Table of Contents

AVERY READY INDEX INDEXING SYSTEM

Tacoma Power
Integrated Resource Plan
2001 - 2011
D R A F T
Table of Contents

Integrated Resource Plan Executive Summary

Purpose of Integrated Resource Plan

The world that utilities must operate in has changed profoundly since Tacoma Power's last published Integrated Resource Plan in 1992. In less than 10 years, wholesale electricity markets have evolved to allow competition among buyers and sellers. Electricity is now traded regularly for delivery an hour-ahead, a day-ahead or on the forward market for delivery at some specified future date. The price of electricity is no longer tied to its production cost. Participants in this trading arena include non-utility generating companies, power marketers that don't produce electricity but buy and sell it for others, and utilities that buy and sell to meet customer demand for electricity. As in all commodity markets, the prices paid for goods vary from day-to-day and hour-to-hour, allowing participants the opportunity to make profits by buying low and selling high. As demonstrated by market prices in 2000 and 2001, the range and volatility of prices is far greater than most market participants ever imagined.

One of the clear differences between this planning effort and the 1992 Least Cost Resource Plan is the scale and scope of uncertainty regarding basic planning assumptions. Not only are electricity price forecasts extremely difficult to bound, load forecasts are harder to make because of the possible arrival of new large loads and conversely, large load losses because of high electricity prices and other economic factors. Regulatory structures are subject to change. Legislation may impose price caps or other market changes. Distributed generation or a sudden shift in technological capability may unpredictably alter the way electricity is provided to customers.

For these reasons, this Integrated Resource Plan (IRP) provides a framework for future decisions, rather than a definite course of action. The emphasis of our planning process has been on investment in improving tools for load and price forecasting, and in developing new models for simulating the dispatch of our supply resources and conducting economic analyses of supply and conservation options. In addition to skill in managing a complex physical infrastructure, competence in understanding and managing risk has become a key component in the long-term success of the utility. Continuing assessment and management of the risks confronting us will ensure that Tacoma Power's customers continue to benefit from earlier investments in generating projects and community ownership of its assets.

The process of developing this IRP included these tasks:

- Forecast future customer demand for energy.
- Determine adequacy of existing resource supply.
- Evaluate new supply and conservation options.
- Forecast future energy prices.
- Model resource choices under a range of demand and price cases.
- Articulate optimal resource strategy for Tacoma Power.

In order to adequately assess resource options, Tacoma Power developed several models to conduct detailed economic analyses. The models developed for this IRP include variables for capital and operating costs of different resources, alternative load forecasts, and alternative price forecasts. The IRP also includes scenario analysis to examine non-quantifiable factors that influence resource decision making. These tools will help Tacoma Power to make the best choices for its resource portfolio in the coming years.

Power Supply

One of the most challenging issues for Tacoma Power is finding the appropriate balance between investment in firm supply resources (utility owned or long term contracts) and reliance on the wholesale power market. If loads are less than forecast and the utility builds too much firm supply, or if it acquires a high cost resource, customers will pay higher rates. On the other hand, over-reliance on the spot market could expose the utility to the kinds of price spikes that have persisted since mid-2000. Similarly, if the utility fails to invest in energy efficiency improvements in customers' homes and businesses, the opportunity to postpone investments in generation resources is lost. Alternatively, over-investment in conservation or investments in high-cost efficiency measures will cause upward pressure on consumer rates.

Three primary needs have been identified through the extensive analyses of supply/demand balance under a variety of water, load, and price cases. These are:

1. The need for insurance to reduce the risk of exposure to high market prices in the event of critical or adverse water conditions and/or higher than expected load growth.
2. The need to augment the reliability and flexibility in our existing firm resource base to cover losses in firm generation from planned and unplanned outages. The need is for both energy and capacity.

3. The need for additional peaking capacity to ensure system reliability during periods of extremely cold weather.

These needs can be addressed through a variety of options, many of which do not entail the construction of a physical resource. The following list provides a range of strategies and actions that should be considered:

- Make purchases on the wholesale market at the time they are needed. In the event of higher than anticipated market purchases or higher than forecast market prices, recover these costs through temporary rate surcharges.
- Purchase a site for a thermal resource and install basic infrastructure. This will shorten the lead-time for construction of a physical resource in the event it is needed.
- Build up cash reserves to lessen rate impacts in the event of another drought or higher than forecast market prices, or rely on short-term borrowing.
- Build or contract for a thermal resource to cover all or part of the identified needs for energy and capacity.
- For planned maintenance of generating units, make forward market purchases when prices are favorable rather than using the spot market.

Tacoma Power issued an RFP for a 40 – 60 MW thermal resource in July 2001. The responses from vendors and developers are currently being reviewed.

A final decision on how best to meet the identified needs for energy and capacity will be significantly influenced by changing market prices, resource costs, and rate impacts. We expect to complete a review of all of the above options and make a determination on the best resource strategy during the fourth quarter of 2001.

Green Power Program

Tacoma Power recommends continuation of the Evergreen Options program beyond the October 1, 2001 Environmentally Preferred Power program (EPP) contract expiration. If the EPP purchase qualifies under the new legislation, Tacoma Power will most likely pursue a contract with BPA. If EPP does not qualify, Tacoma Power will explore other options for providing the resource base for the offering. It is anticipated that one average megawatt will be sufficient to support the retail offering through at least the middle of 2002.

Distributed Generation Tacoma Power can prepare for future distributed generation opportunities by closely monitoring the development of new generating technologies and applications. The utility should consider participating in a pilot project such as the BPA fuel cell beta test beginning later in 2001, or a similar test project in partnership with another interested utility. Finally, Tacoma Power should systematically inventory customer owned generation resources, potential sites and applications for distributed generation, as well as interest in future distributed generation projects.

Conservation Conservation should be the primary strategy for meeting expected load growth in Tacoma Power's service territory. We are recommending that conservation programs be ramped up to acquire 36 aMW of energy savings over the 10 year planning horizon. This level of acquisition will meet 60% of projected load growth under the base case load forecast.

Load Shedding Tacoma Power should begin to develop the infrastructure to deliver a load shedding program. The steps that should be taken include the identification of candidate customers, the analysis of their loads, and discussions with them about their ability to respond to a call for load shedding and their interest in participating in a load shedding effort, and perhaps the installation of meters that would be used in a load shedding program. Any agreement with a customer would be contingent on Tacoma Power's need and therefore the financial incentive paid only when and if load was required to be shut down.

Chapter 1: Introduction

Chapter 1: Introduction

In the past Integrated Resource Planning efforts were generally expected to produce a portfolio of resources – demand- and supply-side – that yielded the least cost resource mix for a utility. These results were more or less fixed in time and expected to be useful for a matter of years. This Integrated Resource Plan (IRP) has a broader purpose. In addition to recommendations regarding acquisition of supply and conservation resources, this plan articulates a process for evaluating resources in an environment full of uncertainty and risk. The results are important, but the process and the tools are what will make this effort truly useful to Tacoma Power and its customers.

Section 1.1 Purpose of Integrated Resource Plan

Tacoma Power identified the following goals for the IRP:

- Anticipate the changing needs of our customers.
- Identify products and services that are responsive to the evolving market place.
- Design a resource strategy that is cost-effective, environmentally responsible, and flexible enough to meet customer demand in a range of plausible futures.
- Integrate the capabilities of the Click! Network into the design of products and services to meet customer demand.
- Maintain high standards for reliability.
- Carefully manage Tacoma Power's exposure to market risk.

The IRP provides an action plan designed to meet future customer needs for energy and capacity that evaluates a full range of alternatives for new generating capacity, power purchases, and energy conservation and efficiency.

Section 1.2 Planning Process

The analyses and assumptions needed for the IRP were developed and refined to accurately capture important characteristics of Tacoma Power's requirements and resource options. The process of developing this IRP included these tasks:

- Forecast future customer demand for energy.
- Determine adequacy of existing resource supply.
- Evaluate new supply and conservation options.
- Forecast future energy prices.
- Model resource choices under a range of demand and price cases.
- Articulate optimal resource strategy for Tacoma Power.

In order to adequately assess resource options staff developed several models that allowed detailed economic analysis. The models developed for this IRP include variables for capital and operating costs of different resources, alternative load forecasts and alternative price forecasts. The IRP also includes scenario analysis to examine non-quantifiable factors that influence resource decision-making.

Section 1.3

Issues and Uncertainties

The world that utilities must operate in has changed profoundly since Tacoma Power's last published Integrated Resource Plan in 1992. In less than 10 years wholesale electricity markets have evolved to allow competition among buyers and sellers. Electricity is now traded regularly for delivery an hour-ahead, a day-ahead or on the forward market for longer-term delivery at some specified future date. Participants in this trading arena include non-utility generating companies, power marketers that don't produce electricity but buy and sell it for others, and utilities that buy and sell to meet customer demand for electricity. As in all commodity markets, the prices paid for goods vary from day to day and hour to hour, allowing participants to make a profit by buying low and selling high.

The commoditization of electricity has had a profound impact on the utility industry. The price of electricity is no longer tied to its production cost. And the price can be extremely volatile. As demonstrated by market prices in 2000 and 2001 the range of this uncertainty is far greater than most market participants ever imagined. Wholesale price risk is now virtually unbounded and planning efforts must address market volatility to obtain resources that will provide low and stable rates for the long term. Price forecasting is an important element of integrated resource planning but it is much more difficult than ever before.

During the past decade government regulators and policy makers have moved steadily toward more competitive markets at the retail level as well. Some states have offered electricity customers a full choice of retail electricity suppliers. The deregulation of retail electricity markets has occurred one state at a time with considerable variation of market structures. Nowhere has this change to provide retail competition had a more profound impact than in California. A flawed market structure and a collision of other forces conspired to send electricity prices spiraling. Because the electricity transmission grid and wholesale market structure transcends state boundaries the problems experienced in California spread to the entire Western region. The resulting chaos may have slowed some state's electric market restructuring efforts. In spite of this, utilities can't know with certainty what retail market structures will prevail over a ten-year planning horizon.

Other risks that utilities must continue to manage are more familiar. Tacoma Power, as an owner of substantial hydroelectric resources, must be prepared for a range of water conditions. From year-to-year it is impossible to know exactly what the output of Tacoma's generating resources will be. The utility strives to be successful under the full range of hydro operating conditions. The past year has provided an unpleasant reminder of just how bad a "bad water year" can be. Water conditions can't be forecast but the range of possibilities must be considered in integrated resource planning efforts.

Utilities don't know with certainty what their loads will be on a daily basis or for years in the future. The IRP includes a load forecast that offers assumptions about levels of future customer demand for electricity. This is a planning tool that offers a framework for evaluating resource acquisitions rather than an exact measure of future utility loads.

One of the clear differences between this planning effort and the 1992 Least Cost Resource Plan is the scale and scope of uncertainty regarding basic planning assumptions about loads and prices. Each variable used to determine the best resource mix embodies a wide range of possible plausible outcomes.

- Electricity price forecasts are extremely difficult to bound because wholesale prices no longer correspond reliably to market fundamentals. The Western power market has demonstrated unprecedented volatility and shows obvious imperfections.
- Load forecasts are harder to make because of the possible arrival of new large loads such as data centers and conversely, large load losses because of high electricity prices and other economic factors. It is also hard to gauge and predict consumer response to higher rates and calls for voluntary conservation.
- Fuel price assumptions have never been straightforward but, here again, recent market trends demonstrate unusual volatility.
- Regulatory structures are subject to change. Legislation may impose price caps or other market changes. Retail access may yet become a reality.
- Distributed generation or a sudden shift in technological capability may unpredictably alter the way electricity is provided to customers.

Organization of this Plan

The remainder of this plan is divided into eight chapters.

Chapter 2 – Forecast of Customer Demand describes the results of Tacoma Power's load forecast and the uncertainties associated with estimates of future customer demand.

Chapter 3 – Energy Supply and Transmission Resources describes the existing portfolio of resources and transmission assets.

Chapter 4 – Forecast of Wholesale Market Prices describes price forecasting methods used for this Integrated Resource Plan and discusses uncertainties related to the wholesale electricity market.

Chapter 5 – Supply Options describes the range of supply resources available to Tacoma Power and screening criteria used to evaluate them.

Chapter 6 – Conservation and Load Management Options describes demand side resources available and results of screening and evaluation to determine the best options for Tacoma Power.

Chapter 7 – Environmental Considerations describes the environmental review of all resource options under consideration for this Integrated Resource Plan.

Chapter 8 – Planning Analyses describes the detailed analyses used to compare resources and determine the best options for Tacoma Power.

Chapter 9 – Recommendations outlines options for implementing the results of the Integrated Resource Plan and a process for further study and analysis of Tacoma Power's resource strategies.

Chapter 2: Forecast of Customer Demand

Chapter 2:
Forecast of Customer Demand

Section 2.1

Profile of Current Customer Base

Service Territory

Tacoma Power's service area consists of a 180 square mile area, including the City of Tacoma, University Place, Fife, Graham, Spanaway, portions of Lakewood, Fort Lewis, and McChord Air Force Base. Tacoma Power recently negotiated an agreement for the acquisition of the City of Fircrest's electrical system; the transfer of the system will occur prior to October 1, 2001. Several cooperative utility companies, a municipal utility, and the Puget Sound Energy Company serve the area which bounds Tacoma Power's service area.

Tacoma Power Customers

Tacoma Power served an average of 148,000 metered customers in 2000, 57% of whom reside within the City of Tacoma. The utility has five classes of customers: Contract Industrial; General Service, including other industrial, large commercial and military customers; Small Commercial; Residential; and Other (principally streetlights). The majority of our customers receive energy from Tacoma Power's portfolio of resources (described in Chapter 3). Our three largest industrial customers receive a combination of energy from our portfolio and from non-portfolio resources (i.e. market purchases).

Customer Base – 2000 Statistics

Customer Class	Number of Customers	Annual Retail Sales (MWh)
Residential (1)	132,693	1,840,902
Small Commercial	12,726	332,098
General Service (2)	2,097	1,941,235
Contract Industrial (3)	4	
Portfolio		304,684
Non-Portfolio		1,045,481
Other	323	33,942
Total	147,843	5,498,342

(1) City of Fircrest acquisition not included (approximately 2,300 accounts).
(2) Non-Contract industrial, large commercial and military.
(3) Includes Abitibi Consolidated Mill that ceased operation at the end of 2000.

Residential Customers. In 2000, Tacoma Power supplied electric energy to 132,693 residential customers with a total demand on the resource portfolio of 209.6 aMW (33.4% of total retail sales).

Small Commercial Customers. Small commercial customers, including retail, restaurants and other small businesses, consumed 37.8 aMW (6.0% of total retail sales) of portfolio resources in 2000. There were 12,726 commercial customers in 2000.

General Service Customers. Tacoma Power had 2,095 general service customers purchasing from its resource portfolio in 2000. Individual loads were as large as 4.0 aMW. These customers include industrial, large commercial, schools, and government facilities.

Tacoma Power serves two military bases as part of the General Service Customer class, the Fort Lewis Army Post and the McChord Air Force Base. In 2000, Fort Lewis Army Post used 24.7 aMW and McChord Air Force Base used 11.0 aMW of electrical energy, making them Tacoma Power's fourth and seventh largest retail customers, respectively.

Contract Industrial. In 1996, our largest industrial customers requested direct access to the wholesale power market. In response, Tacoma Power separated its customers into two types of loads: "Portfolio" and "Non-Portfolio." Portfolio customers are served from Tacoma Power's own generation assets and purchased-power contracts. In addition to purchasing some power (35 aMW) from Tacoma's portfolio, Non-Portfolio customers are provided access, through Tacoma Power, to third-party providers. The Non-Portfolio program currently covers three of Tacoma Power's largest industrial customers and accounted for approximately 119 aMW of load in 2000.

One of Tacoma Power's Non-Portfolio customers, Abitibi Consolidated, ceased to operate in Tacoma Power's service territory at the end of 2000. At that time the customer ended its Non-Portfolio purchases and Tacoma Power was able to reconfigure the existing transmission and distribution equipment to serve residual load at that site. Abitibi is attempting to sell the site to another operator.

Tacoma Power's contracts for Non-Portfolio Power Service expire on September 30, 2001. Tacoma Power and each of the three customers have agreed to negotiate new contracts to take affect October 1, 2001. The terms and conditions of those contracts are not yet finalized. However, Tacoma Power expects to be able to negotiate contracts that satisfy these customers' needs for at least the next five to ten years, which coincides with the term of the BPA power purchase contract.

Other Customers. Tacoma Power's other customers primarily consist of the City's street lighting and traffic signals, and private off-street lighting. In 2000, this class of customers totaled 323 and consumed 3.9 aMW of portfolio.

Section 2.2 Load Forecast Methodology

Forecast of Future Energy Sales

Forecasts of energy sales and peak demand provide the foundation for determining the resource additions that will be needed during the planning period. The forecast of total system load is the sum of the estimates of retail sales for each of the individual rate classes adjusted for losses across the distribution system (3.52% is added to the forecast to compensate).

The forecasts of energy sales for residential, small commercial, schools and general service loads were developed using econometric models. These models use statistical methods to relate energy sales to economic, demographic, and weather data. All forecasts assume average weather throughout the planning period.

For the military, the base engineers at Fort Lewis and McChord AFB provided the sales estimates to us. Net consumption for the military customers is expected to remain flat or increase very slightly because projected increases in troop population and changing mission requirements will be offset by an aggressive conservation program and the replacement of older facilities with new, more energy efficient facilities. [1]

Energy sales over the past few months show that Tacoma's rate surcharge along with its communications campaign encouraging conservation have impacted all classes of customer. The Base A, Low and High load forecasts reflect the recent drop in customer load. An alternate base case (Base B) prepared in late 2000, prior to the rate surcharge, treats this curtailment as a temporary aberration and assumes load will return to its previous level once the 'energy crisis' is over.

Table 2a shows the key assumptions used in these models for each of the two base load forecasts. In addition to the base load forecasts, a Low forecast was generated using the load growth from the Base A forecast and reducing it by 50%, and a High forecast was generated using the load growth from the Base A forecast and increasing it by 50%.

[1] Currently, Fort Lewis is considering privatization of its electrical distribution system. Tacoma Power worked with Fort Lewis in preparation for this process, and will be submitting a proposal for that acquisition. Logically, Fort Lewis may then also consider direct retail access to power supply markets and if that occurs Tacoma Power will then seek to satisfy the Fort's requirements. Presently there are no plans to privatize the electrical distribution systems on McChord Air Force Base.

For the Contract Industrial class, the Base A case forecast assumes sales of 90 aMW through September 2001, increasing to 130 aMW in October 2001 and then staying level for the balance of the planning horizon. The Base B forecast assumes a Contract Industrial load of 139 aMW in 2001, ramping up to 143 aMW in 2011.

All four forecasts include the results of all programmatic conservation efforts through 2000 and the continuing impact of efficiency standards for new construction.

Table 2a – Planning Assumptions

	Customer Growth	Inflation	Unemployment	Programmatic Conservation
Base A	1.20%	2.20%	5.20%	Savings from existing conservation but no new.
Base B	2.00%	2.80%	5.80%	Savings from existing conservation but no new.

Load Forecasts

For the Base A case forecast, load is expected to grow from an average of 609 aMW in the year 2002 to 669 aMW by the end of 2011, an increase of 60 aMW or 1% annually. For the Base B case, load grows about 1.2% annually. For the Low and High cases, the 10-year average annual growth rates are 0.7% and 3.6% respectively. Assuming continuing "price elasticity of demand" effects from higher retail rates, the Base A case is the most probable estimate of load growth in Tacoma Power's service territory.

Figure 2a – Load Forecast Without Programmatic Conservation

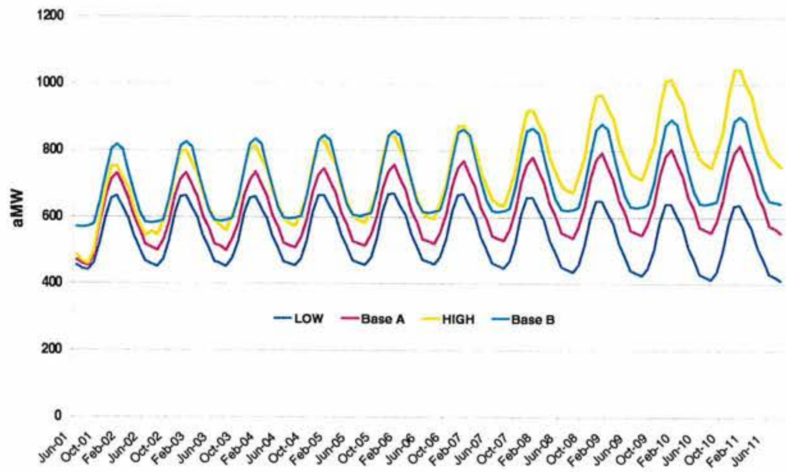


Table 2b – Load Forecast without Programmatic Conservation

Load Case	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Low	553	553	554	558	560	552	542	531	522	512
Base A	609	611	617	625	633	643	654	664	674	669
Base B	683	692	702	715	727	731	737	750	763	763
High	651	681	694	706	722	760	803	846	885	884

Peak Demand

Customer demand for energy must be examined not only from the perspective of average annual and monthly projections, but also on an hourly basis, because this is how the system is managed in real time. While we assume average weather for our long-range base load forecasts, we must be prepared to meet customer demand if we have extended cold weather during the winter. In a 24-hour period, demand typically fluctuates from 160 to 300 MW depending on the season and weather. On an average day, summer demand is usually about 250 MW less than demand in December and January.

The models that Tacoma Power uses to analyze supply and demand balances use load forecasts that are "shaped" hourly to simulate diurnal as well as seasonal variations in loads. This approach allows us to examine customer demand from two perspectives—total energy required and peak demand.

The flexibility inherent in hydro resources allows Tacoma Power to respond to the peaks and valleys in diurnal and seasonal load on both a planned and real-time basis, follow system loads on an instantaneous basis, and meet spinning and non-spinning reserve requirements. However, this flexibility is diminishing. More constraints are being placed on Tacoma's owned hydro resources through operating licenses and requirements for protection of endangered species. In addition, the new BPA contract must be taken as a flat block during off-peak hours and allows no real-time adjustment during on-peak hours. Finally, the expiration of the Priest Rapids contract means the loss of an important resource for load following and shaping.

Section 2.3 Uncertainties in Load Forecasts

One source of uncertainty in our forecast is the future load of our largest industrial customers. In 2000, retail energy sales to the four contract power (CP) industrial customers accounted for 25% of total energy sales. Forecasting electrical demand for the industrial sector is difficult, especially for the CP customers. These firms have production facilities located in several areas and compete in international markets. Since early 2001, Abitibi has closed down and Pioneer has reduced its load by approximately 50%.[2] Decisions by these companies about their Tacoma facilities can result in abrupt changes to our loads.

Another area of uncertainty is the future level of demand for direct market access from our larger customers. We believe the technical expertise and risk entailed in "Non-Portfolio" service may have limited the interest in direct market access for the near future. While Tacoma Power's present rate levels are competitive with available market prices, we intend to examine our current service offerings to make sure we are responsive to future needs of our larger customers.

Finally, there is a significant level of uncertainty related to the phenomenon of "price elasticity of demand." Customers use less of our product – electricity – when the price goes up. In response to our recent rate surcharge of 50%, as well as our public requests for conservation, we have seen a 12% drop in consumption since January 2000. It is difficult to predict how our customers' patterns of use may change after the energy crisis is over and they adjust to a higher priced electricity market.

[2] Pioneer Companies, Inc. issued a press release on March 7, 2001 announcing a 50% curtailment of operations at its Tacoma facility.

Chapter 3:
Energy Supply and Transmission Resources

Chapter 3:
Energy Supply and Transmission Resources

The majority of Tacoma Power's present power requirements are supplied from generating facilities owned by the utility, purchases from BPA, and through long-term contractual arrangements. Tacoma also relies on short and medium-term contracts for power from a variety of wholesale suppliers.

Section 3.1 Water Conditions and Project Output

Tacoma Power's Owned Resources

Tacoma Power owns four hydroelectric generation projects – Nisqually, Cowlitz, Cushman, and Wynoochee. Table 3a shows a summary of the expected output of the first three of these resources under different water conditions. These projections are based on 72 years of recorded data. The extreme low water conditions are represented by 'critical water'. Critical water conditions are defined as the lowest annual inflows during a twelve-month period. Operating year 1941 (August 1940 to July 1941) represents the critical water period for Tacoma Power's system. Adverse water conditions are defined as the annual inflows that are exceeded 75% of the time. Average water conditions represent the historic mean monthly inflows. Good water conditions represent the annual inflows that are exceeded 25% of the time.

