to include 1998 data the overall industrial rates and the rates for non-traditional service might have shown an increase since these rates are now tied to market prices and 1998 market prices were higher than in previous years.

[18] The Changing Structure of the Electric Power Industry: Selected Issues, 1998. U.S. Department of Energy. Energy Information Administration. July, 1998.

[19] The amount of distribution services used by large customers varies from utility to utility, but for the most part large customers use less distribution and are assigned less distribution costs than is the case for smaller volume customers.

[20] This simplification ignores both the cost of constructing the bypass and the potential that a neighboring utility might have power costs below the market price. These factors have opposing effects — the first causes an overestimate of bypass potential and the latter an underestimate. Both of the factors are driven by individual circumstances and, without a detailed analysis of every industrial customer near the borders of all utilities, there is no practical way to improve the accuracy of the assumption.

5.0 Utility Service Territory Agreements in Washington

ESSB 6560 directs the Washington Utilities and Transportation Commission (UTC) and the Department of Community, Trade and Economic Development (CTED) to study

> *"[t]he status, number, and primary characteristics of service territory agreements between electric utilities."*

Our examination of service territory agreements is divided into four parts:

- Brief introduction to the issues surrounding utility service territories and service territory agreements;
- Description of Washington law and background concerning utility service territories;
- Summary of the results of our survey regarding existing service territory agreements;
- Discussion of policy issues concerning utility service territories.

5.1 Introduction

Washington State is unique in that it does not have certificated distribution service territories, as do most other states. This issue of certificated service territories surfaced repeatedly during the several stakeholder meetings conducted by the WUTC and CTED. As discussed in several sections of this report, some stakeholders support the establishment of distribution service territories, arguing that such territories would serve to clarify not only the geographic boundaries within which a utility may serve, but also identify the utility having the obligation to serve the customers within those boundaries. Others oppose the establishment of distribution service territories, arguing that such territories, would serve to undermine competition. Reducing the uncertainty and risk associated with bypass may reduce the competitive pressure to keep electric service rates low.

5.1.2 Certificated Distribution Service Territories in the Gas Industry

The Legislature has established certificated distribution service territories for the gas industry. Under that statutory scheme, a utility may not provide gas service in a particular territory unless it first obtains a certificate of public convenience and necessity. These certificates are not exclusive. They do not preclude private parties from constructing and operating gas delivery facilities for their own use. Moreover, they do not preclude a utility from operating in another utility's service territory, if the incumbent utility is providing inadequate service.

5.2 Service Territory Law and Background

There is no general statute pertaining to the franchising of electric utility service territories in Washington. Entities authorized to provide electricity service in Washington include: public utility districts, cities and towns, cooperative corporations, irrigation districts, certain port districts, and investor-owned utilities. The enabling statutes for each establish, more clearly for some than for others, the extent of utility service permitted.

For the Public Utility Districts (PUD), chapter 54.08 RCW outlines the general election process that establishes a PUD and its geographic boundaries. Essentially, a PUD's geographic boundary is coextensive with the county where the utility is formed, but an area smaller than the county can be established along voting district lines. Annexation of contiguous territory is allowed under RCW 54.04.035.

A PUD's geographic boundary, however, does not limit its potential electric service territory. RCW 54.16.040 allows a PUD to purchase and generate electricity, and to construct and operate distribution and transmission plant, both within and outside its boundaries, for the purpose of "furnishing" electricity to its inhabitants or other persons, including public and private corporations, also both within and outside its geographic limits. Therefore, while the political boundaries of a PUD are generally coextensive with the county in which it is formed, its "service territory", in theory, can extend to the entire state. However, any such extraterritorial activity must be reasonably related to the PUD's core purpose of serving its own customers. (In State ex rel. PUD No. 1 of Skagit County v. Wylie, 28 Wn.2d 113, 182 P.2d 706 (1947), the state Supreme Court rejected Skagit PUD's attempt to take over Puget's electric system in 18 counties, concluding that such an expansion went well beyond what was needed to serve the citizens of Skagit County). In order to construct utility plant inside a city or town to provide service in that city or town, a PUD must gain the consent of the city's governing body and the approval of a plan for the construction, RCW 54.04.040. We are not aware of any similar provision when a PUD decides to locate facilities in the "service territory" of an investor-owned utility.

For municipal utilities, a non-code city or town incorporated under Title 35 RCW has the authority to provide electric service both within and outside its political boundaries (RCW 35.84.010; 35.92.050). Code cities incorporated under Title 35A have similar authority to provide electric service both inside and outside their municipal boundaries, RCW 35A.80.010. The authority of code and non-code cities and towns to provide electric service includes the authority to construct and maintain all necessary facilities and to regulate the control, use, distribution and price of energy, RCW 80.04.500.

For electric cooperatives, there is no statute fixing service territory boundaries or limits at the time the cooperative corporation is formed. The cooperatives are formed under the Cooperative Associations Act, chapter 23.86 RCW, or the Mutual Cooperations Act, chapter 24.06 RCW, as entities formed to engage in any lawful business to serve the collective purposes of their members as a nonprofit cooperation, or on the cooperative plan. Service territories are presumably a function of the geographic distribution of the cooperative's members and the distribution facilities which the cooperative has built, acquired the use of, or owns to provide service to its members.

Irrigation Districts formed under chapter 87.03 RCW are authorized to own and operate electrical distribution systems for the purpose of serving the domestic uses of the district's inhabitants. Nothing in statute authorizes irrigation districts to provide service to persons other than district inhabitants. Consequently, irrigation district boundaries would appear to define the limits of the electric service territory. Currently, one irrigation district acts as an electric utility.

Port districts formed under Title 53 RCW are authorized to operate "water, light, power, and fire protection facilities" within areas established as industrial development districts, RCW 53.25.100. Industrial development districts are established to enhance the use of "marginal lands" the characteristics of which include, among other things, inadequate streets, open spaces and utilities. Ports establish the boundaries of these industrial development districts at the time they are formed and their powers appear only to be authorized within these boundaries. Consequently, electricity service provided by the Port does not extend beyond the boundaries of the industrial development district. It is unclear whether a district could provide light and power services if utility services already existed and were adequate. Currently, one port district acts as an electric utility.

Regarding private electric utilities regulated by the WUTC, there is no state statutory basis for geographic definition of service territories. The existence of electric service territories from the commission's perspective is largely one of historical development, practice, and economics, rather than any legally binding territory definition. While service territory agreements involving IOUs must be approved by the UTC (RCW 54.48.040), the Commission does not, by its approval, gain jurisdiction over a utility which it does not otherwise regulate. Cooperatives are exempt from commission jurisdiction (RCW 54.48.040), as are PUDs (RCW 54.16.040) and municipal utilities (RCW 80.04.500). Once approved, the service area agreement establishes only where the regulated utility must serve subject to UTC jurisdiction.

The Legislature addressed the issue of potential for duplication of lines and facilities given the lack of definition of service territories in chapter 54.48 RCW which allows IOUs, PUDs, coops and municipal utilities to bind each other to a division of adjoining territory through service area agreements. These are voluntary contractual arrangements of up to 25 years in duration which, if they involve an IOU, must be reviewed and approved by the UTC. By authorizing such service territory agreements, state law establishes a basis for defining distribution system boundaries, but only if the affected utilities can come to a voluntary agreement.

Historically, regulated electric companies have petitioned the UTC for approval of service territory agreements based on distinct boundaries for each utility, similar to a certificated area or franchise. However, the UTC recently approved a service territory agreement between a regulated electric company and a cooperative that establishes rules under which the parties will compete with one another today and in the future. That agreement identifies areas of future development where the parties could not agree on which utility should be given the right to serve new customers. For those areas, the agreement establishes rules to determine which utility will serve. The agreement further designates two areas as completely open to competition. Finally, the parties agreed to allow new large-load customers to choose their service providers without regard for the agreed-on boundaries.

The state Supreme Court recently analyzed chapter 54.48 RCW. In Tanner Electric Coop. v. Puget Sound Power & Light Co., 128 Wn.2d 656, 911 P.2d 1301 (1996), the state Supreme Court considered an action by an electric cooperative (which the UTC does not regulate) against a regulated privately-owned utility for violation of a service territory agreement between the two utilities. The Court held that, pursuant to chapter 54.48 RCW, the cooperative did not have a claim against the privately-owned utility under the Consumer Protection Act, chapter 19.86 RCW.

The Tanner Court based its decision in part on its view of the extent of the powers of the UTC. The Court stated:

> *As we stated earlier, the WUTC is charged with administering pervasive regulatory schemes that affect almost every phase of activity of the businesses under its authority. . . . As part of this regulatory process, RCW 54.48.030 provides that the WUTC must approve all service area agreements entered into by public utilities and cooperatives.*
>
> 128 Wn.2d at 682.

The Court further found that the UTC has jurisdiction not only to approve or disapprove service area agreements between private electric utilities and rural cooperatives, but also to apply and interpret relevant statutes when a dispute arises from such an agreement. Id. at 665.

5.3 Current Status of Service Territory Agreements in Washington

The WUTC and CTED developed ten survey questions concerning service territory agreements. Utilities were asked to provide the following information:

- Copies of all service territory agreements to which they are a party;
- Descriptions and dimensions of service territories;
- Dates of contract execution and expiration;
- Whether the agreement contains an option to renew;
- Whether geographic boundaries are well-delineated or subject to change;
- Whether the parties encountered disputes and, if so, how those disputes were resolved,
- Whether the agreement provides for the recovery of stranded costs.

Eighteen utilities responded to the survey. The information collected is briefly summarized below. For detail regarding individual service territory agreements the attached chart (Table 5.1) depicts the primary characteristics of the agreements.

Number of Service Territory Agreements and Coverage Area

There are 17 service territory agreements currently in effect. An additional 11 agreements have formally expired, but many of these are still being observed. The largest geographic area covered by a service territory agreement is 4,296 square miles in size. The smallest is one square mile. Of the 17 service territories, all but 4 have specific geographic boundaries.

Duration of Agreements and Current Status

The overwhelming majority of service territory agreements contain 20 to 25 year terms, the duration allowed by statute. Four of the current agreements will expire before 2005. Six of the agreements have expiration dates between 2012 and 2020. Three agreements contain provisions for automatic renewal of the agreements as they expire. All agreements may be renewed by mutual consent of the parties.

Dispute Resolution

Most service territory agreements have operated successfully without disputes between the parties. Of disputes arising out of service territory agreements, all but one were resolved short of litigation. One service territory agreement contains a provision requiring binding arbitration in the event a dispute arises.

Stranded Cost Recovery

Four service territory agreements currently in effect contain provisions regarding stranded cost recovery.

5.4 Policy Considerations

Currently, no territorial constraint is placed on any entity authorized to provide retail electric service from providing such service to any person in the state. Similarly, no territorial protection is granted to any entity acting as a utility from any other entity authorized to provide electricity service. Practically speaking, however, areas already served by the distribution facilities owned or controlled by one entity could not be served by another without a duplication of facilities, voluntary agreement to permit use of facilities, or outright purchase or condemnation of facilities. Apart from the ability to request unbundled use of another entity's transmission system under section 211 of the Federal Power Act, we are unaware of any statutory basis for an entity authorized to be a utility to demand interconnection or unbundled use of another entity's distribution or transmission facilities. So, while service territories do not technically exist by law, they do exist in practice based on the territorial extent of distribution facilities. These practical territories are, however, vulnerable, particularly in the face of physical duplication of existing facilities.

The first policy issue raised by these circumstances is that contractual service territory agreements may not serve to achieve the state's statutory policy against duplication of lines and facilities (RCW 54.48.020). The contracts only exist in circumstances where distribution utilities can reach agreement. Where utilities cannot reach agreement, there is nothing to discourage or prevent the duplication of facilities. Even where distribution utilities can agree on contract terms, those terms may not entirely prevent the potential for wasteful duplication of facilities. Finally, increasingly competitive circumstances in the electricity industry may serve to undermine the effectiveness of voluntary contracts as a means to discourage facility duplication.

The second policy issue has to do with changes that may evolve in the nature of retail electricity service to enhance competition and expand the service options available to individual customers. Historically, all retail customers have received bundled service. Utility competition for customers existed, but on the basis of large pieces of service territory (e.g. municipalization, PUD formation). Service territory border disputes between utilities did arise periodically and some, although very few, examples of wires bypass did occur. Fundamentally, however, each utility was responsible for arranging for all of the bundled service needs of all of the consumers connected to its system and all of those consumers were responsible for compensating the utility for this service.

Proposals to restructure electricity service vary in both scope and timing, but all approaches will likely result in one utility (or other electricity provider) being able to serve at least some class of customers connected to another utility's distribution system. Such a system can work only if all customers are connected to a distribution system and these distribution systems function as a "common carrier." The extent of the utility's obligation to provide service would become a function of individual consumer choices, rather than the utility being obligated to provide like service to all customers. This obligation may vary from simply connecting the customer to the distribution network, to providing a fully bundled service. Fundamentally, the role of the distribution system and the obligations and rights of a utility and its customers would change significantly if such restructuring were to occur.

If such changes are under consideration, it may be reasonable to consider whether the efficient operation of a restructured retail electricity service industry would benefit from a change in policy concerning electricity franchises. If a distribution system franchise were established, it could follow the model of natural gas "certificates of public convenience and necessity". The UTC grants such certificates to both cities and private gas utilities, and these certificates are subject to existing laws regarding powers of consumer-owned utilities (such as forming utilities and preserving local rate setting). Such a franchise is not exclusive. Essentially, a non-exclusive franchise would function as a contract between the utility and the state. It would establish for the holder the right to provide services in the defined area. In return, it establishes the obligations of the holder (e.g., to operate a reliable and safe system, provide connection and service without undue discrimination).

Proponents of explicit franchises generally argue that they would prevent costly duplication of facilities, clarify service rights and obligations, and help distinguish between monopoly and competitive services. Opponents of explicit franchises generally argue that the threat of bypass exerts competitive pressure on utilities to keep rates low. Exclusive franchises, they suggest, would relieve this pressure and allow utilities to load unnecessary costs into rates. Non-exclusive franchises may mitigate this problem, but by the same token, they may not prevent duplication of facilities.

Additional discussion of policy issues associated with certificated distribution service territories is included in Sections 3 and 4, since establishing such territories may affect both the costs of electric service and distribution of those costs.

Figure 5.1. Characteristics of Service Territory Agreements in Washington.

Description	Start	End	Years	Auto. Renewal	Flexible Boundary	Area Miles^2	Disputes	Dispute Process	Stranded Cost Recovery
Benton PUD/Richland City	1977	2002	25	NO	NO	N/A	YES	NO	NO
Benton PUD/Benton REA	1970	NO	N/A	YES	YES	1703	YES	Mutual	NO
Benton REA/Pacific P&L	1998	2015	17	NO	YES	4296	YES	Mutual	NO
Benton REA/Richland City	1978	2003	25	NO	NO	34	NO	Mutual	YES
Big Bend/Franklin PUD	1955	N/A	N/A	N/A	NO	435	N/A	NO	NO
Grant PUD/Inland P&L	1995	2020	25	NO	NO	12	NO	NO	YES
Grant PUD/Big Bend	1976	2001	25	NO	NO	110	NO	NO	NO
Grays Harbor/Pacific PUD	1990	N/A	N/A	N/A	YES	10	NO	N/A	YES
Grays Harbor/McCleary P&L	1965	1985	20	NO	NO	1	NO	N/A	YES
Inland P&L/WA Water Power	1998	2013	15	YES	YES	N/A	YES	YES	NO
Nespelem/Okanogan PUD	N/A	N/A	N/A	YES	NO	400	NO	NO	NO
Parkland L&W/Tacoma City	1974	1994	20	NO	NO	3	NO	NO	NO
Parkland L&W/Elmhurst	N/A	N/A	N/A	N/A	NO	N/A	NO	N/A	N/A
Parkland L&W/Lakeview L&P	N/A	N/A	N/A	N/A	NO	N/A	NO	N/A	N/A
PSE/Elmhurst	1978	2003	25	NO	NO	17	NO	NO	NO
PSE/Ohop	1987	2012	25	NO	NO	90	NO	NO	NO
PSE/Milton Town	1989	2014	25	NO	NO	2.25	NO	NO	NO
PSE/Sumas Town	1992	2017	25	NO	NO	1.25	NO	NO	NO
PSE/Tacoma City	1990	2015	25	NO	NO	100	NO	NO	NO
Tacoma City/Alder	1974	1994	20	NO	NO	10	NO	NO	NO
Tacoma City/Eatonville Town	1975	1995	20	NO	NO	1.6	NO	NO	NO
Tacoma City/Elmhurst	1974	1994	20	NO	NO	20	NO	NO	YES
Tacoma City/Fircrest City	1975	1995	20	NO	NO	1.5	NO	NO	YES
Tacoma City/Lakeview L&P	1974	1994	20	NO	NO	80	NO	NO	YES
Tacoma City/Milton Town	1974	1994	20	NO	NO	2.4	NO	NO	YES
Tacoma City/Ohop	1974	1994	20	NO	NO	80	NO	NO	YES
Tacoma City/Steilacoom Town	1977	1997	20	NO	NO	2.1	NO	NO	YES
Tanner Electric/PSE	1966	1991	25	YES	NO	N/A	YES	NO	NO

6.0 Consumer Protection Policies and Procedures

6.1 Introduction

Consumer protection standards and policies at the state and federal levels are generally designed to protect consumers from the possibility of unfair service restrictions or inequitable cost recovery practices. The Washington Utilities and Transportation Commission (UTC) establishes consumer protection policies and standards for Washington's investor-owned utilities. Local officials or cooperative boards determine their own standards for protecting consumers of public or cooperative utilities.

Changes in the telecommunications industry may offer valuable lessons for consumer protection in the utility industry. The telecommunications industry today is a mixed-competitive industry. Most consumers have a broad choice of long distance providers, but many still have monopoly local providers. The UTC's experience indicates that, as more providers enter the market and as customers are faced with an increasing number of choices, they become more confused, particularly around billing issues. This confusion, coupled with unscrupulous practices by a few providers, has resulted in escalating complaint levels.

In 1998, the UTC received about 560 billing complaints from customers of long distance providers. This is 3.5 times higher than the number received in 1991, and twice the number received in 1994. Even at the local level, where most consumers do not have a choice of providers, we have seen increased billing disputes as the industry changes. Local providers bill for other providers, giving many companies a vehicle for adding charges to consumers' bills; consumers have an increasing number of choices regarding optional local services, such as Caller ID and Call Waiting; and many local companies are positioning themselves for competition. These factors have combined to add confusion and questionable practices at the local service level. In 1997, consumers filed twice the number of billing complaints for local service providers with the UTC than in 1996. In 1998, this number was about 1.5 times the 1997 level.

Some special characteristics of electric service are worth noting in evaluating the importance and nature of consumer protection policies. Electricity is an essential service for industrial operations, commercial structures, and homes. In many applications, it has no substitute. It is also a very technically complex service; many consumers do not have or want all the information that may be necessary to ensure consumer protection. These special characteristics will continue to exist in any industry structure, and may warrant particular attention in policy decisions regarding consumer protection.

6.1.1 Purpose and Scope

ESSB 6560 directs the Utilities and Transportation Commission (UTC) and the Department of Community, Trade and Economic Development (CTED) to jointly study consumer protection policies and procedures of electric utilities. The legislation further directs the two agencies to report on policy and procedural consistencies and inconsistencies among utilities. In collecting information for the report, the agencies focused on the following general categories of consumer protection:

- How utilities allow customers to establish credit and requirements for deposits.
- How utilities inform customers about initial and subsequent terms, rates and charges.
- Utilities' policies and procedures for metering, estimated billings and adjustments.
- Information about bill payment due dates, late fees, budget payment plans, payment arrangements and financial assistance plans.
- How utilities notify customers of disconnection of service, and how a customer can be reconnected.
- Confidentiality issues, such as what information about a customer's account can be disclosed and how a customer can control access to information.
- How a customer can file a complaint about electric service.
- Whether retail contracts contain consumer protection provisions.
- Whether utilities ask customers what type of protections they believe they need.

6.1.2 Methodology

In order to gather information, UTC and CTED jointly prepared a survey for participating electric utilities. Eighteen utilities returned the survey, although not all utilities were able to provide information in all areas. The survey asked for various materials that utilities provide to their customers and posed a number of specific questions about their consumer protection policies and procedures.

UTC and CTED also researched consumer protection policies and procedures throughout the United States to make comparisons between Washington state practices and other jurisdictions and with standards proposed by consumer protection agencies and experts.

6.2 Consumer Protection Policies and Procedures

6.2.1 Credit and Deposit Requirements

The survey asked questions about how customers establish electric service and what requirements utilities had to reduce their own financial risk in supplying customers with service. The following table illustrates the differing approaches to credit and deposit policies and procedures:

Table 6.1 Credit and Deposit Requirements

Investor-Owned Utilities (3 utilities reporting):

Issue	Yes	Percent of WA Customers	No	Not Available
Does the utility charge for new service?	1	33%	1	1
Does the utility require a deposit for customers who may be a credit risk?	3	45%		
Can the deposit be paid in installments?	3	45%		
Does the utility offer alternatives to paying a deposit?	3	45%		
Does the utility pay interest on deposits?	3	45%		

Public Utilities (15 utilities reporting):

Issue	Yes	Percent of WA Customers	No	Not Available
Does the utility charge for new service?	7	11%	1	7
Does the utility require a deposit for customers who may be a credit risk?	10	31%	1	4
Can the deposit be paid in installments?	9	23%	2	4
Does the utility offer alternatives to paying a deposit?	6	11%	6	3
Does the utility pay interest on deposits?	5	22%	2	8

Several utilities reported charging customers for establishing service. Charges averaged around ten dollars and ranged as high as $100.

Of the 14 utilities who reported on deposits, 13 have the option of requiring deposits either upon application for service or at a subsequent point when the customer proves to be a credit risk. Half the utilities that require deposits state that at the time of establishing an account, the customer's credit history is reviewed to determine if a deposit is needed. Utilities normally look at any previous service history the applicant had with the utility or a similar utility. For example, a utility may look at the number of disconnect notices and disconnections a customer had; whether the applicant is a homeowner; or whether the applicant has two major credit cards with a good payment history. Three of the smaller utilities only require deposits with customers who have started a pattern of not paying their bills. Only one utility does not require a deposit at all.

Most of the utilities offered alternatives or waivers of the deposit in certain cases. Many utilities allowed the applicant to submit a guarantor or co-signer on the account as a second party to pay unpaid balances. A couple smaller utilities waived the deposit requirement for customers who agree to have payments automatically deducted from their bank accounts.

For utilities requiring deposits, half require an estimated average of two months' billing. Three smaller utilities set deposit amounts ranging from $100 to $200. Most utilities allowed the customer to pay the deposit in installments, ranging from half the amount paid in the first month and two payments thereafter, to allowing the customer to propose the payment arrangement. Only two utilities required full payment at the time the deposit was requested.

Eight utilities reported they compensate customers by paying interest on the deposit. Normally the interest rate calculation is 5 to 6 percent, or, for companies regulated by the UTC, a calculated average of the current year's Treasury bills. The deposit with applicable interest is either refunded to the customer after a period of time of satisfactory credit record, usually one year, or is applied to the customer's account when the account is closed or becomes past due.

UTC addresses establishment of credit and deposit issues in WAC 480-100-046, WAC 480-100-051, WAC 480-100-056, and WAC 480-100-116 for investor-owned utilities.

In addressing general credit and deposit issues, the Federal Trade Commission (FTC) stated that policies should be "appropriate." The National Association of Regulatory Utility Commissioners (NARUC) stated they should be "fair and nondiscriminatory."

A fundamental purpose of consumer protection in this area is to avoid redlining, or the discriminatory use of credit information in the use of deposits or in the offering of services. Consumer advocates believe the Equal Credit Opportunity Act and the Fair Credit Reporting Act should be employed to prevent redlining and ensure that deposits are required appropriately.

6.2.2 Customer Billing and Rate Information

The survey questioned how customers were informed about billing issues and rate information. The table below displays the number of companies who provide various information to their customers:

Table 6.2 Customer Billing and Rate Information

Investor-Owned Utilities (3 utilities reporting):

Issue	Yes	Percent of WA Customers	No	Not Available
Does the utility provide customers information about rates and charges upon request?	3	45%		
Does the utility provide customers information about rates and charges proactively, without specific requests?	1	4%		2
Does the utility provide customers information about rate changes?	3	45%		
Does the utility provide customers information about their ability to participate in rate hearings?	3	45%		

Public Utilities (15 utilities reporting):

Issue	Yes	Percent of WA Customers	No	Not Available
Does the utility provide customers information about rates and charges upon request?	15	43%		
Does the utility provide customers information about rates and charges proactively, without specific requests?	4	24%	9	2
Does the utility provide customers information about rate changes?	4	16%		11
Does the utility provide customers information about their ability to participate in rate hearings?	3	16%		12

All utilities stated they provide customers with some information on billing or rates such as proposed rate increases upon request. Less than half provide this type of information without the consumer requesting it, although a few utilities provide billing information at the time of application and provide periodic newsletters or bill inserts to keep customers informed of various issues.

Most utilities stated they only provide this information upon written or verbal request from customers. Only a couple of the smaller utilities and all the larger utilities provided notice to their customers of proposed rate changes and how customers could become involved in the rate-making process.

WAC 480-100-101 sets the requirements for investor-owned utilities regarding what information must be provided on customer bills; and WAC 480-100-041 sets requirements for these utilities regarding information that must be provided to consumers.

A report by the National Consumer Law Center proposes that customers be provided with rate information in simple, uniform language. NARUC advises that companies should provide sufficient and reliable information regarding billing, rates, metering and other issues so consumers can make informed choices. The Regulatory Assistance Project (RAP) suggests customers be provided with a “terms of service” brochure, using simple, understandable language, within three days of service application. In addition, RAP suggests monthly bills explain the total price, rate design and price per kilowatt hour for electric usage. The FTC cautioned that costs of disclosing information cause rate increases.

Wisconsin proposed rules requiring that rate schedules be included annually in customers’ bills or when rate changes become effective. Ohio’s rules require utilities to provide new customers with a “rights and obligations” summary that would also be provided to any customer upon request. Rates and tariffs are to be available upon request at the company’s office. Maine also requires that terms of service be disclosed at the time of initial application.

6.2.3 Metering, Estimated Billings and Adjustments

There is a great deal of variation in both fees utilities charge to customers who request meter testing and bill adjustments that utilities provide to those customers. There is little variation among utilities regarding metering and billing policies, their ability to estimate bills or the reasons for estimating bills.

The following table illustrates metering issues:

Table 6.3 Metering, Estimated Billings and Adjustments

Investor-Owned Utilities (3 utilities reporting):

Issue	Yes	Percent of WA Customers	No	Not Available
Does the utility bill on a regular (either monthly or bi-monthly) basis?	3	45%		
Does the utility bill estimated amounts in lieu of actual meter readings under certain conditions?	3	45%		

Public Utilities (15 utilities reporting):

Issue	Yes	Percent of WA Customers	No	Not Available
Does the utility bill on a regular (either monthly or bi-monthly) basis?	14	45%		1
Does the utility bill estimated amounts in lieu of actual meter readings under certain conditions?	13	45%		2

Metering and billing practices are very similar across the utilities surveyed. The majority of utilities read meters and bill customers monthly. Nearly all commercial and industrial customers are on a monthly basis as are a little more than half of the residential customers. Otherwise, these customer classes receive bi-monthly meter reading and billing. Four utilities indicated separate seasonal meter reading and billing schedules for irrigation customers.

Two utilities indicated that some customers with fixed electricity consumption may not be metered at all and the utility bills the customer a fixed amount. Additionally, at least one utility may estimate electricity consumption on a temporary basis when conditions make metering impractical.

All responding utilities indicated that they are allowed to estimate the consumer's bill in lieu of an actual meter reading. The most common policy is one that states, "if for any reason the utility cannot read the meter, the utility may estimate the bill." Practically speaking, bill estimation is due to inclement weather, hostile animals, broken meters or general meter inaccessibility. Five utilities estimate bills when customers do not send in their meter-reading card on time, with one utility reporting that 70 percent of its consumers read their own meters monthly.

A range of practices and charges is apparent among the nine utilities disclosing their policies on adjusting bills due to meter errors. Five utilities provide free meter testing at the consumer's request as often as once a year or in response to a high bill complaint or as infrequently as once every ten years. Remaining utilities never offer this free testing service. If consumers request more frequent testing, then consumers pay the cost of the test. All nine utilities will test meters at consumer's request for a price. Two utilities charge $25 per test and one utility charges $50 per test. Most utilities require that the meter perform within a 2 percent margin of error. All utilities waive the meter testing charge if the meter fails the test.

Utilities provide a range of bill adjustments upon determination of a meter error. Two utilities adjust the last six months of bills to the current customer. One utility adjusts the last three months of bills, four utilities adjust the last month's bill and one adjusts bills as appropriate.

UTC regulates investor-owned utilities in this area, as described in WAC 480-100-111, 121, 126, 131, 136, 141, 146, 166, 171, 176, 181 and 201. RCW 80.28.170 also addresses meter testing requirements.

6.2.4 Bill Payment and Assistance

The following table illustrates the policies and procedures which utilities employ in establishing requirements for customers to pay bills.

Table 6.4 Bill Payment and Assistance

Investor-Owned Utilities (3 utilities reporting):

Issue	Yes	Percent of WA Customers	No	Not Available
Does the utility charge customers for late payments?	1	33%	2	
Does the utility provide customers with information about late payment fees on its bills?		0%		3
Can the customer choose a payment date other than that assigned by the utility?	3	45%		
Does the utility offer budget payment, or equalized payment, plans?	3	45%		
Does the utility offer customer extended payment options for past due amounts?	3	45%		
Is home heating assistance available to customers?	2	12%		1
Does the company inform customer about the availability of home heating assistance?	2	12%		1

Public Utilities (15 utilities reporting):

Issue	Yes	Percent of WA Customers	No	Not Available
Does the utility charge customers for late payments?	9	28%	4	2
Does the utility provide customers with information about late payment fees on its bills?	6	22%	1	8
Can the customer choose a payment date other than that assigned by the utility?	7	12%	8	
Does the utility offer budget payment, or equalized payment, plans?	15	43%		
Does the utility offer customer extended payment options for past due amounts?	12	24%	3	
Is home heating assistance available to customers?	8	29%	1	6
Does the company inform customer about the availability of home heating assistance?	8	30%	1	6

Among responding utilities, all require customers to pay their bills between 10 and 20 days from either billing or mailing date. Half of these utilities said customers have the option of designating their own payment date different from that normally assigned by the utility. In most cases, these requests are to allow a payment date that corresponds to the customer's income cycle. A couple smaller utilities only allowed the date change if the customer agreed to enter into a budget payment plan or an automatic bank account deduction.

Approximately half the utilities charge a late payment fee on past due accounts. This policy was shared fairly equally by small, medium and large utilities. Fees ranged from $2.50 for smaller amounts past due, and between 1 percent and 5 percent per month on unpaid balances. Fees are applied once the due date has passed or in some cases, if the bill has not been paid by the next billing cycle. Half of the utilities explain their late payment fees on billing statements.

Most utilities allowed customers to make payment arrangements on past due balances. Usually this is done on a case-by-case basis, with some utilities placing a limit on the number of months customers can use to pay past due amounts.

All utilities had a budget billing program, where the customer can pay the same amount each month throughout the year. The advantage of this program for customers is that they do not have to find extra money in the winter for high heating bills. Budget billing amounts are generally calculated by estimating the annual usage amount and spreading that amount over 12 months. Customers are usually notified about the budget billing option when they contact the utility to negotiate payment arrangements on a past due bill. Customers are also informed about budget billing plans through bill inserts, newsletters, information on the bill, new customer packet information, special mailings, and brochures. The number of customers on this plan range from 1 percent to 30 percent of a utilities' residential customers.

In addition, more than half of the utilities either offer their own heating assistance options, or take advantage of assistance options offered by others, to help customers meet electric payments. Options range from governmental programs such as the nationally-funded Low Income Home Energy Assistance Program (LIHEAP) and community action agency programs, to a utility's own rate-discount program for senior, disabled or low income customers. Most utility programs are funded through private donations from customers who donate when they pay their bill. Information on these programs is provided to customers in the same way as budget billing programs. The number of customers receiving financial assistance through these programs ranges from 3 percent to approximately 27 percent of total residential customers. (See Section 9.4 for further discussion of low-income energy services.)

WAC 480-100-072 describes the requirements for investor-owned utilities around issues of payment arrangements. RCW 80.28.010(7) codifies the requirement that investor-owned utilities must offer budget payment plans.

NARUC states that late payment charges should be fair and nondiscriminatory. RAP added that late payment charges should be stated on the front of the bill. Wisconsin allows late payment charges within their rules, limiting the amount to 3 percent of the bill with a minimum charge of 50 cents.

Wisconsin also ruled that utilities with more than 40,000 customers should annually and no later than October 15 of each year provide budget billing and heating assistance program information to those who have been disconnected for non-payment.

6.2.5 Disconnection of Service

Two-thirds of the utilities provided information regarding their service disconnection procedures for past due accounts. A summary of that information follows:

Table 6.5 Disconnection of Service

Investor-Owned Utilities (3 utilities reporting):

Issue	Yes	Percent of WA Customers	No	Not Available
Does the utility provide customers written mailed notice of pending disconnections?	3	45%		
Does the company have any limits on when it may disconnect (i.e., time of day or seasonal restrictions)?	3	45%		
Is the technician sent out to disconnect the company allowed to collect past due amounts in lieu of disconnection?	3	45%		
Does the utility have different disconnection procedures if the account holder is not the same as the service user?	3	45%		
Does the utility have different disconnection procedures if the account holder claims a medical emergency?	3	45%		
Does the utility have different disconnection procedures if the account holder is a medical facility?	2	38%	1	
Can the utility disconnect the customer if a complaint is pending with the utility?		0	3	
Is there a charge to the customer for sending a technician to the premises to disconnect the customer?	2	12%		1
Does the company charge the customer for reconnecting service?	3	45%		
Must the customer pay all past due amounts before reconnection?		0	3	
Must a customer pay a deposit before reconnection?	2	12%	1	

Public Utilities (15 utilities reporting):

Issue	Yes	Percent of WA Customers	No	Not Available
Does the utility provide customers written mailed notice of pending disconnections?	11	35%		4
Does the company have any limits on when it may disconnect (i.e., time of day or seasonal restrictions)?	11	34%	3	1
Is the technician sent out to disconnect the company allowed to collect past due amounts in lieu of disconnection?	8	29%	3	4
Does the utility have different disconnection procedures if the account holder is not the same as the service user?	6	24%	4	5
Does the utility have different disconnection procedures if the account holder claims a medical emergency?	6	39%	5	4
Does the utility have different disconnection procedures if the account holder is a medical facility?	4	24%	3	8
Can the utility disconnect the customer if a complaint is pending with the utility?	1	<1%	13	1
Is there a charge to the customer for sending a technician to the premises to disconnect the customer?	6	31%		9
Does the company charge the customer for reconnecting service?	13	41%	1	1
Must the customer pay all past due amounts before reconnection?	11	38%	3	1
Must a customer pay a deposit before reconnection?	4	4%	10	1

All of the reporting utilities stated they provide written notices, with many of them sending additional reminder notices or personally contacting the customer by telephone or site visit. The average elapsed time between notice and actual disconnect is about eight days. One smaller utility allows 25 days.

Most utilities said if the service person was dispatched to disconnect service, they were allowed to accept payment at the customer's site to avoid the disconnection. One utility said its service person was not allowed to accept payment for safety reasons. Medium to large utilities charge the customer for disconnection of service, in addition to any subsequent charges the customer might incur for reconnection. Charges range from $9 to $22 for disconnection of service.

Four of the smaller utilities disconnect the customer's service even though the customer contacted the utility to dispute the bill. Thirteen of the other utilities representing small, medium and large utilities would not disconnect a customer while a dispute was pending. A few of the smaller utilities said that in order to avoid disconnection, the customer could contact them to negotiate payment.

Approximately twenty percent of the utilities - primarily smaller ones - do not have restrictions on what day they disconnect service. Sixty percent do not disconnect service when the customer is not able to make arrangements for reconnection the same or following day. A few utilities said cold temperatures also restricted disconnection of service.

Almost all utilities charge a reconnection fee if they have to dispatch a service person to reconnect service. There is a wide array of charges imposed, and the charges increase if the service person is required to reconnect after normal business hours. One small and one large utility do not charge for the reconnection. All other utilities charge from $10 to $50 during normal business hours. The average amount is $25. For reconnection after normal business hours, the charge ranges from $30 to $200. Most smaller utilities charge the higher amounts, although one larger utility charges $125 for reconnecting on weekends and holidays.

Most utilities required the customer to pay the total delinquent amount prior to reconnection of service. The others require the customer only to negotiate payment arrangements and possibly pay a portion of the past due amount at the time of reconnection. Thirty-five percent of the utilities required a deposit on the account prior to reconnection of service. Utilities under UTC regulation may not refuse to reconnect a customer for an amount owed on a prior disconnection, as long as the customer is able to make arrangements to pay the reconnection fee and any deposit the utility may require.

The survey asked how utilities handle situations where the person who used the service was not the same person responsible for payment, for example if a landlord paid for electric service, but defaulted and the tenant's service was in jeopardy. Half of the utilities representing small, medium and large providers notified both the service user and the landlord of a pending disconnect by way of mailed notices or a posted notice on the premises. Other smaller utilities stated they would only notify the landlord or allow the landlord the right to decide if the tenant should be notified. Another small utility said they would only notify the service user.

The survey also asked how utilities handled disconnections for customers who needed electricity for a medical problem in their household. Most companies reported that the customer must provide a physician's letter certifying that electricity is required in the household due to a medical problem. Smaller companies said they handled these situations on a case-by-case basis. Most were willing to delay disconnection of service in order for the customer to obtain and transmit the physician's letter.

Finally, in terms of disconnecting services to medical facilities, half the utilities either do not have this situation in their area or if they do, they handle it on a case-by-case basis or they contact the Department of Social and Health Services as well as notifying the medical facility directly. Payment arrangements would then be negotiated for continued service.

The legislature has recognized the need for continued electric service during the winter months. For investor-owned utilities, RCW 80.28.010 (and WAC 480-100-072(3)) provide a moratorium on winter electric disconnections for low-income customers, provided that they are able to make minimum payment arrangements. RCW 54.16.285 places limits on public utilities' ability to terminate utility service for residential heating between mid-November and mid-March. Low-income customers have six criteria they must meet to avoid having heating service terminated:

1) The customer must notify the utility of his/her inability to pay the bill.
2) The customer must provide certification of household income for the prior twelve months.
3) The customer must have applied for home heating assistance from appropriate government and private sector organizations.
4) The customer must have applied for low income weatherization, if available.
5) The customer must agree to a payment plan as specified in the statute.
6) The customer must agree to pay the balance of the bill if he/she moves.

WAC 480-100-071, which addresses disconnection procedures and requirements for investor-owned utilities, includes similar requirements.

Wisconsin has proposed rules requiring that written disconnection notices be provided by mail or in person. To avoid disconnection, customers are allowed to make payment arrangements, enter into a deferred payment arrangement, or obtain energy conservation measures. Customers are allowed up to 17 days between the notice and the day of disconnection to make arrangements. If the service is not disconnected at that time, the utility must provide another 24-48 hour notice delivered to the premises. The utility is not allowed to disconnect when utility representatives are not available the same or following day to negotiate terms of payments and to restore service. Utilities are not allowed to disconnect service while investigating a disputed bill. However, utilities can require a deposit before reconnection.

Wisconsin also proposes that disconnection of customers with medical emergencies be delayed 21 days once documentation from a physician has been received to make payment arrangements.

6.2.6 Customer Complaints

The survey asked how utilities handled customer complaints. Their responses are illustrated in the following:

Table 6.6 Customer Complaints

Investor-Owned Utilities (3 utilities reporting):

Issue	Yes	Percent of WA Customers	No	Not Available
When the utility receives a complaint, is there a required time frame during which it must respond to the customer?	3	45%		
Must the customer pay disputed amounts while a complaint is actively investigated?		0%	3	
Does the utility have an escalation or appeal process?	3	45%		
Must the customer pay disputed amounts while an appeal is pending?		0%	3	

Public Utilities (15 utilities reporting):

Issue	Yes	Percent of WA Customers	No	Not Available
When the utility receives a complaint, is there a required time frame during which it must respond to the customer?	3	<1%	9	3
Must the customer pay disputed amounts while a complaint is actively investigated?	1	<1%	13	1
Does the utility have an escalation or appeal process?	14	43%	1	
Must the customer pay disputed amounts while an appeal is pending?	1	<1%	11	3

For most utilities, there is no policy about how much time may elapse between a customer complaint and the utility's response. Other utilities had time frames as short as one day.

During the complaint review process by the utility, most do not require the customer to pay the disputed amount. If the customer is not satisfied with the review outcome, most utilities do have an escalation process. Generally, the first escalation level is a supervisor or general manager; and the second level is a governing body of some type. Again, during this process, the customer normally is not required to pay the disputed amount until an answer is received. Utilities normally respond either by telephone or in writing to complainants.

UTC establishes complaint procedures for investor-owned utilities in WAC 480-100-096.

Ohio's rules require the utility to respond to customer complaints within three days, either verbally or in writing. In addition, utilities must have an escalation process in place for an additional review of the complaint.

6.2.7 Customer Surveys

The agencies queried the utilities as to whether they have ever done any market research to determine what types of consumer protection their customers might want or need. Generally, no utilities have done this. Many utilities survey their customers on issues of customer satisfaction and in doing so identify additional services for which their customers may pay. Several public utilities shared this data. These surveys may explore issues that are related to consumer protection such as the market for bill insurance that pays a customer's energy bills for six months in the event of a loss of income. This could be construed as a consumer protection benefit, an added value service, or even a shareholder revenue program. (Forty-four percent of the consumers in one public utility's service territory indicated they were very interested in this type of insurance.)

Investigations have not yet identified any organization or utility in the country that is conducting public research into what types of consumer protection electricity consumers may desire.

6.2.8 Retail Contracts

All responding utilities who have customers served by retail contract agreements provide those customers the same consumer protection as they provide the majority of their customers who purchase power through published tariffs.

6.3 Conclusion

The comparison of consumer protection policies and procedures among reporting utilities shows a range of approaches for interacting with and protecting customers. Disparities exist for several reasons. In some cases, the diversity in consumer protection approaches may be a reflection of the diverse nature of the utilities themselves, varying local circumstances, or the regulatory structure under which they operate. It appears the size of the utility, in part, determines policy and procedures. For example, smaller utilities tend to have more informal means of establishing credit, allowing arrangements for past due amounts, and handling customer complaints. It is also clear that UTC regulation affects consumer protection policies and procedures. Investor-owned companies, which are subject to UTC consumer protection mandates, have more uniform policies and procedures. In addition, those protections tend to be more extensive than those of utilities not subject to UTC regulation.

Many policies and procedures are similar among municipalities and public utility districts. These entities generally provide regular access directly to regulators through board or council meetings held within the community. This access, combined with the ability to elect regulators, gives these customers tools to protect their own interests that do not exist in the same way for customers of investor-owned utilities.

6.4 Consumer Protection Considerations

As the electric industry evolves, consumer protections may need to be reevaluated in light of changing market conditions. The following checklist outlines the basic areas where consumer protection issues and considerations typically arise. These consumer considerations may be relevant to the existing market structure as well as competitive market structures. (In 6.5, we briefly examine consumer protection issues that may become more pressing if retail access is required for some or all consumers.)

- *Credit standards for use in determining consumers' credit-worthiness*: Credit models could include permitting the customer to provide a letter of credit from a similar utility, a satisfactory credit history report, evidence of consistent employment or the option of providing evidence of ownership of the premises to be served.
- *Deposit requirements*: These may cover the circumstances under which utilities could require deposits and/or the deposit's magnitude.
- *Application fees*: Determination of what level of connection fee is reasonable or appropriate.
- *Bill information*: Clarification of what information is to be included on a customer's bill. This may include an easily understandable format for listing customer name and address, account number, price per kilowatt hour, itemization of taxes and other charges, total amount due, payment due date, a toll-free number for customer complaints or questions and the phone number of the governing body for escalation of complaints.
- *Energy service provider information, policies, and procedures*: Determination of when and how to provide information such as actual and estimated meter readings; billing practices and due dates; credit and collection policies; late payment charges; rate and fee information (including how customers can provide input on proposed rate changes); availability of heating assistance and conservation programs; safety information; budget payment plans; payment options for delinquent accounts; preferred payment date options; disconnection and reconnection policies; privacy issues and customer complaint procedures.
- *Payment due dates*: Determination of the appropriate amount of time after billing to require payment and consideration of allowing customers to establish their own payment date to coincide with their income cycles.

- *Late payment fees*: Determination of the circumstances and magnitude of appropriate late payment fees.
- *Low-income access to electricity*: Consider special payment arrangements for low-income customers to encourage universal service. (One such arrangement is Clark PUD's "guarantee of service program." This program has reduced low-income disconnects, reduced uncollectibles and resulted in total cost savings for the utility and its ratepayers by reducing administrative costs and securing higher payments from low-income customers. See Section 9.4 and 9.6 for more information.)
- *Disconnection policies*: Determination of conditions under which a utility may disconnect customers, including notification standards, provision for prompt reconnection, and exceptions for medical conditions, extreme weather, etc. Special standards may be applied for low-income customers, based on ability to pay. (See Section 9 for low-income program information).
- *Privacy standards*: Determination of standards for privacy of account and/or proprietary information about customers.
- *Complaint response time and escalation*: Determination of the appropriate time for response to consumer complaints and procedures for appealing responses to supervisory staff or governing bodies.

6.5 Consumer Protection in a Competitive Retail Market

Retail competition may generate new consumer protection challenges. The following are examples of new or revised consumer protections that may be needed if retail competition is formally introduced. These examples imply no judgment as to whether changes in industry structure are desirable.

- Applicability of the Consumer Protection Act to competitive services.
- Allocation of stranded costs and benefits among customers and shareholders.
- Determination of responsibility for the ownership and accuracy of meters.
- Provisions to ensure that bills are clear and accurate; applicable service providers are appropriately identified on customer bills; and generation mix and environmental characteristics are disclosed. Consumers receiving bills for multiple services and perhaps even from multiple companies, may need assurance that partial payment will avoid disconnection of service (that is, payment would first be allocated to the distribution company and second to the generation company). It may also be important to separately list and price each discrete element (such as generation) in a comparable manner on the bill, so that consumers with the ability to choose from a variety of competitors for each service can easily compare prices among providers.

- Determination of responsibility for basic, core customer service and universal service needs (ensure a provider of last resort).
- Protection from unfair and deceptive trade and marketing practices, such as slamming, cramming, fraudulent company names, and phone shark practices; and policies that apply when a customer changes suppliers (such as restricting the use of verbal authorizations for changing service providers).
- Provisions for truth in advertising such as standards for the kinds of comparisons and information that can be used.
- Protection against market power abuses, such as monitoring affiliate transactions.
- Registration and licensing for service providers.
- Adoption of standards for financial viability of service providers.

(USDOE has commissioned a study entitled, "A Blueprint for Consumer Protection for State Electric Retail Competition." The "Blueprint" will present the most current discussion and national assessment of consumer protection in a competitive retail electric industry providing examples from states that have progressed to the implementation stage.)

Experience from the phone industry and the complex nature of electricity industry changes suggest that effective retail competition may require consumer education to alert consumers to their rights and choices. Such education may reduce the costs of making the transition to a new industry model, and may accelerate the transition by small-load customers to a competitive market.

The extent to which further consumer protections and education are necessary may depend on the extent to which choice is available. Full competition for all consumers, including residential consumers, may require more extensive consumer protection measures than a model which allows choice only for large industrial users.

Resources for Section 6

1 National Association of State Utility Consumer Advocates (NASUCA): Proposal for Consumer Bill of Rights; May 19, 1998.

2 American Association of Retired Persons (AARP): “Is Electric Utility Restructuring a Bright Idea for Consumers?”; 1997.

3 Federal Trade Commission (FTC): Response to the Utah Public Service Commission Request for Comments on Consumer Protection in Docket No. 96-999-001, Report to Electrical Deregulation and Consumer Choice Task Force; July 15, 1998.

4 Regulatory Assistance Project (RAP): “Model Electricity Consumer Protection Disclosures”; date unknown.

5 Consumer Federation of America (CFA): News release outlining policies to ensure consumer protection during electric utility restructuring; March 1, 1998.

6 National Consumer Law Center and Barbara Alexander: “Consumer Protection Proposals for Retail Electric Competition”; October 1996.

7 State of Wisconsin: Proposed electric utility service quality rules; March 1998.

8 State of Ohio: Electric Service and Safety Standards; date unknown.

9 State of Maine: Proposed electric consumer protection rules; August 25, 1998.

10 Barbara Alexander: ”Comparison of Consumer Protection Provisions in State Legislation on Retail Electric Competition”; March 1998.

11 Electric Consumers Alliance: ”National Electric Deregulation Survey Summary of Findings”; March 3, 1998.

12 National Association of Regulatory Utility Commissioners (NARUC): “Statement of Issues and Options on Customer Choice”; March 1998.

7.0 Service Quality

Competition in the electric service industry is highlighting the importance of a number of issues affecting the nature and quality of customer service. The quality of service(s) provided to electricity customers may be enhanced by competition, if doing so offers service suppliers a competitive advantage. On the other hand, service quality offered to some consumers could decline if utilities focus their attention on those customers most likely to exercise choice, while reducing effort and investment to serve customers less likely to choose alternatives. This dynamic is important regardless of whether full competition is introduced to the retail service market. Experience over the last decade in the telephone industry indicates that, where companies serve both competitive and monopoly customers, service quality tends to improve for the former (typically in urban areas) and decline for the latter (often rural customers).

The Legislature directed the Utilities and Transportation Commission (UTC) and the Department of Community, Trade and Economic Development (CTED) to study current levels of service quality as measured by available statistics, trends affecting quality of service, and ways to achieve high levels of service quality in the future. This section of our report examines the nature and quality of services provided customers by:

- Summarizing the results of a survey completed by Washington utilities.
- Examining trends affecting the service(s) utilities provide to customers.
- Describing a range of strategies the state might employ to ensure high levels of service quality.

For the purposes of this section, service quality is defined as the way in which the utility interacts with and responds to the needs of its customers. This is closely related, although separate from, the issues addressed in the Consumer Protection section (Section 6). That section dealt specifically with consumer rights in utility service and the protections established in ESSB 6560. This section deals with those matters in which the utility has substantial discretion about the services it provides, the way it provides them, and the information it collects and maintains regarding customer services.

Historically, there have been few standards established to govern customer services. The UTC evaluates customer services and utility practices as they are proposed in utility service tariffs, but does not have prescriptive rules covering all areas of service and practice. Each of the consumer-owned utilities offers customer services consistent with the policies and direction of its local commission, council, or governing board. Consumers and consumer advocate groups suggest that, as competition begins to influence utility decisions about customer service, some basic minimum standards may become necessary. They argue that utility customers, particularly those with few or no choices about service-provider, should be able to expect a level of service that meets a uniform and understood minimum standard.

7.1 Current Level of Service Quality: The Survey and Other Research

The agencies designed a set of survey questions to examine the current level of customer service among Washington's electric utilities. The survey focused on the following issues and services:

- The access that customers have to do business with the utility.
- How utilities measure customer satisfaction.
- Performance measurements in answering customer calls.
- Performance measurements in meeting appointment commitments.
- Information about disconnection of customers.
- Power restoration after an outage has been reported, including priority plans.
- Time frames for provision of new service.
- Information about repair orders.
- Information about customer complaints.
- Meter reading and billing errors.

Eighteen utilities completed and returned the survey, although not all were able to provide information in all areas. The agencies also sponsored a workshop in August 1998. Stakeholders at the workshop addressed service quality, including features and characteristics of service quality, strategies for enhancing service quality, and trends affecting service quality.

Workshop participants identified several characteristics of good service quality, including the ability of customers to get what they want when they want it; the ability of the utility to meet evolving customer needs; and the ability of the utility to deal with special customer needs. Workshop participants identified the need for more consumer education, to include more pertinent and useful information from the utilities. They also expressed the concern that different classes of customers desire different kinds of services. Any service quality principles and standards need to take into account the difference between residential and commercial customers, and the differences between large and small utilities. Stakeholders also felt that service quality issues change constantly in a dynamic environment, and that establishment of formal benchmarks may quickly be out-of-date.

The agencies also researched consumer protection policies and procedures throughout the United States in order to compare service quality in Washington with practices in other states. National consumer organizations and the Federal Trade Commission have recommendations regarding consumer service policy and standards to apply in both competitive and mixed competitive/monopoly circumstances. Where relevant, we have described those policies as they pertain to conditions in Washington. The states of Wisconsin and Ohio have recently proposed or adopted policies and rules concerning utility service quality and we have compared these rules to Washington circumstances where relevant.

7.1.1 Customer Access to the Utility

The survey included a number of questions about how customers could access, interact, and communicate with the utility. Table 7.1 summarizes the responses to those questions.

Table 7.1 Utility Responses to Customer Access Questions

Investor-Owned Utilities (3 utilities reporting):

NR = no response.

Issue	Yes	No	N/A
Does the utility maintain, or have agreements with others to maintain, facilities where consumers can conduct business with the utility (service connection, deposit, complaint)?		3	
Does the utility maintain, or have agreements with others to maintain, facilities where consumers can pay bills?	3		
Can customers pay bills by automatic fund transfer (including credit card)?	3		

Consumer-Owned Utilities (15 utilities reporting):

Issue	Yes	No	N/A
Does the utility maintain, or have agreements with others to maintain, facilities where consumers can conduct business with the utility (service connection, deposit, complaint)?	7	8	
Does the utility maintain, or have agreements with others to maintain, facilities where consumers can pay bills?	11	4	
Can customers pay bills by automatic fund transfer (including credit card)?	11	3	1(NR)

Seven public utilities reported maintaining facilities separate from the main business offices where customers can conduct business. For these seven public utilities, customers can pay bills, apply for service, and disconnect or reconnect existing service at these separate locations. No investor-owned utilities reported maintaining such facilities.

Fourteen utilities reported offering locations other than the main business office where customers can pay bills. The nature of these locations varied widely to include grocery stores, drop boxes, banks, and city halls. Utilities report that the need for such remote-access locations is determined by customer comments, customer convenience and, in some cases, by customer surveys. In addition, most utilities accept alternative means of payment such as electronic transfer, electronic fund transfers or credit card payments.

High quality customer service includes ease of consumer access to the utility and utility responsiveness to customer convenience. According to the workshop participants, more accurate and useful information and more effective communication with customers are strategies to help achieve those characteristics.

7.1.2 Measuring Customer Attitudes and Satisfaction

Nearly all utilities reported regularly assessing customer satisfaction, both with the utility and with the service it provides. The ways in which utilities perform their measurements vary. Three of the smaller utilities do so informally through customer comments and interactions with the local community. Most utilities report using either written surveys or telephone surveys, or a combination of both. Table 7.2 summarizes the utility responses to questions regarding measurement of customer satisfaction.

Table 7.2 Measurement of Customer Attitudes and Satisfaction

Investor-Owned Utilities (3 utilities reporting):

Issue	Yes	No	N/A
Does the utility measure customer satisfaction?	3		
Regular telephone or written surveys?	3		
No formal surveys, but informal input at utility office, etc.			

Consumer-Owned Utilities (14 utilities reporting):

Issue	Yes	No	N/A
Does the utility measure customer satisfaction?	13	1	
Regular telephone or written surveys?	11	3	
No formal surveys, but informal input at utility office, etc.	3		

Proposed rules in the state of Wisconsin direct all utilities to make regular quantitative assessments of the satisfaction of all customer classes. The National Consumer Law Center recommends specifically surveying customers who have initiated a request for service, or who have called the utility with a question or concern on their bill. It further suggests that these transaction-based surveys be conducted monthly or quarterly. Workshop participants generally agreed on the importance of surveying customers regularly.

7.1.3 Telephone Answering Performance

Most utilities report they measure staff telephone answering performance. Smaller utilities do this informally by direct supervisory staff. Larger utilities employ automated telephone systems that electronically monitor and report on telephone answering performance. Six of the seven utilities indicating they kept performance statistics summarized those statistics for the survey.

Table 7.3 Telephone Answering Performance Measurement

Investor-Owned Utilities (3 utilities reporting):

Issue	Yes	No	N/A
Does the utility measure telephone answering performance?	3		
Is measurement done quantitatively and systematically?	3		
Are telephone answering response performance statistics maintained?	3		

Consumer-Owned Utilities (14 utilities reporting):

Issue	Yes	No	N/A
Does the utility measure telephone answering performance?	9	5	
Is measurement done quantitatively and systematically?	5	9	
Are telephone answering response performance statistics maintained?	4	10	

The nature of statistics regarding telephone answering varied widely, so general conclusions cannot clearly be drawn. Statistics range from 42 percent of calls answered within 60 seconds to 80 percent of calls answered within 30 seconds. Two large investor-owned utilities reported average speed of answer: one reported 23 seconds and the other 27 seconds. However, these statistics do not appear to measure the average time a customer may be kept on hold waiting for a response.

Proposed service quality rules in the state of Wisconsin specify that utilities must achieve an average answer speed of not more than 90 seconds. The state of Ohio has mandated that utilities maintain an average answer speed of not more than 60 seconds.

7.1.4 Missed Appointments

Only one utility maintains systematic records regarding missed appointments. A missed appointment is one where the utility fails to fulfill an appointment scheduled with the customer at the customer's premises. Puget Sound Energy tracks this statistic as part of its Service Quality Index (SQI) required by the UTC as a condition of the utility's recent merger with the former Washington Natural Gas Company. Also as required under the SQI, Puget Sound Energy compensates customers $50 for each missed appointment. Several public utilities reported that, while they do not systematically track missed appointments, they do note them and offer an average $20 compensation on a case-by-case basis. Two small utilities reported they do not miss appointments, so there is no need to track them.

While not recommending compensation specifically, Wisconsin's proposed service quality rules require utilities to keep records of the number of times and the length of delay caused by missed appointments.

Table 7.4 Tracking Missed Customer Appointments.

Investor-Owned Utilities (3 utilities reporting): Yes No N/

Issue	Yes	No	N/A
Does the utility formally track or monitor missed customer appointments?	1	2	
Is tracking done quantitatively and systematically?	1	2	
Are statistics maintained?	1	2	

Consumer-Owned Utilities (14 utilities reporting):

Issue	Yes	No	N/A
Does the utility formally track or monitor missed customer appointments?		14	
Is tracking done quantitatively and systematically?		14	
Are statistics maintained?		14	

7.1.5 Disconnecting Customers

Six utilities reported that they do not track any statistics regarding customer disconnection. Of the remaining 11 utilities responding to the question, 6 reported they maintain statistics on any and all reasons for disconnection, and 5 reported only keeping statistics on disconnection for non-payment. For these 11 utilities, approximately 66,000 customers were disconnected for non-payment problems during one annual reporting period. This represents about 3.5 percent of the customer base of the eleven utilities reporting this statistic. This represents 2.8 percent of the 2 IOUs' total customers, and for the 9 COUs utilities, it represents 4.2 percent of their total customers.

The utilities were not requested to indicate when disconnection occurred. For investor-owned utilities, Washington law prohibits disconnection of electricity services necessary for space-heating at a residence between November 15th and March 15th for bill payment delinquency (RCW 80.28.010). This prohibition is conditional on the customer fulfilling a number of requirements and conditions specified in the law. A similar policy is established by RCW 54.16.285.

Table 7.5 Tracking Customer Disconnection.

Investor-Owned Utilities (3 utilities reporting):

Issue	Yes	No	N/A
Does the utility track customer disconnection separately for any and all reasons?	1	2	
Does the utility track customer disconnection for non-payment?	2	1	
Did the utility supply statistics on the reason for disconnection?	2	1	

Consumer-Owned Utilities (14 utilities reporting):

Issue	Yes	No	N/A
Does the utility track customer disconnection separately for any and all reasons?	5	9	
Does the utility track customer disconnection for non-payment?	9	5	
Did the utility supply statistics on the reason for disconnection?	9	5	

7.1.6 Restoring Power Outages

Most utilities do not have a formal policy regarding the time frame in which power outages are to be restored. Not surprisingly the utilities report that the response to outage problems depends on the nature of the cause and the amount of equipment needing repair. All report that response times are as quick as possible and more than half provided rough estimates of expected recovery times based on categories of cause. Perhaps more importantly, the survey asked whether the utility has a formal plan in place for prioritizing restoration efforts in the event of major outages. The 3 investor-owned utilities reported having such a plan and 9 of 14 public utilities also reported having a detailed set of restoration priorities. All of the utility plans that were submitted establish restoration of power to health and safety facilities as a first priority, followed by system priorities ordered from transmission facilities at the high end to local neighborhood laterals at the low end.

7.1.7 New Service

Roughly half of the utilities reported that they strive to meet a target time frame for installing new service. All responding utilities noted that the time necessary to install new connections varied by the complexity of the circumstances and whether or not construction was necessary. The survey questions were not sufficiently specific to determine whether the target time frames reported by the utilities represent estimates, or if they represent assurances the utility provides customers when new connection is requested.

The estimated time frames vary, but the majority fall within one to five working days for simple jobs that require no new construction and substantially longer (two to three weeks) for those jobs that do. For jobs requiring construction, 10 working days from the time all conditions are met was typical of the estimates reported.

None of the utilities reported that scheduling of new service connection varied by customer class. However, several noted that residential connections are usually simpler and require less construction and therefore higher voltage commercial and industrial connections often take longer.

Service quality rules enacted by the state of Ohio direct utilities to install 99% of new service requests within 3 business days if no construction is required. When construction is required, Ohio directs that 90 percent of new service requests be met within 10 business days after the customer is ready for service and all necessary tariff and permit requirements have been met.

7.1.8 Repair Requests

Eight utilities track the number and nature of repair requests, typically defined as any problem adversely affecting a customer. While 7 of these indicated that information was being maintained in a database (one small utility keeps requests on file in the office), only 4 were able to generate and report the total number of repair requests covering the last year. As a proportion of total customers, repair requests were typically in the range of four to five percent for these 4 utilities, but differences in the records tracked causes substantial variation in this proportion.

Table 7.6 Customer Requests for Repair or Trouble Services.
Investor-Owned Utilities (3 utilities reporting):

Issue	Yes	No	N/A
Does the utility track customer requests requiring repair service or other service trouble responses?	2	1	
Is the utility able to generate statistics from this tracking?	2	1	

Consumer-Owned Utilities (14 utilities reporting):

Issue	Yes	No	N/A
Does the utility track customer requests requiring repair service or other service trouble responses?	6	8	
Is the utility able to generate statistics from this tracking?	2	4	8

7.1.9 Customer Complaints

Seven utilities track customer complaints. Of these 7, the three investor-owned utilities track complaints to comply with UTC rules (WAC 480-100-096). Only one of the 7 reports tracking informal (phone calls etc.) complaints as well as those filed in writing on customer comment cards or formal letters. As a percentage of total customers, the number of complaints filed ranges from .03 percent to .18 percent for the 5 utilities that supplied statistics. The higher number is for the utility that tracks both formal and informal complaints. These 5 utilities reported a total of 915 complaints, 60 percent of which were billing or collection related.

Several national organizations advocate record-keeping and utility accountability for customer complaints. The National Association of State Utility Consumer Advocates (NASUCA) recommends that "all consumers should have access to an administrative dispute process which provides simple, quick and effective means of resolving complaints." The American Association of Retired Persons (AARP) believes that policies, including those covering dispute resolution, must exist in order to protect consumers.

The National Consumer Law Center (NCLC) recommends that electric suppliers should maintain a dispute resolution process program, keep records on customer disputes, and allow for appeal to a governing body if disputes with the electricity supplier can not be resolved to the customer's satisfaction.

