

PUGET SOUND AREA ELECTRIC RELIABILITY PLAN SCOPING REPORT
PART B: PRELIMINARY TECHNICAL ANALYSES

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ENVIRONMENTAL IMPACT STATEMENT SCOPING REPORT
PART B: PRELIMINARY TECHNICAL ANALYSES

INTRODUCTION

Background. In December 1989 Bonneville Power Administration (BPA) published an Issue Alert entitled "The Search for a Sound Solution (to Potential Voltage Collapse in the Puget Sound Area)." The publication described a voltage instability problem in the Puget Sound area (*). It also announced the initiation of a study and two-phase planning process which will lead to a proposal for actions, if any, that need to be taken to address the problem. This preliminary technical analysis, along with a companion public comment summary, documents the first phase of the process, "scoping."

Phase I: Scoping. Phase I was designed to serve several purposes: 1) to confirm the existence of a voltage instability problem in the Puget Sound area; 2) to notify the public of the existence of the problem and to begin to involve interested members of the public in the study; 3) to define the problem in terms that would allow analysis of alternative solutions; 4) to identify measures that could compose alternative solutions; and 5) to perform preliminary feasibility studies on the measures identified.

Phase I began with a series of public scoping meetings designed to inform interested individuals and organizations of the upcoming planning process, to obtain comments on the proposed study, and to solicit involvement in the review of study results.

In order to identify and analyze potential measures BPA sought the participation of the four largest retail utilities in the area, Puget Sound Power and Light Company, Seattle City Light, Tacoma City Light, and Snohomish Public Utility District (PUD). BPA and each of the four utilities entered into an agreement to conduct the study as a joint project. A copy of the agreement is included as an appendix to this report. The active participation of these utilities has been vital to the completion of the preliminary analyses and will continue to be essential during the evaluation, decision, and implementation processes. It should be noted, however, that this study does not replace individual utility planning, nor should it be confused with BPA's Resource Program or the Northwest Power Planning Council's plan.

Numerous other individuals and organizations have been involved in shaping the study plan and reviewing interim results through periodic technical review group meetings. In addition, over fifty individuals have submitted written comments. A detailed description of Phase I, including a discussion of the technical review group, is provided in the Scoping Report, Part A: Public Comment Summary.

(*) For the purpose of this study, the Puget Sound area is defined as the electrical service area extending north to the Canadian border, east to the Cascade Mountains, south to Chehalis, and west to the Pacific Ocean.

III. PUGET SOUND AREA POWER SYSTEM CAPACITY

Introduction. Reliable performance of the power system serving Puget Sound requires that system capacity be equal to or greater than peak power demand. Chapter II defined present and future peak power demand that the system must serve. This chapter defines system capacity and discusses how it is determined through technical studies.

BPA and the other Puget Sound utilities establish minimum performance standards for the power system in the form of reliability criteria. The BPA Reliability Criteria establish the minimum performance requirements that are used in planning, designing, operating and maintaining the main grid bulk power system. System capacity is defined in terms of these criteria as the maximum load that can be served without violating performance criteria requirements.

System capacity is determined by conducting computer simulations of system performance for the various disturbances spelled out in the criteria. The capacity of the existing Puget Sound system is indicated in Figure II-2 by the horizontal dashed lines. These values represent the load levels at which there is insufficient reactive reserve or margin to prevent voltage collapse.

Definitions. The following terms are used in throughout this report. A brief explanation of these terms is provided to aid in understanding the transmission system issues facing the Puget Sound area.

Reactive Power. Electric and magnetic fields are the medium by which electrical power is generated, transmitted, and converted to useful work. All elements of the power system including generators, transmission lines, transformers, and motors rely on electric and magnetic fields to perform their function. Electric fields are associated with voltage while magnetic fields are associated with current. These fields store significant amounts of electrical power. In an alternating current (AC) system, voltage and currents alternate between zero and peak 120 times per second (twice each 60Hz cycle). Correspondingly, power goes in and out of the myriad magnetic and electric fields at the same rate. However, no power is consumed; it is only moved from one place to another much like moving funds between accounts in a bank.

This flow of power in and out of storage in magnetic and electric fields is called reactive power. Devices such as motors that function predominantly through magnetic fields are said to consume reactive power while devices that function through electric fields such as capacitor banks are said to produce reactive power. Transmission lines, which function both through magnetic and electric fields, can be either a reactive power consumer or a reactive producer depending on how heavily loaded they are. When lines are heavily loaded the magnetic field dominates and the line consumes reactive power. Under light load the electric field dominates and the line produces reactive power.