Due to the range in available energy supply depending on the water conditions, analyses done for this IRP have included a range of assumptions to encompass the risk of lower than expected precipitation.

Table 3a
Generation Under Different Water Conditions in aMW

	Critical	Adverse	Average	Good
January	216	260	319	392
February	194	262	325	337
March	144	235	292	324
April	147	236	298	332
May	152	256	313	354
June	155	274	323	336
July	139	233	277	298
August	164	182	194	210
September	157	246	299	360
October	228	337	396	434
November	218	311	353	374
December	208	277	338	370
Average	**177**	**259**	**310**	**343**

Cowlitz Project

Tacoma Power's largest hydroelectric project, the Cowlitz Project, consists of two coordinated hydroelectric plants, Mayfield and Mossyrock, both located on the Cowlitz River in Lewis County. The Mossyrock powerhouse contains two generating units, each rated at 150 MW, resulting in a total nameplate rating of 300 MW. The Mayfield powerhouse contains four generating units, each rated at 40.5 MW, resulting in a total nameplate rating of 162 MW. Both plants are operated by Tacoma Power under the terms of a single FERC license, which expires on December 31, 2001. A comprehensive Settlement Agreement for a new license was signed in August 2000, and is expected to be adopted by FERC.

Both of the generating units at Mossyrock (Units 51 and 52) are beyond their design life and will need to be rebuilt sometime during the time horizon for this plan. The construction time would be about 9 months per unit. Alternatively, a third generating unit could be built to replace one of these two units. The advantage of building a third unit would be that any of the units could be taken out of service for maintenance without diminishing the firm generation capability of the plant.

Cushman Project

The Cushman Project consists of two separate concrete arch dams located on the North Fork of the Skokomish River in Mason County. Cushman No.1 has two generating units, each rated at 21.6 MW, with a total installed generating capacity of 43.2 MW. Cushman No. 2 has three generating units; each rated at 27 MW, resulting in a total installed nameplate rating of 81 MW. Both dams are operated under one license issued by FERC.

Under the Federal Power Act, the FERC is required to issue a "reasonable" license, or to commence project termination, which includes paying the licensee the value of the project. The terms of the new 40-year license issued by FERC on July 30, 1998 are prohibitively costly and are being appealed by Tacoma Power. For modeling purposes, we assumed minimum flows of 60cfs through 12/31/05, and 100 cfs thereafter.

Nisqually Project

The Nisqually Project consists of two separate hydroelectric plants, Alder and LaGrande, located on the Nisqually River on the western slope of the Cascade Mountains. The Alder plant has two generating units, each rated at 25 MW, with a total installed nameplate rating of 50 MW. The LaGrande plant has five generating units, one unit rated at 40 MW and four units each rated at 6 MW, with a total nameplate rating of 64 MW. The original license for the Nisqually Project was issued by the FERC on November 27, 1944. On March 7, 1997, Tacoma received a new 40-year license from FERC.

Wynoochee Project

The Wynoochee Project is located on the Wynoochee River in Grays Harbor County, on the Olympic Peninsula. The Wynoochee Project has one generating unit with a nameplate capacity of 12.8 MW. The project's generation is transmitted to Bonneville's grid over Grays Harbor County Public Utility District No.1's transmission system under a contractual arrangement. Currently, the Wynoochee Project is owned and operated by the cities of Tacoma and Aberdeen as co-licensees. In 1995, the cities entered into an agreement to transfer Aberdeen's rights, title and interest in the Wynoochee Project to Tacoma in consideration of Tacoma relieving Aberdeen of its ongoing operations and maintenance responsibility.

Diesel Generation Project

In response to recent market conditions, Tacoma Power installed thirty 1.64 MW diesel generators at Northeast Substation. The generators were operated as a base load facility, turning out approximately 48 aMW at an availability factor of approximately 97%. The recent drop in market prices has resulted in a decision to terminate the lease and return the generators since they are no longer cheaper than power purchased on the spot market.

Tacoma Power also purchased an additional thirteen generator units. The utility is looking for a buyer for these units.

Section 3.2 Power Supply Contracts and Exchanges

Bonneville Power Administration

Current Contract Tacoma Power executed a long-term power sales contract with Bonneville in 1981 and Amendatory Agreement No. 7 in 1996. Under the amended contract, Tacoma Power committed to purchasing 78 aMW from Bonneville on an annual basis for the remainder of the contract period. This contract expires on September 30, 2001. The contract provides limited flexibility through the ability to move deliveries around within the month, and across hours in the day. Greater amounts of energy are delivered in the winter months. In addition, Tacoma Power has the ability to displace portions of the contractual amounts for a nominal fee. The current charges for power are under the Priority Firm Rate (PF-96) at approximately $22.50/MWh on an annual basis.

New Contract Beginning October 1, 2001, Tacoma Power will purchase firm power from BPA under a new power sales contract. This 10-year contract, referred to as the Priority Firm Power Block Power Sales Agreement, supplies Tacoma Power with firm power to serve its retail load. The quantity supplied is termed Tacoma's "net requirement" and was determined by subtracting Tacoma's monthly forecasted demand under heavy load hours (HLH) and light load hours (LLH) from its resource capabilities under critical water conditions. The quantity of power to be purchased over the contract term begins at 385 aMW in the first year, and increases over the first five years to 429 aMW. Each year of the contract, BPA and Tacoma Power will review Tacoma's net power requirement to determine if an adjustment is necessary. The quantities of power to be supplied during the second half of the contract will be subject to future negotiations.[1]

The new contract provides some flexibility. Key elements of the contract include:

- Firm system power backed by the Federal system.
- Monthly HLH/LLH shapes for 10 years based on net power requirement.
- Ability to shape the energy other than flat over the HLH periods.
- Load growth for the first five years; load growth to be negotiated in 2006 for the remaining 5 contract years.
- Lower rate in the first 3 years, higher in second 2 years.
- Rate for the last 5 years will be determined in the 2006 rate case.

In May of 2000, the Bonneville Power Administration (BPA) released its final Record of Decision on the 2002 Power Rate Case. The 2002 Power Rate Case set rates for the purchase of BPA wholesale power for the period of October 1, 2001 through September 30, 2006.

BPA's new rate is designed to build and maintain financial reserves sufficient for the agency to achieve an 88% probability of making all five U.S. Treasury payments in full and on time over the five-year period. (BPA uses the term Treasury Payment Probability or TPP). Even with this design, BPA continues to face a high degree of financial uncertainty, due to volatile market conditions and fish costs.

To lessen the risk of missing a Treasury payment, BPA has employed a mechanism, implemented through its contracts, that adjusts the rate upward to the extent necessary to maintain an 88% TPP. Termed a Cost Recovery Adjustment Clause (CRAC), the CRAC is an automatic temporary upward adjustment to posted power prices.

In August 2000, BPA issued a letter to customers warning them that changed market conditions – large increases in wholesale electricity prices – and increased demand for subscription power would make it difficult for the agency to achieve the agreed upon TPP of 88%. As a result, BPA stopped signing new subscription contracts and requested comments about what it should do about the potential revenue shortfall. BPA decided that they would maintain the present five-year rates included in the May Record of Decision (ROD) but adjust the Cost Recovery Adjustment Clause (CRAC) to make it possible for BPA to

[1] For modeling purposes, we assumed that the quantity of BPA remains at 429 aMW for the remaining five years of the contract.

collect additional revenue that might be necessary to maintain their desired TPP of 88%. This was called a "mini 7(i) process" or "mini rate case".

The mini rate case leaves the posted rates for the new contract period intact but will restructure the CRAC to allow it to raise the Maximum Planned Recovery Amount. This will increase the effective cost of subscription power purchased from BPA above the original estimates.

The final outcome of the mini rate case was to divide the CRAC into three distinct CRACs. The new CRACs are as follows:

Load Based CRAC (LB CRAC) – A CRAC used to recover the increased costs of power purchased to augment the BPA portfolio, in order to serve BPA's requirements load. This CRAC is adjusted every 6 months, with a provision for a rate rebate should BPA over-collect.

Financial Based CRAC (FB CRAC) – A CRAC based on the original CRAC mechanism that is tied to the health of BPA's financial reserves (accumulated net revenues). This CRAC is a temporary upward adjustment of the rates, and applies for one fiscal year. The FB CRAC will be trued-up each January to reconcile the estimated recovery amounts with actual recovery amounts.

Safety-Net CRAC (SN CRAC) – A CRAC that triggers if BPA expects to miss a Treasury payment. This CRAC is intended to be a last resort mechanism, and is intended to be used at the sole discretion of the BPA Administrator.

BPA released its first LB CRAC on June 29, 2001. It increases BPA rates by 46.2%. The following table estimates Tacoma Power's BPA power purchase costs for the first seven years of the contract.

Table 3b
Power Purchase Costs Based on Contract Quantities

Period	Power Cost	Rate ($/MWh)
Oct. - Dec. 2001	$ 26,837,587.00	$33.52
Contract Year 02	$ 101,922,509.00	$30.13
Contract Year 03	$ 103,030,927.00	$30.15
Contract Year 04	$ 103,529,956.00	$29.70
Contract Year 05	$ 100,097,699.00	$28.19
Contract Year 06	$ 98,270,064.00	$26.58
Contract Year 07	$ 99,235,518.00	$26.44

Priest Rapids Hydroelectric Project

Tacoma Power has contracted on a take-or-pay basis for 8% of the production of the Priest Rapids development of the Priest Rapids Hydroelectric Project, which is owned and operated by Grant County PUD No. 2. This agreement is effective through October 31, 2005, the same year the project's FERC license expires. Tacoma Power is obligated to pay its share of the power related costs of the facility whether or not it receives any power. Between 1995 and 2000, Tacoma received an annual average of 395,519 MWh from Priest Rapids.

Tacoma Power is in the process of negotiating a follow-on contract to the current Priest Rapids contract. Although the new contract is still with Grant County for Priest Rapids output, it differs substantially from the previous contract. Until such time as negotiations are finalized, the terms of the contract are uncertain. For modeling purposes, we assumed that this contract expires on 10/31/05 and is not renewed.

Canadian Entitlement Obligation

Because Tacoma Power is a participant in the Priest Rapids project, we also have a Canadian Entitlement obligation. Each project that is downstream of the three Canadian storage projects created by the Columbia River Treaty has an obligation to deliver energy for the Canadian entity. Pursuant to the Treaty, the amounts of Canadian Entitlement capacity and energy are determined six years in advance. Grant PUD and Bonneville have executed an agreement to cover the continued delivery of the Canadian Entitlement. The energy is scheduled flat on the heavy load hours, Monday through Saturday. This arrangement will be effective through the end of the Treaty, for which the earliest termination is 2024.

Columbia Storage Power Exchange (CSPE)

Tacoma Power is one of 41 public and private utilities that, together with the Bonneville Power Administration (BPA), have entered into exchange agreements with the Columbia Storage Power Exchange (CSPE), a non-profit corporation. CSPE has purchased and resold Canada's share of the downstream power benefits that resulted from the development of water storage projects in Canada pursuant to a treaty entered into in 1964 between the United States and Canada. The exchange agreements provide for the transfer and assignment of 12.5% of the downstream power benefits to Tacoma Power and in turn, the transfer and assignment of this power to Bonneville. In return we are entitled to specified amounts of capacity and energy from Bonneville. CSPE output available to us will decrease each year and become zero on April 1, 2003. Tacoma Power received 108,379 MWh of energy from CSPE during 2000.

Grand Coulee Project Hydroelectric Authority

The cities of Tacoma and Seattle have entered into take-or-pay power purchase agreements with three Columbia Basin Irrigation Districts (South, East and Quincy) for the acquisition of the output of five low-head hydroelectric projects that were constructed along irrigation canals in eastern Washington. The California Energy Commission has certified four of the five projects as renewable small hydro resources for the purposes of marketing green power. Tacoma Power has five separate power purchase agreements for the output of these projects, each one lasting 40 years. The contracts were negotiated between 1982 and 1986 and have corresponding expiration dates between 2022 and 2026. These projects are operated by the Grand Coulee Project Hydroelectric Authority (GCPHA) and utilize water released during the irrigation season (generally from late March until mid-October). The total nameplate capacity of all five projects is approximately 130 MW, with an average annual energy production of approximately 450,000 MWh. Tacoma receives 50% of the projects' actual output, which is approximately 225,000 MWh each year.

Exchange with Seattle City Light

An exchange agreement between Tacoma Power and Seattle City Light was executed in January 1992; it expires on October 31, 2003. The agreement specifies amounts of firm energy to be exchanged between the two systems during August and October each year. The exchange is for 37,250 MWh shaped uniformly throughout all hours of the respective months. This exchange provides energy to Tacoma Power in October that is then used to meet system-wide requirements and obligates Tacoma to return like quantities to Seattle in August. It is unlikely that Tacoma will elect to renew this agreement. For modeling purposes, we assumed that this exchange contract is not renewed.

Minnesota Methane

Tacoma Power purchases approximately 15,300 MWh a year from a landfill gas project developed by the Minnesota Methane Limited Liability Corporation (MMLLC). The contract sets a fixed power purchase price of $16/MWh. The City of Tacoma's Public Works Department manages the host site and gas field that is located at the Tacoma Landfill. MMLLC operates two 1 MW generators located at the site. The five-year contract expires in 2003. The contract may be renewed for a second five-year term by mutual agreement. However, as a result of lower than expected methane gas production, output from the plant has steadily dwindled, greatly reducing the reliability and value of the project. For modeling purposes, we assumed that this contract expires on 12/31/03 and is not renewed.

Green Power Program

For the past year, Tacoma Power has provided its customers with a green power choice by way of its Evergreen Options program. The power supply for the program (currently 1 megawatt) is purchased from the Bonneville Power Administration under its Environmentally Preferred Power Program (EPP). The wholesale cost of the power is approximately 35.75 mills/kWh, which is 12.75 mills/kWh above the BPA Priority Firm Power rate (about 23 mills/kWh) (under the existing BPA contract). Power is supplied from a host of environmentally preferred resources, including wind, geothermal, and hydroelectric.

Bonneville Exchange

Tacoma Power and Bonneville have an exchange agreement. The agreement calls for Bonneville to deliver to Tacoma Power 100 MW on every hour from January 1, 2001, through June 30, 2001, and 50 MW on every hour from July 1, 2001, through September 30, 2001. In return, Tacoma Power will deliver to Bonneville 35 MW on every hour from January 1 through September 30 of each year 2002 through 2006. For modeling purposes, we assumed that this contract expires on 9/30/06 and is not renewed.

Goldendale Exchange

Tacoma Power and Goldendale Aluminum Company have an exchange agreement. During January 2001, Goldendale delivered 29,160 MWh to Tacoma Power. In return, Tacoma Power will deliver 7 MW on every hour from January 1, 2002 through December 31, 2002.

Chelan PUD Exchange

Tacoma Power and Chelan PUD have an exchange agreement. During May 2001, Chelan PUD delivered to Tacoma Power 15 MW on every heavy load hour. In return, Tacoma Power will deliver energy of equal dollar value during May and June of 2002.

Section 3.3 Operating Reserves

Tacoma Power is a control area and subject to the policies of the North American Electric Reliability Council, the Western Systems Coordinating Council, and the Northwest Power Pool. The policies require all control areas to maintain operating reserves. Operating reserves require the system to operate its control area resources such that the most severe single contingency will not cause the interconnection to collapse. Each control area, or reserve sharing group, must provide for contingency reserve equal to a minimum of either its most severe single contingency or 5% of its on-line hydro generation plus 7% of its on-line thermal generation. A regulating margin for load following and any interruptible imports are added to the contingency reserves for the total operating reserve requirement. Half of the contingency reserve and all of the regulating reserve must be spinning reserve. The remainder may be non-spinning reserve, which must be capable of being brought on-line in 10 minutes. Interruptible load or interruptible exports can meet the non-spinning requirement. The result is that generation levels must account for the meeting of the operating reserve requirement at all times.

Section 3.4 Short-Term Purchases and Sales

Historically, buying power from the wholesale energy market increases the flexibility of city-owned resources, has the potential to provide lower costs for all Tacoma Power's customers, and allows us to provide customers with market-based and market-priced products. Recent events have demonstrated that trading on the wholesale market is not without risk. One of the key issues to be addressed in this plan is the extent to which we rely on the market to serve load.

In 2000, Tacoma Power sold 227,965 MWh into the wholesale energy market, while purchasing 729,054 MWh. The utility also purchased

1,322,934 MWh on behalf of Non-Portfolio customers. Tacoma Power uses the market to optimize the value of the output of its hydroelectric resources. By purchasing energy during off-peak hours, when prices are relatively low, Tacoma Power can "store" energy at its hydroelectric facilities for release during more expensive on-peak hours. In a wet year, Tacoma Power is primarily a net seller in the wholesale market. Conversely, in a critical water year, Tacoma Power is a net buyer.

Section 3.5 Transmission Resources and Issues

Tacoma's owned transmission lines along with its long-term contracts for transmission allow for the movement of power from its generation source to our service territory. Planning to assure that we have adequate capacity on our transmission system as well as access to the regional transmission system is essential to ensure reliable electrical service. Changes in federal laws and regulations have had a significant impact on the operation of the region's transmission system in recent years.

Owned Transmission Facilities

Tacoma Power owns, operates, and maintains 44 circuit miles of high voltage (230 kV) facilities and 314 circuit miles of sub-transmission (110 kV) facilities which are used to integrate generation, serve retail loads, and provide wholesale transfer service.

Transmission facilities used to integrate power from Tacoma Power generating projects include:

- 18 miles of 230kV transmission integrate Tacoma Power's Mayfield and Mossyrock hydroelectric generation on the Cowlitz River Project into the Bonneville Power Administration's transmission grid. Tacoma Power takes delivery of this power at its Cowlitz and Northeast Substations.
- 43 Miles of double circuit (86 circuit miles) 110 kV sub-transmission facilities, know as the Potlatch lines, integrate Tacoma Power's hydroelectric generation at the Cushman Project into Tacoma Power's 110 kV sub-transmission system.
- 28 miles of double circuit (56 circuit miles) 110 kV sub-transmission facilities, known as the LaGrande lines, integrate Tacoma Power's Alder and LaGrande hydroelectric generation at the Nisqually River Project into Tacoma Power's 110 kV sub-transmission system

Tacoma Power owns and maintains 181 circuit miles of transmission facilities including 13 miles of double circuit (26 circuit miles) 230 kV transmission and 172 miles of single circuit 110 kV sub-transmission that are primarily used to serve Tacoma Power retail loads.

Tacoma Power uses portions of its 110 kV and 230 kV electrical system to provide wholesale transfer service to 10 publicly owned Pierce County utilities and also to the Lewis County Public Utility District. Tacoma Power has provided some of this service for over twenty-five years. Transfer service began in 1974 when Tacoma Power provided access to the Bonneville Power Administration (BPA) for the benefit of its customers. In 1993, Tacoma Power and Lewis County Public Utility District executed an agreement to transfer power generated by the Cowlitz Falls Hydroelectric Project across our system. Finally, in 1996 Tacoma Power provided access to the Peninsula Power and Light Company for its non-BPA power purchases.

In 2000, Tacoma Power reaffirmed its policy to provide non-discriminatory access to its high-voltage system through adoption by the Tacoma Public Utility Board of a new interconnection agreement and transfer tariff. These agreements are progressive and they are aligned with industry and FERC standards.[2]

Capacity Issues

Currently, Tacoma Power has sufficient transmission capacity (lines and points of interconnection with neighboring systems) to serve both its retail and wholesale customers in a reliable manner. However, Tacoma Power believes capacity constraints will occur on both the LaGrande and Potlatch lines due primarily to load growth. The recent influx of Independent Power Producer (IPP) generation integration requests complicates the capacity availability issue.

The LaGrande lines were originally constructed to transmit power from the Nisqually Project to Tacoma. In addition to their original function, these lines now also support wholesale power transfers, enabling BPA to serve five of its customers, Parkland Light and Water, Elmhurst Mutual Power and Light, Ohop Mutual Light Company, Alder Mutual Light Company, and the Town of Eatonville. The existing LaGrande lines are 58 years old; they were rebuilt in 1943 to replace wood pole lines.

Over the last ten years, rapid growth has occurred in south Pierce County affecting primarily Tacoma Power, Parkland Light and Water, and Elmhurst Mutual Power and Light. New substations were constructed and connected to the LaGrande lines to serve this load. The LaGrande lines are currently near their capacity limit; in fact it would be difficult for Tacoma Power to serve addition of significant industrial load in the Frederickson area of its service territory. Further, under certain planning scenarios, loss of one line could over-load the other.

As a result, Tacoma Power's February 2000 Transmission & Distribution Six-Year Plan (T&D Plan), recommends construction of both a new switching station and approximately ten miles of 110 kV line between Cowlitz substation and the new switching station. Under the T&D Plan the pre-construction phase would occur 2001-2003 with the construction phase to span 2003-2006. This schedule would need to be

---

[2] In first quarter 2001, seven Independent Power Producers (IPP) approached Tacoma Power with interconnection requests. Four IPP's, with a cumulative generation capacity of over 1000 MW, have executed study agreements, and the system analysis process has begun. This dramatic increase in interconnection requests is fueled by the energy crisis on the West Coast and the existence of favorable infrastructure within Tacoma and Pierce County (e.g. natural gas, power lines, water, and raw land).

accelerated should any significant amount of load or generation interconnect with Tacoma Power in the Frederickson area.

The Potlatch Lines were originally built over 75 years ago to transmit power from the Cushman Project (Cushman #1 and #2 hydroelectric generating projects) to Tacoma. As with the LaGrande lines, the Potlatch lines not only transmit Cushman generation, but also support wholesale power transfers, enabling BPA to serve its customer, the Peninsula Light Company (PenLight).

While the Potlatch lines have been significantly rebuilt over the last ten years, the Narrows Crossing towers and conductors are original. Due to deterioration and age, additional study of the Narrows towers is warranted. The conductors were analyzed in 1999 and determined adequate for existing transmission requirements. However, BPA has forecasted PenLight's load growth to exceed line capacity by 2006 for an average winter. As a result, the T&D Plan recommends a rebuild of the Tacoma Narrows Crossing, with the pre-construction phase scheduled for 2003-2004, and construction scheduled for 2005-2007.

Long-term Transmission Agreements

Third AC Intertie Capacity. The Third AC Intertie is an expansion of the existing California-Oregon Intertie, and links the Northwest with the Southwest. Access to California over the Third AC Intertie provides Tacoma Power opportunities to maximize the value of its existing resources through power sales into the higher-value California bulk power market. In 1994, Tacoma Power entered into a long-term capacity ownership agreement with Bonneville to purchase 41 MWs of transmission on Bonneville's Third AC Intertie. This capacity is supplemented in September, October and November with an additional 33 MWs of capacity purchased under a long-term transmission contract with Bonneville.

Formula Power Transmission (FPT) Tacoma Power has one Formula Power Transmission Contract with Bonneville to move power across the Bonneville transmission system from Priest Rapids to Tacoma's system. The contract is uni-directional and provides Tacoma Power access from the Mid-C market. Its capacity is 71 MWs.

Point-to-Point Transmission (PTP) Tacoma Power has one Point-to-Point Transmission Contract with Bonneville. The contract includes paths to move energy from the Grand Coulee Project Hydroelectric Authority and the Wynoochee generation projects to Tacoma Power's system, and from Tacoma Power's system to John Day. The total transmission demand under the contract is 121 MW year round. We anticipate increasing the transmission demand for the new Bonneville power contract starting October 1, 2001. During periods when the contracted transmission capacity is not fully utilized due to reduced generation levels at the projects, this excess capacity can be reassigned to move power to and from other points of integration and delivery on the Bonneville system or sold on the secondary market. In addition, other short term purchases of transmission capacity from Bonneville are available under the contract.

Cowlitz Exchange In 1966, Tacoma Power entered into a long-term exchange agreement with Bonneville. The contract specifies Tacoma delivers the output of the Cowlitz Project to Bonneville, and in return, that Bonneville must make available an equivalent transmission loss-adjusted amount of power at Tacoma Power's Cowlitz Substation. The rate for the exchange services is based on Tacoma Power's avoided transmission construction costs. Payments to Bonneville are fixed through December 2001, at which time the City has the option to extend this agreement for 20 years followed by an option to extend the contract for an additional 30 years. Tacoma Power plans to renew this contract for another 20 years.