Table 7.7 Utility Tracking of Customer Complaints
Investor-Owned Utilities (3 utilities reporting):

Issue	Yes	No	N/A
Does the utility track customer complaints?	3		
Does the utility track informal complaints, as well as those in filed in writing?		3	
Did the utility provide statistics on complaints?	3		

Consumer-Owned Utilities (14 utilities reporting):

Issue	Yes	No	N/A
Does the utility track customer complaints?	4	10	
Does the utility track informal complaints, as well as those in filed in writing?	1	3	10
Did the utility provide statistics on complaints?	2	2	10

7.1.10 Metering Errors

Twelve utilities indicated they track meter-reading errors, in some cases through automated systems. Nine of these utilities were able to provide statistics on meter reading errors, but the variety of formats used makes summarization and comparison difficult. In most cases, the rate of reading error appears to run below 1 percent of total readings. Washington law provides that customers of investor-owned utilities can request from the UTC testing of the meter serving them and if the meter is found to be more than four percent in error the cost of the test is borne by the investor-owned utility (RCW 80.28.170). UTC rules regarding meter accuracy, testing and complaints are found in Chapter 480-100 WAC. (See Section 6.2.3 for more on metering.)

Table 7.8 Utilities Tracking Meter Reading Errors

Investor-Owned Utilities (3 utilities reporting):

Issue	Yes	No	N/A
Does the utility tracking meter reading errors?	2	1	
Did the utility supply statistics on meter read errors?	2		1

Consumer-Owned Utilities (14 utilities reporting):

Issue	Yes	No	N/A
Does the utility tracking meter reading errors?	10	4	
Did the utility supply statistics on meter read errors?	7	3	4

7.2 Trends Affecting Service Quality

Several trends are beginning to affect the services consumers receive. Recently, some utilities have begun to close local utility business offices that are believed not to warrant the investment it takes to keep them open. Where offices have been closed, utilities have replaced them with payment agencies or drop boxes where customers can make payments but cannot conduct other business. It remains to be seen if the alternative arrangements for customer access to the utility through these payment locations and enhanced reliance on telephone-conducted business will meet consumer needs.

Puget Sound Energy recently curtailed its hours for reconnecting disconnected customers. Citing safety reasons, PSE will provide same-day reconnection only for customers who call before 7 p.m. Customers who call after 7 p.m. will be reconnected the next day. PSE has also proposed, again for safety reasons, that it will not accept cash from the customer at the customer’s premises after 5 p.m. Other utilities are reportedly considering similar policies.

While some utilities are reducing access to business offices, many are expanding the number of other services they plan to offer customers. Virtually all of the utilities responding to the service quality survey indicated that they plan to offer new services in the near future.

The utility responses on new service offerings varied greatly in detail, but there was no significant difference among the various types of utilities. The difference seemed more to reflect differences in utility "personality" and sense of role, than to reflect the size or type of utility. In general, utilities described three drivers of new and expanded services and improved service quality: technology, competition, and customer desires. Taken together, the responses show a retail utility industry that is aware that customers are demanding better and new services, aware that new technologies can deliver services that many customers want, and aware that a more competitive environment will put a premium on meeting customer needs.

The survey responses revealed that utilities are typically pursuing the following new customer services:

- ❖ Expanded and more user-friendly bill payment and account access services, often using the internet and other new communication technologies.
- ❖ Expanded information and consulting service for customer energy efficiency investments.
- ❖ Expanding and bundling other utility services, such as internet and telephone.

In the area of expanded and bundled services, some utilities are constrained by law or regulation from providing certain services. While municipal utilities and cooperatives have little restraint to their ability to offer a broad range of utility services, public utility districts have more restrictions. Generally, PUDs are authorized only to provide electricity and water services, although some have offered the use of their excess internet and telecommunications capacity to their customers. The Attorney General recently reviewed the ability of PUDs to offer these services, and concluded that PUDs can install fiber for purposes of their electric business, and sell or lease the excess fiber to public or private entities. This means that PUDs can provide bandwidth for other service providers (internet, telephone, or cable) to use. PUDs cannot, however, directly provide those other services (such as internet or telephone), nor do PUDs have authority to provide natural gas service (AGO 1998 No. 14, November 30, 1998). Investor owned utilities may offer both gas and electric service under UTC regulation and could, with UTC approval, enter the telecommunications business. Utilities with large industrial loads are also planning to offer industrial customers enhanced services, especially in power quality.

Utility responses to open-ended survey questions about new services and future plans indicated that the major area of difference was business strategy and industry role. Some utilities indicated aggressive plans to expand and enhance service in almost all areas already mentioned. Other utilities, especially the smaller ones, report future plans of upgrading basic customer service, such as improving customer access to accounts and easier bill payment.

7.2.1 New Services Offered in a More Competitive Market

The survey responses provide a snapshot of how Washington utilities view both their current responsibility to customers and new marketing opportunities. The survey does not tell us what trends might develop if there were to be a significant move to more open retail markets. To find out where electricity restructuring and greater competition might lead us, we examined the information that exists regarding electricity markets that have opened and the experience of other industries that have gone through significant deregulation and restructuring. The following is a brief summary of some of the experience with open, retail access in California and elsewhere.

7.2.2 Experience in California's Retail Market

Under any scenario of open retail electricity markets, consumers face two fundamental changes in the availability and quality of electricity products and services. First, there are more products and services. Second, a new and constantly changing set of providers is available to supply those services.

California is experiencing an expansion of new products and services being marketed directly to consumers. Most of these are services that were previously bundled as part of integrated, regulated utility electricity services. Examples of services that are being offered separately, or as "rebundled" packages include: energy, metering, billing, and demand-side management and energy efficiency.

Competitive suppliers have developed a range of offerings for each of these products. For example, meters are offered for sale or lease by the monopoly distribution utility, new electricity providers and independent vendors. Customers who stayed with their old utility still have utility-owned meters. Billing is now almost completely sub-contracted to separate companies, and customers have a range of billing options from which to choose. Consumer-driven energy management and energy efficiency are being offered either as bundled or unbundled products and services. Utilities are providing both new energy management services along with traditional conservation programs, such as insulation, HVAC and building efficiency services, and window, furnace, appliance and motor replacement. New technology allows suppliers to remotely control the electricity usage of residential and business customers, and to reduce or increase usage according to diurnal and peak pricing schemes. This enables the supplier to offer a mix of pricing and reliability. All of these services can also be bought separately from companies that don't provide electricity. Finally, a number of entrepreneurs have explored bundling electricity with other utility services, such as phone, internet and cable TV.

As dynamic as the California electricity market has become, it remains the case that the changes described above have yet to affect most consumers. There is a significant difference between the services being offered to large customers and those being offered to small customers. Large customers, especially industrial companies and very large commercial customers, have received much more sophisticated service offerings than small and residential customers, as well as significant price advantages. Some large customers have responded favorably to "green power" offers and some businesses are starting to use their purchases of environmentally friendly energy as part of their own marketing campaigns. As a result, more large customers – about 25 percent of those eligible - have switched electricity providers than have small and residential customers, of whom less than five percent have switched suppliers.

These developments exemplify the issue raised in the introduction of this section. Competition may tend to focus provision of service options and attention to customer service for the most profitable and competitive customers. The general lack of interest on the part of small commercial and residential customers is likely both a cause and consequence of the lack of new service options being offered to them. This is a sector that may not offer concentrated profit opportunities and takes considerable marketing skill and cost to reach.

7.2.3 New Businesses and Suppliers in a Competitive Market

While new products and services are important, the emergence of new players in the electricity market is of equal importance. In California, any company that wants to sell electricity to small consumers must register with the California Public Utility Commission, but the options for consumers are not as numerous as originally anticipated. As of early October 1998, 36 service providers were registered, but this had declined from several hundred that had initially registered. While the mix of registered providers includes large multi-national energy companies, co-operatives, small businesses and non-profit agencies, some of the largest, including Enron, have since dropped out. Some of these are energy service companies (ESCOs) that moved from providing energy efficiency and other services to providing electricity as well. California has chosen to require registration of these new market entrants to ensure that services provided to small customers are reliable, safe, and as advertised. Existing and new companies have also moved into the billing and metering market, providing some service directly to customers but mainly by acting as contractors to existing utilities and new energy providers. While registration and certification of competitive providers is more properly a consumer protection issue (see Section 6, above), it has an important service quality element: In a competitive environment, who will the consumer call for service questions? Clarifying roles and responsibilities for ensuring non-discriminatory network reliability may also be an important concern for all industry participants.

7.2.4 Consolidation and Mergers

While retail electricity competition is too new in other states to assess fully their experience, one additional national trend has become clear: consolidation of existing utility companies. Many mergers and acquisitions in the electricity industry as well as in the telecommunications industry have taken place during the past few years. Most of these mergers are also too recent to allow for any systematic studies to be done of their effect on service quality, but they do raise concerns that too much consolidation may reduce the effectiveness of competition.

In Washington, the 1996 merger of Puget Sound Power and Light with Washington Natural Gas prompted a number of consumer and labor interests to raise concerns about the service quality impacts of the merger. The UTC shared the view that the merger should not result in a deterioration of service for the customers of either utility. As a condition of the merger, the UTC approved a stipulation which, in part, required the merged company to establish a "Service Quality Index" (SQI). The SQI establishes performance benchmarks and monitoring in areas such as telephone center answering performance, gas safety response time, customer disconnection, missed appointments, and survey-measured customer satisfaction with the call center, field services and overall utility performance. Puget Sound Energy's performance is measured against benchmarks annually. Failure to meet the performance standards can result in monetary penalties. In addition, the stipulation included a "customer service guarantee" which provides compensation to individual customers who do not receive a minimum standard of service.

7.2.5 Lessons from Other Industries

Deregulation and restructuring in other industries, notably natural gas, long-distance telephone, airlines and railroads are often cited as indicators of what is likely to happen to electricity. In all of these industries, there has been a decline in average service prices. However, some areas – particularly rural areas — have seen a decline in services and an increase in prices. Some hard-to-serve areas see service providers leave and the level of service decline. Rural areas also tend to lag behind urban areas in the availability of new services. Telecommunication service quality and service availability in rural Washington are examples, as are the reduced number of transportation options available in rural areas of Washington and other states.

The deregulation of long-distance telephone service has led to lower prices, more reliable service, and more service options. At the same time, billing and rate structures have become more and more complex, consumers complain about incessant marketing, and actual service providers are obscured by the introduction of new "brands" of telephone service. ("The Formerly Staid Ma Bell Hatches a Secret Offspring," *The New York Times,* October 7, 1998). This raises the question of whether it is possible to have the benefits of improved technology and lower prices without the costs of greater pricing complexity and more unwanted and confusing marketing.

7.3 Strategies to Ensure High Service Quality

Both the prospect of competition and the reality that some competition for customers is beginning to occur may combine to place pressure on the quality of customer services. The state has an important interest in the quality of electric service because electricity is an essential service. If the Legislature determines that minimum service quality standards should be established, at least two alternative strategies are available. As elsewhere in the report, the discussion and description of strategies below does not imply a recommendation on the part of CTED or the UTC.

1. *Focus on administrative flexibility and local decision-making. The Legislature could determine the general areas in which consumer service quality standards are to be established and principles these standards should achieve. The UTC could establish specific and measurable service quality standards for investor-owned utilities, while locally elected councils, commissions, and boards of the consumer-owned utilities could establish standards for the utilities they regulate.*

   Argument For: Establishes a statewide policy concerning customer service, but provides for specific standards to be established that match varying circumstances and consumer preferences across the state.

   Argument Against: Variation in local decisions could result in the quality of customer service varying widely across the state and being subject to competitive pressures that could result in diminished service to some customers.

2. *Focus on uniform statewide minimum standards. The Legislature could establish specific and comprehensive customer service quality standards to be achieved by all electric utilities in the state. The UTC and the consumer-owned utility boards, councils, and commissions could implement standards established by the Legislature.*

   Argument For: Establishes uniform statewide standards. Utilities have an incentive to meet the standards cost-effectively for all customers. Incentives to reduce services to some customer groups in favor of others are removed.

   Argument Against: Does not recognize the variety of circumstances facing utilities across the state nor the differing expectations or values of consumers across the state. A one-size-fits all approach is likely to be very difficult to implement practically. It could impose significant and unnecessary costs on small utilities, and could be too prescriptive to encourage innovative approaches to consumer services.

If retail electric service competition is broadly implemented in Washington a third strategic path may be possible.

3. *Focus on mixture of uniform standards and competitive innovation. The Legislature could establish a set of minimum service quality standards and competitive supplier licensing standards. Energy service providers would have to meet minimum performance rules, but could compete by offering additional services at competitive prices.*

   Argument For: Establishes uniform statewide standards for all energy service providers, whether they are existing utilities or new market entrants. Competitive retail markets may stimulate energy providers to innovate and offer additional services competitively.

Argument Against: While minimum statewide standards will ensure that competition is not based on reducing service to those with the fewest service choices, it also fails to recognize that consumer expectations and values vary across the state. If such standards are established they should not be one-size-fits-all.

Under a more market-oriented system, policy makers might leave much of service quality to the marketplace in the expectation that electricity service providers would compete on service quality as well as price and resource mix. California has adopted a mixture of regulation— setting some standards for all energy service providers, especially in the residential sector — and competition— allowing providers to offer wide variation in service quality with commensurately wide variations in price, especially in the industrial sector. Should a more competitive environment develop, a service quality threshold may still be necessary to ensure that all providers offer adequate service, both to ultimate consumers and to other providers who deliver services over a common network. Performance-based benchmarks could be established to ensure that basic service does not deteriorate as a result of any changes in the industry.

7.3.1 Measuring Customer Service Quality

It is difficult to draw reliable conclusions about service quality in Washington from the information collected for this study. With few service quality standards in place and an extraordinarily wide variety of utilities, collection of data regarding service quality varies substantially in scope and content across the state. Development of effective policy strategies to encourage high service quality may require more detailed and comparable measurement of service quality performance. In order to assess consumer needs and develop strategies to resolve problems, for example, it may be helpful to track consumer complaints. In both measurement and application of service quality standards, there may be some tension between establishing minimum levels of service and ensuring continued local control of most of Washington's diverse utilities. As discussed above, it may be possible to balance these objectives through the use of broad standards and principles at the state level with flexibility for local implementation.

One strategy for measuring and enhancing service quality is the use of a service quality index. This is a performance-based approach in which measurable service quality performance indicators are tracked, evaluated, and in some cases linked to a regulated utility's allowed revenues. The service quality index approach is recommended by the National Consumer Law Center. Developing an effective service quality index requires judgment as to what types of service quality indicators can be measured reliably and at a reasonable cost. Table 7-9 includes sample service goals, standards, and evaluation criteria that could be used to construct a service quality index.

Table 7.9 Example Service Quality Goals and Standards

Service Goal	Standard	Track & Evaluate
Customers are satisfied with their utility service.	Annual written and/or telephone surveys to measure customer satisfaction.	Results of customer satisfaction surveys.
Utility responds to and resolves customer complaints in a timely manner.	Utilities respond to customer complaints within a specific time. Also require a maximum number of complaints per number of customer.	Number and type of customer complaints received directly by the utility from the customer. Also length of time the utility takes to respond to the complaint.
Customer convenience in bill payment.	A specific number of payment agencies per number of customers or requiring alternative payment options.	If customers have convenient places for in-person payment, where those are located, if customers can use automatic deduction from checking accounts, and internet payments.
Customer convenience in accessing account information.	Toll-free access for all customers and requiring specific billing information.	If customers have convenient telephone inquiry or internet access, and if customers have clear and meaningful billing information.
Electric outages do not last long and installation of new service is quick.	Maximum length of time a utility can take to restore service after an outage and maximum length of time a utility can take to provide new service.	Length of time utilities take for restoration of electricity service after an outage, and for the provision of new service.
Customers receive a quick response to their telephone calls to the utility.	Minimum answering speed , minimum number of calls answered within 60 seconds, and maximum number of unanswered calls.	Utilities' telephone monthly answering performance by measuring such things as average speed of answer and percentage of calls answered within 60 seconds.
Customers receive response to repair requests within a reasonable period of time.	Maximum time between a customer repair request and repair by the utility.	Length of time between the customer repair request and repair by the utility.
Utilities do not receive an unreasonable number of repair requests.	Maximum number of repair requests per number of customers.	Number of repair requests per number of customers.
Utilities do not miss appointments made with customers.	Maximum number of missed appointments per number of customers, and requiring compensation for missed appointments.	Number of missed appointments per number of customers.
Utilities make minimal billing errors.	Maximum number of billing errors per number of customers.	Number of billing errors per number of customers.
Utilities supply and maintain accurate meters and meter readers.	Maximum number of meter errors per number of customers.	Number of meter errors per number of customers.

Endnotes for Section 7.0

[1] National Association of State Utility Consumer Advocates (NASUCA): Proposal for Consumer Bill of Rights; May 19, 1998.

[2] Federal Trade Commission (FTC): Response to the Utah Public Service Commission Request for Comments on Consumer Protection in Docket No. 96-999-001, Report to Electrical Deregulation and Consumer Choice Task Force; July 15, 1998.

[3] State of Wisconsin: Proposed electric utility service quality rules; March 1998. State of Ohio: Electric Service and Safety Standards; date unknown. State of Maine: Proposed electric consumer protection rules; August 25, 1998.

[4] National Consumer Law Center and Barbara Alexander: "Consumer Protection Proposals for Retail Electric Competition;" October 1996.

[5] National Association of State Utility Consumer Advocates (NASUCA): Proposal for Consumer Bill of Rights; May 19, 1998.

[6] American Association of Retired Persons (AARP): "Is Electric Utility Restructuring a Bright Idea for Consumers?" 1997.

[7] National Consumer Law Center and Barbara Alexander: "Consumer Protection Proposals for Retail Electric Competition;" October 1996.

[8] Green Buyers Beware: A Critical Review of "Green Electricity" Products, Rader, Nancy. Public Citizen. Washington D.C., October 1998.

[9] National Consumer Law Center and Barbara Alexander: "Consumer Protection Proposals for Retail Electric Competition;" October 1996.

8.0 Electricity Service Reliability

ESSB 6560 directs the agencies to examine:

The current level of service quality and reliability as measured by available statistics, trends affecting quality of service and the integrity and reliability of the distribution system, and ways to ensure high service quality and reliability in the future.

Previous sections of this report document that electricity generation costs and retail rates are low in Washington compared to those in the rest of the country. That fact is important, but electricity service is diminished in value if it is not reliable. We depend on electricity as a critical component of our lives at home and at work. In fact, we depend on it so much that we take it for granted, until something goes wrong.

8.1 Introduction

The reliability of electric service can be described through answers to three questions.

- Is the power there when I need it?
- Is it the right voltage and frequency?
- Can I consume as much as I need (or my contract allows)?

If the answer is “no” to any of these questions, our ability to rely on the electricity system is undermined. The more frequently the answer is “no,” the more unreliable is the service. These three questions address the three fundamental dimensions of reliability: power interruptions, power quality and system adequacy. These dimensions can be measured by physical performance data.

A fourth and equally important dimension of reliability is consumer expectation and perception. Consumers are the beneficiaries of a reliable system and consumers are the ones who are asked to pay for it. Ultimately, understanding reliability requires understanding both the engineering performance measures and the level of consumer satisfaction with system performance. The “right” level of reliability is not determined by the engineering data alone or by consumer expectation alone. It is the combination of engineering performance that satisfies consumers at a cost they are willing to pay.

In this section, we examine electricity reliability in four ways:

1. We present current levels of reliability measured from the perspective of the consumer, as well as data collection and interpretation issues.
2. We present current levels of reliability measured by engineering performance, as well as data collection and interpretation issues.
3. We describe and discuss factors and issues that are likely to affect electricity service reliability.
4. We describe actions and policies for preserving high levels of service reliability.

8.2 Consumer Perspective

Since consumers are the ultimate beneficiary of electricity system reliability, customer perspective is an important measurement of whether the system is meeting needs and expectations.

Twelve utilities were required to submit customer satisfaction surveys to the state under ESSHB 2831.[1] These surveys arrived in time for consideration in this study. Unfortunately, most surveys do not address reliability as a separate and specific issue. Table 8.1 describes how utilities address reliability in their surveys. Except for the utilities that specifically asked their customers to rate reliability, it is difficult to conclude from these surveys what customers think about the reliability of their service. It is reasonable to infer that if customers are satisfied with the utility as a whole then they must be satisfied with service reliability, but this is more a general conclusion than a specific one.

Table 8.1: Utility Customer Satisfaction Surveys and Reliability

Number of Utilities	Approach
3	No surveys taken
4	Asked customers to rate satisfaction with company “overall,” but no specific reference to reliability. Customers may have been asked why they provided such a rating, which may have led them to mention reliability issues.
5	Asked customers to rate some aspects of reliability, but with great variability in depth of coverage. The utility may have asked a single question such as, “was the response to outages timely,” or “should reliability be a priority for the utility?” Only three utilities asked customers to rate reliability performance specifically. Only one asked customers to rate a number of reliability aspects including power quality.

General customer satisfaction statistics can be difficult to interpret, let alone compare. One utility asked five different questions and reported a single, mixed approval rating. For most utilities a satisfied customer is defined as one answering in the top categories of a range, such as answering “excellent” or “good” in a range that also includes “fair” and “poor,” or answering 6 or 7 in a range of 1 to 7. Results were often reported as a percentage, for example, “85 percent of customers are satisfied.”

Based on statistics calculated in this way, utilities reported the range of satisfied customers to be from 70 to mid 90 percent. Responses to questions specifically focused on reliability showed satisfaction to be in the 70 to high 80 percent range.

These data do not provide a very definitive look at what is arguably the most important measurement of the reliability of Washington’s electricity system. However, such surveys are the only information currently available. While these results suggest that consumers may be generally satisfied, the importance of the issue and the changing environment faced by utilities both argue for more definitive and regular measurement of the consumer’s view of service reliability.

8.3 Engineering Performance Perspective

While the consumer's perspective of reliability is important, the engineering perspective can provide actual yardsticks for measuring what level of performance the system is delivering. The three performance dimensions of reliability referred to above are measured in different ways. In many cases, however, it is difficult to get consistent data because utility data collection and interpretation vary. This means that the engineering performance data are useful, but must be considered very carefully. Detailed analysis of trends and comparison of performance among utilities is, in many cases, problematic. The data are primarily useful to provide a sense of the average performance of distribution systems in the state.

8.3.1 Power Delivery Interruption

The most important aspect of reliability is power delivery; whether the power is on or off. Power delivery is measured by a number of indices that count the number of times power is interrupted and for how long. There is no federal or industry standard for these indices. A committee of the Institute of Electrical and Electronic Engineers Inc. (IEEE), has proposed a reliability standard.[2] The IEEE will likely adopt this proposed standard, or a similar one, before the end of 1998. Some states, including California and Oregon, use a similar standard to measure utility performance. Information consistent with the proposed IEEE standard was reported by most utilities as key indicators of engineering performance reliability. Specifically, two of the proposed indices were identified by the utilities as useful performance measures. The System Average Interruption Frequency Index or SAIFI, is the average number of interruptions experienced by customers during the year. A customer interruption is recorded each time an individual customer experiences a loss of service. These interruptions are summed and divided by the total number of customers to find a utility average. A SAIFI of "2" means there were two interruptions for each customer during the year. This is an average; some customers experienced more than two interruptions and some fewer.

The System Average Interruption Duration Index or SAIDI, is the average number of minutes of interruption experienced by customers during the year. A SAIDI of "10.5" means there were ten and one-half minutes of interruption for each customer during the year. This also is an average.

The SAIFI and SAIDI indices for each utility are reported in Appendix 8.1, along with other utility system and reliability information.

Power Delivery Interruption: Data Limitations

Comprehensive collection of consistent system performance and interruption data is both difficult and expensive. Consequently, much of the data provided by the utilities for this report may suffer from both inconsistency and lack of precision. Thoroughness of data collection varies among the utilities. For example, not all utilities collect data consistent with the proposed SAIFI and SAIDI industry standard. The proposed standard only counts "sustained interruptions," which are defined as those lasting five minutes and longer. Some utilities maintain information on all interruptions, no matter how fleeting in duration.[3] Others collect data that may lead to inconsistent or misleading calculations.[4]

Increasing sophistication and capability in data monitoring also complicates interpretation of service interruption and duration figures. Utilities are constantly trying to improve their methodology to develop more accurate estimates. This makes it difficult to trace trends in reliability at a single utility, let alone across the industry. For example, in 1996 Seattle City Light changed the way it counts distribution line-miles from a manual process to one based on a Geographic Information System. Although there was no actual loss of distribution line, the utility reported a one year change from 2,568 miles to 1,836 miles; nearly a 30 percent reduction! This is a consequence of more accurate measurement, but it complicates examination of trends in factors such as maintenance expenditures per mile of distribution line. Several utilities report that their SAIFI and SAIDI numbers are deteriorating even as they believe their reliability is improving: this, again, is a function of better counting not decreasing performance. The IEEE reports hearing estimates of up to 100% increases in SAIFI due to better measurement, record keeping, and calculations. The agencies asked utilities about the effect of changes in data acquisition and analysis methodology on the interruption and duration data they reported. Other than to point to increasing accuracy and coverage, only one was able to quantify an effect: an increase in interruptions of from 5 to 20 percent.

Until recently, utilities nationwide have not valued detailed system-wide customer reliability data very highly. The cost of data acquisition and management did not justify the investment. Many utilities preferred to spend money on operating and maintaining their distribution system, not keeping detailed records about its performance. Knowledgeable employees “knew” which lines had problems and when equipment needed upgrading, repair or replacement. Operations personnel and planners worked together without extensive reliability data. In many cases, historical performance data is either unavailable or only crudely measured.

With the advent of computers and digital communications such information has become more cost-effective. At the same time, with the rise of competition, detailed customer information has become more valuable. Most utilities are now investing in data management systems that will make more precise reliability data more readily available. But utilities are proceeding at different paces and none in Washington has yet implemented a data management system that is entirely comprehensive and free of reliance on some level of estimation.

The lesson of the forgoing discussion is that even the most standard engineering performance measures have significant limitations. Unfortunately, these weaknesses limit their value for purposes in which we have the most interest: providing consistent measures of current levels of reliability, tracing trends over time and for comparing one utility (or group of utilities) to another. Nevertheless, these are the best reliability performance indices available. And, so long as we keep these limitations in mind, they allow for some observations about performance reliability in Washington to be made.

Power Delivery Interruption: Data for Washington Utilities

Table 8.2 includes the statewide average SAIFI and SAIDI for 1997 and compares these figures with like indices for the nation, Canada and the United Kingdom. In 1997, the average customer in Washington experienced 1.37 interruptions that lasted a total of 150.05 minutes.[5] 1997 figures include all interruptions from generation, transmission and distribution system failures including those caused by storms.

Table 8.2: Comparison of System Average Interruption Frequency and Duration Indices.

	Washington 1997	U.S. Average 1995*	Canada 1997	United Kingdom 1997
SAIFI	1.37	1.26	2.35	8.90**
SAIDI	150.05	117.00	222.00	80.00

* Latest IEEE Industry Survey.
** UK statistics include momentary interruptions.

Figures 8.3 and 8.4 track the statewide average from 1990 through 1997 in SAIFI and SAIDI, respectively, as well as the range among the utilities included in the averages. These data are mixed, meaning some utilities included storm-caused interruptions in their data and others did not. Excluding storm data can provide a better sense of system performance under normal operating conditions. Unfortunately, utilities representing about nine percent of the customers in the study were unable to exclude storm data.

Figure 8.3 Washington Utility System Trend in SAIFI 1990-1997
Average Interruptions/Year/Customer

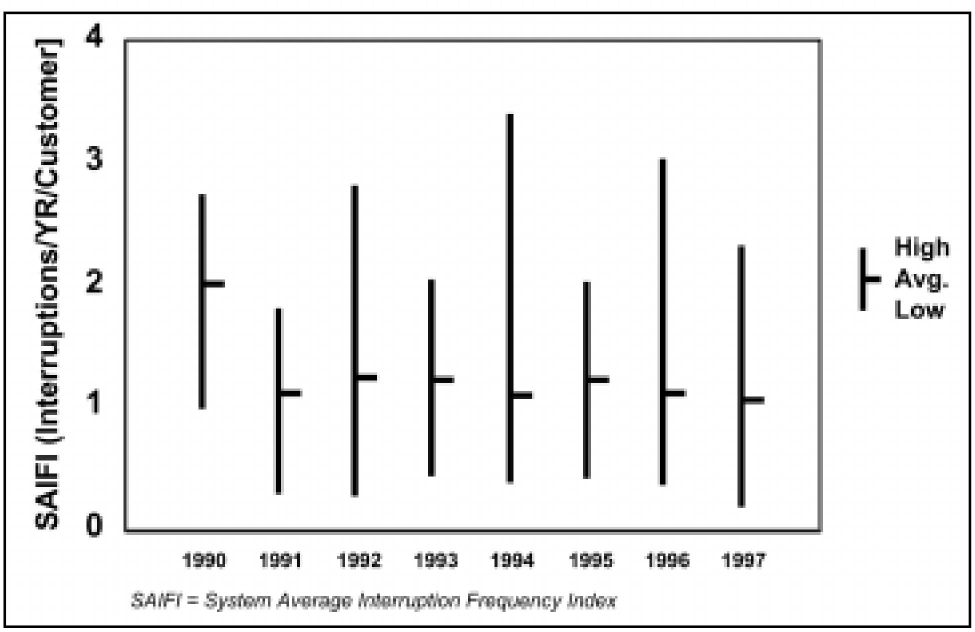
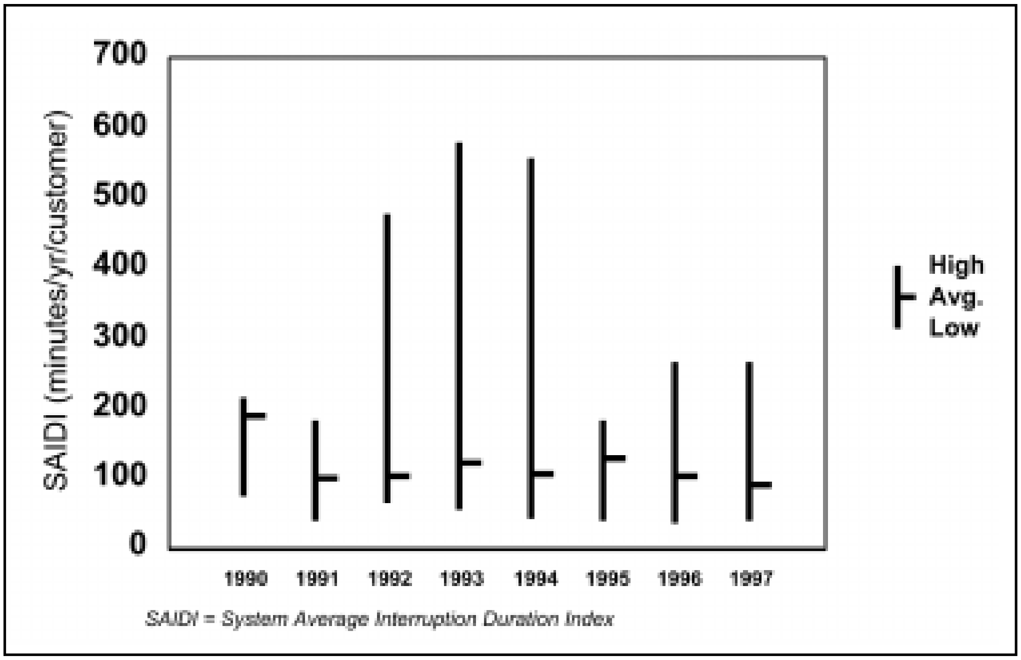


Figure 8.4 Washington Utility System Trend in SAIDI 1990-1997
Average Minutes/Year/Customer



Over the eight year period of the study, generally under normal operating conditions, the average customer in Washington has experienced about one interruption per year lasting about two hours (SAIDI = 1.24 interruptions, SAIDI = 116 minutes).

Over this period, the lowest average number of statewide interruptions occurred in 1997, when 1.06 interruptions per customer were reported. The highest average number of interruptions, 2.01 per customer, occurred in 1990. Given the diversity of geography and weather conditions over this period, a range of 1.06 to 2.01 in the statewide average is not large. Moreover, the average consistently falls between 1 and 2 interruptions (of greater than 5 minutes) for the typical customer with no clear increasing or decreasing trend evident over the period.

The statewide average SAIDI ranged from a low of 91.6 minutes in 1997 to a high of 191.5 minutes in 1990. Again, considering variation in geography and weather from year to year, this range in the statewide average is modest. And, there is no clear increasing or decreasing trend evident in the average SAIDI over the period.

Variation among utilities was significant, but also not excessive given the difference in utility territory characteristics and the data consistency problems noted above. The lowest SAIFI reported by any utility over the period was 0.2 in 1997; the highest was 3.4 in 1994.[6] The lowest SAIDI reported was 37.3 in 1996; the highest was 581.1 in 1994. Where individual utilities fell in these ranges varied from year to year, with no utility consistently appearing at either the high or the low end.

The SAIFI and SAIDI measure averages for the utility's distribution system, so it is important to remember that they reveal nothing about the extreme values that may be included in the average. A low SAIFI or SAIDI could result from circumstances where all customers experience a low number of interruptions, or they could reflect circumstances where most customers experience no interruptions, while others experience a great number. Portions of a utility's service territory might have very poor reliability. This is not revealed by a system-wide average SAIFI or SAIDI.

The Utility Data Survey asked utilities if they could submit data for sub-sections of their systems, such as: best and worst performing feeders, and low- and high-density feeders (as surrogates for rural and urban areas). Nine utilities reported they do collect and maintain information at the sub-system level. Some maintain data for relatively small sections of their systems, such as for communities or even small laterals. No utility can provide the data for each customer.[7] Time limitations did not permit a second round of data collection to examine sub-system variation and averages in this study. We are unable to report or compare the reliability of service for individual customers or selected sub-circuits that might represent industrial and residential customers, urban and rural customers or communities of differing demographics or other characteristics.

Power Delivery Interruption: Storms and Other Extraordinary Events

Environmental conditions are probably the greatest overall cause of interruptions. Even equipment failure, such as underground cable breakage, is often the result of deterioration brought on by contact with soil and water. Weather-related interruptions are common; most tree and branch-caused interruptions are really caused by wind, rain, ice and snow. The most serious weather-caused interruptions result from major storms.

Five utilities were able to report SAIFIs and SAIDIs for storms and other extraordinary events separately from other interruptions. By comparing these to their full interruption statistics it is possible to see the significance of these events. Storms were responsible for a significant number of the total interruptions reported by the five utilities in 1997 and an even greater percentage of minutes of interruption.

Comparison of these statistics is difficult because of the general limitations of data described earlier and because the definition of "extraordinary event" varies from utility to utility. However, these figures do support two general observations. First, while storms account for a significant proportion of interruptions for all five of these systems, storms account for a larger percentage of total interruptions for those systems that are generally more rural in character. Much of Seattle's distribution system in the central city is underground. Second, storms contribute a greater percentage of average interruption duration (proportion of SAIDI) than interruption frequency for all five of these utilities. This is just another way of saying that storm damage takes longer to repair than other equipment failures. Steps taken to minimize storm damage and to improve response capability could have a significant impact on service reliability in Washington.

Table 8.5 Percentage of Interruptions and Minutes of Interruption Caused by Storms at Five Utilities in 1997[8]

	Seattle City Light	Cowlitz County PUD	Puget Sound Energy	Snohomish PUD	Inland Power & Light
Percent of SAIFI	13.3%	25.0%	32.0%	34.0%	41.2%
Percent of SAIDI	30.0%	31.4%	48.0%	46.4%	61.7%

Source: Data reported by utilities to 6560.

Power Delivery Interruption: Classification of Causes

Whether associated with storms or not, most utilities are able to report the principal causes of service interruptions. Not counting the amorphous "other" category, Figure 8.5 indicates that four categories account for the majority of the causes for interruptions: Equipment Failure, Trees and Branches, Animals, and Accidents. These were the cause of more than 80 percent of interruptions in Washington in 1995, 1996 and 1997.

Interruptions Caused by Equipment Failure

Failure of installed equipment is by far the largest cause of interruptions on both sides of the state. The data available for this study do not include sufficient detail to support conclusions about why equipment failed. Equipment failure reflects to some degree the relationship between operations policy and maintenance practices. We discuss system maintenance and its relationship to equipment failure in more detail in Section 8.4: Factors and Trends Affecting Electricity System Reliability.

There is a real possibility that the category "equipment failure" may be exaggerated. Some interruptions may have been categorized in this way when no other cause was identified. While such interruptions might more properly be categorized as "unknown," not all utilities maintain such a category. In other cases, a clear cause may be evident, such as an ice storm, but the utility does not have an "ice-caused" category.

In addition, it may be both practical and reasonable for a utility to allow some equipment to fail and be repaired before it is replaced. Underground cable is a good example. Cable is difficult to inspect and expensive to replace. It may be sound maintenance and management policy to replace a section of cable only after a few failures indicate it is deteriorating. However, the policy does increase the number of interruptions caused by failed equipment.

Each utility tracks the causes of interruption in its own way. Utilities may use different cause categories or have different definitions for what is included in the same category. These differences make it difficult to track the causes for interruption statewide in a fully consistent way. Inconsistency in classification of causes may even make it difficult for some utilities to track trends in causes of interruption on their own systems. The industry association, IEEE, is considering the inclusion of consistent cause codes in its reliability standard.

System maintenance is a key factor affecting equipment failure. However, the need for system maintenance varies significantly across the state. An area with few trees, few customers, and a mild climate may have minimal need for maintenance. On the other hand, a system serving an area with a severe climate, many trees, and a concentrated customer base may have more need for systematic maintenance. Maintenance efforts may also vary because of customer service preferences. A utility may choose to incur greater maintenance costs to provide a higher level of reliability.

In 1997, utility maintenance expenditures varied from $323 per mile of distribution line to $16,438 and from $25 per customer to $192.[9]

Interruptions Caused by Trees

Utilities on both sides of the state also report falling trees and branches as a major cause of interruptions (20% Statewide, 21% West side, 16% East side). As a percentage of all interruptions, tree-caused interruptions reported by individual utilities in 1997 ranged from 4.49 percent to 64.58 percent, reflecting in part the differences in forest types across the state.

The “tree-caused” category suffers from some of the same classification problems as equipment failure. Interruptions caused by an ice-laden branch may be categorized as ice-caused or tree-caused depending on the utility or the crewmember that reports it. Nevertheless, trees are a major cause of interruptions throughout the Northwest.

All utilities have vegetation management programs designed to reduce tree-caused interruptions. Programs may include trimming and removing tress, injecting growth inhibitors to slow growth, or working with property owners to help them select “line-friendly” trees (i.e. slow growing trees, or those that attain low maximum heights).

Like maintenance in general, trimming requirements and local conditions result in large differences among utility vegetation management programs and budgets. In 1997, utilities reported trimming over 15,000 miles of utility right-of-way (ROW). The range among utilities was from 300 to 1559 miles and expenditures ranged from $126 per mile trimmed to $7,122.

Interruptions caused by Animals or Accidents

This combined category includes animal damage as well as damage caused by automobile collisions with power poles. It makes up the next greatest number of interruptions statewide. Birds and squirrels are the animals most likely to create faults. Equipment can be reconfigured (at considerable expense) and animal guards can be placed on equipment to thwart bridging.

To reduce the likelihood of collisions with power poles, utilities work with local traffic enforcement and public works agencies to identify high accident locations and vulnerable poles. Solutions include installation of guardrails and relocation of equipment.

Other Causes of Interruption

The “other” category combines numerous causes, including operating error, electrical overload, vandalism and faulty installation. For most utilities, these categories each represent less than one percent of total interruptions. However, categories called “unknown” and “other – unspecified” are also included and represent a significant number of interruptions for some utilities. The agencies did not determine what may be included in these categories. Five utilities provided data that indicated they track causes by weather - wind, rain, ice/snow and lightning. These were also included in the “other” category for this report, and represent a significant number of interruptions for some. For all the reasons above, the “other” category can be quite large (10% statewide, 6% West-side, 30% East-side.)

8.3.2 Engineering Performance Perspective: Power Quality

Power quality refers to the voltage and frequency characteristics of delivered power. It is similar to the “product quality” of more standard commodities. Delivered electricity must meet certain stringent specifications to do its work without damaging utility or end-use equipment.

Microprocessors are especially sensitive to excursions in electric voltage and frequency. With the proliferation of computers, sensitivity to power quality is increasing in homes and businesses. It is no longer just the concern of industries with mainframes and sophisticated production equipment.

For various reasons, including both practicality and cost, utilities generally have not monitored voltage and frequency at the customer level.[10] Therefore we cannot say what the actual level of power quality reliability is on utility systems, let alone observe a trend. As a surrogate for actual system measurements, the agencies asked utilities to provide statistics on measures that might be indicators of the level of power quality, including: power quality complaints by customers, power quality problems identified and solved and claims made and damages paid for power quality problems.

However, this information is also not generally tracked, except by a few utilities. Six utilities reported the data did not exist or were not readily available for any of the questions; three provided responses for every question. Almost every utility has staff that respond to power quality complaints and most of their work is with industrial customers. However, to date, records are not adequate to determine whether residential power quality problems might be on the increase.

Four utilities report tracking power quality complaints (two began the effort within the last two to five years). No clear trend is evident. Three utilities track complaints by type of event (voltage sag, flicker, etc.), one tracks complaints by type of problem (long secondary, bad connection, etc.). Even for these utilities, record-keeping practices are not yet sufficiently detailed to identify increases in power quality complaints. A customer may call to complain about a surge that caused loss of data in a computer. If the utility knows there were lightning strikes in the area, the fault will likely be attributed to circumstances beyond the utility's control and no record will show that this was a power quality complaint versus an interruption complaint. Several utilities report that they think residential power quality issues are on the increase and they are instituting tracking mechanisms in 1998 for the first time.[11]

The UTC maintains a record of the complaints it receives from customers of investor-owned utilities. More often than not, the agency is contacted after direct contact with the utility fails to result in a response satisfactory to the customer. Therefore, the database of UTC complaints more accurately represents instances of unsatisfactory dealings with companies rather than the nature of power problems. A review of complaints from 1993 through 1998 revealed no trend in the quantity or nature of complaints. The number of power quality complaints per year has been modest (five to 14).[12]

Utility tariffs hold customers responsible for protecting appliances and equipment. Unless utility negligence can be proved, which is often difficult to do, the customer pays damage costs. Three utilities reported the type of equipment for which customers have made power quality damage claims. The list includes: computers, printers, stereos, televisions, VCRs, phones, answering machines, microwaves, refrigerators and freezers, washers and dryers, fans, garage door openers, furnace controls, heat pumps, satellite receivers, variable-speed drive motors, irrigation pumps, and compressors.

Five utilities report paying damages for power quality claims. Presumably these are instances where utility negligence was evident, or where utilities chose to settle a claim rather than pay the cost of contesting it. The data do not indicate any clear increasing or decreasing trend in damage claims. For those utilities that reported paying damages, annual reported damage payments per utility over the period of the study ranged from $4,000 to $20,000.

In summary, while power quality may be an important emerging issue, data currently available do not allow an accurate assessment of either the current level of power quality being delivered by utilities, nor any trends in that level. We discuss power quality issues in more detail in Section 8.4: Factors and Trends Affecting Electric System Reliability.

8.3.3 Engineering Performance Perspective: Generation Supply Adequacy

The first two dimensions of service reliability focus on *delivery* of electricity service. The third dimension of reliability concerns the adequacy of generation supply — is there enough generation available to meet all needs and requirements?

Generation supply adequacy in the Pacific Northwest involves several time dimensions. Is there enough water in the region's reservoirs at the beginning of the winter peak season to ensure an adequate supply of generation late in the season? Is there enough water in the reservoirs each day to meet 10-hour sustained peak demands?

Is there enough peaking capacity, including demand management schemes such as interruptible power supply contracts, to meet the highest peak on the coldest day of the year?

In our region, reliability problems stemming from generation adequacy shortfalls are most likely to occur late in a cold winter after a year or more of lower than average rainfall and snow pack. In this scenario, heavy winter demand depletes already low reservoirs. The failure of one or more large plants in the region could then trigger a situation where the resulting shortfall exceeds the ability of the transmission system to import sufficient replacement power to meet all customer needs. If the shortage were expected to last for a significant length of time, the state would respond by implementing a customer curtailment plan that would first call for voluntary, then if necessary, mandatory reductions in energy use.[13] While a plan exists to address this situation, no such curtailment has ever been necessary in Washington.

Planning for adequate generation has historically been carried out on a regional basis as well as by individual utilities. Utilities that own generation and operate control areas generally forecast demand in the areas they serve and either build or contract for enough generating capacity to meet that demand under an assumed worst-case scenario, e.g., arctic conditions in a drought year. Upon request, and within the constraints of notice and contract terms, BPA is legally obligated to meet all net loads of Northwest public and investor-owned utilities. Small public utilities have generally placed their entire load on the federal system. Since the passage of the Northwest Power Act in 1980, planning for the federal system has been carried out by the Northwest Power Planning Council.

However, with the introduction of competition to the power generation market and with uncertainty about the obligations of utilities in the retail electricity market the potential exists for utilities to alter the way they plan for adequate generating capacity. In particular, there is concern that utilities will be reluctant to secure new generation resources because of uncertainty about their obligations to retail customers when those customers may be granted the right to leave their systems. A number of utilities raised this issue as a concern during the information gathering process for this study.

There is also a question about whether BPA's historical responsibility to meet the net loads of Northwest utilities is appropriate in an era of wholesale competition. Some believe that the federal government should avoid competing with private utilities and power sellers whenever possible, and would like to limit BPA's role in the market by restraining its ability to acquire new generating resources. Others would like to see BPA continue to acquire resources to meet regional needs.

However, with the development of a robust power market, stimulated by the emergence of independent power producers and open transmission access, BPA customers may have attractive alternatives to the federal system that formerly did not exist. This significantly raises the risk to the federal government of new resource acquisition. As a result of these pressures, the governors' Comprehensive Review recommended that BPA refrain from acquiring new resources except on a bilateral contract basis. In the two years since the Comprehensive Review, BPA has cut costs and become more compeitive. It is now expecting strong demand for its products and, in its subscription strategy, promises to meet all eligible loads. BPA, therefore, may need to make substantial purchases in the market to ensure it has adequate supply.

There is some indication that these changes to the electricity system might result in supply shortages in the Northwest. BPA's 1997 Pacific Northwest Loads and Resources Study, known as the "White Book", projects that the region could experience a shortage of up to 7000 MW of peak generating capacity during winter months under extreme drought and arctic weather conditions.[14] Much of this shortfall is on the federal system and could result in an electricity shortage of as much as 2000 aMW. This study has sparked a good deal of concern around the region, and the Northwest Power Planning Council has recently begun a study of the region's power supply adequacy.

In the absence of any changes in utilities' obligation to serve, utilities retain the responsibility to ensure that adequate resources are available to meet their customers' loads. However, utilities do not all hold the same view of this obligation. Information gathered from 16 utilities indicates that the 10 largest believe that they have the obligation to ensure that adequate generation supply is available to meet customer loads. The 6 that do not believe this is their obligation state that it is either BPA's responsibility (4), or that it is the responsibility of the customer and the market (2). Even among those large utilities that believe they do have an obligation to ensure adequate generation, there is ambiguity in the scope of this responsibility. More than half — 6 of the 10 – indicated uncertainty about the extent of their obligation to customers who select "open access" service.

Those utilities that indicated how they plan for generation adequacy did not report making major changes over the last few years in the planning criteria used. Most utilities continue to plan to meet peak load under arctic weather and extreme drought conditions. Only one utility reported that it had changed the way it plans for generation resources to rely more heavily on purchases of capacity from the wholesale market. The agencies are uncertain how to square the potential for deficits as projected in the BPA White Book with assurances that utility planning criteria have not changed. This is an issue that may be addressed by the Northwest Power Planning Council in its review.

8.4. Factors and Trends Affecting Electricity System Reliability - Issues Discussion

Electricity reliability in the near future will be strongly influenced by two key factors: competitive pressure and institutional uncertainty. These factors are affecting all sectors of the electricity industry including power generation, transmission and local distribution.

Competition has both benefits and costs. On the benefit side, competition encourages innovation and aggressive pursuit of cost-reductions in all the industry sectors. It also encourages expansion in the choices provided to customers, be they utilities buying power from generators, or consumers buying service from utilities. Some of these benefits are due to technological and fuel market changes that may have appeared regardless of the introduction of competition to electricity markets. On the negative side, reduced revenue and the need to cut costs may tempt utilities to test the limits of their transmission and distribution systems, which may lead to reduced reliability.

Fundamentally, reliability is a function of investment; in generating, transmission and distribution plant, and in operations and maintenance. Competition and the prospect of competition are spreading through the industry. At the same time, uncertainty is growing regarding obligations and opportunities for both generators and local distribution utilities. That uncertainty makes investment risky, even if it is needed to maintain reliability. Both utility and non-utility power plant developers may be reluctant to invest in new generation capability if they do not know who they will be obligated to serve or what customers will be available to buy their output. Utilities may be reluctant to invest in needed maintenance or facility replacement if they are uncertain about from whom they will be able to recover the cost of this investment. Clarifying institutional responsibilities, obligations and rules is likely to moderate concern about these risks and remove disincentives for needed investment.

This section discusses the relevant issues and trends in three industry sectors:

1. Local Distribution (maintenance, replacement, and expansion)
2. Transmission (system control, maintenance, and expansion)
3. Generation (power plant development)

8.4.1 Factors and Issues Affecting Reliability: Local Distribution

Factors Affecting Distribution System Investment

Distribution companies have the responsibility for investments to maintain, upgrade and expand distribution system infrastructure. Reliability is a function of those investments. Uncertainty about recovery of the costs incurred for distribution infrastructure represents risk that can act as a disincentive for needed investment. Risks may be highest in areas where customers may bypass the utility facilities, or where some existing or new customers are especially expensive to serve.

The more likely a customer is to bypass the system, the higher the risk to recovery costs to maintain the system. In some areas, particularly along service boundaries, the probability of bypass is highest and utilities may be reluctant to make investments there. Service territory policy in Washington does not preclude such bypass and utilities report instances of one utility courting another utility's customers.[15] Competitive pressure from the wholesale power market and access to transmission systems through FERC jurisdiction may increase this level of risk. Lack of clarity in distribution system obligations and territorial rules increases the risks to cost recovery and may serve as a disincentive for investment.

Utilities also report that connecting and serving some customers or areas can involve costs significantly higher than average. Because rates reflect average costs, serving these customers and areas raises the rates for everyone. In an effort to keep service costs as low as possible and reduce the risk to cost recovery, utilities may turn to less generous line-extension policies, or may try to avoid serving some areas altogether. Again, lack of clarity in distribution company obligations and prospects for cost recovery may act as a disincentive for utilities to make necessary investments in reliable infrastructure.

These uncertainties add pressure to cut costs and may erode the ability of distribution companies to make the investments required to provide reliable service to all customers.

It is equally true that utilities may increase investments in reliability for the express purpose of retaining customers or securing new ones. This may be difficult to do in a cost-cutting environment. It would require accepting the risk that higher costs will not drive away customers. An alternative would be to target specific at-risk customers to be the beneficiaries of such investment, but this might result in reduced reliability for customers deemed not at risk.

Objectives of Distribution System Reliability Investment

Presuming investments in the distribution system are made, utilities must evaluate and balance investment alternatives, many of which involve reliability tradeoffs. For example, paying more for labor may leave less for equipment. Underground lines fail infrequently but the outages last longer - reducing SAIFI but increasing SAIDI. Automatic reclosers keep faults from turning into long interruptions, decreasing SAIDI but increasing the number of sags, surges and momentary interruptions. Utilities must weigh and balance the options available in each circumstance. No single solution, such as under-grounding, is everywhere appropriate. The best alternative for an individual project may include a number of options: e.g. one mile of underground, two miles of aggressive tree trimming, three miles of tree wire. Making the right choice involves complex analyses. However, we can see from the data that there are key areas of investment that every utility makes.

Key Reliability Investment - Storm Response

We noted earlier that storms are the cause of a significant proportion of Washington's service interruptions. Improving system condition and reducing vulnerability to trees can help defend the distribution system against storms. This is accomplished primarily through good planning, operations, maintenance and vegetation management programs.

Being prepared to respond to storm damage can lessen the impact of storms by reducing the length of outages. While all utilities have procedures for dealing with contingencies, preparedness can vary greatly. There is no single correct way to address an emergency. However, some basic components must be addressed in any emergency preparedness plan. These include:

- Damage to Company Facilities
- Storm Anticipation
- Emergency Ramp-Up and Emergency Operations Center Activation
- Command and Control
- Restoration Priorities
- Material and Personnel Resources
- Information Management and Communication
- Interagency Coordination

A review of the details of utility preparedness is beyond the scope of this study. However, utilities were asked to provide copies of contingency plans to make a general assessment about preparedness documents. The plans vary greatly in both scope and detail. Five utilities have no written plan. Those that do, have plans that vary from a few brief pages to sophisticated documents that address all of the components listed above. Taken alone, even a good plan is no assurance of a good response; sophisticated plans may have flaws and be poorly implemented.

Data management capabilities are fast becoming the key to improving response times. Utilities are more able today to identify faults from operations centers and to implement appropriate response efforts more quickly. Automatic system monitoring and switching equipment lets operators do from a distance what used to be done in the field. But utilities vary greatly in their information management capabilities. Some still have no remote switching capability.

Utilities often must rely on contract crews to assist in emergency response. While contract crews may have skill equal to regular employees, they lack knowledge of specific distribution systems. This could lead to increased restoration times during emergencies. For various reasons, including reduced growth, some utilities have reduced the number of employee crews over the study period.

Key Reliability Investment - System Maintenance

The fact that failure of installed equipment is the largest single cause of interruptions on both sides of the state underscores the importance of maintenance. Distribution system equipment is unusual in that there are almost no moving parts. Equipment life is primarily a function of temperature and age. Lightly loaded equipment in a mild environment can last a long time. Heavily loaded equipment in severe conditions wears faster. Equipment nearing the end of its life is the most vulnerable to weather and other contingencies.

Maintenance consists primarily of monitoring equipment and repairing or replacing it before it fails. Manufacturing specifications, industry standards and utility experience are the bases on which maintenance is conducted. Each utility establishes its monitoring, repair and replacement procedures based on available resources and the amount of risk it is willing to incur. Utilities differ in the degree to which they allow equipment with reduced life expectancy to remain on the system. More rapid replacement reduces failures, but it is more costly. Wood poles may be inspected every five years or every 15 years. Some utilities have no centralized, routine basis for pole inspection at all. Some conduct infrared inspection of overhead conductors annually, while others check only priority locations. Some may conduct infrared scanning only infrequently, if at all. Many utilities inspect equipment on a time-scheduled basis regardless of the different conditions equipment may be subject to. Others prioritize inspection of equipment based on risk analysis - key equipment is inspected more often, or may be replaced sooner.

The fact that much of our distribution infrastructure is growing old is a key issue affecting distribution system maintenance. The current stock of installed poles contains many that were originally erected fifty or more years ago. Yet, neighborhoods are now more densely populated and old equipment is being more heavily loaded.

Over the period of the study, most utilities reported an increase in maintenance expenditures. However, not all increases kept up with the rate of inflation. On a per-customer basis, expenditures did not keep pace with inflation for a majority of utilities. Table 8.6 lists the number of utilities for whom reported maintenance expenditures represent an increase or decrease over the period 1990 to 1997. Adjustments are made to reflect inflation and changes in the number of customers served. The greatest increase in non-inflation-adjusted expenditures was on the order of 14 percent, the greatest decrease (minus) 1 percent. The greatest per customer increase was 10 percent, the greatest decrease (minus) 3.3 percent.

Declines in per customer expenditures may reflect an increase in customer density, where it costs less to provide the same level of service per customer. Our information does not contain enough detail to examine specific maintenance practices, for example, to examine whether shifts have occurred between equipment purchases and labor.

Table 8.6: Number of Utilities with Increased or Decreased Maintenance Expenditures over Study Period[16]

Maintenance Expenditures	Increase	Decrease
Total (Nominal Dollars)	11	2
Total (Versus Rate of Inflation)	7	4
Per Customer (Versus Rate of Inflation)	4	7

Source: Data reported by utilities to 6560.

The data in Table 8.6 suggest that, in general, utilities are not greatly increasing or decreasing their maintenance expenditures. Expenditures for most utilities are a few points above or below inflation. Nevertheless, the stated concerns of utilities about competitive pressures and the future ability to make needed investment in the distribution system should be taken seriously. Equipment, operations and maintenance costs are all candidates for reduction in a cost-cutting environment.

Across the country, some state governments have taken the step to set maintenance standards for utilities, including California, Oregon, Pennsylvania, Iowa and Kentucky. Standards primarily address monitoring cycles, testing specifications and repair and replacement criteria. Also in California, the California Independent System Operator (CAISO), which operates the state's transmission grid, has been granted statutory authority to sanction utilities that cause problems on the transmission grid. The CAISO has responded by requiring utilities to monitor in great detail all aspects of their transmission maintenance programs. In the future, poor maintenance practices and reduced expenditures may be used as evidence for assessing penalties and sanctions in California. Such an approach could be applied to a distribution system as well.

Key Reliability Investment - System Expansion

Utilities continually redesign and expand their systems to address new development and increasing density on existing circuits. There is no easy way to evaluate whether criteria or standards for system construction have changed over time. Declining standards could lead to higher system loading. Under traditional regulation and local rate-setting, utilities operated with the expectation of a reasonable return on prudent investment. In some cases, this led to suspicions of gold-plating; installing premium equipment whether or not it was necessary. In addition, utilities built many lines anticipating future load. These two factors have led to what appears to be a general industry perception that past infrastructure was somewhat over built, though perhaps more reliable because of it.

System construction upgrades and expansions are designed, built and inspected by the utilities themselves. Utility plant is expressly exempted from the National Electric Code (NEC) that covers all other electrical construction and is enforced by the Department of Labor and Industries (L&I).[17] Utilities *are* subject to the National Electrical Safety Code (NESC) and L&I may inspect utility plant for compliance with public and worker safety standards. The safety standards are performance-based; meaning that installed equipment must meet specified performance criteria under specified conditions. However, the choice of what equipment to install is up to the utility, not specified by the NESC, and there are no specific standards related to service reliability.

Utility system design, construction and expansion in the future will face opposing trends. Technological improvements, including promising distributed generation alternatives, may make reliability cheaper and easier to attain in design and construction. The drive to cut costs and deal with obstacles to construction may make it more difficult. Utilities report increasing difficulty and costs in attaining access permits necessary to construct new lines and equipment. The public may generally value reliability yet oppose new construction that would provide it, especially if it is to be located "in their backyard."

Key Reliability Investment - Vegetation Management

Utilities on both sides of the Cascades report large numbers of tree-caused interruptions. Most of these are weather-related. Wind, rain, ice and snow force trees and branches into lines. A branch that simply settles across two lines causes a fault. Second to maintenance, vegetation management is probably the most important reliability program for most utilities, clearly for those west of the Cascades.

The primary focus of vegetation management is trimming or removal of trees that may cause system damage or a ground fault. Programs usually have an operations component that addresses immediate problems and a preventative maintenance component that manages feeder and lateral lines on a cycle. Most utilities trim on a full system cycle (every feeder is trimmed every 1 to 4 years depending on the utility). Some utilities use a number of criteria, such as tree type and customer density, to set different cycles for different areas. For example, rural feeders lined primarily with coniferous trees may need to be trimmed only once every six to ten years. Urban feeders lined with deciduous trees, especially certain fast growing types, may need to be trimmed every two years. Utility tree trimming crews are usually solely dedicated to vegetation management. Crews may be utility employees, but the trend is for utility personnel to manage a program that relies extensively on contract crews.

There is no uniform standard for vegetation management programs. Utilities develop their own criteria for trimming cycles, trimming distances and tree removal. Across the nation, some states have established vegetation management standards. California and Oregon, for example, require investor-owned utilities to trim all trees within a certain cyclical period. California, in addition, has prescribed a year round, minimum distance between branches and lines, regardless of trimming cycles.

Table 8.7 includes the number of utilities for whom vegetation management expenditures increased or decreased between 1990 and 1997. Comparisons are adjusted for inflation, number of employees (FTE), and number of distribution system miles cleared. Over the period of the study, most utilities increased their annual expenditures for vegetation management. For 10 of 16 utilities the increase was greater than inflation. Most utilities also reported an increase in both dedicated staff and annual miles of distribution line cleared. As a result, for 6 of 13 utilities, expenditures per mile cleared decreased (for 9 if inflation is taken into account).

Table 8.7: Number of Utilities with Increased or Decreased Vegetation Management Expenditures over Study Period.

Expenditures	Increase	Decrease
Total (Nominal Dollars)	12	4
Total (Versus Inflation)	10	6
Per FTE (Nominal Dollars)	11	2
Per FTE (Versus Inflation)	3	10
Per Mile Trimmed (Nominal Dollars)	7	6
Per Mile Trimmed (Versus Inflation)	4	9

Source: Data reported by utilities to 6560.

Most utilities' expenditures are a few points above or below inflation. It appears that, in general, utilities are maintaining about the same level of effort over time. However, reductions in expenditures per employee and per miles trimmed could reflect increases in productivity, changes in trimming requirements, or reductions in program quality.

Over the last three years, statewide tree-caused interruptions have decreased from 30 to 20 percent. The ten-percentage point decrease is primarily due to reductions in tree-caused interruptions for two West Side utilities. These utilities faced some serious storms during that period. While there is substantial evidence that vegetation management is effective in reducing outages, this study did not attempt to determine to what degree the three year reduction was the result of vegetation management or was weather-related.

Tree trimming alone does not address all the variables that influence tree-caused outages. Development practices that leave thin stands of trees abreast power lines are an invitation to tree-caused outages. Thin stands are not protected from wind, as are denser forest stands. Compacting and paving land results in increased water runoff that can erode the base of tree stands, making the trees more vulnerable to wind-throw. Over the last two decades, western Washington has experienced relatively rapid population growth and suburban development.

If utilities are kept informed, they may be able to coordinate with other parties and projects involving tree cutting or tree removal. Tree removal often requires approval of a Forest Practices Application by the Department of Natural Resources (DNR). However, environmental criteria consume the bulk of DNR's approval and enforcement efforts; power issues are not high on the list. Though the application provides notice to the applicant that they must notify the utility if any trees are within two tree lengths of a power line, utilities report that they often are not notified.

Finally, urban vegetation management also presents some challenges. Utility right-of-way is often very narrow and may be squeezed between roads and city or private property. A single mile of right-of-way may include some utility property, city easements and a large amount of private property. Utilities must work with each property owner, and many, including cities, are not eager to have their trees cut. Utilities do not have authority to trim against an owner's wishes.

Key Reliability Investment - Power Quality

Power quality was once the exclusive concern of industrial customers. There is growing evidence that residential and commercial customers should be equally interested. Utility tariffs make customers responsible for the protection of their own equipment.[18] Customers who do not know this may find out too late at considerable cost.

Power quality standards primarily regulate electricity voltage and frequency. Authority to set reliability standards resides in the general regulatory authority of utility governing bodies granted by state law. By rule, each investor-owned utility must set a standard frequency and voltage, which are then subject to minimum and maximum excursions.[19] The governing boards of publicly-owned utilities set their own standards. While all utilities deliver a uniform 120/240 volts to customers, they operate their distribution systems at higher voltages that may differ from utility to utility. All utilities in North America operate their systems at the same frequency: 60 hertz (60 cycles per second).

Standards are set, in part, to protect customers from utility negligence. Utility operating activities and maintenance practices can cause voltage and frequency problems. For example, overloaded equipment may fail before scheduled replacement. Tree branches that are not properly trimmed may bridge lines when the wind blows. But, negligence can be very hard to prove. Voltage and frequency can only be measured at specific places and times with equipment designed for the purpose. It is costly to locate such equipment everywhere around the grid, so the grid is not continually monitored.[20] This means it is often difficult to know what the nature of an excursion was, let alone what caused it so that responsibility can be determined.