These production and consumption labels are purely a convention to account for the fact that some devices are discharging stored field power as others are absorbing it. At any given moment, the reactive power produced and consumed in the power system must be in balance.

Voltage Collapse. This reactive power balance is necessary for stable voltage on a power system. If more reactive power is being produced than consumed, voltage will rise, whereas a deficit of reactive power will cause voltage to drop. Generators are extremely important in maintaining the balance of reactive power necessary for stable voltage. A generator can either produce or consume reactive power depending on the setting of its field winding excitation control. Generator exciters constantly monitor system voltage. If voltage starts to sag, the exciter automatically increases field current causing reactive power injection into the system to counteract the sag. On the other hand, if voltage rises, the exciter reduces field current to absorb reactive power.

In major load centers fed by long transmission lines, capacitor banks are used to supply reactive power during periods of heavy load. The capacitor banks are switched on when voltage sags as a result of reactive power consumption by the heavily loaded lines. Capacitor banks are good inexpensive sources of reactive power and perform well if voltage is fairly steady. However, if system voltage drops, their reactive power output goes down by the square of the voltage drop. Unlike generators, capacitor banks are inherently a destabilizing force in reactive power dynamics. A further destabilizing effect is that, as voltage drops, current flows increase in transmission lines react to maintain constant power. The reactive power consumption of the lines increases by the square of the current, driving voltage down further.

The stabilizing force of generators counteracts this process and restores reactive power balance maintaining stable voltage. But generators have limited reactive power capacity, and their exciters will limit reactive power output to protect the generator. Moreover, only the generators near the load center are effective at stabilizing voltage because long, heavily loaded transmission lines cannot transport reactive power from remote generators.

During heavy peak load, occurrence of a major disturbance, such as loss of a critical line, causes an increase in reactive power consumption, and voltages drop. Generators in the load area automatically adjust reactive output to restore balance but quickly reach their capacity limits. Once this point is reached there is no stabilizing force to counteract the destabilizing response of the capacitor banks, and voltage drops to either a sustained extreme low voltage condition or a cascading total loss of load.

Brownout. Outage of a major facility such as a generator or line may cause a reactive power deficit. The power system may reach an operating point where voltages are severely depressed yet the system stays intact. This is called a brownout. The low voltage may damage some loads such as motors. Other loads such as computers may malfunction while some loads are likely to disconnect for self protection.

Blackout. System voltages may drop far enough so that protective relays misinterpret the condition as a line fault and disconnect a transmission line. This will cause voltages to drop further causing more lines to disconnect in cascading fashion. Ultimately loads are totally disconnected from generation, and the system goes black.

Reliability Criteria. As discussed earlier, the BPA Reliability Criteria set standards for planning, designing, operating and maintaining the transmission system to insure cost-effective reliability of service. Cost-effectiveness is viewed from the perspective of the electricity consumer. The system is planned to have sufficient strength or capacity to maintain continuity and quality of service to electrical loads during certain more common contingencies or system disturbances. For other less common contingencies, it is not economical to provide enough capacity to maintain full service, so interruption of service or some reduction of quality of service is allowed.

The performance requirements of the criteria that pertain to the main grid transmission system are summarized in Table III-1. The first section of the table lists contingencies in order of decreasing likelihood and specifies the performance level the system must meet for the particular contingency. The second section defines each of the performance levels in terms of load served, voltage requirements and overloads of facilities.

Transmission Modeling. The severity and extent of the peak load capacity problem in the Puget Sound area can be determined by computer simulation studies that model the response of the power system to various critical disturbances specified in the Reliability Criteria. Planning data from utilities throughout the Western United States and Canada are used to project load levels, available generation and transmission network configurations at various points in the future as far out as 20 years. Base cases, which are the detailed technical data bases required by the modeling programs, are developed from this planning information for the future years to be studied. Within a given study year there are typically a number of variations set up to represent seasonal load and generation patterns. Initial studies have shown that the critical outage cases for Puget Sound voltage stability are:

- o Outage of the Chief Joseph - Monroe 500-kV line during an abnormal winter peak.
- o Outage of both circuits of the Coulee-Raver double-circuit 500-kV line during a normal winter peak.
- o Outage of the Trojan generator with one of the Centralia generators already out of service during an abnormal winter peak.