National & Regional Issues

Over the last nine years a number of significant initiatives that affect transmission facilities, operations, and service have occurred on both the national and regional level. These initiatives have or will affect the utility's operations because: (1) Tacoma Power is a system operator/control area and it owns assets over which wholesale transfer transactions occur; and (2) Tacoma Power uses the regional transmission network to deliver and receive the majority of its power. As such, Tacoma Power has tracked and/or participated in these initiatives.

National Issues

Congress and FERC have taken three major steps designed to establish the foundation necessary for competitive bulk power markets and to bring more efficient, lower cost power to the nation's electricity consumers. The Energy Policy Act of 1992, FERC Orders 888 and 889, and FERC Order 2000 address open access to the nation's transmission system and the construction of new generation.

The first step was the enactment of the Energy Policy Act of 1992 (the Energy Policy Act). This Act encouraged new generation and expanded the regulatory authority of FERC over wholesale transmission service.

FERC Order Numbers 888 and 889 established procedures for offering transmission services in a non-discriminatory manner and established rules for the recovery of stranded costs. Order 888 required utilities under FERC jurisdiction to develop and file Open Access Transmission Tariffs (OATTs). It also required utilities to unbundle wholesale services – power supply, transmission, distribution, and ancillary services. With limited exceptions, FERC required utilities to offer to provide ancillary services under terms and conditions specified in their

OATT. Order 889 set guidelines for standards of conduct and for the provision of equal access to data for all parties.

Order Numbers 888 and 889 stopped short of ordering the development of regional transmission organizations although FERC clearly favored their formation. However these orders spurred attempts – successful and unsuccessful – to form such organizations and led to the third major step, FERC Order Number 2000.

In December 1999, FERC approved Order No. 2000, which governs the development and implementation of regional transmission organizations (RTO). An RTO is an umbrella organization that will put under common control all public utility transmission facilities in a region. While RTO formation is voluntary under Order 2000, FERC asserts authority to mandate RTO participation to remedy undue discrimination, to address market power, or as a condition of merger approval.

Order 2000 requires all FERC-jurisdictional public utilities that own, operate, or control interstate transmission to file by October 15, 2000, either a proposal for an RTO or explain why it has opted not to participate in an RTO. Order 2000 requires RTOs to be operational by December 15, 2001 while existing, FERC-approved, regional entities must make compliance filings by January 15, 2001.

Regional Issues

Since 1992 Northwest utilities have made four significant efforts to coordinate and/or unify regional transmission entities, much of which is in response to national initiatives. These efforts are discussed below.

Northwest Regional Transmission Association The Northwest's first effort to coordinate regional transmission was the formation of the Northwest Regional Transmission Association (NRTA). The NRTA was one of three regional transmission organizations formed in the early 1990s in the western interconnected region (the others being the Southwest Regional Transmission Association (SWRTA) and the Western Regional Transmission Association (WRTA)). NRTA originally had three main objectives:

- promote open access;
- facilitate coordination of regional transmission planning; and,
- facilitate development of a regional transmission tariff.

NRTA added a fourth objective after a year of operation – promotion of a set of neutral commercial practices for the transmission system, independent of the other functions of the utilities owning the system.

NRTA is composed of transmitting utilities in the U.S. and Canada, transmission users in the U.S. and Canada, and Northwest regulatory commissions. Tacoma Power was a founding member of NRTA, and continues to be a member to this date.

NRTA is at a crossroads. To enhance coordination, SWRTA and WRTA are merging with the Western System Coordinating Council (WSCC) into one organization called the Western Electric Coordinating Council (WECC). NRTA has yet to join this merger effort due to the unique Northwest perspective on transmission access issues, and may remain independent, operating in its current or an altered form.

Western Electric Coordinating Council An ongoing effort in the western interconnection system is the merger of the WSCC, WRTA and SWRTA into a single organization, the WECC. The fundamental mission of the WECC is to maintain a reliable electric power system that will support efficient competitive power markets within the western interconnection, and to provide a forum for resolving transmission access disputes that may arise between members.

With industry in the midst of a gradual evolution toward centralized regional coordination under RTOs, regional discussion focused on how best to create a region-wide coordinating council that would effectively integrate existing organizations, yet complement the efforts of RTOs and North American Electric Reliability Council (NERC) and its probable successor, the North American Electric Reliability Organization (NAERO). The participants ultimately decided to combine WSCC, WRTA and SWRTA into a single new organization. Thus, the WECC will perform many of the same functions as its predecessor organizations, offering, however, a superior governance structure and significant improvements in efficiency.

Independent Grid Operator Between 1996 and 1998 twenty-one utilities undertook an extensive effort to develop an Independent Grid Operator (IGO) called IndeGO. IndeGO was to be a nonprofit, independent operator of the aggregated transmission systems of the 21 participants, including Tacoma Power. IndeGO's region included Washington, Oregon, Idaho, and parts of Montana, Wyoming, Utah, Colorado, Nevada and Nebraska.

IndeGO's main objective was to be a common carrier electric transmission system operator, independent of the energy sales and power production aspects of the participating owners. IndeGO's goals were to ensure comparable transmission access to all grid customers, promote economically efficient use and expansion of the IGO grid, and avoid "pancaked transmission charges" wherein a transmission customer must pay charges to several utilities as it wheels power from source to sink.

While the IndeGO proposal was never submitted to the FERC for approval, FERC was supportive of the effort to form an IGO. The IndeGO effort ultimately ended when it became apparent that the pricing proposals would result in cost shifting between utilities.

Tacoma Power and the other participants invested significant amounts of staff time and resources, the results of which have formed the basis for much of the RTO West effort that followed.

RTO West In March 2000, in response to FERC Order 2000, eight utilities initiated RTO West, a broad Regional Transmission Organization (RTO) that will span eight Western states. The eight "Filing Utilities" are Avista Corporation, Bonneville Power Administration, Idaho Power Company, Montana Power Company, Nevada Power Company, PacifiCorp, Portland General Electric, Puget Sound Energy, Inc., and Sierra Pacific Power Company.

RTO West is an on-going collaborative process to develop an RTO for the Pacific Northwest that meets or exceeds Order 2000's minimum requirements, while meeting the needs of the Filing Utilities, their consumers, and other interested parties.

On April 25, 2001, FERC predominately approved Stage 1, wherein the Filing Utilities asked for a declaratory order on the governance, scope and configuration, and an agreement limiting liability. The Stage 2 filing will contain more detailed information, to be filed fourth quarter 2001.

To date, work on RTO West has not progressed in sufficient detail to enable Tacoma Power to determine the impact and/or benefit of RTO West on Tacoma Power rate-payers. As such, Tacoma Power continues to track RTO West.

Chapter 4: Forecast of Wholesale Market Prices

Chapter 4:
Forecast of Wholesale Market Prices

Strategic planning requires identification and clear understanding of future consequences of decisions made or not made today. For Tacoma Power, a primary factor that underlies many of its strategic decisions is the wholesale market price of electricity. Analysis of power supply and conservation alternatives requires accurate information and a defensible depiction of future power markets. Accuracy in forecasting is a challenge that rewards the analytic effort with higher quality decisions, and reduced risk to the utility and its customers. In this chapter of the IRP, the wholesale market price forecast is presented with a discussion of the evolution of the market, key considerations, forecasting methodology, and factors that impact future power market prices.

Section 4.1

Forecast Methodology

We have used two methods to prepare price forecasts for this IRP. One method uses the latest version of the Aurora model, a commercially available model used throughout the Northwest region by BPA and others to forecast long-run electricity prices for the West Coast. In addition, we developed our own marginal supply model to develop a separate price forecast based on the costs of building and operating a large combined cycle combustion turbine.

Aurora Model

Aurora is a "fundamentals model", which means that it attempts to model the fundamental structure of the West Coast power market and the relationships of supply and demand that impact prices. This model requires management of a large number of inputs. Some of the most influential inputs, such as the forecast of natural gas prices, must be obtained from various sources and then carefully scrutinized to assure forecast validity. All inputs to this model require internal consistency on specific assumptions about the nature of future electricity market conditions.

Marginal Supply Model

As a check of Aurora based forecasts, Tacoma Power developed another forecast using marginal supply assumptions for the conversion of natural gas into electricity. This model assumes that a 500 MW combined cycle combustion turbine using the best available technology will be the marginal supply resource for the next decade. High, low, and base price forecasts were derived from the costs of operating this resource under various assumptions for gas prices and returns on capital investment. The base case assumes \$3/MMBtu gas and 12% return on equity; the high case assumes \$5/MMBtu gas and 18% return on equity; and the low case assumes \$3/MMBtu gas and no return on equity.

Forward Electricity Prices

Both Aurora and the marginal supply model exhibit weaknesses in forecasting near-term prices. Therefore, we have used forward market prices for the first two years of the price forecast. Forward market prices also have limitations. Forward markets for electricity tend to be thinly traded and therefore not representative of a liquid market. In less volatile markets, forward prices do tend to be a better predictor of prices than a fundamentals model, but as we have seen in the last few months, they fall very short on accuracy when markets are disrupted. Tacoma Power obtains forward price information from published sources, broker quotes, and information gathered from market participants.

Hourly Shaping of Price Forecasts

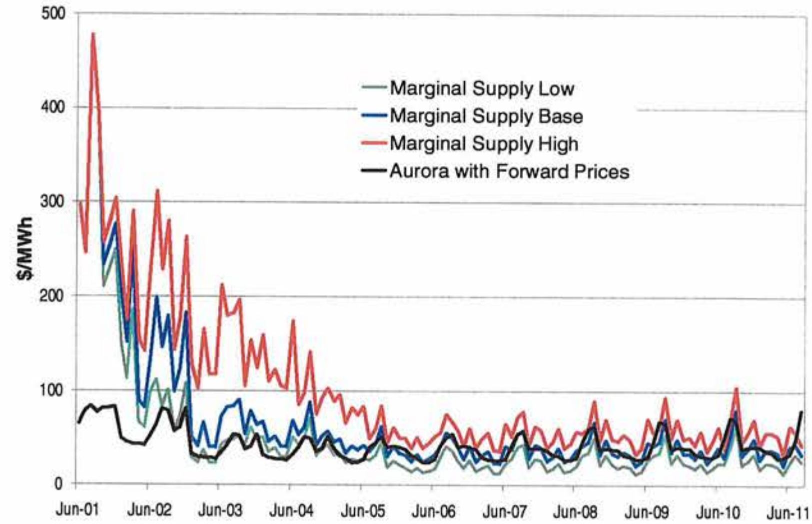
The Aurora model and the marginal supply model generate prices by quarter and by month. Published prices in the forward market are by month for heavy load and light load hours. The model that Tacoma Power uses to analyze resource decisions requires hourly prices. The price of electricity in any given hour is dependent on many factors: what time of day it is, whether it is a weekday or weekend, what month it is, etc. Historical quarterly and hourly prices were used to derive historical shapes. Then mathematical equations were developed and applied to the quarterly price forecasts and the forward prices to derive an hourly price forecast for the base, high and low cases.

Section 4.2

Price Forecasts

The base, high and low case forecasts are presented in annual all-hours values by year in nominal $/MWh in Figure 4a below. This figure also shows forward prices as of June 22, 2001 shaped according to data compiled by Tacoma Power. After an initial decline in prices during the near-term horizon, this forecast shows prices generally rising with inflation throughout the forecast horizon.

Figure 4a
Price Forecast Comparisons



Section 4.3

Uncertainties in Price Forecasts

Major disruptions of regional wholesale power markets have occurred during 2000 and 2001 that severely impacted the electricity industry on the West Coast. Wholesale electricity prices increased from low and stable levels of $20 to $30 per megawatt hour to prices as high as $3,000/MWh. In 2000, prices at the Mid-Columbia trading hub averaged $118/MWh compared to $13.36/MWh in 1997, $23.12/MWh in 1998 and $23.58/MWh in 1999. Prices during December 2000 averaged $514/MWh. The average wholesale electricity price for the first quarter of 2001 was $270/MWh. Wholesale electricity prices remained far above historical levels until June 2001 when prices dropped to levels closer to historical patterns.

There are many causes for the unprecedented increase in wholesale electricity prices. Contributing factors include a legislated, yet flawed power market structure in the State of California, greater than expected load growth on the West Coast, inadequate power plant construction, and extremely low rainfall leading to dramatically reduced hydroelectric power production in the Northwest.

After nearly a year of dramatic increases in both price levels and volatility, wholesale electricity prices began to decline significantly in June of 2001. Some of the reasons for the lower prices include:

- moderate weather in the western United States
- decline in customer demand due to the economic factors
- stepped up conservation efforts
- industrial load curtailments
- short-term increases in hydroelectric output because of rain and snowmelt (although drought conditions persist)
- lower natural gas prices

- some increases in power supply (mostly temporary generators)

On June 19th the Federal Energy Regulatory Commission (FERC) issued a sweeping order mandating price mitigation (price cap) based on the cost of natural gas and the heat rate of natural gas fired generating units dispatched to meet load in California. The price mitigation plan covers all 11 states in the Western System Coordinating Council and went into effect the day after FERC issued the order. Because prices had already gone down, the order did not immediately lower prevailing market prices.

Forward market prices, which had also been declining through May and June, continued to decline after the FERC order until stabilizing at levels slightly below the current price of $91.87/MWh (as of July 3, 2001).

Although the FERC price caps appear to be having an effect on the wholesale power market, it is too early to claim that the worst is over. Many of the factors that contributed to high price levels and volatility are not simply waved aside. For example, new supplies of resources need to emerge quickly enough to satisfy future demand for both electricity and natural gas. Yet price caps, in general, tend to inhibit the pace of resource development, thus exacerbating energy shortfalls that foster price instability. The dilemma for all electricity industry participants is whether to believe the validity of price caps so soon after implementation, or to resist complacency and continue to plan for significant uncertainty.

The price forecasts prepared for this Integrated Resource Plan were prepared before the June shift in market conditions. However, it is only the near-term price forecasts that have been affected by this market shift. As noted above, the early years (2001 through 2003) of the price forecast were derived from forward market prices. Tacoma Power believes its price forecast for 2003 onward is still valid because it is derived from two independent price forecasting models. Since most of the supply resources being evaluated are not available until later in 2002, the model results are still useful for comparing resource alternatives. We are in the process of updating the price forecast to reflect changed market conditions.

Chapter 5: Supply Options

Chapter 5: Supply Options

Tacoma Power's primary supply resource options for the planning period include purchase of power from the wholesale market, the construction of its own generating resources, or the purchase of energy from generating resources owned by others.

The recent escalation of wholesale power market prices has lead to a boom in new resource development and construction. As a result, Tacoma has received many unsolicited proposals for development of new supply resources. In order to evaluate these proposals, as well as resources developed in-house, a resource database was developed to capture all of the available information on candidate resources. The database includes information on the project characteristics (capacity, lifecycle, heat rate, etc.), economics, and potential environmental concerns.

The process for winnowing down the large pool of potential resources to identify the best options is described below.

Section 5.1 Evaluation of Resource Options

Evaluation of resource choices is a complex task. Many attributes, both quantitative and qualitative, must be taken into consideration in determining the best options. The primary criteria that Tacoma Power uses to evaluate candidate supply resources include:

Costs and Economic Benefits A primary goal for Tacoma Power is to keep consumer rates low, stable and competitive with other energy providers. Power supply costs are a significant portion of consumer rates. The cost effectiveness of supply and conservation resources is evaluated against our base case forecast of the market price of power. Life cycle costs are computed for each resource, based on its fixed costs (capital and fixed O&M), and the variable costs associated with its hours of operation. The net benefits are calculated as the projected market value of the megawatt-hours produced, less the costs to produce them. The costs and net benefits are then compared to forecasts of market prices and the costs of alternative resources to determine the resource with the lowest overall cost, the highest net benefit, and the highest benefit/cost ratio.

Environmental Impact Tacoma is committed to preserving the quality of the environment yet recognizes that all resources have some level of environmental impact associated with their development and operation. In evaluating the environmental impacts of a resource, Tacoma Power considers the life cycle of the resource, and residual impacts remaining after actions to mitigate the impacts are taken. From an environmental standpoint, the best resources are those that have the least incremental impacts to human beings and natural systems.

Reliability Tacoma manages a highly reliable power supply and seeks to maintain or increase reliability with each investment in its system. Reliability has become increasingly important to our customers. When costs are equal, we prefer resources that increase the reliability of our system.

Resource Flexibility For the purposes of this analysis, resource flexibility is assumed to be the ability of a resource to quickly and efficiently dispatch either in full, or in part, to meet load and maximize market value. Flexible resources are those that can ramp up to full generation quickly, ramp down quickly, and possess low start/stop costs. Over time, increased non-power constraints on the Tacoma hydro system have diminished the flexibility of our system. Therefore, Tacoma Power is especially interested in resources which add flexibility to the system as a whole. In cases where two resources appear to have the same costs and reliability, but show significant differences in flexibility, the more flexible resource is preferred.

Control/Ownership/Location When costs and other attributes are equal, Tacoma Power prefers to control a resource through direct ownership or a tightly structured contract. In addition, a resource located closer to Tacoma Power's service territory is generally preferable to one located farther away because there is less uncertainty (reliability/availability of transmission) and cost involved in delivery of electricity to our customers.

Portfolio Diversity In general, Tacoma seeks to own and/or contract for a diversity of resources in order to minimize its exposure to risks from drought, oil and gas prices, and the wholesale power market. In addition, resources vary in their operational capabilities. Diversity of resources adds to the overall reliability and flexibility of Tacoma's power supply system.

Resource Timing As a result of the current prices in the wholesale power market, timing of resources has become a more critical attribute than in years past. In order to reduce its exposure to extraordinarily high market prices, Tacoma Power recently has been seeking resources that would be available very quickly. At the same time, the volatility and uncertainty of future market prices, i.e., the very real possibility that prices will plummet once the drought and problems in California mitigate, has led the utility to be cautious in making long-term commitments to resources, particularly those with high capital costs that must be recovered over a long period of time.

Risk/Uncertainty While all resources have some level of uncertainty associated with them, certain resources may involve more risk. Examples of project level risks include: delays in bringing the project on-line due to community opposition; increases in construction costs because of the escalating cost of raw materials or labor; and increases in operating costs because of fuel price escalation. Examples of market level risks include building a resource and facing an unexpected drop in load or investing in technology that becomes obsolete before project costs are recovered. The key uncertainties for each alternative resource need to be analyzed so that, when possible, risks can be managed appropriately.

A three-step process was used to screen and evaluate options. The first step involves gathering enough information about the project to do a preliminary benefit/cost analysis and basic environmental assessment. Resources that are too costly relative to the benefits (benefit/cost ratio of less than 1), or that could result in significant adverse environmental impacts are eliminated from further consideration. Resources that appear viable after this initial screening are then assessed to determine how well they match the supply needs determined through the analysis of Tacoma Power's load/resource balance. (This analysis is described in Chapter 8.) Candidate resources that meet the specified supply needs then undergo a thorough economic analysis and a qualitative environmental assessment.

Section 5.2 Near-Term Supply Options

Six resources passed initial screening and were determined to match Tacoma Power's project supply needs for the near- to mid-term planning horizon. With the exception of the Combined Cycle Combustion Turbine, the resources selected for detailed analysis are generally intended for use as peaking units, rather than base load units. With the loss in flexibility over time of Tacoma Power's hydro system, it was determined that Tacoma Power requires a resource that will primarily be used for peaking and as "insurance" against poor water conditions and higher than expected load growth, and extended outages due to planned or unplanned maintenance/replacement of existing generating plants. This type of resource would enable Tacoma to meet load under peak periods (such as a period of extreme cold weather), and provide additional flexibility to the overall portfolio, which was diminished with the sale of the Centralia Coal Plant.

Generic Simple Cycle Combustion Turbine (SCCT)

(On-line date = April 1, 2002. Lifecycle = 15 years) This resource is assumed to consist of a single GE LM6000 Sprint Combustion Turbine with a net capacity of 45 MW and a heat rate of 10,030 Btu/kWh.[1] Siting requirements include access to Tacoma's transmission system, access to a high-pressure natural gas pipeline, and access to water.

[1] Heat Rate is a measure of generating station thermal efficiency--generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electricity generation by the resulting net kilowatt-hour generation. Heat rates quoted herein are Higher Heating Values (HHV).

Generic Combined Cycle Combustion Turbine (CCCT)

(On-line date = October 1, 2002. Lifecycle = 20 years) This resource is assumed to consist of a single GE LM6000 Sprint Combustion Turbine in combined cycle operation, with no duct firing. Its capacity is assumed to be 70 MW and its heat rate 7,366 Btu/kWh. Siting requirements include access to Tacoma's transmission system, access to a high-pressure natural gas pipeline, and access to a high capacity water main line.

Contract Resource A

(On-line = January 1, 2002. Contract term = 6 years) A developer has proposed a natural gas fired reciprocating engine project in the Fredrickson area. The project is comprised of sixteen 3.2-MW reciprocating engines with heat rates of 9,200 Btu/kWh. The developer proposes to deliver 25 MW in all hours to Tacoma Power during Q1 and Q4. Tacoma would pay a capacity charge and an energy charge based on the heat rate of the units and the cost of natural gas.

Contract Resource B

(On-line = October 1, 2001. Contract term = 10 years) A second proposal under consideration is a long-term contract with the same project developer discussed above for a flat 25 MW/year around the clock from the same project. With the exception of the capacity charges, the project specifics are the same as in the previous proposal.

Tacoma Gas Reciprocating Engines

(On-line date = January 1, 2002. Lifecycle = 15 years) This resource is a natural gas fired reciprocating engine project with a capacity of 40 MW. The units discussed are 2.9 MW Waukesha reciprocating gas engines with an average heat rate of 8,859 Btu/kWh. This option includes two alternatives, one in which Tacoma undertakes the engineering, procurement and construction, and a second in which a developer 'turn-keys' the project. Tacoma would take responsibility for securing and managing the natural gas contract. The gas recips, unlike CTs, run on low-pressure gas (45 to 60 psi gage). As a result, the gas infrastructure required to supply the engines is greatly simplified, eliminating the need for high-pressure gas lines, as well as power intensive gas compression. Other siting requirements include access to Tacoma's transmission system and incidental water.

Northeast Substation Diesel Generators

(On-line date = February 1, 2002 Lifecycle = February 1, 2002 – January 2003) Tacoma Power was operating thirty 1.64 MW Caterpillar diesel generators at the Northeast Substation (under lease from NC Power System, Inc.). Tacoma Power purchased an additional thirteen generator units, but these units have not been installed. The additional units would have brought the total plant capacity to 68 MW. The current permit to operate the plant, issued by the Puget Sound Clean Air Agency, expires on January 30, 2002.

When market prices dropped in mid-June, it was determined that this facility was no longer economic to run as a base load plant. The leased units were returned to NC Power Systems in July and a buyer is being sought for the 13 units that were purchased.

Section 5.3

Long-Term Supply Options

Some of the more promising long-term supply options that might be of interest in the latter part of the planning horizon include a larger combined cycle combustion turbine (350 to 500 MW), wind power, geothermal power, and distributed generation.

Combined Cycle Combustion Turbines

The majority of new plant construction in the United States scheduled in the next several years consists of large scale (350 to 500 MW) Combined Cycle Combustion Turbines. These installations consist of industrial grade combustion turbines (commonly referred to as "F-class" machines), paired with an efficient heat recovery steam generator (HRSG), and a second stage turbine generator. Typically these plants have a second stage of gas combustion which greatly increases the efficiency of the HRSG and second stage generator. Generally the combustion turbine generator generates two-thirds of the total power produced, and one third is generated by the second steam turbine. The CCCTs are approaching thermal efficiencies of 53%, while traditional oil- or gas-fired steam power plants typically possess efficiencies of 38 to 40%. The most efficient CCCTs operating today offer heat rates of less than 7,000 Btu/kWh.

Because of their very low heat rates and high availability factors, CCCTs are seen as the marginal cost resource of the future. In theory, and assuming a balance between and supply and demand, the long-run price of power should converge with the marginal cost to produce power – in this case the variable cost of the large scale CCCT.