Standards also are set to protect utilities from circumstances beyond their control. Environmental conditions like wind, lightning, ice, snow, and sunspots all affect the quality of power delivered over utility distribution systems. Utility regulators and local governing bodies recognize the difficulty of maintaining grid standards under all conditions. Therefore most standards are qualified to allow considerable excursions to occur. For example, investor-owned utilities are required to maintain frequency "*reasonably* constant," and maintain minimum and maximum levels only under "normal operating conditions," (emphasis added).[21] Such qualifications permit frequent excursions from the standard.

The degree to which off-specification voltage and frequency causes problems is a function of the nature and magnitude of an excursion and the sensitivity of the conductors and equipment involved. Small sags can bring expensive production equipment to a grinding halt. Large surges may only affect a few transformers. Many power excursions cause only inconvenience; lights flicker, clocks stop and computers reboot.

But, equipment sensitivity is growing. Microprocessors are especially sensitive to power excursions. Critical applications, such as financial transactions, security monitoring and production processes increasingly rely on sensitive electronic controls. Even in the home, computers, entertainment systems and heating and cooling controls may be sensitive to power quality. Manufacturers are producing increasingly sensitive equipment, which we are using with increasing frequency for critical applications. So, even if the reliability of power quality remains constant, we can expect power quality problems to increase.

Sensitive equipment can, in many instances, be protected with devices designed for the purpose, such as external surge protectors and uninterruptible power supply systems. Whole-house surge protectors that protect the entire home have been advertised recently. For industrial applications, a new power quality industry has arisen, with consultants recommending sophisticated new power regulating equipment to protect factories and offices. This means that power quality reliability can be achieved at the customer's site and expense, rather than on the distribution system at ratepayers' expense. Customers with special needs or wants have always been able to secure high reliability at a price. In the past, however, this was usually the concern of industrial, not residential, customers.

Key Investment - Year 2000 Compliance

The Year 2000 (Y2K) problem poses a momentous challenge for the electric utility industry. The complexities and uncertainties surrounding Y2K have so far kept utilities from guaranteeing reliability, which has fueled speculation that there could be widespread and long-lasting power outages at the turn of the century. Most utility executives believe, having seen the early results of testing, that major outages can be avoided, but that minor outages may occur. Because all sectors of society depend so heavily on electricity, there is no more important industry to become Y2K compliant.[22] The state and utility governing bodies are well aware of this and have put into place comprehensive plans to ensure compliance.

There is no single compliance plan covering all Washington utilities and no single organization that is coordinating utility efforts. Instead, depending on the size and nature of the system, each utility is working with numerous organizations. Eleven key utilities that operate transmission control areas under the Western Systems Coordinating Council report compliance progress to the National Electrical Reliability Council. Investor-owned utilities submit quarterly reports to the UTC. The BPA has taken a lead role in coordinating the efforts of its customers. Cooperatives, municipal utilities and PUDs are coordinating with key associations such as the Association of Washington Cities and the Washington PUD Association. The Northwest Public Power Association is considering implementation of an Electric Power Research Institute (EPRI) compliance program for member utilities. Utilities also are cooperating with the state Division of Emergency Management to coordinate contingency planning.

Working toward compliance generally means taking the following steps: inventory (accounting for all utility devices), assessment (determining the vulnerability of each device), testing, remediation (applying a solution), and retesting. Steps are worked in parallel, though there is a natural order to the process. Most utilities have completed or are progressing on inventory and assessment and have begun the testing phase. Testing has already revealed control and communications vulnerabilities that, if left uncorrected, could have caused major outages. On the positive side, at least one large Washington utility has completed testing nine of 12 generating plants and has found few significant compliance problems. However, many utilities are not so far along and far more than generating plant must be tested. According to EPRI, a moderately sized utility may have as many as 30,000 devices with failure potential. As compliance testing intensifies in 1999 and test data become more available, we will have a much better understanding of our reliability risk in the year 2000 and what needs to be done to prevent or minimize the impact of failures.

8.4.2 Factors and Issues Affecting Reliability: Transmission System

Most of this chapter has focused on reliability of distribution systems. This section focuses on the reliability of the interstate transmission grid, otherwise known as the bulk power system.[23] The bulk power system consists of generating units, transmission lines and substations and system controls. Although the transmission system has historically been responsible for only a small percentage of all power outages, the scope of such outages are usually much broader than those caused by distribution system failures. Bulk power outages may have regional implications and impact many utility distribution systems.

Utilities began to interconnect their transmission systems early in the century as plants became larger and began to be located at greater distances from the loads they served. As decades passed, an increasing number of generators, transmission facilities and load centers were interconnected over increasingly large areas. Expansion of interconnecting transmission systems in the western United States and Canada resulted in the complete interconnection of the western system during the mid 1960s. These changes required increased coordination and planning among utilities to maintain reliability.

In 1965, a blackout in the northeast U.S. that left almost 30 million people without electricity triggered national concern about the reliability of interconnected bulk power systems. This concern resulted in the formation of ten regional reliability councils, including the Western Systems Coordinating Council (WSCC). The WSCC is a voluntary organization made up of electric utilities that are engaged in bulk power generation and transmission in the western interconnection. The WSCC region encompasses electric systems serving all or part of 14 Western States, British Columbia and Alberta, Canada, and Baja California Norte in Mexico. The ten regional councils created the North American Electric Reliability Council (NERC) in 1968 to coordinate the efforts of the regional councils, to set national standards for electric system operation and to monitor voluntary compliance with those standards.

The primary concern in operation of the interconnected transmission grid is maintaining system "security." Security refers to the ability of an electric system to withstand sudden disturbances. The sudden loss of a generating unit or transmission line can lead to rapid changes in voltage levels and frequency that, left uncorrected, could damage equipment of both utilities and customers. In some cases, these disturbances can lead to other disturbances elsewhere in the system, taking down generators and transmission lines one-by-one in what is referred to as a cascading outage. Preventing these is the work of regional grid management organizations such as the WSCC.

This system of securing reliability through voluntary compliance with industry-established rules has worked well for the past 30 years. However, the electric industry is changing in a number of ways that are making the current system of voluntary compliance increasingly untenable. First, the Energy Policy Act of 1992 and FERC's

Orders 888 and 889 are changing the commercial relationships among users of the transmission grid. FERC is creating competitive wholesale power markets and requiring utilities to unbundle generation from transmission and provide nondiscriminatory access to all users of the grid. In response, a number of states, including California, Montana, Nevada and Arizona are in the process of restructuring their retail electric markets. These actions are creating substantial changes in the character of participants in bulk power markets. Transmission operations were far less complex and more secure when operators had both access to system information *and* control of generating resources. Those capabilities have been separated. Second, the significant increases in the number and complexity of transactions associated with greater competition increases the chances for operating error. Third, there is increased pressure to ensure that system operators make minute-to-minute decisions in ways that do not favor certain market participants over others, because many actions taken to operate the grid under conditions of heavy use have potentially significant financial implications for market participants. Finally, the diverse market pressures facing many of the participants in bulk power markets could discourage compliance with voluntary reliability requirements.

As a result of these changes, existing electric reliability organizations have begun to reassess whether the current structure will be sufficient to ensure electric system reliability in the future. This process was hastened by two major transmission system outages in the western interconnection in 1996. While it is impossible to determine to what extent these outages were due to industry changes such as those described above, the outages brought national attention to the problem of electric system reliability in a changing industry environment.

National Developments

In August 1997, NERC assembled a "Blue Ribbon" Electric Reliability Panel to recommend the best ways to set, oversee and implement policies and standards to ensure the continued reliability of North America's interconnected bulk electric systems in a competitive and restructured industry. The panel issued its report, *Reliable Power: Renewing the North American Electric Reliability Oversight System*, in December, 1997. The report recommended the creation of a new Self-Regulating Reliability Organization (SRRO), which it dubbed the North American Electric Reliability Organization (NAERO), that would have authority to enforce compliance with reliability standards.

NAERO was launched by vote of the NERC Board of Trustees on July 9, 1998. However, key elements of the NAERO plan, including compliance enforcement and funding, cannot go into effect without federal legislation. A bill addressing these issues was introduced in the House of Representatives in August of 1998, but has not been acted on. The 106th Congress is expected to address the issue.

Western Developments

The WSCC differs from most regional reliability organizations in that it is coterminous with an AC interconnection. This means that system security problems caused by operations in the WSCC region cannot have any effect on operations outside of the region. It also means that the voluntary standards developed by the WSCC are applicable to every party whose actions can have a negative impact on WSCC reliability. This stands in contrast to the situation in the eastern interconnection, where rules and standards are developed by seven different regional reliability organizations, and each region is vulnerable to the actions of companies in neighboring regions.

The West is also unique in that it has three functioning Regional Transmission Associations, (the Western, Northwest and Southwest Regional Transmission Associations, or WRTA, NRTA and SWRTA). These organizations were developed by western interests to address commercial issues related to transmission system operation brought on by the burgeoning wholesale electric power trade. In the eastern interconnection, commercial issues are addressed primarily by NERC.

These factors have resulted in a unique set of institutional relationships in the western interconnection. Solutions to transmission system operational issues, related both to reliability and commercial interests, have traditionally been devised and implemented on a consensus basis within the western interconnection, with a minimum of oversight from outside parties. Because of this tradition, some in the West have resisted the development of a new, national reliability organization with enforcement powers and have called instead for the creation of a separate Self Regulating Reliability Organization for the western interconnection that would be independent from NAERO.

Discussions have been taking place during 1998 under the auspices of the Western Interconnection Forum (WICF), an ad-hoc, umbrella organization created by the WSCC and the three RTAs to discuss the future roles of regional grid-management organizations. Key questions being raised include: whether the western interconnection should form its own self-regulating reliability organization that would be independent of NAERO; what kind of governance, funding and authority a new western grid management organization should have; and how reliability and commercial interests should be weighed when making decisions about the operation of the regional transmission grid. It is unclear at this writing what direction these discussions will ultimately take. Attempts are being made to foster a unified Western position so as to maximize the region's bargaining position should Congress debate the issue of mandatory reliability standards in 1999. It is likely that some form of SRRO will eventually be legislated by Congress, but it is too early to predict exactly what form that entity might take.

Formation of an Independent Transmission Operator

Some in the industry believe that all utilities will ultimately be required to divest either their generation or their transmission assets. They believe it will prove too difficult to enforce codes of conduct governing relationships between generation and transmission subsidiaries of a single company and point to the experience of the natural gas industry, where FERC required divestiture of pipeline assets. A related alternative is to require divestiture of all transmission assets and formation of an independent operator to run the transmission system. While arguments in favor of the formation of independent operators rest primarily on economic grounds, e.g., mitigation of vertical market power, many believe it would enhance the reliability of the bulk power system.

There are several reasons for this belief. First, many believe that the reliability of the interstate transmission system would be best protected by an entity with a neutral position in the generation market. If the operator's primary mission is to operate the transmission system reliably, the argument goes, the operator is less likely than is a vertically integrated utility to engage in activities that may benefit a subsidiary while degrading the reliability of the bulk power system. This is most likely to be the case if the effect of an outage would be felt by customers of a competitor, perhaps in a neighboring state.

Second, an independent operator may also be better positioned to safeguard reliability because its system operators would know about all major events that occur on the regional system. One of the factors that exacerbated the 1996 outages was that not all system operators were made aware of the seriousness of the problems in a timely manner. An independent operator would be connected electronically to generators and transmission lines throughout the region, and might be better able to isolate a potential problem than today's system of dozens of control areas. An independent operator would also have knowledge of all generation-to-load schedules across the regional bulk power system. This might give it the ability to better monitor potential trouble spots. Independent operators now operate several systems in California and the Northeast.

8.4.3 Factors and Issues Affecting Reliability: Generation System

Earlier sections of this report have discussed the development of a competitive market for power generation. Prior to the 1978 Public Utility Regulatory and Policy Act, utilities were solely responsible for construction of adequate generation facilities to meet customer loads. Trade in electricity did occur, but at far lower levels than in today's robust wholesale market. Non-utility generators entered the scene through the 1980s and were joined by a broad and diverse set of wholesale generators, marketers, and power brokers after the Energy Policy Act of 1992. As a consequence, trade in wholesale power has grown substantially and utilities no longer face the need to construct their own power plants to meet customer loads. [24] They now have the ability to purchase electricity generation from market sources at prices set by competition.

Traditionally, utilities have maintained a "reserve margin" of generation capability to ensure that sufficient generation will be available to meet load even if some part of the system fails. Increased reliance on markets may reduce this margin, making the region more vulnerable to contingencies. This is not necessarily a bad thing. Traditional margins of 20 percent or more have meant that one-fifth of the region's generation plant is left idle during most hours in anticipation that it might be needed to respond to an emergency. This is an expensive insurance policy, and if utilities have overestimated customers' desire for reliable power supply, then lowering reserve margins will save costs and bring the supply and demand of peak generating capacity closer to balance.

There is another reason why utilities might allow reserve margins to fall: uncertainty about what their retail load will be and what their obligations will be vis-à-vis that load. This uncertainty stems from at least two sources: the potential for physical bypass of the utility's distribution system, and the potential for new state or federal laws that grant retail customers access to the market.

Physical bypass, i.e., construction of redundant power delivery lines to access service from another utility, has always been an option for customers who have practical opportunities to do so. Only recently, however, with transformation of the high voltage transmission system into an open-access common-carrier and the emergence of a competitive wholesale power market with numerous suppliers, has the attractiveness of this option increased to the point where it might be affecting utilities' willingness to invest in new generating capacity.

Of greater concern for many utilities is uncertainty about retail market structure. Developments at the federal level and in neighboring states such as California, Montana, Nevada and Arizona have created uncertainty about the retail market structure in Washington. Faced with the possibility of losing customers to competition from other suppliers, utilities are reluctant to make long-term commitments to new supply, especially when they can purchase generation on the wholesale market on a monthly, daily, or even hourly basis. This reluctance to make long-term commitments could result in delays in the construction of needed generating capacity.

Another trend that could potentially have an impact on generation supply adequacy is the increasing prominence of independent, non-utility power providers in the wholesale market. These non-utility developers are building most new generating capacity. The utilities themselves have placed a number of prominent utility-owned power plants in the region up for sale. These include the Centralia plant, currently owned by a consortium of eight Northwest utilities, and the shares of the Colstrip plants in Montana belonging to Puget Sound Energy, PacifiCorp and Montana Power. These utilities are likely to replace these generating resources with spot market purchases or power supply contracts, potentially from independent power providers.[25]

The emergence of independent power providers as a major player in the wholesale generation market may or may not have implications for reliability. As long as independent power providers have the ability to obtain long-term power purchase contracts with utilities, they should have the same incentive as utilities to build sufficient generating capacity and operate it reliably. However, we have already seen that utilities may be increasingly reluctant to engage in long-term commitments. This problem stems from uncertainty about retail market structure and would exist regardless of who builds generating capacity. However, to the extent that independent providers face greater risk than utilities in constructing new capacity, the effect may be amplified. Independent power providers may be willing to take that risk. The existence of a structured market, such as now exists in California, wherein a power developer can expect to make a series of shorter-term sales may be a sufficient basis on which to construct additional generation.

Another issue associated with independent power providers is credit-worthiness. Market transactions rely solely on contractual commitments. While contracts establish obligations and responsibilities, they are also subject to default if companies do not have the financial resources to fulfill their obligations. This is not an abstract possibility. The electricity shortages and price spikes that occurred during the heat wave in the Midwest U.S. this past summer were aggravated by the default of an independent power provider, and the inability of its guarantors to deliver on their obligations. Such a collapse of market arrangements need not result in interruptions in power supply, as long as sufficient generating capacity exists AND the operator of the transmission system has the authority to order idle generators into service. If either of these two conditions fail to hold, load would have to be shed in order to keep the system in balance.

Despite the uncertainties described in this section and elsewhere in this report, some new generating capacity has come on line in the region during the past few years. Several hundred megawatts of new, natural gas-fired generation were added by utilities and by non-utility developers with long-term utility contracts. In addition, over 3000 MW of new facilities have been issued site licenses (permits to construct) or are in the siting process in Washington, Oregon and Idaho.[26] For the most part, these site licenses or applications involve non-utility developers. No construction is currently underway on these sites.

The experience in California, where retail markets have been restructured, and a formal wholesale market has been established, may also be instructive. The California Energy Commission (CEC) reports that it anticipates receiving applications to site some 7000 MW of new capacity.[27] At the same time, however, the CEC has performed analyses suggesting that prices on the California Power Exchange during its first six months of operation have not generally been high enough for investment in new generating capacity to be profitable.[28]

These developments indicate that many of the site licenses and applications in the Northwest and in California may be speculative. In Washington, no construction has taken place on some 1,650 MW of capacity-granted site licenses over the past few years. Site licenses are held by non-utility, private developers who will make decisions to actually begin construction based on their expectation of the price that power from these plants will receive in the competitive power market. The question of whether facilities will be built in time to meet the needs of growing demand, or, more importantly for the Northwest, to prepare for the contingency of poor water years, remains unanswered. It remains to be seen whether the market can produce new generation supply without pricing volatility, economic risks, and possible decreases in customer satisfaction.

8.5 Strategies to Ensure High Reliability in the Future

The preceding discussion documents that distribution system reliability in Washington is generally good, or at least comparable with other states and countries. In that light, one obvious alternative is to maintain the status quo. However, the discussion also reveals that some trends and issues associated with the emergence of competition may be putting pressure on key factors that will affect service reliability in the future. This section describes strategies and actions that could be taken to address these pressures and maintain, or even improve, reliability of electricity service. In each case we have described the strategy and its rationale, as well as summarizing arguments that could be made for or against the strategy.

The strategies presented in this study should not be viewed as exact blueprints; they are examples of the kind of actions that can be taken to address reliability. For example, a strategy that calls for a statewide reliability standard generally does not address what that standard should be, how it would be set, or who might be exempted (for instance, small, rural utilities). The legislature could mandate such a standard, or it could be voluntarily implemented by utilities.

The strategies are organized into categories that address:

- ❖ The Distribution Sector
- ❖ The Generation and Transmission Sector

The Distribution Sector strategies are further categorized into those that involve:

- ❖ Performance Standards
- ❖ Program Standards
- ❖ Institutional and Market Issues

8.5.1 Reliability Enhancing Strategies: Distribution Sector.

8.5.1.1 Performance Standards:

1. Establish Minimum Levels of Grid Reliability.

Description: Mandate minimum levels of grid reliability. These standards could be uniform statewide, or be utility-specific, and could address both system interruption and power quality performance. Statewide standards would allow electricity customers to locate anywhere in the state and expect the same minimum level of service. Utility-specific standards would establish a minimum level of reliability while recognizing the geographic differences among utility service territories. Oregon has recently adopted requirements for investor-owned utilities to maintain performance records and has also established performance standards for these utilities. California has also established standards for both data monitoring and system performance. Consistent measurement and record keeping of distribution performance statistics would be required both to set and to ensure compliance with standards.

Rationale: Minimum standards act as an incentive to keep reliability at a desired level. They promote equity. Standards also allow customers to assess their electricity service requirements more accurately and plan accordingly.

Arguments For: A reasonable level of reliability is required for convenience, safety and normal business operations everywhere. All communities and customers should be able to expect a reasonable level of electricity reliability.

In the absence of a consistent standard, differences among utility management strategies, investment incentives, and the relative influence of customers with specific reliability needs could lead to wide variation in service reliability from place to place. Some areas could experience significantly degraded reliability.

Arguments Against: Reliability decisions are best made at the local level. Statewide standards would usurp control from locally elected boards and impose a potentially costly mandate on service territories where providing reliable service is more expensive. Besides, both the UTC and the governing boards of public utilities have already established minimum standards. In general, standards covering power quality are specific, but flexible, recognizing the influence of forces beyond utility control. Interruption standards are primarily descriptive, not prescriptive.[29] Present levels of reliability are reasonably good and equitable. In addition, setting stricter or more prescriptive standards may undermine the concept of appropriate reliability, i.e. providing what the customer wants. Setting a prescriptive minimum standard requires choosing an arbitrary level that for some customers may be too high, or for whom the expense may not justify the added measure of reliability.

Program Standards:

1. *Require utilities to track and maintain a record of performance reliability data.*

Description: Require utilities to systematically track reliability data. The nature of the data to be maintained should be clearly defined and standardized. A consistent record of reliability data would support a number of purposes ranging from public information, to utility decision-making, to evaluation of performance targets upon which incentives and penalties might be based. Oregon has recently adopted requirements for investor-owned utilities to maintain performance records and has also established performance standards for these utilities. California has also established standards for both data monitoring and system performance.

Rationale: If reasonably accurate and meaningful reliability measurements can be made, governing bodies can determine whether increased investments in reliability are warranted, customers can have a more firm basis for judging service reliability and available alternatives, and utilities can have better decision-making tools at their disposal. All of these could lead to more effective and efficient management and targeting of reliability investments.

Arguments For: Lack of consistent information makes it difficult for utility governing bodies and regulators to know what level of reliability is being delivered. More consistent and meaningful measures would allow them to track reliability over time (for improvement or deterioration), and to know how utilities compare. In addition, this would allow for better assessment of appropriate levels of reliability investment. Publishing reliability indices or other statistics would act as an incentive to utilities to maintain reliability.

Arguments Against: Utilities are very different, both in the nature of their systems and in their approach to managing reliability issues. Utilities and their governing bodies and regulators should be allowed to determine for themselves the degree to which investments in data collection and record keeping are necessary and appropriate. Intensive data management can be expensive and a utility may prefer to dedicate resources to operations and maintenance. Moreover, decisions about how performance data should be reported, to whom, and for what purposes should rest with the utility so that misinterpretation is avoided. As long as customers are satisfied, there may be no need for a utility to track reliability data.

2. *Improve Customer and Public Information*

Description: Require utilities to implement programs that provide better reliability information to customers and to the public in general.

Rationale: Customers who have better information about reliability will make better decisions about the types and levels of reliability that are appropriate to them.

Arguments For: Competition works best when good information is available to all market participants. Some utilities today cannot provide their customers with system-level reliability performance information, let alone sub-system or customer specific information. Regarding power quality, customers may know that it is a good idea to protect their appliances and equipment, but they may not know that tariffs make it their responsibility to do so, exposing them to significant risk.

Arguments Against: Better information is important and will occur naturally as competition between utilities grows. In the past, most utilities have not been able to provide detailed reliability information to customers because the data were too expensive to gather and manage. Such information is becoming more cost effective and as it becomes available it will find its way to the customer.

3. *Establish Requirements for Emergency Preparedness Planning*

Description: Require utilities to take consistent and uniform steps to prepare for response to emergencies. Steps could include: preparing response plans, meeting mutual aid standards, participating in exercises and conducting joint planning with local emergency response agencies.

Rationale: Requiring utilities to take certain proven steps to prepare for emergencies guarantees a minimum level of preparedness by all utilities. Standardization also facilitates the exchange of information improving both preparedness and response. Improved response will reduce the length and impact of storm-caused interruptions (SAIDI).

Arguments For: Emergency response does not involve guesswork. Law enforcement and fire and rescue agencies, including the military services, know what needs to be done and have developed emergency management practices that work. These include developing plans, establishing an appropriate management structure and participating regularly in exercises. These practices are all designed to prepare a responding agency to act quickly and cooperatively with other agencies, the key to success in emergency response. Not all Washington utilities currently take these steps. Requiring them to do so would improve their response capabilities and Washington's reliability.

Arguments Against: It's true that if all Washington's utilities took all these steps response capabilities would improve; but at what price? And is it necessary? There is no evidence that a small utility that doesn't have a written plan and that doesn't participate in annual exercises *needs* to improve its response capabilities. The cost of doing so uses capital that could be better spent elsewhere, perhaps on investments that would improve reliability in some other way. Individual utilities should be left to determine on their own the kind of preparedness that is appropriate for them. Emergencies are public relations nightmares for utilities and provide sufficient incentive to develop adequate response capabilities. A standard is not required.

4. Set Programmatic Standards for Key Reliability Programs such as System Maintenance and Vegetation Management

Description: Establish facility maintenance and inspection standards designed to address factors that are likely to affect system performance, such as vegetation management and system maintenance. Standards might be general, such as the requirement to have a tree trimming plan and to set trimming cycles, or they could be more prescriptive such as the requirement to trim trees within a specified time cycle and to keep branches clear from lines to a specified distance. The standards could be set on a uniform, statewide basis, or they could be set on a utility-specific basis. Oregon and California have established standards that are a mix of statewide and utility-specific programmatic maintenance and inspection standards.

Rationale: Maintenance and inspection standards ensure utilities will take specific actions that have been proven to have a positive effect on reliability.

Arguments For: A clear set of standards for system maintenance informs utilities and customers alike of what actions should and will be taken to keep the distribution system in good working order. Focusing standards on parts of the system that most affect its reliable operation should ensure that actions taken are cost-effective. Establishing state-level standards that are general and local level standards that are specific allows for local circumstances to be reflected in standard-setting.

Arguments Against: The factors that affect system reliability vary from utility to utility. Statewide standards, even if general, may not capture those issues that are most important for any particular utility and therefore may be of little value. More specific statewide standards may impose requirements that are not relevant or effective in specific local circumstances. Even if standards are set at the local level, requiring them to address specific issues may be too rigid a prescription to allow for local factors to be prioritized. Some trees do not need to be trimmed very often. Some transformers do not need to be inspected very often. Dedicating resources to do unnecessary work in order to meet a standard will mean that more appropriate work will not be done.

8.5.1.2 Institutional and Market Issues

1. Clarify Distribution Company Authorities and Obligations.

Description: Clarify utility service obligations. Establish a more definitive service territory policy. Establish a policy for addressing stranded costs associated with reliability investments.

Rationale: Clarifying distribution company obligations would allow for better assessment of the risks of various reliability investments. For example, requiring that customers who take market access and accept market risks be responsible for their own supply arrangements frees the utility from making most supply investments on their behalf. Allowing distribution companies to establish stranded cost charges or exit fees would provide greater certainty that reliability investments will be recovered. Strategies to clarify utility obligations, service territories, and conditions for market access are discussed in greater detail, along with arguments for and against, in Section 4.0

2. Set Electricity Rates to Represent More Accurately the Costs of Providing Reliable Service.

Description: Allow or require rates to be set for electricity service in a manner that more closely reflects the costs of reliability. Encourage the implementation of alternatives that allow for different levels of grid reliability and opportunities for customers to enhance the service provided by the grid at their own cost. For example, rates could include a reliability component that differed for urban, rural, island or other customers and that was set based on the cost of achieving a certain level of reliability in that area. Communities could vote on investment alternatives (such as undergrounding) that would improve their reliability and incur a portion of the cost as a rate adder. Approaches similar to this are being implemented in the United Kingdom.[30]

Rationale: This alternative would “improve” reliability in the sense that it would allow customers to experience levels of reliability suited to their choice. It would promote equity in payment for reliability rather than in level of reliability.

Arguments For: Customers differ greatly in the level of reliability they need, want and are willing to pay for. Current rate structures do not address those differences and send few cost signals to customers about alternative levels of service. Precedent for a customer-specific cost-based approach already exists in line-extension policies. This concept builds on the line-extension approach. Better pricing will encourage the implementation of reliability alternatives and create an industry that delivers appropriate reliability at appropriate prices.

Arguments Against: Cost unbundling studies make clear how difficult it is to allocate costs to classes let alone to individual customers. Line extension is a distinct service, far more amenable to distinct rate treatment than reliability. Reliability is a general characteristic of the distribution system that should be priced at average cost for all customers served by the system. Electric service is essential to the economy and quality of life of all citizens of the state. Allocation of the costs of reliability to specific customers and extensive reliance on customer-funded alternatives, rather than on a universal level of reliability, will eventually limit reliable service to those who can afford it.

3. Encourage Manufacture of Equipment Less Sensitive to Power Quality Problems.

Description: Develop and implement ways to encourage or require manufacturers to produce appliances and equipment that are less sensitive to surges, sags, or other power quality problems. Federal standards and government/industry initiatives are two examples of ways to influence manufacturer practices.

Rationale: Encouraging the equipment and appliance market to produce equipment that is more forgiving of power quality variation will reduce the importance and potential expense of maintaining rigid power quality standards on the distribution system.

Arguments For: Because of manufacturing economies of scale, building protection directly into a device can often be done for less money than it costs to purchase an external protective device. Manufacturers would also be more likely to know what kind and level of protective devices were required and to install them appropriately. Cost, risk and inconvenience would be reduced for the customer.

Arguments Against: Making equipment and appliances less vulnerable to power quality problems could raise production costs and prices. Manufacturers may oppose establishment of standards. Bundling such devices in equipment and appliances may undermine the market for external equipment and the ability of customers to choose their own levels of power quality protection. An array of external protective devices has been developed in response to the sensitivity of equipment, including devices that soon may protect the entire home. If consumers value products that provide either external or internal protection sufficiently, this may provide sufficient incentive to manufacturers to solve this problem without standards. Providing greater information to consumers about power quality issues would help create a market for less sensitive equipment.

4. Establish Reliability-Based Forest Practice Laws and Regulations.

Description: Establish policies and regulations that either disallow forest practices that place power lines at significant risk or that facilitate mitigation of risks to power lines. Ensure that power issues are addressed in forest practice application processes.

Rationale: Disallowing forest practices that place power lines at risk will improve reliability, especially in regions in Washington that experience rapid suburban development. Enforcing forest-practice power requirements would reduce activities that place power lines at risk. Requiring those who put power lines at risk to pay to reduce that risk or for damages caused would act as an incentive to reduce forest practices that adversely affect electricity reliability.

Arguments For: Cutting trees to allow very thin stands abreast power lines creates significant reliability risk. Such practices should not be allowed, or those who benefit from such cutting should bear the burden for the risk or damage that results. At the least, a way should be found to ensure that utilities have an opportunity to work with the public before cutting begins. A good first step is to ensure that power related issues remain on the forest practices application so that utilities can benefit from practical access to the information generated by these applications.

Arguments Against: Disallowing current practices that place risk on power lines may significantly reduce the amount of developable land in Washington and concomitant jobs and revenue. Utilities can purchase wider rights-of-way to ensure that there are no thin tree stands that put lines at risk.

8.5.2 Reliability Enhancing Strategies: Generation and Transmission Sector.

1. *Mandate Minimum Levels of Generation Reserves be Maintained.*

Description: Establish that power providers or distribution companies must maintain, by plant or contract, some level of reserves.

Rationale: The availability of a reserve margin protects the system against power shortages. Mandating the acquisition of reserves guarantees their availability.

Arguments For: While market forces *may* facilitate construction of sufficient and timely supplies, they do not guarantee it. Mandating reserves guarantees sufficiency at a specific level above market supply.

Arguments Against: Mandating a specific level of reserves can lead to the construction of unused, uneconomic plant. Instead, the notion of long-term supply sufficiency should be separated from short-term contingency-caused supply problems. Market mechanisms should be fostered to deal with contingencies. (see following strategy)

2. *Facilitate Development of Market Mechanisms to Address Short Term Supply Shortages.*

Description: Require power providers or distribution utilities to develop specific service and contract alternatives for addressing supply shortage contingencies and authorize them as necessary. For example, these could include a broader application of voluntary curtailment and interruption contracts for customers, or a market for reserves where generators bid in emergency capacity and end users bid in demand reductions. Large-volume customers could be granted access to the market and required to make their own supply sufficiency arrangements.

> *Rationale*: Sufficiency can be attained through decreased demand as well as increased supply. Knowing that a certain level of supply shortage is covered through flexibility in customer demand provides the same security as generation held in reserve.
>
> *Arguments For*: The concepts of appropriate reliability and unbundled services (plus innovative new services) provide a basis for developing new mechanisms for addressing supply shortages. Customers have very different reliability needs and some may be willing to voluntarily reduce their consumption if the alternative is to pay high hourly market prices during periods of peak demand. Some European countries have used such energy management programs for years, using radio controls to curtail even residential consumption during peak demand periods.
>
> *Arguments Against*: These approaches will develop naturally; there is no need to require utilities to develop them. The market itself has evolved as a way to address short-term supply shortages._Some alternatives, such as installing controls to curtail loads, may be costly to implement, and should be voluntary, rather than mandatory. Competition should lead to the development of cost-effective alternatives.

3. Establish an Independent System Operator, TRANSCO, or other Independent Transmission Management Organization.

Description: Work with regional and western transmission-owning utilities to form an independent transmission management organization. Such organizations can take many forms depending on profit or non-profit status and scope of operation. The Federal Energy Regulatory Commission is promoting the formation of Independent System Operators (ISOs). ISOs have already been formed in California, New England, the Pennsylvania-New Jersey-Maryland region (PJM), and the Midwest. These new entities exercise direct operational control over regional, high-voltage transmission systems, and either operate or coordinate operations of lower-voltage, subtransmission systems. While the primary purpose for forming independent transmission management organizations, such as ISOs, is to facilitate competitive wholesale markets, they may also have transmission reliability benefits. This strategy is also described in Sections 3.0 and 4.0.

> *Rationale*: An independent transmission management organization could be an effective response to potential reliability problems on the bulk power system. Utilities that own both transmission and generation have an incentive to operate the transmission system in ways that benefit their own generation, potentially undermining system reliability. By operating the transmission system over a wider area, an ISO may have access to better information

about developing reliability problems in real time. Finally, a transmission management organization would exercise control over all parties that might affect transmission reliability, including utility and non-utility generators.

Arguments For: The current system of fragmented transmission ownership is not sustainable in a more competitive industry. Utilities currently have some financial incentive to operate the system unreliably, since doing so may benefit associated businesses, while the consequences are just as likely to be borne by competitors as by the utility that caused the problem. States are unable to exercise effective authority over transmission owners because of the inter-state nature of the transmission grid, and attempts to create enhanced federal authority may not go anywhere. Even if Congress passes mandatory standards, enforcement is likely to be spotty, at best. And the rapidly increasing number and complexity of transactions scheduled across the transmission grid greatly increases the likelihood of errors and breakdowns in communications between neighboring control areas. The current system is not designed to ensure reliability in a competitive electric market.

Arguments Against: There is no evidence that the transmission system has experienced decreasing reliability as a result of changes in power markets. The current system of voluntary compliance with WSCC standards will be sufficient to carry the region through until the formation of NAERO. Mandatory compliance with standards set by NAERO, or a western equivalent, is a better way to ensure grid reliability while not disturbing the current system of utility control areas. The dominance of BPA and the publicly-owned utilities in the Northwest greatly complicates the formation of a transmission management organization, especially a privately-owned one operated for profit. Certain models are likely to shift costs from other states to Washington. An ISO that covers a wide region may actually *decrease* reliability because it will not be sufficiently attuned to reliability issues that are specific to local areas. Attempts to implement congestion management schemes that change the way transmission is currently scheduled in the WSCC may be risky.

4. Promote Increased Deployment of Distributed Generation

Description: Utilities and the state should increase their support for deployment of distributed generation systems such as fuel cells, microturbines, windmills, or solar systems. A further description of these technologies is included in Section 2.0 and programs that might be considered to encourage their implementation are described in Section 9.0.

Rationale: Strategically placed utility-scale systems could help improve power quality on the distribution system and reduce system losses. Larger systems, such as cogeneration, can help provide reliable power to areas that are transmission-constrained. Residential-scale distributed systems such as solar panels or fuel cells can provide enhanced reliability to on-grid customers located in areas where interruptions are a chronic problem. They are in some cases the most cost-effective way to serve off-grid customers.

Arguments For: Large commercial and industrial buildings are an increasingly attractive target market for vendors of fuel cells and microturbines. Residential-scale systems can also be cost-effective in some circumstances, particularly off-grid or in areas where reliability is a problem. To the extent that customers bear the majority of the cost of these systems, their deployment increases the likelihood that customers will pay for and get the level of reliability they desire.

Arguments Against: Integrating distributed systems may pose technical challenges. Utilities should not use ratepayer money and the state should not use taxpayer money to provide financial support to projects that provide a benefit only to individual parties. Increased deployment of distributed systems might lead to stranding of distribution or transmission costs.

Endnotes Section 8.0

1. The study directed by ESSHB 2831 was conducted simultaneously as this report directed by ESSB 6560. Washington's legislature passed both bills in 1998.

2. IEEE proposed standard P1366 Guidelines, developed by the Task Force on Distribution Reliability Indices.

3. One of Washington's utilities, which generally does not track interruptions statistically, counted all its interruptions, including those caused by lightning that may have lasted only a second or two. The utility calculated a SAIFI of 8.3 interruptions (per customer per year). This contrasts to an average SAIFI of 1.24 for utilities reporting only sustained interruptions. It is impossible to say whether the utilities with the lower SAIFI actually have better reliability, because they do not count momentary interruptions.

4. In the following example, a hypothetical event is described along with the calculation of a correct SAIFI and SAIDI ratio — assuming that all necessary data are collected. Following the description is an examination of the potential data inconsistencies that can result from different data collection approaches and limitations.

Imagine a tree falls at the halfway point on a feeder line that serves 20,000 customers. An automatic recloser (breaker) takes the whole line out for 5 seconds, then recloses, re-energizing the line. The fault is still there when it recloses and so it reopens again for 10 seconds. When it recloses the second time fuses blow and the faulted section is cut off from the first half of the feeder. Therefore half the customers are safely restored after 2 interruptions lasting 15 seconds; the remaining customers experience a third interruption. Thirty minutes later a utility crew is able to switch some of the remaining customers (25% of the feeder) temporarily to another circuit, restoring them to power. Fixing the line break takes 3 hours at which point some customers are immediately restored while others are restored block by block as blown fuses are replaced.

The actual customer interruptions and duration would be calculated thus:

10,000 x 15 seconds +

5,000 x (15 seconds + 30 minutes)+

4,975 x (15 seconds + 30 minutes + 3 hours)+

5 x (15 seconds + 30 minutes + 3 hours + 5 minutes)+

5 x (15 seconds + 30 minutes + 3 hours + 10 minutes)+

5 x (15 seconds + 30 minutes + 3 hours + 15 minutes)+

5 x (15 seconds + 30 minutes + 3 hours + 20 minutes)+

5 x (15 seconds + 30 minutes + 3 hours + 25 minutes).

This leads to a total of 2 interruptions for 10,000 customers and 3 interruptions for 10,000 customers, or 50,000 customer interruptions and a total of 1,205,375 minutes of interruption. Interruption indices would be calculated thus:

SAIFI = 50,000 / 20,000 = 2.5 (interruptions per customer)

SAIDI = 1,205,375 / 20,000 = 60.27 (average minutes of interruption for each customer)

In actuality, utilities would not calculate this number.

First, most utilities would not count interruptions lasting less than five minutes. This would result in a reduction of SAIFI by 60 percent, from 2.5 to 1, and slightly reduce SAIDI by the 15 seconds of interruption experienced by all 20,000 customers. This practice is consistent with the proposed industry standard.

Second, most utilities would not know where the power was out. They would wait until they received a phone call from a customer to start the time of duration and send a crew to find the fault and see how many customers were affected. This would result in undercounting duration because some time would likely elapse between the start of the interruption and the first phone call.

Third, some utilities track the impact of switching and other aspects of incremental restoration while others do not. This would result in a duration difference between utilities because some would report the number of customers restored by switching and others would continue to count them as without power. In fact, some utilities would count all the customers without power until the last customer was restored. This would lead to an over-counting of duration, which would offset the undercounting that occurred above, but to what degree?

Fourth, utilities use different methods to estimate the number of customers affected. Some utilities do not know how many customers are on individual feeders; numbers change frequently due to new development and the reconfiguration of circuits. Other utilities attempt to keep accurate customer counts updated monthly to the level of laterals (shorter lines connected to a large feeder). In other cases crews on the scene estimate the number of affected customers. Differences in estimating techniques can have significant effects on calculated SAIFIs and SAIDIs.

5. Average refers to an arithmetic mean, where the total number of interruptions (or minutes of interruption) is divided by the total number of customers. Calculations were made using the best available data provided only by utilities that were subject to the study.

6. Data from two utilities was dropped from the statewide analysis because they reported momentaries as well as sustained interruptions (those lasting more than five minutes). They reported SAIFIs as high as 8.3 (interruptions per customer). Their SAIDIs (minutes of interruption) were comparable to other utilities, reflecting that fact that many very short interruptions do not add up to many minutes of duration. Occasional outlier and questionable data were also dropped from the analysis.

7. The United Kingdom requires utilities to report customer level reliability. However, not all UK utilities have that capability. France requires utilities to provide prospective customers with a five-year reliability profile (power delivery and power quality). That capability is not yet in place for all French utilities.

8. Data are from a period that included some severe winter weather (Jan./Feb. 1997) and more mild winter weather (Nov./Dec. 1997). This may indicate that these percentages are typical.

9. The highest expenditure per mile of distribution line was reported by Seattle City Light, the next highest expenditure was $5,991. Seattle City Light has a high customer density of 199 customers per mile of distribution line and a major urban network that is different from any other in the state.

10. Some utilities monitor key locations on a regular basis, such as substations. Temporary monitoring at customer locations occurs when a problem has been discovered or a complaint has been made.

11. 6560 Study - Topic Area Meeting - Reliability, July 8, 1998.

12. In 1998, 8 of 14 recorded complaints addressed the same power quality problem. Counting these only once, the total for 1998 would be seven – slightly higher than some years and less than others, though 1998 is not yet over.

13. WAC 194-22: Washington State Curtailment Plan for Electric Energy. Most utilities offer "interruptible" contracts to large industries. Utility-requested or state-mandated curtailment does not refer to such contracts and would only occur after these contracts had already been invoked.

14. Bonneville Power Administration, *1997 Pacific Northwest Loads and Resources Study*, December, 1997.

15. 6560 Study – Area Topic Meeting – Reliability: July 8, 1998.

16. This simple analysis only looks at 1997 versus the beginning year of the data, which varies by utility. It does not look at intervening years. A utility could have an anomalous beginning or ending year that would affect the results. That does not appear to be the case. While data differs substantially across the individual years for some utilities, the data trend is firm. No utility appeared to have a noticeably anomalous beginning or ending year.

17. In the future, non-utility entities may desire to construct and operate infrastructure that normally has been the responsibility of utilities. The NEC exempts construction from its standards based on whether or not it will eventually be owned and operated by a utility (as indicated by a utility license). Non-utility operators may be discouraged from constructing and offering these services if they are subject to the NEC.

18. A typical tariff reads, "...the customer shall provide adequate protection for equipment, data, operations, work and property under his control from (a) high and low voltage, (b) surges, harmonics, and transients in voltage, and (c) overcurrent..." Puget Sound Energy, Schedule 80, General Rules and Provisions, #10.

19. WAC 480-100-186 regulates frequency. WAC 480-100-191 regulates voltage.

20. When a customer reports a problem, a utility may set up equipment at a specific location to see if the problem is reoccurring. If it was a one-time event, it will not be recorded. Some utilities locate monitoring equipment at key locations. This kind of monitoring may increase if technological capabilities continue to bring the cost of such equipment down and if utilities begin to find such information more valuable.

21. WAC 480-100-186.

22. "Compliance," means that equipment is *not* vulnerable to problems that can arise when microprocessor dates change from 1999 to 2000.

23. There is no clear distinction between which facilities are transmission and which are distribution. High-voltage facilities whose main purpose is transmitting bulk power over long distances are clearly transmission. Low voltage facilities whose main purpose is transmitting power to individual homes and businesses are clearly distribution. The facilities that fall in-between are known as sub-transmission and can be classified as either transmission or distribution, depending on their primary function.

24. For example, power purchases by U.S. IOUs increased from 563 TWh in 1990 to 843 TWh in 1996, while sales for resale increased from 444 TWh to 608 TWh over the same period. Energy Information Administration*, The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, July, 1998, Table 9.

25. In November of 1998, Montana Power and Puget Sound Energy announced that they reached agreement to sell these facilities to Pennsylvania Power and Light.

26. The Washington Energy Facility Site Evaluation Council (EFSEC) has approved permits for three commercial combustion turbine facility sites at Satsop, Chehalis and Creston, Washington. The three units represent a maximum of approximately 1,648 megawatts capacity. Additional sites have been approved in Oregon.

27. See CEC news release at http://www.energy.ca.gov/releases/98_releases/98-07-23_powerprojects.html

28. California Energy Commission, Wholesale Energy Price Review, September 1998, http://www.energy.ca.gov/electricity/wepr/9809WEPR.HTM

29. For example, investor-owned utilities must "…endeavor to avoid interruptions of service, and, when such interruptions occur, …reestablish service with a minimum of delay." WAC 480-100-076

30. Dr. Brian Wharmby. United Kingdom Office of Electricity Regulation. Speech at conference Reliability in a Deregulated Market. Arlington, Virginia, September, 1998.

9.0 Conservation, Renewables, and Low-Income Energy Services

Scope: ESSB 6560 directs the WUTC and CTED to study and report on current levels of investment in conservation, non-hydro renewable resources, and low-income energy services; trends affecting such investment; and ways to fairly, efficiently, and effectively foster future achievement of the purposes of such investment. Discussion and description of strategies in this report does not imply a recommendation on the part of CTED and or the WUTC.

Methodology: The two agencies developed a survey and used it to collect data from the participating electric utilities, the Department of Community, Trade and Economic Development's Housing and Community Services Divisions (for low-income data), the Bonneville Power Administration, industrial self-generators using renewable resources, the Northwest Power Planning Council and the Northwest Energy Efficiency Alliance. Seventeen utilities completed and returned the surveys, though some did not have all the data available for reporting. The survey focused on investments in conservation, savings achievements, financial support for low-income customers, qualifications for determining low-income eligibility, investments in weatherization, and the amount of electricity generated from renewable resources and sold to Washington customers.

In addition, agency staff held a workshop with stakeholders and researched relevant federal and state statutes, reports on public purpose legislation in the other states, and documents on current trends affecting public purposes.

This section includes a brief history of policies guiding collective investment in energy efficiency, renewable resources, and low-income services (collectively "electricity system benefits" or "public purposes"). Each of these electricity system benefits is described using a common format:

- a brief summary of important points,
- a discussion of policy goals and statutes,
- a discussion of current investment and achievement,
- a description of trends affecting investment and achievement, and
- the industry's current responses to those trends.

Section 9 includes a brief status report on the way public purposes have been addressed in states that have adopted retail competition for electricity service, and concludes with a discussion of policy strategies and administrative mechanisms for achieving public purpose goals.

9.1 Introduction

State and federal governments have adopted many policies in support of an electricity system that provides energy service at the lowest total cost and access to affordable energy services for all. These two primary policy goals - minimizing total system costs[1] and providing universal access - are the rationale for achieving conservation, renewable resource development and delivery of low-income energy services. Other benefits associated with these electric system benefits may include environmental quality, improved service, more comfortable homes, economic development and more competitive businesses.

This study focuses on the electricity industry, as directed by the legislation. However, many of the policy goals and market barriers that are relevant to achieving conservation, developing renewable resources and delivering low-income energy services in the electricity system are also applicable to other energy markets.

9.1.2 History/background

As the Northwest developed its hydropower-based electricity system, low-priced supplies became abundant. The Northwest was not densely populated, and large hydropower projects created a supply surplus. The projects were also intended to spur the economic development of the region. Hydroelectric generation was the cleanest power generation choice available at the time. With ample supplies and low prices, efficient use was not a priority.

The seeds of change were planted as Washington grew and developed during the 1960's. With demand growing and choice hydropower sites gone, planners turned to thermal plants, using steam generated by the heat of nuclear fission, coal, and other combustion sources, as new generation resources. Regional utilities began an ambitious program of nuclear and coal plant development to meet projections of rapidly and continuously increasing demand.

The oil embargo of the 1970's set in motion a number of economic and institutional changes that altered these plans forever. Higher energy prices produced a textbook economic result - lower demand for energy - that in turn called into question the need for new generating facilities. Rising inflation produced much higher capital costs for new plants. Greater environmental awareness and activism was manifested in citizen opposition to siting thermal power plants and passage of the Clean Air Act to address pollution from sources such as electricity generation.[2] Risks associated with reliance on imported energy led lawmakers to value energy independence, which in turn led to legislation that spurred the development of independent power producers. Energy efficiency became recognized as a low-cost source of new supply; kilowatt-hours saved through energy efficiency investments could provide the same energy services as kilowatt-hours generated by new power plants, and often at lower cost. This led to the adoption of "least-cost planning" statutes and rules that required utilities to even-handedly and systematically evaluate all supply-side and demand-side alternatives for meeting new demand. Conservation became an integral part of the way utilities acquired the resources necessary to meet their supply obligations.

9.1.3 Regional Power Act

Congress passed the Pacific Northwest Electric Power Planning and Conservation Act (the Regional Act) in 1980 and, in doing so, transformed electricity resource planning in the Northwest. The Regional Act includes conservation and renewable resource development among its primary statutory purposes. It created the Pacific

Northwest Electric Power and Conservation Planning Council (Council) and directed the Council to prepare and adopt 1) a regional conservation and electric power plan (the Plan) and 2) a program to protect, mitigate, and enhance fish and wildlife. Congress directed the Council's Plan to give priority to electricity resources in the following order: first, to conservation; second, to renewable resources; third, to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency; and fourth, to all other resources.

The Regional Act required the Plan to outline a strategy for implementing conservation measures and developing resources to reduce or meet the federal power system's (BPA's) obligations. It empowered the Council to be a regional resource planner, and directed the BPA Administrator, "to the maximum extent practicable, make use of [her] authorities under this Act to acquire conservation measures and renewable resources, to implement conservation measures, and to provide credits and technical and financial assistance for the development and implementation of such resources and measures." [3]

Under the direction of the Regional Act, BPA worked cooperatively with its customers and stakeholders to design and fund energy efficiency research and programs and to investigate and fund renewable energy opportunities through the mid-1990s.

9.2 Conservation

Summary: Energy efficiency has strong policy support in federal and Washington state laws. Utility investment in conservation as a power resource has declined significantly from its peak five years ago. Key trends include the advent of competition, a dramatic decrease in BPA funding, a decrease in the avoided cost of power, and a greater focus on market transformation and commercial and industrial programs.

9.2.1 Conservation Policy Goals and Statutory Background

As early as the 1930s and throughout the late 1970's and early 1980's, federal and state lawmakers articulated strong policy support for energy efficiency and conservation. This support developed during a period of utility and government construction of large, long lead-time generating resources, high avoided costs, and energy prices that did not reflect the total costs of energy production and distribution. In 1931 the state set forth the purpose of public utility districts to, "conserve the water and power resources of the State of Washington for the benefit of the people thereof,…" (RCW 54.04.020). Energy efficiency and conservation were also established as policy objectives for municipal utilities, irrigation districts, state and other publicly-owned buildings managed by the Department of General Administration; the Utilities and Transportation Commission; the state building code, the state's clean air and solid waste programs, and the low-income weatherization program. The constitutional ban against lending public credit has been amended three times to provide exceptions for investments in energy efficiency. (See Appendix 9.1 for a more complete list of legislative policy related to energy efficiency). In these laws, the legislature has articulated several policy rationales for favoring energy conservation and efficiency:

- To eliminate wasteful and uneconomic uses of energy and materials. [RCW 43.21F.015]
- To use energy efficiently. [RCW 19.27A.015]
- To reduce environmental impacts related to energy consumption, including air pollution. [RCW 70.94.011 and 39.35 RCW]
- To reduce the operating costs of state-run facilities. [39.35 RCW]
- To reduce the risk of energy shortages due to growth. [RCW 80.04.250]
- To provide a reliable supply of energy based on renewable resources. [RCW 80.28.024]
- To provide incentives to public and private utilities to invest in conservation measures. [RCWs 80.28.024, 80.28.025, and 80.28.303]
- To assist owners of structures and equipment in investing in energy conservation [RCW 54.16.280].

Conservation and energy efficiency have also been prominent policies in federal laws over the past 20 years, including the National Energy Act (1978), the Public Utility Regulatory Policies Act (PURPA) (1978), the Pacific Northwest Electric Power Planning and Conservation Act (1980 Public Law 96-051), the National Appliance Energy Conservation Act (1987), and the National Energy Policy Act of 1992 (EPAct).

The Utilities and Transportation Commission adopted a least-cost planning regulation in 1987 (WAC 480-100-251) that requires investor-owned electric utilities to evaluate energy efficiency and supply-side investments on an equivalent basis and to select the lowest-cost way of meeting demand.

Washington's Energy Strategy, prepared in 1992 and adopted by the legislature in 1993, contains many recommendations for delivering system benefits. It recommends:

- All cost effective conservation and efficiency opportunities should be pursued aggressively in both public and private utility markets.
- Improve the ability to evaluate the full range of benefits from renewable energy technologies, e.g. by explicitly considering fuel diversity, resource cost, environmental impact, system reliability, risk of future environmental regulations on energy sources, and exposure to fuel price risk.
- Ensure that low-income weatherization programs address energy savings for the largest number of low-income citizens possible.

The 1996 Comprehensive Review of the Northwest Energy System, convened by the governors of Idaho, Montana, Oregon, and Washington, recommended "that all cost-effective electric efficiency opportunities be captured in a manner consistent with increasingly competitive electricity markets." The Review further recommended that nearly 2% of system revenues (approximately $73 million annually in Washington) be targeted to local and market transformation energy efficiency investments for at least a ten-year period.

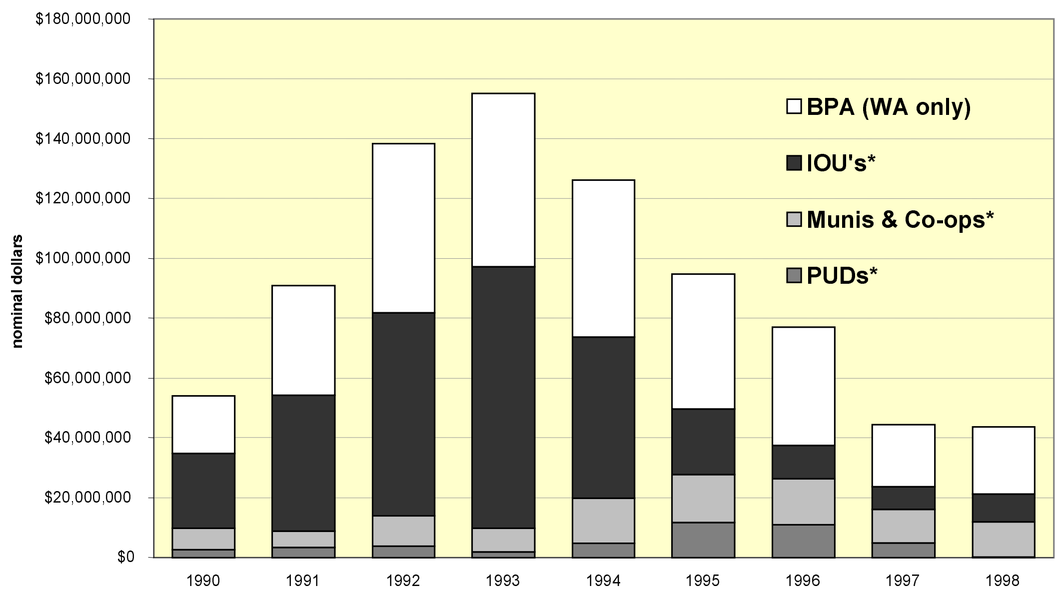
9.2.2 Conservation Investment Data

The combined efforts of utilities, the Bonneville Power Administration, consumers and state government in the Pacific Northwest delivered some of the most successful electric conservation and research programs in the country between the late 1970s and early 1990s. The rationale for utilities' active pursuit of conservation stemmed from the fact that, during this period, substantial energy savings could be acquired for less than the cost of new generation or other power supply alternatives. When utilities acquired conservation at a lower cost than these alternatives, the total cost of electricity service was reduced.

It is still the case that many energy efficiency measures are available that deliver saved energy for less than the cost of new supplies. However the costs of new generation and power supply alternatives in the wholesale market have declined since the early 1990s. Some efficiency measures that were cost-effective relative to new coal or nuclear plants are not cost-effective relative to today's combustion turbines or wholesale market purchases. Even cost-effective efficiency measures have become less attractive to utilities because they reduce electricity sales and may put upward pressure on rates. And, because of uncertainty regarding future market structure and service obligations, many utilities may be reluctant to make long-term resource investments of any kind.

Figure 9.1 and Table 9.2 show total investment in conservation programs by utilities responding to data requests for this report. These tables also include the weatherization and conservation investments that BPA made in Washington state. BPA's investments were distributed through the utilities, the state's energy code program, the aluminum industries and to government agencies providing technical assistance. (This study does not include data on non-utility private sector investment in conservation.) Responding utilities represent 86% of Washington utility sales. Conservation investment peaked in 1993, when utilities reported spending over $155 million, but has declined significantly in recent years to less than one-third this amount. BPA funding has declined steadily since 1993, when its investment in Washington was at least $58 million. After 1999, Bonneville expects to limit its funding to $10 -$12 million in regional market transformation. (BPA is considering a rate discount proposal to stimulate further conservation in the region. See 9.2.6.) See Appendix 9.2 for utility reported conservation investment data.

Figure 9.1 Electric Utility Conservation Expenditure Estimates in Washington



*Data submitted by utilities, and Bonneville Power Administration

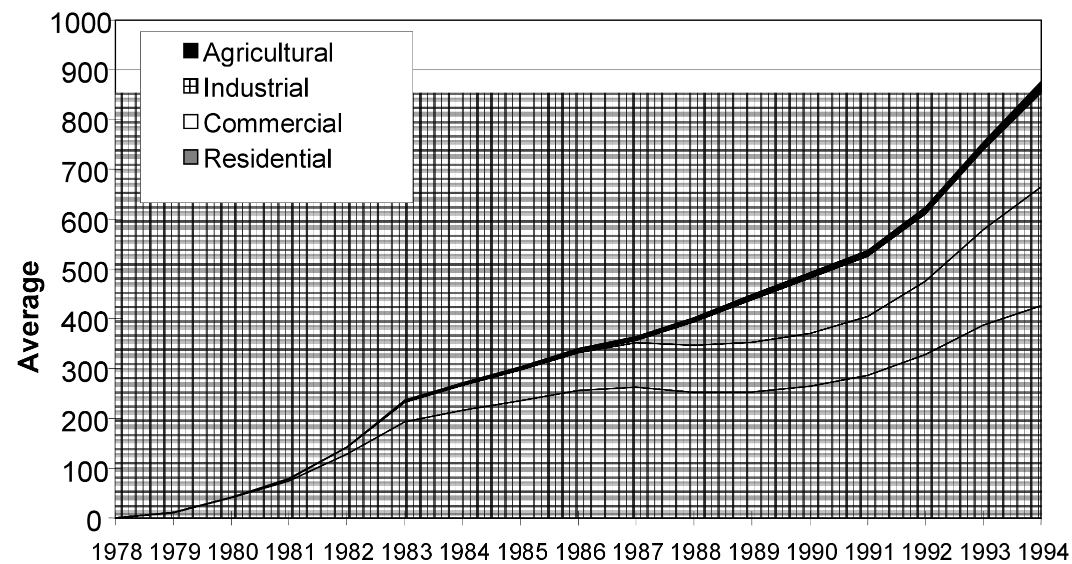
Table 9.2 Total Investments in Conservation (millions of dollars)

	Year	Dollars/year Constant 1997$	Dollars/year Current $	BPA Dollars Current $	Percent from BPA
	1990	64.37	54.04	19.21	36%
	1991	104.43	90.91	36.72	40%
	1992	154.77	138.47	56.6	41%
	1993	169.14	155.08	57.82	37%
	1994	134.57	126.24	52.66	42%
	1995	98.47	94.73	45.2	48%
	1996	78.39	77.05	39.54	51%
	1997	44.45	44.45	20.86	47%
Est.	1998	42.53	43.59	22.42	51%

9.2.3 Conservation Achievement

According to the 1996 Northwest Power Plan, the region's utilities **acquired** over 800 average megawatts of cumulative electricity savings from 1979 to 1995. (See Figure 9.3.) New codes and standards (including Washington State energy codes, and new federal commercial heating, ventilating and air conditioning systems and lighting equipment standards) will save about 165 aMW over the next 18 years. Federal standards for clothes washers, dishwashers and showerheads are projected to save the region 140 aMW. New energy efficiency standards for manufactured housing, in combination with the region's Manufactured Housing Acquisition Program (MAP), successfully transformed the energy efficiency of new manufactured homes. As a result, under the Council's medium electricity load forecast, space heating loads for manufactured homes across the Northwest in the year 2015 will be approximately 270 aMW lower than would have been the case without the standards.

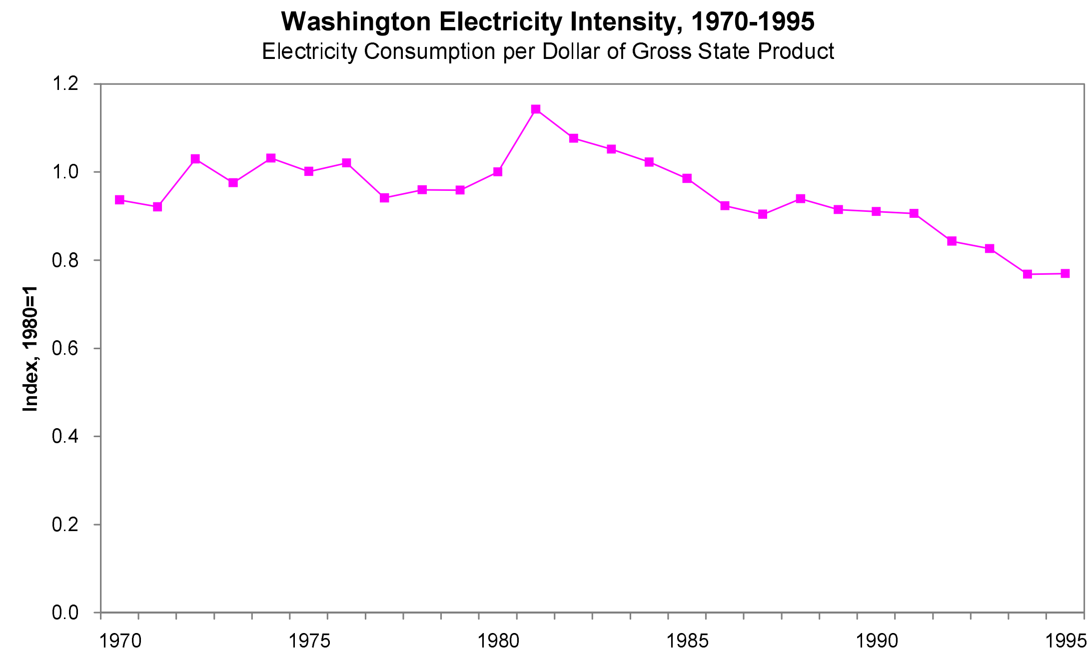
Figure 9.3 Regional Summary of Cumulative Conservation Savings by Sector, Available 1979-1995, in Average Megawatts



Source The 1996 Green Book, Northwest Power Planning Counci

This investment in conservation has produced substantial and continuing benefits in efficiency for Washington homes and businesses. Due to a variety of factors including economic changes, fuel switching, and investments in energy efficiency, average Northwest electricity use per residence declined about 13% from its peak in 1982.[4] Regional per capita electricity use declined 10% between 1990 and 1996.[5] Washington's electricity intensity, defined as electricity consumption per dollar of gross state output, declined 20% between 1985 and 1995. See Figure 9.4.