Wind Turbines

About 2,000 MW of new wind energy projects have been proposed or are under construction in the United States. One of the larger projects is the 300 MW Stateline Wind project under development on the Washington/Oregon border. The Bonneville Power Administration recently announced that it had received over 1,000 MW of proposals for new wind resources. BPA plans to pursue the development of about 850 MW from this group.

Wind energy installations typically consist of an array of small wind driven turbines that range in size from 250 kW up to 1 MW. The American Wind Energy Association claims that electricity can be produced by state of the art wind turbines at costs as low as 3.69 cents/kWh. Because of the variability of wind resources, actual costs may be higher.

From Tacoma Power's perspective, while wind will provide MWhs of energy to Tacoma's system, it does not provide any additional operational flexibility, and in particular, peaking capability. Energy from a wind resource is produced solely when the wind blows – not necessarily during periods of high market prices, or high load, or both.

Geothermal

Utility scale geothermal resources use heat from below the earth's surface to turn steam generators. There are three basic types of geothermal power technologies:

- Dry steam plants, which directly use geothermal steam to turn turbines;
- Flash steam plants, which pull deep, high-pressure hot water into lower-pressure tanks and use the resulting flashed steam to drive turbines; and
- Binary-cycle plants, which pass moderately hot geothermal water by a secondary fluid with a much lower boiling point than water. This causes the secondary fluid to flash to steam, which then drives the turbines. [2]

The technology is not new. The Geysers geothermal energy development in Northern California has been generating electricity for about 35 years. Nationwide there are 2,800 MW of geothermal resources located primarily in California, Hawaii, Nevada and Utah. The Pacific Northwest has potential geothermal sites that could be developed to produce electricity.

Section 5.4 Distributed Generation

One response to uncertainty related to electricity prices and transmission and distribution constraints is to install smaller decentralized generation resources when and where they are needed. The concept of distributed generation has been around for some time but technology developments and market conditions make this idea more relevant to the electricity supply business than at any point in the last few decades.

Distributed generation can range from small home sized units that can be installed to serve all or part of a customer's residential load, up to much larger industrial gas turbines and reciprocating engines that could serve as a backup or supplement to power supplies for industrial sites or utilities.

Tacoma Power has some experience with both extremes. Net metering requirements established by the state caused the utility to establish interconnection specifications for small-scale residential distributed generation units. Although no customers have installed their own generation yet, there have been a number of serious inquiries. In

[2] Source: U.S. Department of Energy, Energy Efficiency and Renewable Energy Network, http://www.eren.doe.gov/geothermal/geobasics.html

January of 2001 Tacoma Power installed 30 temporary diesel generators with a capacity of 48 MW – at the very large end of the distributed generation spectrum.

Distributed generation presents complicated issues for resource planning because there are such wide ranges of sizes, applications, ownership schemes and technologies to be considered. Some of the variations are:

Generation Technology Types

- Fuel Cells
- Micro Turbines
- Diesel Generators
- Reciprocating Engines
- Aeroderivative Turbines
- Micro-hydro
- Wind
- Photovoltaic

Ownership Possibilities

- Customer owned
- Operated and maintained by customer
- Operated and maintained by utility or third party vendor
- Utility owned, operated and maintained
- Third party ownership (energy service company)

Applications

- Green alternative (environmental preference of customer)
- Power quality and high reliability (for customers that require extremely high reliability such as data centers and some manufacturing operations)
- Back-up power supply
- Avoidance of distribution system expansion costs
- Rural or remote locations not served by utility grid
- Economic alternative to high electricity prices
- Peak shaving

Size Ranges

- Residential scale – up to 5 kW
- Commercial scale – under 1 MW
- Industrial scale – 1 MW to ~25 MW (upper end of this range is unclear, could include customer-owned generation)

Section 5.5 Other Technologies

Two renewable technologies that are of potential long-term interest are tidal and solar powered resources.

It is possible to use ocean currents and tides to generate electricity. One technology under development relies on changes in the level of the tides and works by impounding water during high tides and releasing it at low tide. The Puget Sound region doesn't have sufficient tidal range for these technologies to work. The other method of harnessing tidal energy relies on strong ocean currents such as those that exist in the Tacoma Narrows. Blue Energy Canada, a small company located in Vancouver, B.C. is pursuing development of such a facility sited in the Tacoma Narrows. The generators, termed "Davis turbines", are vertical axis turbines that can be arranged in rows to form a tidal fence. The Blue Energy project as envisioned would involve construction of a second Tacoma Narrows bridge on top of a tidal fence. This project is at a conceptual stage. There are no commercial-scale installations using this technology and it is unclear when this form of tidal generation will be fully feasible.

Solar energy[3] is the most abundant renewable source of energy available to the Pacific Northwest. Although seasonally and geographically variable, solar energy is the one power source available virtually everywhere in the Northwest. It produces no carbon dioxide or other greenhouse gasses during operation and has no up-stream environmental impacts associated with fuel production and transportation. There are some environmental impacts associated with the land used for collector arrays and with the production of collector materials, particularly by-products of the manufacturing of semiconductors for photovoltaics.

While it is abundant, solar energy is also a very diffuse resource and, unlike the region's hydro and wind resources, solar does not have any naturally occurring features that concentrate the resource for collection. Therefore, the largest barriers to development of the resource are the cost of constructing the facilities to capture and convert solar to electric energy. Currently, the cost of the conversion devices makes it uneconomical as an alternative to other bulk-power generating resources. Costs range from 15 to 20 cents per kilowatt-hour using current technology for rooftop, grid-connected photovoltaic systems. Technology improvements and expansion of production capacity continue to reduce the cost of photovoltaic devices. If this cost reduction continues at the rates observed over the past decade, power costs from central station photovoltaic plants will decline to 5.8 cents per kilowatt-hour by 2015.

[3] Source: Fourth Power Plan, Northwest Power Planning Council and the National Renewable Energy Labs General Information Website.

Other issues slowing the development of the solar resource are also cost-related. Because the best sites are located a long distance from the load centers, central station solar installations will incur costs and energy losses to transmit the power to the existing system. This cost will be increased by the low capacity factor of the solar resource. Because solar is a summer-peaking resource, it provides a poor match to the winter-peaking loads of the Pacific Northwest, thus reducing the value of the annual energy output to the regional system.

Chapter 6: Conservation and Load Management Options

Chapter 6:
Conservation and Load Management Options

Section 6.1 Background

Since the enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Power Act) in 1980, conservation has been an integral part of the resource strategy for Tacoma Power. The Power Act resulted in the creation of the Northwest Power Planning Council (Power Council), a planning agency charged with preparing a coordinated conservation and generating resource development plan to guide BPA and local utilities in their decisions about how to meet future electricity loads. The original Northwest Conservation and Electric Power Plan, adopted by the Power Council in 1983, identified about 1,500 average megawatts of achievable conservation potential available in the Pacific Northwest by the year 2002. Subsequent revisions of that plan continued to identify large amounts of conservation potential for the region. In response to the 1983 Power Plan, BPA proposed to acquire 660 aMW from its own system and in the service territories of its public utility customers. In the years that followed, BPA continued to support conservation acquisition through a variety of funding agreements with its utility and direct service industrial customers. In the early 1990's, Bonneville was spending about $150 million per year to acquire conservation savings, mostly through the programs run by its utility customers.

Tacoma Power began its first conservation program in 1980. Since that time Tacoma Power, like the rest of the region, has actively and continuously pursued energy conservation in the homes and businesses of its customers, often with the financial assistance of the BPA. Tacoma Power became a regional leader in the development of conservation as an efficient, cost-effective and environmentally sound resource. While Tacoma Power has followed the principles of least cost utility planning, it first published an integrated Least Cost Plan document in 1990. The conservation planning framework described in the 1990 least cost resource plan has since been formally updated in 1992 and 1997.

Tacoma Power signed its first major contract with BPA in 1982 and has since designed and successfully implemented programs to acquire savings in all sectors, residential, commercial, industrial and military. Life-to-date conservation savings achieved between 1980 and 2000 are 50.7 aMW, with just under 40 aMW achieved between 1990 and 2000 as reflected in Table 6a below.

Table 6a
Conservation Achievements 1990-2000

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Cumulative
Residential	0.47	0.81	0.93	2.33	0.66	0.84	0.67	0.29	0.17	0.13	0.10	7.40
Commercial	0.20	0.36	1.01	1.80	2.47	1.38	1.50	0.93	0.08	0.00	0.01	9.74
Industrial	0.00	2.77	1.66	1.75	3.09	0.87	8.16	1.74	0.01	0.12	0.00	20.18
Military	0.00	0.00	0.00	0.06	0.11	0.41	0.39	1.33	0.35	0.00	0.00	2.66
Total	0.67	3.94	3.60	5.95	6.33	3.51	10.72	4.29	0.61	0.25	0.11	39.98

By 1996, significant changes were occurring in the utility industry. Retail competition was on the horizon and there was a glut of inexpensive energy on the wholesale market. As a result, a number of BPA's customers reduced the amount of their firm power contracts. In response, BPA slashed funding for its conservation programs, fearing that its investment would be "stranded." Tacoma Power also ramped down its conservation programs although it continued to provide weatherization assistance and zero-interest loans to residential customers and to businesses for conservation investments.

The events of the past year have lead to a renewed interest in conservation, both as a short-term and as a long-term strategy. In response to the current energy crisis, Tacoma Power distributed additional emergency conservation measures identified as cost-effective including compact fluorescent lamps, vending misers, clock thermostats and conservation kits. These measures have resulted in savings of just under one aMW. The crisis has also caused renewed interest in the utility's core conservation services.

Section 6.2 Methodology for Determining Conservation Potential

The following discussion describes the methodology used in the assessment of each of the three customer sectors - residential, commercial, and industrial - to determine how much conservation can be achieved. The conservation potential assessment follows the basic steps outlined below:

1. Determine base year loads for each sector. With the exception of residential weatherization - the base year loads are 2000. All residences with electric heat built prior to the1984 MCS energy code comprise the base load for weatherization.
2. Forecast the loads in 2011 with no new programmatic conservation occurring after the year 2000. Separate the forecasted loads into existing and new components.
3. Determine the total technical potential and apply this as a percentage of total energy use for each market segment or end-use. The term "technical potential" is used to refer to the amount of conservation savings that would result from installing all of the conservation measures that are cost-effective in a given market segment or end-use. The technical conservation potential is the upper bound of what is possible.

4. Identify the total amount of achievable potential conservation resource and adjust the technical potential as a percentage. The term "achievable potential" is used to refer to the amount of conservation savings that could reasonably be expected if a relatively aggressive conservation program that was designed to capture as much of the technical potential as possible was implemented over a reasonably long period of time. The difference between the technical potential and the achievable potential derive from (1) market, financial and personal/corporate interest barriers that result in some potential program participants choosing not to participate or participate fully in the program offered; (2) less than ideal regulatory compliance (where regulations are being used to compel the incorporation of conservation strategies); and (3) unanticipated underperformance of the energy saving equipment resulting from substandard installation, maintenance or use of the energy saving equipment.
5. Identify prior conservation accomplishments and deduct from the achievable potential to determine the remaining achievable potential. The term "remaining achievable potential" is used to refer to the amount of the achievable potential that has not yet been captured through previous programs, the adoption of codes and standards or independent consumer action.
6. Determine the levelized costs for all conservation acquisition strategies.

Section 6.3 Residential Sector

*Weatherization*_Residences with electric heat permanently installed prior to 1984 are eligible to participate in the weatherization program. The first step in identifying the potential for conservation is to estimate the number of eligible residences and group them by housing stock: 1) single family (including duplexes), 2) multi-family and 3) manufactured homes. The results of the 1990, 1992, 1996 and 1999 Residential Conservation Characteristics Surveys and data from Pierce County serve as the basis for this information. The resulting eligible residences represent the "technical potential."

Approximately 43,000 residences meet these criteria, which represent 32% of our total current (year 2001) residential households.

Historical data and programmatic experience provide guidance as to what energy savings can be attained - the "achievable potential." The Conservation Assessment Potential projections assume zero interest loans continue to be offered as financial incentives; with grants available to owner occupied low-income residences. Retail energy prices, cost of measures and program delivery methods are major drivers in determining what is actually achieved. Of single family and multi-family residences, 80% and 70%, respectively, are deemed achievable.

Since the weatherization program began in 1980, approximately 25,600 weatherization jobs[1] have been completed. Technology improvements in measures such as windows continue to create cost effective replacement opportunities. An adjustment factor is used to distinguish between the jobs completed and residences treated. Of the technically eligible residences, approximately 45% have already participated in the weatherization program. To date, Tacoma Power has been able to achieve the 45% participation level without direct marketing to customers. As the market becomes more difficult to reach, effective strategic marketing will be needed to help reach the achievable potential levels.

Life-to-date weatherization accomplishments of 7.76 aMW are deducted from the achievable potential. The resulting 13,800 residences (6,250 single family, duplexes and manufactured and 7,550 multi-family) are defined as the remaining achievable potential. Depending on the complement of measures installed, the energy savings from the weatherization program are estimated to be 3,000 to 3,750 kWh for single family, 1,058 to 1,160 kWh for multi-family and 2,000 to 2,200 kWh for manufactured housing. This translates to potential annual savings of 4.1 aMW to be acquired at a levelized cost of 39.6 mills.

Appliances All residential households are eligible for efficient appliance replacements. Data from the Association of Home Appliance Manufacturers is used to establish the replacement rate of appliances and to estimate the saturation of specific appliances within the housing market. These factors, applied to our total residential base, determine the technical potential.

As new federal standards are adopted, the efficiency bar for appliances continues to rise. The focus for the conservation potential is the incremental efficiencies to be gained by early retirement of older, inefficient unit in service and purchase of new models that exceed current standards. The incremental costs for upgrading to the most efficient models determine the cost effectiveness of conservation investments. Dishwashers, clothes washers, refrigerators and water heaters are available with cost effective efficiencies beyond the standards.

The achievable potential, as a percentage of the market that can be influenced to purchase the most efficient appliances, is difficult to project. The estimates for market penetration (the number of people who might participate) range from 25% to 75% and are obviously closely tied to the investment cost to be incurred by the customer. This range is broad because the success of the program depends on offering

[1] Residences have and will continue to go through the weatherization program more than once. Each time that a residence goes through the program (as evidenced by a new weatherization contract with the utility) it is counted as a completed job. It is estimated that approximately 25% of the homes that have been through the weatherization program have been through more than once, usually getting insulation improvements during one time through the program and window improvements at another time.

an attractive program to our customers that encourages retirement of inefficient appliances still in service and influences their decision to purchase the most efficient model available when a new purchase is planned. The program delivery strategies are projected to have an achievable potential of .4 aMW for appliances to be acquired at a levelized cost of 29 mills.

Lighting Tacoma Power's experience in residential lighting is the source of the technical and achievable potential, which is based on the replacement of interior and exterior incandescent light bulbs and fixtures with compact fluorescent equipment. The estimated achievable potential is 3.0 aMW in the residences and the multi-family common areas at a levelized cost of 18.8 mills.

Section 6.4 Commercial and Industrial Sectors

Dunn & Bradstreet data and Tacoma Public Utility's Customer Information Service (CIS) account information were matched and then combined to provide a more comprehensive picture of the commercial and industrial sectors. Care was taken to ensure matches for all larger loads. The unmatched records are grouped in a miscellaneous category. The Dunn & Bradstreet data provides Standard Industrial Classification (SIC) information for each matched account while the CIS information identifies energy consumption. Based on the assigned SIC codes, customers are segmented into commercial and industrial.

Existing Commercial Ten commercial building prototypes were developed back in 1980 for regional utility use. The SIC codes, derived from the Dunn & Bradstreet data, provide the basis for grouping commercial customers into these ten prototype-buildings. The Northwest Power Planning Council (Power Council) assigns technical potential savings ranging from 10% to 37% to each of the prototypes as a percentage of the total load. These percentages are applied to our specific loads to derive the technical potential by building type within the commercial sector. Tacoma Power has achieved 11.3 aMW in this sector. Based on this experience, an achievable potential of 60% is assigned to the technical potential.

Commercial loads are assumed to decline by 1% annually as a result of building demolition/ removal or major renovation. This reduction in load is subtracted from the existing commercial load and added to the new commercial loads for 2001 through 2010 with the assumption it meets minimum building code. Tacoma Power's historical program experience is applied to reduce the net technical potential to the achievable potential of 14.9 aMW. The levelized cost of 19.2 mills for these savings assumes grants of 65% supplemented by zero interest loans.

Existing Industrial The SIC codes define the broad industrial categories. Again, as for the commercial sector, the Power Council identifies the technical potential as a percentage of the total load. No conservation opportunities are identified for the large loads of the remaining contract power customers. This combined load is subtracted from the year 2000 baseline, effectively removing it from the loads to be assessed for conservation potential. The considerable experience in industrial conservation projects serves to establish the achievable potential savings of the remaining load. The estimate is for savings of 1.3 aMW at a levelized cost of 10.8 supported by a combination of grants and zero interest loans.

New Commercial and Industrial (including major renovations and expansions) The 2001 through 2011 load forecast for new and increased commercial and industrial loads is based on historical growth rates. The forecasted total loads in 2011 represent a combination of new and renovated building plus increased load within existing businesses. The increased loads are anticipated to come from higher use of personal computers and other electronic equipment.

Technical potential savings ranging from 17% to 20% are applied to our specific loads to derive the potential savings. These technical savings are based on methodology used by the Power Council. An achievable potential of 60% is assigned to the technical potential. The resulting estimate is for savings of 9.4 aMW for new commercial at a levelized cost of 18.6 mills. The estimate for new industrial is for savings of .9 aMW at a levelized cost of 10.8 mills.

Section 6.5 Military Sector

Tacoma Power's military load is composed primarily of two large customers, Ft. Lewis Army Post and McChord Air Force Base. During the 1990's, the utility implemented an aggressive conservation effort at Ft. Lewis. This Bonneville Power Administration-supported effort resulted in savings of 2.66 average megawatts. Since that effort, Ft. Lewis staff have identified additional energy savings potential of approximately 1.1 aMW.

The utility has not had a conservation funding relationship with McChord. It is believed that savings potential at McChord exists in roughly the same proportion of its total load as existed at Ft.Lewis in the early 1990's. Therefore, the estimated savings available at McChord are assumed to be the same percentage of their total load as was achieved at Ft. Lewis during the major conservation initiative during the 1990's. This translates to approximately 11% of their load for energy savings of 1.3 aMW.

Section 6.6 Conservation Potential Summary

All sector analyses combined result in a total achievable conservation of 37.7 aMW under the projected load growth in Tacoma Power's forecast over the next ten years. Imbedded within each sector analysis are general assumptions about basis program design, funding and delivery that drive the achievable conservation levels.

Conservation is unique in the potential it offers to adjust the pace of resource acquisition. A gradual ramp up of activity is projected to accommodate the development, testing and implementation of new conservation programs, as well as modification of existing programs. Critical to the successful delivery of programs is the development of infrastructure within both Energy Services and the contractor/vendor community.

Section 6.7 Load Management

The term demand-side management (DSM) refers to utility efforts to induce customers to modify their energy use to achieve a utility business goal such as getting the most out of existing energy resources. The goal of demand-side management is to either reduce energy requirements overall or to smooth out the daily peaks and valleys in electric energy demand. The four basic demand strategies are peak shaving, load shifting, valley filling, (collectively referred to as load management) and conservation.

Tacoma Power, like most other Northwest utilities, has limited experience with load management, and specifically peak reduction. Load management has not been a significant part of resource strategies in a region that has been able to use the flexibility of the regional hydroelectric system to meet short-term demand peaks. Since the bulk of our owned and contract resources are hydro, we have been able to respond to the peaks and valleys in diurnal and seasonal load on both a planned and real-time basis, follow system loads on an instantaneous basis, and meet spinning and non-spinning reserve requirements. However, as discussed in Chapter 2, this flexibility is diminishing.

A range of load control options was reviewed. Two different load management approaches that address quite different system needs are of potential interest: 1) direct utility control of electric water and space heat and 2) contracted commercial and industrial load shedding. Below is a description of both approaches, the issues surrounding them and specific recommendations.

Water and Space Heat Load Control The peak periods in the residential sector are quite predictable. There are two definite peak periods during a given heating season day. The peak periods are generally 7 a.m. to 10 a.m., and 5 p.m. to 9 p.m. While we can easily isolate the load shape for individual commercial or industrial customers, much less is known about the cumulative load shape of these two sectors. Defining the cumulative load shape is an area recommended for additional research.

The customer loads identified as potential controllable loads are residential electric water heat and space heat (standard central forced air and electric supplemental heat strips on heat pumps). Switches would be installed on customers' equipment allowing the utility control at its discretion. Customers could have their water heaters shut off for periods of two to four hours; while heating systems could be cycled on and off by the utility or the thermostats could be set back for a period of time. A typical cycling strategy might be 15 minutes off, 45 minutes on each hour.

Control of water heaters could expect to reduce demand by an average of 1 kW per water heater. (.8 kW to 1.2 kW is the average demand per electric water heater that is coincident with the peak period.) Approximately two-thirds of Tacoma Power's residential customers heat water with electricity (the rest heat water with natural gas).

The average coincident residential peak heating demand is between 4 and 5 kW. A cycling strategy that interrupted the heating system for 15 minutes of each hour could expect to reduce demand by 25%, or between 1 and 1.25 kW per residence. Approximately half of Tacoma Power's customers have electric space heating systems; most of those have baseboard or wall heater systems that are more costly than electric furnaces to control.

One major issue in load control programs is customer acceptance. While programs can be designed to minimize their impacts on customers, many may be unwilling to have their water or space heating controlled at all, for any amount of incentive that the utility can cost-effectively afford to pay.

When load control programs are introduced, the natural diversity within the utility system is disrupted. A phased restoration schedule is necessary to prevent secondary peaks. The diversity issue is common to load shifting strategies and is an important issue to address in program design.

There are a variety of ways to establish the communication necessary for a load control program. The final selection of the communication systems to utilize must take into consideration the technical and practical ability to meet the defined load reduction needs; implementation and operational costs; integration with utility infrastructure; and practical application, based on logistics. Tacoma Power is in the unique position to utilize the existing hybrid fiber coaxial network –Click!

Load Shedding While the utility does not have much data on commercial and industrial loads in the aggregate, it does have the ability to learn about the loads of individual customers relatively quickly. And while the desirability of curtailing business customer loads in the morning and afternoon on a regular basis is probably low, the capability to shed large loads can provide a hedge against critical conditions beyond Tacoma Power's control, such as the weather or natural disasters. Under such conditions, Tacoma Power may have difficulty meeting high loads and resorting to market purchases under such conditions is costly.

The initial step is to identify potential customer candidates by taking a look at commercial and industrial customers' loads, profiles, logistics and availability of on-site backup generation. Understanding the load and back-up generation situation at the facilities of candidate customers will help understand what would it take to motivate specific customers to participate. Questions to be answered include how often and for what duration, would customers be willing to reduce load and at what price and under what conditions. The next step in developing an offering would be working with the customers to establish load base lines, either through the existing metering equipment or upgraded equipment and contractual terms and conditions that would govern a load shedding relationship. Finally, before implementing a load shedding effort with customers, the communications system on which the program would operate would need to be developed.

Temporarily shedding discreet loads may result in reduced consumption or merely shift energy use to non-peak hours. Most successful load shedding programs include a customer feedback mechanism that depends on having real time utility communication with the electric meter. The equipment required to establish this level of communication with the meter is readily available.

It may be necessary to upgrade the meters at the facilities of participating customers. The meter would have to be capable of high-speed two-way communications via the Click! network. Additionally it will have to contain sufficient memory to store and date-time stamp the customer's load information.

Chapter 7: Environmental Consideration

Chapter 7: Environmental Considerations

This chapter begins with general discussion of the potential adverse environmental impacts associated with various resource options and how and to what level such impacts can be mitigated for. After this, the manner in which we incorporate environmental analyses into the IRP process is discussed. Additional environmental analysis of the six candidate supply options is included in Chapter 8.

Section 7.1 Environmental Impacts of Resource Options

One very important factor for evaluating potential resource options is the environmental impact associated with each option. The following discussion identifies and evaluates the general adverse impacts that are associated with various energy resources, including conservation. The discussion is not necessarily exhaustive, but is designed to identify and describe the most significant potential impacts associated with each option and illustrate some of the environmental criteria taken into consideration within the IRP process.

Conservation

Energy conservation improvements generally reduce the exchange between indoor and outdoor air, thus can potentially increase the accumulation of indoor air pollutants (from both indoor and outside sources). In commercial, industrial and residential structures, examples of such pollutants include formaldehyde, radon, asbestos fibers, cigarette smoke, disease microorganisms, gases released from construction materials, carpets and furniture, dust mites and PCB's (from fluorescent light ballasts). Many of these adverse effects can be mitigated for with the provision of adequate ventilation and air filtering, radon monitoring, and asbestos removal.

Additional adverse environmental impacts of conservation include those related to the disposal of light bulbs (many of which contain lead and/or mercury), fluorescent light ballasts (PCB's), refrigerants (CFCs), and asbestos. Impacts can be mitigated for by proper disposal.

Hydro

Adverse environmental impacts associated with hydroelectric projects differ depending upon the physical attributes of the project and its location. Nonetheless, in general, impacts may include: degradation of water quality such as nitrogen super saturation, turbidity, temperature changes and oxygen depletion; disruption of natural river flows including changes in stream velocity, flow diversions, inundation, soil erosion and sedimentation; alteration of river, riverside and wetland habitats leading to habitat loss/transformation, obstacles to fish migration and other related impacts. Hydroelectric projects may also cause adverse impacts on visual resources and river recreation opportunities.[1] Many of these adverse environmental impacts can be mitigated for at some level in a number of ways, including but not limited to water quality monitoring, adjustments to hydro operations (e.g., ramping limitations, minimum flows etc.), erosion control, wetland creation, riparian rehabilitation, provision of recreation facilities and other mitigative measures.

Wind

The environmental impacts associated with wind generation projects include visual impacts (can be seen, often from a long distance), noise impacts (can be heard from the vicinity of the project), and impacts to wildlife resources - particularly birds flying into the blades. New turbine designs and more careful siting of projects have minimized impacts on wildlife resources.

Solar

The nature and magnitude of impacts related to solar energy depend upon the specific technology and application being considered. In general, the most notable impacts are those related to land use. Most larger scale projects, typically using solar thermal or parabolic trough systems require substantial amounts of land. Photovoltaic technologies, on the other hand, are often used as distributed systems and are mounted on buildings, thus do not require much land. Solar thermal systems also require the use of water to create steam. In use, solar projects emit no emissions, but, depending upon specific technology, minimal amounts of air emissions or other hazardous materials may be produced during manufacture of components. Potential adverse environmental impacts from solar projects are generally seen as being relatively minimal compared to other forms of electrical generation.

Fuel Cells

Specific effects on air quality depend on the fuel used to produce hydrogen gas for operation of the fuel cells. Assuming natural gas were used, emissions of CO2, CO and NOx would occur, but would be substantially less per unit of energy produced than any other form of generation using natural gas because of the inherent efficiency of fuel cell technology compared to combustion processes. In addition, air emissions can be mitigated for in large part with the use of control technologies. Other potential adverse environmental impacts include those related to resource extraction and fuel delivery – including impacts associated with drilling and exploration, and pipeline installation.

Biomass

Whether engaged in gasification or combustion, electricity generation from biomass does generate air emissions. Emissions of particular

[1] It should be noted that hydroelectric projects also provide many positive benefits (other than power), including recreation and aesthetic benefits associated with project impoundments, flood control and other benefits.

concern include NOx and CO. NOx emissions vary significantly among biomass facilities, primarily depending upon what type of fuel is being used – and in particular, the fuel's nitrogen content. Biomass generation also produces CO2 emissions and some level of particulates. Emissions (particulates) can be reduced with the use of advanced emission control systems. Depending on specific fuels, and considered on a life cycle basis, biomass can generally have substantially less adverse environmental impacts compared to fossil fuel generation.

Natural Gas

Although the cleanest of all fossil fuels, natural gas combustion emits, primarily, carbon dioxide (CO2), and nitrogen oxide (NOx) and to a lesser extent carbon monoxide (CO) and volatile organics. In addition, depending on the specific technology utilized, natural gas projects (combined cycle combustion turbines in particular) can require the use of significant amounts of water. Other potential adverse environmental impacts include those related to resource extraction and fuel delivery – including impacts associated with drilling and exploration, and pipeline installation; effects on visual resources (e.g., cooling towers, emissions stacks); and noise. State of the art technologies limit air emissions substantially, especially NOx. "Dry" technologies that reduce water consumption are also available on some types of projects (simple cycle). Selective catalytic reduction units can also be utilized on combustion turbines to further reduce emissions. Noise issues can be effectively mitigated for with appropriate facility design.

Diesel/Gas Generation

Diesel combustion produces air emissions of primary concern including CO2, CO, NOx, SOx, particulates including suspected and known carcinogens, and some minimal levels of volatile organics. Other potential adverse environmental impacts include those related to resource extraction and fuel delivery. SOx emissions can be reduced substantially by using low sulfur diesel fuel and NOx can be reduced with the use of selective catalytic reduction devices. Adverse environmental impacts from the combustion of diesel fuel are generally considered to be high relative to other supply options.

Section 7.2 Challenges in Analyzing Environmental Impacts of Resources

A major challenge associated with integrated resources planning is weighing all of the benefits and costs associated with a given resource option in an objective manner. As "standard" economic analyses alone do not necessarily incorporate all environmental costs and benefits into the equation, other means of analysis are also important to assure a "level planning field."

One approach to better understanding the effect of environmental impacts is to consider them within an environmental externality framework. Externalities, or external costs, are costs that result as a byproduct of production (e.g., air pollution) that accrue to someone other than the parties involved in the activity. In most cases, these costs are borne by nearby residents (e.g., noise or air pollution) or our society at large (e.g., loss of habitats or impacts on birds and animals). Consistent with economic theory, decisions that are made without consideration (internalization) of external costs are inefficient (do not bring about an optimal allocation of resources and thus do not maximize social welfare). In this case, an inefficient decision is made because the project owner is not required to consider or pay (internalize) the external costs associated with the construction and operation of a facility. For example, if two supply options – a coal fired plant and photovoltaic project were being considered, the results of a "standard" economic analysis would likely recommend pursuing the coal resource option. However, if the external costs associated with coal combustion were incorporated into the analysis (internalized), the photovoltaic option may look more competitive.

In practice, various methods to incorporate environmental 'costs' are utilized, including both quantitative and qualitative methods. While none is perfect, most do help to level the playing field and make "apples to apples" decisions somewhat possible. With respect to economic theory, the most desirable way of incorporating environmental externalities into an analysis it to assign dollar values to all external costs and incorporate them into the economic analysis. As part of the IRP process, we reviewed the literature on externalities and external cost adders associated with electrical generation and evaluated the use of such methods by other utilities and regulatory agencies.

As the result of our review, we did find a substantial body of literature on the subject and were able to identify a small number of agencies around the country that utilize (or require utilization of) external cost adders in their economic analysis. However, in the exercise of attempting to determine an appropriate range of external cost adders for purposes of our own analysis, we discovered many ambiguities in the existing literature, particularly with respect to the size of the range of external costs suggested by different studies (sometimes differing by several orders of magnitude). As a result, we concluded that the existing literature was, at best, unreliable for determining specific external cost adder amounts to be utilized in the economic analysis and that a qualitative approach would better serve our purposes.[2]

Within our IRP process, environmental considerations are one of several important factors in resource planning and have been effectively incorporated into the analysis of alternative supply options in two steps. Environmental considerations are first incorporated into an initial screening phase. Along with an initial economic analysis, each resource

[2] Although we do not include "quantified" external cost adders in the economic analyses, we do include environmental compliance costs (e.g., the cost of installing selective catalytic reduction units). Arguably, the inclusion of such (compliance) costs internalizes at least some portion (perhaps most or all) of the external costs associated with the alternatives considered.

option is evaluated on the basis of what is known about its potential environmental impacts. At this stage, resources that could result in significant environmental impacts (or are too costly relative to economic benefits) are eliminated from consideration. Resources that are selected for detailed economic analysis also receive additional environmental review. The results of our environmental analyses of the six candidate resources considered in this IRP are included in Chapter 8.

An additional environmental consideration, related to externalities, that deserves attention, is the question of the potential for future, more stringent environmental regulations that could affect a project's economics in the future. As an example, there is a possibility that a tax on carbon emissions could be instituted in the future. A federal taxing authority would likely institute such a tax as an attempt to internalize the externality costs associated with the combustion of carbon based fuels. Due to the uncertainty of a carbon tax actually being instituted in the future, and if instituted, what the magnitude of such a tax would be, we have thus far not incorporated hypothetical carbon tax related costs into the economic analysis. Nevertheless, we suggest further study of this issue and may consider the incorporation of hypothetical carbon tax costs in future economic analyses.

Chapter 8: Planning Analyses

Chapter 8: Planning Analyses

There is significant financial risk entailed in misjudging the need for supply resources and underestimating the costs of acquisition and operation. If the utility over-builds (too much firm supply) or invests in a high cost resource, customers will pay higher rates. On the other hand, reliance on the spot market could expose the utility to the kinds of price spikes that have persisted since mid-2000. If the utility fails to invest in energy efficiency improvements in customers' homes and businesses, the opportunity to postpone investments in generation resources is lost. Alternatively, over-investment in conservation or investments in high-cost efficiency measures will cause upward pressure on consumer rates.

Due to the complexity and uncertainty entailed in planning for future resource investments, Tacoma Power used both quantitative tools for economic analyses and optimization modeling, as well as qualitative tools for environmental analysis and scenario planning. This chapter describes each of these tools and the results of the analyses.

Section 8.1 Analysis of Energy Supply and Demand Balance

Because of the importance of understanding resource needs on a 'real-time' basis, the utility invested in the development of an hourly analysis model (referred to as HAM). This model simulates the effects of resource choices under different water conditions and market prices, and variations in customer load. By running multiple 'cases' under different combinations of assumptions about the critical variables and then testing alternative supply strategies in the model, the utility can assess the costs and potential risks of various resource strategies.

In order to determine Tacoma Power's energy/supply demand balance over the planning horizon (June 2001 to July 2011), a number of analyses were done to determine the range of surpluses and deficits that could be anticipated depending on water conditions and load growth. These analyses assumed Tacoma Power's existing supply remained available over the planning horizon (with anticipated changes accounted for such as the new BPA contract).[1] For the base case analyses of supply/demand balance, no new resources were included in the model runs. Varying assumptions were made about wholesale market prices to determine the financial consequences of depending on spot market purchases to make up for deficits in supply, and to determine potential revenues from sales of excess supply into the wholesale market.

[1] The diesel generation farm (capacity of 68 MW) was assumed to be available through January, 2002. The new BPA contract was included beginning October 1, 2001. All load forecasts (Low, Base A, High) except Base B were adjusted downward to assume 4.9 aMW of programmatic conservation being acquired by July 2003, ramping up to 16.5 aMW by July 2011.

Most of the model runs have been developed to test a combination of critical and adverse water conditions. The base case ('critical/adverse') runs assumed critical water supply through September 30, 2001 and then adverse water conditions through the rest of the planning period. The low case ('critical/critical') runs assumed critical water supply throughout the planning period. For the high case, average water was assumed after September 30, 2001. While the probability of having an extended low water period is small, the financial consequences are high. The lack of diversity in the Northwest generating supply portfolio means that low water affects hydro output throughout the region. When Tacoma is short of power, so are BPA and most of the other utilities in the region. This means a constrained supply on the wholesale market and hence, higher prices.

Table 8a shows the cases that were modeled to determine Tacoma Power's expected surpluses/deficits under a range of water, load, and price conditions, with no new supply resources other than the new BPA contract.

Table 8a
Cases Analyzed in Hourly Model [2]

Case	Water Condition	Load Forecast	Market Price Forecast
BBaB	Critical to 9/30/01 then Adverse	Base A	Base
HBaL	Critical to 9/30/01 then Average	Base A	Low
LBaH	Critical	Base A	High
BLB	Critical to 9/30/01 then Adverse	Low	Base
BHB	Critical to 9/30/01 then Adverse	High	Base
BBbB	Critical to 9/30/01 then Adverse	Base B	Base
LBbH	Critical	Base B	High
HBbL	Critical to 9/30/01 then Average	Base B	Low

The results of analyses for these 8 cases are shown in Table 8b. Results by quarter are shown for the near-term planning period (June 1, 2001 through July 30, 2003) and annually thereafter. In Table 8b, the negative numbers indicate the average number of megawatts in spot market purchases for that quarter (year). Positive numbers indicate a surplus, which could be sold into the market. Since this table averages hourly surplus/deficit information, it is useful for evaluating overall energy balances but should not be used to draw conclusions about the flexibility of Tacoma's system to meet peak loads on an hourly or daily basis.

[2] Please refer to Chapters 2, 3 and 4 for details about these water, load, and price cases.

Table 8b
Base Cases – Net Sales (Purchases) to Market
(aMW)

Quarter/Year	BBaB	HBaL	LBaH	BLB	BHB	BBbB	LBbH	HBbL
Q3 2001	(40)	(24)	(72)	(24)	(49)	(148)	(173)	(132)
Q4 2001	72	109	31	132	47	(1)	(48)	36
Q1 2002	57	156	(37)	121	34	(31)	(125)	66
Q2 2002	112	131	(11)	167	90	50	(73)	72
Q3 2002	25	72	(7)	77	(28)	(46)	(75)	2
Q4 2002	55	106	(54)	108	(11)	0	(110)	34
Q1 2003	(14)	75	(111)	52	(82)	(37)	(135)	59
Q2 2003	103	175	(44)	160	39	67	(77)	151
Q3 2003	89	147	(11)	148	15	6	(96)	63
2004	79	141	(17)	144	0	(6)	(101)	57
2005	61	116	(29)	130	(23)	(26)	(116)	29
2006	57	114	(27)	142	(51)	(28)	(112)	29
2007	53	105	(36)	155	(81)	(31)	(121)	21
2008	49	95	(46)	167	(111)	(34)	(130)	12
2009	44	86	(56)	179	(140)	(38)	(139)	4
2010	49	106	(34)	204	(167)	(28)	(112)	28
Average MW	57	111	(33)	147	(55)	(22)	(113)	32

The results of this analysis indicate that with the new BPA contract, a return to adverse water conditions (or better), modest load growth (Base A or Low load growth cases), and acquisition of 16.5 aMW in conservation, Tacoma Power will be in relative supply/demand balance over the planning period. This relative balance is **only** for average energy. The utility no longer has the flexibility to consistently cover its daily and seasonal peaks. If critical water conditions persist or reoccur, load growth is higher than anticipated, and/or the output of existing supply resources is reduced, the utility will be deficit in energy and even worse off for peaking.

A second set of model runs was done to estimate the financial risk entailed in relying on the spot market to meet deficits in supply, while investing in 16.5 aMW of conservation to offset load growth. The results of this analysis are shown in Table 8c. The negative numbers are purchases from the market (in millions of 2001 dollars). Positive numbers are revenues from sales into the market. The financial impact of being deficit depends on the forecast of market prices. In a worst case scenario (critical water, Base B load growth, and high wholesale prices), Tacoma would be buying tens of millions of high priced power on the spot market. (An even worse scenario—critical water, high load growth, and high prices—was not modeled).

As has been noted throughout this document, there has been a significant drop in prices on the wholesale market since mid-June 2001 and forward prices also have come down significantly. Therefore, the magnitude of the purchases and sales shown in Table 8c through then end of 2003 are high.

Table 8c
Base Cases--Dispatch Net Revenues (Costs) by Scenario (Million 2001 $)

Quarter/Year	BBaB	HBaL	LBaH	BLB	BHB	BBbB	LBbH	HBbL
Q3 2001	(16.0)	(8.0)	(48.0)	(2.0)	(23.0)	(108.1)	(133.1)	(99.8)
Q4 2001	41.0	59.0	24.0	74.0	27.0	(0.2)	(27.3)	22.3
Q1 2002	39.0	69.0	(8.0)	65.0	28.0	0.3	(52.6)	40.7
Q2 2002	37.0	34.0	13.0	48.0	31.0	22.8	(12.2)	25.0
Q3 2002	30.0	31.0	15.0	50.0	8.0	1.6	(23.1)	15.2
Q4 2002	37.0	32.0	(7.0)	52.0	16.0	20.2	(30.7)	18.7
Q1 2003	3.0	8.0	(23.0)	11.0	(4.0)	0.8	(30.2)	6.2
Q2 2003	18.0	15.0	(2.0)	25.0	11.0	13.2	(13.3)	13.3
Q3 2003	74.3	74.3	41.4	106.8	33.8	28.0	(68.8)	41.3
2004	52.1	58.1	14.4	78.9	18.2	15.5	(53.4)	31.5
2005	27.4	25.1	2.6	47.6	1.9	1.3	(37.5)	9.4
2006	29.2	27.7	5.9	55.6	(6.6)	2.3	(34.6)	11.2
2007	30.6	26.2	1.2	65.1	(18.5)	2.7	(40.5)	8.7
2008	31.8	24.5	(3.4)	74.6	(30.8)	2.9	(46.3)	5.8
2009	33.1	22.7	(8.0)	84.2	(43.0)	3.1	(52.2)	3.0
2010	36.6	33.1	2.1	89.2	(43.0)	8.1	(39.0)	14.0
NPV at 7/1/01	408.0	444.0	14.0	731.0	47.0	(4.0)	(577.0)	130.0

These findings pose a dilemma for the utility. On an expected basis, Tacoma may be able to defer investment in a new generation resource and instead rely on conservation investments to offset growth in energy demand and use spot market purchases to meet short-term deficits. But this strategy is risky. If Tacoma is caught short of supply, it could face months of market purchases because of the long lead times involved in bringing new supply resources on-line. The recent "energy crisis" combined with the drought in the Northwest resulted in unanticipated expenditures of $28.7 million in capital and O&M for the diesel generation project, and $127 million in unplanned market purchases between October 2000 and July 2001.

The recent distortions in the market caused by drought, supply/demand imbalance, and flawed approaches to de-regulation are not expected to continue into the future. However, future periods of market imbalance leading to high prices and volatility cannot be ruled out. Our analyses show that relying entirely on the spot market to meet firm load entails more risk than is prudent at this time.

In summary, the analyses of power supply/demand balance indicate two needs: (1) insurance against poorer than expected water conditions, higher than expected load growth, or an unplanned plant outage; and (2) capability to compensate for loss of flexibility in our existing supply portfolio, to meet peak demand, and to preserve system reliability. The next section describes the analyses that were performed to determine the best type of resource for the identified needs.

Section 8.2 Calculation of Resource Costs

Economic Analysis of Supply Options

As described in Chapter 5, information was gathered on many resources to create a supply database. Initial screening of these resources involved estimating the costs and benefits of each resource. An initial assessment of environmental impacts was done also. After initial screening of a range of potential options, six supply resources were determined to fit the needs identified from the supply/demand analysis described above.

The costs associated with acquisition and operation of these supply resources were divided in the following categories: Capital Costs, Fixed Operations and Maintenance (O&M) Costs, and Variable Operations and Maintenance Costs, which include fuel costs (gas, diesel).[3] The following is a summary of each cost category.

Capital Costs Capital costs encompass all of the costs associated with engineering, procurement, construction, and owner's costs prior to the commercial operation date. For the purposes of this analysis, the capital costs were treated as overnight costs, meaning they occur at the beginning of the lifecycle of the project. By treating the capital costs as overnight costs, the effects of financing options played no role in the economic analysis of the projects. The capital cost numbers for the resources were derived from a number of sources, including informal procurement and construction bids.

Fixed O&M Costs Fixed operations and maintenance costs involve costs which occur during the life of the project, and whose magnitude are not directly affected by the quantity of megawatt hours (MWhs) produced from the unit. Such costs are incurred whether the unit operates or not. Examples include property taxes, personnel, insurance, maintenance contract costs, and transmission and gas demand charges.

Variable O&M Costs These costs derive from operation of the facility. Such costs typically include consumables (lubricants, filters, fuel, urea, catalyst), interval-based maintenance, maintenance personnel, and air emission control equipment. Fuel costs are based on the heat rate of the resource (in Btu/kWh), multiplied by the delivered cost of fuel.

Calculation of Benefits

In order to calculate the monthly benefits of ownership (or control via a firm contract) of a specific resource option, the HAM model was used to calculate cost savings attributable to having control of the resource in

[3] Environmental costs were divided into two categories, capital and variable O&M. Included in the capital costs were the costs of permit application, consultant costs, and pollution control equipment. Other environmental mitigation costs (e.g., mitigation programs) were included in the variable operations and maintenance costs because these expenses were based upon the number of hours of operation. Environmental externalities were not included in the capital, fixed, or variable costs.

each month instead of purchasing power on the spot market. In essence, these cost savings reflect the difference between the hourly wholesale market price and the hourly variable O&M cost for operating the candidate supply resource.

Dispatch-related cost savings attributable to each candidate resource were estimated in the following manner. First, the model calculates the least-cost dispatch of Tacoma Power's firm resources to meet its loads in each hour of each month. These resources include owned plants (e.g., Alder dam) and contractual rights (e.g., Priest Rapids). Loads include contractual obligations (e.g., the exchange with Seattle City Light) as well as retail customer demand. When the utility's firm resources are insufficient to meet load, the model assumes purchases from the wholesale market at prevailing market prices (from the base, high or low market price forecast, depending on which case is being run). When the utility has surplus energy, the model assumes sales into the wholesale market.

To estimate the dispatch-related cost savings of a candidate supply option in each month of the analysis period, two runs of the HAM model were made. First, the model was run without any new resources under base case assumptions (base water, Base A load growth, base price forecast). The total dispatch-related costs (i.e., costs of market purchases) for each month were retained from this run. Second, the model was run (under base case assumptions) with the new resource included in the portfolio of resources available to meet the load. The model would choose to run the new resource whenever its dispatch cost was less than the market price of electricity. The dispatch-related costs from this run were also retained. The difference in dispatch-related costs between the two runs was calculated and assigned as the benefit of running the resource over the planning period.

Calculation of Net Present Value

A separate financial analysis model was used to calculate the net present value of the candidate supply option. This model uses the capital costs, fixed O&M costs, and the benefits (i.e., dispatch costs savings from the HAM model) to determine the net present value (NPV) of the resource. An annual discount rate of 6% was used for the discounting of cost streams (and benefits) into present value (PV) dollars. The analysis consisted of the following steps:

1. Calculate the capital costs (overnight) minus the present value of salvage at the end of the lifecycle.
2. Calculate the present value (PV) of dispatch cost savings (benefits) for the lifecycle of the resource.
3. Calculate the present value (PV) of fixed costs for the lifecycle of the resource.
4. Calculate the net present value of benefits (NPV) by subtracting the overnight capital costs and the PV of lifecycle fixed costs, from the PV of dispatch cost savings.

5. Calculate the levelized NPV of the resource by dividing the NPV by the PV of MWhs produced.

The NPV represents the net benefit of the resource, in present day (2001) dollars, taken over the lifecycle of the facility. A NPV of zero would represent a resource that is essentially a break-even investment over its lifecycle. NPVs for resources of different lifecycles cannot be directly compared. Therefore, the levelized NPV is used to compare the average net benefit per MWh produced from the various supply options.

Results for Supply Options

The six supply options described in Chapter 5 were evaluated in the HAM model under several combinations of water, load, and price assumptions. These options are:

- Generic Simple Cycle Combustion Turbine (SCCT) – 45 MW (On-line date = April 1, 2002; Lifecycle = 15 years)
- Generic Combined Cycle Combustion Turbine (CCCT) –70 MW (On-line date = October 1, 2002; Lifecycle = 20 years)
- Contract Resource A – 25 MW (On-line = January 1, 2002; Contract term = 6 years)
- Contract Resource B – 25 MW (On-line = October 1, 2001; Contract term = 10 years)
- Gas Reciprocating Engines (Gas Recips)– 40 MW (On-line date = January 1, 2002; Lifecycle = 15 years)
- Northeast Substation Diesel Generators[4] – 68 MW (On-line date = February 1, 2002 Lifecycle = February 1, 2002 – January 2003)

Lifecycle Economic Analysis

After evaluating the supply options, three alternatives emerged with the best economic values. The following table (Table 8d) summarizes the results of the BBaB run (base water, base A load, base price), under the mid-range capital cost assumptions, and the assumed start dates.

[4] The economic analysis for the diesel generation project was complicated because some of the costs are "sunk" and the high market prices in the early months of our forecast significantly affected the calculation of NPV. Following the drop in market prices in June 2001, Tacoma Power terminated its lease for 30 of the diesel units and a purchase is being sough for the remaining 12.