Figure 9.4



Sources: Energy Information Administration, Bureau of Economic Analysis

Looking forward, the Council estimates the regional potential for additional cost-effective conservation resources over the next 20 years to be over 1,500 aMW, nearly one-and-one-half times the electricity use of the City of Seattle. This does not include the efficiency potential in the aluminum industry, which the Council has not estimated. About one-third of this available conservation is in non-aluminum industrial facilities. (Stakeholders dispute whether the Council's industrial estimates are too high or too low.) The energy savings potential of other technologies or processes is listed below in Table 9.5. The average levelized cost of these resources is approximately 1.7 cents per kilowatt-hour, roughly two-thirds of the cost of new generating resources. The Council estimates that market forces alone will capture about 20 percent of this potential.[6] If the remaining 80 percent is not captured by some combination of utility, public, and private actions, the region is projected to spend approximately $1.7 billion in added electricity expenses over the next 20 years.[7] Nearly half of this cost would fall to Washington electricity consumers.

Table 9.5 Average Achievable Conservation

End Use Sector	Average Megawatts	Average Levelized Cost (Cents/kWh)
Freezers	15	1.9
Refrigerators	45	2.9
Water Heating	335	2.0
Residential Lighting	30	2.6
New Residential Space Heating	140	2.1
Existing Residential Space Heating	25	1.8
New Commercial	230	1.3
Existing Commercial	95	1.4
Commercial Renovation/Remodel	50	1.3
New Non-Aluminum Industrial	225	1.5
Existing Non-Aluminum Industrial	335	1.5
Direct Service Aluminum Industrial	Not Estimated	Not Estimated
Irrigated Agriculture	10	1.8
Total	**1.535**	**1.7**

NWPPC, 1996 Nortwest Conseration and Electric Power Plan.

9.2.4 Trends Affecting Energy Efficiency Investments and Achievement

Growing competitive pressure. While no retail restructuring legislation has been adopted in Washington State, many of the competitive pressures accompanying retail access are affecting Washington utilities. As discussed in Section 2, many of Washington's large customers are already eligible for some form of market-based price. Competitive pressure on utilities naturally leads to a focus on minimizing short-term rates. Utilities may be reluctant to fund conservation that reduces energy sales, or places upward pressure on their near-term costs, possibly undermining their competitive position.

With active wholesale competition, BPA energy efficiency funding has declined sharply. BPA dramatically scaled back its conservation budget when the price of wholesale electricity dropped and BPA power became subject to price competition. BPA indicated in 1995 that it would be more appropriate to fund conservation at the retail level.

Lower wholesale energy prices and lower costs for new generation. The rationale for utility investment in conservation has rested on the fact that energy savings may represent a cost-effective alternative to new supply resources. Lower wholesale electricity prices mean that fewer conservation measures may meet standard cost effectiveness tests.

Shift of conservation emphasis to industrial and commercial programs. In the 1980's, most conservation funds were invested in the residential sector.[8] Through the late 1980s and the 1990s utilities and BPA directed increasing proportions of efficiency funds to the commercial and industrial sector. Survey data indicate that by 1998, Washington utilities are directing 75 percent of their budgets to commercial and industrial programs and 25 percent of their budgets to residential programs. The Council's most recent plan estimates that roughly a third of the region's cost-effective conservation potential is in the industrial sector.[9] These are the customer sectors that are also most interested in competitive retail electricity markets.

Focus on regional market transformation. "Market transformation" efforts are designed to secure lasting, self-sustaining improvements in the energy efficiency of buildings and equipment. Since late 1996, the region's investor-owned utilities and BPA have funded a regional non profit organization - the Northwest Energy Efficiency Alliance (Alliance) to administer market transformation efforts. The Alliance's Board is composed of Northwest environmental, utility, government and energy service representatives. The Alliance supports programs ranging from energy efficiency in the microelectronics and food storage industries to resource saving front-loading clothes washers. The Alliance's analysis of its current program mix indicates that its programs are achieving conservation at less than one cent per kWh. The Alliance attributes the low cost of savings to: intervention at high leverage points in the market; implementing programs with non-energy benefits; and securing structural changes to the market that deliver sustained savings over time.

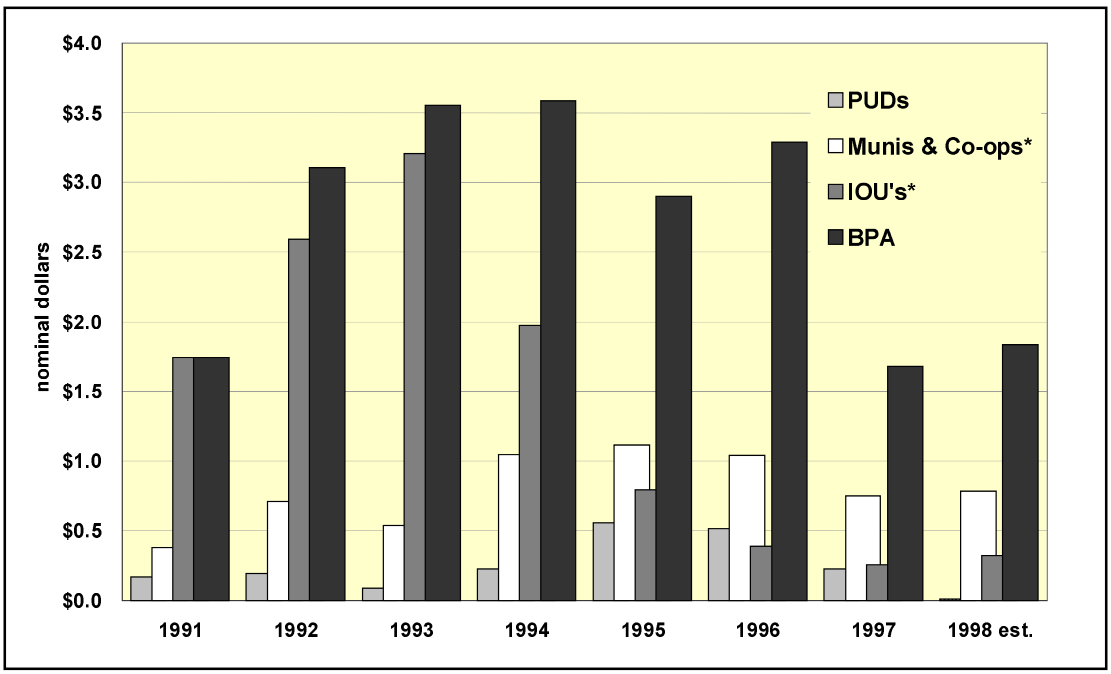
Performance contracting for commercial and industrial consumers. Large commercial, industrial, and institutional customers are increasingly using performance contracting as a way to invest in energy conservation without putting their capital at risk. Under performance contracting, a contractor provides design, capital, construction, and often maintenance for new energy efficient systems or equipment. Energy savings are shared between the contractor (who uses the savings to pay back the capital investment and to make a profit) and the customer. Performance contracting is used extensively to implement federal Executive Order 12902 (March 1994), which called for a 30% reduction in energy consumption at federal buildings within 10 years. The Departments of Energy and Defense have pre-qualified several contractors so individual agencies can choose from the list without having to conduct their own bidding. Federal facilities in Seattle (NOAA) and Auburn (FAA) are among those conducting energy audits.[10] The Washington Department of General Administration has developed a Statewide Energy Savings Performance Contract for use by cities, counties, school districts, the state and other special-use districts interested in improving the efficiency of their energy and utility systems.[11]

9.2.5 Effect of General Trends on Conservation Investment

Utility investment in energy efficiency is declining rapidly. Electric utilities' response to the trends discussed above has generally been to reduce investment in conservation. Expenditures are expected to drop 72% from their high in 1993 to the current levels in 1998. (See Figure 9.6 for investments proportional to electricity sales.) All but two utilities reported recent declines in their conservation budgets. The most commonly cited explanations for budget reductions were that:

- ❖ BPA has discontinued funding for utility programs. BPA cuts were cited by nine utilities as a primary reason for reducing their conservation budgets.
- ❖ Utilities are experimenting with the use of programs that require greater consumer cost-sharing. Washington's utilities are shifting toward loan and information programs and away from programs that involve direct payment for conservation measures. These programs rely on the program participants to bear most or all the costs of efficiency measures. This change has typically been accompanied by a shift in emphasis, from programs focused primarily on savings to programs that offer other services. Nine of the ten residential programs that Washington utilities expect to implement from 1998 to 2000 are either loan or information programs. There are no available data yet on how this shift affects achievement of savings.
- ❖ Competitive pressures - utilities are generally trying to minimize near-term rate impacts, decrease costs, and increase revenues.
- ❖ Two utilities indicated that availability of lower-cost power in the wholesale market has affected their conservation investments.
- ❖ Some utilities indicate they have weatherized most of their housing stock.

Figure 9.6 Conservation Spending per MWh Sales Washington



The status of least cost planning is unclear. Utility investment in conservation over the past two decades has been guided by least cost planning analysis or an integrated resource plan. (WAC 480-100-251 for investor owned utilities; RCW 80.52.080 for public utilities). This analytical process directed utilities to choose the mix of supply and demand side resources that minimize the total cost of service to consumers.

The UTC has recently examined the role of least-cost resource planning and, in its summary of a recent inquiry, stated: "The Commission believes revisions to the [least-cost planning] rule may be appropriate for the purposes of focusing its application to monopoly utility-supplied services, bundled or unbundled. Consequently, the major emphasis should be on planning for generation and energy efficiency resources and distribution services for loads that continue to be served on a monopoly bundled basis, and only on distribution services for those loads to be served on an unbundled basis. Additionally, such planning should focus on maintaining reliability of the distribution network." [WUTC Notice of Termination of Inquiry, Docket #UE-940932, April 22, 1998]

We do not know whether and to what extent consumer-owned utilities are still performing least cost planning analysis. With growing competition and an active wholesale power market, it is increasingly difficult for utilities to conduct a meaningful analysis of future customer load. As competitive pressures mount, and with considerable uncertainty about their responsibilities, many utilities are unwilling to plan as if they will be the sole supplier for their traditional customers.

New funding mechanism for conservation. Prior to 1995, most utilities in the country capitalized the bulk of their conservation costs and recovered those costs in bundled rates. In 1995, Washington Water Power became the first utility in the nation to begin funding its programs through a non-bypassable distribution charge - the Energy Efficiency Tariff Rider. This approach - a type of systems benefit charge to finance conservation programs - enables the utility to collect all the funds necessary to operate efficiency programs in the same year that they spend the funds, and thereby removes the need for the utility to finance the investments. Other companies (including Puget Sound Energy) and some state legislatures across the country have since adopted similar funding mechanisms. Because it can be structured to be competitively neutral, the tariff rider has been considered as a possible funding mechanism for public purposes in the future as the industry moves to a more competitive environment (see 9.6.4).

Declining research and development funds. In order to leverage consumer investments in energy efficient products and processes, program designers rely heavily on research about market infrastructure, consumer preferences, and the capability and reliability of new products. Funding for efficiency-related market and technical research has dropped dramatically in the Northwest and across the country. Such research has, in the past, provided technical, cost, and market data that formed a foundation for many conservation programs, including energy-efficient industrial motors; resource-efficient clothes washers; commercial and residential energy codes; and energy-efficient manufactured homes. BPA was a regional leader in designing and funding energy efficiency research in the past, often bringing in private and industry partners. BPA recently eliminated this function. Nationally, the US General Accounting Office reported that utility investment in electricity R&D decreased by 33 percent between 1993 and 1996.[12]

9.2.6 Recent Developments

BPA subscription incentive proposal. In September 1998, as part of its power subscription process, BPA proposed a rate discount on firm power sales to "customers who voluntarily choose to finance their own development of conservation and renewable resources…In the rate case BPA plans to propose a base discount not to exceed one-half mill [.05 cents per kilowatt-hour] (approximately a total annual discount of $30 million)." BPA reports in its "Final Subscription Document" that, "BPA wants to serve as a catalyst in encouraging its customers to make investments in these important and valuable resources [conservation and renewables]. Further, BPA wants to complement and supplement the efforts of state legislatures and the Northwest Power Planning Council in addressing the regional need to support these resources."

Regional Technical Forum. In 1996, Congress directed BPA and the NWPPC to convene a Regional Technical Forum to develop standardized protocols to verify and evaluate conservation savings, track regional progress toward achieving conservation and renewable resource goals, and recommend ways of improving the effectiveness of programs and activities in the region. In July 1998, the NWPPC issued a proposal to initiate the Regional Technical Forum. The Council proposes that it perform the functions of the Regional Technical Forum with the assistance of a standing advisory committee to ensure broad technical and policy input. The Regional Technical Forum's roles, responsibilities and guiding policy structure are still evolving.

Possible future supply and/or capacity deficits. In late summer, 1998, BPA presented a forecast that estimated a 50% chance of monthly supply deficits during peak periods within 5 years. The NWPPC is evaluating BPA's forecast. (See Section 2.3 and Section 8.) Measures to prevent such a shortfall could include a variety of energy efficiency and load management strategies.

9.3 Renewable Energy

Summary: Renewable energy sources can reduce air emissions, offer less fuel price risk, and provide non-power benefits (e.g. by facilitating waste disposal). Globally, renewable power generation is a growth industry with a declining cost curve. Less than one percent of electricity sales to Washington consumers are generated with non-hydro renewable resources. However, several of the nation's leading renewable energy manufacturers are located in Washington.

9.3.1 Background

Definitions. ESSB 6560 defines renewable resources as: electricity generation facilities fueled by: (a) water; (b) wind; (c) solar energy; (d) geothermal energy; (e) landfill gas; or (f) biomass energy based on solid organic fuels from wood, forest, or field residues, or dedicated energy crops that do not include wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic. Only non-hydro renewable resources are included in the language authorizing this study (Section 5(1)(g)).

Wind energy can be produced anywhere the wind blows with consistent force. As a general rule, the windier the location, the more energy can be produced, and the lower the cost. Wind is an intermittent resource. The ease with which wind can be integrated into the grid and the economic feasibility of wind depend in part on the match between wind availability and patterns of consumer demand. Sites with significant wind energy resources in Washington state are located along the Pacific Ocean coast, the Columbia River corridor bordering Oregon, and the Ellensburg area in Central Washington.[10]

Solar radiation is used to produce electricity in two ways: photovoltaic (PV) systems and solar thermal systems. PV systems change sunlight directly into electricity, and are most commonly used in remote areas where line extensions are costly. However, grid-integrated systems are becoming more common[14]. Solar thermal systems can either be direct applications, such as solar hot water systems, or can generate electricity by using solar energy to heat a fluid that produces steam used to turn a turbine and generator.

Geothermal energy is generated by bringing hot water or steam from subterranean cavities to the earth's surface and using it to spin a generator. Geothermal generation requires ground water at temperatures at or above 300° F., fractured or otherwise highly porous rock, at depths less than 10,000 feet. Washington has modest possibilities for geothermal power generation along Cascade range volcanoes, particularly Mounts Baker, Adams, Rainier, and St. Helens. Geothermal heat can also be used in heat pumps and district heating systems.

Biomass fuels are any organic matter that is available on a renewable basis. ESSB 6560 limits this definition to include only wood, forest or agricultural field residues, or dedicated energy crops that do not include wood pieces that have been treated with chemical preservatives. Biomass can be burned in an incinerator to produce energy.

Biomass - landfill gas and sewage treatment. The legislative definition does not identify landfill gas or use of sewage treatment methane as biomass. However, energy scientists generally categorize both of these as biomass. Anaerobic decay of organic materials, such as in a landfill or sewage treatment plant, produces a gas with high concentrations of methane. Once collected, this gas can either be cleaned to pipeline quality, used to fuel engine-generator sets or small combustion-turbine power plants, used in fuel cells, or sold for use as a boiler fuel.[15]

Fuel cells generate electricity through chemical processes rather than combustion. Most rely on hydrogen for a fuel source. Although they are not included in traditional definitions of renewable resources, fuel cells are an emerging technology that may be an important partner with renewable resources in delivering distributed energy and serving off-grid systems in the future. Unlike biomass plants, fuel cells do not emit traditional pollutants such as nitrous oxide and carbon monoxide into the air. However, the reforming process that extracts hydrogen from a fossil fuel for use in a fuel cell emits carbon dioxide, a contributor to global warming. The long-term renewable potential for fuel cells relies on extracting hydrogen from water and using renewable energy to power the extraction process.

9.3.2 Renewable Policy Goals and Statutory Background

The Legislature has enacted a number of laws to promote the use of wind, geothermal, and small-scale renewable energy. (See Appendix 9.1.) RCW 80.28.025 finds that actions and incentives by state government to encourage the use of renewable resources will be of benefit to the citizens of the state. Meeting energy needs with renewable energy can prevent environmental damage, assist the state in diversifying its energy resources, reduce transmission and distribution costs in remote areas, reduce exposure to fuel price risk and reduce health problems related to air pollution.

Climate Change and Air Quality.[16] Renewable generation sources emit little or no carbon dioxide, the most significant of the “greenhouse gases” to which scientists attribute global warming. (See Section 2.4.2) Wind and solar energy have no atmospheric emissions and contribute no greenhouse gases to the atmosphere. Geothermal plants generally produce substantially fewer emissions than fossil fuel combustion. Biomass combustion releases more pollution than natural gas to generate an equivalent amount of power, but controlled burning of biomass residues for power generation is less polluting than the uncontrolled burning that might otherwise occur.[17] To the extent that renewables contribute to emission reductions, they may improve public health and provide economic benefits due to reduced medical expenditures.

Risk reduction. A diverse resource portfolio that includes renewable resources may reduce exposure to fuel price, technology and environmental risks and uncertainties.

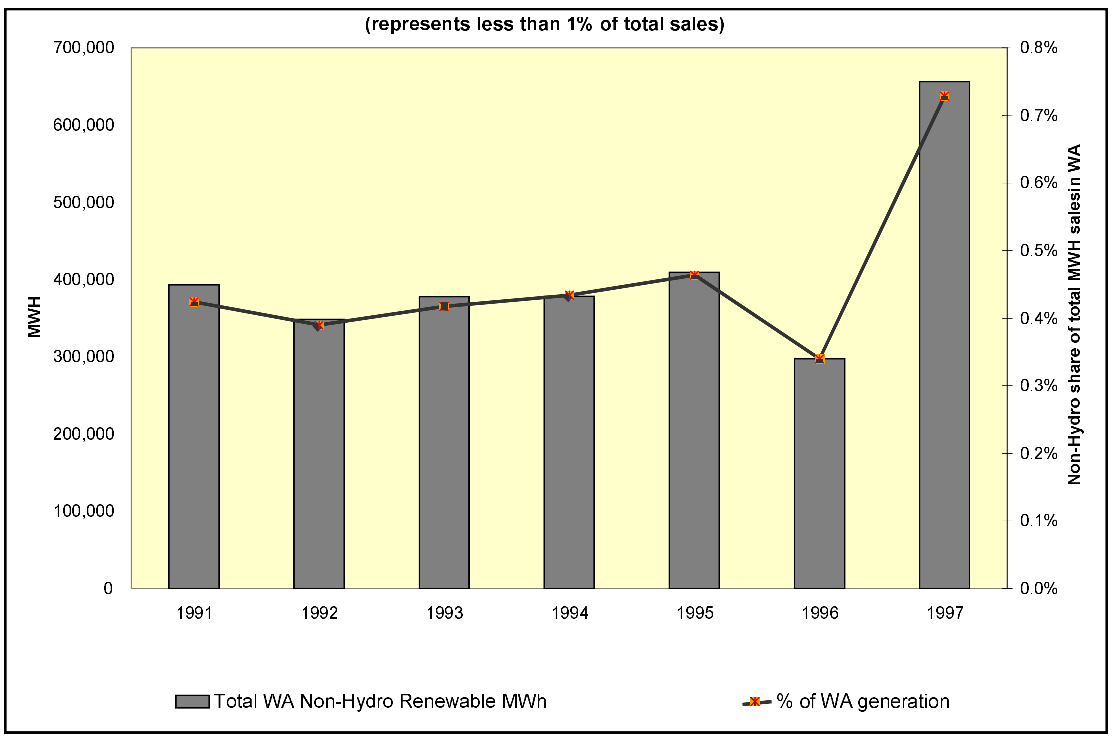
System efficiency improvement. Renewables such as photovoltaics and fuel cells may offer utilities opportunities to improve the overall efficiencies of their systems. As noted in Section 1, about 40% of the cost of providing electricity to a residential consumer is attributable to transmission and distribution. Providing electricity to remote areas can be quite expensive. Distributed resources (smaller scale, locally sited electricity generators, see Section 2.5.2) could be less expensive than some long line extensions, and could also offer reliability benefits. Distributed renewables may also serve to reduce or postpone the need for expansion of transmission and distribution systems.

9.3.3 Current Renewable Resource Initiatives

Non-hydro renewable resources generate less than one percent of the electricity sold by utlitities in the state. Six of 15 utilities that provided data on renewable resourses for this report supply some form of renewable power or are considering doing so in the near future. As shown in Figure 9.7, non-hydro renewable resource use increased significantly in 1997, with biomass as the most utilized source. Landfill and sewage treatment gas recovery offer non-power benefits by facilitating waste disposal and reducing methane gas that would otherwise be released to the atmosphere. (Methane is a much more potent contributor to global warming than carbon dioxide.) See Appendix 9.2 for utility reported data on renewable resourses.

A report prepared for CTED in September of 1998 identified 134 firms involved in various sectors of the renewable energy industry in Washington. The estimated revenues for 1997 totaled $147 million, and the companies employed about 900 workers.[18] Nearly half of this activity is due to the solar energy industry in the state. While only about 2 percent of U.S. electric sales are currently derived from non-hydro renewables sources, renewable energy use worldwide is growing relatively rapidly.

Figure 9.7 Non-Hydro Renewable Sales by Washington Utilities



Wood and paper waste biomass. Until 1995, wood and paper waste biomass represented more than 90 percent of the total non-hydro renewable power generated in the state. However, they have dropped to less than half the total due to an increase in production from other sources (particularly landfill gas) and the closure of three paper and pulp mills.[19] Washington Water Power (WWP) is the main supplier of biomass-generated electricity, with power generated by the Kettle Falls plant, and purchased from two co-generation projects - Wood Power, Inc. and Rayonnier. (However, the latter plant burned down in July 1998). In addition, at least four non-utility generators meet on-site power needs with energy from wood residues generated by their own industrial operations.

Landfill gas. Power generation from landfill gas has become the second largest source of non-hydro renewable electricity in the state and may surpass wood waste biomass by the end of 1998. Benton REA is one of twelve rural cooperatives in Idaho, Oregon, and Washington that have developed the Coffin Butte Resource Project located in Oregon, a landfill gas-to-energy plant. Both Tacoma Power and WWP began supplying power from landfill gas in 1998. Klickitat County PUD and Rabanco, the Bellevue-based solid waste firm, are developing a project to generate electricity using methane from Rabanco's Eastern Washington landfill near Roosevelt.

Wastewater. Ninety-five percent of the state's power generated from wastewater treatment is supplied by Seattle City Light from a King County sewage treatment plant at West Point. The LOTT Wastewater Treatment Plant in Olympia uses power from methane to operate the plant.

Wind. Florida Power and Light is building a merchant wind plant, on Vansycle Ridge in Oregon, between Walla Walla and Umatilla. PacifiCorp and BPA are the major partners in a 41.4 MW wind facility under construction in Wyoming.

Geothermal. In 1998, geothermal energy is expected to provide less than 2 percent of the non-hydro renewable power in the state. BPA has signed memoranda of understanding signifying its intent to purchase output from two new geothermal facilities (29.7 aMW each) in Northern California. PacifiCorp has included the output of the Blundell Project in Utah in its resource mix since 1991.

Solar. Between 1,000 and 2,000 PV systems have been installed in the state, mainly in the San Juan Islands and Northeastern Washington. The Conservation and Renewable Energy System (CARES), a joint operating agency composed of the Benton, Clallam, Franklin, Grays Harbor, Klickitat, Okanogan, Pacific, and Skamania PUDs, is facilitating utility participation in the federal Million Rooftops Program. The Coulee Dam Federal Credit Union provides favorable loan rates for PV systems.[20]

9.3.4 Trends Affecting Investments in Renewables

Declining wholesale electricity prices. In general, the declining cost of power has made it more difficult for renewable resources to compete on price, notwithstanding significant declines in the cost of renewable technologies. Competitive pressures may increase the financial risks associated with investments in resources with longer payback horizons or desirable environmental characteristics.

Restructuring legislation providing for renewables. Several states have adopted restructuring legislation that assures the development of renewable resources, through portfolio standards or buying down the incremental price of renewables.

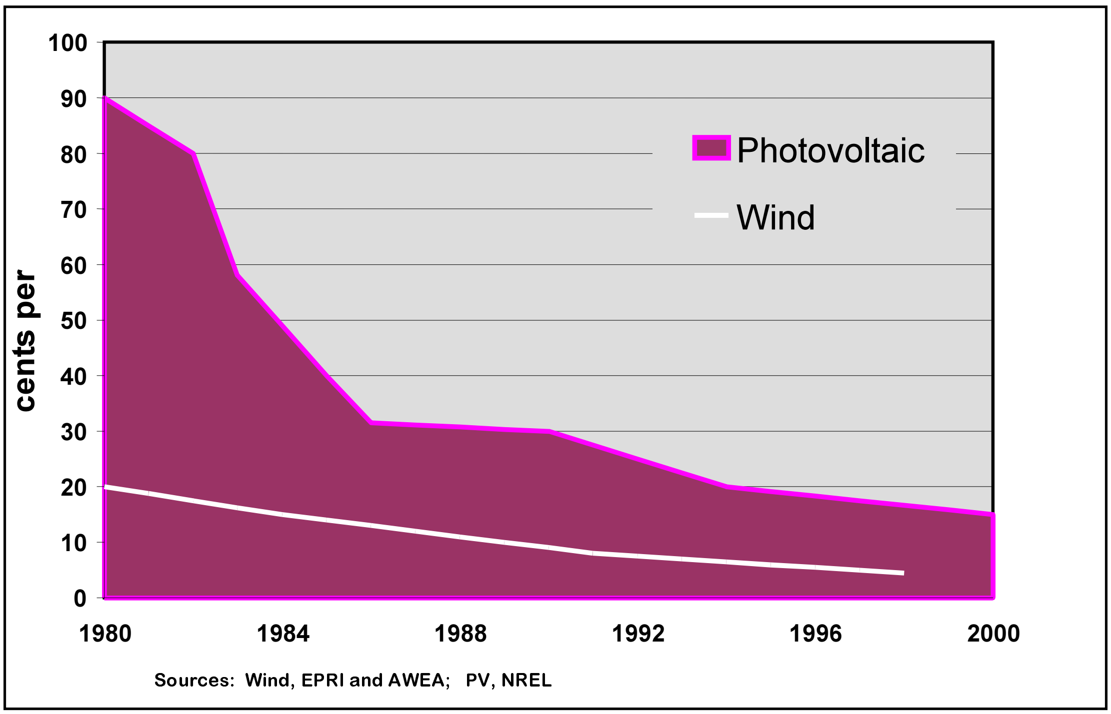
Growth in overseas markets. In the next 20 years, energy use in the developing world is projected to increase dramatically. Regions that do not already have a power grid are considered good markets for distributed renewables. Growth in overseas markets may allow for production scale economies that would decrease prices.

Global warming. Global efforts to stabilize the climate by decreasing carbon dioxide emissions may put a premium on development of cost-effective renewable technologies.[21]

Decrease in public research funds. Federal funding for renewable energy R&D declined throughout the 1980s, and still constitutes only a small percentage of total federal funding for energy supply R&D.

Decline in prices for both wind and photovoltaic power. Technology improvements and expanding international and national markets for renewable energy are resulting in per unit cost reductions. See figure 9.8 for price trends.

Figure 9.8 Cost of Large-Scale Wind and Photovoltaic Generation



9.3.5 Effect of General Trends on Renewable Resource Development

Washington wind project cancelled. BPA, through the Resource Supply Expansion Program (RSEP), developed a wind power strategy to help utilities develop small-scale wind demonstration projects. In September 1992, BPA issued a Request for Proposals for a Wind Demonstration Project to implement the RSEP. In response, the CARES consortium of PUDs proposed the Columbia Wind Farm #1 Project. However, progress on this project stopped in September 1998 when CARES and the site owner could not reach final agreement.

"Green marketing" programs. In increasingly competitive generation markets, some suppliers are marketing the environmental benefits of renewables as a potential source of competitive advantage and product differentiation. To the extent that premium revenues from "green marketing" are used for new renewable resources, green marketing may result in increased investment in renewables.

Disclosure and Labeling. At least 12 states have adopted, by law or commission order, standards for disclosure of the fuel mix and/or emissions of power sources. Consumer research conducted for the National Council on Competition and the Electric Industry indicates that electricity consumers seek information on the environmental characteristics of energy resources in a simple, uniform format similar to food labels.[22] (See Section 9.5 for a more thorough status report on state activities relating to disclosure.)

Representatives of the WUTC and 11 other states and British Columbia are participating in the Western Disclosure and Tracking Project to develop a mechanism to track electricity generation attributes from the source to the consumer. Under the Project's proposal a neutral third party or clearinghouse would issue certificates to electricity generators based on the characteristics of their generation. Retail electric service providers would need to possess certificates to justify any claims they make about their product. (See the 2831 legislative study, "Washington Electric Utility Service Quality, Reliability, Disclosure and Cost Report" for greater detail on disclosure mechanisms and issues.)

9.3.6 Barriers to Renewable Energy Development

The largest barrier to increased use of renewable energy is price. Renewables are typically higher in both total price and up-front capital costs than natural gas-fired combustion turbines. Like any generation source, the geographic proximity of the renewable power supply to the existing transmission system or to energy consumers will affect the total cost of the project. The lower environmental cost of renewables is generally not fully captured in prices, since many of the environmental costs of conventional resources remain external to price.[23]

Financing renewables may be difficult. Wall Street is taking a cautious stance on merchant power plant investment of all fuel types. Renewables may be harder to finance than fossil-fueled resources for several reasons:

- Obtaining long-term purchase agreements from residential customers will be difficult given consumer mobility and high transaction costs. Lack of long-term contracts increases risk to investors.
- Gas-fired plants are less capital intensive than renewables. Capital costs for combustion turbines can be paid off in as little as six years, while the fixed costs of renewable plants usually require at least ten years to pay back.

- Fossil fuel suppliers have new tools to maintain their market share by reducing risks to electricity generators (for example reverse tolling, in which fossil fuels are sold in fuel markets instead of converted to electricity when fuel prices are high). These tools are generally unavailable to renewable energy projects, which do not have control over the price or location of wind, solar, biomass, and geothermal "fuels".[24]

As with any energy project, renewable generation can face site-specific opposition. For instance, even though the environmental community generally supports renewable energy, the cancelled CARES Washington Wind project, mentioned above, was opposed by an environmental group concerned about potential impacts on wildlife.[25]

9.4 Low-income Energy Services

Summary

Low-income energy services take two primary forms: assistance to reduce or pay energy bills, and increasing the efficiency of energy use, primarily through weatherization. Federal assistance for these functions has decreased more than 35% since the early 1990s. BPA currently plans to discontinue support for low-income weatherization after September 1999. At least 5 consumer-owned utilities offer rate discounts to low-income seniors and 2 more offer rate discounts to all low-income customers. The total annual value of these discounts was $5 million in 1997. Many homes have been weatherized, and a few utilities report a saturated market for weatherization. However, there has not been a standard definition for weatherization in the past and homes have received different weatherization treatments over the years from utilities, the state or others. Low-income advocates report a continued need for weatherization in every county in Washington. The need for low-income energy services may have grown as the percent of Washington's population earning below the federal poverty level increased significantly this decade.

9.4.1 Policy Goals and Statutory Background

The Legislature has found that it is in the state's interest to: preserve affordable natural gas and electric services to the residents of the state; maintain and advance the efficiency and availability of natural gas and electric services to the residents of the state; ensure that customers pay only reasonable charges for natural gas and electric service; and to permit flexible pricing of natural gas and electric services. (RCW 80.28.074)

In 1987, the Legislature found that weatherization of low-income residences will:

- reduce energy consumption, making space heat more affordable for persons in low-income households;
- reduce uncollectable accounts of energy suppliers resulting from low-income customers not being able to pay fuel bills; and
- help conserve energy resources, reducing the need to obtain energy from more costly conventional energy resources. (RCW 70.164.010)

Many federal, state, utility and charitable low-income service programs are based on the premise that affordable energy service should be available to all consumers. Weatherization addresses multiple objectives, not all related to energy. A 1994 evaluation of weatherization programs throughout the country, including Washington's, found that it, "has concrete positive consequences for housing, neighborhoods, jobs, the environment, the payment of utility bills and the economic well-being, health, and safety of the low-income people it serves."[26] By improving the physical and operating characteristics of homes, weatherization may: create safer living conditions for families; contribute to the scarce stock of affordable housing; extend the life and increase the value of homes; and reduce arrearage to utilities, which lowers the carrying cost of bad debts.[27]

While consumer-owned utilities have global authority to set customer rates, RCW 74.38.070 specifically authorizes public utilities to offer rate discounts to all their low-income senior citizens or to all their low-income customers. Compared to the average consumer, energy costs represent a higher proportion of a low-income family's budget. Washington's low-income households on average spend 14.9 percent of their income on home energy, compared to 3.6 percent for non-low-income households.[28] Low-income households are likely to have young children (50% of the households in low-income weatherization programs had children under 6 years old) or be seniors (25% of the weatherization households had seniors over 60 years old).

9.4.2 Program Descriptions

Low-income service programs include: grants to help pay heating bills, weatherizing homes of low-income households, rate discounts, charitable contributions, and various "safety-net" provisions.

The federal and state governments and utilities currently offer a variety of energy service assistance programs to low-income consumers in Washington. These include federal energy heating bill assistance, weatherization programs, rate discount programs and percent of income payment programs.

9.4.2.1 Low-income home energy assistance program (LIHEAP)

CTED administers the State's Energy Assistance Program, which helps low-income consumers pay their heating bills. This assistance is available to low-income households with any heating fuel type.

CTED receives LIHEAP funds from the U.S. Department of Health and Human Services. The agency then contracts with a statewide network of community based service providers including non profits (generically known as Community Action Agencies which operate Community Action Programs, or CAPs) and, in a few cases, local governments to deliver energy assistance services. The local CAP agency screens clients and then provides a level of grant funding that is a function of household income and the previous year's heating costs. The lowest income households receive up to 80 percent of heating costs as a benefit and those at 125 percent of poverty receive 40 percent of heating costs as a benefit. The maximum heating season benefit is $700. Currently, federal funds are available to serve 18% of the state's eligible population. Funds are typically obligated by December on a first come, first served basis. Consumers facing imminent disconnection of service are able to receive priority appointments. Funds often run out in the late winter or early spring.

Households earning 125% of the poverty level are eligible to receive funds. This qualifies a household of three earning $17,063 or less per year. CTED has estimated that there are approximately 290,000 households in Washington that currently meet the income criteria for LIHEAP assistance. In 1990 CTED provided 96,000 households with energy assistance, or about one-third of the eligible population. By 1998, due to a decline in funding, CTED provided assistance to approximately half that many or 46,000 households. The average annual payment for 1998 is approximately $260 per household.

9.4.2.2 Low-income weatherization.

In addition to the bill assistance programs, CTED administers several low-income weatherization programs including the federally funded Weatherization Assistance Program, the Energy Matchmakers program and a BPA-funded weatherization program. Both the Weatherization Assistance Program and Energy Matchmakers could support weatherization for homes with any type of heat.

The bulk of the funds for the Weatherization Assistance Program come from the U.S. Department of Energy. Washington also invests 15 percent of its federal LIHEAP funds in low-income weatherization programs. These funds are allocated by formula to provide weatherization services in every county in the state.

The Energy Matchmakers program leverages funds by requiring a dollar-for-dollar match from local sponsors. Historically, Energy Matchmakers has leveraged approximately $5 million per year in cash or in-kind matches from utilities, rental owners, local governments, etc, (RCW 70.164.040). Funding sources for this program included state capital funds and oil company payments received pursuant to a lawsuit alleging overcharges during the 1970's energy crises. (RCW 70.164.030). The oil overcharge funding source has nearly expired.

CTED also administers a BPA-funded low-income weatherization program, providing services to low-income households in electrically heated homes in the service territories of BPA customer utilities.

CTED's program services are provided through a network of community based agencies, including community action agencies and local government agencies. Current weatherization measures include diagnostic air sealing, attic, wall and floor insulation, and heating system efficiencies. The program also provides energy conservation education, measures to mitigate health and safety hazards (such as carbon monoxide poisoning and other air quality dangers), and emergency repairs to protect the weatherization measures.[29] Local service providers select measures in accordance with a benefit-cost effectiveness audit tool.

Many utilities have been weatherizing residential housing for 15 years. In recent years, the approaches to low-income weatherization have changed. Community-based service providers now install more energy saving measures and weatherize a more diverse housing stock, including manufactured (mobile) homes. Some low-income weatherization programs report facing a recruiting challenge in that they primarily benefit low-income tenants and yet require the support of the landlord.

9.4.2.3 Rate discounts

Several PUDs and municipal utilities offer rate discounts to some or all of their low-income customers. At least 5 consumer-owned utilities serving 15 percent of the state's consumers reported offering rate discounts to qualifying low-income senior citizens. In addition, 2 consumer-owned utilities serving 22 percent of the state's consumers now report offering 30 to70 percent rate discounts to all their qualifying low-income customers. One municipality has offered a rate discount to all its low-income customers for over a decade.

Prior to the passage of ESSB 6560, RCW 74.38.070 authorized public utilities to offer a rate discount to low-income senior citizens and to low-income disabled citizens throughout their service territory. ESSB 6560 modified this authority so that public utilities could offer rate discounts to all low-income seniors or to all low-income consumers throughout their service territory. In response to ESSB 6560 one PUD extended their rate discount to all low-income customers. Several consumer-owned utilities eliminated their rate discount to disabled citizens after ESSB 6560 passed. There is currently some question as to whether and under what conditions current Washington law authorizes the UTC to permit investor-owned utilities to charge special rates for low-income customers. (See endnote 51).

9.4.2.4 Percent of income approach.

Clark PUD initiated a "Guarantee of Service Plan" in 1988 that caps utility bills at 9 percent of a qualifying family's income. Customers agree to pay this amount each month while the utility absorbs any past-due amounts and utility charges above this amount. An educational counselor performs a walk-through audit of participants' homes and provides tips on reducing energy bills and home weatherization. Clark PUD reports that this program is saving money for the utility and its ratepayers and has resulted in higher payments from more low-income consumers. The savings come in the form of lower uncollectible bills, lower administrative costs and increased payments from the consumers. [30]

9.4.2.5 Charitable contributions and other programs

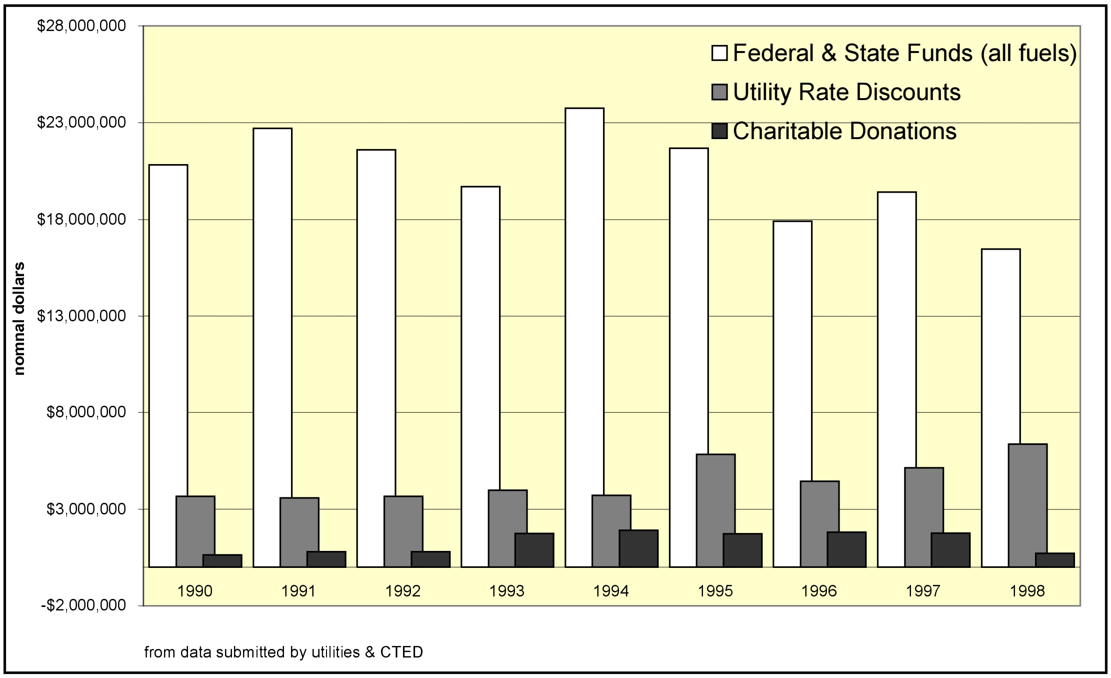
Many utilities allow ratepayers to make voluntary contributions to low-income bill assistance through their utility bills. Other safety-net measures include RCW 80.28.010 and RCW 54.16.285 which limit investor-owned and consumer-owned utilities' ability to terminate utility service to low-income consumers for residential heating between mid-November and mid-March. (Low-income customers must meet six conditions to avoid having heating service terminated.[31]) These statutes also require utilities to offer budget payment plans to consumers. In addition, WAC

480-100-071 addresses disconnection procedures and requirements for investor-owned utilities.

9.4.3 Expenditures on Low-income Services

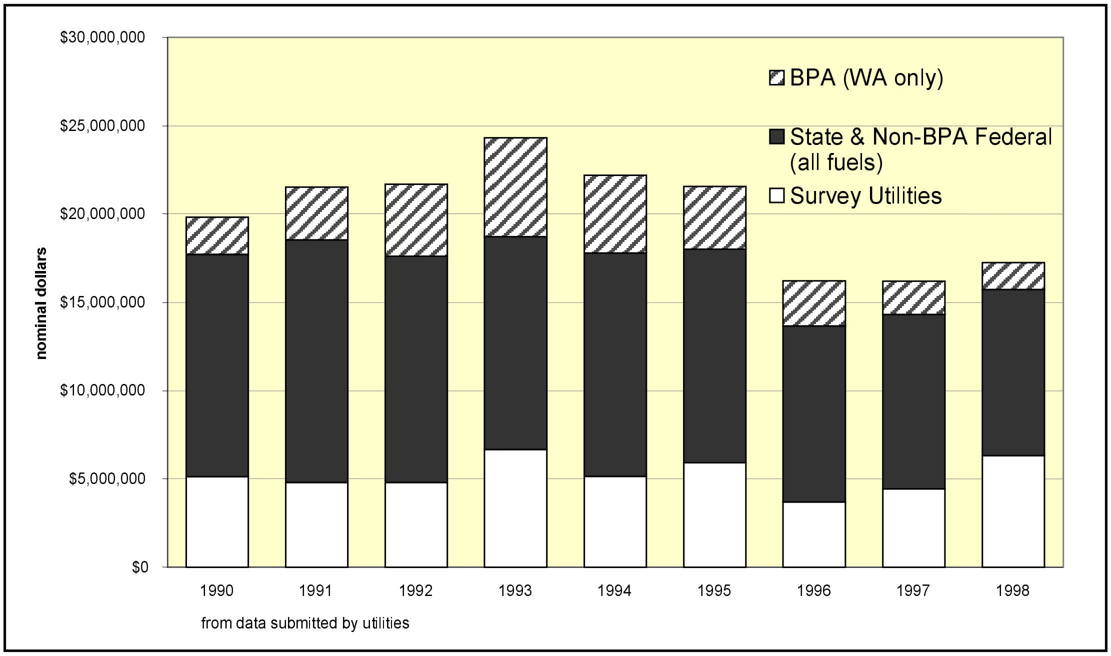
The amount spent on bill assistance by different organizations is shown below in Figure 9.9. The amount spent on weatherization is shown in Figure 9.10. (The 1998 funding increase for utility weatherization is primarily the result of a merger settlement requirement.) Federal LIHEAP block grants for Washington State are $19.964 million in FY 1998 and $21.96 million in FY 1999.[32]

Figure 9.9 Low-income Bill Assistance Expenditures in Washington



From 1988 to 1995, Energy Matchmakers leveraged $33.5 million for low-income weatherization. Over two-thirds of these funds came from electric utilities or BPA: 48% from retail utilities, 21% from BPA, 14% from rental owners, 9% from gas utilities, and 8% from other funding sources.[33]

Figure 9.10 Low-Income Weatherization Expenditures in Washington



The average low-income weatherization expenditure is $2,600 per home. CTED has estimated that as many as 160,000 low-income housing units need weatherization. At current state and federal funding levels this means that approximately 3,560 low-income homes could be weatherized per year and that it would take over 40 years to service all eligible households.

Utilities reported that low-income and low-income senior rate discounts were valued at $5 million in 1997. Ratepayers contributed nearly another $2 million a year in charitable contributions for each of the past four years.

(See Appendix 9.2 for utility reported expenditures on low-income energy services.)

9.4.4 Trends Affecting Delivery of Low-income Energy Services

Need is increasing. From 1990 to 1995, the percentage of Washington's population below the poverty level increased by nearly forty percent, rising from 8.9% to 12.5%. In the same period, Washington's median income declined in real terms, from $37,444 to $35,568.[34] Assistance does not cover need. Under the current system, energy assistance aid runs out before the end of the heating season, so many eligible households may not be served. Aid is distributed on a first-come, first-served basis, not targeted to the greatest need.

Low-income funding is both declining and unstable. Low-income funds are subject to fluctuation from year to year. Nationally, LIHEAP appropriations fell from $2.078 billion in 1985 to $1.1 billion in 1999. In 1996, energy assistance funds in Washington fell to the decade's lowest, $12.8 million, 23% below the 6 year-average of $15.75 million.[35] BPA is projecting no funding after 1999. Congress regularly debates whether to continue LIHEAP funding.

Value of rate discounts is increasing. Some of the utilities that offer rate discounts to low-income or low-income seniors report that the total value of these discounts is increasing. Answers to data requests for this report indicate that the annual value of rate discounts increased from about $3.5 million in 1994-96 to $5 million in 1997, to an estimated $6.3 million in 1998. Five utilities offer rate discounts to low-income senior citizens. At least two utilities make rate discounts available to all low-income citizens; one initiated this practice in 1998 after passage of ESSB 6560.

Drop in wholesale energy prices. Utilities that funded low-income weatherization strictly as a resource acquisition program found that weatherization had difficulty passing their cost-effectiveness tests.

Changing weatherization markets. Three utilities indicate that their budgets for weatherization have decreased because there is less consumer demand for weatherization. One large public utility reports that they have now weatherized 80 percent of the 1 to 4 unit homes they serve. In addition, they expect to reach 80 percent penetration of large, multi-family units by 2001. However, significant energy savings may be available in homes that were previously weatherized. Today's standard practice for weatherization includes home-sealing and insulation techniques that were not available in the past, when weatherization often included only a water heater wrap and weatherstripping. Also, while some utilities have treated most of their single-family, site-built homes, large portions of the rental and manufactured housing stock remain unweatherized.

9.5 Approaches to Electricity System Benefits in Other States

As of summer 1998, 13 states had passed restructuring laws and regulatory commissions in four more states had issued restructuring orders. Twelve of these 17 states were actively addressing electric system benefit programs.[36] The following summarizes where those states are focusing their system benefit investments.

Research and Demonstration: Nine states are addressing the need for public benefit research and demonstration projects that focus on renewables, energy efficiency and environmental quality. Six of these specify funding guidelines in legislation or commission order.

Energy Efficiency: Eleven of the 17 states have developed provisions for supporting energy efficiency and another four are still studying this. Most programs have been designed to maintain historic investment levels and are typically funded by a nonbypassable system benefit charge.

Renewable Energy: Eleven states provided funding or created portfolio standards to support renewable energy development.

Low-income: Fourteen states have legislated a system benefit charge to continue low-income support. Another two have made other provisions for low-income services. Some states that have passed restructuring legislation have revised their criteria for funding low-income weatherization to address affordability, health and safety, and comfort.

Disclosure: Twelve states have information disclosure policies required by law or commission order. These policies cover one or more of the following: fuel mix, environmental characteristics of fuels, and prices. Another 4 are considering mandatory disclosure policies. Additionally, stakeholders in at least 8 states that are not actively pursuing electricity restructuring are considering disclosure policies.[37]

9.5.1 System Benefits Strategies and Administration in States with Retail Competition

Eleven of the thirteen states with retail competition laws have identified mechanisms for funding their system benefits programs. All of them are utilizing electric system revenues as the funding sources. The mechanism adopted by ten of these states is the system benefit charge - a competitively neutral, non-bypassable charge on delivery service. Seven states have adopted renewable resource portfolio standards.

Ten of these 13 states have developed or implemented administrative mechanisms for achieving system benefits. Of these ten, eight have clearly identified an independent administrator for renewable resource programs. The administrator is an executive agency, a statewide board, a non profit or a quasi-public organization.

Approaches for administering energy efficiency and low-income services are more varied. Several states direct utilities to administer low-income or efficiency programs with oversight from the regulatory commission or an executive agency. Executive agencies or non profit independent entities administer the energy efficiency and low-income investments in other states. Several have directed administrators to include competitive bidding processes to allocate some funds for renewable resource development or energy efficiency programs.

9.6 Strategies to Achieve Conservation, Renewable Resources and Low-income Energy Services

9.6.1 Overview

This part of the report describes ways that Washington might achieve energy efficiency, encourage development of renewable resources, and deliver low-income services (collectively, "electric system benefits" or "public purposes") in light of changes in the electricity industry described in this report.

- 9.6.2 provides background on the roles of private and public investment in delivering these benefits.
- 9.6.3 describes potential criteria for delivering electric system benefits "fairly, efficiently, and effectively," as intended by ESSB 6560.
- 9.6.4 examines public investment in electric system benefits funded by a System Benefits Charge. It also describes potential applications for the revenues collected from such a charge.
- 9.6.5 examines the principal alternative to a SBC for public investment in electric system benefits - tax revenues and incentives.

- 9.6.6 examines alternatives for administration of public investments in electric system benefits.
- 9.6.7 examines other policy strategies for encouraging delivery of electric system benefits that may require little or no public investment.
- 9.6.8 describes alternatives for coordination and assessment of efforts to deliver electric system benefits.

9.6.2 Background - Private and public investment in electric system benefits

Historically, energy efficiency, renewable resources, and low-income services have been accomplished with a mixture of public and private investment. Over the last two decades in particular, a substantial amount of public investment for these purposes was collected from energy service revenues and administered primarily by electric utilities. The primary alternative form of public investment is through tax revenue or tax incentives.

Consumers acting in their own self-interest sometimes make investments in energy efficiency or renewable resources. For example, some consumers will voluntarily pay more initially for energy efficient lighting. Generally, they are willing to make such investments either in anticipation of future savings on their electricity bills or because they believe that efficient lighting is more environmentally sound. However, in many cases, consumers acting in their own interest will not choose energy-efficient alternatives, even when the additional cost of these alternatives is more than repaid in the form of energy savings over time. This is sometimes called the "energy efficiency gap" - the difference between the energy efficiency of products that consumers purchase and the cost-effective levels of energy efficiency that are available for those products.[38]

Similarly, consumers and utilities may not choose renewable resource alternatives, even when the total (internal plus external) costs of those resources are less than fossil-fueled resources. Where private incentives are not sufficient to capture all cost-effective energy savings and renewable resources, public investment or other public policies may be needed. Some of the most widely documented reasons why private incentives may be insufficient to capture cost-effective energy efficiency and renewable resources include:

- *"Split incentives."* Often, the person who pays for a piece of energy-consuming equipment is not the same person who pays the energy bill. For instance, landlords often purchase appliances while tenants pay the bill. As a result, the landlord may have little incentive to choose an energy-efficient appliance, since the landlord would pay the initial cost while the tenant would reap the benefit in the form of energy savings. Another example is state government, where capital budgets and operating budgets are generally separate. This makes it difficult to finance cost-effective energy efficiency measures from a capital budget that result in savings on the operating side.

- *The "payback gap."* Utilities' costs of investment in new power plants historically have been recovered over periods of twenty years or more. Substantial up-front investments in power-generating capability require access to financing and long payback horizons. In contrast, the implicit payback period for consumer investment in energy-consuming equipment is much shorter - generally less than three years[39]. That is, consumers will generally not choose energy-efficient equipment unless the additional cost of that equipment is paid back in energy savings within three years or less. The result is that power plants with payback periods over twenty years may be chosen over energy-saving equipment with payback periods of less than 10 years. Consumers routinely forego energy efficiency investments that would have earned a rate of return 2-3 times higher than the prevailing market rates.[40]
- *Transaction and information costs.* The energy consumption characteristics of power-using equipment and appliances are often not apparent to the consumer. The costs of gathering information, locating energy efficient products and putting them into service can discourage investment.
- *Externalities.* Not all of the costs of energy resources are borne by energy consumers. For example, health impacts due to air emissions from fossil-fueled resources may be borne by citizens who are not served by those resources. As a result, consumers and utilities may not choose renewable resources with relatively high internal costs (price) but relatively low total costs (price plus environmental impacts). Utilities and consumers facing competitive pressure may be particularly unwilling or unable to pay a higher price for resources with lower external costs.
- *"Public goods"* Closely related to externalities is the "public goods" problem. When a consumer spends more to purchase a product that reduces environmental impacts, they reap only a small fraction of the benefits. Most of the benefit accrues to the public at large. Since the environmental benefits of energy efficiency and renewable resources are what economists call "public goods," consumer purchasing decisions may not capture those benefits.

As a result of these and other market barriers, private investment will generally capture only a portion of the total potential energy savings and renewable resources that are cost-effective to society. For example, the Northwest Power Planning Council's 1996 Plan estimates that 1,535 aMW of cost-effective electric power savings are available over the next two decades but only about 20 percent of these savings will be captured through private investment alone in the current market structure.[41]

The discussion above describes why private incentives and market forces are sometimes insufficient to secure investments in energy efficiency and renewable resources, even when those investments minimize the total cost of energy service over time. There are, of course, other reasons for public investment besides minimizing the cost of energy service such as preventing environmental damage or assuring universal service. To accomplish these goals, policy-makers and utilities have chosen to direct public investment toward energy efficiency, renewable resources, and low-income services.

Strategies

The discussion of strategies below is organized as follows:

- ❖ A brief discussion of potential criteria for accomplishing electric system benefits "fairly, efficiently, and effectively". (9.6.3)
- ❖ A description of the two primary sources for public investment in electric system benefits:
  - electric system revenues (system benefits charge) (9.6.4) and
  - tax revenues or incentives (9.6.5)
- ❖ A discussion of options for administering public investment in electric system benefits (9.6.6)
- ❖ A description of other policy strategy alternatives that may require little or no public investment. (9.6.7)
- ❖ A description of alternative means for assessing and coordinating public investments in electric system benefits (9.6.8)

As elsewhere in the report, discussion and description of strategies does not imply a recommendation on the part of CTED and/or the WUTC.

9.6.3 Delivering Electric System Benefits "Fairly, Efficiently, and Effectively"

ESSB 6560 calls for strategies to achieve conservation, renewable resource, and low-income service delivery goals "fairly, efficiently, and effectively." Input from stakeholders suggests that the following criteria for funding and administration of electric system benefit initiatives may help in the evaluation of alternative strategies. These criteria represent a collection of perspectives on the subject, not a consensus.

Attributes of a fair strategy include:

- ❖ *Competitive neutrality:* The mechanisms for funding or administering these initiatives would confer no undue competitive advantage on any firm or industry.
- ❖ *Accountability:* Decision-making should be transparent. Results should be evaluated, documented, and used to inform future program decisions. Program administrators should be accountable for results.
- ❖ *Equitable distribution of the costs and benefits of public investment:* Investment in electric system benefits may be targeted to maximize achievement. However, all customer classes and locations that contribute to such investments should have some ability to benefit from them.

- *Appropriate funding:* The source and level of funding should bear a logical relationship to the nature of the investment.

An efficient strategy would:

- Minimize administration and overhead so that the largest possible proportion of investment goes directly toward achievement of program goals.
- Use market forces to deliver electric system benefits wherever possible and focus collective efforts on areas where the market does not deliver these benefits. Public investment would be administered in a way that encourages rather than supplants private investment.
- Use simple methods for collecting funds, administering programs, and evaluating and reporting results.
- Maximize the ratio of achievement to investment.

An effective strategy would:

- Achieve all cost-effective conservation, accelerate the development of renewable resources, and deliver needed low-income services.
- Have clearly articulated goals and sufficient resources and authority to accomplish them.
- Align the incentives of the program administrator with the achievement of results and minimize conflicting incentives.
- Have strong stakeholder support and involvement.
- Use empirical evidence to assess results, evaluate market progress and adjust investment levels and strategies accordingly.
- Stimulate further development of private industries to competitively deliver energy efficiency products and services.

These criteria may be used to evaluate alternative methods of funding and administering efforts to deliver electric system benefits. Some of these alternatives are described below.

9.6.4 Public Investment Through Electric Service Revenues: System Benefits Charge

System Benefits Charge - Background: Much of the historical public investment in energy efficiency, renewable resources, and low-income services, particularly at the state level, has been funded by electricity system revenues. Utilities have included the cost of these investments in their bundled rates, often as part of the cost of implementing their least-cost plans. The rationale for including these investments in utility rates (as opposed to other forms of public investment) grows from the connection of these purposes to two basic policy goals for energy service: 1) minimizing the total cost of energy service and 2) ensuring access to affordable energy service for all consumers. Energy efficiency, renewable resources, and low-income services are directly related to the achievement of these two basic goals. This distinguishes them from other policy initiatives with little or no connection to energy service goals that receive public support from tax revenues.

Where energy efficiency and renewable resources represent cost-effective alternatives to other power supply sources, then their costs are collected in electricity rates for the same reasons that the cost of conventional power plants are collected in rates. Where investments in low-income services are not strictly cost-effective from a resource acquisition perspective, the rationale for including them in electric service rates may rest more on the notion of universal service. This is akin to including many of the extra costs of serving low-density rural systems, or remote users, in general rates in order to ensure affordable service for all.

For reasons documented above, utility investment in these purposes is generally down sharply in recent years. While some of the reduced investment is justified by lower wholesale power costs (and therefore reduced availability of cost-effective conservation and renewable resources), competitive pressures have also been a major factor. In response to these competitive pressures, some Washington utilities (including Washington Water Power and Puget Sound Energy) and a number of states have turned to the "System Benefits Charge" approach. The basic purpose of this approach is to ensure that all consumers share the cost of these investments, regardless of their choice of power supplier.

A System Benefits Charge (SBC) is a uniform, competitively neutral, non-bypassable charge assessed on the sale of electricity (and/or other energy) services to all customers for the purpose of investment in electric system benefits. As a result of these characteristics, differential exposure to the cost of these investments does not become a source of competitive advantage for any supplier or consumer. The mechanics of the SBC represent an accounting change that separates the cost of these investments from general rates and assesses them in the form of a delivery charge.

An SBC can be based on either energy sales or revenues. A uniform, revenue-based charge would be higher for the customers of utilities with high distribution, transmission or generation costs. In recommending such a charge, the Comprehensive Review acknowledged the potential need to modify the SBC formula to avoid excessive charges on high cost, low-density rural utilities.

System Benefits Charge: Applications

A System Benefits Charge can be used to support existing and new approaches to delivering energy efficiency, renewable resources, and low-income services. The following examples are by no means exhaustive, but are meant to suggest some of the existing and new approaches to delivering these benefits.

9.6.4.1 Energy efficiency initiatives

- *Local energy efficiency programs.* Washington's electric utilities have operated a wide variety of local energy efficiency programs for over two decades. These programs include: paying part of the cost of energy-saving equipment; making loans or offering incentives for the purchase of energy-saving equipment; design and technical assistance; weatherization; window upgrades; appliance rebates; efficiency measures for irrigated farms; education or marketing programs promoting energy efficiency and/or resource management; commercial building design assistance; industrial audit and process retrofit programs; industrial motor rebate programs; and others.

- *Market transformation:* Market transformation is a relatively new approach that focuses on making far-reaching structural changes in the market for energy efficient products and services. Market transformation initiatives are generally designed to ensure that changes in the market will be accomplished in a way that reduces or eliminates the need for public investment over time.[42] These types of programs can only be implemented at a scale - statewide, regional or national – sufficient to influence manufacturers and others to implement structural market changes. The Comprehensive Review recommended that a portion of revenues from a SBC be allocated specifically to market transformation.

- *Low-income weatherization:* Revenues from a SBC can be used to complement federal investments in low-income weatherization. Low-income weatherization programs may not meet conventional cost-effectiveness criteria for utility resource acquisition. However, they provide additional benefits that help to ensure affordable and adequate electric service for low-income households.[43] The Comprehensive Review recommended that a portion of SBC funds be allocated to weatherization and that weatherization be administered through the existing state and local network of community action agencies.

- *Research, development, demonstration and commercialization: Research* and development initiatives for energy efficiency are designed to move energy efficient products down the cost curve so that they may be commercialized in the future. For reasons discussed in the section on technology trends affecting electric service costs (Section 2.5), R&D investments in the utility industry generally are declining rapidly. Additionally, utility focus on energy R&D has shifted away from collaborative, longer-term projects to those that may help utilities compete in the near term.[44] In four states that have adopted SBCs, R&D for energy efficiency is one of the targeted purposes for investment.

- *Education and information*: Consumer investment in energy efficiency is often limited by lack of access to credible, simple information. Utilities and public agencies have historically undertaken a variety of education and information initiatives, including: information clearinghouses such as the Energy Ideas Clearinghouse; demonstration facilities such as the Lighting Design Lab; energy resource and use curricula for schools;[45]

energy extension services; marketing information and promotional campaigns for energy efficient products; billing information describing energy use patterns and energy-saving strategies. Information programs can be run in conjunction with other strategies (such as loans or rebates) to help maximize the effectiveness and/or minimize the cost of such strategies.

9.6.4.2 Renewable resource initiatives

- *Compensation to consumers or energy service providers for the above-market cost of renewable resources.* Utilities that purchase renewable resources could use SBC revenues to offset some or all of the difference between the cost of those resources and the cost of other available alternatives. The incremental cost that would be funded through the SBC could be minimized in a variety of ways, including competitive bidding or a production incentive program. Production incentives could be allocated competitively and phased out after a relatively short period, which allows for recovery of some of the initial capital costs of the facilities.[46] This would encourage the initial development of resources with strong potential to attract and sustain private investment over time. Alternatively, where consumers may choose renewables, compensation for some or all of the above-market costs could be available to retail customers.
- *Purchasing or providing incentives for distributed renewables.* In some remote locations, distributed renewables including solar and wind may already be cost-effective because of their ability to displace expensive investments in low-density distribution systems. SBC funds could be used to increase the application of these resources through: direct purchases; loan programs; matching grants to leverage other sources of financial support for distributed renewables; or technical assistance to consumers who purchase these systems. (Use of distributed renewables by retail customers presents some of the same financial hurdles for utilities as energy efficiency measures, since it generally reduces demand and revenues).
- *Renewable resource research, development, demonstration, and commercialization.* RDD&C investment may be particularly vulnerable to short-term competitive pressures. RDD&C initiatives could involve partnerships with the many private and public institutions in Washington with experience and knowledge in renewable resources. (Section 3.5 discusses RDD&C strategies more generally.)

9.6.4.3 Low-income services

- *Weatherization.* As noted above, SBC revenues can be used to fund low-income weatherization programs that deliver energy savings and help to ensure universal access to electric service.