Table 8d
Lifecycle Economic Analysis Results Comparison

	SCCT	CCCT	Gas Recips
Start Date	April 2002	October 2002	January 2002
Present Value of Benefits			
PV Dispatch Cost Savings	$ 45,964,592	$ 97,945,857	$ 54,800,858
Present Value of Costs			
Capital Costs	$ 30,442,500	$ 57,470,000	$ 32,000,000
PV Fixed Costs	$ 5,243,756	$ 32,927,557	$ 9,383,884
Net Present Value (NPV)	$ 10,278,336	$ 7,548,300	$ 13,416,973
Levelized NPV	$ 8.20	$ 2.23	$ 10.69

In examining the results of the BBaB runs, it is first appropriate to examine the Present Value (PV) of dispatch cost savings as modeled in HAM. The CCCT has the highest present value (PV) of dispatch cost savings, followed by the Gas Recips, and the SCCT. (At this stage of the analysis, only variable operating costs are included.) This result is expected primarily due to the fact that the CCCT has a higher generating capacity, lower heat rate and a lifecycle that is 5 years longer than the SCCT or the Gas Recips. However, after deducting capital and fixed O&M costs from the benefits of these resources, the preference for technology changes, with the Gas Recips facility showing the highest lifecycle value. The economic order observed in these results is the direct result of one of our evaluation criteria: resource timing. Given the forecast of high market prices early in the planning period, which decline over time to an equilibrium state, an economic advantage is given to resources that come on soon enough to capture those high priced market benefits.

Market Timing

In general, with the market price forecasts used in analysis, resources that were available earlier greatly increase their NPVs. Although the base case price forecast approaches equilibrium by December 2004, the magnitude of earlier prices dominates the dispatch cost savings of the resources. Table 8e illustrates the relative effect of start dates and elevated prices on the dispatch cost savings of the resources for the first 17 months of operation. Since this analysis was conducted, market prices have declined dramatically along with expected future prices. The dollar values shown on this table are indicative only of the value of these resources under very high near term electricity prices.

Table 8e
Dispatch Cost Savings of Earlier Start Dates (6/01 – 10/02)

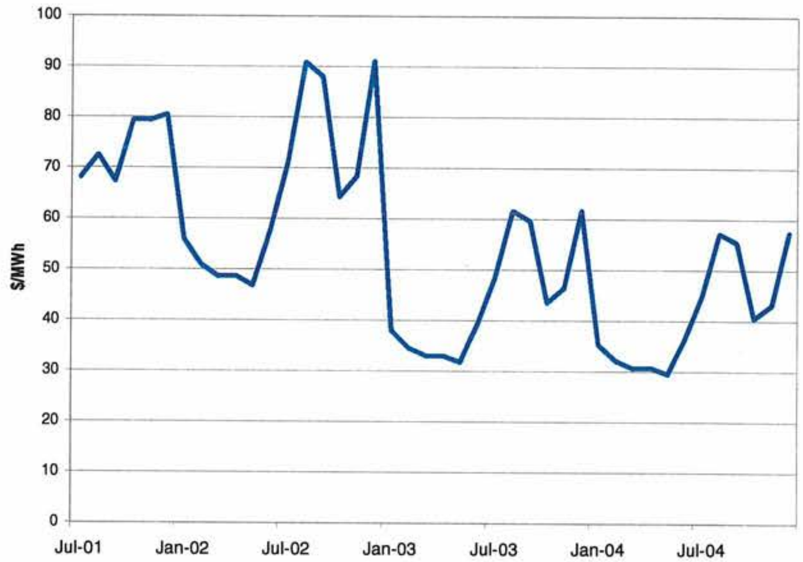
	SCCT	CCCT	Gas Recips
Jun-01	$ -	$ -	$ -
Jul-01	$ -	$ -	$ -
Aug-01	$ -	$ -	$ -
Sep-01	$ -	$ -	$ -
Oct-01	$ -	$ -	$ -
Nov-01	$ -	$ -	$ -
Dec-01	$ -	$ -	$ -
Jan-02	$ -	$ -	$ 4,102,000
Feb-02	$ -	$ -	$ 2,501,000
Mar-02	$ -	$ -	$ 5,730,000
Apr-02	$ 1,178,000	$ -	$ 1,100,000
May-02	$ 1,010,000	$ -	$ 948,000
Jun-02	$ 2,430,000	$ -	$ 2,219,000
Jul-02	$ 4,545,000	$ -	$ 4,095,000
Aug-02	$ 3,175,000	$ -	$ 2,892,000
Sep-02	$ 3,998,000	$ -	$ 3,623,000
Oct-02	$ 1,535,000	$ 3,062,000	$ 1,432,000
Summation	**$ 17,871,000**	**$ 3,062,000**	**$ 28,642,000**
% of Dispatch Cost Savings	**36%**	**3%**	**49%**

As can be seen, between the start date of the Gas Recips (Jan 02), and the start of the CCCT (Oct 02), the market price forecast used in analysis exhibits the highest prices observed during the lifecycles of the resources. Hence the majority of benefits are captured almost entirely in the first year of operation.

The imposition the Federal Energy Regulatory Commission (FERC) price caps on June 19, 2001 has greatly deflated market prices. Both the current prescheduled prices, and forward prices have dropped dramatically, signaling that the price caps may be both effective and sustainable. Forward prices as of 7/10/01 are shown on Figure 8a for reference. Forward prices as of 7/10/01 dovetail well with the long range price forecast, indicating that from a market theory perspective the price caps may have had the effect of reducing near term prices to a level approximating the long-term equilibrium prices.

Figure 8a

Average Mid-C Prices based on July 10, 2001 Forward Prices



A final economic analysis was performed to compare the SCCT, CCCT and Gas Recips without the bias resulting from different start dates and rapidly declining market prices. Table 8f illustrates the results, based on the BBaB case.

Table 8f

Resource Comparison with Start Date of January 2003

	SCCT	CCCT	Gas Recips
Start Date	January-03	January-03	January-03
Benefits			
PV Dispatch Cost Savings	$ 24,093,431	$ 85,591,997	$ 23,015,307
Costs			
Capital Costs	$ 30,442,500	$ 57,470,000	$ 32,000,000
PV Fixed Costs	$ 4,851,215	$ 32,226,866	$ 8,463,821
Net Present Value	$ (11,200,283)	$ (4,104,869)	$ (17,448,514)
Levelized NPV	$ (11.24)	$ (1.26)	$ (18.50)

With the start dates constant and two years out, all three resources have a negative NPVs. While this result may seem counter-intuitive at first, the base case price forecast beyond January 2003 does not exhibit the same degree of price magnitude and volatility as seen over the past year. The CCCT has the highest (least negative) lifecycle NPV and a slightly negative levelized NPV, indicating that in the long run the net value of the unit, based on its operating costs and heat rate, is just above market. This is expected because the long run market price is set in theory by the marginal resource – in this case the variable costs of a large scale CCCT with a heat rate between 6500 and 7000 Btu/kWh (below the heat rate of

7366 Btu/kWh of the resource used in our analysis).

Analysis of System Flexibility

Over the past several years, the composition of Tacoma Power's generation portfolio has changed, resulting in an overall loss in flexibility. In this context, flexibility is defined as the portfolio's ability to quickly adapt to changes in load, meet peaking requirements, provide adequate load following and reserves, and remain responsive to market conditions in such a way as to maximize the overall value of the portfolio (sell in high priced hours, buy in low priced hours). Although our modeling framework provides valuable insights into how resources compare and could be used to maximize the value of Tacoma Power's existing hydro portfolio, its results are a reasonable, but incomplete proxy for the illusive value that we seek: the value of flexibility lost or gained. Although we can model many combinations of price, water and demand (load), flexibility is the strongly desired commodity that is difficult to define and evaluate.

The loss in Tacoma Power's system flexibility is due in part to changes in the operation of Tacoma Power's hydroelectric resource due to license requirements (increased fish passage requirements, recreational constraints, and flood control), the removal of the Centralia Steam Plant, and a transition from the BPA 1981 Power Sales Contract to the new BPA Block Power Sales Agreement.[5]

Tacoma Power is close to supply and demand balance at most times during the planning horizon with enough steady-state base load resources to meet average loads, as long as none of our existing plant capacity is lost. The detailed analyses in this plan demonstrate that there are periods of peak demand when Tacoma Power will need additional supply. Resources that are easily dispatchable, can come on-line quickly and ramp swiftly, respond to load following requirements, and remain reliable under frequent up-ramping and down-ramping are valuable. The flexibility of a new resource that can be dispatched to meet peak demand will allow Tacoma Power to use existing supply resources to maximize their value in the market.

Alternatives to a Physical Resource

Tacoma Power continues to evaluate other market-based instruments for meeting future needs that include adding to system flexibility. The power market, still lacking the liquidity desired of a market, does not

[5] In comparing the previous BPA PF Contract and the new contract that will begin October 1, 2001, Tacoma Power both gained and lost flexibility. The new contract does not allow real time changes, shaping during the light load hours, or the ability move energy day-to-day within a month. However, the utility gained the ability to shape the energy during the heavy load hours, which was not available in the old contract. The amount the heavy load energy can be shaped hourly above and below the heavy load energy entitlement varies by month. We have the ability to move energy into the super-peak hours and out of the shoulders and valleys, on a pre-schedule basis. The daily heavy load hour energy total must be at the pre-defined amount every day within each month, and there are no real time changes allowed.

allow for buyers and sellers to observe the true price/value of a wide range of products that could meet some of Tacoma Power's needs for low water insurance or increasing system flexibility. For example, at this time, the price of a call option for guaranteed power at a guaranteed price in the future tends to be higher than the calculated carrying cost of a physical product (like a CT).

Conclusions About Supply Options

In the overall evaluation of resource acquisition, be it a new resource, a power contract, or contract options, the value of flexibility must be taken into account in the final analysis. Owned resources such as Simple Cycle Combustion Turbines and Gas Reciprocating engines provide such flexibility. Contract purchases typically do not provide as much flexibility at the same cost as ownership.

Based on the extensive economic analyses and modeling that has been performed to date, some conclusions can be made as follows:

- The SCCT, CCCT and the Gas Recips are the highest valued resource alternatives available to Tacoma Power.
- Given Tacoma Power's resource needs for increasing system flexibility and insurance against risk of low water and major unplanned plant outages, either the SCCT or Gas Recips have merit compared to market purchases across the many water, load and price cases that were modeled.
- When market prices are high, the capital costs of the SCCT and Gas Recips can be recovered in months, rather than years.
- Ownership of a resource will capture the value of the market by way of cost savings if Tacoma Power is deficit in supply, or revenues if surplus.
- Owned resources provide insurance against purchase exposure in times of high market prices and insufficient hydro capability.

If Tacoma Power has an energy need (MWhs), the CCCT is the most economically viable resource over the long-term. For peaking applications, the SCCT and Gas Recips are close in benefits (dispatch cost savings) and NPV. Further refinement is necessary to determine the best overall resource for these various purposes. Specifically, natural gas-fired resources that are intended to provide insurance against the risk of low water and/or system flexibility need to be sufficiently reliable and available to meet those needs. Key components of the reliability and cost of such resources are the arrangements for firm natural gas transportation and fuel contracts.

Section 8.3 Environmental Assessment of Supply Options

Tacoma Power is committed to preserving the quality of the environment, yet realizes that all resources have some level of environmental impact associated with their development and operation. In evaluating the environmental impacts of a resource, Tacoma Power considers the residual impacts remaining after mitigative actions are taken. From an environmental standpoint, the best resources are those that have few and minor incremental impacts to human beings and natural systems.

In order to determine how resource options compare from an environmental impact perspective, and which have the least impacts in terms of number and magnitude, a resource evaluation methodology was developed. Each resource was compared within the context of a range of adverse environmental impacts, including impacts on air quality, surface and groundwater, soils and geology, wildlife and aquatic resources, land-use, aesthetics and recreation, and human health. The relative impacts of each option were evaluated qualitatively assuming best available control technologies and other mitigation measures that would effectively minimize environmental impacts. Quantitative information such as relative amounts of air pollutants and relative water requirements of each technology were also taken into consideration.

The results of the resource evaluation suggest a ranking of options in terms of environmental impact. From least impact to most impact, the candidate supply options were ranked as follows: combined cycle combustion turbine, gas reciprocating engines, simple cycle combustion turbine, and diesel/gas combination fueled generators.

The most significant potential adverse environmental impacts associated with the supply options being evaluated are primarily related to air quality. All six supply options require the burning of fossil fuels, thus emit greenhouse gases and other air pollutants. Exhaust emissions vary by type of fuel, heat rate, control technologies, and other factors. The primary air pollutants of concern, with respect to the alternatives considered, are CO2, CO, NOx, VOC's and Particulates. The emissions associated with each of the supply options are summarized in Table 8g.[6] All six supply options would emit some level of CO2, CO, and NOx. As CO2 and CO emissions are directly related to a resource's heat rate, a combined cycle combustion turbine option would, theoretically, produce the least amounts of CO2 and CO on a per unit of energy basis, followed by a resource that utilizes gas reciprocating engines, the diesel/gas option and finally the simple cycle CT option. With respect to NOx, a combined cycle resource would, theoretically, emit the least amount of NOx per unit of energy. This would likely be followed by either an option that utilizes gas reciprocating engines or the simple cycle combustion turbine option (both units would emit approximately the same quantity of NOx per unit of energy produced). The diesel/gas option would likely emit the most NOx per unit of energy produced. Any option that would solely utilize natural gas as a fuel would produce negligible amounts of particulates and minor amounts of VOC's. A resource option that utilizes diesel as a fuel will produce significant levels of particulates, including suspected and known carcinogens, and a

[6] Among the six alternatives, negligible amounts of SOx may also be emitted. Diesel combustion, in general, emits significant levels of SOx. However, SOx emissions are significantly reduced in the diesel/gas option considered here with the use of low sulfur diesel fuel.

minor amount of VOC's (comparatively less than straight gas options).

Table 8g
Air Emissions Associated with Supply Options*

	NOx	CO2	Particulates	CO	SOx	VOCs
Simple CT	√	√		√		√[3]
Gas Recips	√	√		√		√[3]
Combined CT	√	√		√		√[3]
Diesel/Gas	√	√	√[2]	√	√[1]	√[1]
Contracts (Gas Recips)	√	√		√		√[3]

*Assumes best available control technology
[1] Negligible amount
[2] Contains suspected and known carcinogens
[3] Minor amounts – may contain suspected or known carcinogens.

From the standpoint of air emissions, assuming best available control technology, a combined cycle CT would produce the least adverse environmental impacts, followed by any of the options that utilize gas reciprocating engines, followed by a simple cycle CT. Any option that utilizes diesel as a fuel is the least desirable from an air emissions standpoint.

The second most likely significant potential adverse environmental impacts associated with the supply options being evaluated are those related to surface and ground water. Combined cycle CT technology entails significant amounts of water consumption (over one million gallons per day when in operation) and may entail some level of thermal water discharge or treatment. Simple cycle CT technology requires substantially less water consumption relative to combined cycle CT, particularly if "dry" emission abatement technology is utilized. Supply options that utilize gas reciprocating and diesel/gas engines require only negligible water consumption.

From the standpoint of potential adverse impacts to surface and ground water resources, assuming best available control technology, a combined cycle CT would produce the most impacts. A simple cycle CT supply option would entail significantly less impacts on surface and ground water resources and gas reciprocating and diesel/gas engines would generally produce no adverse environmental impacts.

Potential adverse environmental impacts to other categories of resources were identified and discussed. These include potential adverse impacts to threatened and endangered species (primarily aquatics), anadromous and resident fish populations, visual and noise related impacts, and impacts to land use and recreation resources. Potential impacts to aquatic species are likely correlated with surface water impacts, are largely dependent on site location, and are generally relatively minimal (although can be moderately high for a combined cycle CT). Noise impacts are generally minimal and can be adequately mitigated for with appropriate facilities design. Visual impacts are minimal and also depend largely upon specific site location, and impacts to land use and recreation resources are relatively minor. Finally, while it was noted that extraction and transportation of fuel would likely impose varying levels of additional adverse impacts, no attempt was made to compare such impacts among supply alternatives.

Section 8.4 Analysis of Conservation Options

A detailed assessment of each of the three customer sectors--residential, commercial, and industrial--as done to determine how much conservation could be achieved during the planning horizon. This assessment is summarized in Chapter 6.

Thirty-six average megawatts of conservation have been identified as cost-effective to Tacoma Power and achievable over the next ten years. The evaluation of the costs and benefits to acquire conservation is based on Tacoma Power's perspective, as opposed to the regional or societal view. No effort has been made to determine the net societal costs and benefits of acquiring the identified conservation savings. Determining the value of conservation is much more complex than comparing the cost of conservation measures to the cost of additional power supplies. Conservation measures produce a variety of other benefits to the utility and its customers that impact the overall economics. These additional benefits range from saving water through the customer purchase of a new energy efficient clothes washer, on increasing home values and comfort levels through the installation of weatherization measures, to the potential for conservation to help defer the need for distribution system upgrades.

Economic Analysis of Conservation Measures

The economic net benefits of the proposed conservation measures were analyzed using the same methods as the generating resources. By utilizing similar methods, the results of the lifecycle analysis of the conservation measures are comparable to the results of the generating resources. Table 8h summarizes the results of the analysis:

Table 8h
Lifecycle Analysis of Conservation Measures

Measure	Lifecycle (years)	PV Benefits	PV Costs	NPV	Levelized NPV
Weatherization	30	$ 13,994,772	$ 18,190,217	$ (4,195,445)	$ (13.51)
CF Bulbs*	20	$ 6,457,760	$ 2,820,795	$ 3,636,965	$ 28.23
Appliances	30	$ 1,059,896	$ 987,676	$ 72,220	$ 2.98
Commercial	20	$ 57,458,726	$ 34,806,403	$ 22,652,323	$ 16.76
Industrial	25	$ 6,266,014	$ 2,192,685	$ 4,073,328	$ 28.21
Military	18	$ 5,803,805	$ 2,895,275	$ 2,908,530	$ 20.74

* Compact fluorescent bulbs and fixtures.

Present Value of Benefits The benefits of conserved MWhs gained through conservation were calculated by taking the annual MWhs saved by the program, multiplied by the base price forecast converted to annual average megawatts. Benefits were calculated over the entire expected lifecycle of the conservation measure. The MWhs used in the analysis include Tacoma Power's system transmission and distribution losses. By including losses, the megawatt-hour savings from the measure reflect the true quantity of power saved (i.e., power produced at the generator, less transmission losses, less distribution losses is equal to the delivered power). The benefits stream was discounted at 6% over its lifecycle to determine the Present Value (PV) of benefits.

Present Value of Costs Costs for the program included procurement costs, implementation costs, administration costs, and if applicable, loan costs. The cost stream was discounted at 6% over the lifecycle of the measure to determine the Present Value of costs.

Net Present Value The PV of Costs was subtracted from the PV of Benefits to produce the net present value (NPV) of the measure against the market. Given the base price forecast, the NPVs shown are the present value net benefits of the conservation measures, excluding lost revenues.

Levelized NPV The measure NPV is divided by the PV of MWhs saved to determine the levelized NPV. Positive levelized NPVs indicate that the net benefits of the program, spread over the MWhs of savings, have net positive value. Negative levelized NPVs indicate a net negative value (again, the NPVs and Levelized NPV figures do not include the effects of lost revenues). Levelized NPV is only calculated to account for differences in program life. CF bulbs and industrial measures have the highest levelized NPV, and Weatherization Measures has the lowest.

Results

Under current assumptions, the programs for the industrial sector and compact fluorescent bulbs/fixtures have the highest NPV, followed by the programs for the commercial and military sectors. Appliances do have a positive NPV, although it is low. Weatherization measures have the only negative NPV, which indicated the program, as proposed, is uneconomic. This program will need to be revamped to improve its cost-effectiveness.[7]

One element absent from the conservation economic analysis is the effect of lost revenues to the utility associated with the conservation measure. Lost revenues include the cost of foregone retail power sales, transmission and distribution sales, and other cost items normally recovered through sales. In many cases, the utility's costs associated with conservation, including program costs and lost retail revenue exceed savings associated with avoided power purchases. This alone, however, does not necessarily refute the value of investments in energy savings.

A more comprehensive economic analysis should consider the net economic impacts to the customer, the utility, and the region. For example, a zero interest loan for weatherization that reduces a consumer's bill may produce long-term savings to the consumer (even after the loan repayment is considered). For the utility, savings may be realized from a reduction in purchased power expenses. However, the utility may also be negatively affected by an increase in its debt-to-equity ratio, encumbered loanable funds, lost retail power revenues, and lost transmission and distribution revenues. From the regional perspective, the reduction in load may result in a decrease in power plant emissions, or an increase in available water for fish migration. In total, the conservation of one MW affects the consumer, the utility, and the region differently. Additional work is needed to fully evaluate the long-term effects of each conservation measure.

Section 8.5 Scenario Analysis

The Integrated Resource Planning team developed four different scenarios that describe possible future events related to the electric utility industry. The four scenarios were intended to capture some of the changes that might occur and have an impact on Tacoma Power. Realizing that there is significant uncertainty in a 10-year Integrated Resource Plan, scenario planning allows the opportunity to consider the possible effects of factors such as different public policies and new technologies.

Scenario analysis does not predict the future. The process of identifying possible futures and writing stories or scenarios about them gives planners a feel for a range of possible outcomes that may develop. Scenario analysis allows planning teams to evaluate the effects that non-quantifiable factors may have on resource decisions. These qualitative factors could include such things as regulatory and political events or

[7] A comprehensive review of the program design and operation is currently underway to identify and incorporate new efficiencies that decrease costs while maximizing the energy savings realized. Initial staff efficiencies identified by staff include centralized scheduling to maximize the use of field staff time, computers and printers in the field allowing recommendations to be made before leaving customers' homes, and improved tracking of outstanding offer to customers. Program design efficiencies being implemented include financial caps on window loans and reductions in the length of loan terms for all residential measures.

sudden advances in technological capability.

This kind of analysis does not substitute for traditional economic evaluations based on known and quantifiable characteristics of available supply resources. It does allow planners to add another layer of understanding to their decisions. Scenario analysis allows "what if" games to play out against decisions based on economics and engineering. For example, a decision to pursue a fossil fueled combustion turbine might be advantageous to a utility on an economic basis and yet look far less attractive if a steep carbon tax were enacted.

After developing the scenarios for Tacoma Power's Integrated Resource Plan, the team then identified portfolio components and strategies that would foster success under each one of the scenarios. At the same time, the team tried to determine what indicators or signposts would suggest that events are moving toward one of the possible scenarios.

The process of identifying and watching for sign posts is intended to provide an early warning that one of the scenarios, or elements of a scenario, are becoming more likely. If the possible outcome might require a shift in resource strategy, the utility will be poised to act swiftly with a clearer understanding of what reasonable responses are available.

The four scenarios are:

- **The Way We Were**, a scenario that turns back the clock to the time just before the wholesale electricity market crisis and imagines a patchwork of restructuring initiatives without a federal mandate;
- **Free Market Prevails**, in which competition in the electricity industry spurs new products and technologies and requires the development of sophisticated risk management tools;
- **Green Renaissance**, a future that envisions global efforts to improve the environment and limit greenhouse gases; and
- **Retrenchment,** representing a possible future that would return to regulated cost-based rates and vertically integrated utilities.

The table on the following pages shows the Portfolio Components and Strategies along with the Sign Posts identified for each of the four scenarios.

Scenario	*Portfolio Components*	*Sign Posts*
Retrenchment	▪ Big Combustion Turbine ▪ Expand Service Territory ▪ Buy from BPA	▪ California Power Authority is formed ▪ Utilities build power plants ▪ New municipal utilities are formed ▪ Re-regulation either by state or federal government ▪ Independent Power Producers fail or quit operating
Green Renaissance	▪ Proactive distributed generation program ▪ Encourage distributed generation by installing and marketing distributed generation to reduce load or as a new line of business ▪ Proactive energy conservation program ▪ Meet customer demand for green resources ▪ SCBID or other small hydro or low impact hydro resources ▪ Peak shifting ▪ Time-of-use pricing ▪ Utility scale fuel cells or battery storage systems ▪ Renewable or environmentally preferred resources ▪ Partnerships with ESCOs	▪ More players emerge in the energy industry – distributed generation; technology alternatives; ESCOs and RESCOs ▪ Demand for green power options and sustainable resources ▪ High fossil fuel prices *or,* fossil fuel surpluses because demand declines ▪ Environmental catastrophe ▪ Global warming is proved beyond any doubt ▪ Technology breakthroughs occur that offer new clean generation resources ▪ Carbon tax is enacted ▪ Democrats are elected in 2004 ▪ Fewer independent power producers (merchant plants) and more small alternative providers
Free Market Prevails	▪ Low capital investment ▪ Limit stranded cost exposure ▪ Avoid long-term contracts (more than 2 years) ▪ More use of market risk management tools ▪ Must have green resource to meet any renewable portfolio requirement ▪ Use Click! Network for real-time pricing ▪ Rates offer market price signals ▪ Utility must be responsive to customer needs and wants ▪ Offer more products and services	▪ Bush Energy Plan legislation is enacted ▪ Forward prices should reflect gas prices ▪ Other states move forward with restructuring ▪ Customers ask for market access ▪ More private investment in new generation technologies ▪ Relaxation of environmental standards ▪ Availability of hedging tools ▪ Continued utility divestiture

Scenario	*Portfolio Components*	*Sign Posts*
The Way We Were	▪ Buy as much BPA as possible ▪ Avoid distributed generation ▪ Don't invest in new technology ▪ Transmission system operates free of constraints ▪ Market access is easier ▪ Coal resource? ▪ Long-term commitments are OK	▪ Price volatility declines ▪ Research and development related to distributed generation declines ▪ Muddling along – nothing big changes ▪ Transmission infrastructure development

Chapter 9: Recommended Actions

Chapter 9: Recommended Actions

The study and evaluation contained in this Integrated Resource Plan point to some specific courses of action. These recommendations, summarized below, range from simple efforts to monitor changing market conditions and watch for the development of new energy technologies, to consideration of much more complicated resource acquisition decisions. The results presented here, along with these recommendations, form the basis for continuing refinement of Tacoma Power's resource optimization strategies.

Section 9.1 Supply Resources

One of the most challenging issues for Tacoma Power is finding the appropriate balance between investment in firm supply resources (utility owned or long term contracts) and reliance on the wholesale power market. If loads are less than forecast and the utility builds too much firm supply, or if it acquires a high cost resource, customers will pay higher rates. On the other hand, over-reliance on the spot market could expose the utility to the kinds of price spikes that have persisted since mid-2000. Similarly, if the utility fails to invest in energy efficiency improvements in customers' homes and businesses, the opportunity to postpone investments in generation resources is lost. Alternatively, over-investment in conservation or investments in high-cost efficiency measures will cause upward pressure on consumer rates.

Three primary needs have been identified through the extensive analyses of supply/demand balance under a variety of water, load, and price cases. These are:

1. The need for insurance to reduce the risk of exposure to high market prices in the event of critical or adverse water conditions and/or higher than expected load growth.
2. The need to augment the reliability and flexibility in our existing firm resource base to cover losses in firm generation from planned and unplanned outages. The need is for both energy and capacity.
3. The need for additional peaking capacity to ensure system reliability during periods of extremely cold weather.

These needs can be addressed through a variety of options, many of which do not entail the construction of a physical resource. The following list provides a range of strategies and actions that should be considered:

- Make purchases on the wholesale market at the time they are needed. In the event of higher than anticipated market purchases or higher than forecast market prices, recover these costs through temporary rate surcharges.
- Purchase a site for a thermal resource and install basic infrastructure. This will shorten the lead-time for construction of a physical

resource in the event it is needed.

- Build up cash reserves to lessen rate impacts in the event of another drought or higher than forecast market prices, or rely on short-term borrowing.
- Build or contract for a thermal resource to cover all or part of the identified needs for energy and capacity.
- For planned maintenance of generating units, make forward market purchases when prices are favorable rather than using the spot market.

Tacoma Power issued an RFP for an approximately 50 MW thermal resource in July 2001. The responses from vendors and developers are currently being reviewed.

A final decision on how best to meet the identified needs for energy and capacity will be significantly influenced by changing market prices, resource costs, and rate impacts. We expect to complete a review of all of the above options and make a determination on the best resource strategy during the fourth quarter of 2001.

Section 9.2 Green Power Program

In May of 2001, Governor Locke signed into law legislation that will require utilities to provide retail customers, by January 1, 2002, the voluntary option to purchase "qualified alternative energy resources." This law is seen as an effort by the legislature to facilitate the development and sale of generation facilities fueled by wind, solar energy, geothermal energy, landfill gas, wave and tidal power, digester gas, qualified hydropower[1], and biomass fuels.

For the past year, Tacoma Power has provided its customers with a green power choice by way of its Evergreen Options program. The retail end of the program was designed to offer customers the choice of supporting a green purchase. Several levels of participation are currently offered at the retail level: Frog ($3), Salmon ($6), and Otter ($10)). Additional levels of participation are offered to Tacoma Power's Schedule B and G customers. Participation in the program goes toward support of the additional incremental cost of the green power purchase. At this time, Tacoma Power is not offering a direct sale of green megawatts to customers, but rather a voluntary bill adder program that is designed to collect additional revenues to support a system-wide green purchase.

Tacoma Power recommends continuation of the Evergreen Options program beyond the October 1, 2001 Environmentally Preferred Power program (EPP) contract expiration. If the EPP purchase qualifies under the new legislation, Tacoma Power will most likely pursue a contract with BPA. If EPP does not qualify, Tacoma Power will explore other options for

[1] The legislation defines qualified hydropower as energy produced either: (a) as a result of modernizations or upgrades to existing facilities made after June 1, 1998 which have been demonstrated to reduce mortality of anadromous fish; or (b) by run of river or run of canal hydropower facilities that are not responsible for obstructing the passage of anadromous fish.

providing the resource base for the offering. It is anticipated that one average megawatt will be sufficient to support the retail offering through at least the middle of 2002.

Section 9.3 Distributed Generation

It is possible that distributed generation will become common within the 10-year planning horizon of this IRP. For this reason, it is important for Tacoma Power to understand the range of possibilities and the strategic value they offer for the utility and its customers. Potential advantages for Tacoma Power include resource diversification and ability to meet customers' needs and preferences for ultra-high reliability or environmentally preferable electricity supplies. Distributed generation may also allow Tacoma Power to avoid or reduce some distribution system costs and, some day, provide lower cost power supplies.

A range of issues need to be understood before Tacoma Power can include distributed generation in its resource portfolio. These include:

- Value of distributed generation projects to strategic objectives of utility
- Knowledge about specific generating technologies and stage of development
- Interconnection and operation standards and requirements
- Customer interest and preferences
- Siting and permitting requirements
- Safety, liability and legal concerns
- Costs and pricing
- Delivery mechanisms
- Partnership opportunities

Tacoma Power can prepare for future distributed generation opportunities by closely monitoring the development of new generating technologies and applications. The utility should consider participating in a pilot project such as the BPA fuel cell beta test beginning later in 2001, or a similar test project in partnership with another interested utility. Finally, Tacoma Power should begin to systematically inventory customer owned generation resources, potential sites and applications for distributed generation, as well as interest in future distributed generation projects.

Section 9.4 Conservation

Conservation should be the primary strategy for meeting expected load growth in Tacoma Power's service territory. We are recommending that conservation programs be ramped up to acquire 36 aMW of energy savings over the 10 year planning horizon. This level of acquisition will meet 60% of projected load growth under the Base A load forecast. The recommended acquisition schedule and summary of anticipated program expenditures are shown in Tables 9a and 9b.

Tacoma Power will pursue strategies that encourage customer participation and investment in conservation. These approaches include education and promotion to inform customers about the benefits of conservation along with specific ways to use electricity more efficiently;

adoption of codes and standards that move the minimum efficiency requirements higher; and financial assistance, grants or loans, to provide incentives to install conservation measures.

Tacoma Power's Conservation Potential Assessment identified energy savings in the residential, commercial, industrial and military sectors. Tacoma Power proposes to support the direct acquisition of these savings through a combination of program offerings as described below.

Residential Sector

Weatherization Tacoma Power energy specialists provide Home Energy Checks to evaluate the energy efficiency of customers' homes. The specialists make specific recommendations for cost-effective energy savings improvements, including insulation and window replacements. Insulation measures include ceiling, floor, water pipe, duct and wall insulation. Residences with electric heat installed prior to 1984 are eligible candidates for weatherization. (Homes built later than 1984 are required to meet the Model Conservation Standards.)

The cost of weatherizing homes varies depending on the improvements selected. Zero interest loans are available for customers to cover most costs - with the specific exception of loan limits on certain window replacements. The loan term may be up to ten years, depending on the amount borrowed and is secured with a lien on the home. Prior to any payments, a Tacoma Power energy specialist inspects all work done to make sure it is completed to the required specifications.

Both owner occupied and rental properties; single family and multi-family are eligible to participate. It is necessary to have the property owner's approval before weatherization improvements can be made to rental property. Additional grant funding may be available for customers who meet certain income guidelines. Funding for the loan program is provided through the revolving loan fund established by Tacoma Power.

Lighting Cost-effective lighting opportunities exist both in the residences and in the common areas of multi-family buildings and complexes. The current technological approach used to acquire these savings is the replacement of regular incandescent light bulbs with compact fluorescent bulbs that use one quarter to one half of the energy to produce the same amount of light as comparable incandescent bulbs. Compact fluorescent light bulbs come in a variety of shapes and sizes to accommodate customer lighting needs. In addition to bulb replacement, compact fluorescent fixtures are energy efficient replacements for standard fixtures. Multi-family lighting projects are currently funded with the revolving loan program. Grants or rebates to pay for 50% of the cost of compact fluorescent lights and fixtures are proposed.

Appliances Energy Star appliances are identified by the US Department of Energy as highly energy efficient products, exceeding minimum federal standards. Energy Star qualifying products are initially more expensive to purchase than less efficient units. However, Energy Star appliances cost less to operate each month than similar non-qualified models. A combination of point of purchase rebates and loans for early retirement of older units in service is proposed to provide an incentive for customers to purchase Energy Star models. Eligible appliances include dishwashers, clothes washers, water heaters, and refrigerators. Financing for these appliances may be incorporated into the weatherization loan program.

Commercial Sector

Existing The commercial conservation program offers technical and financial assistance for the installation of energy efficient measures in existing commercial buildings, both publicly and privately owned. In order to identify opportunities to reduce energy consumption and energy demand, a Tacoma Power commercial energy specialist performs a building survey tailored to the specific building and customer needs. A more complex survey may include a detailed accounting of all energy-using equipment and engineering calculations or computer simulation modeling of the building. A benchmarking analysis tool allows energy use comparisons to be made with similar buildings to show trends or inconsistencies that need to be addressed.

Recommended measures include energy efficient lighting and lighting controls, heating, ventilating, and air conditioning (HVAC) system modifications, HVAC control systems, efficient refrigeration systems, and efficient motor and drive systems. Tacoma Power is proposing grants for up to 65% of the cost of retrofit projects based on the calculated payback of the measures to be installed. The balance of project costs could be financed through the existing Commercial Loan Program. Depending on the amount of money to be borrowed, loans are offered at zero interest for up to a five-year term. Loans are available to customers who meet the established financial criteria. Conservation savings available from multi-family buildings will be acquired through this program mechanism.

Commercial–Non Building Applications

Tacoma Power has identified energy savings opportunities to be gained from "non-building" end-uses. Applications being pursued include LED traffic lights, vending machine "misers", and efficient lighting and timers for billboards and other business signage.

Industrial Sector

Existing Industrial The targeted goal for existing industrial customers is to acquire energy savings from industrial process improvements, refrigeration, lighting, efficient motors and drives, and compressed air systems. Tacoma Power is proposing assistance with the purchase of high-efficiency equipment and providing incentives for up to 75% of the costs for efficiency modifications to industrial processes or systems.

The balance of the project's costs can be financed through the existing loan program. Loans are offered at zero interest for up to a five-year term. For simple efficiency improvements, standard engineering calculations will be used to determine energy savings. For more complex, energy intensive process improvements, calculations may be supplemented with pre-condition and post-condition energy monitoring, in order to more accurately quantify energy savings.

Commercial/Industrial New Construction

Optimizing the energy efficiency of a new building often depends on decisions made at the very beginning of a project. New construction is the time to incorporate techniques and strategies that take a building or facility beyond code to help save energy and increase comfort levels. Tacoma Power provides information on efficient technologies and the impacts of various design decisions

State law prohibits loans to achieve conservation in new buildings. Incentives of 65% for commercial and 75% for industrial are proposed to help defer the incremental costs of efficiency modifications for equipment and processes.

Military

Tacoma Power has a successful history working with Ft. Lewis on capturing energy efficiency opportunities including a major retrofit completed in 1998 that acquired 2.66 average megawatts. Additional savings can be acquired through lighting controls and sensors, LED traffic lights, energy efficient appliances and other various measures currently being looked at by Ft. Lewis. Opportunities for energy efficiency improvements do exist at McChord Air Force Base. Much of the vintage housing will be either demolished or remodeled. An additional 424,000 square feet of new construction are in the planning stages. The commercial buildings have opportunities for efficient lighting and lighting controls.

Table 9a
Conservation Summary

Conservation Project	Costs(1)	Loans(2)	Annual Savings aMW(3)	Levelized Cost
Residential Weatherization	$ 18,190,217	$ 44,084,552	4.1	39.6
Compact Fluorescent Lights	$ 2,820,906	$ -	3.0	18.8
Appliances	$ 964,538	$ 653,080	0.4	29.0
Commercial	$ 34,806,403	$ 4,779,815	24.3	19.0
Industrial	$ 2,192,685	$ -	2.2	10.8
Military	$ 2,895,275	$ -	2.4	15.7
Total Levelized Cost	$ 61,870,025	$ 49,517,448	36.4	21.6

(1) Costs are present value of all lifetime costs including O&M costs, incentives and the values of the loan.
(2) Loans are the present value of the face value of the loans.
(3) Includes savings for T&D line loss of 1.17% for military and 5.14% for non-military.

Table 9b

Tacoma Power Conservation Acquisition Schedule (in aMW)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Totals
Residential Weatherization	0.18	0.31	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	4.1
Appliances	0.02	0.02	0.04	0.04	0.05	0.05	0.06	0.06	0.05	0.05	0.4
Compact Fluorescent Lighting	0.96	0.63	0.64	0.64	0.02	0.02	0.00	0.00	0.00	0.00	2.9
Commercial	0.62	1.51	2.60	3.07	3.07	3.07	3.07	2.78	2.60	1.88	24.3
Industrial	0.05	0.18	0.24	0.28	0.28	0.24	0.24	0.24	0.24	0.24	2.2
Military	0.00	0.24	0.42	0.42	0.42	0.42	0.42	0.00	0.00	0.00	2.4
Total aMW	1.83	2.89	4.38	4.90	4.29	4.25	4.24	3.53	3.34	2.62	36.4

Load Management

Based on our analysis of supply and demand, there is growing concern about loss of flexibility in managing our system to meet peaks and follow loads. Of particular concern are periods of abnormally cold weather during the months of December, January, and February. Therefore, it makes sense to begin work on potential load control options.

Water and Space Heat Load Control The costs of building the infrastructure to support this approach are high when weighed against the benefit. The recommendation is to stay abreast of changes in the technology and deployment of similar systems in other parts of the country and perform some technology testing when testing other uses of the Click! system, but take no further action at this time.

Load Shedding Tacoma Power should begin to develop the infrastructure to deliver a load shedding program. The steps that should be taken now include the identification of candidate customers, the analysis of their loads, discussions with them about their ability to respond to a call for load shedding and their interest in participating in a load shedding effort, and perhaps the installation of meters that would be used in a load shedding program. Any agreement with a customer would be contingent on Tacoma Power's need and therefore the financial incentive paid only when and if load was required to be shut down.

9.5 Sign-post and Technology Monitoring

The scenario analysis developed for this IRP identified some possible future conditions that could affect the utility's resource strategy. Similarly, our investigation of distributed generation issues determined that new technologies and applications could have a significant impact on Tacoma Power. As a result, we recommend forming a multi-functional working group to meet quarterly to watch for sign-posts identified in scenario analyses and to keep track of distributed generation developments that may be useful to Tacoma Power.

10
Appendix A: Glossary of Terms

Appendix A: Glossary of Terms

adverse water conditions: Adverse water conditions are defined as the annual inflows that are exceeded 75% of the time.

aMW or average annual megawatt or average megawatt (aMW): A unit of energy output over a year that is equal to the energy produced by the continuous operation of one megawatt of capacity over a period of time. (Equal to 8,760 megawatt-hours).

average water conditions: Average water conditions represent the historic mean monthly inflows.

base load: A power plant that is planned to run continually except for maintenance and scheduled or unscheduled outages. Base load also refers to the minimum load in a power system over a given period of time.

Btu or British thermal unit: The amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit (3,412 BTUs are equal to one kilowatt-hour).

capability: The maximum generation that a machine, station or system can generate under specified conditions for a given interval without exceeding approved limits.

capacity: The maximum power that can be produced by a generating resource at specified times under specified conditions.

CO (Carbon Monoxide) – A colorless and odorless gas that is commonly formed when carbon containing fuels are not completely burned. CO inhalation decreases the oxygen carrying capacity of blood, weakens the pumping of the heart and in turn reduces the amount of blood pumping throughout the body.

CO2 (Carbon Dioxide) – CO2 is emitted through both natural and human activities. As fossil fuels are combusted the carbon in them is almost entirely emitted as CO2. Since the industrial revolution, the natural equilibrium of atmospheric CO2 has been altered as a result of fossil fuel combustion. As a result of its heat trapping properties, CO2 (along with methane and nitrous oxide) are theorized to be the primary cause of global warming.

critical water: The extreme low water conditions are represented by 'critical water'. Critical water conditions are defined as the lowest annual inflows during a twelve-month period. Operating year 1941 (August 1940 to July 1941) represents the critical water period for Tacoma Power's system.

demand: The rate at which electric energy is delivered to or by a system at a given instant or averaged over a designated period, usually expressed in kilowatts or megawatts.

DSM or demand-side management: Strategies for reducing consumption by influencing when and how customers use electricity. Demand-side management includes such things as conservation programs and incentives for switching electricity use from peak usage periods to off-peak hours.

distribution: The transport of electricity to ultimate use points such as homes and businesses.

FERC or Federal Energy Regulatory Commission: A federal agency responsible for regulating key activities of the nation's natural gas utilities, electric utilities, natural gas pipeline transportation utilities and hydroelectric power producers.

good water conditions: Good water conditions represent the annual inflows that are exceeded 25% of the time.

grid: The linking system of transmission lines, regionally and locally.

heat rate: a measure of generating station thermal efficiency--generally expressed in Btu per net kilowatthour. It is computed by dividing the total Btu content of fuel burned for electricity generation by the resulting net kilowatthour generation.

historical streamflow record: The unregulated streamflow data base of the 50 years from July 1928 to June 1978. The data are modified to take into account adjustments due to irrigation depletions and evaporations for the particular operating year being studied.

IPP or independent power producer: A non-utility power generating entity, defined by the 1978 Public Utility Regulatory Policies Act, that typically sells the power it generates to electric utilities at wholesale prices.

independent system operator (ISO) or independent grid operator (IGO): Independent manager of transmission lines to assure safe and fair transfer of electricity from generators to distribution companies.

kW or kilowatt: A unit of electrical power equal to one thousand watts.

kWh or kilowatt-hour : A basic unit of electrical energy which equals one kilowatt of power used for one hour.

load: The amount of electric power delivered or required at a given point on a system. (Amount of electric power consumed at a location).

marginal cost: The cost of the next generator needed to serve additional electricity demand.

MW or megawatt: A unit of electrical power equal to one million watts or one thousand kilowatts.

MWh or megawatt-hour: A unit of electrical energy which equals one megawatt of power used for one hour.

mill: One-tenth of one cent. The common unit for pricing electricity.

nameplate rating or nameplate capacity: A measurement indicating the approximate generating capability of a project or unit, as designated by the manufacturer. In many cases, the unit is capable of generating substantially more than the nameplate capacity since most generators installed in newer hydroelectric plants have a continuous overload capacity of 115 percent of the nameplate capacity.

NOx (Oxides of Nitrogen) – A family of gases that enter the air through a variety of natural and human activities. In general, any activity that involves combustion creates some NOx. Oxides of Nitrogen are harmful both on their own and in combination with other pollutants.

particulates – Particulates can cover a wide range of pollutants including diesel soot, wood smoke, road dust, fly ash and sulfate aerosols. Combustion of fossil fuels is the principal source of particulate emissions. Studies have suggested that particulates can produce injury within the human respiratory tract. Elderly people, small children and people suffering from respiratory illnesses are especially prone to harmful effects from particulates.

peak demand: The maximum electrical load demand in a stated period of time. On a daily basis, peak loads occur at midmorning and in the early evening.

peaking capability: The maximum peak load that can be supplied by a generating unit, station or system in a stated time period.

power: A term usually meant to imply both capacity and energy.

RTO or regional transmission organization: A group of utilities, independent power producers and state agencies that join to provide more equitable and easier access to power lines in an area covering many states.

restructuring: Reconfiguring the market structure by eliminating the monopoly on the essential functions of an electric company.

shaping: The scheduling and operation of generating resources to meet changing load levels. Load shaping on a hydro system usually involves the adjustment of water releases from reservoirs so that generation and load are continuously in balance.

SOx (Oxides of Sulfur) – Sulfur oxides include sulfur dioxide (SO_2), sulfur trioxide (SO_3), sulfurous acid (H_2SO_4) and sulfuric acid (H_2SO_4). The major sources of sulfur dioxide is fossil fuel combustion (primarily fuel containing sulfur)http://www.epin.ncsu.edu/apti/ol_2000/module6/sulfur/character/figures/figure01.htm. SO2 is converted in the atmosphere into sulfuric acid, which is the main component of acid precipitation, and particulate sulfate compounds which are corrosive and are potentially carcinogenic.

transmission: The act or process of transporting electric energy in bulk from one point to another in the power system, rather than to individual customers.

transmission grid: An interconnected system of electric transmission lines and associated equipment for the transfer of electric energy in bulk between points of supply and points of demand.

variable cost: The total costs incurred to produce energy, excluding fixed costs which are incurred regardless of whether the resource is operating. Variable costs usually include fuel, maintenance and labor.

Volatile Organic Compounds (VOCs) – Volatile organic compounds are organic gases and vapors that can volatize and participate in photochemical reactions. The sources of VOC's are numerous. but include evaporation of fuels and incomplete combustion of fossil fuels. When VOCs react with oxides of nitrogen and sunlight, they create smog.

wet water conditions: Wet water conditions represent the highest annual inflows

wholesale power market: The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Appendix B: Alternative Future Scenarios

Retrenchment

Energy markets are in chaos going into the summer and fall of 2001 -- prices are high, not just in the west but across the entire nation. New York City has rolling blackouts. Prices in the Midwest and south shoot up because of extremely hot weather and high fuel costs. The coal industry has figured out the law of supply and demand and cut production of coal just in time for peak summer generating demand. Short supply, hot weather and high fuel prices (gas AND coal) keep prices at unprecedented levels nationwide. This squeezes industry and leads to more layoffs. Energy intensive industries move off-shore.

The hot high tech economy has turned ice cold. Japan announces that their economy is on the skids. The Fed reacts too late and the recession accelerates downward.

Tideflats industry shuts down. Tacoma loses industrial, commercial and residential load. Mass unemployment nationwide leads people to involuntarily leave the grid -- their power is turned off. Some survivalists retreat to the back woods and go it alone.

Looking for parties to blame for the economic disaster, people see FERC as a major culprit for allowing energy prices to spiral upward unchecked. The FERC Commissioners are removed and replaced with commissioners dedicated to re-regulating the electricity market and bringing prices back down to reasonable levels. The nation reverts to cost-based rates.

The Power Marketing Administrations created during the last great depression are once again viewed as essential public works. The recent experience with astronomical energy prices has reminded people of the pitfalls of a free market. As a result BPA remains a Federal Agency with cost-based rates. As the depression deepens Federal and State Governments form power authorities to build new generation in an attempt to try to prop up industry by providing affordable electricity. The new public works projects create jobs too. RTOs survive but mostly as non-profit organizations. Private RTOs have regulated rates.

The technology boom of the 1990s dies a slow death as dot.coms fade away. As electricity prices decline there is less innovation and research on new energy technologies. The overall decrease in electricity demand slows the development of new transmission lines in the early years of the depression. New transmission is constructed later as part of other public works projects. Investor owned utilities that have gone bankrupt are taken over by state power authorities.