- *Energy efficiency initiatives that reduce the operating costs of public housing.* Public housing authorities may be reluctant to make investments in energy-saving construction practices and equipment when their primary goal is to maximize the number of housing units provided. SBC funds can cover some, or all, of the incremental cost of energy-efficient alternatives to traditional practices. Alternatively, SBC funds can be used as financing for efficient equipment and paid back through savings over time, then reused for new financing on a revolving basis.
- *Universal service fund.* The Comprehensive Review recommended establishment of a universal electric service fund to provide bill assistance to households that would otherwise have to pay more than a fixed percentage of their incomes for electric service. Such a fund could apply to gas, oil, and propane as well as electricity bill assistance. It could be funded by SBC revenues, federal or state program assistance, private donations, or a combination of sources. An alternative to collecting electric service revenues through a volumetric (per kWh) SBC is to collect them through a fixed retail distribution system access fee or meters charge. This alternative was included in draft legislation considered by the Oregon legislature in 1997 and discussed in the recommendations of the Comprehensive Review.
- *Conservation fund for low-income residents.* Massachusetts created a permanent energy efficiency fund available only to programs serving low-income residences. Such a fund could be collected through a SBC.

9.6.5 Public Investment Through Tax Revenues and Incentives

At the federal level, tax revenues support significant investments in energy efficiency, renewable energy, research and development, low-income weatherization, and low-income heating assistance. Federal taxes also provide modest support for the energy efficiency, renewable resource, and low-income service activities of the states through the State Energy Program. State tax revenues could also be used as an alternative to electric service revenues or as an additional source of public investment for most or all of the applications discussed above. Since most funding at the state level has historically been collected from electric service revenues, this would represent a new tax and potentially be subject to I-601 limitations. The section below describes alternative approaches for supporting investment in system benefits from tax revenues.

9.6.5.1 System benefits tax or modified Public Utility Excise Tax

Energy efficiency, renewable resources, and/or low-income services could be directly funded through a state tax designed specifically for those purposes. Any of the applications of a system benefits charge discussed above could presumably be supported by a conventional tax.

Alternatively, utilities could be allowed to take credit against the Public Utility Excise Tax (PUET) for some or all of the cost of investments in qualifying energy efficiency, renewable resources, or low-income services. The PUET is a tax on electricity sales the proceeds of which go into the state general fund, so allowing a credit against the tax is essentially equivalent to spending general fund revenues for these purposes.

An alternative approach would be to replace the PUET with a sales and use tax levied at the conventional sales and use tax rate. Because a sales and use tax would apply to all energy purchases, it would eliminate the unequal taxation of in-state and out-of-state suppliers that may occur under the existing PUET (which only applies to sales from in-state utilities). Since the sales and use tax rate is higher than the PUET, it would also generate more revenues. This would make the change revenue neutral or positive from the perspective of the general fund, while potentially providing a new source of tax revenue for energy efficiency, renewable resources, and low-income services.

9.6.5.2 Other tax incentives

A variety of more targeted tax incentives to support energy efficiency, renewable resources, and low-income services could be considered. A few examples include:

- Reducing the size threshold for renewable resources to qualify for the existing sales tax exemption. Washington currently exempts solar and wind systems larger than 200 kW in capacity from state sales tax. However, a growing share of the market for solar systems in particular is in smaller, household-sized applications. The threshold for the tax exemption could be reduced to 100 watts, which would cover most household applications. This strategy may not appreciably increase demand, but it would level the playing field for in-state suppliers and help build a local infrastructure of qualified businesses to sell and service these systems.
- Supporting extension of the existing federal production tax credit for wind. The federal government offers a tax credit for electricity generated from wind power. The credit is scheduled to expire in 1999. State officials could support extension of this credit.
- Tax credits or deferrals to private developers or rental owners of energy efficient low-income housing.
- Tax credits for energy efficiency and renewable resource investments in homes and businesses. Oregon has a long history of granting personal and business income tax credits for energy efficiency and renewable energy investments. This model is obviously not directly applicable in Washington, which has no income tax. However, credits against other taxes, such as the B&O tax, could be considered.

9.6.6 Administration of Public Investment

The strategies described above address the potential sources of public investment in electric system benefits and some of the potential applications of public investment. This section addresses administration of investment. In particular, it poses alternative answers to the question "Who should administer the funds used for public investment in electric system benefits?"

The answers to this question may depend on a variety of factors, including the source of the investment. For example, general-purpose governments most often administer tax revenues, whereas electric service revenues are most often administered by utilities. The answer may also depend on the specific function; some investments may be most effectively implemented by local agencies, while others are more efficiently administered at a statewide, regional, or even national level. The choice of administrative options may also bear directly on the extent to which these purposes are accomplished fairly, efficiently, and effectively.

A wide variety of entities could conceivably administer public investment in electric system benefits. The discussion below focuses on five alternatives: utilities, the state, general-purpose local governments, non profit organizations, and consumers. It also describes coordination and assessment functions and alternative ways to administer those functions. The discussion of arguments for and against each approach is meant to be illustrative of the issues that arise under each alternative.

9.6.6.1 Utilities as administrator

- *Arguments for:* Utilities have traditionally administered much of the public investment in energy efficiency, renewable resources, and low-income services, particularly the investments that use electric service revenues as the funding source. Utilities generally have an established relationship with customers that may facilitate effective administration. They have a regular, familiar communication device in the form of monthly billing. Metering equipment potentially provides another form of interaction and communication with consumers. (Some stakeholders argue, however, that billing and metering should be subject to competition.) Most utilities have experience administering energy efficiency initiatives and low-income services, and many have some experience with renewable resources. The narrower geographic scope and electric service orientation of utilities may be particularly appropriate for administering local conservation programs tailored to local needs and opportunities.
- *Arguments against:* Utilities' financial interests may be at odds with the public interest in securing electric system benefits. Because their net revenues are generally a function of their electricity throughput, utilities may be reluctant to achieve energy savings. Successful energy efficiency initiatives, distributed renewables, and low-income services generally reduce utility revenues. This acts as a disincentive to making these investments and making them effectively, since the more effec-

tively a program saves energy, the greater its tendency to reduce revenues. This disincentive is exacerbated by near-term competitive pressure to minimize prices, since even cost-effective investments in energy efficiency may put upward pressure on prices. This disincentive may be mitigated by adoption of a competitively neutral funding mechanism such as the SBC. It may also be mitigated by adjustments to ratemaking formulas that change the relationship of net revenues to electric sales volumes.[47]

9.6.6.2 State as administrator

- *Arguments for:* In some states that have adopted a system benefits charge, a state agency administers the funds. Since states generally do not sell power, they do not face the disincentive associated with revenue reductions. State administration may facilitate simpler, more effective evaluation of results, to the extent that it is easier and less intrusive to track the activities of a single agency than it is to track numerous utilities or local governments. Economies of scale may be gained by administering programs on a statewide basis. Statewide administration may allow investments to be allocated where the opportunities and needs are greatest, maximizing the total return on public investment. The statewide scope and general-purpose focus of state government may be particularly appropriate for administering investments in codes and standards, market transformation, and research and development.
- *Arguments against:* Investments administered by the state may not be informed by the same level of understanding of unique local needs and circumstances as investments administered locally. By targeting resources to maximize return on public investment, a state administrator may distribute resources in a geographically uneven way, raising equity concerns. State administration of these programs may introduce an unnecessary layer of bureaucracy that reduces local control. To mitigate this problem, a state administrator could award public investment funds by competitive bid, allowing utilities and other providers to compete to provide the most effective programs and minimizing the state's involvement in program implementation.[48] As a general-purpose government, the state may face competing pressures and goals that detract from its focus on achievement of energy efficiency, renewable resources, and low-income services. States may also face staffing restrictions and inflexible contracting procedures.

9.6.6.3 Local governments as administrator

- *Arguments for:* Many of the arguments for local administration of public investment apply to local governments as well as utilities. General-purpose local governments arguably offer a more direct form of local control than utilities. Unlike most local utilities, however, most general-purpose local governments do not face a direct disincentive to effective implementation of energy saving strategies, because their revenues are not strongly dependent on electric power sales. Administration of public investment by general-purpose local governments may also facilitate integration of electric system benefits initiatives with related programs such as water resource management. Administration by county governments, which are authorized as administrative agents of the State, may be a way to help reconcile state interests with the desire for local control. Local, general-purpose governments may be particularly effective in capturing economies of scope associated with coordinated resource management activities.

- *Arguments against:* General-purpose governments may not have the experience and expertise necessary for administering electric system benefit investments. Because these investments are directly related to the basic goals and functions of electric service, they may be best administered by entities with a narrower focus on electric service delivery. To the extent that local governments provide direct accountability, some of this benefit is offset by the fact that much of Washington is already served by consumer-owned utilities. Because of their general purpose obligations, local governments may understandably be inclined to focus limited resources on priority issues for which they are directly responsible (such as public safety) to the exclusion of electric system benefits. Insofar as electric service revenues fund public investments in electric system benefits, this pressure to devote available resources to general-purpose government priorities may raise equity concerns.

9.6.6.4 Non profit organization as administrator

- *Arguments for:* Many of the arguments for a state administrator would also support a non profit organization. Such an organization could be statewide in scope, allowing economies of scale and targeted investment to maximize returns. A non profit organization would not face conflicts associated with reduction in revenues due to successful program implementation. Unlike general-purpose government, a non profit organization could be directly accountable to energy stakeholders through a board comprised of a balanced representation of energy service providers, consumers and other stakeholders. Such a board could be tightly focused on achievement of electric system benefits, and therefore not face the multiple pressures and objectives faced by general purpose governments. A non profit organization may be particularly effective in administering market transformation, research and development, or other investments that require coordination among interest groups and a shared focus on electric system benefits.
- *Arguments against:* Many of the arguments against a state administrator apply equally to a non profit administrator, insofar as a non profit would be statewide in scope. A non profit organization would require a new accountability structure, whereas utilities and general-purpose govern-

ments have built-in accountability structures. While the non profit board would allow for direct representation of stakeholders, the competing interests embodied in its governing structure could limit its effectiveness and efficiency.

9.6.6.5 Consumers as administrator

Consumers could administer public and private investment by taking credit against system benefits charges or taxes for qualifying energy efficiency and renewable resource activities in their own facilities.

- ❖ *Arguments for:* To the extent that energy efficiency and renewable energy investments provide a direct benefit to the facilities in which they occur, this approach could help align costs and benefits. Consumers would have a particularly strong stake in ensuring delivery of results, since they would bear the costs and benefits more directly. Administration could be fairly simple, especially for larger customers, insofar as it would rely on existing models and mechanisms for claiming tax credits. This approach may be particularly suited to energy efficiency investments with unique characteristics that do not lend themselves to more generalized program approaches, such as industrial process improvements.
- ❖ *Arguments against:* This approach could reduce achievement of system benefits by allowing public investment to be used for measures that market forces are capable of delivering. If consumers can claim credit for investments with very short payback periods, for example, then public investment may replace rather than encourage private investment. Since this approach would entail a much larger number of entities, administration could be complicated and accountability could be unclear. This approach may raise equity concerns, since not all consumers have equal ability to conceive and administer these investments. It may be poorly suited for investments such as renewable generation, research and development, market transformation, and low-income services that cannot be made in individual customer facilities.

As noted above, these administrative options have different strengths. If public investment is to be administered fairly, efficiently, and effectively, one size may not fit all. Determination of the appropriate level of administration depends on the specific purpose and the unique aptitudes of the different administrators.

9.6.7 Other Policy strategies to secure electric system benefits that may require little or no direct public investment

The discussion above focuses on funding and administrative strategies for energy efficiency, renewable resources, and low-income services that require some level of public investment. Alternative strategies may focus primarily on improving the incentives for private investment in these purposes. They may be used in combination with public investment strategies or independent of them.

9.6.7.1 Policy strategies for energy efficiency

- *Energy Codes.* Energy code improvements have delivered substantial energy savings to Washington consumers over the past 15 years. Residential and commercial codes in Washington will capture over 270 aMW in cost-effective savings by 2003. Energy codes may promote equitable achievement of energy efficiency goals, since they tend to align the costs and benefits of energy efficiency investments. Codes could be examined and updated to incorporate new cost-effective measures on a regular cycle to coincide with other routine code updates. (However, frequent code changes can undermine compliance by preventing users of the code from gaining familiarity with rapidly changing provisions.) Adoption of and compliance with energy codes generally requires some familiarity with the new practice on the part of designers, builders, and building code officials. Code improvements in Washington to date would probably not have been possible without public investment in new energy efficiency technologies and in education, training and compliance activities. However, these public investments are generally modest relative to the magnitude of the savings achieved.
- *Product efficiency standards.* Unlike building codes, product efficiency standards are generally the province of federal rather than state or local government. However, state officials can and do play a significant role in the adoption of federal appliance efficiency standards. (Washington State participation in development of national product efficiency standards has decreased significantly in recent years.) Here again, codes and standards generally do not “push the envelope” on new energy efficiency technologies; they are generally preceded by public and private investments in research and commercialization of new technologies. However, they can substantially increase efficiency by adjusting industry standard practices to keep pace with commercialization of proven, cost-effective technologies.
- *Establish energy savings targets for public facilities.* Public facilities are often major energy consumers. The world’s largest energy consumer is the U.S. federal government. Federal Executive Order 12902 requires federal agencies to substantially reduce their energy consumption over time. Non-federal public facilities in Washington State spent nearly $200 million per year for electricity in 1990, the last year for which data are available. One study estimates that up to one-quarter of that expenditure could be reduced cost-effectively by energy conservation measures and energy efficient operations.[49] State law (RCW 39.35) requires life cycle cost analysis for all new and remodeled public facilities. However, implementation of this requirement is sporadic and even when the analysis is conducted, cost-effective energy efficiency opportunities are often missed.

Capturing energy savings can reduce the cost of providing public services and/or free up public funding for accomplishment of other public priorities. However, the same market barriers and short-term cost pressures that prevent private investment also affect public agencies. Lack of coordination between state capital and operating budgets impedes capital investments that reduce operating costs.

Like their counterparts in the private sector, public facility managers may be reluctant to make investments in energy efficiency unless they produce positive net cash flows from the outset. This can frequently be accomplished through the use of Energy Savings Performance Contracts in which public agencies defray first costs by pledging a percentage of energy savings to repay financing costs.[50] Energy efficiency in public facilities can also be enhanced through comprehensive building commissioning to ensure optimal performance and training and support of resource conservation managers who can maintain and improve energy performance over time. The general approach of establishing public facility targets can also be applied to renewable resource use. The federal government presently encourages agencies to use renewables and provides technical and contracting assistance to agencies that choose to do so.

9.6.7.2 Policy strategies for renewable resources

- *Portfolio standards:* Portfolio standards establish a requirement for power suppliers to provide a minimum proportion of their power from renewable resources. State policy-makers could support a federal renewable portfolio standard (RPS) or adopt one at the state level. Some national restructuring proposals would establish a RPS. Most proposals would attempt to minimize the cost of meeting the standard by allowing suppliers either to acquire the output of renewables or purchase credits toward the requirement from suppliers who have more than the minimum requirement. A state portfolio standard may be somewhat more difficult to administer, due to complications associated with extensive interstate electricity sales. However, seven states have adopted portfolio standards.

  Portfolio standards represent a direct policy choice to deliver a certain proportion of renewables rather than to provide public investment or subtly change market incentives. As such, they are sometimes viewed as excessive intervention in private markets. However, others argue that by establishing a goal for renewable resource achievement and then letting the market achieve that goal as efficiently as possible, portfolio standards minimize the need for government involvement in implementation.

- *Fuel and emissions disclosure and labeling.* This strategy would attempt to improve the ability of the market to deliver renewable resources by providing better information to consumers about environmental characteristics. [51] (The impact of this strategy would clearly be more pronounced in a retail access environment or where consumers may choose renewables. See following strategy.) This strategy requires development of a standard tracking mechanism for wholesale transactions and a standard labeling format for communicating fuel mix and emissions data to consumers. (Development of a tracking system for the western interconnection is currently under way.[52]) In addition to facilitating market functions by providing information, this strategy may also build consumer confidence by ensuring that consumers know what they're getting when they choose "green" electric power products. This strategy is discussed at length in the study prepared for the Legislature under HB 2831.
- *Delivery of renewable resources to customers who choose them.* The Comprehensive Review recommended that retail utilities provide direct customer access to renewable resources in advance of any action with respect to retail access generally. Alternatively, utilities could be required or encouraged to offer a green option for consumers who request it. This strategy could be combined with public investment to buy down some or all of the incremental cost of renewables for the customers who choose them. This strategy would not address underinvestment due to the "public goods" quality of renewables.[53] Also, it may be difficult to justify the administrative costs of providing direct access on such a limited basis.
- *Internalize environmental costs.* Prices that accurately and fully reflect costs are one of the preconditions for efficient operation of competitive markets.[54] One reason that private investment in energy efficiency and renewable energy may not be sufficient to minimize total costs is that many of the environmental costs of energy remain external to price. Internalization of environmental costs would raise prices for some energy resources, but may encourage minimization of total costs and enhance private investment in energy efficiency and renewable resources.

  The costs associated with carbon dioxide emissions are perhaps the largest external cost of fossil-fueled energy resources, because these emissions are unregulated. Options for internalizing the cost of carbon dioxide emissions include state or federal emission standards and carbon taxes. Carbon taxes could be structured to be revenue neutral by offsetting other taxes, or they could be used as an alternative to the system benefits charge and tax options discussed above. A market-based strategy for internalizing environmental costs is to establish a standard (based on scientific and/or policy determinations) and then establish a system of tradable credits that allows the standard to be met with the least costly mix of mitigation strategies. This is the strategy advocated by U.S. representatives in global climate treaty negotiations.

It is also the strategy used to minimize the cost of sulfur dioxide reduction in the Clean Air Act.

Policies that internalize environmental costs tend to raise concerns among price-sensitive customers, many of whom locate in Washington because of low power prices. However, internalization of the cost of greenhouse gases due to national or international actions would probably increase the relative attractiveness of Washington power rates, since relatively little of Washington's power is provided by fossil fuels.

9.6.7.3 Policy strategies for low-income services

- *Rate Discounts.* A rate discount for low-income service could be adopted in legislation or required by state or local utility regulators. Massachusetts' law, for instance, requires that utilities provide rate reductions of 25-35%. California adopted needs-based funding for its low-income rate discount program. (Rate discounts currently offered by Washington utilities are discussed in 9.4.2 .) There is some question as to whether and under what conditions current Washington law authorizes the UTC to adopt special rates for low-income customers.[55] Rate discounts could be partially or fully supported by public investment in the form of SBC funds or tax revenues.
- *Universal electric service based on percent of income.* Clark County PUD guarantees that low-income consumers will not be disconnected or charged additional fees if they spend at least 9 percent of their income on their electric power bill. This mechanism tends to index the level of assistance to the level of need. Utility evaluations of the program indicate that the utility and its ratepayers are saving money by operating this program. The utility has experienced fewer uncollectible bills, improved payment collection from its low-income customers, and lower administrative costs. Public investment funds (SBC or tax credits) could be made available for some or all of the difference between the actual bill and the percent-of-income threshold for utilities that elect to use this approach. (Public investment may not be necessary, however, to the extent that the program decreases costs for utilities, as it apparently has for Clark.) Some state regulatory commissions including Ohio and Pennsylvania require such programs for their jurisdictional utilities due to the financial savings associated with improved payment collection and reduced administrative costs. Utilities serving areas with disproportionately large low-income populations may find this approach more difficult.[56]

9.6.8 Coordination and Assessment

Regardless of which entities administer investments and which policy strategies are employed, there are a number of functions that may require cooperation and coordination among the many entities involved in delivering electric system benefits. These functions may include, but not be limited to:

- Assessment and periodic reevaluation of the appropriate level of public investment.
- Establishment of performance objectives and tracking of achievement of those objectives.
- Development of strategies to ensure that public investment encourages rather than supplants private investment and facilitates the efficient functioning of markets for energy efficiency and renewable resources.
- Identification of opportunities to achieve system benefits more effectively and efficiently.
- Identification of opportunities to form partnerships among the many private and public institutions involved in energy efficiency, renewable resources, and low-income service delivery.
- Participation of energy service providers, consumers, and other stakeholders in crafting policies and procedures to improve delivery of electric system benefits over time.

Some of these functions may be performed at the regional level by the Regional Technical Forum that the Northwest Power Planning Council proposes to form.[57] To the extent that these functions are not performed by the RTF (or that they need to be performed at a state level) the state could:

- Form an electric (or energy) system benefits board comprised of electric service providers, consumers, and other stakeholders to fulfill these functions. The responsibilities of such a board could be limited to periodic assessments of electric system benefits achievements and investments. Or its responsibilities could be as broad as administration of competitive bids for delivery of electric system benefits. It could focus only on administration of public investment in electric system benefits, or it could also focus on other policy strategies to achieve these benefits that may not require direct public investment.
- Alternatively, assign the coordination and assessment functions described above to existing institutions. A stakeholder advisory group could be formed to guide such institutions in their administration of coordination and assessment functions.

Endnotes for Section 9

[1]As defined by the 1980 Regional Act, system cost means "an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and, among other factors, waste disposal costs, end-of-cycle costs, and fuel costs, and such quantifiable environmental costs and benefits as... are directly attributable to such measure or resource."

2Clean Air Act of 1970 (PL 91-604), Amendments of 1977 (PL 95-95), Amendments of 1990 (PL 101-549)

[3]Public Law 96-501, Pacific Northwest Electric Power Planning and Conservation Act, December 5, 1980.

[4] *Clearing Up*, no. 777, May 27, 1997, 4.

[5] *Clearing Up*, no. 764, February 24, 1997, 4.

[6]The Council estimate of the proportion of cost-effective conservation that will be captured by market forces assumes the current system of average rates. It may be not applicable to restructured electricity markets, where changing incentives could increase or reduce this proportion.

[7]NWPPC, *Fourth Draft Northwest Conservation and Electric Power Plan*, Volume II, p. G-21. Portland, OR. 1996.

[8] NWPPC, *Green Book*, February 1996.

[9] NWPPC, *Fourth Draft Northwest Conservation and Electric Power Plan.* Portland, OR. 1996.

[10] Marvin Brown, "Miss Liberty's energy diet", *Hart's Energy Markets*, June-July 1998, 13-20.

[11] Washington State Department of General Administration brochure, "Energy Savings Performance Contract."

[12] US General Accounting Office, August 1996. *Federal Research: Changes in Electricity-Related R&D Funding*. GAO-RCED-96-203. Washington, DC.

[13]ECONorthwest, *The Next Generation of Energy*, CTED, August 1998.

[14] Last year, the Washington legislature past "net metering" legislation that allows excess solar electricity produced in grid-connected residential applications to be credited against the customer's power bill.

[15] Northwest Power Planning Council, 1996; Lafond, 1992.

[16] The Intergovernmental Panel on Climate Change, a panel of world scientists considered to be the world's most authoritative scientific body on climate change, has concluded that stabilizing the climate requires reducing carbon dioxide (CO2) emissions by 50 to 70 percent. Intergovernmental Panel on Climate Change, *IPCC Second Assessment Climate Change 1995*. United Nations.

[17] NWPPC, *Fourth Draft Northwest Conservation and Electric Power Plan*. Portland, OR. 1996.

[18] ECONorthwest, 1998.

[19] List the three: ITT Rayonier, Port Angeles; Gorge Energy, Bingen;

[20] WSU Energy Program; M. Nelson, 1998.

[21] IPCC, *First Assessment Report*, August 1990, cited in Australia Department of Environment and Heritage, *News of the Intergovernmental Panel on Climate Change Vol. 1 No 1 - December 1993*, http://www.environment.gov.au/portfolio/esd/climate/air/climate/clim_change/ipcc1_1.html

[22] Holt, Edward, "Information Consumers Want In Electricity Choice: Summary of Focus Group Research." The National Council on Competition and the Electric Industry, December 1997.

[23] Economists distinguish between "internal costs" - those that are recognized and recovered in the price of goods and services - and "external costs" - the costs of "consequences and damages which third persons or the community sustain as a result of productive processes." K.W. Kapp, "The Societal Costs of Private Enterprise." Cambridge, Mass: Harvard University Press, 1950.

[24] Rader and Short, 1998.

[25] *Clearing Up*, No. 848, October 12, 1998, 7-8.

[26] Barry, L., M. Brown, and L. Kinney, 1997. *Progress Report of the National Weatherization Assistance Program*. ORNL/CON-450. Oak Ridge, Tennessee: Oak Ridge National Laboratory.

[27] CTED, "Weatherization Works in Washington." n.d.

[28] Barry, L., M. Brown, and L. Kinney, 1997. *Progress Report of the National Weatherization Assistance Program*. ORNL/CON-450. Oak Ridge, Tennessee: Oak Ridge National Laboratory.

[29] Washington State University Energy Extension, http://web03.energy.wsu.edu/org/wa-enrgy/

[30] Clark PUD, "Evaluation of Guarantee of Service Program," September 14, 1990.

[31] RCW 54.16.285 identifies six conditions that a low-income customer must meet to avoid disconnection of energy for winter heating use: 1) notifies utility of inability to pay bill within 5 days of notice of overdue account; 2) self-certifies household income for 12 prior months to CTED; 3) has applied for home heating assistance from applicable government and private sector organizations; 4) has applied for low-income weatherization assistance; 5) agrees to a payment plan and agrees to maintain the plan; and 6) agrees to pay moneys owed even if he or she moves.

[32] National Consumer Law Center, *Energy and Utility Update*, Nov/Dec 1997, 3.

[33] "Weatherization Works in Washington."

[34] *Statistical Abstract of the United States*, 1997, Washington State, http://www.census.gov/statab/www/states/wa.txt.

[35] OFM, Washington State Data Book 1997, Table ST01.

[36] Kushler, Martin, *An Updated Status Report of Public Benefit Programs In An Evolving Electric Utility Industry*, American Council for an Energy Efficient Economy, September 1998.

[37] Ibid

[38] Levine, M, E. Hirst, J. Koomey, J. McMahon, and A. Sanstad, 1994. *Energy Efficiency, Market Failures, and Government Policy*. LBL-35376; ORNL/CON-383. Berkeley, CA: Lawrence Berkeley Lab.

[39] Ibid.

[40] Meier, Alan and J. Whittier, 1983. "Consumer Discount Rates Implied by Purchases of Energy-Efficient Refrigerators." *Energy*. 8(12):957.

[41] NWPPC. *Fourth Northwest Conservation and Electric Power Plan*. 96-5A. Portland, OR: p G-18. This estimate is based on an assumption that consumers will purchase all energy-saving equipment that pays for itself in energy savings within three years. Some evidence suggests that for many purchasing decisions, consumers require an even shorter payback period.

[42] Commonwealth of Massachusetts Department of Public Utilities, Electric Industry Restructuring Plan: Model Rules and Legislative Proposal, D.P.U. 96-100, 12/30/96. (pp. A-17)

[43] Barry, L., M. Brown, and L. Kinney, 1997. *Progress Report of the National Weatherization Assistance Program*. ORNL/CON-450. Oak Ridge, Tennessee: Oak Ridge National Laboratory.

[44] General Accounting Office, August 1996. GAO-RCED-96-203. *Federal Research: Changes in Electricity-Related R&D Funding*. Washington, DC: United States General Accounting Office.

[45] For example, Supertintendent of Public Instruction 's "Food and You" curriculum included an energy efficiency component.

[46] Tutt, Timothy, California Energy Commission. 1998. *Bidding the Green: Incentivizing New Renewable Power Development in California*. Proceedings of ACEEE 1998 Summer Study on Energy Efficiency in Buildings.9.223-9.233

[47] For example, the Oregon PUC has adopted an "alternative form of rate-making" for PacifiCorp in which distribution revenues are not a direct function of electric sales volumes. This means that PacifiCorp will not suffer a reduction in distribution revenues due to successful energy efficiency initiatives. A similar rate-adjustment mechanism was implemented for Puget Sound Power and Light Company in the early 1990s. Due to unintended consequences it was discontinued by the UTC in 1995.

[48] Massachusetts, California, and Rhode Island will use competitive bidding processes to allocate at least some of their energy efficiency funds. See Kushler, M. September 1998. An Updated Status Report of Public Benefit Programs In An Evolving Electric Utility Industry. Washington DC: American Council for An Energy Efficient Economy

[49] Ecotope, Inc. *Energy Conservation in Public Buildings*, April 15, 1991 report for the Washington State Energy Office. This report is based on 1990 data. However, energy savings potential has probably not changed dramatically, because the estimates of cost-effective potential were based on retail prices (which have not declined) rather than "avoided costs" (which have declined substantially since 1990).

[50] Washington State Department of General Administration brochure, "Energy Savings Performance Contract."

[51] The Regulatory Assistance Project. *The National Council on Competition and the Electric Industry Synthesis Report: A Summary of Research on Information Disclosure*. April 1998. Gardiner, Maine.

[52] Washington Commissioner Bill Gillis and staff joined utility commissioners and staff from eleven states and British Columbia on a Western Disclosure and Tracking Project. The objective of the project is to develop a mechanism to track electricity generation attributes from the source to the end user. Since electricity is traded regionally, tracking will be much easier if the Western grid develops a common system. The group reached consensus this summer on a preferred approach: a "claims-based certificate" tracking mechanism, in which a neutral third party (a "regional clearinghouse") would issue certificates to electricity generators based on their generation; generators could sell the certificates to marketers or keep them; any electricity retail seller must possess certificates to justify any claims they make about their product. Details of the proposal are still under development.

[53] Perhaps because of these "public goods" characteristics, some surveys indicate that consumers would prefer that all customers share the cost of delivering these resources rather than just those who elect to pay more. See, for example, "Study of PUD Customer Acceptance of Renewable Energy." Final report prepared for CARES by Gilmore Research Group, November 1997, p. 2. "There is strong support to spread the costs of new renewables across the customer base, rather than just among the customers who support developing these sources."

[54] Energy economics literature contains numerous descriptions and analyses of the external costs of electric power production as well as the general theory of externalities. Perhaps the most comprehensive review of the literature is contained in Environmental Costs of Electricity, Pace University Center for Environmental Legal Studies, 1990.

[55] An Attorney General's opinion has held that the WUTC does not have authority to extend rate discounts to low-income residents because it would constitute unreasonable discrimination or be unduly preferential (in violation of RCW 80.28.080) and because the provision allowing reduced rates does not apply to low-income persons because they would not be considered indigent or destitute (RCW 80.28.080).

[56]The 1990 census identified 8 counties with concentrations of low-income residents greater than 25%: Columbia, Ferry, Franklin, Grays Harbor, Kittitas, Okanogan, Pend Oreille, and Whitman.

[57] Northwest Power Planning Council, July 1998. "Draft Proposal for Initiating the Regional Technical Forum." 98-18. Portland, OR.

Appendix 1.1

Schedule of Average Utility Rates

	Schedule of Average Utility Rates					
	1993-1997					
		Cents/kWh				
Utility	Source	1993	1994	1995	1996	1997
Alder Mutual	EIA					
Residential		4.69	4.91	5.16	4.77	---
Commercial		4.80	5.03	5.43	5.58	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Benton REA	6560					
Residential		4.44	5.03	5.04	4.97	4.81
Commercial		3.65	3.98	4.14	3.84	3.74
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		2.91	3.06	3.19	3.09	2.97
Big Bend Electric Coop	EIA					
Residential		4.43	4.78	4.91	4.82	---
Commercial		4.09	4.41	4.62	4.52	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Blaine	EIA					
Residential		4.34	4.60	4.62	5.16	---
Commercial		4.64	4.99	4.94	5.60	---
Industrial-tariffed		5.28	5.75	5.07	6.19	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Bonneville Power Admin.	EIA					
Residential		---	---	---	---	---
Commercial		---	---	---	---	---
Industrial-tariffed		1.90	2.31	2.66	2.29	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---

Cashmere	EIA					
Residential		1.92	2.15	2.51	2.64	---
Commercial		2.36	2.50	2.82	2.91	---
Industrial-tariffed		1.58	1.68	1.83	1.86	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Centralia	EIA					
Residential		3.45	4.02	4.21	4.34	---
Commercial		3.37	4.07	4.25	3.92	---
Industrial-tariffed		3.52	3.71	3.82	3.97	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Cheney	EIA					
Residential		4.76	5.14	5.35	5.32	---
Commercial		3.87	3.98	4.45	4.17	---
Industrial-tariffed		3.79	4.22	4.06	4.39	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Chewelah	EIA					
Residential		5.43	5.49	5.65	5.65	---
Commercial		5.55	5.61	5.78	5.87	---
Industrial-tariffed		---	---	6.55	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Clearwater Power	EIA					
Residential		6.88	7.42	7.45	7.03	---
Commercial		5.73	6.23	6.33	5.73	---
Industrial-tariffed		3.88	3.77	3.80	3.48	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Columbia REA	EIA					
Residential		5.09	5.64	5.68	5.61	---
Commercial		6.88	6.79	6.82	6.50	---
Industrial-tariffed		3.47	3.79	3.78	3.77	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---

Coulee Dam	EIA					
Residential		3.65	3.96	4.30	4.49	---
Commercial		4.05	3.79	4.69	4.86	---
Industrial-tariffed		7.93	1.62	4.49	5.09	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Eatonville	EIA					
Residential		4.72	5.06	5.27	5.27	---
Commercial		4.35	4.84	4.85	7.17	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Ellensburg	EIA					
Residential		4.60	5.12	5.05	5.21	---
Commercial		4.32	5.18	4.71	4.77	---
Industrial-tariffed		3.83	4.21	4.06	4.13	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Elmhurst Mutual	EIA					
Residential		3.82	4.13	4.31	4.34	---
Commercial		3.73	4.02	4.19	4.23	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Fircrest	EIA					
Residential		4.80	5.24	5.23	5.56	---
Commercial		5.57	5.73	5.21	5.50	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Inland Power & Light	6560					
Residential		5.85	6.05	6.09	5.79	5.34
Commercial		5.17	5.23	5.20	5.14	4.85
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		5.37	5.43	4.34	3.95	4.11

Kootenai Elec. Coop	EIA					
Residential		5.45	5.60	5.71	5.77	---
Commercial		6.33	7.76	7.84	6.00	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Lakeview P & L	EIA					
Residential		3.23	3.50	3.51	3.50	---
Commercial		3.54	3.97	3.87	3.84	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
McCleary	EIA					
Residential		4.41	4.72	5.01	5.15	---
Commercial		4.36	4.64	4.93	5.04	---
Industrial-tariffed		3.57	3.87	4.18	4.38	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Milton	EIA					
Residential		4.09	3.74	4.07	4.08	---
Commercial		3.59	4.68	4.78	3.39	---
Industrial-tariffed		2.51	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Modern Electric	EIA					
Residential		4.37	4.39	4.39	4.41	---
Commercial		4.51	4.48	4.46	4.43	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Nespelem Valley Coop	EIA					
Residential		5.24	5.73	5.81	5.96	---
Commercial		3.47	5.00	5.05	5.22	---
Industrial-tariffed		---	---	---	4.65	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---

Northern Lights	EIA					
Residential		6.40	7.19	6.70	6.80	---
Commercial		---	---	---	---	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Ohop Mutual	EIA					
Residential		4.94	5.36	5.37	5.34	---
Commercial		4.95	5.65	5.26	5.31	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Okanogan Co. Elec Coop	EIA					
Residential		5.22	6.19	6.24	6.21	---
Commercial		4.30	4.75	4.77	4.78	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Orcas P & L	6560					
Residential		7.55	8.00	8.21	7.82	7.44
Commercial		5.42	5.90	6.11	5.83	5.54
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		6.30	6.35	6.00	6.00	6.04
PacifiCorp	6560					
Residential		4.67	4.88	4.91	4.94	5.05
Commercial		4.71	4.72	4.73	4.73	4.73
Industrial-tariffed		3.63	3.59	3.63	3.65	3.72
Non-traditional		---	---	---	---	2.39
Other		4.36	4.28	4.67	4.41	5.03
Parkland L & W	6560					
Residential		4.04	4.42	4.72	4.75	4.73
Commercial		3.75	4.06	4.28	4.38	4.13
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---

Peninsula Light	EIA					
Residential		5.03	5.39	5.41	5.37	---
Commercial		4.73	4.81	4.83	4.85	---
Industrial-tariffed		4.37	3.51	3.50	3.51	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Port Angeles	EIA					
Residential		4.35	4.88	4.92	4.93	---
Commercial		3.98	4.39	4.36	4.41	---
Industrial-tariffed		2.61	3.07	2.93	2.77	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Puget Sound Energy	6560					
Residential		5.59	5.97	5.99	6.15	5.90
Commercial		5.77	5.96	6.21	6.43	6.14
Industrial-tariffed		4.07	4.39	4.62	5.06	5.57
Non-traditional		---	---	---	3.31	3.38
Other		13.51	13.77	14.04	14.53	14.23
PUD #1 of Asotin Co	EIA					
Residential		---	---	---	---	---
Commercial		---	---	3.77	3.77	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #1 of Benton Co.	EIA					
Residential		4.71	5.33	5.34	5.26	---
Commercial		3.86	4.23	3.80	3.64	---
Industrial-tariffed		2.84	2.93	3.00	2.85	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #1 of Chelan Co.	6560					
Residential		1.98	2.23	2.57	2.76	2.76
Commercial		2.36	2.54	2.84	2.99	2.98
Industrial-tariffed		1.56	1.64	1.81	1.87	1.81
Non-traditional		---	---	---	---	---
Other		2.98	3.11	3.70	3.75	4.05

PUD #1 of Clallam Co.	EIA					
Residential		5.16	5.41	5.61	5.62	---
Commercial		5.11	5.34	5.54	5.60	---
Industrial-tariffed		3.95	4.10	4.46	4.26	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #1 of Clark Co.	6560					
Residential		4.21	4.63	4.61	4.62	4.66
Commercial		3.29	3.57	3.56	3.48	3.57
Industrial-tariffed		2.56	2.75	2.74	2.81	2.57
Non-traditional		---	---	---	---	---
Other		5.99	6.39	5.91	5.96	6.84
		---	---	---	---	---
PUD #1 of Cowlitz Co.	6560					
Residential		2.64	2.91	2.89	2.90	2.69
Commercial		3.55	3.90	3.88	3.86	3.38
Industrial-tariffed		2.89	3.14	3.09	3.11	2.82
Non-traditional		2.53	2.76	2.64	2.34	2.10
Other		4.52	4.67	4.72	4.75	4.66
PUD #1 of Douglas Co.	EIA					
Residential		1.56	1.69	2.01	2.08	---
Commercial		1.40	1.62	2.00	2.20	---
Industrial-tariffed		1.39	1.58	1.77	1.79	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #1 of Ferry Co.	EIA					
Residential		5.35	5.65	5.64	6.12	---
Commercial		5.20	5.48	5.60	5.90	---
Industrial-tariffed		3.98	4.22	4.22	4.22	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #1 of Franklin Co.	6560					
Residential		4.75	5.25	5.36	5.16	5.00
Commercial		3.69	4.08	4.14	4.00	3.84
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		3.05	3.23	3.51	3.34	3.51

PUD #1 of Grays Harbor Co.	6560					
Residential		4.54	4.84	4.87	4.85	4.86
Commercial		4.70	4.95	4.97	4.98	4.96
Industrial-tariffed		3.67	3.56	3.71	3.64	3.67
Non-traditional		---	---	---	---	---
Other		11.46	11.32	10.77	11.40	12.31
PUD #1 of Kittitas Co.	EIA					
Residential		5.43	5.83	5.86	5.83	---
Commercial		4.07	5.70	5.60	3.53	---
Industrial-tariffed		---	3.63	3.70	5.54	---
Non-traditional		---	---	---	---	---
Other						
PUD #1 of Klickitat Co.	EIA					
Residential		5.14	5.60	5.61	5.56	---
Commercial		5.20	5.66	5.67	5.64	---
Industrial-tariffed		3.27	3.58	3.46	3.50	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #1 of Lewis Co.	EIA					
Residential		4.10	4.35	4.28	4.25	---
Commercial		4.20	4.45	4.47	4.20	---
Industrial-tariffed		4.77	3.91	3.96	3.66	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #1 of Mason Co.	EIA					
Residential		5.81	6.25	6.28	6.21	---
Commercial		5.79	6.17	6.16	6.03	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #1 of Okanogan Co.	EIA					
Residential		2.62	2.73	2.87	2.92	---
Commercial		2.98	3.06	3.23	3.32	---
Industrial-tariffed		1.97	2.28	2.68	2.84	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---

PUD #1 of Pend Oreille Co.	EIA					
Residential		3.11	3.14	3.10	2.86	---
Commercial		2.48	2.48	2.45	2.43	---
Industrial-tariffed		1.99	2.30	2.12	2.00	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #1 of Skamania Co.	EIA					
Residential		4.70	5.17	5.18	5.21	---
Commercial		4.21	4.49	4.53	4.50	---
Industrial-tariffed		3.39	4.06	4.09	4.18	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #1 of Snohomish Co.	6560					
Residential		4.42	5.12	5.12	5.11	5.06
Commercial		3.89	4.43	4.41	4.39	4.35
Industrial-tariffed		3.03	3.37	3.45	3.35	3.65
Non-traditional		---	---	---	2.61	2.71
Other		7.30	9.30	7.20	7.25	7.25
PUD #1 of Wahkiakum Co.	EIA					
Residential		5.33	5.76	5.90	5.95	---
Commercial		6.05	6.43	6.51	6.57	---
Industrial-tariffed		---	8.52	8.78	8.77	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #1 of Whatcom Co.	EIA					
Residential		---	---	---	---	---
Commercial		---	---	---	---	---
Industrial-tariffed		2.42	2.38	2.70	2.61	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #2 of Grant Co.	6560					
Residential		2.29	2.50	2.64	2.85	3.21
Commercial		1.43	2.01	2.11	2.26	2.45
Industrial-tariffed		1.11	1.14	1.27	1.45	1.63
Non-traditional		---	---	---	---	---
Other		2.04	1.99	2.28	2.45	2.93

PUD #2 of Pacific Co.	EIA					
Residential		4.61	5.25	5.27	5.24	---
Commercial		5.14	5.62	5.64	5.64	---
Industrial-tariffed		3.35	3.59	3.59	3.66	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
PUD #3 of Mason Co.	EIA					
Residential		4.76	5.22	5.39	5.54	---
Commercial		4.52	4.97	4.99	5.08	---
Industrial-tariffed		3.06	3.46	3.43	3.55	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Richland	EIA					
Residential		4.82	5.07	5.00	4.60	---
Commercial		3.93	4.22	4.28	4.18	---
Industrial-tariffed		3.26	3.51	3.50	3.38	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Ruston	EIA					
Residential		5.00	4.77	9.47	4.60	---
Commercial		---	---	---	---	---
Industrial-tariffed		2.64	2.68	2.08	3.22	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Seattle City Light	6560					
Residential		3.73	3.78	3.92	4.05	4.25
Commercial		3.50	3.65	3.65	3.74	3.83
Industrial-tariffed		3.02	3.20	3.27	3.44	3.41
Non-traditional		---	---	---	3.62	3.74
Other		6.15	6.30	5.85	5.87	6.04
Steilacoom	EIA					
Residential		4.49	5.38	6.02	6.09	---
Commercial		4.71	5.01	5.40	5.38	---
Industrial-tariffed		4.09	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---

Sumas	EIA					
Residential		5.42	5.48	5.54	5.78	---
Commercial		4.98	4.96	5.02	5.52	---
Industrial-tariffed		4.90	4.94	5.00	5.50	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Tacoma	6560					
Residential		3.95	4.16	4.33	4.41	4.42
Commercial		4.02	4.24	4.44	4.51	4.53
Industrial-tariffed		3.17	3.37	3.47	3.47	3.48
Non-traditional		2.22	2.39	2.44	2.41	2.37
Other		---	---	---	---	---
Tanner Electric Coop	EIA					
Residential		6.26	6.48	6.13	6.02	---
Commercial		5.57	5.84	5.71	5.67	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Vera Irrigation	EIA					
Residential		3.77	4.16	4.25	4.29	---
Commercial		3.92	4.27	4.30	4.40	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---
Washington Water Power	6560					
Residential		4.90	4.86	4.92	4.96	4.95
Commercial		5.26	5.28	5.30	5.35	5.35
Industrial-tariffed		4.10	4.01	4.00	3.82	3.90
Non-traditional		3.46	3.61	3.73	4.57	21.15(a)
Other		13.59	13.65	14.01	14.01	14.01
Waterville	EIA					
Residential		2.26	2.45	2.42	2.75	---
Commercial		2.34	2.40	2.36	2.79	---
Industrial-tariffed		---	---	---	---	---
Non-traditional		---	---	---	---	---
Other		---	---	---	---	---

(a) standby service contract with high fixed charges and few kwh delivered.

Appendix 2.1

BPA Cost Review Committee Recommendations

Appendix 2-1: Recommendations of the Management Committee for the Cost Review of the Federal Columbia River Power System	Average Annual Reductions, FYs 2002-2006, $ in millions	
	Total Reductions	**Power BL Expense Reductions**
1. Further reduce staffing and support costs of power marketing and other PBL functions not directly related to operation of the Federal power system, through efficiency initiatives and reoriented long-term marketing efforts.	14.7	14.7
2. Fund regional conservation market transformation at a level proportional to the percent of regional firm load served by Bonneville, as called for in the Comprehensive Review. Recommended reduction brings the Cost Baseline into line with estimates of the firm power load served by Bonneville. Review the appropriateness of continued Bonneville support no later than 2004.	4.6	4.6
3. Reduce projected legacy conservation contract expenses to reflect historical under-spending. Do not modify or extend existing contracts, except that the State's low-income weatherization contract should be extended consistent with the end of the legacy commitment to utilities. Reduce associated staffing.	2.5	2.5
4. Further reduce funding for the NW Power Planning Council to reflect changes in Bonneville's regional role (i.e., curtail new resource acquisitions), carry out the Council role in power recommended by Comprehensive Review and the continued importance of fish and wildlife issues. Seek additional funding from other sources for Council activities that are of regional scope. Reductions assume one Council representative per state. A process should be carried out to determine both the functions the region wishes the Council to perform and how the functions should be funded.	1.1	1.1
5. Provide funding for costs of the three renewable resource projects that Bonneville currently is planning, and currently planned levels of renewable resource data collection and R&D. Annual net cost above project revenues should not exceed $15 million per year, including the data collection and R&D costs. No additional renewable resource projects unless Bonneville's costs are recovered fully by project revenue.	2.2	2.2
6. Develop and implement a consolidated, integrated capital/asset management strategy for federal hydro directed at maximizing value, including both financial returns and public benefits. The strategy should encompass the operation and maintenance of the physical assets, a coordinated investment plan, potential consolidation of duplicative administrative support services among FCRPS agencies, and the creation of integrated performance measures. Performance should be measured explicitly and reported publicly, accountabilities established, and incentives created and applied FCRPS-wide. Estimates at right include a combination of reduced O&M expenses from the Cost Baseline and increased revenues from higher production.	Corps: 40.0 Bureau: 8.0	Corps: 40.0 Bureau: 8.0
7. Implement a strategy for WNP-2 that combines aggressive cost management with a flexible response to market conditions and unforeseen costs. Manage annual operating costs to annual revenues achievable at market prices. In BPA's subscription process and upcoming rate case, determine how to allocate the plant's costs in Bonneville rates and market a portion of the Federal Base System (FBS) equivalent to the planned output of WNP-2 priced in a manner that ensures recovery of the plant's operating costs while allowing a lower price for the rest of the FBS,	19.0	19.0

unless legal or other issues prevent doing so. To the extent revenues exceed operating costs, use a portion of the resulting net operating revenues to build up the decommissioning fund. Biennially subject the plant to a market test. Evaluate termination in the event operating costs are projected to exceed revenues significantly if uneconomical at market prices. Estimated reduction includes a combination of reduced O&M expense from the Cost Baseline and potential increased revenues.		

Recommendations	**Average Annual Reductions, FYs 2002-2006, $ in millions**	
	Total Reductions	**Power BL Expense Reductions**
8. Further reduce the cost of Bonneville administrative and other internal support service costs including financial, human resources, information management, procurement, strategic planning, public affairs, legal services and other internal service costs, by an aggregate 50 percent from 1996 actual levels. Achieve through benchmarking, adopting "best practices," enterprise software, and outsourcing of non-core functions where economic.	31.7	14.5
9. Obtain legislative changes in the areas of personnel management and procurement to improve administrative flexibility and ability to manage internal costs.	10.0	7.0
10. Further reduce transmission internal O&M expenses through improved efficiencies.	2.5	1.5
11. Conform to Federal Power Act requirements, adjusting and correcting functionalization (allocation) of costs between Power and Transmission BLs.	0.0	30.0
12. Further reduce federal and non-federal debt service expenses through refinancings, greater reliance on variable rate debt, and other debt reduction actions	20.0	20.0
13. Targeted, but unspecified reductions already included in Power Cost Baseline.	(19.4)	(19.4)
TOTAL	**136.9**	**145.7**

In addition, the TBL should meet the cost management objectives in its baseline, in particular:

- Obtain operational efficiencies, tighter control on timing and prioritization of capital investments to achieve superior performance compared to the WSCC transmission providers (top one-third);
- Reduce fully allocated hourly costs of transmission maintenance service by 20 to 30 percent by 2001; and
- Increase flexibility of cost structure.

Appendix 2.2

Electric Utility Restructuring: Legislation Comparison Table

Summary of Major Provisions of S. 1401, H.R. 655, H.R. 1230, S. 722, H.R. 1960 and S. 2287

Provision	S. 1401	H.R. 655	H.R. 1230	S. 722	H.R. 1960	S. 2287
Deadline for Retail Competition	January 1, 2002	December 15, 2000	January 1, 1999	No federally imposed deadline	No federally imposed deadline	January 1, 2003, with state and nonregulated utility opt out provisions
Federal Role in Implementing Retail Competition	Federal mandate enforceable in federal courts	Federal mandate enforceable by FERC	Federal mandate enforceable by FERC	No federal mandate. Retains role in interstate transmission	No federal mandate. En-hanced utility oversight, environmental and consumer protection role	Federal mandate enforceable by state courts. Enhanced utility oversight, and environmental role
State Role in Implementing Retail Competition	Retains role in protecting the public interest, and regulating distribution and retail transmission service	Detailed state implementation requirements for retail competition along with retaining role in local distribution and consumer protection	Retains role in protecting the public interest, and regulating local distribution service	Lead role in deciding on retail competition reforms. Retains role in protecting public health and safety	Lead role in deciding on retail competition reforms based on detailed federal provisions. Enhanced role in utility oversight	Lead role in deciding on retail competition re-forms, and retains role in regulating local distribution service. May tap into federal public benefits fund for public purpose programs
Transitional Concerns -- Stranded Costs	Detailed requirements for stranded cost recovery with FERC serving as a backstop	No requirement. States may choose to impose a charge to provide for such recovery	No requirement. States may not impose an exit charge to provide for such a recovery	No requirement. States may choose to impose a charge to provide for such recovery	No requirements. Any stranded cost recovery must be allocated in an equitable manner to all customer classes	No requirement. States may choose to impose a charge to provide for such recovery
Structuring the Market -- Reliability	Detailed provisions for ISOs, along with state authority to ensure reliability	State authority to ensure reliability	FERC to ensure transmission reliability; states to ensure local distribution reliability	State authority to ensure reliability	Creates self-regulating utility councils under FERC oversight to protect reliability	Creates self-regulating utility councils to protect reliability FERC authority to create ISOs
Structuring the Industry -- Corporate Structure (including PUHCA)	ISOs must be independent PUHCA repealed 1 year after enactment, replaced by enhanced federal and state access to company records "Ohio Power" provision to permit state review of affiliate transactions	PUHCA ceases to apply to a company when the affected states determine the company offers effective retail competition. Replaced by enhanced federal and state access to company records	Functional divestiture of transmission/ distribution and generation components PUHCA ceases to apply to a company when the affected states determine the company offers effective retail competition	PUHCA repealed 18 months after enactment and replaced by enhanced federal and state access to company records	PUHCA ceases to apply to a com-pany when the affected states certify the com-pany's compli-ance with federal retail competition and public benefit standards. Re-placed by en-hanced federal and state author-ity to oversee utility mergers, acquisitions, affiliate relation-ships, and diver-sification efforts	PUHCA repealed 18 months after enactment and replaced by enhanced federal and state access to company records

Structuring the Industry -- Corporate Transactions (including PURPA)	Sec. 210 of PURPA does not apply to new facilities after January 1, 2002 Existing contracts are unaffected	Sec. 210 of PURPA does not apply to a utility the state determines provides effective retail competition Existing contracts are unaffected	Sec. 210 of PURPA does not apply to a utility the state determines provides effective retail competition Contracts as of the date of enactment are unaffected	Sec. 210 of PURPA does not apply to new facilities after the date of enactment unless a power purchase contract had been entered into beforehand Existing contracts are unaffected	Sec. 210 of PURPA ceases to apply to a utility when the affected state certifies the utility's compli-ance with federal retail competition and public benefit standards Existing contracts are unaffected	Utilities are not required to enter into new con-tracts under to Sec. 210 of PURPA after enactment
Structuring the Industry -- Public Power	TVA fence is removed if in U.S. interests; purchase con-tracts with TVA may be termi-nated on 1-year notice after January 1, 2001; privatization study required. BPA regional governing body authorized. Authorized BPA compliance with FERC open ac-cess rules and participation in a ISO shall not threaten U.S. Treasury receipts.	Purchasers of Power Marketing Administration (PMA) power may not resell that power outside their distribution area	No specific provisions	All transmitting utilities are subject to FERC with respect to any wholesale transmission service Study of tax benefits of public and investor-owned power	Except for existing arrange-ments, TVA and PMAs may not provide retail service to custo-mers outside their areas unless retail competition is available to all customers within such area	FERC's open access and stranded cost rules would extend to public power, including TVA and PMAs. Prohibits public power from issuing tax-exempt bonds for new generating facilities. Out-standing tax-exempt bonds would be grandfathered.
Environment	EPA study of air pollution standards and electricity restructuring by January 1, 2000	States may assess charges to fund environmental programs	No specific provisions	States may assess charges to fund environmental programs	President to pre-vent advantage to utilities whose plants emit exces-sive amount of sulfur dioxide, nitrogen oxides, and carbon dioxide	EPA may estab-lish regional NOx "cap and trade" programs to im-plement trans-ported air pol-lution provisions of the Clean Air Act.
Renewable Energy	Renewable set-aside requirement and trading program	Renewable set-aside requirement and trading program	States may permit consumer choice with regard to renewable energy	States may assess charges to fund renewable energy programs	Renewable set-aside requirement and trading program	Renewable set-aside requirement and trading program
System Benefits (Energy Efficiency, low-income programs, R & D, and renewables	States may assess charges to fund public benefit programs, such as universal service protection for customers, low-income energy assistance, R&D programs, and energy efficiency and conservation	States may assess charges to fund public benefit programs, such as universal service protection for customers, low-income energy assistance, and/or environmental, renewable, efficiency, conservation, or other such programs	States may assess charges to continue universal service protection for customers States retain authority over conservation, R&D, and other programs deemed appropriate by the state	States may assess charges to fund public benefit programs, such as universal service protection for customers, low-income energy assistance, R&D efforts, and environmental, renewable energy, energy efficiency or conservation programs	As part of the certification process, states must generally assess charges to fund public bene-fit programs, such as low-income services, renew-able energy and energy efficiency	States may tap into a federal public benefit fund to provide for low-income energy assistance, consumer education, R&D, rural assistance, and energy efficiency or conservation programs

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Appendix 2.3

Restructuring Activity in the States

Summary of Major Provisions

Activity as of November 1, 1998

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
Alabama	**4/98:** PSC issued an order to begin a new investigation into electric restructuring. Comments were due in August. A series of workshops were scheduled on market power, stranded costs, service reliability and other issues to aid the PSC in decision making. **12/97:** PSC approved preliminary staff report on restructuring the electric power industry, "Report and Policy Development Plan of the Staff Electric Industry Restructuring Task Force."	**5/96:** SB 306, "The Electricity Customer Severance Law," enacted. The law provides utilities the opportunity to collect from customers who leave their system the amount of stranded costs associated with the customers' service.		**1/97:** Alabama Electricity Consumers Coalition and American Energy Solutions filed in Federal court a suit challenging the statute on stranded costs as unconstitutional. The suit was dismissed because the law has yet to be invoked. The suit could be reinstated if the law is used. **5/96:** SB 306 allows recovery of "reasonable" stranded costs through exit fees.
Alaska	**10:98:**Matanuska Electric Association, Chugach's largest wholesale customer, offered to buy out Chugach. Chugach assets are valued at $486 million. Chugach officials were surprised by the offer and are withholding judgement. **6/98:** PUC rejected Chugach's	**8/98:** The State Legislative Committee, established to develop recommendations for the legislature on electric industry restructuring which are due in January when the legislature reconvenes, conducted its first hearing. The Alaska Rural Electric Cooperative Association stated that, due to the		

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	argument and affirmed the PUC's authority to regulate retail wheeling. **1/98:** Chugach Electric Association, the State's largest utility, urged to PUC and legislators to allow retail competition in Anchorage and surrounding areas. HB 235 primarily failed because Chugach did not support it unless it was amended to allow retail wheeling in Anchorage and surrounding areas. **10/97:** Public meeting held to discuss "Future Market Structure of Alaska's Electric Industry."	isolation and unique characteristics of Alaska's rural electric industry, it should be left out of any restructuring plans. Chugach Electric Association, the State's largest electric utility, stated that consumers would benefit if the State embraced a broad policy of allowing competition. **8/98:** No action was taken on HB 235 or HB 287. Both bills appear stalled in committee. **1/98:** Two bills, HB 235, and HB 287, concerning retail competition were introduced in 1997 session and held over to the 1998 session. HB 235, supported by cooperatives, would prevent retail competition in existing certified service areas unless clearly evidenced that it would be in the public interest.		
Arizona	**8/98:** ACC approved final rules for restructuring. A 2-year phase-in schedule will accelerate retail competition from the 12/96 plan, and retail access will begin for customers with more than 1 MW demand by 1/1/99, and all consumers by 1/1/01. Utilities must file deregulation plans by 9/98 with proposals for rate reductions for consumers not participating in retail competition. **8/98:** ACC approved Tucson Electric Power's rate decrease of 3.1% over 2 years. The decrease will apply to all standard offer consumers who do not	**5/98:** HB 2663 enacted. The law affirms the ACC's authority to require utilities to open territories to retail competition. Competition will phase-in 20% by 12/31/98 and 100% by 12/31/00. The bill will also extend deregulation to municipals and other publicly owned utilities, such as the Salt River Project. **4/96:** HB 2504 established a Joint Committee to study electric industry restructuring with a report due by 12/97.		**8/98:** Tucson Electric Power filed a divestiture plan with ACC . The ACC order on stranded costs provides utilities 2 options: 1 - divestiture of assets; the amount of recoverable stranded costs will be the difference between the value of generation assets under traditional regulation and their market value determined through an

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	yet have retail access during the phase-in of competition. **8/98:** The Salt River Project has agreed , after negotiation with legislators, utility officials, and industrial users, to allow 110,000 residential and 12,000 commercial and industrial consumers retail access by 12/31/98. **6/98:** The AZ Corporation Commission approved a competitive market plan that will require utilities to fully divest generation assets if they want 100% recovery of stranded assets. The plan also provides for a residential pilot program, 5% residential rate cuts over the next 2 years, and retail access for 20% of customers (the largest) by 1/1/99 and all customers by 1/1/01. **5/98:** The AZ Supreme Court upheld a lower court ruling that the ACC has the authority to adopt rules requiring IOU's to open their territories to retail competition. **4/98:** ACC sent letters to the Governor and legislators in opposition to the electric restructuring bill (HB 2663) that passed the House and appears to have significant support in the Senate. **10/97:** Work group report submitted to the Joint Legislature Study Committee regarding phase-in dates, taxes, the roles of the legislature and Arizona Corporation Commission.			action process, and 2 - a transition revenues methodology; the ACC "would provide sufficient revenues necessary to maintain financial integrity for a period of 10 years," allocating stranded costs among consumers and shareholders as deemed "to be in the public interest." TEP estimates its stranded costs to be between $475 million and $1.1 billion. **12/96:** ACC's deregulation plan allows for stranded cost recovery using exit fees and mandates using mitigation measures; full recovery of stranded costs is possible but not assured.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	9/97: Work group report submitted regarding stranded costs, legal issues, and customer selection. Stranded costs recovery gained support but securitization questions were deferred. **12/96:** ACC issued a final order to phase-in retail access beginning 1/99 with 20 % of a utility's load, 50% by 1/2001, and all consumers by 1/2003. The plan includes a solar portfolio standard. The ACC also established work groups to report on restructuring issues with reports due by the end of 1997. Utilities were ordered to file restructuring plans by 12/97.			
Arkansas	**8/98:** PSC issued a draft report, "Report on Restructuring the Arkansas Electric Utility Industry," recommending retail competition no later than 1/1/02. The report asks the legislature to act in 1999 on restructuring and give the PSC authority to implement retail competition, determine stranded costs and appropriate recovery methods, including securitization. A final report will be submitted to the legislature in October. **8/98:** The PSC approved a merger between American Electric Power and Central and Southwest Corporation. AEP & CSW have proposed a regulatory plan providing savings to consumers from fuel cost savings and synergies crated by the merger. Also, AEP/CSW have committed to not raise	Comments were due 2/98. The PSC will issue recommendations to the legislature by October 1998. **4/97:** AR General Assembly requested, with Senate Resolution 24, a study on competition in the electric industry with a report due by January 1999. A series of hearings were held through 3/98, and a restructuring bill is expected to be introduced in 1999.		**12/97:** In Entergy's restructuring plan, the Transition Cost Account to be used for funds for stranded costs will be funded by excess earnings above 11% return on equity during the rate freeze period (at new levels through 2001).