Californians, the first to be pushed to the edge by the power crisis of 2001 react -- after getting no help from the federal government -- by taking privately owned power generation facilities by right of eminent domain and forming the California Power Authority, an agency even larger and more powerful than the BPA. The two agencies work together to reinforce the north/south transmission path and restore the cooperative power exchange arrangements that served the west coast for so many years.

In the midst of what has become a global depression the world's attention has strayed from climate change issues. Although the weather is notably more erratic, hotter, drier, colder, wetter -- agreement on international controls on greenhouse emissions are delayed until 2005. As the world begins to climb out of the economic crisis more investments in renewables, conservation and R&D resume.

Green Renaissance

The effects of the drought and a tight supply of electricity and natural gas combine to keep energy prices high through 2003. Just as a spate of gas fired resources come on line to relieve the supply crunch, the Congress enacts a carbon tax. Continued warming throughout the world, severe storms, increasingly strong warnings from the scientific community, and support from private sector leaders finally result in a major shift away from a fossil fuel based economy. In addition to the carbon tax, the Congress provides significantly increased funding for R&D on new energy technologies and tax incentives for renewables. State agencies provide incentives for renewed conservation efforts and pass stricter energy codes. Higher gasoline prices and higher levels of environmental awareness lead workers to choose to live closer to their places of employment. Telecommuting becomes increasingly common, along with in-home businesses.

Energy prices remain high through 2008 because of carbon taxes and tight gas supplies. After the drought of 2001-2002, output from the NW hydro system never recovers to historic levels because of requirements for fish protection. At the end of the forecast period, energy prices start to decline because of major breakthroughs in technology.

Motivated initially by high energy prices and rolling blackouts on the West Coast and subsequently by federal subsidies, developers make major investments in distributed generation and renewable technologies. Fuel cells become cost competitive in the NW by 2005. Heat pump technology improves and competes with natural gas space heat. New companies come into the NW market offering larger commercial and industrial companies full service distributed generation at prices competitive with power from the grid. To companies who have been rocked by high and volatile prices, along with diminished reliability, getting off the grid sounds attractive. All customers want to receive more value for their energy dollar.

Small utilities find it increasingly difficult to play in the complex market. Some well-run municipals are able to increase their service areas. The market favors larger companies who are able to innovate quickly and provide excellent customer service. In particular, gas and electric utilities are able to take advantage of the changing marketplace. Continued high energy prices throughout the planning horizon lead to thin margins. Companies must be efficient or risk bankruptcy or takeover.

In Washington State, there isn't any action taken by the legislature to de-regulate the electric utilities. However, some small PUDs are taken over by larger municipals, and in some cases, by IOUs in exchange for rate guarantees. Customers are more demanding and expect more service in exchange for higher prices. Due to the high risk of investing in generation, BPA becomes a major acquirer of resources for the region.

Free Market Prevails

Everyone who thought that competition was going to lower costs, improve service and spur the development of new products turns out to be right. With this shift toward laissez faire economics environmental regulations on air permitting are relaxed and the Arctic National Wildlife Refuge (ANWR) is opened for drilling. With everyone at the "party", the emphasis on price caps and market "fixes" diminishes. President Bush's energy plan produces much new generation within the WSCC, and improved pipeline and transmission infrastructure. New gas supplies are developed and pipeline companies expand transportation capacity. Free market theorists are right: generation supply and demand come into reasonably close balance.

Amidst all the happy capitalists are investors eager to find the next dot-com craze. Investors put their money into micro-turbines, fuel cells, gas recips and CTs. Daunted by the environmentalists, Bush concedes tax breaks for fuel cells, microturbines, and other new technology. Distributed generation alternatives become more attractive as a result of tax cuts. The interest in new technologies spurs new R&D efforts and the Tacoma Narrows becomes a UW tidal energy pilot project, generating between 0 and 10 MW, depending on the tide.

The regional economy thrives as Tacoma offers home buyers and businesses a reasonable alternative to locating in Seattle or other areas of the Puget Sound Region. Around the clock, high load factor loads enter the service territory; some are configured to get under BPA's 10 MW New Large Single Load limit. Due to its significant spending on IT infrastructure, Tacoma's service territory attracts from California's Silicon Valley. The digital boom changes the way business is transacted. Paper becomes a niche product, demand for newspaper and other paper products plummets because the paperless office finally prevails. Heavy industry is replaced with light industry and technology enterprises. Off shore manufacturing and stable trade relations make low cost goods available in the United States. Foreign built Combustion Turbines, micro-turbines and fuel cells are widely and inexpensively available

The Way We Were

The United States muddles along with a patchwork of restructuring efforts. Regulatory policies follow a middle road and offer only incremental increases to national and regional air and water quality standards. Those concerned about global warming continue to talk about the need to take dramatic action to reduce carbon emissions, but only voluntary reduction programs are adopted at the federal level. Moderate salmon recovery efforts increase cost and output pressures on Northwest hydro system. Nimby-ism continues to make the siting of new large energy facilities difficult, particularly in California. RTO development proceeds, creating a stable planning environment for transmission system improvements throughout the West. The Northwest congressional delegation continues to successfully ward off attacks on regional and public preference, as well as defending cost-based pricing for power from Bonneville Power Administration. No significant state legislation on market access is passed in Washington because large customers continue to be satisfied with their local utilities' responses to requests for market-based products.

Combined cycle plants continue to make small improvements in efficiency. No significant breakthroughs are made in transmission system technology that are cost-effective in normal utility applications (superconducting, etc.), but there is some improvement in control systems that allow increased energy transmission over existing equipment. Fuel cells continue to be a niche technology, but costs remain too high for large scale deployment outside of the transportation industry. Other distributed generation technologies remain too expensive or complicated to generate customer interest. The environment-friendly choices in transportation become fuel cell and gas-electric hybrid vehicles instead of electric cars. Despite ubiquitous, inexpensive broadband internet access and cheap, powerful computers, telecommuting and other forms of decentralizing work continue to represent only a small fraction of Puget Sound area work

International concerns about global warming remain, but the international focus is on mitigating the impacts of the expanding economies of developing countries. Boeing continues to maintain a significant construction presence in the Puget Sound area, and there is continued growth of information technology and communications industries, and further rapid expansion of the biotechnology sector. The military presence in the Puget Sound area continues to be strong, with the existing bases thriving in their new roles in the redefined United States armed forces. Transportation bottlenecks in central Puget Sound continue to improve gradually and the second Narrows bridge is completed. Overall, Western Washington is a nice place to do business with tolerable inconveniences.

Appendix C Transmission Resources and Issues

Transmission

Tacoma Power owns, operates, and maintains 44 circuit miles of high voltage (230 kV) facilities and 314 circuit miles of sub-transmission (110 kV) facilities which are used to integrate generation, serve retail loads, and provide wholesale transfer service.

Facilities

Tacoma power owns and maintains 160 circuit miles of transmission facilities used to integrate power from Tacoma Power generating projects:

- 18 miles of 230 kV transmission integrate Tacoma Power's Mayfield and Mossyrock hydroelectric generation on the Cowlitz River Project into the Bonneville Power Administration's transmission grid. Tacoma Power takes delivery of this power at its Cowlitz and Northeast Substations.

- 43 Miles of double circuit (86 circuit miles) 110 kV sub-transmission facilities, know as the Potlatch lines, integrate Tacoma Power's hydroelectric generation at the Cushman Project into Tacoma Power's 110 kV sub-transmission system

- 28 miles of double circuit (56 circuit miles) 110 kV sub-transmission facilities, known as the LaGrande lines, integrate Tacoma Power's Alder and LaGrande hydroelectric generation at the Nisqually River Project into Tacoma Power's 110 kV sub-transmission system

Tacoma Power owns and maintains 181 circuit miles of transmission facilities including 13 miles of double circuit (26 circuit miles) 230 kV transmission and 172 miles of single circuit 110 kV sub-transmission which are primarily used to serve Tacoma Power retail loads.

Tacoma Power is a member of the Western Systems Coordination Council (WSCC), one of the ten reliability organizations that compose North American Electric Reliability Council (NERC). Tacoma Power is a WSCC Control Area. None of Tacoma Power's transmission facilities are WSCC "rated" paths or considered significant to the operation of the regional interconnection transmission system.

Interchange Points

Tacoma Power has four points were it connects to the regional interconnected transmission network:

- Northeast - 230 kV interconnection with BPA

- Cowlitz – 230 kV interconnection with BPA

- Starwood – 115 kV interconnection with Puget Sound Energy

- Cowlitz Hydroelectric Project – 230 kV with BPA

Wholesale Use

Tacoma Power uses portions of its 110 kV and 230 kV electrical system to provide wholesale transfer service to 10 publicly owned Pierce County utilities and also to the Lewis County Public Utility District. Tacoma Power has provided some of this service for over twenty-five years.

Transfer service began in 1974 when Tacoma Power provided access to the Bonneville Power Administration (BPA) for the benefit of its Pierce County customers. In 1993, Tacoma Power and Lewis County Public Utility District executed an agreement to transfer power generated by the Cowlitz Falls Hydroelectric Project across our system. Finally, in 1996 Tacoma Power provided access to the Peninsula Power and Light Company for its non-BPA power purchases.

In 2000, Tacoma Power reaffirmed its policy to provide non-discriminatory access to its high-voltage system through adoption by the Tacoma Public Utility Board of a new interconnection agreement and transfer tariff. These agreements are progressive and they are aligned with industry and FERC standards.

In first quarter 2001, seven Independent Power Producers (IPP) approached Tacoma Power with interconnection requests. Four IPP's, with a cumulative generation capacity of over 1000 MW, have executed study agreements, and the system analysis process has begun.

This dramatic increase in interconnection requests is fueled by the energy crisis on the West Coast and the existence of favorable infrastructure within Tacoma and Pierce County (e.g. natural gas, power lines, water, and raw land). While other transfer providers exist in this area, the majority approached Tacoma Power because they view it as able to conduct the interconnection process in a reasonable and timely manner.

Capacity

Currently, Tacoma Power has sufficient transmission capacity (lines, point of interconnection with neighboring systems) to serve both its retail and wholesale customers in a reliable manner. However, pursuant Tacoma Power's February 2000 Transmission & Distribution Plan Six-Year Plan (T&D Plan), Tacoma Power believes capacity constraints will occur on both the LaGrande and Potlatch lines. The constraints are primarily due to load growth, however the recent influx of IPP generation integration request complicates the capacity availability issue.

<u>LaGrande Lines</u>

The LaGrande lines were originally constructed to transmit power from the Nisqually Project to Tacoma. In addition to their original function, these lines now also support wholesale power transfers, enabling BPA to serve five of its customers, Parkland Light and Water, Elmhurst Mutual Power and Light, Ohop Mutual Light Company, Alder Mutual Light Company, and the Town of Eatonville. The existing LaGrande lines are 58 years old; they were rebuilt in 1943 to replace wood pole lines.

Over the last ten years, rapid growth has occurred in south Pierce County affecting primarily Tacoma Power, Parkland Light and Water, and Elmhurst Mutual Power and Light. New substations were constructed and connected to the LaGrande lines to serve this load. The LaGrande lines are currently near their capacity limit, in fact it would be difficult for Tacoma Power to serve addition of significant industrial load in the Frederickson area of its service territory. Further, under certain planning scenarios, loss of one line could over-load the other.

As a result, the T&D Plan recommends construction of a new switching station and construction of approximately ten miles of 110 kV line between Cowlitz substation and the new switching station. Under the T&D Plan, the pre-construction phase would occur 2001-2003 with the construction phase to span 2003-2006. This schedule would need to be accelerated should any significant amount of load or generation interconnect with Tacoma Power in the Frederickson area.

Potlatch Lines

The Potlatch Lines were originally built over 75 years ago to transmit power from the Cushman Project (Cushman #1 and #2 hydroelectric generating projects) to Tacoma. As with the LaGrande lines, the Potlatch lines not only transmit Cushman generation, but also support wholesale power transfers, enabling BPA to serve its customer, the Peninsula Light Company (PenLight).

While the Potlatch lines have been significantly rebuilt over the last ten years, the Narrows Crossing towers and the conductors are original. Due to deterioration and age, additional study of the Narrows towers is warranted. The conductors were analyzed in 1999 and determined adequate for existing transmission requirements. However, BPA has forecasted PenLight's load growth to exceed line capacity by 2006 for an average winter.

As such, the T&D Plan recommends a rebuild of the Tacoma Narrows Crossing, with the pre-construction phase scheduled for 2003-2004, and construction scheduled for 2005-2007.

National and Regional Issues

Over the last nine years a number of significant initiatives that affect transmission facilities, operations, and service have occurred on both the national and regional level. These initiatives have or will affect Tacoma Power in two areas: One, Tacoma Power is a system operator/control area, and it owns assets over which wholesale transfer transactions occur, and Two, Tacoma Power uses the regional transmission network to deliver and receive the majority of its power. As such, Tacoma Power has tracked and/or participated in these initiatives.

National Issues

Over the last nine years, Congress and FERC took three major steps designed to establish the foundation necessary for competitive bulk power markets and to bring more efficient, lower cost power to the Nation's electricity consumers. The Energy Policy Act of 1992, FERC Orders 888 and 889, and FERC Order 2000 have focused primarily on promoting open, non-discriminatory transmission access. The three major steps are described below.

Energy Policy Act of 1992

The U.S. Congress passed the Energy Policy Act of 1992 (the Energy Policy Act) to encourage new generation entrants, known as exempt wholesale generators (EWGs), and to expand FERC's authority under sections 211 and 212 of the Federal Power Act (FPA) to approve applications for transmission services.

FERC aggressively implemented the revised sections of the FPA leading to a number of industry changes. One such change was FERC began ordering utilities to provide "network" transmission service – a service similar to the service transmission-owners provide to their own retail electric customers. Previously, most utilities had offered point-to-point service and refused to offer network service.

Another change was the articulation of a "comparability standard." FERC and others noted that transmission owners provide themselves and their affiliates with several services and levels of quality of service, but really only offered one or two types and levels of service to other parties. FERC articulated a comparability standard, and began ordering utilities to offer comparable levels of service to third parities.

Transmission access changes occurred case-by-case, and generally when FERC was deciding another question – such as how to mitigate market power in a merger proceeding. FERC recognized the need for generic findings, and undertook a process that resulted in Orders Numbers 888 and 889.

FERC Order Numbers 888 and 889

April 1996 FERC issued Order Numbers 888 and 889. Order 888 established procedures for offering transmission services in a non-discriminatory manner and established rules for the recovery of stranded costs. Order 889 set guidelines for standards of conduct and for the provision of equal access to data for all parties.

The main thrust of Order 888 was to order FERC jurisdictional utilities to develop and file Open Access Transmission Tariffs (OATTs). Order 888's central theme was "comparability." FERC ordered utilities to post an OATT that offered transmission service and the terms and conditions under which it was available. FERC ordered utilities to provide transmission access to all parties under the same terms and conditions offered to their own affiliated companies. FERC provided a pro forma OATT, which became the template used by most utilities in the development of their own OATT.

Order 888 also required utilities to unbundled services – power supply, transmission, distribution, and ancillary services. With limited exceptions, FERC required utilities to offer to provide ancillary services under terms and conditions specified in their OATT.

Order 889 set guidelines for standard of conduct, called for the establishment of Open Access Same-Time Information Systems (OASIS), and listed contents of the OASIS. The purpose of an OASIS is to ensure equal, non-discriminatory access to real-time information about transmission capacity availability, service prices, and pricing discounts offered to customers. Real-time access to information helps ensure that utilities do not use their ownership, operation, or control of transmission to unfairly deny access or provide competitive advantages to selected parties.

Order Numbers 888 and 889 stopped short of ordering the development of regional transmission organizations although FERC clearly favored the formation of regional organizations. Orders 888 and 889 spurred attempts – successful and unsuccessful – to form such organizations and led to FERC's next major order, Number 2000.

FERC Order Number 2000

In December 1999, FERC approved Order No. 2000, which governs the development and implementation of regional transmission organizations (RTO). An RTO is an umbrella organization that will put under common control all public utility transmission facilities in a region.

While RTO formation is voluntary under Order 2000, FERC asserts authority to mandate RTO participation to remedy undue discrimination, to address market power, or as a condition of merger approval. FERC also set a clear direction for the industry, outlining guidelines for what RTOs must do, effective pricing mechanisms, a timetable for action, a collaborative process, and a persuasive case for the need for RTOs.

Order 2000 requires all FERC-jurisdictional public utilities that own, operate, or control interstate transmission to file by October 15, 2000, either a proposal for an RTO or explain why it opted not to participate in an RTO. Order 2000 requires RTOs to be operational by December 15, 2001 while existing, FERC-approved, regional entities must make compliance filings by January 15, 2001.

Order 2000 permits several different types of RTO, including non-profit independent system operators and for-profit transmission companies. The Order also provides flexibility in ratemaking options and enables RTO participants to design an organization which meets their regional needs. However, all RTOs must embrace four core characteristics (independence, scope and regional configuration, operational authority, and short-term reliability) and eight key functions (tariff administration and design, congestion management, parallel path flows, ancillary services, OASIS, market monitoring, planning and expansion, and interregional coordination.)

Regional Response

Since 1992 Northwest utilities have made four significant efforts to coordinate and/or unify regional transmission entities, much of which is in response to national initiatives. These efforts are discussed below.

Northwest Regional Transmission Association

The Northwest's first effort to coordinate regional transmission was the formation of the Northwest Regional Transmission Association (NRTA). The NRTA was one of three regional transmission organizations formed in the early 1990s in the western interconnected region (the others being the Southwest Regional Transmission Association [SWRTA] and the Western Regional Transmission Association [WRTA]). NRTA originally had three main objectives:

- promote open access;
- facilitate coordination of regional transmission planning; and,
- facilitate development of a regional transmission tariff.

NRTA added a fourth objective after a year of operation – promotion of a set of neutral commercial practices for the transmission system, independent of the other functions of the utilities owning the system.

NRTA is composed of transmitting utilities in the U.S. and Canada, transmission users in the U.S. and Canada, and Northwest regulatory commissions. Tacoma Power was a founding member of NRTA, and continues to be a member to this date.

The NRTA concept pre-dated the Energy Policy Act, and centered on a perceived need for open transmission access for non-transmission owners. Formation of NRTA was further spurred by pro-regional transmission organization sentiments in Congress at the time of the Energy Policy Act, and similar sentiments at the FERC prior to Order 888.

To this date NRTA still provides a benefit to members in the form of dispute resolution related to transmission access, and NRTA still produces periodic transmission planning documents. NRTA's original tariff related goal was subsumed by the subsequent IndeGO effort described below.

NRTA is presently at a crossroads. To enhance coordination SWRTA and WRTA are merging with the WSCC into one organization called the Western Electric Coordinating Council (WECC). NRTA has yet to join this merger effort due to the unique Northwest perspective on transmission access issues, and may remain independent, operating in its current or an altered form.

Western Electric Coordinating Council

An ongoing effort in the western interconnection system is the merger of the WSCC, WRTA and SWRTA into a single organization, the WECC. The fundamental mission of the WECC is to maintain a reliable electric power system that will support efficient competitive power markets within the western interconnection, and to provide a forum for resolving transmission access disputes that may arise between members.

With industry in the midst of a gradual evolution toward centralized regional coordination under RTOs, regional discussion focused on how best to create a region-wide coordinating council that would effectively integrate existing organizations, yet complement the efforts of RTOs and NERC and its probable successor, the North American Electric Reliability Organization (NAERO). The participants ultimately decided to combine WSCC, WRTA and SWRTA into a single new organization. Thus, the WECC will perform many of the same functions as its predecessor organizations, offering, however, a superior governance structure and significant improvements in efficiency by decreasing existing overlap and duplicated efforts between organizations.

WSCC, NERC and NAERO

WSCC and NERC represent all segments of the electric industry, including private utilities, municipalities, rural electric cooperatives, federal power marketing agencies, and power marketers. The primary responsibility of WSCC and NERC is to promote electric system reliability.

WSCC and NERC were formed in 1967 and 1968, respectively, and operate as a voluntary organization, dependent on reciprocity and the mutual self-interest of all parties involved. However, the growth of competition and the structural changes that have occurred in the industry have significantly altered the incentives and responsibility of major participants. These changes have created challenges to the historically voluntary system of maintaining reliability.

WSCC and NERC's new mission will be to develop, promote and enforce standards for a reliable North American bulk electric system. Under the existing system, compliance is mandatory, but not enforceable. WSCC established enforcement though a contractual arrangement with many of its members, which NERC adopted as a model. Further, NERC is seeking federal legislation in the U.S. to ensure that NERC and its reliability councils have the statutory authority to enforce compliance with reliability standards among all market participants.

As a member of WSCC, Tacoma Power has not executed an enforcement agreement. However, it reports reliability statistics to WSCC and has a perfect compliance record.

Independent Grid Operator

Between 1996 and 1998 twenty-one utilities undertook an extensive effort to develop an Independent Grid Operator (IGO) called IndeGO. IndeGO was to be a nonprofit, independent operator of the aggregated transmission systems of the 21 participants, including Tacoma Power. IndeGO's region included Washington, Oregon, Idaho, and parts of Montana, Wyoming, Utah, Colorado, Nevada and Nebraska.

Under the proposal, IndeGO would not have owned any facilities. Rather, IndeGO would have controlled each participating owner's transmission facilities in exchange for an annual payment that would cover the owner's capital, operation, and maintenance costs. IndeGO's main objective was to be a common carrier electric transmission system operator, independent of the energy sales and power production aspects of the participating owners. IndeGO's goals were to ensure comparable transmission access to all grid customers, promote economically efficient use and expansion of the IGO grid, and avoid "pancaked transmission charges" wherein a transmission customer must pay charges to several utilities as it wheels power from source to sink.

While the IndeGO proposal was never submitted to the FERC for approval, FERC was supportive of the effort to form an IGO. The IndeGO effort ultimately ended when it became apparent that the pricing proposals would result in cost shifting between utilities.

Tacoma Power and the other participants invested significant amounts of staff time and resources, the results of which were large numbers of contracts, organizational documents, white papers, and other documentation. The resulting documents have formed the basis for much of the RTO West effort that followed.

RTO West
In March 2000, in response to FERC Order 2000, eight utilities initiated RTO West, a broad Regional Transmission Organization (RTO) that will span eight Western states. The eight "Filing Utilities" are Avista Corporation, Bonneville Power Administration, Idaho Power Company, Montana Power Company, Nevada Power Company, PacifiCorp, Portland General Electric, Puget Sound Energy, Inc., and Sierra Pacific Power Company. RTO West is an on-going collaborative process to develop an RTO for the Pacific Northwest that meets or exceeds Order 2000's minimum requirements, while meeting the needs of the Filing Utilities, their consumers, and other interested parties.

The Filing Utilities designed RTO West as a nonprofit organization with an independent board that will act as the independent system operator for the aggregated transmission systems of participating transmission owners. Upon initial operation, RTO West will not own any transmission facilities but will control each participating transmission owner's transmission facilities.

Further, six of the filing utilities (Avista Corporation, Montana Power Company, Nevada Power Company, Portland General Electric Company, Puget Sound Energy, Inc., and Sierra Pacific Power Company) propose to create an independent, for-profit transmission company (ITC) within the RTO West structure. The ITC will own and operate the interstate transmission facilities of participating utilities, with the ITC participating in RTO West as a single transmission owner. Those participating in the ITC will exchange their transmission assets for a passive ownership interest in the company.

In fourth quarter 2000, the Filing Utilities submitted the RTO West Stage 1 filing to FERC, wherein the Filing Utilities asked for a declaratory order on the governance, scope and configuration, and an agreement limiting liability. On April 25, 2001, FERC predominately approved Stage 1, although rejected the proposal to incorporate a limited liability agreement into the RTO West operating agreement.

The Stage 2 filing will contain more detailed information, including a Tariff with all attachments. The Filing Utilities plan to submit an interim Stage 2 filing to FERC by August 31, and a December 1 completion filing. The August 31 filing will include information about key components of RTO West, such as the congestion management model, an "illustrative" pricing model, planning/expansion principles, and lists of facilities for inclusion.

To date, work on RTO West has not progressed in sufficient detail to enable Tacoma Power to determine the impact and/or benefit of RTO West on Tacoma Power rate-payers. As such, Tacoma Power continues to track RTO West.