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	rates above current levels prior to 1/1/02. **5/98:** The PSC concluded hearings on when and how to open the electric market to competition. Entergy and two other IOU's agreed that competition should not begin before 2002, as neighboring Oklahoma and Texas are scheduled to open their electric markets to retail competition. **12/97:** Arkansas PSC agreed to Entergy's restructuring plan. The plan includes rate reductions of about $217 million over 2 years; debt reduction of $165 million over 5 years on the Grand Gulf Nuclear Station; and creation of a special Transition Cost Account to be used to collect funds for stranded costs recovery. **12/97:** The PSC will conduct public hearings in 1998 to address restructuring issues. A report is due to the State General Assembly by October 1998. Four dockets were established to investigate specific restructuring issues.			
California	**10/98:** Based on CPUC data, New Energy Ventures, a retail electricity marketer, calculated it has won about 40 % of the 13,648 Gwh load being served by nonutility energy service providers. **4/98:** PUC issued the final order officially opening the electric industry market to competition as of/3/31/98 for	**10/98:** Proposition 9 will be on the ballot November 3. The three investor-owned utilities and the trustee for the IOU's stranded cost notes, worth nearly $6 million, plan to take legal action if Proposition 9 passes. **8/98:** Proposition 9, the ballot initiative to alter provisions of the electric restructuring law, is gaining support		**9/97:** AB 360 allows utilities to issue $7.3 billion in bonds (securitization) to pay off stranded investments.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	all consumers in IOU service territories. Jurisdiction of transmission lines was transferred from the State to Federal authority with 70% of the transmission grid under control of the ISO, making California the first State to introduce a state-wide competitive electric industry. **3/98:** PUC issued regulations to protect consumers from fraud and market abuses. Electric competitors must 1) provide clear information on price, service, and power-generation mix; 2) use a standard bill format; 3) provide proof of technical, operational and financial capability; and 4) post a $25,000 bond. **12/97:** Starting date for competition is delayed to March 31, 1998, due to additional time needed for testing software at the ISO and PX. **12/95:** CPUC issued a final order to deregulate the electric power industry and phase-in retail competition. Later, the plan was amended to allow retail competition for all consumers simultaneously, beginning 1/98 (extended to 3/98).	from some groups, including the League of Women Voters, the Sierra Club, consumer advocate Ralph Nader, the Consumers Union, and other consumer groups. The opposition includes the Association of California Water Agencies, the investor-owned utilities, and the Coalition for Affordable and Reliable Electric Service. An analysis released by the California Energy Commission (stated as "not reflecting its official view") indicates rates would drop beyond the 10% guaranteed by the ballot measure. **7/98:** The CA Supreme Court denied a request by a group of IOU's and business organizations to prevent a vote on the ballot initiative that would change provision of CA's restructuring law. **6/98:** The coalition of consumer advocates initiative to challenge the law that restructured the electric power industry has qualified for the 11/98 ballot. The initiative would prohibit California's investor-owned utilities from recovering the costs for nuclear power plants or imposing surcharges on customer bills. Also, it would give consumers a 20% rate reduction. The IOU's and business and industrial groups oppose the initiative, and the utilities have filed a lawsuit aimed at striking the initiative from the ballot. **5/98:** Consumer groups are gathering signatures for a ballot initiative challenging AB 1890, preventing utilities		

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
		from collecting stranded costs, and allowing a 20% rate reduction. A coalition of business and taxpayer groups have filed a lawsuit in the state's 3rd district court of appeal to keep the initiative off the ballot in November. **9/97:** SB 90 provides administrative guidelines for the Renewables Program under AB 1890. It gives the California Energy Commission authority to administer funds collected for renewable energy technologies support. **9/97:** SB 1305 requires retail suppliers of electricity to disclose the sources of electricity; requires generators to report fuel type and consumption to system operators, who make the information available to the CEC; and requires other reporting requirements for emissions, purchased power, losses, and retail sales. **9/96:** AB 1890 enacted to restructure CA's electric power industry. The law includes provisions for the creation of an ISO and a PX, a Competitive Transition Charges (CTC) for recovery of stranded costs (from 1998 through 2002); a 10% rate reduction; and the continuance of energy efficiency programs financed with rate surcharges.		
Colorado	**12/96:** PUC conducted a survey of 360 stakeholders regarding retail competition and released a report on electric restructuring.	**7/98:** The CO electricity advisory panel (created by SB 152)met for the first time in July. The purpose of the panel is to study electric industry deregulation and report the findings to the legislature by		

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	Colorado PUC cannot order statewide electric industry restructuring without a change in State law.	11/1/99. **5/98:** SB 152 was enacted. It created a 21-member panel to assess whether retail competition will benefit the state's consumers. **5/98:** None of the three bills being considered in the 1998 legislative session made it out of committee. **3/98:** HB1284, HB 1381, and SB 178 were introduced to allow retail competition and restructure the electric industry were introduced in the legislature. The bills stalled in committee, although technically the legislation could be revived as a compromise bill, but it would face strong opposition. **1/98:** Legislature will debate several restructuring bills in the 1998 session that would allow retail competition in 2 to 4 years. All 1997 restructuring bills introduced failed to pass.		
Connecticut	**10/98:** United Illuminating filed its divestiture plan with the PUC to sell its non-nuclear generating assets. Plants being sold include the 590 MW Bridgeport Harbor and the 466 MW New Haven Harbor. Also in filing are plans on how to unbundle the generation business from the wires or distribution business. United Illuminating will become a "wires" company responsible for power delivery.	**4/98:** RB 5005, An Act Concerning Electric Restructuring, was signed into law on 4/29/98. The bill will allow retail competition for generation suppliers for 35% of consumers by 1/2000 and for all consumers by 7/2000. Utilities will be required to sell non-nuclear generation assets by 1/2000 and interests in nuclear generation by 1/2004, making CT the first State to require divestiture of nuclear assets. The bill also provides for creation of an ISO, public interest		**5/98:** The United Illuminating Company announced its plan to divest its 3 fossil-fueled plants and power purchase agreements to comply with Connecticut's new restructuring law. **4/98:** To recover stranded costs, utilities

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	8/98: PUC opened dockets on tasks delegated by HB 5005 to restructure the industry. **7/95:** CT DPUC issued a final report that calls for deregulating generation and gradually moving to retail competition.	program funding, functional unbundling, renewable energy funding, a 5.5 % renewable portfolio standard, environmental protections, and a 10% rate reduction beginning 1/2000.		must separate their transmission and distribution business and sell their non-nuclear generation by 1/2000 and interests in nuclear generation by 1/2004. Utilities will be allowed to sell bonds to cover stranded costs (securitization) up to the 10% rate reduction.
Delaware	**1/98:** PSC adopted final report on electric industry restructuring with recommendations including unbundling of rates and stranded cost recovery using Competitive Transition Charges. The report calls for competition for all Delaware consumers to begin 12 months after restructuring legislation is enacted. **8/97:** PSC issued a report recommending phase-in of retail competition beginning 4/99.	**7/98:** HB 570, a bill to restructure the electric industry, failed when the 1998 session ended in June. The issue will likely be readdressed in the 1999 legislative session. **4/98:** HB 570, Electric Restructuring Act of 1998, was introduced in the legislature. The bill would phase in retail competition beginning 7/99 for Delmarva customers and by 1/2000 for Delaware Electric Cooperative customers. **6/97:** HR 36 called for PSC to report on restructuring alternatives by 1/98.		**1/98:** PSC final report recommends that utilities have an opportunity to recover stranded costs. The PSC is to determine the magnitude of reasonable stranded costs for each utility.
District of Columbia	**9/97:** The PSC continues to study restructuring and issued a notice of inquiry for issues to investigate on retail competition. A report is expected in 1998.			
Florida	**8/98:** Responding to competitive pressures that can lower electric bills for large consumers, the PSC approved	**4/98:** HB 1888 died in committee without a hearing, reflecting both the strong opposition from utilities and lack		

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	discount rates (up to 20%) for new and expanding businesses. The Florida Alliance for Lower Electric Rates Today opposes the discounts, and proposes state-wide competition for all consumers. **4/98:** The PSC approved a plan for Florida Power & Light to offer new industrial customers discounted rates of 20% the first year, and declining over a five-year period.	of consumer interest. **3/98:** HB 1888 was introduced and referred to committee. The bill, which would deregulate the electric power industry and allow retail access by 2001, faces strong opposition and is not expected to get out of committee. **10/97:** House Committee on Utilities and Communication sponsored informal hearings on electricity restructuring issues. **10/97:** Legislature has a special subcommittee to track restructuring developments in other States.		
Georgia	**1/98:** PSC issued a Staff Report on Electric Industry Restructuring. Recommendations include market-based rates, unbundled services, and stranded cost recovery. A docket has been established for comments from stakeholders. **4/97 - 7/97:** Public workshops were held to address the issues related to restructuring. The results of the public hearings were incorporated in the Staff Report issued 12/97.			
Hawaii	**1997:** PUC began to develop a draft restructuring plan and a formal investigation into the issues. **12/96:** PUC began investigating competition in electric power industry. A report is expected by 10/98.	**12/97:** Bill was introduced to request the PUC to provide recommendations for legislation to implement economical electric competition by 12/98. **1997**: Bills introduced in 1997 failed to pass.		

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
Idaho	**1/98:** PUC issued the "Electric Costs Report" to the Governor and Legislature. The report contains the findings on the unbundled average costs fro utilities in ID compared to national averages. **9/97:** ID PUC hosted technical workshop to discuss public purpose costs as part of unbundling. **7/97:** Proceedings on electric restructuring began.	**1997:** HB 399 passed; directs commission to establish a committee to obtain information on the costs of supplying electricity to consumers. Utilities are required to unbundle costs of electric service and report to the PUC. **5/97:** Governor signed an executive order creating the Governor's Council on Hydroelectric and River Resources that will establish guidelines for electric industry restructuring in ID.	**2/98:** PUC approved Washington Water Power Company pilot program, MOPS II, for approximately 6,000 consumers. The pilot will offer customers a portfolio consisting of four rate options: Traditional Energy Service, Monthly Market Rate, Annual Market Rate, and Standard Offer Service. **4/97:** 2-year pilot program began for residential and commercial customers of WWPC in ID. **4/97:** Idaho Power's pilot program for 900 customers will begin 7/97 and go through 6/99.	**8/97:** Public hearings were held on the issue of stranded costs.
Illinois	**8/98:** The phase-in of rate cuts took effect. The State's largest utilities, Illinova and Commonwealth Edison, cut rates 15%; another 5% reduction is due 5/02. Smaller utilities will phase-in 5% reductions by 5/02. **6/98:** The Illinois Commerce Commission (ICC) issued a ruling that prohibits utility affiliates from exploiting the name, reputation, or logo of the	**10/98:** As required by the restructuring law in Illinois, a 15% rate reduction went into effect in August 1998. To date, Illinois Power customers have saved about $12.5 million. **3/98:** Legislation was introduced to add environmental provisions to the current	**2/96:** CILCO and IL Power conducted retail wheeling pilot programs in 1995 - 1996. IL pilot included only large customers; only in IL pilot; CILCO pilot included all classes of customers.	**5/98:** Illinois Power withdrew its proposal for a securitized bond issue. **4/98:** Enabled by the Restructuring Law enacted in 12/97, Commonwealth Edison is seeking ICC approval of a bond issue. By law,

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	utility in advertising or marketing campaigns. The rule will protect ratepayers from cross-subsidization of utility affiliates. **5/98:** The Illinois Commerce Commission (ICC) approved Commonwealth Edison's plan to offer nonresidential customers hourly rates under its "Hourly Energy Pricing" program.	electric restructuring law. The bill would increase utility funding for energy efficiency programs, provide tax credits for energy efficient appliances, and allow net metering. **12/97:** HB 362, "The Electric Service Customer Choice and Rate Relief Act of 1997," was enacted. The bill provides for rate cuts for ComEd and Illinois Power effective 8/98. The law accords some commercial and industrial customers choice by October 1999, and all customers, including residential, choice for their generation supplier by 5/2002. Customers who choose an alternative supplier will pay transition charges until 2006.		the proceeds from bonds will be used to refinance debt and equity in preparation for competition. **12/97:** HB 362 allows for recovery of stranded costs based on a formula for lost revenue.
Indiana	**7/98:** Consumers of Indianapolis Power & Light were offered 3 billing options. Consumers can choose a fixed rate, a fixed monthly bill based on last years average bill, or a "green power" rate under an alternative pricing plan approved in March by the Indiana Utilities Regulatory Commission (URC).	**8/98:** Executives from the 5 major investor-owned utilities met on 8/21 to reach agreements on issues. The group will continue to meet to attempt to draft restructuring legislation for 1999. **2/98:** Deregulation bill (SB 431 to deregulate the industry by 2004) was defeated. IN's major utilities and other groups promised to begin meeting this spring to work out differences. Lawmakers will revisit restructuring issues in 1999 when new legislation is expected to be written. **5/97:** SB 427 created a legislative study committee that will meet through November on electric restructuring issues. A report is due 11/97.		

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
Iowa	**9/97:** IUB adopted its "Action Plan to Develop a Competitive Model for the Electric Industry in Iowa." The plan includes a statewide pilot program for residential and commercial customers (about 3% of load) over 2 years. **8/97:** IUB reopened its restructuring docket to adopt principles proposed in 1996 upon which any restructuring plan must be based. **1/97:** IUB final report on restructuring concludes there are few reasons to move quickly to retail competition. **4/96:** IUB adopted principles for restructuring the electric power industry.	**5/98:** A bill was passed to adopt a new method of taxing utilities where property taxes would be replaced with excise taxes. **4/98:** A bill to introduce retail competition by 1/2000 was drafted, but will not be introduced until the 1999 legislative session.	**8/98:** IUB approved MidAmerican's pilot, the first major electric choice pilot program in the State, expected to include about 15 large consumers. The following residential pilot, proposed in 5/98, is yet to be approved. **5/98:** MidAmerican filed a proposal with the IUB for a pilot program to allow 15,000 residential and 2,000 small commercial customers (approximately 3%) to choose their power supplier competitively. **9/97:** MidAmerican Energy proposed a wheeling pilot for commercial and industrial customers for 60 MW of load in first year and an additional 15 MW each following year.	**7/97:** Mid-America Energy's proposal to use excess profits to write off stranded costs was approved.
Kansas	**8/98:** A proposal for a merger between Western Resources and Kansas City Power & Light has been filed with the KCC. Shareholders from both companies have approved the merger. The new company would be Westar Energy.	**4/98:** The Task Force's restructuring bill was not acted on in the 1998 session. Legislation will likely be introduced again in 1999. **2/98:** The Retail Wheeling Task Force's restructuring bill is introduced in the		

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
		legislature. Also being considered are a bill to establish a joint committee on taxation of public utilities and a bill to require utilities to disclose generation, transmission, and distribution charges and sales, use, and franchise taxes and any fees relating to the retail sale of electricity. **10/97:** Retail Wheeling Task Force issued a final report and draft restructuring bill that calls for retail access after 7/2001. **4/96:** Retail Wheeling Task Force established with passage of HB 2600, which prohibits the Commission from authorizing retail competition prior to July 1, 1999. A report with a model for legislation is due 1/98.		
Kentucky	**10/98:** As required by the merger approval, Kentucky Utilities and LG&E asked the PSC to consider performance based rate-making, hopefully leading to reductions in customers bills. Performance-based rate-making uses factors such a fuel costs, generation performance, and service quality to calculate charges. It would provide financial incentives for utilities to reduce costs, improve efficiency, reliability, and customer service. Currently, rate reductions as a result of the merger approval have helped LG&E rates stay low, as much as 25% lower than the national average. **5/98:** The merger between LG&E and	**4/98:** The 1998 legislative session ended with no action taken on the restructuring bill, HB 443. During the interim session, a special subcommittee on energy will review and draft a bill to prefile for the 1999 session. **4/98:** HRJ 95 passed legislature and signed by Governor to create the Kentucky Task Force on Electric Restructuring. A report is due 11/99. **1/98:** HB 443 to restructure the electric power industry is introduced and referred to committee. The bill proposes retail access be phased in beginning 1/2000 and having full retail access by		

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	KU is final. **9/97:** PSC approved merger between LG&E; Energy Corp. and KU Energy Corp.	12/2005. **9/97:** Interim Joint Special Subcommittee on Energy sponsored a 2-day workshop on electric power industry restructuring.		
Louisiana	**8/98:** PSC conducted hearings on stranded costs. Participants included Central Louisiana Electric Company, Enron, and Gulf State Utilities. **12/97:** LA PSC voted to accept a staff report recommending further study on issues surrounding electricity deregulation. PSC will develop draft legislation for 1999. **9/97:** Entergy New Orleans submitted plan seeking 6-year transition to retail competition. **8/97:** PUC opened docket U-21453 on whether electric restructuring is in the public interest.	**3/98:** The PSC committee and the legislative committee, both on deregulation of the industry, met on 3/16/98 to discuss the tax implications of deregulation. **6/97:** Resolution 150 created a study committee on electric power restructuring with reports on various issues due in 1998. **5/97:** All bills that were introduced in 1997 session failed.		
Maine	**5/98:** PUC adopted a requirement that beginning 1/1/99 utilities must issue bills showing "unbundled" charges for generation and distribution, rules for consumer education, and standard offer service for all consumers when competition begins 3/1 2000. **5/98:** PUC approved Central Maine Power's corporate reorganization into a holding company, CMP Group, Inc., and 10 subsidiaries as it prepare for retail competition. Central Maine Power will	**5/97:** LD1804 was enacted. The law will allow retail competition by 3/2000, and for large investor-owned utilities, features a market share cap of 33% in old service areas, a requirement for divestiture of generation assets by 3/00, and the nation's most aggressive renewables portfolio, requiring 30% of generation to be from renewable energy sources (including hydroelectric).		**10/98:** PP&L Global has reached an agreement with Bangor Hydro to purchase 100 % of it hydro plants and its interest in an oil-fired plant, totaling 89.2 MW for $89 million. PUC and FERC approvals are pending. **5/98:** Bangor Hydro announced the

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	remain the core business group offering distribution and transmission services. A new unit, Maine Power, will market electricity. **9/97:** PUC issued comprehensive schedule of restructuring proceedings. **5/97:** PUC will determine "how deregulation will effect the consumer" by public rule-making hearings. **12/96:** PUC issued a plan requiring utility unbundling, divestiture of generation assets by 3/2000, and retail competition by 2000.			schedule for bids on its divestiture of generation assets. Final bids were due 8/7/98. Maine Yankee nuclear plant will also be offered for sale. **4/98:** Central Maine Power's plan to divest its hydro, fossil-fuel, and biomass generation was approved by the PUC. **5/97:** LD 1804 allows recovery of stranded costs after reasonable mitigation efforts, but deferred detailed decisions to the 1998 legislative session.
Maryland	**10/98:** Five utilities in Maryland announced that they asked a state court to stop the PSC deregulation effort until several issues are resolved, including the issue of stranded costs recovery. **7/98:** The four major IOU's in the state filed with the PSC requests for recovery of stranded costs. The majority of these costs were requested by BG&E for the Calvert Cliffs nuclear plant. The PSC is expected to rule on the requests by 10/99. Final plans will be due 11/99. **12/97:** PSC issued orders establishing a framework for the restructuring of the	**4/98:** A proposal to allow retail competition by 7/2000 was introduced as an amendment to a bill that would restructure BG& E into a holding company. No action was taken on the bill by the Senate, effectively killing restructuring legislation for this session, which ended in April. **12/97:** Legislative Task Force held hearings and issued conclusions and recommendations. **4/97:** SB 851 created a task force on electric industry restructuring that will		**12/97:** PSC order states that utilities be allowed recovery of stranded costs. Utilities must file plans for stranded cost recovery by 3/98. CTC's and securitization are being considered.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	electric industry. A third of the State's consumers will have retail access by 7/2000; another third by 7/2001; and the entire State by 7/2002. "Round tables" to address implementation of specific issues will commence in April 1998. For the order to be effective, legislation must be passed. **5/97:** Staff report recommends retail choice be phased-in beginning 4/99 and be complete by 4/2000.	issue a report by 12/97.		
Massachusetts	**6/98:** Massachusetts utilities received no bids for standard offer or default power supply. Western Massachusetts Electric has asked DTE to remove the price cap on standard offer service, hoping to attract suppliers. SOS is set at 2.8 cents/kWh for consumers this year; bids were sought for no higher than 3.2 cents/kWh. **5/98:** Education program for consumers begins with showing the labels that will disclose the price of electricity, generation sources, and air emission contents. **4/98:** Boston Edison has received DPU approval to reorganize as a holding company, BEC Energy. **4/98:** DTE issued rules for distribution, default generation services, standard offer generation, aggregation requirements, and ownership of meters. **1/98:** Department of	**7/98:** The Supreme Judicial Court cleared the way for the ballot referendum to repeal the restructuring law to appear on November's ballot. Both challenges brought by business and industry groups, the signatures' validity and the constitutionality of the law in reference to appropriations, were rejected by the court. **6/98:** Customers in Massachusetts are signing up to purchase from competitive suppliers. **6/98:** The Ballot Law Commission said the effort to repeal utility deregulation should be on the November ballot. But, industry groups plan to appeal the matter to the Supreme Judicial Court in an effort to keep the repeal off the ballot. **2/98:** A ballot initiative to repeal the restructuring legislation was successfully submitted for the	**9/98:** PG & E Corporation's subsidiary, PG & E Energy Services has secured a multi-year contract with the Massachusetts High Technology Council (with over 200 members) to provide electricity to its members. This is the largest aggregation of customers in the U.S., representing about 1.2 million megawatthours annually. **5/98:** Massachusetts Electric's pilot has saved $1.3 million for about 5,000 small commercial and residential customers. Also, $3.8 million has	**10/98:** NEES subsidiaries, Massachusetts Electric and Nantucket Electric Co, report savings for their consumers of $67.5 million due to rate reductions. The state's restructuring law reduced rates by 10% and the recent sale of NEES generating assets at ta high sale price. The sale allowed additional rate reductions prior to the law's further requirements in one year. **10/98:** Eastern Utilities (Montaup) plan to sell the Somerset Station for $55 million to NRG Energy.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	Telecommunications and Energy issued implementation rules for the restructured industry. Included are licensing and information disclosure for retail suppliers and provisions for public interest programs, standard offer service, and utility transition cost recovery filings. **11/97:** DPU final decision is to officially open electric market to competition by March 1, 1998. **12/96:** DPU issued restructuring plan for full retail competition by January 1, 1998.	November election. **11/97:** Legislation enacted to restructure the electric power industry. The law requires retail access by 3/98, rate cuts of 10% by 3/98 and another 5% 18 months later, and encourages divestiture of generation assets.	been saved by the 14 customers in the Massachusetts High Technology Council pilot. **1/97:** Mass. Electric Co. began a 1-year pilot program in four communities. Of the pilot participants, 96% of the business and 66% of the residential consumers chose supplier based on price, 31% of residential consumers choose supplier based on "green power." **10/96:** Commonwealth Electric implemented a retail choice pilot program. **7/96:** Mass Electric Co. begins pilot program for members of High Technology Council; another 10,000 consumers will be added later. **1/96:** Boston Edison began a pilot program.	**5/98:** Commonwealth Energy System and Eastern Utilities Montaup subsidiary will sell their fossil-fueled generating assets in Massachusetts to Southern Company for $462 million, approximately 6 times the book value. The sale will allow the 10% rate cut that began 3/1/98 to increase to a 15% cut beginning 9/1/99. **5/98:** NEES sale of generating assets representing over 5,100 MW to U.S. Generating, a subsidiary of PG & E Corporation, is complete. 3 fossil-fueled and 15 hydro plants were included in the $1.6 billion sale. Customers in NEES subsidiaries, Massachusetts Electric and Nantucket Electric, should see significant rate reductions of about 19%. **5/98:** Boston Edison completed the sale of its entire portfolio of

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
				fossil-fueled generating assets to Sithe Energy. **4/98:** Boston Edison is seeking buyers for its Pilgrim nuclear plant. The company has already sold its non-nuclear generation to Sithe Energies. **4/98:** Eastern Utilities is selling generation assets and purchase power contracts. **11/97:** Legislation allows full recovery of stranded costs over a 10-year transition period; DPU has approved 2 utilities' plans for stranded cost recovery. Mass. Electric agreement allows 2.8 cent per kilowatt-hour access charge. Commonwealth Edison will minimize stranded costs by selling its generation assets and power contracts.
Michigan	**6/98:** Detroit Edison and Consumers Energy filed revisions of draft plans that address comments from the MPSC	**4/98:** Legislation to introduce retail competition has apparently stalled in		**1/98:** Proposed PSC plan would allow full recovery of stranded

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	staff, customers, suppliers, and other interested parties. Both plans will phase-in retail competition over the next 4 years beginning with large industrial consumers by 11/98 and full retail access by 1/1/2002. **4/98:** Responding to the PSC order, Consumers Energy and Detroit Edison filed restructuring plans to implement retail competition. In other PSC action, the utilities were ordered to file plans for obtaining additional capacity for this summer. **1/98:** PSC completed final action on rehearing orders required to introduce competition into the state's electric utility market. A phase-in schedule was adopted allowing 2.5% of Consumer's Energy and Detroit Edison customers retail access as early as 3/98, adding another 2.5% on 6/98, 1/99, 1/2000, and 1/2001 and all consumers retail access by 2002. **6/97:** PSC order set forth the Commission's framework for electric industry restructuring.	1998. **1/98:** Bill introduced to provide a 3-year phase-in for retail access, stranded cost recovery, and major customer protections.		costs using exit fees through 2007.
Minnesota	**5/98:** Northern States Power is proposing to divest its transmission assets and form an Independent Transmission Company (for profit) to own and operate its $1 billion in transmission assets. The "Transco" would be a publicly traded corporation, fully separate from utility generating	**1/98:** The Minnesota Legislative Electric Energy Task Force, created by HB 3654, in a newly released report to the 1998 legislature recommended against acting on electric industry restructuring in the 1998 session. It recommended further study of the issues with a report due 1/99.		**10/97:** PUC report proposed exit fees to pay percentage of stranded costs.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	assets. **10/97:** PUC issued a report that reflects the discussions held by the MN PUC Electric Competition Work Group from 2/96 to 10/97. The report identifies restructuring issues and is intended as a starting point for state policy makers and stakeholders to restructure the electric industry. **2/96:** PUC established a workgroup.	**5/97:** Legislation created a task force to review and analyze issues relating to electric power industry restructuring. A report is due 1/98.		
Mississippi	**6/98:** The PSC issued a Revised Proposed Plan for retail competition that addresses the comments received from industry, consumers, suppliers, and utilities. Hearings will be held throughout 1999 to address the issues and retail competition will be phased-in beginning 1/1/01 through 1/1/04, pending authorizing legislation. **5/98:** PSC issued orders to conduct studies on market power and cost of service. **4/98:** The PSC will receive comments and hold hearings on its restructuring plan. **1/98:** Entergy Mississippi commented to the PSC that the restructuring plan was overly optimistic and recommended January 2002 as the earliest date to begin retail competition. **11/97:** The Public Utilities Staff presented a report to the PSC	**9/98:** The first legislative hearing on restructuring the electric power industry were held in September 1998. The Mississippi Senate Committee heard 2 days of testimony on the impact of restructuring the electric power industry. The committee chair said Mississippi stands to gain from electricity deregulation because of its abundant natural resources. **3/97:** HB 1130 authorized the PSC to consider alternative methods of regulating the electric and gas industries. **1/97:** Bill introduced that proposed retail choice by 7/2003. Bill failed.		**11/97:** Report recommends PSC have discretion in recovery of stranded costs, on a utility-by-utility basis, through a wires charge. Exit fees and securitization were deemed anti-competitive and would not be used.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	proposing retail choice to begin by 1/2001and be completed by 12/2004, unbundling of services and rates, and recovery of stranded costs to be determined by the PSC. Implementation of the plan requires legislation to be passed by 1999. **7/97:** PSC issued an order requesting the Public Utilities Staff to develop a plan for restructuring the industry, due by 11/97. The plan, if accepted, will be a basis to draft legislation for 1999.			
Missouri	**5/98:** The Retail Electric Competition Task Force issued its Final Report to the PSC with recommendations on issues including public interest programs, stranded costs, taxes, reliability, and market power. **3/97:** PSC established the Retail Electric Competition Task Force to prepare reports to the PSC and study retail wheeling and related issues. Four working groups were established and are to submit reports no later than 4/98.	**5/98:** SB 728, to restructure the electric power industry and allow retail competition by 1/2000, was introduced. No action was taken in the 1998 legislative session. **1997:** HCR7 created a panel of legislators to study retail wheeling; a report is due by 1/98.	As part of the settlement for merger of Union Electric and Central Illinois Public Service, UE will implement a pilot program for 100 MW and about 5,000 customers. A Utilicorp 2-year pilot is limited to 10 customers with a demand of at least 2.5 MW.	
Montana	**6/98:** PSC approved a plan to phase-in competition. Beginning 7/1/98, Montana Power's largest customers (with loads over 1 MW) will be able to choose their energy supplier. Beginning 11/98, 5% of residential and small consumers will select their power supplier under a pilot program. Full retail access should be	**6/98:** Issue 138, to repeal the restructuring law has not obtained adequate signatures for inclusion on the November ballot. Official verification of signatures will be made in 7/98. **4/98:** A ballot initiative was filed that would repeal the 1997 restructuring law. The groups involved must gather the	**3/98:** Montana Power accelerated its schedule for residential and commercial customers pilot program. All customers will have retail access by 4/2000, 2 years earlier than the	SB 390 allows recovery of stranded costs through nonbypassable customer transition charges. It also allows for securitization for financing certain transition costs.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	complete by April 2000. **5/98:** Pacificorp will offer retail choice to all its Montana customers (30,000) on 7/1/99. **9/97:** PSC issued a notice of interim license filing provisions for electricity suppliers to retail customers. **9/97:** PSC rejected Pacificorp restructuring plan and asked for resubmission. **8/97:** PSC rejected Montana Power restructuring plan and asked for resubmission. **7/97:** Pacificorp and Montana Power submitted restructuring plans to the PSC in accordance with SB 390.	required signatures by June 1998 to put it on the November ballot. **4/97:** SB 390, the Electric Utility Industry Restructuring and Customer Choice Act, was enacted allowing large industrial consumers retail access by 7/98 and all consumers by 7/2002. The bill also includes a 2-year rate freeze beginning 7/98.	law requires. **7/97:** SB 390 requires utilities to conduct pilot programs for small commercial and residential customers beginning 7/98. Montana Power and Pacificorp have submitted plans.	**1/98:** Montana Power's intention to sell its plants sets off concerns by deregulation critics that foretell higher rates; a move for a special legislative session to slow deregulation failed. **12/97:** Montana Power announced that it will offer for sale all of its Montana electric generating facilities - 13 dams and four coal-fired plants, as well as its leased interest in another coal-fired plant and its contracts for power purchased from independent producers.
Nebraska		**2/98:** Phase I final report on electric power industry was issued. The report focuses on the existing structure of the industry and how to improve it. Phase II of the study will address competition issues and policy changes needed to keep public power viable. The Phase II report is due 12/99. **6/96:** Legislation enacted to allow a 3-year study on electric power industry restructuring, with reports due in 12/97 and 12/99.		
Nevada	**10/98:** Sierra Pacific and Nevada Power	**7/97:** Restructuring legislation, AB 366,		The PUC is authorized

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	filed their joint merger application with FERC. **7/98:** Sierra Pacific and Nevada Power filed a joint merger application with the PUC. In the filing, the utilities propose to sell their generation assets. **6/98:** PUC issued an order that defines which utility-related services, aside from selling electricity, could be open to competition. Areas of activity expected to be opened up to competition include metering, billing, and customer service. **3/98:** PUC issued a draft report on the unbundling of services and costs. **11/97:** As part of its ongoing investigation, PUC order requests Nevada Power Co and Sierra Pacific Power Co submit filings which demonstrate each distinct component of electric service (unbundled costs). Hearings will be held beginning in 12/97. **8/97:** PUC Order opened Docket to investigate issues to be considered as a result of restructuring.	enacted. The law directs the PUC of NV (formally the PSC) to establish a market in which customers have access to potentially competitive electric services from alternative suppliers no later than December 31, 1999.		in AB 366 to determine recoverable stranded costs and may impose a procedure for the direct and unavoidable recovery of allowable stranded costs from ratepayers. However, stranded cost recovery is not guaranteed.
New Hampshire	**9/98:** Unitil (subsidiaries include: Concord Electric, Exeter & Hampton Electric, and Fitchburg Gas & Electric) filed its restructuring settlement agreement with the PUC. In the agreement, Unitil will sell its New Hampshire power supply portfolio and be allowed to recover 100% of stranded	**6/98:** A net metering law was enacted to allow customers with 25 kW or less renewable generation to utiize net metering. **6/98:** US District Court issued an order enjoining the PUC from implementing any restructuring plans until the court	**7/98:** The competition pilot program was extended beyond its original ending date in 5/98 until PSNH's legal disputes are settled and retail competition	**9/98:** Unitil began the process to sell about 200 MW of entitlements under a portfolio of power purchase agreements and related transmission

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	costs over 12 years. Customer choice will be phased-in beginning 3/1/99. **8/98:** PUC ruled that New Hampshire Electric Cooperative can offer customers choice if FERC approves the "interpretation of its contract" for power purchases with PSNH. **6/98:** The PUC gave approval to a settlement, the first in the state, with Granite State Electric to bring retail competition to the electricity market. Under the settlement, Granite State customers could see a 17% rate cut and choose their generation supplier as early as July. **5/98:** The NH Supreme Court heard arguments in the PSNH rate agreement case. A ruling is expected early in June. **4/98:** PUC asked a federal court to dismiss the PSNH lawsuit against the state's restructuring plan in an effort to keep 7/1/98 as the start up date for retail competition. **4/98:** Granite State restructuring plan is approved by PUC and the governor. Retail choice will begin 7/98 regardless of other utilities in the State. A 10 % rate reduction will go into effect and, after divestiture of generation assets, a 17% reduction. Stranded cost recovery is set at 2.8 cents/kWh, decreasing by 50% once divestiture is completed. **3/98:** PUC issued a revised	holds trail for the suit filed by PSNH, scheduled in November. **4/98:** Legislators are discussing a delay until 1/31/99 for beginning retail choice in the State or authorizing the PUC to postpone the date indefinitely, due to the delay until November of the stranded costs case brought by PSNH. **5/96:** HB 1392 enacted requiring the PUC to implement retail choice for all customers of electric utilities under its jurisdiction by January 1, 1998, or at the earliest date which the Commission determines to be in the public interest, but no later than July 1, 1998.	begins. **2/97:** Results of pilot program available. Results indicate a 15 to 20% savings was achieved. **5/96:** PUC began a 2-year state-wide pilot program covering approximately 3 percent of the load served by 6 utilities. **6/95:** Legislation directed the PUC to establish a statewide pilot program for retail competition for about 17,000 customers (approximately 3% of the state's consumers).	agreements. **9/98:** NEES completed the sale of its 18 power plants and 23 power contracts to U.S. Generating. As a result, customers of Granite State, a NEES subsidiary, will see about a 17% rate reduction (including the 10% already realized in June). HB 1392 states that utilities should be allowed to recover net unmitigated stranded costs, and are obligated to take reasonable measures to mitigate their stranded costs. Nonbypassable charges to consumers is recommended as the recovery mechanism (entry and exit fees are not preferred). The PUC Final Plan discusses stranded cost recovery through divestiture of generation assets and contracts and securitization of debts.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	restructuring order concerning cost-based Interim Stranded Cost charge for the Public Service Company of New Hampshire. **1/98:** The PUC formally delayed the 1/98 start of retail competition to 7/98 due to the continuing litigation between the PUC and Public Service of New Hampshire. **3/97:** Public Service Company of New Hampshire filed a complaint with Federal District Court requesting the court enjoin the PUC restructuring plan, due to basing stranded cost recovery on market forces rather than utility costs. The court issued a stay on the plan as it applies to PSNH. **2/97:** PUC issued a Final Plan and Legal Analysis for restructuring the electric industry in NH. Among the restructuring issues addressed by the plan are Market Structure, Unbundling Electric Services, Stranded Costs, and Public Policy Issues (such as universal service, renewable energy, and customer protections).			
New Jersey	**9/98:** **8/98:** BPU is reviewing PSE&G's and Atlantic City's (Conectiv) restructuring plans. **5/98:** BPU announced a 6-month delay in its plan to offer retail competition. Phase-in of retail competition should	**9/98:** Restructuring legislation, "Electric Discount and Energy Competition Act," was introduced in the Assemble, A-10, and the Senate, S-5. If passed the bill will begin a 4-month phase-in for customer choice by 6/99; open metering and billing to competition after one year; implement rate reductions of 5-10% within 4 months; unbundle rates; require	**10/98:** Jersey Central Power & Light began a pilot program in 9/97 for customers in the Monroe township.	The pilot was recently extended though 12/31/98. **8/98:** In a ruling on PSE&G's restructuring plan, an ALJ has opined that PSE&G should recover from ratepayers

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	now begin by April 1999. **9/97:** An Initial decision on the four investor-owned utilities' restructuring filings is set for May 1998. PSE&G's plan would provide full retail competition by 1/99, and Rockland Electric's by 5/99. GPU's (Jersey Central P&L) and Atlantic Energy's adhere to the BPU schedule. **7/97:** The four investor-owned electric utilities in the state submitted three filings each to the BPU consisting of a rate unbundling filing, a stranded cost filing, and a restructuring filing. **4/97:** BPU issued an order adopting and releasing its final report for the Energy Master Plan. The revised plan accelerates the time line for retail competition. Competition will be phased-in beginning with 10% by 10/98, 35% by 4/99, 50% by 10/99, 75% by 4/2000, and all consumers by 7/2000. **1/97:** The BPU issued an order releasing its Energy Master Plan for public comment. The proposal calls for a phase-in of retail choice that would give all NJ residents and businesses the option of choosing their electric supplier by 4/2001.	disclosure of emissions and fuel mix; and give the BPU authority to determine the amount of stranded costs and recovery mechanisms, including securitization. The bill does not require divestiture of power supply assets, but would give the BPU authority to order divestiture to alleviate market power. Hearings on the issues of electric power industry restructuring are being held in the Senate. The governor of NJ and the investor-owned utilities in the state support the legislation. **7/98:** Legislative session ended in June without passing restructuring legislation. Details on issues with retail competition are still being worked on by the committee and the BPU. Competition , originally scheduled to begin 10/98, will likely be delayed until the spring. **3/98:** Legislation is expected to be introduced in the 1998 legislative session. **7/97:** AB 2825, a tax reform bill, enacted. The law abolishes the gross receipt and franchise tax on sales of electricity by regulated utilities and replace it with a corporate income tax and sales and use tax to create tax equity between utility companies and potential competitors in a deregulated market.		most of its stranded costs and would have to cut rates by 10 - 12 %. Another ALJ issued an initial decision on Atlantic City Electric Co.'s stranded costs and unbundling filings agreeing that stranded cost estimates are acceptable and should be recovered. Legislative and BPU approval are needed to implement utility restructuring plans. **4/97:** The Energy Master Plan allows for the potential recovery of stranded costs, but does not guarantee it. Securitization is being considered. **7/97:** Utilities submitted filings for stranded cost recovery. PSE&G plan estimates $3.9 billion in stranded costs and includes recovery of $2.5 billion through securitization; GPU estimated stranded costs at $1.8 billion. An initial decision by the BPU is due by 5/98.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
New Mexico	**2/98:** PUC submitted legislative language to the legislature and Governor that would give PUC authority to resolve deregulation issues. The PUC is pushing for retail competition; legislation will likely be introduced in the 1999 legislative session. **1/98:** The PSC issued its restructuring report to the legislature. The report calls for full retail competition by 1/01 and for legislative adoption of rules by 7/99. The report also states that $60 million/year could be saved. **9/97:** Public Service of New Mexico submitted its restructuring plan to the PUC. The plan proposes open access for all consumers by 1/2001, unbundling of services, and recovery of stranded costs using nonbypassable wires charges, exit fees, and securitization.	**8/98:** A New Mexico Senator is developing legislation to restructure the NM electric industry and plans to introduce it when the 1999 session begins. **5/98:** Restructuring legislation was introduced in January and strongly supported by the PUC. However, legislation was tabled until next year. The legislation would have set the date for retail competition at January 1, 2001.	**9/98:** The Public Service of New Mexico, under order of the PUC, will conduct a pilot program with its Albuquerque customers. About 16 MW of PSNM's load will open to competition in December 1998. PSMN opposes the order. **3/97:** PSC approved Texas-N.M. Power's "Community Choice" plan to introduce customer choice by 1998 through a pilot program. The program is scheduled to begin in May 1998.	
New York	**6/98** PSC set rules for a Systems Benefit Charge to fund R&D related to energy service, storage, generation, the environment, and renewables; pilot programs for energy management for low-income consumers; and environmental protection. **6/98:** Con Ed and Orange & Rockland filed a joint petition with the PSC requesting approval to complete the merger announced in May 1998. **6/98:** Con Ed became a member of NEPOOL, increasing its opportunities in	**2/98:** A bill, A.7942 - D was introduced by Senator Tonko to provide an alternative deregulation plan to the PSC, saying the current PSC plan does not go far enough to protect consumers. The bill calls for competition in electric generation no later than 3/1/2000 for all consumers, including municipal systems and 10% rate cuts by September.	**6/97:** PUC approved a pilot program for more than 17,600 qualified farmers and food processors, beginning in 11/97. **7/96:** PUC approved O&R;'s pilot program, "Power Pick," that will allow industrial consumers retail access to competitive generation suppliers. The program will begin	**5/96:** In the PUC order, it states that the PUC will determine each utility's allowable recovery of stranded costs. Utilities are expected to use creative means to reduce the amount of stranded costs prior to consideration. Utilities will include stranded cost recovery plans in their restructuring filings with the PUC.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	electric trade through participation in New England's bulk power market. **5/98:** Due to over-subscription of ConEd first phase of retail competition, the load for residential and small commercial customers was doubled to 1000 MW; a lottery will be conducted for large customers. Customers will begin receiving power from their suppliers of choice among more than 20 registered ESCO's on June 1. **5/98:** PSC approved generation divestiture plans for New York State Electric and Gas, Niagara Mohawk, and Orange and Rockland. The total capacity to be sold is over 7,500 MW. **5/98:** ConEd has announced that it will seek approval to buy Orange and Rockland. **5/98:** Orange and Rockland became the first utility in New York to offer retail choice to through its Power Pick program as customers began to receive power from their suppliers of choice on May 1, 1998. **4/98:** PSC approved LILCO/Brooklyn Union Gas Co merger. LILCO's non-nuclear generating assets are transferred to KeySpan Energy Services, parent company of Brooklyn Union. **4/98:** PSC approves O&R's and NIMO's divestiture plans. O&R will sell its		5/98.	

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	interest in the Bowline Plant, and its coal, gas, and hydro facilities. NIMO plans to sell its fossil-fueled and hydro plants by mid-1999. **2/98:** PSC approved restructuring plan for Central Hudson Gas & Electric. The plan requires divestiture of fossil-fueled plants, a rate freeze until June 30, 2001, rate reductions, and transition to full retail competition by July 2001. **2/98:** PSC approved Niagara Mohawk plan for rate restructuring, a nonbypassable CTC to fund $3.6 billion in debt for settlement with 16 independent power producers to restructure uneconomic contracts, and divestiture of fossil-fueled and hydroelectric plants. Retail competition will begin in 1998 for large customers and be available to all customers by January 1, 2000. **1/98:** PSC approved New York State Electric & Gas restructuring plan. The plan includes phase-in of retail competition for small industrials begins 8/98, full retail competition by 8/99, a rate freeze and rate cuts, and divestiture of its coal plants by 8/99. **1/98:** PUC approved Rochester Gas & Electric's restructuring plan. RG&E; will begin in 7/98 with open access for 10% of its customers and phase-in full retail access by 7/2001. Divestiture of fossil-fueled and hydro plants and rate cuts			

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	are included in the plan. **12/97:** PSC settled Orange and Rockland's proposal for restructuring. O&R will phase-in retail competition beginning 5/98, allow full retail competitive by 5/99, provide rate cuts, and require divestiture of generation assets by 5/99. **9/97** PSC approved ConEd's restructuring plan. The plan calls for rate cuts, retail competition to phase-in beginning 6/98, and full retail access by 12/01. In addition, ConEd will file by 1/98 unbundled tariffs for all classes of customers, to become effective 4/98. The plan calls for divestiture of at least 50% of ConEd's New York City fossil-fueled generation by the end of 2002. **5/96:** PSC issued its decision to restructure NY's electric industry. The Competitive Opportunities Case adopted the goal of having a competitive wholesale market by 1997, and a competitive retail market by early 1998. Electric utilities are required to submit restructuring plans by 10/96. It also states that utilities should have a reasonable opportunity to recover stranded costs consistent with the goals of restructuring.			
North Carolina	**9/97:** PUC reopened electric restructuring Docket concerning emerging issues in the electric industry.	**8/98:** At a "Mayor's Day" event mayors and city officials urged the legislature to pass restructuring legislation to prevent large industrials from relocating and thus protect the economies of NC cities		

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
		and the State. **7/98:** Research Triangle Park produced a report for the General Assembly Study Commission on the Future of Electric Service in NC that summarizes the rate disparity between publicly owned and private utilities in NC. The report recommends the Legislature pass deregulation legislation in 1999. **11/97:** The Study Commission commenced its work to investigate restructuring in NC and determine whether legislation is needed. Reports are due to the General Assembly in 1998 and 1999. **4/97:** SB 38 established a 23-member commission on restructuring. A report is due by 1999 to the legislature.		
North Dakota		**2/98:** ND Electric Utilities Committee met and discussed tax implications of restructuring and electric rates of investor-owned and cooperative utilities. **7/97:** First meeting of Electric Utilities Committee. Final report is due 11/98. **3/97:** HB 1237 enacted to create Joint Legislative Study Committee on Restructuring. Committee work should be completed by 2003.		
Ohio	**7/98:** The PUC approved consumer protection standards. The improved standards address new service installation, meter testing, disconnects,	**8/98:** In response to requests from the General Assembly, representatives of the 5 major IOU's have been developing a consensus framework for a	**8/98:** A lawsuit aimed at blocking conjunctive service regulations was thrown out of court. The	**12/97:** Stranded costs were addressed in the report issued by the co-chairs of the Legislative

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	complaint resolution, outage reporting, and utility reporting requirements. **6/98:** The PUC approved Monongahela's tariff for conjunctive electric service, the first tariff approved that will allow groups of consumers to aggregate and negotiate the price for electricity. **4/98:** The PUC is concerned with AEP's announcement that it is joining discussions with the Alliance ISO. There is concern that having two "competing" ISO's, Alliance, which has members stretching from Virginia to Michigan, including First Energy, and the MidWest ISO, which has ten members, including Cinergy, Commonwealth Edison, Illinois Power, CILCO, and Louisville Gas & Electric. **11/97:** PUC ordered newly formed First Energy to declare its intent to join the MidWest ISO. **2/96:** PUC adopted guidelines for "interruptible buy-through contracts," allowing power purchases from alternative suppliers to avoid interruptions.	restructuring proposal. Their proposal includes choice for all consumers by 1/1/01. **7/98:** The Coalition for Choice in Electricity, a broad group of consumer representatives, met with Sen. Johnson and Rep. Mead to urge the General Assembly to pass restructuring legislation. **5/98:** Hearings on the deregulation legislation began. SB 237 and its companion bill, HB 732, would create about 80 regional marketing areas that would be bid out to utility companies in an open public process. The Coalition for Choice in Electricity strongly supports passage of SB 237. **3/98:** Identical bills to deregulate the electric power industry were introduced in the House and Senate. The bills were sponsored by the co-chairs, Rep. Mead and Sen. Johnson, of the Legislative Joint Committee on Electric Deregulation. The proposed legislation will allow retail competition beginning 1/2000 and sets a 5-year transition period to full competition by 12/2004. **2/98:** The Legislative Joint Committee on Electric Deregulation plan was adopted. The report calls for retail access to begin by 1/2000 and allows for a 5-year transition period. Utilities may receive "transition revenues" in the form of nonbypassable wires charges to partially recover stranded costs after	PUC can now move ahead with the plans for conjunctive billing service. **12/96** PUC adopted guidelines for Conjunctive Electric Services. The 2-year pilot program would allow ratepayers to band together for collective billing under rates designed for the group. (This pilot is an experiment in innovative pricing, and does not allow retail wheeling.)	Joint Committee on Electric Deregulation. The plan allow for recovery of stranded costs using nonbypassable wires charges. Utilities would be allowed during the 5-year transition period beginning 1/2000 and ending 12/2004 to receive "transition revenues" or stranded costs under certain conditions, but likely expect less than 100% of recovery.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
		relinquishing control of transmission to an ISO.		
Oklahoma	**2/98:** The Corporation Commission issued final rules for unbundling. The rules now go to the legislature and governor for review. **4/97:** The OK Corporation Commission is directed by SB 500 to undertake a study of all relevant issues relating to restructuring the electric utility industry in OK and to develop a framework for the restructuring. Four reports: ISO Issues, Technical Issues, Financial Issues, and Consumer Issues are due 2/98, 12/98, 12/99, and 8/2000, respectively.	**10/98:** The Joint Electricity Task Force began meeting to discuss deregulating the state's electric utilities. Issues studied will include customer choice, reliability, unbundling, and tax impacts. The studies are to be completed by 10/99. **6/98:** SB 888 was enacted. The bill will speed up the time line for restructuring the industry. Currently, under SB 500, studies and recommendations for restructuring should be completed by the SCC by 2000. This new legislation would required that all studies by completed by 10/99, allowing some retail competition to begin as early as 1999. **4/97:** SB 500, the Electric Restructuring Act of 1997, is enacted allowing retail competition by 7/2002. The SCC is directed to study the issues and develop a framework to implement retail competition.		**4/97:** Under SB 500, each entity must propose a recovery plan for stranded costs. Transition charges can be collected over a 3- to 7-year period and must not cause the total price for electric power to exceed the cost per kWh paid by consumers when the law was enacted during the transition period.
Oregon	**2/98:** Portland General Electric's deregulation plan, which could become a model for the State, faces opposition from The Oregon Intervenor Coalition that includes Pacificorp, Washington Water Power, and consumer groups. Portland's plan calls for selling all its generation and allowing all customers to choose competitive generation suppliers. The coalition prefers a	**8/97:** Restructuring bill failed to pass 1997 session; expected to be reintroduced for 1999 session.	**7/98:** Pacific Power has filed a proposal with the PUC for a "portfolio" pilot program for residential and small commercial consumers and direct access for large industrial consumers.	

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	"portfolio model" for customer choice. The portfolio model would allow large industrial customers to shop for power suppliers, but small customers would continue to be served by the incumbent utilities and be offered a menu of plans to choose from. Options would include current, market, or "green" rates.		**7/98:** Portland General Electric's pilot program involving four Oregon cities will end as the two participating energy companies, Enron and Electric Lite, both discontinued marketing to consumers. **1/98:** Pacificorp filed a pilot program plan for residential and small commercial customers in Klamath County, OR. The pilot program would allow customers to select from a "portfolio" of pricing options for electricity and would go through 6/99. Another proposed pilot program will allow schools and customers with demands greater than 5 MW in Pacificorp's service territory to choose alternative generation suppliers for up to 50% of their load. Additionally, all of their large customers in Klamath County would be allowed retail access. **10/97:** PUC approved Portland General	

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
			Electric pilot program which will allow 50,000 customers in four cities to choose alternative generation suppliers. Large industrial customers could begin to choose immediately, and residential customers by 12/97.	
Pennsylvania	**10/98:** The PUC and PP&L reached an agreement on capacity prices; PP&L agreed to sell installed capacity at $19.72/kw-year through 1999. **10/98:** The PUC and GPU reached a settlement in GPU's restructuring cases, clearing the way for GPU customers to choose their electric generation suppliers on schedule beginning January 1999. **9/98:** About 1.8 million customers have registered to choose their electric generation supplier. The customers have received a "How to Shop" guide and a list of competitive suppliers and are now in the process of making choices. Two-thirds of the state's consumers are eligible to begin receiving power from their supplier of choice in January 1999. All residential customers will receive an 8% rate reduction, and so far competitive suppliers will provide customers about 14% savings. Also, 4 "Green-e" products (a product with the Green-e	**3/98:** HB 2286, a bill to accelerate retail choice for all consumers by 2 years, to 1/99, was introduced. **12/96:** HB 1509, the Electricity Generation Customer Choice and Competition Act, was enacted. The law allows consumers to choose among competitive generation suppliers beginning with one third of the State's consumers by 1/99, two thirds by 1/2000, and all consumers by 1/2001. Utilities are required to submit restructuring plans by 9/97.	**4/98:** The Pennsylvania pilot program is called "the most successful in the United States" with about 230,000 customers and many energy suppliers. **3/98:** Pilot programs are fully subscribed with more than 72,000 participants, making it the largest pilot program nationally. **2/98:** Pilot programs complete lotteries to select final pilot participants. The first portion of the State's customers, chosen earlier, are actively participating in retail access pilot programs since November 1997. **8/97:** As required by HB 1509, PUC approved	**10/98:** GPU announced an agreement with AmerGen Energy (jointly owned by PECO and British Energy) to buy Three Mile Island Unit 1 Generating Facility. If completed, this wil be the first sale of a nuclear power plant in the U.S. Approvals must be sought form various Federal and State agencies, including the Nuclear Regulatory Commission. **10/98:** Duquesne Light Co has struck an agreement with FirstEnergy Corp. to swap its interest in the Beaver Valley nuclear plant for three plants owned by FirstEnergy. The swap could reduce

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	logo is certified to be produced with 50% or 100% generation from renewables; see California) are being offered to Pennsylvania customers. **9/98:** The PUC capped installed capacity (guaranteed access to a supply of electricity) prices at $$19.72 per kilowatt-year. PP&L has argued that Federal law allows capacity sale at "whatever the traffic will bear." Higher prices are keeping competitive power marketers out of PP&L's retail market where no competitor has been able to quote a price to beat PP&L's "price to compare" at 4.26 cents/kilowatthour. **8/98:** PP&L reached a settlement on its restructuring case. Under it, all consumers will get a 4% rate reduction. PP&L will be allowed $297 billion in stranded cost recovery over 11 years. Consumer choice will follow the same phase-in schedule. **8/98:** The Electric Choice Program has enrolled 1.75 million customers and 70 electric service providers as of 8/1/98. In September, consumers will receive information on shopping for an electric service provider and the "shopping phase" will begin. Retail access is set to begin on 1/1/99. **7/98:** PUC rejected a petition filed by PP&L for reconsideration of its restructuring plan in regard to the stranded costs recovery. PP&L intends		statewide pilot programs for 5% of each utility's load, beginning 11/97.	Duquesne's stranded costs and lower customer rates. **9/98:** Duquesne Light filed a divestiture plan with the PUC, hoping to open an auction in early 1999 to sell 3,035 MW of coal and nuclear capacity. Approval is hoped for by December 1998. **12/97:** HB 1509 allows stranded cost recovery through CTC's; however, the detailed decisions and amount of recoverable costs are left to the PUC. The legislation expects utilities to use reasonable mitigation measures, and securitization is allowed but not required.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	to initiate a court challenge. **7/98:** In response to the PUC's rejection of GPU's restructuring plans, GPU filed 2 legal actions challenging the PUC decision related to stranded cost recovery and nonutility generator contracts. The legal actions could possibly delay the start of competition. GPU also filed a compromise restructuring plan. **7/98:** Pennsylvania consumers began signing up to participate in the first phase-in of competition, two thirds of consumers. In the first week, over 1.1 million consumers signed up for the Electric Choice Program. **6/98:** The PUC began its consumer education program. A Electric Supplier Selection Form will be mailed to all consumers in the state to begin enrollment in the first part of the phase-in of competition, set to begin with 2/3 of consumers in January 1999. Sign-up for retail choice begins July 1, 1998. The first third will begin taking power from the supplier of choice on January 1, 1999, the second third on January 2, 1999, and the final third on January 2, 2000. Most consumers should realize savings of 10% over what they now pay. **6/98:** The PUC approved restructuring plans for UGI Utilities, allowing $32.5			

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	million of the requested $58.5 million in stranded cost recovery. It also gave final approval to Pennsylvania Power & Light, Pennsylvania Power Co. (approved recovery of $234 million out of $273 million in stranded costs), and GPU's subsidiaries, Metropolitan Edison and Pennsylvania Electric. Also, the PUC authorized the Philadelphia Gas Works to sell retail electricity to its customers. **6/98:** GPU, PP & L, and Allegheny Energy (West Penn Power) plan to file petitions to challenge the PUC final orders on the allowed amount of stranded cost recovery in the final restructuring plans. **5/98:** The PUC gave final approval to PECO's restructuring plan in a compromise agreement. Under the plan, PECO customers will receive an 8% rate reduction next year, 6% in 2000, with 20% savings expected for those willing to shop for power. PECO will be allowed to recover $5.26 billion in stranded costs over a period of 12 years. Two thirds of customers will be phased in to retail competition by 1/99 and all customers by 1/2000. **5/98:** PP&L's restructuring plan was tentatively approved by the PUC. In the plan, PP&L will provide a 10% rate reduction and phase-in retail competition in thirds, beginning with two thirds in 1/99 and all by 1/2000. The amount of recoverable stranded costs			

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	allowed is $2.864 billion. Customers should see savings of about 10%. **5/98:** The PUC approved Allegheny's West Penn to recover $524 million in stranded costs. Consumers will be phased-in beginning 1/99 and going to full retail choice by 1/2000. **5/98:** PUC approved Duquesne Light's restructuring plan. Stranded cost recovery is set at $1.331 billion over 7 years beginning 1/99. Consumers should expect to save about 12%. Retail competition will be phased-in beginning 1/99 and be complete by 1/2000. **5/98:** An administrative law judge issued an opinion on GPU and its subsidiaries, Metropolitan Edison and Penelec, restructuring plans, appearing to fail to include full recovery of nonutility generator costs. GPU filed its reaction to the ALJ opinion on NUG recovery, saying it denied recovery of a significant portion of transmission and distribution costs and fails to assure full recovery of NUG costs. **11/97:**Enron's petition to serve as the "Provider of Last Resort in the Service Territory of PECO Energy Co" is denied.			
Rhode Island	**8/98:** Narragansett is proposing to cut rates 12.4% as a result of selling its power plants for $1.6 billion to US Generating. **5/98:** PUC reluctantly approved a rate	**8/96:** The Rhode Island Utility Restructuring Act of 1996 enacted allowing retail choice beginning 7/97 and continuing in phases. In July 1997, Rhode Island became the first state to begin phase-in of statewide retail		**9/98:** The now completed sale of NEES's generation assets (see New Hampshire) will result in increasing rate

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	increase for Narragarsett Electric Co for its standard offer rate from the current 3.2 cents/kWh to 7.1 cents/kWh by 2009. Similar increase were approved for Blackstone Valley and Newport Electric. **1/98:** Retail access was implemented with 25 registered generation suppliers, but the standard offer interim rates (3.2 cents/kWh) offered by the State's investor-owned utilities are low enough that no real competition has occurred. **12/97:** PUC issues an order accepting interim rates and approving retail choice for all RI consumers on January 1, 1998.	wheeling (for industrial customers). Residential consumers were guaranteed retail access by 7/98.		reductions, already 7% under the restructuring act, to about 19% for Narragansett customers. Stranded costs recovery is allowed through a customer transition charge of 2.8 cents per kilowatthour from 7/97 through 12/2000, and at rates subsequently set by the PUC through 2009.
South Carolina	**10/98:** The PSC released a report on deregulation that stated the cost of deregulating the 3 large investor-owned utilities in the state would be about $14 billion. Stranded costs for South Carolina Electric and Gas were estimated to be $882 million; for Carolina Power & Light, $410 million; and for Duke Energy, $81 million. **6/98:** PSC decided to conduct stranded cost proceedings for the 4 investor-owned utilities in the State, expecting completion by the end of the year. **4/98:** The PSC requested utilities to calculate their stranded costs under a retail access scenario. **2/98:** PSC issues Proposed Electric	**5/97:** House speaker requested a PSC study and recommendations for restructuring electric industry by 1/98. **1997:** Legislation (Bills 346 and 3414) to restructure the electric industry and allow retail wheeling were introduced in the House and Senate. The bills would allow retail competition to be phased in beginning 1/98 and going through 1/99. Neither were acted on in the current 2-year legislative session that ended in June 1998.		**2/98:** In the proposed implementation plan submitted by the PSC, recovery of reasonable, verifiable stranded costs is allowed. Utilities would submit recovery plans for approval by the PSC.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	Restructuring Implementation Process as requested by House Speaker. The plan calls for a five-year transition period following passage of legislation to deregulate the electric industry.			
South Dakota		**1/98:** The Legislative Research Council is hosting an informational forum on developments in utility competition. This is the first time the State legislature has addressed restructuring of the electric industry. No action is expected. Current law allows retail wheeling for new, large customers.		
Tennessee	**5/98:** The Department of Energy advisory committee on TVA issued a final report calling for more regulation controls on TVA once national electric deregulation begins. It recommends TVA remain mainly in the "wholesale electric business." There is little interest in restructuring in Tennessee due to TVA, a federal utility and thus not subject to state regulation, being the primary electricity provider in the State. Tennessee currently is among the States with the lowest electric rates in the U.S.	**6/98:** The General Assembly Study Commission is continuing into 1999. **6/97:** General Assembly created a special joint legislative committee to study electricity deregulation. A report is due October 1998.		
Texas	**7/98:** PUC approved Texas-New Mexico's five-year transition plan. Along with the rate reductions (described below) are a provision for a pilot program and plans to allow retail choice of generation providers to all retail	**6/98:** The Legislature is expected to consider four bills to open electricity to competition when it convenes in January 1999. A hearing was recently held with the Texas Industrial Electric Consumers that claimed residential customers would also benefit from	**10/98:** Texas-New Mexico Power Co. named 2 communities, Gatesville and Olney City, in which to initiate its pilot program, "Community Choice,"	**5/98:** The PUC's revisions to their plan for deregulation would allow securitization of stranded assets, estimated to be $4.5 billion if retail

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	consumers by 2003. **5/98:** An administrative law judge recommended the PUC reject Texas-New Mexico's restructuring plan. The plan would provide residential customers an immediate 3% rate reduction and another 3% in 1/00 and 1/01, totaling 9% over 3 years. Also, the plan provided for full recovery of stranded costs through a CTC. A final decision by the PUC is expected by July. **4/98:** The PUC is finalizing its plan and recommendations for deregulation and expects to forward it to the legislature within days. **3/98:** PUC approved both Texas Utilities and Houston Power and Light restructuring plans. The HP&L plan provides a 4 percent rate cut this year and another 2 percent next year. **12/97:** Houston Light and Power, Texas Utilities Electric Co., and Texas-New Mexico Power Co. announced agreements with the PUC on proposed competition plans, although final approval by the PUC is still needed. All three contain rate reduction measures. Texas-New Mexico's plan offers a guaranteed date, 2003, for full retail choice beginning with a phase-in of customers as early as 1/98, and a plan for stranded cost recovery. **10/97:** Houston Light and Power	deregulation. **3/98:** Texas House Standing Committee will debate restructuring in April. **12/97:** Senate Interim Committee on Electric Industry Restructuring met, and will continue meeting with stakeholders; next meeting set for February 1998. The committee expects to issue a report prior to when the 1999 legislative session reconvenes in January. **8/97:** Senate committee formed to review electric industry deregulation. A report is hoped for in 1999. **1995:** SB 373 enacted to restructure TX wholesale electric industry, consistent with FERC requirements. The law requires utilities to provide unbundled transmission service on a non-discriminatory basis and establish an ISO.	for retail access to generation suppliers of choice. **10/97:** West Texas Utilities announced a pilot program to allow about 1,000 customers in San Angelo to support the development of renewable energy resources by adding certain amounts to monthly bills and receiving increments of power from renewable energy sources (not a retail wheeling pilot).	competition happens in 2001. Deferring full competition one more year would lessen stranded costs to $3.3 billion, and delaying competition until 2003 would set stranded costs at approximately $2.3 billion.

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	presented its transition proposal for restructuring. Included is a 4-percent rate decrease over 2 years for residential customers. **1/97:** PUC issued three reports as directed by the legislature. Volume I is on the scope of competition in the electric industry in Texas; Volume II is an investigation into retail competition; and Volume III focuses on recovery of stranded costs and competition. **8/96:** ISO is authorized by PUC, to be operational by 7/97.			
Utah		**10/98:** The Utah Task Force on Electric Deregulation issued a report on stranded costs. The Task Force favors allowing he market to calculate the value of stranded costs. **6/98:** The PSC's "Unbundling Electricity Related Services" report to the Electric Deregulation and Customer Choice Task Force details technical options for separating the costs for generation, transmission, and distribution. **4/98:** The Utah Legislative Task Force on Electric Deregulation and Restructuring is favoring a slower approach, and will not begin working on draft legislation until the fall of 1998. **11/97:** The task force voted to recommend no restructuring legislation for 1998 session. The task force will prepare draft legislation for a		

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
		restructuring plan by April 1998 for introduction in the 1999 General Session. **3/97:** Legislature creates a task force to study the various issues of electric industry restructuring. A draft report is due 11/97, and the final report is due 11/98.		
Vermont	**12/96:** Vermont PSB issued is plan to restructure the electric power industry that called for retail competition by 1998, functional unbundling, and allowed recovery of stranded costs. Implementation of the plan requires legislation.	**4/98:** Several restructuring bills were considered in 1998 session. The session ended on 4/17 with no action taken on any of the bills. **10/97:** House Electric Utility Regulatory Reform Committee voted to not propose any retail wheeling legislation in 1998, but will draft its version of a restructuring bill for 1999. **8/97:** Prompted by the Senate bill, the House formed a special committee to study restructuring issues. **4/97:** Senate passed a bill based on the plan issued by the PSB that would have allowed retail choice by 1998; however, the bill stalled in the House.		**12/96:** PSB plan proposed partial recovery of stranded costs.
Virginia	**8/98:** The SCC approved more than $700 million in refunds and rate reductions. A total of $150 million in refunds will be provided by 11/2/98. In return for the refund/rate cuts, VA Power will use $220 million in revenue to reduce debt on generation assets. **6/98:** In an agreement between	**6/98:** Market power through control of transmission lines was cited as a major concern in the opening of electric to retail competition. The legislative committee will be looking at the concept of an ISO. **5/98:** Legislative committee met to discuss electric restructuring details.	**3/98:** The SCC ordered investor-owned utilities in the State to begin working on plans for pilot programs, as required by HB 1172, recently passed by the legislature and expected to be signed	

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	regulators, government, and business and Virginia Power, VEPCO will refund $920 million, the biggest rate adjustment in Virginia history, in rate cuts and refunds over the next 5 years. The rate reduction refund agreement is subject to approval by the SCC. A public hearing is scheduled for 7/21/98 on the proposed settlement. **3/98:** SCC ordered investor-owned utilities to begin work on change to introduce retail competition to the State including the creation of an ISO, PX, and plans for pilot programs. Utilities are to report on their previous activities and future plans by 4/15/98. **3/98:** SCC recommends a $277 million rate cut, approximately 7 percent, for Virginia Power consumers. **11/97:** SCC issued a study on electric industry restructuring and a model for competition. The draft model recommends a five-year transition to full retail access. Phase I, from 1998 to 2001, would involve rate experimentation, unbundled rates and bills, a study of stranded costs, formation of an ISO and power exchange, and pilot programs to study retail wheeling. Phase II, from 2000 through 2002, would involve decision-making for a competitive industry and utility plans for restructuring. Full competition would then be phased-in through 2005.	Concern was given to market power, and whether to require divestiture of generating assets to control it. An estimate of $3 billion in stranded costs was given for Virginia Power, and the costs to the consumers to transition to a competitive environment should be tracked. Draft legislation on the details of restructuring is expected to be written beginning this fall. **4/98:** Restructuring legislation, HB 1172 was signed into law. The law establishes a schedule for retail competition beginning 1/2002 and full competition by 1/2004. The law also requires establishment of an ISO and allows recovery of net stranded costs. The General Assembly will deal with details of the restructuring issues, such as stranded costs and public interest programs in the 1999 session. **2/98:** Two bills, HB 1172 and SB 688, to establish a schedule for retail competition in the industry were introduced in the 1998 General Assembly. HB 1172, which is supported by Virginia Power, was passed by the House on 2/17, and the Senate Commerce Committee is scheduled to consider it on 3/2. HB 1172 calls for establishment of an ISO and Regional Power Exchange and wholesale competition by 1/2001; transition to retail competition beginning 1/2002 and completed by 1/2004; and provides for the recovery of just and reasonable net	by the Governor. Detailed plans are due to the SCC by 8/98.	

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	11/96: SCC issued an order calling for more study on competition in the industry. The SCC asked that the state move slowly toward retail competition.	stranded costs.		
Washington	**5/98:** WUTC completed Phase I of its investigation into electric restructuring concluding the pace nationwide is faster than expected. **12/95:** WUTC issued its final guidelines after a year long inquiry into retail wheeling and restructuring issues, favoring a gradual approach.	**5/98:** Several bills were passed by the legislature: a net metering bill to allow net metering for on customer site generation from solar, wind, and small (under 25 kW) hydro; an unbundling bill to require generation, distribution, transmission, control area services, and programs to benefit the public, i.e., low-income, conservation, to be shown as separate charges; and a consumer protection bill requiring disclosure to consumers investments in conservation, renewable research, low-income assistance programs, etc. **4/98:** HB 2831 passed the legislature and the Governor is expected to sign it. The bill requires utilities to study and submit reports on unbundling their costs and the quality of service and reliability. Reports must be submitted by 9/98, and a the WUTC will provide a consolidated report to the legislature by 12/98. **1/98:** Several bills are pending that would require utility cost unbundling; utility consumer protections; and net metering of customer-produced electricity.	**6/98:** The MOPS II pilot that will allow WWPC's customers to choose the type of electric power they want to buy will begin 7/1/98. **2/98:** WWPC is selling blocks of wood and wind powered electricity in its pilot program. **12/97:** Washington Water Power filed a new pilot program with the WTUC, "More Options for Power Service II," to replace their previous one. The pilot will allow about 7,800 customers in WA and ID to choose among five energy service alternatives without changing energy service providers. The portfolio of options includes traditional energy service, 2 variable market rate options, a "standard rate offer" based on BPA's	

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
			preference rate, and a renewable resource rate. The pilot is scheduled to begin in 1998 and go through 5/2000. **8/97:** PUC approved 2-year Pilot program submitted by Puget Sound Energy for 10,000 customers. The pilot will begin 11/1/97 and go through 12/99.	
West Virginia	**10/98:** The PSC pushed back the October 1998 deadline for its final report on restructuring to 11/16/98. **9/98:** The PSC suspended an October 1998 hearing on deregulation, delaying any plan to submit recommendations to the1999 legislature. No hurry is seen to enact deregulation since WV rates are low. **6/98:** In a report filed with the PSC, the PSC Consumer Advocate Division stated that he public interest would not be served by the current proposals to deregulate the electric power industry in West Virginia. WV residents have among the lowest rates in the nation, and it is feared that rates for residential customers would rise under a competitive electric industry. **5/98:** In compliance with HB 4277, a new restructuring docket was	**3/98:** House and Senate passed a bill (HB 4277) to give the PSC authorization to develop a restructuring plan for presentation to the legislature in January 1999. The plan will require legislative approval. **1/98:** A bill was introduced to the legislature to authorize the PSC to design and implement an electricity deregulation plan.		

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	established. Proponents of deregulation are requested to file plans meeting criteria in HB 4277. A series of restructuring workshops will be held this summer and fall. Proposed plans have been submitted by 11 parties including AEP. **5/98:** PSC resumed debate on electric deregulation. Recommendations to the legislature are expected by 9/98. **10/97:** The staff report of the WV PSC Task Force was issued. **5/97:** The PSC formed a task force to study restructuring; a report is due 10/97.			
Wisconsin	**5/98:** The merger between IES, Interstate, and Wisconsin Electric was finally approved effective 5/31/98 creating Alliant Energy. Alliant filed a proposal with the FERC to join the Midwest ISO. **11/97:** PSC issued its final decision on electric industry restructuring. The plan does not recommend retail access before 2000, but focuses on improving the utility infrastructure. Recommendations included improving transmission facilities; removing barriers to open transmission access; developing an ISO; promoting construction of merchant plants; and promoting the development of renewable energy resources.	**4/98:** Legislation to improve reliability and prevent power shortages by establishing a competitive merchant plant generating industry and creating a regional independent system operator was signed into law on 4/28/98. The law will allow merchant plants up to 100 MW to be built without PSC approval, and utilities are required to join an ISO and create 50 MW of power from renewable sources by 2000. **1/98:** A bill authored by the Governor was introduced in the 1998 session that considers the reliability issues as proposed in the PSC final decision of 10/30/97.		

State	Regulatory	Legislative	Pilot Programs	Stranded Costs
	8/97: PSC submitted its draft 7-step work plan to restructure the electric industry to the Legislature. The plan focuses on reliability and infrastructure improvements, and does not recommend retail access at least until 2000. A final decision is set for 10/30/97.			
Wyoming	**6/98:** The PUC had scheduled a hearing on deregulation in June 1998 to establish voluntary guidelines for utilities, but the hearing was canceled in response to legislator's concerns. **9/97:** An analysis of electric industry restructuring in the state was issued by the PSC. The paper stated that further study was needed; legislation would be needed; stranded costs should be recoverable; and pilot programs should be developed.	**6/98:** A controversial bill was revived which was killed in January 1998. **9/97:** A joint committee of the Wyoming legislature began a series of hearings on electric industry restructuring.		

Appendix 4.1

Department of Revenue's Briefing Paper on Tax Policy and Restructuring the Gas and Electricity Industries

REVISED FINAL

I. Introduction.

A series of federal acts and rules restructured the wholesale gas and electric market and paved the way for states to restructure the retail market. Even though a restructuring of Washington State's retail energy market may or may not happen in the near future, in-state energy businesses and consumers are affected by the changes in the industry occurring outside our state's borders. While the industry is changing, Washington's tax laws remain the same. Tax laws that are non-responsive to industry realities may result in lost revenues to the state and create a competitive disadvantage for in-state businesses. This paper looks at the energy industry, current taxation of that industry, threats to the state's revenue, and emerging tax policy issues.

II. Why and how the energy industry is changing.

a) Federal laws and rules

i) Electricity industry

1978 - Public Utility Regulatory Policies Act (PURPA). Out of the "energy crisis" of the 1970's came this search for new approaches to power generation. PURPA imposes an obligation upon the traditional vertically integrated utility (power generation, transmission, and distribution owned and operated by the same entity) to purchase power from non-utility power generators at the utility's cost of new power generation. This obligation fostered the rise of the independent power producers.

1992 - Energy Policy Act (the Act). The Act initiated competition in the wholesale market by empowering the Federal Energy Regulatory Commission (FERC) to order utilities to provide access to their transmission systems to wholesale sellers of power. The Act applies to investor-owed and public-owned utilities as well as the Bonneville Power Administration (BPA). (BPA need only comply to the extent the Act is not inconsistent with BPA's other statutory obligations.) The Act specifically prohibits FERC from ordering transmission access for retail load.

The two following rules implement and augment the 1992 Act.

1996 - Rule 888. This rule furthers the nondiscriminatory open access requirement of the Energy Policy Act of 1992. It establishes a FERC-regulated tariff system to set pricing for transmission. The effect is to facilitate competition in the nascent power marketing industry.

1996 - Rule 889 is also called OASIS (Open Access Same-time Information System rule). The rule requires all parties to share information about available capacity of the transmission system on the Internet, thus facilitating real-time trading. Further, it prohibits self-dealing between a utility and its affiliates to ensure a competitive level playing field. These provisions set the stage for open access to the national wholesale electricity market.[1] Additionally, the rule orders separation of wholesale power marketing from transmission functions; this is not an order of divestiture or corporate re-organization but an order of functional unbundling. Industry has found the separation language to be unclear.

Industry generally complies with Rules 888 and 889. It is notable that a 1996 news release from FERC states that the rules cannot by themselves achieve an efficient, competitive electric industry. The news release points to both state and regional issues that need to be settled. One such issue is the question of where local distribution ends and interstate transmission begins; the rule states that local distribution remains in the hands of the local utility under the jurisdiction of the state but leaves it up to the state to place the dividing line between interstate transmission and local distribution based upon criteria set in Rule 888.

Bills introduced in Congress last session sought to shape state restructuring of the retail market. The bills proposed limitation on fees charged to departing customers (exit fees), set required retail access dates, and addressed various concerns regarding BPA and the Tennessee Valley Authority.

Other federal influences on restructuring are occurring in the courts. For example, one court case originating in New York and now pending in federal district court in Washington DC, questions who has jurisdiction over retail transmission. FERC asserts it does; the plaintiff states, including Washington State, disagree.

ii) Gas industry

The re-structuring of the wholesale gas market occurred earlier and with fewer ripples compared to the electricity industry. No federal statute directed the regulatory changes in the gas industry. The restructuring occurred through administrative orders relative to the common-carrier role of the interstate pipelines.

1985 - FERC Order 436. This Order affords incentives, not an order, for pipelines to offer gas transportation services to other gas providers. The Order fostered the beginning of bypasses, i.e. large industrial consumers of gas who build their own spurs from the pipeline and purchase gas directly from the pipeline.

1987 - FERC Order 500. The Order prohibits preferential treatment between pipelines and their marketing arms.

1992 - FERC Order 636. This ordered interstate pipelines to separate their transportation from the gas marketing functions and to provide open access (common carrier service) to all buyers of gas from all sources as well as the pipeline. This order succeeded in breaking up the pipelines' grip on the natural gas industry.

b) The unsettled issue: Bonneville Power Administration
BPA is both the marketer of electric power generated by federally-owned facilities and the controller of interstate and intrastate transmission of that power. Federal law, based on historical economic reasons, requires BPA to sell power at cost-based rates to certain preferential customers located in the Northwest; these are public (government) utilities, electric cooperatives, investor-owned utilities (but only for their residential and small-farm consumers), and direct service industries (mostly aluminum companies). Some eastern U.S. interests are opposed to the preferences received by the Northwest from BPA; legislation was introduced in Congress last session to require BPA to charge market rates rather than sell at cost.

In the year 2001 many of the contracts for purchase of BPA wholesale power expire. In 1995-1996, there was much concern that in the unregulated market of 2001, customers currently committed to purchase power at cost from BPA would find cheaper market-priced power elsewhere thereby leaving BPA insufficient income to meet its treasury obligations. More recently, however, changing market predictions suggest that BPA's rates will compare favorably to market rates and that BPA's traditional customers will be competing for shares of BPA's power. Nevertheless, the fear of an unstable BPA led to the formation of the Northwest Energy Review Transition Board composed of gubernatorial designees from Montana, Oregon, Washington, and Idaho. The Board concentrates on the following issues respective to BPA:

- cost control - so that BPA's cost price is competitive with market price
- fish and wildlife considerations - may result in reduced power generation and higher costs
- stranded costs - who pays?
- subscription - pricing and negotiations on new contracts
- transmission - separation of BPA's transmission from its marketing
- river governance

The Board seeks to foster a regional solution to these issues to present to Congress. If Congress goes ahead with national restructuring legislation, the region wants to be ready with a "Northwest" chapter to that legislation.

III. Summary of non-tax related Washington legislation.

a) Legislation passed this year.

E2SHB 2831. This Bill authorizes a study and requires electric utilities to unbundle the costs of their assets and operations. The legislation intends to force utilities to account for their cost structure. At a minimum the utility must separately account for generation and energy supply, delivery services, metering and billing, customer account services, conservation and renewable resource programs, general administration, overhead, and taxes. The study focuses on costs and service quality. Study data must be reported by investor-owned utilities to the UTC and by municipally-owned utilities to their own elected body and then to the State Auditor. Small utilities are exempted. By December of 1998, the UTC and State Auditor will submit a joint report to the legislature.

ESSB 6560. This bill authorizes a study and imposes certain consumer-protection duties upon utilities. Utilities must provide to consumers on a regular basis information about rates, metering policies, billing and payment options, disconnect requirements, and complaint procedures. The study, to be conducted jointly by the UTC and DCTED, focuses on retail rates and costs, demographics, cost-shifting, service territory agreements, reliability, and related retail/consumer issues. The study report is due to the legislature by December 31, 1998.

The Department of Revenue is not a participant in either study; however, the UTC invites Department staff to the study meetings and generally keeps staff apprised.

b) Legislation proposed

At the end of the 1998 legislative session, Senator Finkbeiner distributed to interested parties a preliminary draft of a bill restructuring the electrical industry under the portfolio model.[2] Key non-tax features of the bill are:

- ❖ Requires utilities to provide to consumers, classified by the size of their electricity usage, a choice of a retail package of service and energy supply (the portfolio);
- ❖ Allows for stranded costs to be recovered from consumers provided the costs are deemed prudent. Divestiture of assets is not required, however, the utility's governing body could so order.
- ❖ Requires out-of-state power suppliers to register with the UTC and allows the UTC to deny registration thereby prohibiting that supplier from entering into contracts with Washington businesses or consumers.
- ❖ Imposes public-purposes funding by the utilities for conservation, social, and environmental programs. The amount of money due from each utility is determined in a complex (but workable) manner by the Department of Revenue. The public purposes funding is not a tax.

IV. Current taxation of the energy industry.

In Washington, gas distribution businesses and light and power businesses are subject to state and local excise taxes, property taxes, and in-lieu-of property taxes; in addition, consumers of gas pay a use tax. Each of these taxes are discussed below and comment made on the vulnerability of the tax both in the event of restructuring in Washington and in the current status of restructuring nationally.

a) Property taxes

The property tax liability of utilities located in more than one county is determined by the Department through central assessment. Utilities situated in a single county are assessed by the county in which it is located. The chart below shows receipts for the thirteen light and power businesses and the four gas distribution businesses which are centrally assessed.

Property Tax Paid By Centrally Assessed Light and Power Businesses

Year	Equalized Value Personal and Real	Avg. Rate	Tax
CY 1997	$2,866,549,565	$0.01352	$38,755,750
CY 1996	2,912,126,655	0.01393	40,565,924
CY 1995	2,638,577,987	0.01382	36,465,148
CY 1994	2,757,166,376	0.01353	37,304,461
CY 1993	2,560,862,432	0.01344	34,417,991
CY 1992	2,575,011,773	0.01336	34,402,157

Property Tax Paid By Centrally Assessed Gas Distribution Businesses

Year	Equalized Value Personal and Real	Avg. Rate	Tax
CY 1997	$1,051,367,794	$0.01352	$14,214,493
CY 1996	969,260,176	0.01393	13,501,794
CY 1995	843,633,039	0.01382	11,659,009
CY 1994	875,500,139	0.01353	11,845,517
CY 1993	735,400,183	0.01344	9,883,778
CY 1992	682,541,402	0.01336	9,118,753

In many of the restructuring states, particularly eastern states, the property values of the utilities were artificially inflated either because the regulated utilities were a convenient tax base or because uneconomic capital investments (nuclear plants) were on the books at construction costs rather than value. In those states, when restructuring arrived and utilities sought to divest themselves of generation facilities at their true market value, local and state programs dependent upon property tax revenues were imperiled. In Washington, the values upon which the tax is based represents market value of tangible assets or net book value; we do not anticipate a significant threat to property tax revenues from restructuring in this state. On the other hand, as other states restructure and competition increases, light and power businesses in Washington may wish to sell off unprofitable generation plants. We cannot predict the tax consequences of such sales. For example, if a centrally assessed utility sells off a generation plant located within a single county as a stand-alone operation, that asset will then be locally assessed. The valuation will be influenced by the use to which the new owner puts the facility and land. In the alternative, the unprofitable plant could be purchased by another entity subject to central assessment. Each scenario presents a number of variables that could positively or negatively impact property tax revenues.

b) Privilege or in-lieu-of property taxes

The 25 public utility districts (PUD's) pay a privilege tax, often referred to as an in-lieu-of property tax, based on a combination of a percentage of gross revenues plus a rate times the number of kilowatt hours of power generated for retail and wholesale sales. Restructuring does not present a threat to the revenue from this tax. However, the tax statutes respective to PUD's are not structured to capture revenues from activities outside a vertically owned and operated system. For example, purchases and subsequent sale by a PUD of power generated from assets not owned or operated by the PUD do not come within the statutory provisions of the privilege tax.

PUD Privilege Tax

	Distribution of State Tax	
Year	State	Local
FY 1997	$12,540,274	$15,253,653
FY 1996	12,161,330	14,686,088
FY 1995	11,815,000	14,303,000
FY 1994	10,862,000	13,107,000
FY 1993	10,041,000	12,240,000
FY 1992	10,231,000	12,622,000

c) Use tax on brokered natural gas

In 1989, in response to the restructuring of the gas market, the legislature passed a use tax on brokered natural gas. The tax is at the same rate as the public utility tax on purchases of gas not already subject to tax. The intent of the legislation was to impose the tax on consumers who, by reason of restructuring in the gas industry, were able to purchase gas on the open market. In Washington, there are two such groups of customers, one group is called "bypass customers" and the other is called "transportation customers." Bypass customers are those who build their own spurs from the pipeline for direct delivery of gas. In Washington, we have seven bypass customers, two of which have an additional customer each for a total of nine consumers receiving gas outside the local distribution system. Transportation customers are those industrials, hospitals, schools, and large commercials who might have opted to bypass but instead, through UTC permission, were granted more favorable rates from the local distribution company for gas obtained on the wholesale market.

The use tax is designed to capture tax revenues from bypass and transportation customers that would otherwise be lost to the state because of purchase from out-of-state gas providers without nexus. Between bypass and transportation customers, 180 consumers pay the use tax on brokered natural gas. The chart below shows use tax revenues collected by the Department.

Brokered Natural Gas

State Tax Rate .03852

Year	Collections
FY 1997	$8,712,000
FY 1996	8,177,000
FY 1995	7,938,000
FY 1994	6,184,000
FY 1993	4,219,000
FY 1992	2,989,000

The use tax on brokered natural gas is under legal attack. Three suits filed in Superior Court challenge the constitutionality of the tax on the basis that it impermissibly burdens interstate commerce. However, at the end of September, 1998, opposing counsel in one of the suits informed our assistant attorney general that he will drop the action.

d) Gross receipts taxes

In the state of Washington, the public utility tax (PUT) is paid by investor-owned light and power business, municipal light and power business, public utility districts, gas sales and distribution businesses, and rural electric associations and cooperatives. While approximately 74 utilities pay the PUT on electricity and 20 businesses pay the PUT for gas distribution, ten businesses pay over 80% of the PUT revenues. In addition to PUT, the utilities pay B&O tax on certain activities such as services rendered for persons who are not yet customers of the utility.

The chart below shows PUT taxable gross receipts and tax revenues for all payers over the last six fiscal years.

Public Utility Tax (PUT)

	Electricity		Gas Distribution	
Year	Taxable	Taxdue	Taxable	Taxdue
FY 97	$3,249,289,228	$125,844,928	$646,292,605	$24,894,839
FY 96	3,182,375,923	123,246,987	684,029,552	26,348,424
FY 95	3,093,267,900	119,795,805	678,999,972	26,155,030
FY 94	2,935,825,298	113,704,470	662,003,051	25,500,351
FY 93	2,654,769,474	102,819,229	573,613,578	22,095,595
FY 92	2,357,262,583	91,296,769	486,202,017	18,728,501

The gross receipts tax is vulnerable under various possible scenarios of restructuring. That vulnerability is discussed in the Section V below.

e) Local taxation of utilities

Local taxing districts receive property tax revenues from centrally and locally assessed utilities and from the PUD privilege in-lieu-of-property tax. In addition, some cities assert a gross receipts tax on utilities. In 1996, 5.62% of revenues paid to cities were attributable to this gross receipts tax. The measure of tax is the gross receipts of energy sales to customers or the gross receipts of an energy business located within the city.

V. Tax policy in a restructuring environment.

Certain aspects of Washington's excise tax system are outdated and vulnerable in the face of federal restructuring of the wholesale market and the small but significant number of states restructuring their retail markets. The section below discusses the possible impacts to the excise tax system in the changing energy industry.

a) The energy industry in a restructured environment

Under restructuring, the energy industry is separable into three entities: local distribution, transmission, and power generation. If restructuring occurs in this state, Washington consumers may do business with three separate businesses rather than just one in obtaining their electricity. Each of the separate entities present distinct tax issues.

Local distribution: If Washington restructures its retail electricity market, the local distribution company (LDC), the keeper of the meter, will more than likely remain a regulated local monopoly as it has under gas restructuring. In general, the LDC is the convenient collector of a consumption tax and an identifiable, localized point for imposition of an excise tax. There are no legal barriers to asserting a state tax against LDC's.

While the LDC, for both gas and electricity, does not present significant potential for revenue loss either now or in the event of restructuring, certain tax issues will need to be addressed by the legislature. For example, under Senator Finkbeiner's proposal, approved stranded costs may be recovered over a 10-year period as transition charges passed on to consumers. Will the revenues from payment of these costs be taxable as PUT or B&O? Similarly, if the legislature provides for exit fees (charges made to customers who leave the LDC), the same question applies to the revenues from the fees.

Transmission: Transmission refers to the "carrying" of gas and electricity. Intrastate transmission is subject to the PUT; interstate transmission may not be taxed by the state. While transmission itself does not present significant tax policy issues, the legislature may wish to keep the cost of transmission in the tax base. That is, Washington consumers pay for interstate transmission, either through the rates paid to their local utility or, for consumers of brokered natural gas, through costs paid directly to the owner of the interstate transmission. Costs of transmission paid to the utility are subject to the PUT and the costs for interstate transmission directly paid by the consumer are included in the tax base for calculating the use tax on brokered natural gas. In the event Washington imposes a consumption tax on electricity, the legislature may wish to include a similar provision respective to electricity transmission.

Power generation: With or without Washington restructuring, in-state power generators may participate in the national wholesale and retail energy market. That participation together with out-of-state power generators possibly entering into Washington's markets presents significant challenges to Washington's tax system.

Under current law, when an in-state power generator exports power out of state, the export is not subject to the PUT or to B&O wholesaling. The table below shows reported exports of power or in other terms this is the amount of deduction taken on the Combined Excise Tax return for power sold out of state. The Department is not confident that these figures represent total exported power. It is likely that the light and power businesses deduct the exported power from gross receipts without showing such deduction on their combined excise tax return.

Reported Exports Of Electricity

Year	Count	Deduction Amount
CY 1991	0	$ 0
CY 1992	0	0
CY 1993	4	63,477
CY 1994	3	887,722
CY 1995	2	confidential*
CY 1996	3	54,276
CY 1997	4	1,183,374

** State law does not allow disclosure of aggregated tax information for less than 3 taxpayers.*

Regardless of the possible infirmities of the figures, the trend is clear: Washington in-state power generators are exporting more power than they used to. Where does the sold power go? What if the power is sold to an out-of-state marketer who turns around and resells the power to an in-state consumer? The result is that electricity produced and consumed in Washington escapes taxation altogether. Such a scenario is possible although the Department does not know the extent to which it happens.

Some of the exported power is sold in the open retail market. For example, Seattle City Light sells power to Nordstrom in California. The sale of the power is not subject to Washington tax. The state does not lose revenue from this sale presuming that Seattle City Light is selling excess power. However, the possibility remains that net-importing or net-exporting of power eventually could result in loss of state revenues. If the cost of power is cheaper to purchase than it is to generate and sell (subject to the PUT), the utility may make the economic choice to purchase untaxed, cheaper power for its load and export produced power. Another twist on this possible scenario could occur under BPA's proposed allocation of its power. Pursuant to the proposed allocation, BPA will sell enough low-cost power to the investor-owned utilities to serve almost all of their residential/small-farm load. This would free up the utilities' more expensively produced and priced power for export. Under this possible scenario, the measure of the public utility tax is the low-cost BPA power rather than the higher-priced power.

If Washington restructures, power purchased by a retail customer from an out-of-state generator will not be subject to tax unless the generator has nexus. For example, a power generator in Montana could make a retail sale of power to any consumer in Washington. Absent nexus, the sale is not taxable. Not only would the state lose revenue but also an in-state power generator, whose price includes PUT, would lose a customer because its price is not competitive. Out-of-state power generators would have a competitive edge over in-state generators.

b) New players in the energy business

Open retail access gives rise to an active market where the hope of profit inspires entrepreneurial risk. This active market poses problematic taxation issues. Even without restructuring, three non-industry players: marketers, brokers, and investors, present tax policy questions.

Marketers. Marketers take "possession" (or title or ownership) of the gas or electricity. Rule 889 facilitated establishing this market on the internet. A marketer can sit at her desk in Montana and buy and sell electricity or gas all over the U.S. through her computer. Or, to put this another way, without establishing any presence for tax purposes in Washington, a power marketer can provide every bit of energy consumed in this state. Neither the marketer's income, nor the power imported, is subject to Washington tax. The amount of state revenues likely to be diverted in this arena cannot be measured, but the potential is significant.

Marketers located in-state raise their own tax issues. Since the in-state marketer is not a light and power business or a gas distribution business as defined in the public utility tax statutes, one of the B&O categories should be applicable to their gross receipts. Since gas is tangible personal property, the applicable B&O categories are wholesaling and retailing. On the other hand, electricity is not classified as tangible personal property; therefore, marketing of electricity falls into the service category. This may be perceived as unequal treatment for the two types of energy. At a minimum, it illustrates the point that the difference in property type between gas and electricity must be taken into account when considering tax alternatives.

Brokers. Brokers are distinguished from marketers in that brokers do not take possession of or title to the power. They serve the function of putting together buyers and sellers. Brokers, lacking a plant or system, are not subject to the public utility tax but are subject to the service B&O on the commissions they receive for putting together a sale if they have nexus. Because of the definitions in the PUT statues, Washington discourages in-state broker businesses. Brokers do not meet the definition of a "light and power business" or a "gas distribution business" for purposes of the PUT. While sales made by in-state light and power business or gas distribution business to another light and power business or gas distribution business are not taxable, such sales to brokers are. Then, when the broker sells the power, she is subject to B&O. Because the power they sell is subject to both PUT and B&O, in-state brokers claim they cannot compete with out-of-state brokers, thus leaving the Washington market open to out-of-state brokers or marketers.

Investors. Since the energy market functions similarly to the commodities market, investors are a component of restructuring. Investor buying and selling creates instability in prices.[3] With a tax system based on value such as Washington's, a volatile market makes it more difficult to accurately project state revenues.

c) Nexus in the restructured environment

As the above discussion shows, nexus is the most perplexing tax issue that accompanies restructuring. Since no court has yet ruled on nexus arising specifically out of restructuring, the issue is far from settled. As open access moves along, such a suit is inevitable. Policy makers note with interest a recent case out of Rhode Island in which the court found nexus for an out-of-state heating oil marketer by reason of the marketer's control of the product as it passed through interstate commerce and its contract with in-state deliverers. See Koch Fuels, Inc. v Clark, 676 A2d 330 (1996). Although tax practitioners often refer to Koch Fuels, to date, no court has relied upon or quoted the case.

d) Special consumers, restructuring, and tax policy

In Washington, two groups of consumers are direct beneficiaries of BPA preferences, the direct service industry and rural electric associations. Each presents unique issues for consideration.

Direct Service Industries. Thus far, the DSIs are not enthusiastic about restructuring. They have historically been dependent upon their ability to purchase power at the most economic price possible to keep their electricity-intensive operations viable. The eleven DSI's in Washington already purchase electricity in an open market. These purchases generally are not subject to state taxation, either because the purchase is from BPA or because the purchase is from an out-of-state supplier without nexus. Only if a DSI elects to purchase from an in-state utility is the sale subject to the utility tax. Historically, DSIs have purchased much of their power from BPA, but their reliance on BPA power has diminished, and will diminish further if BPA implements its proposed allocation of power for the 2001 - 2006 period. DSIs are not required to make reports to the Department regarding their electricity purchases, so their expenditures for electricity are unknown. However, the aluminum industry provided the following data showing their combined consumption of electricity measured in dollars.

Power Consumption By The Aluminum Industry

	Dollars in Millions
CY 1996	$393.3
CY 1995	$372.6
CY 1994	$357.2
CY 1993	$341.8

In the past, some DSIs have said imposition of a tax on electricity would make their cost of operations too high thereby jeopardizing continued operation in this state.

Rural electric associations. The rural electric association (REA) is another group unenthusiastic about restructuring. This group, similar to the DSIs, already participates in the wholesale market through purchase of power from BPA or out-of-state marketers. Subsequent sale of that power is subject the PUT. The tax changes that accompany restructuring may negatively impact REAs, especially if those changes impose a consumption tax. A value-based consumption tax is particularly unwelcome to the state's eight REAs because their rates are approximately 36% higher than the rest of the state.

e) Other states' response to electricity restructuring

Eleven states restructured their retail electricity markets either through legislation or through orders issued by their utilities commission. Of the eleven, California and Massachusetts have ballot initiatives pending to repeal or modify the re-structuring; New Hampshire's restructuring is delayed pending litigation over the provisions for recovery of stranded costs. The restructuring legislation of two other states, Montana and Pennsylvania, survived recent administrative appeals and are slowly going forward.

The tax provisions of the restructuring states are not necessarily instructive for Washington for two reasons. First, the hot issue in many states is the negative impact to property tax revenues with the divestiture of assets that were over-valued on the tax rolls. This is not perceived to be an issue in Washington. Second, states with a utilities gross receipts tax (UGRT) also generally have a corporate business tax. Consequently, when restructuring, the UGRT is repealed and easily replaced with a corporate business tax. Such an alternative is not possible in Washington. Further, some states, such as California and Montana, made no changes to their taxing scheme.

However, the tax provisions of some restructuring states are instructive. In Pennsylvania, rather than repeal the UGRT, the legislation strengthened it by redefining the definition of gross receipts to include out-of-state power suppliers. This is accomplished by saying a sale of electricity occurs within the state if the meter of the customer is located within the state. Meter-equaling-nexus is only one of the provisions in the bill designed to create nexus; the other provision requires out-of-state suppliers to register with the public utilities commission. The commission has the authority to revoke a registration for failure to pay the UGRT. To further avoid erosion of state revenues, the bill allows for a surcharge to be attached to the UGRT in the event revenues fall below a specified amount through the year 2004 and a use tax is imposed on in-state companies for power purchased from out-of-state, non-nexus companies. Pennsylvania's legislation, passed at the end of 1996, orders pilot programs only in 1997 and 1998; retail access is not proscribed until 1999 and then for only 66% of the market. The statutorily-imposed nexus has yet to stand the test of time. A recent telephone conversation with counsel for the Pennsylvania Department of Revenue revealed that each day that passes without notice of a lawsuit surprises the legal department.

Illinois imposed a consumption tax on users of electricity. The volume-based tax is assessed upon kilowatts consumed at rates descending as usage increases. The tax will be collected by the local distribution company. The legislation allows commercial and industrial consumers to "self-assess" and pay on the cost of electricity purchased rather than the kilowatts consumed provided the taxpayer complies with certain registration requirements. The governor has not yet signed this portion of the legislation and the "self-assessment" process will probably not be implemented in time for the August 1, 1998, effective date.

New Jersey provides an interesting case. Rather than a restructuring bill, the legislature passed an Energy Tax Reform bill effective January l, 1998. The bill repeals both the UGRT and the franchise tax on gas and electricity and imposes a sales and use tax. Federal installations are the only significant exemption from the new tax. The tax treatment presumes electricity and gas both to be tangible personal property. According to a contact at the New Jersey Department of Revenue, the legislation received little publication and has not generated any taxpayer protest. This is attributed to the fact that not only does the consumer see little net change to total energy costs, the law allowed the new tax to not be reflected on the bill to consumers.

A recent report lists Kansas as currently considering a legislative tax change in anticipation of restructuring.

VI. Taxation alternatives.

a) Legislation proposed during the last two sessions

DOR 1997 bill. Operates much the same as the use tax on brokered natural gas. The proposed legislation imposes a use tax on the consumption of electrical energy to the extent that the PUT has not been paid on the value of the electrical energy consumed. The DSI's floated an amendment to the Department bill that exempted them from this tax.

Representative Thomas' bill. Asserts a state and local consumption tax on gas, electricity, and telecommunications and repeals state and local PUT and the use tax on brokered natural gas. Imposes B&O at retailing and wholesaling rates as applicable and service rate for wheeling. The bill specifies that electricity is not tangible personal property.

*DSI/Aluminum industry bi*ll. Asserts a retail and use tax on electricity but exempts from that tax the aluminum industry, DSI, deep-well irrigators, and anyone who gets power from BPA. While the bill does not eliminate the PUT, it eliminates from the definition of gross receipts subject to PUT the amounts received for electricity and wheeling.

Senator's Finkbeiner's proposal. Similar to the DSI/Alum's proposal.

Flat tax on consumption of electricity (PSE's 1997 strawman). Imposes a per kilowatt-hour tax on the consumption of electricity and repeals the state and local PUT. Allows the locals to impose a per kilowatt tax. Changes the definition of manufacturer to include electric companies.

b) The great debate: consumption tax versus a gross receipts tax

If the Washington legislature should decide to move forward with a new tax scheme for the energy business, the choice may boil down to a policy choice between a consumption tax or a gross receipts tax (similar to the current public utility tax or a variation on a B&O tax) strengthened to address nexus. A consumption tax could be based on either the value paid for the energy or on the volume (kilowatt and cubic feet) consumed.

The advantages of a consumption tax are as follows:

- avoids problems with nexus
- can be efficiently and easily administered with the regulated local distribution company as the tax collector [4]
- offers flexibility for local option city and county taxation
- may promote energy conservation
- in-state power producers would have less of a competitive disadvantage when competing with out-of-state power producers who, lacking nexus, do not have to pay and then recoup the PUT in their sales price

The disadvantages of a consumption tax are as follows:

- adds to the regressivity of Washington's already regressive tax system by reason of the consumption-based sales tax
- in some cases, establishing the point of sale may be difficult for industry as the location of the meter and the billing address are not necessarily the same
- those consumers who located in Washington because of low energy prices or BPA preferences will feel disadvantaged unless the consumption tax accommodates their high-volume use
- if the consumption tax is value-based, it places an additional tax burden on those who pay a comparatively high price for power such as REA's

The advantages of a strengthened gross receipts tax are as follows:

- it is consistent with Washington's current tax system
- businesses are used to the gross receipts tax and do not need to make adjustments to their accounting systems to accommodate the tax
- it places no additional administrative burden on the state
- cities could maintain revenues

The disadvantages of a strengthened gross receipts tax are as follows:

- even if strengthened similarly to Pennsylvania's gross receipts tax, nexus may still be subject to legal challenges thereby putting revenues at risk
- the electricity sold to and consumed by direct service industries remains untaxed unless a strengthened gross receipts tax also includes a use tax on brokered electricity

c) other tax alternative

As an alternative, the state may wish to consider a combination value-based and volume based tax similar to the tax enacted by Illinois but adapted to Washington's gross receipts tax scheme. The PUT or B&O would continue to be imposed where applicable; an indexed kilowatt per hour tax would be imposed on consumers. With a volume-based tax, the consumer would not be impacted by fluctuations in the price of power and the revenues would be predictable. Large industrials and DSI's could opt for an indexed value-based or volume-based tax. The purpose of the option would be to help these industries remain competitive and at the same time share in the obligation to pay taxes.

Briefing Paper prepared by:

Anne Solwick, Department of Revenue

Ray Philen, Department of Revenue

With thanks to the following for their contributions:

Don Gutmann, Department of Revenue

David Saavedra, Department of Revenue

Chuck Boyce, Department of Revenue

Marilyn Showalter, Office of Financial Management

Dick Byers, Utilities and Transportation Commission

Merton Lott, Utilities and Transportation Commission

Jeffrey Showman, Utilities and Transportation Commission

Sandi Swarthout, Capitol Connection, for Aluminum Industry information

Endnotes for Appendix 4.1

[1] There are over 400 FERC-regulated wholesale power marketers.

[2] There is no indication that the Senator intends to submit this bill to the legislature.

[3] In late June a power trading company defaulted on several large contracts to supply power to eastern states. Not only could the company not provide the electricity at the agreed upon price, it could not even provide the electricity at an economically viable price. The company blames, in part, the aggressive trading by investors for its inability to purchase electricity at a reasonable cost.

[4] If the consumption tax is value-based rather than volume based, the ease of administration may be somewhat complicated because a power supplier who is unaffiliated with the local distribution company may want to keep the selling price confidential between the consumer and the supplier.

Appendix 8.1

Utility Reliability Profiles

The System Average Interruption Frequency and Duration Indices, SAIFI and SAIDI, are the primary reliability statistics calculated for the 6560 study. They were calculated by the agencies based on data provided by the utilities. The tables below show each utility's calculated SAIFIs and SAIDIs and describe the inputs used to calculate them. Utilities employ a range of methods for gathering and processing the data used to calculate SAIFI and SAIDI. These differences can be significant and mean the resulting statistics are not truly comparable. The Example Table explains the table contents and the significance of the answers.

Example Table

<table>
<tr><td colspan="10">In this cell a brief description of the utility is provided, with an emphasis on aspects that may have an impact on reliability. For example, utilities East of the Cascades experience less wind and have fewer severe storms than those in the West. Rural utilities may have relatively higher SAIDIs because their distribution lines are often isolated and customers cannot be restored by switching them to a different circuit.</td></tr>
<tr><td colspan="10">In this cell are comments about use of the data in the 6560 Study.</td></tr>
<tr><td></td><td>1990</td><td>1991</td><td>1992</td><td>1993</td><td>1994</td><td>1995</td><td>1996</td><td>1997</td><td>Average</td></tr>
<tr><td>SAIFI</td><td>Data here</td><td>Data here</td><td>Data here</td><td>Data here</td><td>Data here</td><td>Data here</td><td>Data here</td><td>Data here</td><td>Data here</td></tr>
<tr><td>SAIDI</td><td>Data here</td><td>Data here</td><td>Data here</td><td>Data here</td><td>Data here</td><td>Data here</td><td>Data here</td><td>Data here</td><td>Data here</td></tr>
<tr><td colspan="3">Utility Confidence in SAIFI</td><td colspan="7">Recognizing that all SAIFI and SAIDI calculations are based on estimates, utilities were asked to estimate how accurate the calculations might be and whether they tend to be high or low. This cell contains those estimates.</td></tr>
<tr><td colspan="3">Utility Confidence in SAIDI</td><td colspan="7">Same as Above (SAIFI).</td></tr>
<tr><td colspan="10">SAIFI & SAIDI Input Details</td></tr>
<tr><td colspan="2">Input Options</td><td>Use</td><td colspan="7">Utility Specific Issues</td></tr>
<tr><td colspan="2">Based on Sustained Interruptions only</td><td></td><td colspan="7">A yes answer means the calculations are based on sustained interruptions only – those lasting one minute and longer or five minutes and longer – depending on the utility. It is generally agreed that there are few interruptions that last longer than one minute but less than five, therefore the data are presumed comparable.</td></tr>
</table>

Includes Momentary Interruptions		A yes answer means the utility is counting momentary interruptions – those that last less than a minute - in addition to sustained interruptions. The effect is generally to greatly increase SAIFI, because there may be many very short interruptions lasting only a second or two, especially in areas that experience lots of lightning strikes. These many momentary interruptions usually do not add up to a long duration time, therefore SAIDI is not greatly increased.
Includes Extraordinary Events		A yes answer means the utility has included interruptions from storms and other extraordinary events in its calculations. Generally, gathering data during storms is not a high priority, as is restoration, and therefore data collected during storms is generally not as accurate as data gathered during normal operations. Including storm-based data in SAIFI and SAIDI diminishes their accuracy. It can also greatly increase SAIFI and SAIDI. Utilities reported storm-caused interruptions that represented from 13% to 50% of total system SAIFI and from 30% to 87% of total system SAIDI. Knowing that utilities have or have not included storm-based data in their calculations does not mean the numbers can be compared, because the utilities likely use different definitions for storms.
Includes Interruptions from Generation, Transmission and Distribution System Events		A yes answer means that no matter what the cause, all interruption events are included in the calculation.
Includes Partial Feeder Outages		A yes answer means that the utility has attempted, through estimate or direct measure, to include all customer interruptions, even if only a few customers were affected. Full feeder outages often can be monitored automatically at a substation. If only part of a feeder loses power, the utility usually must estimate the number of customers affected and the length of outage. Not counting partial feeder outages would likely result in SAIFIs and SAIDIs that were very low.

Includes Step Restoration		As explained in Section 8, Endnote 4, customers often lose power and are restored in incremental steps. Some utilities attempt to track these steps and include the data in their calculations. The more capable the tracking, the more accurate the SAIFI and SAIDI. Other utilities begin the duration count with the first phone call and end the count when the last customer is restored, regardless of who may have been restored along the way. Not starting the count until the first phone call generally leads to a small underestimate of duration. Not ending the count until the last customer is restored can lead to a significant overestimate of duration. The final result is likely an inflated SAIDI.
Includes Estimates of Customer Interruptions		All utilities have some basis for counting customers who are out of power. Few utilities know exactly how many customers there are on a given line, especially for small sub-circuits of their systems. Both SAIFI and SAIDI are affected by the accuracy of customer counts, either upward or downward.
Instituted Data Management Changes During Study Period		Over the study period, many utilities have made significant changes in the way they collect and estimate data used to calculate SAIFI and SAIDI, often due to employment of new technologies or outage tracking software. A yes answer means the utility has made such changes and the statistics may not be comparable from year to year.

Benton County PUD

Eastside, mixed urban and rural, consumer-owned utility. 39,157 customers, 30.4 customers per line-mile.									
Benton PUD currently does not statistically track customer interruptions. Therefore it provided no data from which to calculate SAIFI or SAIDI.									
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI									
SAIDI									

Utility Confidence in SAIFI		
Utility Confidence in SAIDI		
SAIFI & SAIDI Input Details		
Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only		
Includes Momentary Interruptions		
Includes Extraordinary Events		
Includes Interruptions from Generation, Transmission and Distribution System Events		
Includes Partial Feeder Outages		
Includes Step Restoration		
Includes Estimates of Customer Interruptions		
Instituted Data Management Changes During Study Period		

Benton REA

Eastside, rural, consumer-owned utility. 11,984 customers, 6.0 customers per line-mile.									
Data were not included in calculation of state averages. The data were originally incorrect. The data included here are accurate, but were not corrected in time for inclusion in the study.									
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI				1.22	.93	.71	1.14	.79	.95
SAIDI				145.47	94.05	105.98	582.5	124.43	214.09
Utility Confidence in SAIFI			Within 10%, overestimate						
Utility Confidence in SAIDI			Within 10%, overestimate						

SAIFI & SAIDI Input Details

Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only	Yes	Five minutes and longer
Includes Momentary Interruptions	No	
Includes Extraordinary Events	Yes	"…three substation feeders are out of service or when three line crews called out to respond."
Includes Interruptions from Generation, Transmission and Distribution System Events	Yes	
Includes Partial Feeder Outages	Yes	
Includes Step Restoration	No	"The duration of the outage is logged beginning with the time the first customer call is recorded. Once the power has been restored or the disturbance resolved, the crew reports the time which is logged in as the time of resolution."
Includes Estimates of Customer Interruptions	Yes	Customer counts are based on accounting records linked to an engineering database. The count is made based on which protective device operated.
Instituted Data Management Changes During Study Period	Yes	Developed accounting / engineering link during last several years. Accuracy has increased. "It would appear that the number of consumer hours of outage have increased over the last few years, when in fact the number of outages have decreased."

Chelan County PUD

Eastside, mixed urban and rural, consumer-owned utility. 37,633 customers, 29.2 customers per line-mile.								
Data were included in calculation of state averages.								
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI		.31	.51	.44	.39	.42	.57	.20	.41
SAIDI		40.95	71.97	68.97	44.49	82.12	115.71	40.69	66.87
Utility Confidence in SAIFI		Within 5%, underestimate							
Utility Confidence in SAIDI		Within 10%, underestimate							

SAIFI & SAIDI Input Details		
Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only	Yes	Five minutes and longer
Includes Momentary Interruptions		
Includes Extraordinary Events	Yes	
Includes Interruptions from Generation, Transmission and Distribution System Events	Yes	
Includes Partial Feeder Outages	Yes	
Includes Step Restoration	Unclear	Insufficient information provided.
Includes Estimates of Customer Interruptions	Yes	Use billing information for customer counts. Insufficient information to assess accuracy of data.
Instituted Data Management Changes During Study Period	No	

Clark County PUD

Westside, mixed urban and rural, consumer-owned utility. 134,400 customers, customer to line density not available.									
Data were not included in the calculation of state averages because they include momentary interruptions.									
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI	2.43	5.02	2.22	4.60	3.77	4.07	4.86	2.15	3.64
SAIDI	107.26	26.12	55.44	64.51	75.74	680.78	126.55	51.90	152.18
Utility Confidence in SAIFI			Within 10% either way.						
Utility Confidence in SAIDI			Within 10% either way.						

SAIFI & SAIDI Input Details

Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only	No	
Includes Momentary Interruptions	Yes	
Includes Extraordinary Events	Yes	Utility definition: "Event that requires all of the Utility's crews to restore power – lasting at least 12 hours."
Includes Interruptions from Generation, Transmission and Distribution System Events	Yes	
Includes Partial Feeder Outages	Yes	
Includes Step Restoration	Unclear	Insufficient information to determine. Duration based on first phone call and "actual restore time."
Includes Estimates of Customer Interruptions	Yes	Few details provided. Customer count based on "transformer KVA installed." Customer / grid link allows calculation of customer counts "to a moderately poor degree of accuracy."
Instituted Data Management Changes During Study Period	No	

Cowlitz County PUD

Westside, mixed urban and rural, consumer-owned utility. 42,700 customers, 22.9 customers per line-mile.

Data were included in the calculation of state averages.

	1990	1991	1992	1993	1994	1995	1996	1997	Average
SAIFI			0.77	1.49	1.26	1.19	3.05	1.87	1.79
SAIDI			116.48	161.21	160.49	147.70	267.30	201.41	196.44

Utility Confidence in SAIFI	Within 10% either way
Utility Confidence in SAIDI	Confidence not estimated, “probably close for annual averages.”

SAIFI & SAIDI Details

Input Options	Use	Utility Specific Issues
Based on Sustained Interruptions only	Yes	Five minutes and longer
Includes Momentary Interruptions	No	
Includes Extraordinary Events	Yes	Defines “all significant outages as ‘emergencies’”
Includes Interruptions from Generation, Transmission and Distribution System Events	Yes	
Includes Partial Feeder Outages	Yes	
Includes Step Restoration	Unclear	Some aspects of step restoration not calculated, such as the effects of switching to other feeders. May cause overestimates and an increase in SAIFI & SAIDI. Unclear whether other aspects of step restoration are calculated.
Includes Estimates of Customer Interruptions	Yes	Number of meters served (customers) is an estimate based upon figures developed annually for feeds in a normal configuration. Load growth or system switching may introduce some error into the calculations.
Instituted Data Management Changes During Study Period	Yes	Accuracy has not changed but more detail is available.

Franklin County PUD

Eastside, mixed urban and rural, consumer-owned utility. 17,680 customers, 19.5 customers per line-mile.									
Data were not included in calculation of state averages. Accurate data were not available until after study calculations were completed.									
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI			0.38	0.27	0.28	0.53	0.34	0.54	0.39
SAIDI			82.87	44.04	17.26	59.40	59.51	90.33	59.28

Utility Confidence in SAIFI	Within 5%, underestimate
Utility Confidence in SAIDI	Within 5%, overestimate

SAIFI & SAIDI Input Details

Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only	Yes	Five minutes and longer
Includes Momentary Interruptions	No	
Includes Extraordinary Events	Yes	"No written definition of extraordinary event"
Includes Interruptions from Generation, Transmission and Distribution System Events	No	"Only Franklin PUD transmission"
Includes Partial Feeder Outages	Yes	
Includes Step Restoration	Unclear	Insufficient information.
Includes Estimates of Customer Interruptions	Yes	Insufficient information to understand process. However, "…numbers of customers may not be current" in the software used to estimate customer interruptions.
Instituted Data Management Changes During Study Period	No	

Grant Count PUD #2

Eastside, mixed urban and rural, consumer-owned utility. 38,538 customers, 11.4 customers per line-mile.									
Data were included in the calculation of state averages.									
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI				1.55	1.24	0.79	1.05	0.83	1.08
SAIDI				152.43	102.33	60.92	85.02	63.73	91.58
Utility Confidence in SAIFI			Estimates within 5% either way.						
Utility Confidence in SAIDI			Estimates within 5% either way.						

SAIFI & SAIDI Input Details		
Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only	Yes	One minute and longer.
Includes Momentary Interruptions	No	
Includes Extraordinary Events	Yes	Utility does not have a definition for extraordinary event.
Includes Interruptions from Generation, Transmission and Distribution System Events	Yes	
Includes Partial Feeder Outages	Yes	
Includes Step Restoration	Yes	"Steps and times those steps occurred in restoration are also included."
Includes Estimates of Customer Interruptions	Yes	Utility operates "an AM/FM system that allows accurate customer counts to be made past any device on the system."
Instituted Data Management Changes During Study Period	Yes	Customer data used to be downloaded once a year…now can get accurate up-to-date customer count at time of event.

Grays Harbor County PUD

Westside, mixed urban and rural, consumer-owned utility. 38,680 customers, 27.1 customers per line-mile.									
Data were included in the calculation of state averages.									
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI		1.67	2.83	1.73	3.40	2.03	1.38	2.33	1.93
SAIDI		183.60	477.60	581.14	558.80	174.50	160.88	268.40	301.63
Utility Confidence in SAIFI		Estimate within 10% either way.							
Utility Confidence in SAIDI		Estimate within 10% either way.							

SAIFI & SAIDI Input Details

Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only	Yes	One minute and longer.
Includes Momentary Interruptions	No	
Includes Extraordinary Events	Yes	Utility defines as “a major storm or weather condition requiring multiple crews over an extended period of time.”
Includes Interruptions from Generation, Transmission and Distribution System Events	Yes	
Includes Partial Feeder Outages	Yes	
Includes Step Restoration	Unclear	Insufficient information. “…staffs work together to maintain outage logging system.”
Includes Estimates of Customer Interruptions	Yes	Insufficient information to access method or accuracy.
Instituted Data Management Changes During Study Period	No	

Inland Power and Light Company

<table>
<tr><td colspan="10">Eastside, rural, consumer-owned utility. 29,133 customers, 4.4 customers per line-mile.</td></tr>
<tr><td colspan="10">Data were included in the calculation of state averages. However the data include data from the utility's entire system which include customers in Idaho as well as in Washington.</td></tr>
<tr><td></td><td>1990</td><td>1991</td><td>1992</td><td>1993</td><td>1994</td><td>1995</td><td>1996</td><td>1997</td><td>Average</td></tr>
<tr><td>SAIFI</td><td>.99</td><td>.51</td><td>.29</td><td>Not Available</td><td>Not Available</td><td>1.11</td><td>1.21</td><td>1.43</td><td>.73</td></tr>
<tr><td>SAIDI</td><td>161.23</td><td>105.54</td><td>85.83</td><td>134.80</td><td>115.64</td><td>126.77</td><td>159.34</td><td>194.36</td><td>137.85</td></tr>
<tr><td colspan="3">Utility Confidence in SAIFI</td><td colspan="7">Estimates within 10% either way.</td></tr>
<tr><td colspan="3">Utility Confidence in SAIDI</td><td colspan="7">Estimates within 10% either way.</td></tr>
<tr><td colspan="10">SAIFI & SAIDI Input Details</td></tr>
<tr><td colspan="3">Input Options</td><td>Use</td><td colspan="6">Utility Specific Issues</td></tr>
<tr><td colspan="3">Based on Sustained Interruptions only</td><td>Yes</td><td colspan="6">Five minutes and longer</td></tr>
<tr><td colspan="3">Includes Momentary Interruptions</td><td>No</td><td colspan="6"></td></tr>
<tr><td colspan="3">Includes Extraordinary Events</td><td>No</td><td colspan="6">Utility definition: "Major storms that interrupt power to a large number of customers."</td></tr>
<tr><td colspan="3">Includes Interruptions from Generation, Transmission and Distribution System Events</td><td>Yes</td><td colspan="6"></td></tr>
<tr><td colspan="3">Includes Partial Feeder Outages</td><td>Yes</td><td colspan="6"></td></tr>
<tr><td colspan="3">Includes Step Restoration</td><td>Unclear</td><td colspan="6">Insufficient information provided. "Duration calculations are manually performed by using information from line personnel."</td></tr>
<tr><td colspan="3">Includes Estimates of Customer Interruptions</td><td>Yes</td><td colspan="6">"Customer interruptions are estimated by counting the number of active accounts that are between the pole where an outage begins and the pole where the outage ends." Use billing system information</td></tr>
<tr><td colspan="3">Instituted Data Management Changes During Study Period</td><td>Yes</td><td colspan="6">"Data collection efforts have been refined and improved resulting in an increase in measured outage minutes."</td></tr>
</table>

Nespelem Valley Electric Cooperative

Eastside, rural, consumer-owned utility.									
No data provided for calculation of SAIFI and SAIDI.									
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI									
SAIDI									
Utility Confidence in SAIFI									
Utility Confidence in SAIDI									

SAIFI & SAIDI Input Details		
Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only		
Includes Momentary Interruptions		
Includes Extraordinary Events		
Includes Interruptions from Generation, Transmission and Distribution System Events		
Includes Partial Feeder Outages		
Includes Step Restoration		
Includes Estimates of Customer Interruptions		
Instituted Data Management Changes During Study Period		

Orcas Power and Light Company

<table>
<tr><td colspan="10">Westside (San Juan Islands), primarily rural, consumer-owned utility. 10,605 customers, 11.4 customers per line-mile.</td></tr>
<tr><td colspan="10">Data were not included in the calculation of state averages. Annual customer data were not provided. The data provided also were presumed to be interruption events rather than the total number of customer interruptions.</td></tr>
<tr><th></th><th>1990</th><th>1991</th><th>1992</th><th>1993</th><th>1994</th><th>1995</th><th>1996</th><th>1997</th><th>Average</th></tr>
<tr><td>SAIFI</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>.14</td><td></td></tr>
<tr><td>SAIDI</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>1194.82</td><td></td></tr>
<tr><td colspan="3">Utility Confidence in SAIFI</td><td colspan="7"></td></tr>
<tr><td colspan="3">Utility Confidence in SAIDI</td><td colspan="7"></td></tr>
<tr><th colspan="10">SAIFI & SAIDI Input Details</th></tr>
<tr><th colspan="3">Input Options</th><th>Use</th><th colspan="6">Utility Specific Issues</th></tr>
<tr><td colspan="3">Based on Sustained Interruptions only</td><td>Unclear</td><td colspan="6">Insufficient information</td></tr>
<tr><td colspan="3">Includes Momentary Interruptions</td><td>Unclear</td><td colspan="6">Insufficient information</td></tr>
<tr><td colspan="3">Includes Extraordinary Events</td><td>Yes</td><td colspan="6">Defined as “When over 25% of our customers are out of power, or we have lost power to a business center.”</td></tr>
<tr><td colspan="3">Includes Interruptions from Generation, Transmission and Distribution System Events</td><td>No</td><td colspan="6">Distribution only</td></tr>
<tr><td colspan="3">Includes Partial Feeder Outages</td><td>No</td><td colspan="6"></td></tr>
<tr><td colspan="3">Includes Step Restoration</td><td>No</td><td colspan="6">Because only full feeder outages are tracked, the only restoration tracked is that of the full feeder.</td></tr>
<tr><td colspan="3">Includes Estimates of Customer Interruptions</td><td>Unclear</td><td colspan="6">Only full feeder outages are tracked. If customer numbers are accurate by feeder there is no need to estimate them. They may still be estimated however.</td></tr>
<tr><td colspan="3">Instituted Data Management Changes During Study Period</td><td>No Answer</td><td colspan="6"></td></tr>
</table>

PacifiCorp

Eastside, mixed urban and rural, investor-owned utility. 110,956 customers, 27.7 customers per line-mile.									
Data were included in the calculation of state averages.									
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI	1.17	0.97	0.69	1.32	1.06	0.88	0.57	0.81	0.93
SAIDI	73.65	65.29	68.03	82.92	69.87	71.20	53.06	63.19	68.28
Utility Confidence in SAIFI		Possibility for error greater than 25% either way							
Utility Confidence in SAIDI		Possibility for error greater than 25% either way							

SAIFI & SAIDI Input Details		
Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only	Yes	One minute and longer
Includes Momentary Interruptions	No	
Includes Extraordinary Events	No	A major event means an event that: Exceeds the design limits of the electrical power system; Causes extensive damage to the electric power system; and Results in a simultaneous sustained interruption to more than 10 percent of the customer in an operating area.
Includes Interruptions from Generation, Transmission and Distribution System Events	Yes	
Includes Partial Feeder Outages	Yes	
Includes Step Restoration	Unclear	Insufficient information to understand process and methodology.
Includes Estimates of Customer Interruptions	Yes	Insufficient information to understand process and methodology.
Instituted Data Management Changes During Study Period	No	

Parkland Power and Light Company

Westside, urban, consumer-owned utility. 3720 customers, 52.4 customers per line-mile.									
Data were not included in the calculation of state averages. Customer count is so small it would have had little affect on the averages, but the statistics are very low and would have extended the range significantly.									
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI							.058	.054	.056
SAIDI							13.91	6.54	10.13
Utility Confidence in SAIFI			Within 5% either way						
Utility Confidence in SAIDI			Within 5% either way						

SAIFI & SAIDI Input Details

Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only	Yes	One minute and longer
Includes Momentary Interruptions	No	"No known outages less than one minute."
Includes Extraordinary Events	No	Defined as "Event that impacts a widespread area of service."
Includes Interruptions from Generation, Transmission and Distribution System Events	Yes	
Includes Partial Feeder Outages	Yes	
Includes Step Restoration	Unclear	
Includes Estimates of Customer Interruptions	Yes	"Outages occur so infrequently and system small enough that no data is recorded except on time sheets."
Instituted Data Management Changes During Study Period	No	

Puget Sound Energy

Westside, mixed urban and rural, investor-owned utility. 872,410 customers, 48 customers per line-mile.									
Data were included in calculation of state averages.									
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI	2.15	1.05	1.33	1.07	1.10	1.60	1.26	1.04	1.31
SAIDI	215.98	95.31	101.56	93.03	120.22	183.66	139.63	104.65	131.28
Utility Confidence in SAIFI		"No idea"							
Utility Confidence in SAIDI		"No idea"							

SAIFI & SAIDI Input Details		
Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only	Yes	One minute and longer.
Includes Momentary Interruptions	No	
Includes Extraordinary Events	No	Defined as "Any natural caused event that causes five percent or more of our customers to lose electrical service during any day. Natural causes include weather, earthquake, fire, flood, land slides, volcanic eruptions or solar flares."
Includes Interruptions from Generation, Transmission and Distribution System Events	Yes	Including transmission with operating voltages up to and including 500 kV.
Includes Partial Feeder Outages	Yes	
Includes Step Restoration	Yes	Insufficient information to understand process. Claims to track incremental loss and restoration "to a great degree of accuracy."
Includes Estimates of Customer Interruptions	Yes	Insufficient information to understand process and methodology
Instituted Data Management Changes During Study Period	Yes	Over past three years have established a link between a "System Operations" software package and a "Service Restoration System" software package. The link has increased accuracy of calculations and the utility has experienced an increase of from 5% to 20% in recorded outages.

Seattle City Light

Westside, urban, consumer-owned utility. 363,968 customers, 199.4 customers per line-mile.									
Data were included in the calculation of state averages.									
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI				NA	.78	.52	.88	1.24	.69
SAIDI				56.95	51.63	40.41	37.34	72.68	51.86
Utility Confidence in SAIFI			Within 5% either way						
Utility Confidence in SAIDI			Within 5%, underestimates						

SAIFI & SAIDI Input Details

Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only	Yes	One minute and longer
Includes Momentary Interruptions	No	
Includes Extraordinary Events	No	Defined as “Over 10% of our customers are affected by the storm or event; a regional or wide-area impact event is the cause; outages are prolonged due to extensive damage to the power system.
Includes Interruptions from Generation, Transmission and Distribution System Events	Yes	Last transmission outage was in 1994.
Includes Partial Feeder Outages	Yes	
Includes Step Restoration	Yes	Tracks all aspects of step restoration including switching down to the transformer level.
Includes Estimates of Customer Interruptions	Yes	Customer numbers are based on a GIS and Customer Information System that links services (customers) to transformers.
Instituted Data Management Changes During Study Period	Yes	Logging system changed from manual to database in May, 1997. Now tracking smaller outages that were not tracked previously.

Snohomish County PUD No. 1

Westside, mixed urban and rural, consumer-owned utility. 238,365 customers, 48.8 customers per line-mile.								
Data were included in the calculation of state averages.								
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI	1.61	1.20	1.13	1.19	1.02	1.10	.82	.73	1.09
SAIDI	190.19	96.12	101.37	97.23	101.69	94.50	60.33	50.49	97.29
Utility Confidence in SAIFI		Within 25% either way							
Utility Confidence in SAIDI		Within 25% either way							

SAIFI & SAIDI Input Details

Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only	Yes	One minute and longer
Includes Momentary Interruptions	No	
Includes Extraordinary Events	Yes	Defined as "An event when all available and qualified District personnel are working during the declared major emergency (i.e. wind and snow/ice storms, natural catastrophic disaster) or when it becomes apparent to the Energy Control Superintendent that outage work exceeds the ability of the available District crews to restore the electric system in a short period of time. A major emergency may be declared when an unusual non-storm event of significant magnitude has occurred which can/does negatively affect a large number o f customers and/or requires intensive and extended work effort by a group of employees.
Includes Interruptions from Generation, Transmission and Distribution System Events	Yes	
Includes Partial Feeder Outages	Yes	
Includes Step Restoration	Unclear	"The time of the first customer phone call becomes the outage beginning time. The ending time is when field personnel report that service has been restored.
Includes Estimates of Customer Interruptions	Yes	Insufficient information to understand process and methodology
Instituted Data Management Changes During Study Period	No	

Tacoma Power

<table>
<tr><td colspan="10">Westside, urban, consumer-owned utility. 140,000 customers, 83.9 customers per line-mile.</td></tr>
<tr><td colspan="10">Data from Tacoma Power were included in the calculation of state averages, however the numbers in this table reflect changes made after the study calculations were completed.</td></tr>
<tr><th></th><th>1990</th><th>1991</th><th>1992</th><th>1993</th><th>1994</th><th>1995</th><th>1996</th><th>1997</th><th>Average</th></tr>
<tr><td>SAIFI</td><td>2.75</td><td>1.81</td><td>1.20</td><td>1.60</td><td>1.40</td><td>1.83</td><td>1.40</td><td>1.20</td><td>1.64</td></tr>
<tr><td>SAIDI</td><td>156.69</td><td>147.40</td><td>63.00</td><td>75.00</td><td>74.00</td><td>134.26</td><td>73.00</td><td>70.40</td><td>98.58</td></tr>
<tr><td colspan="3">Utility Confidence in SAIFI</td><td colspan="7">Within 10%, overestimates</td></tr>
<tr><td colspan="3">Utility Confidence in SAIDI</td><td colspan="7">Within 5%, overestimates</td></tr>
<tr><th colspan="10">SAIFI & SAIDI Input Details</th></tr>
<tr><th colspan="3">Input Options</th><th>Use</th><th colspan="6">Utility Specific Issues</th></tr>
<tr><td colspan="3">Based on Sustained Interruptions only</td><td>Yes</td><td colspan="6"></td></tr>
<tr><td colspan="3">Includes Momentary Interruptions</td><td>No</td><td colspan="6"></td></tr>
<tr><td colspan="3">Includes Extraordinary Events</td><td>No</td><td colspan="6">Defined as “When three or more distribution feeders are open due to a single event (i.e. windstorm, snowstorm, etc.)</td></tr>
<tr><td colspan="3">Includes Interruptions from Generation, Transmission and Distribution System Events</td><td>Yes</td><td colspan="6"></td></tr>
<tr><td colspan="3">Includes Partial Feeder Outages</td><td>Yes</td><td colspan="6"></td></tr>
<tr><td colspan="3">Includes Step Restoration</td><td>Yes</td><td colspan="6">“…time is logged as switching actions are completed.”</td></tr>
<tr><td colspan="3">Includes Estimates of Customer Interruptions</td><td>Yes</td><td colspan="6">“Number of customers affected are determined by meter count or estimated by the area or section of the feeder compared to the total number of customer meters on each feeder.”</td></tr>
<tr><td colspan="3">Instituted Data Management Changes During Study Period</td><td>No</td><td colspan="6"></td></tr>
</table>

Washington Water Power

Eastside, mixed urban and rural, investor-owned utility.									
The utility does not generally track interruption data statistically. The data provided were estimated for an industry study. Data were not included in the calculation of state averages because they include momentaries.									
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**Average**
SAIFI				8.30					
SAIDI				80.78					

Utility Confidence in SAIFI	30% to 50% underestimate	
Utility Confidence in SAIDI	Possible error greater than 50%, underestimate	
SAIFI & SAIDI Input Details		
Input Options	**Use**	**Utility Specific Issues**
Based on Sustained Interruptions only	No	
Includes Momentary Interruptions	Yes	
Includes Extraordinary Events	Yes	Utility has no formal definition
Includes Interruptions from Generation, Transmission and Distribution System Events	Yes	
Includes Partial Feeder Outages	No	
Includes Step Restoration	No	
Includes Estimates of Customer Interruptions	Yes	"Operations technician summarized 1993 outages based on an estimated number of customers per feeder."
Instituted Data Management Changes During Study Period	No	

Appendix 9.1

Energy Efficiency, Renewable and Low Income Policy

This appendix is a digest of policy statements by the federal and state government about energy efficiency and renewable energy.

A.1 General State Policy: Conservation of Electricity and Energy

> The legislature finds and declares that it is the continuing purpose of state government, consistent with other essential considerations of state policy, to foster wise and efficient energy use and to promote energy self-sufficiency through the use of indigenous and renewable energy sources, consistent with the promotion of reliable energy sources, the general welfare, and the protection of environmental quality. (RCW 43.21F.010; 1975-'76 2nd ex.s., c 108 § 1.)
>
> State policy. It is the policy of the state of Washington that:
>
> (1) The development and use of a diverse array of energy resources with emphasis on renewable energy resources shall be encouraged;
>
> (2) The supply of energy shall be sufficient to insure the health and economic welfare of its citizens;
>
> (3) The development and use of energy resources shall be consistent with the statutory environmental policies of the state;
>
> (4) Energy conservation and elimination of wasteful and uneconomic uses of energy and materials shall be encouraged, and this conservation should include, but is not limited to, resource recovery and materials recycling;
>
> (5) In energy emergency shortage situations, energy requirements to maintain the public health, safety, and welfare shall be given priority in the allocation of energy resources, and citizens and industry shall be assisted in adjusting to the limited availability of energy in order to minimize adverse impacts on their physical, social, and economic well being;
>
> (6) State government shall provide a source of impartial and objective information in order that this energy policy may be enhanced; and
>
> (7) The state energy strategy shall provide primary guidance for implementation of the state's energy policy. (RCW 43.21F.015; 1994 c 207 § 3; 1981 c 295 § 1.)

In 1991, the legislature directed that the state prepare a state energy strategy, and found, ". . . that the state energy strategy presented to the legislature in 1993 was developed by a dedicated and talented committee of hard-working representatives of the industries and people of this state and that the strategy document should serve to guide energy-related policy decisions by the legislature and other entities within this region." (1994 c 207 §1.) With respect to conservation, the *State Energy Strategy* states that, "All cost-effective conservation and efficiency opportunities should be pursued aggressively in both public and private utility markets. Utility and BPA conservation programs should recognize the importance of vigorous implementation by all parties."

In the chapter governing municipal utilities, the legislature found:

> The conservation of energy in all forms and by every possible means is found and declared to be a public purpose of highest priority. The legislature further finds and declares that all municipal corporations, quasi municipal corporations, and other political subdivisions of the state which are engaged in the generation, sale, or distribution of energy should be granted the authority to develop and carry out programs which will conserve resources, reduce waste, and encourage more efficient use of energy by consumers.
>
> In order to establish the most effective state-wide program for energy conservation, the legislature hereby encourages any company, corporation, or association engaged in selling or furnishing utility services to assist their customers in the acquisition and installation of materials and equipment, for compensation or otherwise, for the conservation or more efficient use of energy. The use of appropriate tree plantings for energy conservation is encouraged as part of these programs. [RCW 35.92.355; 1993 c 204 § 5; 1979 ex.s. c 239 § 1.]

In the public utility district (PUD) laws (RCW 54.16.280) the legislature states:

> Any district is hereby authorized, within limits established by the Constitution of the State of Washington, to assist the owners of structures or equipment in financing the acquisition and installation of materials and equipment, for compensation or otherwise, for conservation or more efficient use of energy.

This language is parallel to that authorizing municipal utilities to finance conservation in customers' structures or facilities. Both statutes were passed in 1989 subsequent to the amendment of Article 8 of the state's Constitution permitting the use of public money and credit for purposes of conservation.

The State Constitution's ban on lending of public credit has been amended three times to provide exceptions for conservation investments. In Article 8, section 10, energy and water conservation assistance, the Constitution currently provides:

> Notwithstanding the provisions of section 7 of this Article, any county, city, town, quasi-municipal corporation, municipal corporation, or political subdivision of the state which is engaged in the sale or distribution of water or energy may, as authorized by the legislature, use public moneys or credit derived from operating revenues from the sale of water or energy to assist

> the owners of structures or equipment in financing the acquisition and installation of materials and equipment for the conservation or more efficient use of water or energy in such structures or equipment. Except as provided in section 7 of this Article, an appropriate charge back shall be made for such extension of public moneys or credit and the same shall be a lien against the structure benefited or a security interest in the equipment benefited. Any financing for energy conservation authorized by this article shall only be used for conservation purposes in existing structures and shall not be used for any purpose which results in a conversion from one energy source to another. (Amendment 86, 1989 Senate Joint Resolution No. 8210, Approved November 7, 1989. See also Amendment 82 (1988 House Joint Resolution No. 4223, p 1552. Approved November 8, 1988) and Amendment 70, (Substitute Senate Joint Resolution No. 120, p 2288. Approved November 6, 1979)).

In a manner parallel with PUDs and municipal utilities, irrigation districts are authorized to use public funds or credit to assist their customers in improving energy efficiency. (RCW 87.03.017)

The preamble to the state energy-related building standards states:

> The legislature finds that using energy efficiently in housing is one of the lowest cost ways to meet consumer demand for energy; that using energy efficiently helps protect citizens of the state from negative impacts due to changes in energy supply and cost; that using energy efficiently will help mitigate negative environmental impacts of energy use and resource development; and that using energy efficiently will help stretch our present energy resources into the future. The legislature further finds that the electricity surplus in the Northwest is dwindling as the population increases and the economy expands, and that the region will eventually need new sources of electricity generation.
>
> It is declared policy of the state of Washington that energy be used efficiently. It is the intent of this act to establish residential building standards that bring about the common use of energy efficient building methods, and to assure that such methods remain economically feasible and affordable to purchasers of newly constructed housing." [1990 c 2 § 1, see RCW 19.27A.015.]

Chapter 39.35 RCW directs the Department of General Administration to consider energy conservation in the design of publicly-owned (state and schools) buildings. It requires life-cycle cost analysis be done for new schools and state buildings and that these analyses include operating costs associated with energy. Further it directs that state agencies and school districts "...shall implement cost-effective conservation improvements and maintain efficient operation of its facilities in order to minimize energy consumption and related environmental impacts and reduce operating costs". As part of statutory direction to, this section establishes an aggressive program to improve the energy efficiency of state-owned buildings under the Department's jurisdiction. (RCW 43.19.668)

In Washington's Clean Air Act, energy efficiency is identified as one means for achieving improvements in air quality:

> The legislature further recognizes that energy efficiency and energy conservation can help to reduce air pollution and shall therefore be considered when making decisions on air pollution control strategies and projects. (RCW 70.94.011)

Conservation of the energy resources of the state is identified as one of the several purposes of the state's solid waste program. (RCW 70.95.020)

The legislature identifies conservation of energy resources as one of the objectives of the Low-Income Residential Weatherization Program. (RCW 70.164.010)

In considering major, publicly financed energy projects, the legislature directs that:

> In planning for future energy expenditures, public agencies shall give priority to projects and resources which are cost-effective. Priority for future bond sales to finance energy expenditures by public agencies shall be given: First, to conservation; second to renewable resources; third, to generating resources using waste heat or generating resources of high fuel-conversion efficiency; and fourth, to all other resources. (RCW 80.52.080)

A.2 Legislative Policy and Direction Specific to the Washington Utilities and Transportation Commission (WUTC)

The 1991 legislature appended the following finding to the section of law dealing with valuation of utility property:

> The legislature finds that the state is facing an energy shortage as growth occurs and that inadequate supplies of energy will cause harmful impacts on the entire range of state citizens. The legislature further finds that energy efficiency is the single most effective near term measure to lessen the risk of energy shortage. . . (RCW 80.04.250)
>
> The legislature finds and declares that the potential for meeting future energy needs through conservation measures ... may not be realized without incentives to public and private energy utilities. The legislature therefore finds and declares that actions and incentives by state government to promote conservation and the use of renewable resources would be of great

> benefit to the citizens of this state by encouraging efficient energy use and a reliable supply of energy based upon renewable energy resources." (RCW 80.28.024)

This section directed the Commission to adopt policies to encourage meeting or reducing energy demand through cogeneration, conservation, or renewable resources. The section authorized a 2% increment to be added to the allowed rate of return on common equity for investment in such projects between June 1980 and December 31, 1989. (RCW 80.28.025).

The legislature has also authorized the Commission to approve tariffed conservation services that require repayment by the customer of funds made available by the utility. The tariffed service may also provide for application of the payment obligation to successive property owners and for notification of same to the county auditor or recording officer. (RCW 80.28.065)

> (1) The Commission shall adopt a policy allowing an incentive rate of return on investment (a) for payments made under [the state's residential energy building code] (b) for programs that improve the efficiency of energy end-use if priority is given to senior citizens and low-income citizens in the course of carrying out such programs. The incentive rate of return on investments set forth in this subsection is established by adding an increment of two percent to the rate of return on common equity permitted on the company's other investments.
> (2) The Commission shall consider and may adopt a policy allowing an incentive rate of return on investment in additional programs to improve the efficiency of energy end use or other incentive policies to encourage utility investment in such programs.
> (3) The Commission shall consider and may adopt other policies to protect a company from a reduction of short-term earnings that may be a direct result of utility programs to increase the efficiency of energy use. These policies may include allowing a periodic rate adjustment for investments in end use efficiency or allowing changes in the price structure designed to produce additional new revenue. (RCW 80.28.260)

In 1994, the legislature provided for conservation bonding, one of the first "securitization" laws in the United States. Under this law, the Commission has authority to review, examine, and approve or reject a conservation service tariff filed by a company. A company may ask the Commission to determine that conservation investments are prudent, consistent with the conservation service tariff, and, therefore, bondable conservation investment. Bondable conservation investment must be included in ratebase and not later revalued. This section does not preclude the Commission from adopting other policies intended to provide incentives for and to encourage utility investment in conservation. (RCW 80.28.303; 1994 c 268, § 2). RCW 80.28.005 establishes the definitions for "bondable conservation investment", “conservation bonds”, and “conservation investment assets”.

Apart from the above-listed statutes addressing conservation (and renewable) resources, chapter 80.28 RCW provides no similar treatment, or legislative direction for any other category of utility investment or resource.

A.3. Orders, Tariffs, and WUTC Policy History

Conservation received prominent mention by the Commission as early as 1974. During the early and mid 1970’s, orders focused on rate design — generally approving or directing rate design that more closely approximate marginal cost. Decreasing block rates were gradually “flattened”,and eventually moved to increasing block rates for residential customers. This had the effect of sending price signals that encourage more efficient electricity consumption.

Beginning in 1978, all three utilities were granted authority to offer no interest loans for conservation measures, and to place the cost of these programs in rate base and earn an investment on them. Since that time, all three utilities have run such programs, and all three have recovered their cost through a return on their investment in rate base. In rate cases through the 1980’s the Commission approved the 2% increment to rate of return on common equity authorized by RCW 80.28.025.

<u>Commission Policy Statements Concerning Conservation</u>

Throughout the early- and mid-1970’s the Commission promoted the importance of conservation as a means to slack the growing demand for electricity. In 1978, all three utilities were ordered to implement a 5% surcharge on the rates charged commercial and industrial customers during the winter of 1974/75. (U-74-4,U-74-8, U-73-57)

Orders in 1976 and 1977 for all three companies contained the following or similar language:

> “No allowance will attach to Respondent’s expenditures designed to encourage increased use of electricity for any purpose. Allowance will be made only for such expenditures as are directly related to encouragement of conservation of electric use or for encouragement of diverting peak-period consumption to off-peak periods.” (see, for example, U-76-18)

With the exception of an experimental program run by Puget in 1977, utility-run conservation programs did not begin until 1978. In response to the Federal mandated Residential Conservation Service, companies filed, and the Commission approved, programs in 1978. The 1978 order indicated that the Commission felt such programs were in the public interest, and that conservation programs with utility payments that did not exceed the avoided cost of resources were cost-justified and did not constitute preferential treatment of program participants. (U-78-45, U-78-46, U-78-47)

In 1985, the Commission indicated in an Order to Puget that it, ". . . strongly expects that Puget will adopt a much more aggressive program. We encourage more active participation by the company in regional conservation efforts." (U-85-53 pp. 24). Further, it ordered Puget to develop a "least-cost" plan which carefully considered conservation options on a consistent basis with other electricity service supply alternatives.

In 1987, the Commission adopted its least-cost planning rule which states that, "Each electric utility regulated by the commission has the responsibility to meet its load with a least cost mix of generating resources and improvements in the efficient use of electricity. Therefore, a 'least cost plan' shall be developed by each electric utility in consultation with commission staff." A least cost plan" was defined as "a plan describing the mix of generating resources and improvements in the efficient use of electricity that will meet current and future needs at the lowest cost to the utility and its ratepayers", and contained:

> (a) A range of forecasts of future demand using methods that examine the impact of economic forces on the consumption of electricity and that address changes in the number, type, and efficiency of electrical end-uses.
> (b) An assessment of technically feasible improvements in the efficient use of electricity, including load management, as well as currently employed and new policies and programs needed to obtain the efficiency improvements.
> (c) An assessment of technically feasible generating technologies including renewable resources, cogeneration, power purchases from other utilities, and thermal resources (including the use of combustion turbines to utilize better the existing hydro system.)
> (d) A comparative evaluation of generating resources and improvements in the efficient use of electricity based on a consistent method, developed in consultation with commission staff, for calculating cost-effectiveness.
> (e) The integration of the demand forecasts and resource evaluations into a long-range (e.g., twenty-year) least cost plan describing the mix of resources that will meet current and future needs at the lowest cost to the utility and its ratepayers. (WAC 480-100-251)

In 1988, as part of the settlement agreement on the Pacific Power and Utah Power and Light merger, the Commission ordered that Pacific devote $280,000 per year to low income and other residential conservation programs. (U-87-1513)

In its 1991 Order establishing the Periodic Rate Adjustment Mechanism (PRAM) experiment with Puget, the Commission stated that, "Rate making practices should align utilities= pursuit of profits with least-cost planning" (UE-901183-T). Later in 1991, the Commission approved a one-time incentive mechanism for Puget's conservation program which resulted in 6.7 million dollars included in PRAM 2 (UE-920630)

In 1992 the Commission approved an experimental conservation (and fuel switching) program for WWP which provided for booking of "lost-margins" for conservation program savings, and the recovery of electricity "lost-margins" directly from fuel-conversion participants. (UE-920351)

In the merger of Puget Sound Power and Light and Washington Natural Gas to create Puget Sound Energy, the Commission reaffirmed its commitment to conservation:

> The Commission wants to emphasize its continuing commitment to the importance of public purpose issues raised by NCAC and NRDC and others in this proceeding. If these values are to be preserved, and the Commission believes they should, efforts should focus on finding methods, mechanisms and approaches that will be compatible with, and sustainable in, a more competitive industry. As competition comes to this industry, attention will focus on consumer values and on price. Methods to accomplish public purpose objectives and funding that rely on leveraging monopolies, and which assume that consumers will not be sensitive to price, will not be successful. The Commission does not take its responsibility to consider public purpose values and objectives lightly. However, our actions are confined by the limits of our statutory authority and by the realities of the emerging marketplace.
>
> The Commission is disappointed by the lack of constructive detail and substance about new methods for accomplishing public purpose objectives in the Regional Review's recommendations, which seem to focus on finding the right dollar level rather than the right mechanism. We are prepared, and expect our Staff to be as well, to work with all parties to seek ways to preserve public purpose values and programs. We trust that mechanisms can be developed that will be consistent with changing market structures, and that will achieve these objectives in cost-effective and sustainable ways. (Docket Nos. UE-951270 and UE-960195, *Fourteenth Supplemental Order Accepting Stipulation; Approving Merger*)

<u>Commission Rate Treatment of Conservation:</u>

Since 1978, utilities have been permitted to accumulate investments in conservation (loans and grants to customers and related costs) in accordance with approved tariffed programs, and to include these cumulative investments in general rate requests. Review of the orders in these rate cases indicates that controversy concerning conservation expenditures has been rare, and that the Commission has never disallowed conservation costs for any measures deemed to be consistent with an approved tariff.

Conservation advertising was raised as an issue in Puget rate cases in 1985, 1989, and 1992. In the 1989 and 1992 cases the Commission disallowed a portion of conservation advertising expenditures on the basis that they were generally promotional rather than integral to conservation programs. Puget's water heater efficiency programs were questioned in 1989. The Commission permitted their cost in ratebase (since they were incurred consistent with an approved tariffed program) while at the same time ordering that the program be changed to improve cost-effectiveness. In 1992, under Puget's PRAM 2 request, the cost-effectiveness of its weatherization and residential heat-pump programs were questioned. Again, the Commission declined to disallow costs for these programs, since they were incurred consistent with an existing tariff, but did order changes to the programs.

Conservation investments have been treated very favorably by both the Commission and its staff: accounting treatment which affords conservation expenditures the accumulation of AFUCE, no amortization until inclusion in rates, and an end-of-test-year conservation balance appears to treat conservation more favorably than other resource expenditures.

In 1995, the Commission approved the nation's first non-bypassable distribution charge - Washington Water Power's Energy Efficiency Tariff Rider. The Rider enables the utility to collect all the funds necessary to operate efficiency programs in the same year that they spend the funds, and thereby removes the need for the utility to finance the investments. This funding mechanism has proven to provide a stable source of funds for conservation programs. Companies around the nation have used this as a model to develop similar funding mechanisms.

A.4. State Legislation Affecting Renewables

In 1979, the legislature established financial incentives for developing electric power, mechanical power, or useful heat energy from cogeneration. Developers could credit 50 percent of their capital investment at a rate of 2 percent per year. The bill exempted the generation of power by a non-polluting, renewable energy source by individuals not otherwise engaged in power generation from all statutes and rules that regulate the generation of power (1979 ex. s., c 191)

The legislature established two financial incentives encouraging electric and gas utilities to invest in renewable resources for ten years, from June 1980 to January 1, 1990. The first incentive applied to investor owned utilities (IOUs), and directed the WUTC to allow a 2 percent higher rate of return on the common equity portion of a qualifying investment, defined as measures to improve end use efficiency, cogeneration facilities, and facilities that produced energy from renewable resources. (RCW 80.28.0250) The second incentive, which applies to both IOUs and public utilities, allows utility tax deduction (from the gross income that is subject to the public utilities tax) for production cost of energy derived from cogeneration or renewable resources. (1980, c 149).

In 1982, the legislature increased the B&O tax credit rate to 3 percent per year and limited eligibility for the tax credit to $10 million per application for facilities built and operated by December 31, 1984. (1982 1st ex.s., c 2). Also in 1982, SB 3156 amended the life cycle cost procedures to encourage the use of renewable resource in new public buildings or facilities undergoing major renovations (RCW 39.35; 1982, c 159).

In June 1998, HB 2773, the Net Metering Bill became effective (1998, c 318). Among its other purposes is encouraging private investment in renewable energy resources. Utilities must offer to make net metering available to eligible customer-generators on a first-come, first-served basis until the cumulative generating capacity of net metering systems equals 0.1 percent of the utility's peak demand during 1996. The bill defines a net metering system as a facility for the production of electrical energy that uses solar, wind, or hydro power, has a generating capacity of no more than 25 kilowatts, is located in the customer's premises, operates in parallel with the electric utility's transmission and distribution facilities, and it is intended primarily to offset part or all of the customer's requirements for electricity. Customers operating their own systems will be billed for their net consumption.

Geothermal Energy

In 1979, the Washington Legislature declared geothermal resources to be distinct and separate from mineral or water resources. Geothermal resources were also declared to be the private property of the party holding title to the surface above the resource. (1979 ex.s., c 2). Because most of the potential for geothermal exploration in the state is in federal lands, in 1980, the legislature memorialized Congress (HJM 25) to enact comprehensive geothermal legislation.

By 1981, federal land was being leased, explored, and assessed for its potential. Under provisions of the Geothermal Stream Act of 1970, a portion of the rents and royalties received for federal geothermal leases was to be returned to the states. To take advantage of this situation, the legislature passed SHB 466 creating a geothermal account in the state general fund, allocated funds in the geothermal account and established that thirty percent would go to the Department of Natural Resources for exploration and assessment, thirty percent to the Washington State Energy Office for encouraging the development of geothermal energy, and forty percent to the county of origin for the mitigation impacts caused by the exploration, assessment, and development. These provisions ended June 30, 1991. (1981, c 158).

Solar Energy

The State Legislature exempted solar systems installed as improvements to real property from property taxes in 1977. These exemptions were for seven years after a claim was filed with the county assessor. Exemptions could not be renewed and no new claims could be filed after December 31, 1981. (1977 ex.s., c 364) The 1980 legislature repealed the solar tax exemption and, in its place, directed that buildings with unconventional heating, cooling, domestic water heating, or electrical systems should not be assessed at a higher valued than similar buildings with conventional systems. The 1987 legislature allowed this provision to sunset on December 31, 1987. (1980, c 155).

In 1979, the legislature declared that, "Athe potential economic and environmental benefits of solar energy are considered to be in the public interest; therefore, local governments are authorized to encourage and protect access to direct sunlight for solar energy systems." (1970 ex.s., c 170 § 1). City and county planning commissions were to investigate the potential for solar energy development and encouraged to include solar issues in local plans. This law also authorized private parties to negotiate easements and established that easements would be real property interests, subject to the same conveyancing and recording requirements as other easements.

A. 5 Major Federal Legislation Affecting the Electric Power Industry

The National Energy Act of 1978

This Act was a response to the OPEC ban of oil exports to the United States. The Act was signed into law in November of 1978 and includes five different statutes: the Public Utility Regulatory Policies Act of 1978 (PURPA), the Energy Tax Act, the National Energy Conservation Policy Act, the Powerplant and Industrial Fuel Use Act, and the Natural Gas Policy Act.. The general purpose of the act was to ensure sustained economic growth while permitting the economy time to make an orderly transition from the past era of inexpensive energy resources to a period of more costly energy. With increased awareness of energy issues, the primary goal of the National Energy Act was to reduce the Nation's dependence on foreign oil and its vulnerability to interruptions in energy supply.

The Public Utilities Regulatory Policy Act of 1978

PURPA was the most significant part of the National Energy Act of 1978 with regard to the structure of the electric power industry. PURPA was designed to encourage the efficient use of fossil fuels in electric power production. Specifically, Section 2 of the Act states:

> The Congress finds that the protection of the public health, safety, and welfare, the preservation of national security, and the proper exercise of congressional authority under the Constitution to regulate interstate commerce require—

> (1) a program providing for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric customers. (PURPA; Public Law 95-617)

The Public Utilities Regulatory Policies Act (PURPA) encouraged the development of cogeneration, biomass-fired powerplants, and renewable generating resources. PURPA requires utilities to interconnect with qualifying cogenerators and small power producers (qualifying facilities, or QFs) located in their service territories, to purchase power at a price based on the utility's full avoided cost for energy and capacity, and to provide non-discriminatory rates for back-up services. PURPA also exempts small power producers from portions of the Federal Power Act, the Public Utility Holding Company Act, and certain state utility regulations.

Small power producers generate electricity from fuels other than oil and natural gas. They are automatically QF if they meet specific size, fuel use, and ownership criteria. General QF criteria require that the total power production capacity, together with the capacity of other facilities owned by the same person, using the same energy resource and located at the same site, cannot exceed 80 MW. Cogenerating QFs have no size limitation. In addition, no more than 50 percent of the equity interest in the facility can be held by an electric utility, an electric utility holding company, or a combination of them. For multifuel fired facilities, at least 75 percent of the total energy input must be from biomass, wastes, renewable resources, geothermal resources, or any combination of them. For cogeneration, PURPA requires the facility's useful power output plus one-half of its thermal output to be no less than 42.5 percent of the total energy input from natural gas and oil (WSEO, 1989).

The National Energy Conservation Policy Act of 1978 (Public Law 95-619)

Also part of the National Energy Act of 1978, this Act required utilities to provide residential consumers with free conservation services to encourage slower growth of electricity demand. It required all sectors of the economy to "significantly reduce the demand for nonrenewable energy resources such as oil and natural gas by implementing and maintaining effective conservation measures for the efficient use of these and other energy sources" (Sec 102, a, 3)

Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Public Law 96-901)

This Act created the Pacific Northwest Electric Power Conservation Council to coordinate operations of the BPA. The purpose was to encourage "conservation and efficiency in the use of electric power and...the development of regional plans and programs related to energy conservation" (Sec.2, 1a, 3a).

The Northwest Electric Power Planning and Conservation Act encouraged the development of renewable energy resources within the Pacific Northwest. The Northwest Power Planning Council's 1991 Plan identified the need to determine cost and availability of new cost-effective resources.

The Energy Policy Act of 1992 (Public Law 102-486)
This Act, often referred to as EPAct, was an omnibus energy bill with three primary policy goals: conserve energy supplied by electric utilities; make more efficient use of utilities' facilities and resources, and establish equitable rates for electric consumers. Among its provisions, EPAct:

- Calls for electric utilities to promote energy efficient products.
- Requires state governments to incorporate efficiency standards into building codes.
- Regulates energy efficiency standards for light fixtures, office equipment, windows, appliances, electric motors and plumbing products
- Promoted integrated resource planning (IRP) for regulated electric utilities.
- Stated a policy that demand-side investments should become as financially attractive to utilities as investments as supply-side investments.
- Called for investments in conservation and efficiency to be monitored and evaluated to determine that expected savings were, in fact, achieved.
- Consider the impact of the IRP and demand-side profitability standard standards on small businesses providing energy conservation and efficiency

The U.S. Energy Policy Act of 1992 (EPAct) extended a 10 percent federal income tax credit for production of solar and geothermal energy power, and offered operators or power projects based on energy crops and wind power a federal tax credit of 1.5 cents per kilowatt-hour generated during the first 10 years of the project. Subsidizing electric generation rather than capital investment creates more incentive for operators to lower their costs. City- and state-owned utilities, which are exempted from federal income taxes, receive a federal payment of 1.4 cents per kilowatt-hour for wind and closed-loop biomass projects (Flavin and Dunn, 1997).
In June of 1997, President Clinton announced the Million Solar Roofs Initiative aimed at installing 3,000 megawatts of solar energy systems on one million United States buildings by 2010. The initiative is intended to increase the demand for, and to lower the cost of solar photovoltaic systems, solar water heating systems and solar space heating systems, located on or near residential, commercial or industrial buildings. The Department of Energy is leading the initiative working with partners in the building and electric industries, local governments and non-governmental organizations to remove market barriers and strengthen local demand for solar technologies (www.nwppc.org)

A.6 A complete list of federal energy legislation would include the following laws:

Tennessee Valley Authority Act of 1933 (Public Law 73-17)
Public Utility Holding Company Act of 1935 (PUHCA) (Public law 74-333)
Federal Power Act of 1935 (Title II of PUHCA)
Rural Electrification Act of 1936 (Public Law 74-605)
Bonneville Project Act of 1937 (Public Law 75-329)
Reclamation Project Act of 1939 (Aug. 4, 1939, ch. 418, 53 Stat. 1187)
Flood Control Act of 1944 (Dec. 22, 1944, ch. 665, 58 Stat. 887)
First Deficiency Appropriation Act of 1949 ((Public Law 81-71)
Energy Supply and Environmental Coordination Act of 1974 (ESECA) (Public Law 93-319)
DOE Organization Act of 1977 (Public Law 95-91)
National Energy Act of 1978 (Public Law 95-617 - 95-621)
Public Utility Regulatory Policies Act of 1978 (PURPA) (Public Law 95-617)
Energy Tax Act of 1978 (ETA) (Public Law 95-618)
National Energy Conservation Policy Act of 1978 (Public Law 95-619)
Powerplant and Industrial Fuel Use Act of 1978 (Public Law 95-620)
Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Public Law 96-501)
Economic Recovery Tax Act of 1981 (Public Law 97-34)
Electric Consumers Protection Act of 1986 (ECPA) (Public Law 99-495)
Tax Reform Act of 1986 (Public Law 99-509)
Clean Air Act Amendments of 1990 (CAAA) (Public Law 101-549)
Energy Policy Act of 1992 (EPACT) (Public Law 102-486)

Appendix 9.2

Summary of Utililty Reported System Benefit Data

Utility Reported Investments in Conservation

	Nominal Dollars per Calendar Year								*Budgeted*
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	***1998***
Benton PUD -- Expenditures	284,226	563,774	1,354,717	1,869,744	2,981,307	3,576,885	2,806,265	1,318,218	1,743,179
Reimbursements from BPA	284,226	563,774	1,354,717	1,869,744	2,981,307	3,576,885	2,806,265	1,318,218	1,743,179
Net Investment	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Chelan PUD -- Expenditures	407,673	538,748	673,640	947,350	1,441,078	624,539	742,986	590,147	566,147
Reimbursements from BPA	91,988	106,127	272,091	589,454	217,930		458,000		
Net Investment	**$315,685**	**$432,621**	**$401,549**	**$357,896**	**$1,223,148**	**$624,539**	**$284,986**	**$590,147**	**$566,147**
Clark PUD -- Expenditures	1,303,000	1,377,000	2,175,000	6,152,000	4,324,000	9,397,000	8,258,000	3,895,000	
Reimbursements from BPA	1,229,000	1,377,000	1,984,000	6,601,000	4,324,000	3,730,000	1,750,000	750,000	
Net Investment	**$74,000**	**$0**	**$191,000**	**-$449,000**	**$0**	**$5,667,000**	**$6,508,000**	**$3,145,000**	**$0**
Cowlitz Co. PUD -- Expenditures	481,364	646,600	776,435	1,783,856	1,467,052	1,446,576	1,240,638	1,441,235	1,730,000
Reimbursements from BPA	419,589	533,960	586,704	1,505,427	1,196,305	1,065,250	1,032,430	1,174,459	1,472,801
Net Investment	**$61,775**	**$112,640**	**$189,731**	**$278,429**	**$270,747**	**$381,326**	**$208,208**	**$266,776**	**$257,199**
Franklin Co. PUD -- Expenditures	249,265	368,034	825,849	1,046,523	963,902	776,119	744,225	780,056	96,060
Reimbursements from BPA	195,067	327,574	614,265	958,050	635,150	593,117	649,980	853,848	0
Net Investment	**$54,198**	**$40,460**	**$211,584**	**$88,473**	**$328,752**	**$183,002**	**$94,245**	**-$73,792**	**$96,060**
Grant Co. PUD -- Expenditures	161,192	598,571	855,284	574,759	918,583	782,547	1,015,611	985,797	985,797
Reimbursements from BPA	0	0	0	0	0	0	0	0	0
Net Investment	**$161,192**	**$598,571**	**$855,284**	**$574,759**	**$918,583**	**$782,547**	**$1,015,611**	**$985,797**	**$985,797**
Grays Harbor PUD -- Expenditures	646,243	840,666	1,694,851	2,566,657	2,552,894	1,690,491	2,468,749	1,693,954	1,671,075
Reimbursements from BPA	573,337	917,448	1,763,128	2,736,306	2,809,995	1,675,303	2,659,137	1,549,946	1,671,075
Net Investment	**$72,906**	**-$76,782**	**-$68,277**	**-$169,649**	**-$257,101**	**$15,188**	**-$190,388**	**$144,008**	**$0**
Orcas Pwr & Light -- Expenditures	Unknown	0	188,190	493,719	312,851	297,388	101,335	398,771	398,771
Reimbursements from BPA	0		188,190	493,719	312,851	297,388	101,335	285,845	285,845
Net Investment	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$112,926**	**$112,926**

Utility Reported Investments in Conservation

	Nominal Dollars per Calendar Year								*Budgeted*
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	***1998***
PacifiCorp -- Expenditures	NA	NA	NA	5,962,148	4,828,406	3,198,102	1,479,721	450,677	243,694
Reimbursements from BPA	0	0	0	0	0				
Net Investment	**$0**	**$0**	**$0**	**$5,962,148**	**$4,828,406**	**$3,198,102**	**$1,479,721**	**$450,677**	**$243,694**
Parkland -- Expenditures	97,569	109,531	228,129	633,820	342,224	191,775	95,944	77,355	202,000
Reimbursements from BPA	97,153	119,145	278,512	613,006	325,726	136,794	123,573	84,268	193,600
Net Investment	**$416**	**-$9,614**	**-$50,383**	**$20,814**	**$16,498**	**$54,981**	**-$27,629**	**-$6,913**	**$8,400**
Puget Energy -- Expenditures	24,623,000	41,961,000	62,630,000	63,764,000	36,662,000	16,965,000	7,387,000	3,949,000	6,655,000
Reimbursements from BPA	-	1,025,000	5,194,000	1,452,000	899,000	1,325,000	0	0	0
Net Investment	**$24,623,000**	**$40,936,000**	**$57,436,000**	**$62,312,000**	**$35,763,000**	**$15,640,000**	**$7,387,000**	**$3,949,000**	**$6,655,000**
Seattle City Light -- Expenditures	10,206,370	9,478,728	13,991,738	21,285,342	22,939,683	24,828,935	19,758,511	14,838,239	17,740,358
Reimbursements from BPA	2,190,598	3,208,450	5,310,531	11,653,542	12,060,591	13,032,673	9,904,627	5,310,336	5,700,000
Net Investment	**$8,015,772**	**$6,270,278**	**$8,681,207**	**$9,631,800**	**$10,879,092**	**$11,796,262**	**$9,853,884**	**$9,527,903**	**$12,040,358**
SnoPUD -- Expenditures	5,608,987	5,939,725	8,757,886	9,479,815	8,736,280	8,944,648	7,181,725	2,340,886	1,500,000
Reimbursements from BPA	3,726,480	3,750,354	6,786,401	8,432,198	6,789,905	5,028,653	4,200,007	2,562,752	3,256,980
Net Investment	**$1,882,507**	**$2,189,371**	**$1,971,485**	**$1,047,617**	**$1,946,375**	**$3,915,995**	**$2,981,718**	**-$221,866**	**-$1,756,980**
Tacoma Power -- Expenditures	6,751,079	5,894,042	8,935,118	10,619,970	18,459,062	15,540,817	18,071,432	6,426,593	2,826,190
Reimbursements from BPA	4,166,018	3,501,946	5,442,712	8,705,611	9,333,695	6,941,039	10,948,840	3,425,728	1,825,000
Net Investment	**$2,585,061**	**$2,392,096**	**$3,492,406**	**$1,914,359**	**$9,125,367**	**$8,599,778**	**$7,122,592**	**$3,000,865**	**$1,001,190**
Washington Water Pwr -- Expenditu	538,187	2,540,238	7,366,689	19,235,762	13,237,047	3,000,849	2,252,607	3,058,669	2,367,602
Reimbursements from BPA	0	0	0	0	0	0	0	0	0
Net Investment	**$538,187**	**$2,540,238**	**$7,366,689**	**$19,235,762**	**$13,237,047**	**$3,000,849**	**$2,252,607**	**$3,058,669**	**$2,367,602**

Utility Reported Data for Top Energy Efficiency Programs for 1990-2000

Benton PUD

Top 6 Past Programs by Funding Level

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Residential Weatherization	Weatherization	1990 to present	$4,533,695	8,033,301
2	Long Term Super Good Cents	New Home	1992 to present	$2,396,387	2,238,022
3	Waterwise	Irrigation	1992 to present	$2,342,908	34,849,897
4	Energy Smart	Commercial	1990 to present	$1,938,323	12,303,677
5	Heat Pump Program	Res. Heat Pumps	1990 to present	$1,234,556	5,125,706
6	Industrial	Industrial	1992 to present	$688,287	32,133,371

Three Most Effective Programs

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Industrial	Industrial	1992 to present	$688,287	32,133,371
2	Waterwise	Irrigation	1992 to present	$2,342,908	34,849,897
3	Energy Smart	Commercial	1990 to present	$1,938,323	12,303,677

Top Two Future Programs by Funding Level

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Residential Weatherization	Weatherization	1998 - 2000	$285,000	160,843
2	Long Term Super Good	New Home	1988 - 2000	$135,000	144,552
	Additional programs: rebates for heat pumps and water heaters; energy smart for small commercial; SGC L-I wx				

Chelan PUD

Top 6 Past Programs by Funding Level

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Residential Weatherization Loan Program	Retrofit weatherization	1990-Present	$130,000	750,000
2	Residential New Construction	New construction efficiency enhancements	1990-1994 w/ incentives; 1995 - 1997 no incentives	$696,845	
3	Commercial New Construction - pre NREC	Incentives for new construction efficiencies	1993-1996	$427,890	3,812,882
4	Industrial Efficiency Program	Incentives for new construction efficiencies	1992-1996 w/ incentives; 1997 - Present, no incentives	$437,410	10,547,501
5	Non Residential Code Compliance	new construction efficiencies	1995 - Present	$30,000	
6	Pressure Diagnostics of Buildings & HVAC Systems	Technical Assistance	1996 - Present	$74,000	

Three Most Effective Programs

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Industrial Efficiency Program	Incentives for new construction efficiencies	1992-1996 w/ incentives; 1997 - Present, no incentives	$437,410	10,547,501
2	Commercial New Construction - pre NREC	Incentives for new construction efficiencies	1993-1996	$427,890	3,812,882
3	Residential Weatherization Loan Program	Retrofit weatherization	1990-Present	$130,000	750,000

Top Two Future Programs by Funding Level

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Residential Weatherization Loan Program	Weatherization	1998-2000	$130,000	750,000
2	Commercial/Industrial	Technical Assistance	1998-2000	$200,000	1,900,000

Clark PUD

Top 6 Past Programs by Funding Level

	Program Name	Type of Program
1	Industrial - Energy Efficient	Facility Improvement
2	Commercial - Investment	Efficiency

Utility Reported Data for Top Energy Efficiency Programs for 1990-2000

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
3	Residential Weatherization	House Tighten			
4	Heat Pump	Heat Pump Instal			
5	New Construction Grant	Measure Upgrade			
6	Water Heat Rebate	Water Heat Rebate			

Three Most Effective Programs

1 *no detail provided*

Top Two Future Programs by Funding Level

1 Residential Loans

2 Commercial Loans

Cowlitz Co. PUD

Top 6 Past Programs by Funding Level

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh) **
1	Residential Weatherization Retrofit Program	Residential Retrofit	1990 - Present	$3,036,453	5,002,470
2	Energy Smart Design	Commercial Retrofit	1992 - Present	$2,883,716	15,364,198
3	Washington State Energy Code Payments & Utility Heat Pump Payments	Energy Code	1992 - 1996	$1,020,751	1,989,177
4	Energy Efficient Showerhead/ Faucet Aerator Installation Program	Resid/Commercial	1993 - 1994	$527,000	5,007,560
5	Energy Efficient Water Heater Rebate Program ($60 & $40 Rebates)	Residential	1993 - Present	$495,000	1,253,200
6	Energy Savings Plan (ESP)	Industrial	1992 - Present	$630,382	9,359,378

Three Most Effective Programs

1	Energy Savings Plan (ESP)	
2	Energy Smart Design (ESD)	
3	Energy Efficient Showerhead/ Faucet Aerator Installation Program	

** This is the sum of the annual savings for the first year only, Annual kWh savings. A measure life would need to be established for each program and the annual kWh savings calculated for each year of the measure life that the program was in effect

Top Two Future Programs by Funding Level

1	Energy Smart Design (ESD)	Comm'l Retrofit	1998 - 2000	$1,660,000	?
2	Commercial Energy Savings Plan	Industrial Retrofit	1998 -1999	$1,892,000	?

Franklin Co. PUD

Top 6 Past Programs by Funding Level

1	Non-low Income Residendital Weatherization	Rebate	1990-present	$1,929,284	184,808,000
2	Low-income Residential Weatherization	Rebate	1990-present	$1,068,375	55,016,000
3	Energy Smart Design (commercial)	Rebate	1993-1998	$858,674	46,669,056

Utility Reported Data for Top Energy Efficiency Programs for 1990-2000

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
4	Low Flow Shower Heads and Water Heaters (appliances)	Rebate		$361,155	34,720,000
5	Energy Savings Plan (Industrial)	Rebate	1992-1997	$241,640	12,430,596
6	Irrigation Program	Rebate	1990-1996	$201,181	31,018,640
	Three Most Effective Programs				
1	Irrigation Program	Rebate	1990-1996	$169,060	31,018,640
2	Low Flow Shower Heads and Water Heaters (appliances)	Rebate		$303,491	34,720,000
3	Non-low Income Residendital Weatherization	Rebate	1990-present	$1,929,284	184,808,000
	Top Two Future Programs by Funding Level				
1	Residential Efficiency	low interest loan	1998-2000	$1,060,000	19,968,000
2	Improvements *no further details provided*				

Grant Co. PUD

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
	Top 6 Past Programs by Funding Level				
1	Industrial	Grant	1990-Present	$1,013,518	172,203,060
2	Irrigation Hardware	Rebate	1988-Present	$862,712	86,504,060
3	Commercial	Rebate	1991-Present	$524,368	99,209,847
4	SGC MSG	Rebate	1991-Present	$44,000	81,000,000
5	SGC Site Built	Rebate	1987-Present	$1,932,879	216,102,800
6	Residential Weatherization	Loan	1988-Present	$107,317	132,169,650
	Three Most Effective Programs				
1	Irrigation Management	Contract	1991-Present	$1,147,123	142,729,831
2	Irrigation Hardware	Rebate	1988-Present	$862,712	86,504,060
3	Industrial	Grant	1990-Present	$1,013,518	172,203,060
	Top Two Future Programs by Funding Level				
1	Irrigation Hardware	Rebate/Loan	1998-2000	$300,000	3,000,000
2	Irrigation Management	Contract	1998-2000	$150,000	6,000,000

Grays Harbor PUD

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
	Top 6 Past Programs by Funding Level				*
1	Energy Savings Plan	Industrial	92-'98	$3,198,245	22,114,245
2	Weatherwise	Residential	82-98	$5,187,014	4,455,755
3	Energy Smart Design	Commercial	92-98	$2,416,685	10,822,579
4	Efficient Showerhead Program**	Residential	92-98		5,918,800
5	Super Good Cents	Residential	86-98	$1,124,326	233,976
6	Hot Water Tank Rebate Program	Comm/Res	86-98		520,340
	Heat Pumps	Res.			520340
	Three Most Effective Programs*				
1	Energy Savings Plan	Industrial			
2	Energy Smart Design	Commercial			
3	Efficient Showerhead Program**	Comm/Res			

* BPA has program savings figures for these programs

** Program expenditures are combined

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
	Top Two Future Programs by Funding Level				
1	CARES ESE CPS for Comm/Indus. & Institutional	Loan/lease	1998-on	$4.5 mm est.	Unknown

Utility Reported Data for Top Energy Efficiency Programs for 1990-2000

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
2	Efficiency Plus for Residential	Loan/lease	1998-on	$2.5 mm est.	Unknown

Orcas Power & Light

Top 6 Past Programs by Funding Level

1	Residential Weatherization		1980-1996	$1,512,750	1,782,320
2	Energy Smart Design (Commerical)		1980-1995	$153,311	351,931
3	Super Good Cents		1980-1991	$129,172	77,700
4	Long Term Super Good Cents		1992-1994	$89,000	72,720
5	Water Heater Wrap		1980-1991	$56,448	352,800
6	Water Heater Rebates		1992-1998	$39,210	93,350

Three Most Effective Programs

1 *no detail provided*

Top Two Future Programs by Funding Level

1 *no detail provided*

PacifiCorp

Top 6 Past Programs by Funding Level

1	Home Comfort	Res	1993-98	$6,590,000	600,000,000
2	Super Good Cents	Res	1993-97	$2,970,000	606,000,000
3	MAP	Res	1993-97	$2,450,000	610,000,000
4	Showerheads	Res	1993	$1,703,945	61,818,024
5	Industrial Finanswer	Indus	1993-98	$1,340,000	260,000,000
6	Commercial Finanswer	Commercial	1993-98	$1,050,000	35,000,000

Three Most Effective Programs

1	Industrial FinAnswer	same as above
2	MAP	same as above
3	Super Good Cents	same as above

Top Two Future Programs by Funding Level

1	Industrial Finanswer	Indus	1998-2000	Not budgeted (*)	Not easily available
2	Commercial Finanswer	Commercial	1998-2000	Not budgeted (*)	Not easily available

Parkland

Top 6 Past Programs by Funding Level

1	Commercial	LIGHTING	92-PRESENT	$900,000	2,590,000
2	Residential	WEATHER.	90-PRESENT	$850,000	2,581,100
3	*no further details provided*				FIRST YEAR SAVINGS

Three Most Effective Programs

1	Commercial Lighting
2	Residential Weatherization
3	

Top Two Future Programs by Funding Level

1	Commercial Lighting
2	Residential

Puget Energy

Top 6 Past Programs by Funding Level

1	Residential Retrofit - Space Heat	1979 - present	$ 62,437,000	101,516,000
2	Residential New Construction (incl. ComfortPlus & code)	1979 - 1996	$ 26,869,000	92,150,000
3	Residential Water Heating Efficiency	1982 - present	$ 25,616,000	220,404,000

Utility Reported Data for Top Energy Efficiency Programs for 1990-2000

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
4	Residential Lighting and Appliances		1991 - present	$ 4,918,000	19,885,000
5	Commercial/Industrial Energy Management (incl. Lighting)		1980 - present	$ 98,951,000	457,099,000
6	Commercial/Industrial New Construction (incl. NREC)		1988 - 1997	$ 29,283,000	180,165,000

Three Most Effective Programs

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Residential Water Heating Efficiency		1982 - present	$ 62,437,000	101,516,000
2	Commercial/Industrial Energy Management (incl. Lighting)		1980 - present	$ 98,951,000	457,099,000
3	Commercial/Industrial New Construction (incl. NREC)		1988 - 1997	$ 29,283,000	180,165,000

Top Two Future Programs by Funding Level

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Residential Information		1996 -		5,920,000
2	CI Energy Management		1996 -		25,344,000

Seattle City Light

Top 6 Past Programs by Funding Level

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Energy Smart Design Program (active 1998)	comcl/indstl	1989 - 1997	$49,832,886	3,141,885,000
2	Multifamily Conservation Programs (active 1998)	residential	1986 - 1997	$38,515,622	1,228,338,000
3	Home Energy Loan / Warm Home Programs (closed)	residential	1981 - 1997	$15,680,898	307,500,000
4	Low-income Electric Program (active 1998)	residential	1981 - 1997	$8,228,703	148,710,000
5	Energy $avings Plan Program (active 1998)	industrial	1988 - 1997	$7,520,717	710,400,000
6	Lighting Design Lab (active 1998)	informational	1988 - 1997	$4,111,429	0

Three Most Effective Programs

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Home Water Savers Program ($ 1.98 / MWh)	residential	1992 - 1995	$1,367,029	691,395,000
2	Energy $avings Plan Program ($10.50 / MWh)	industrial	1988 - present	$49,832,886	3,141,885,000
3	Energy Smart Design Program ($15.86 / MWh)	commercial	1989 - present	$7,520,717	710,400,000

NOTES:

* Savings from 1990-1997 participants.

Top Two Future Programs by Funding Level

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Energy Smart Design Program	comcl/indstl	1998 - 2000+	$22,713,800	1,261,440,000
2	Multifamily Conservation Programs	residential	1998 - 2000+	$10,418,006	478,953,000

SnoPUD

Top 6 Past Programs by Funding Level

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Residential Loans	Loan	1980-Present	$0	85,384,621
2	Commercial Conservation	Incentive	1986-1997	$16,606,126	88,736,716
3	Industrial Conservation	Incentive	1992-1997	$10,267,958	131,156,416
4	SESCO	Weatherization	1996-1997	$2,336,360	12,927,440
5					

Three Most Effective Programs

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
1	Industrial Conservation	Incentive	1992-1997	$10,267,958	131,156,416

Utility Reported Data for Top Energy Efficiency Programs for 1990-2000

	Program Name	Type of Program	Dates Program Offered	Program Expenditures	Estimated Program Savings (kWh)
2	Commercial Conservation	Incentive	1986-1997	$16,606,126	88,736,716
3					

Top Two Future Programs by Funding Level

1	Residential/Commerical Weatherization Loans	Retrofit	1998	$3,716,000	n/a
2	Schools Conservation	Retrofit	1998	$500,000	n/a

Tacoma Power

Top 6 Past Programs by Funding Level

1	Conservation Project Agreement (includes low income)	grant	2/94 to 12/97	$22,071,389	2,138,206,900
2	Fort Lewis Conservation Project	Performance based	9/92 to 12/98	$10,001,985	247,630,720
3	Residential Conservation Agreement	Residential, New Construction	3/92 to 9/96	$5,101,877	not available
4	Energy Smart Design	Commercial	1992 to 2/94	$9,200,000	600,000,000
5	Energy Savings Plan	Industrial	7/91 to 2/94	$4,827,922	994,207,530
6	Weatherwise & other BPA weatherizations (Est., w/ Low-Inc.)	Residential,Wx	1/90 to 2/94	$14,682,500	581,427,000

Three Most Effective Programs

1	Energy Savings Plan	Industrial	7/91 to 2/94	$4,827,922	994,207,530
2	Conservation Project Agreement	grant	2/94 to 12/97	$22,071,389	2,138,206,900
3	Energy Smart Design	Commercial	1992 to 2/94	$9,200,000	600,000,000

Top Two Future Programs by Funding Level

1	Conservation Incentives	Grants	1/97 to 12/98	$1,588,505	N/A
2	Conservation Loans -	Grants	1/97 to 12/98	off budget	N/A

Washington Water Power

Top 6 Past Programs by Funding Level

	Program		Operation	Budget	lifecycle kWh savings
	Residential Energy Exchanger	fuel switching	5/92 to 12/94	34,366,676	5,410,380,700
	C/I Site-Specific	incentives	1/91 to present	8,796,171	1,235,760,120
	MAP	manufactured homes	x/9x to 2/98	6,276,822	349,350,000
	Limited Income programs		1/90 to present	1,783,183	112,544,055
	Residential New Construction		7/91 to 12/96	1,582,051	164,591,800
	NEEA	market transformation	10/96 to present	629,353	not yet available

Top Two Future Programs by Funding Level

			1997 (annual kWh's / lifecycle kWh's)	1998 (annual kWh's / lifecycle kWh's)
C/I Site Specific	1,060,000		10,428,780 / 208,575,600	10,428,780 / 208,575,600
Limited Income	590,000		2,027,940 / 50,698,500	2,027,940 / 50,698,500

Utility Reported Data for Non-Hydro Renewable Power

PacifiCorp
Non-Hydro Renewable Projects

Project Name	Project Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
		MWh Produced or Purchased								Amount Budgeted in Each Year		
Blundell	Geothermal		186,241	186,369	148,148	194,804	130,742	191,912	168,518	150,000	not budgete	not budgeted
Foote Creek	Wind								-	10,000	50,000	not budgeted

Seattle City Light
Non-Hydro Renewable Projects

Project Name	Project Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
		MWh Produced or Purchased								Amount Budgeted in Each Year		
West Point Sewage Treatment Plant (methane gas)	co-generation	9,852	7,306	8,706	8,459	7,948	9,168	8,829	8,296	10,513	10,512	10,541

SnoPUD
Non-Hydro Renewable Projects

Project Name	Project Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
		MWh Produced or Purchased								Amount Budgeted in Each Year		
Everett Cogeneration P	Biomass/Steam						24,186	272,678	301,400	325,000		

Washington Water Power
Non-Hydro Renewable Projects

** Amounts in italics pro-rate utility-wide data to reflect the proportion available to Washington consumers, using a utility supplied ration)*

Project Name	Project Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
		MWh Produced or Purchased								Amount Budgeted in Each Year		
Minnesota Methane	Landfill methane	-	-	-	-	-	-	-	-	2,700	7,200	7,200
Wood Power, Inc.	cogen-wood	40,438	39,632	40,261	36,772	36,116	37,147	34,114	-	-	-	-
Rayonier	cogen-wood	-	-	-	-	-	-	-	15,319	5,801	-	-
Eduard Ribic	wind	-	-	-	-	-	3	1	-	1	1	1
Kettle Falls	wood	333,775	264,408	291,630	307,968	329,841	200,237	284,098	279,887	304,146	369,139	369,139
	WA total	*249,974*	*203,099*	*221,703*	*230,286*	*244,459*	*158,575*	*212,566*	*197,198*	*208,849*	*251,395*	*251,395*

NOTE: DOES NOT INCLUDE WIND RESOURCE ESTIMATIONS FOR 1998-2000 UNDER THE MOPS II PROGRAM

Q11-If your non-hydro renewable resource budgets and programs have changed since 1995 (as reported in Q6), please describe what factors or considerations have influenced these changes.
Methane gas project came on-line in May 98
Bought out the Wood Power, Inc. project in 1997
Rayonier facility project burned down 7/97. Assumed project would not come back on-line.

Note: Only utilities reporting activity are shown.

Summary of Utility Reported Data for Low-Income Energy Services

	Nominal Dollars per Calendar Year								Budgeted
	1990	1991	1992	1993	1994	1995	1996	1997	1998
Benton PUD -- Low Income Programs									
Low Income Weatherization Expenditures	53,958	79,129	313,115	136,869	52,162	97,867	114,908	53,270	90,000
Reimbursements from BPA	53,958	79,129	313,115	136,869	52,162	97,867	114,908	53,270	30,000
Net Weatherization	0	0	0	0	0	0	0	0	**60,000**
Bill Discounts and Direct Assistance	0	0	0	0	0	0	0	0	0
Chelan PUD -- Low Income Programs									
Low Income Weatherization Expenditures	26,968	114,371	102,938	102,892	150,125	50,000	60,000	60,000	65,000
Reimbursements from BPA	26,968	114,371	102,938	102,892	100,125				
Net Weatherization	0	0	0	0	**50,000**	**50,000**	**60,000**	**60,000**	**65,000**
Bill Discounts and Direct Assistance	0	0	0	0	21,178	70,942	80,280	89,191	90,000
Clark PUD -- Low Income Programs	none reported								
Low Income Weatherization Expenditures									
Reimbursements from BPA									
Net Weatherization	0	0	0	0	0	0	0	0	0
Bill Discounts and Direct Assistance	351,629	354,675	318,712	588,056	698,944	639,744	1,036,722	999,273	
Cowlitz Co. PUD -- Low Income Programs *	* (Specific data for expenditures were not reported; amounts reported as BPA reimbursements were assumed as a proxy)								
Low Income Weatherization Expenditures	44,142	37,689	44,854	28,241	61,933	47,306	16,979	22,845	25,000
Reimbursements from BPA	44,142	37,689	44,854	28,241	61,933	47,306	16,979	22,845	25,000
Net Weatherization	0	0	0	0	0	0	0	0	0
Bill Discounts and Direct Assistance	0	0	0	0	0	0	0	0	0
Franklin Co. PUD -- Low Income Programs									
Low Income Weatherization Expenditures	49,225	97,277	331,170	650,415	253,464	124,937	86,516	39,001	20,000
Reimbursements from BPA	38,522	86,583	246,324	310,854	100,677	54,119	40,334	20,381	-
Net Weatherization	**10,703**	**10,694**	**84,846**	**339,560**	**152,787**	**70,817**	**46,182**	**18,620**	**20,000**
Bill Discounts and Direct Assistance	none reported								
Grant Co. PUD -- Low Income Programs									
Low Income Weatherization Expenditures	3,600	25,000	50,000	22,000	60,000	20,000	10,000	20,000	65,000
Reimbursements from BPA	0	25,000	50,000	22,000	60,000	20,000	10,000	20,000	45,000
Net Weatherization	3,600	0	0	0	0	0	0	0	**20,000**
Bill Discounts and Direct Assistance	0	0	0	0	0	0	0	0	0
Grays Harbor PUD - Low Income Programs									
Low Income Weatherization Expenditures*	235,628	404,310	437,960	412,629	363,484	273,681	217,909	137,949	50,000
Reimbursements from BPA	235,628	404,310	437,960	412,629	363,484	273,681	217,909	137,949	0
Net Weatherization	0	0	0	0	0	0	0	0	**50,000**

Summary of Utility Reported Data for Low-Income Energy Services

	Nominal Dollars per Calendar Year								Budgeted
	1990	1991	1992	1993	1994	1995	1996	1997	1998
Bill Discounts and Direct Assistance	not available	not available	not available	142,128	144,251	138,846	161,041	156,484	160,000
Orcas Power -- Low Income Programs									
Low Income Weatherization Expenditures	Unknown	14,006	31,711	49,252	15,677	0	0	0	0
Reimbursements from BPA	Unknown	14,006	31,711	49,252	15,677	0	0	0	0
Net Weatherization		0	0	0	0	0	0	0	0
Bill Discounts and Direct Assistance	Unknown	0	0	0	0	0	0	0	0
PacifiCorp - Low Income Programs									
Low Income Weatherization Expenditures				970,792	841,443	678,746	720,507	586,567	350,000
Reimbursements from BPA	0	0	0	0	0	0	0	0	0
Net Weatherization	0	0	0	**970,792**	**841,443**	**678,746**	**720,507**	**586,567**	**350,000**
Bill Discounts and Direct Assistance	23,208	23,208	23,208	23,208	23,208	23,208	23,208	23,208	23,208
Parkland -- Low Income Programs									
Low Income Weatherization Expenditures	16,817	20,342	65,705	104,100	2,426	1,000	0	2,783	
Reimbursements from BPA	16,817	20,342	65,705	104,100	2,426	1,000	0	2,783	
Net Weatherization	0	0	0	0	0	0	0	0	0
Bill Discounts and Direct Assistance	0	0	0	0	0	0	0	0	0
Puget Energy -- Low Income Programs									
Low Income Weatherization Expenditures	1,732,000	1,519,000	1,156,000	1,877,000	886,000	546,000	698,000	511,000	1,892,235
Reimbursements from BPA									
Net Weatherization	**1,732,000**	**1,519,000**	**1,156,000**	**1,877,000**	**886,000**	**546,000**	**698,000**	**511,000**	**1,892,235**
Bill Discounts and Direct Assistance	0	0	0	0	0	0	0	0	0
Seattle City Light -- Low Income Programs									
Low Income Weatherization Expenditures (co	3,115,347	3,321,306	3,330,139	3,088,972	3,614,652	3,726,790	1,786,295	2,137,019	2,144,574
Reimbursements from Bonneville (conservati	433,353	668,645	709,487	1,018,619	1,766,165	545,490	427,887	167,540	0
Net Weatherization	**2,681,994**	**2,652,661**	**2,620,652**	**2,070,353**	**1,848,487**	**3,181,300**	**1,358,408**	**1,969,479**	**2,144,574**
Bill Discounts and Direct Assistance	3,235,694	3,341,513	3,606,858	4,005,166	4,265,326	4,238,046	4,574,829	4,182,858	4,555,894
SnoPUD -- Low Income Programs									
Low Income Weatherization Expenditures	266,038	269,431	275,696	265,252	267,867	267,943	274,384	349,943	450,000
Reimbursements from BPA	0	0	0	0	0	0	0	0	0
Net Weatherization	**266,038**	**269,431**	**275,696**	**265,252**	**267,867**	**267,943**	**274,384**	**349,943**	**450,000**
Bill Discounts and Direct Assistance	476,263	428,586	553,496	637,333	657,701	653,288	1,500,852	1,051,081	2,800,000
Tacoma Power -- Low Income Programs									
Low Income Weatherization Expenditures	976,202	866,318	1,060,204	2,083,392	630,720	2,047,778	364,915	591,145	900,000
Reimbursements from BPA	976,202	866,318	1,060,204	2,083,392	630,720	1,156,482	304,096	0	0
Net Weatherization	0	0	0	0	0	**891,296**	**60,819**	**591,145**	**900,000**
Bill Discounts and Direct Assistance	1,251,317	1,361,273	1,361,309	1,378,451	1,367,968	1,423,367	1,438,596	1,588,748	1,500,000
WWP -- Low Income Programs *****	* (These amounts pro-rate utility-wide data to reflect the proportion spent in Washington, using a utility supplied ration)								

Summary of Utility Reported Data for Low-Income Energy Services

	Nominal Dollars per Calendar Year								Budgeted
	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
Weatherization Actuals	449,417	363,939	425,426	670,291	666,449	80,528	149,386	28,704	65,536
BPA Funding	0	0	0	0	0	0	0	0	0
Net Weatherization	**449,417**	**363,939**	**425,426**	**670,291**	**666,449**	**80,528**	**149,386**	**28,704**	**65,536**
Bill Discounts and Direct Assistance	0	0	0	0	0	0	0	0	0