In the fall of 1988, BPA system planners, while conducting routine studies of future Puget Sound voltage support needs, discovered the first signs that there could be a serious voltage stability problem in the Puget Sound area. Small changes in study assumptions produced wide variations in results and many cases would not converge (arrive at a solution in the computer model) or converged at extremely low voltages.

Further in-depth studies were made using a new methodology, referred to as the post-transient method, developed to study voltage stability problems on the AC intertie. These studies revealed that for certain critical line or generator

TABLE III-1

MAIN GRID DISTURBANCE/PERFORMANCE TABLE

DISTURBANCE-PERFORMANCE TABLE	
CONTINGENCY (ELEMENTS LOST) (independent unless otherwise noted)	PERFORMANCE LEVEL REQUIRED
none (system normal)	A
one generator	B
one transformer, or two generators, or one line	B
one generator + one transformer, or one line + one generator, or stuck breaker or bus, or two lines (common row, bus, or PCB) *	D
two transformers, or one line + one transformer	E
two lines, or three or more lines in a pass or corridor *	G
* Dependent contingencies	

PERFORMANCE LEVELS

REQUIREMENTS	PERFORMANCE LEVEL				
	A	B	D	E	G
Serve abnormal cold load	X	X			
Serve normal cold load			X		
Load tripping allowed				X	X
Area separation and load loss allowed					X
Some intertie opening allowed (but no interregional separation)					X
Maintain nominal or better voltage (525-kV or better on the 500-kV system)	X				
Maintain minimum or better voltage		X	X	X	X
No line or transformer loading above thermal rating	X				
No transformer loading above emergency rating		X	X	X	X
No line above rated conductor temperature		X	X	X	X

outages during extreme winter peak loads the Puget Sound area did not have enough reactive margin to prevent voltage collapse. In the spring of 1989, studies representing system conditions that occurred during the severe February cold spell showed that loss of one of the 500-kV cross-Cascade transmission lines could have caused voltage collapse and widespread loss of load over the entire Puget Sound area.

Post-Transient Method. The time line of events following a major system disturbance such as loss of a transmission line or large generator can be divided into three distinct periods. In the first 1-2 minutes following the disturbance, automatic control systems respond to counteract power oscillations and imbalances that could otherwise cause system breakup. This is called the transient period. Examples of these automatic actions include disconnecting a faulted transmission line, action by generator controls to maintain constant frequency and terminal voltage or automatic disconnecting of interruptible loads. At the other end of the time line, approximately 10-15 minutes after the disturbance, system operators have had sufficient time to assess the state of the system and to begin taking manual control actions to readjust the system. Such actions might include switching on capacitor banks, changing voltage taps on main grid transformers or sending orders to generating plants to reschedule generation levels. This period is commonly referred to as the steady-state period.

The intermediate period after automatic control actions have taken place, but before system operators have had time to readjust the system, is known as the post-transient period. It is during this period that the system is most vulnerable to voltage collapse. In the past system planners assumed that if the system survived the transient period, then it would stay intact long enough for system operators to respond during the steady-state period. Transient stability studies modeled system performance during the transient period to determine if the system would survive the initial disturbance. Power flow studies examined the performance of the system during the steady-state period to determine if voltages and line loadings were within limits after system operator response.

In the last few years, however, the utility industry has become increasingly concerned about the performance of power systems during the post-transient period. Financial pressures on utilities have led them to operate their systems ever closer to capacity limits to defer major investments in new facilities. Blackouts of major load centers in Japan, France, Canada and the U.S. caused by voltage collapse during the post-transient period have occurred since 1985. System planners can no longer assume that the system is inherently secure during the post-transient period. Planning studies must consider the vulnerability to voltage collapse during this period.

There are no totally adequate computer models to simulate power system response during the post-transient period. Substantial utility R&D resources have been committed to developing extended term dynamics models that will extend the capability of traditional transient stability programs to model system performance during the post-transient period. However, production grade versions of these computer models currently under development will not be available to system planners before the end of 1990. In late 1988,

compelled by the need to investigate the emerging voltage collapse threat in the Puget Sound area, BPA developed an interim study methodology that allowed using the conventional power flow model to analyze post-transient voltage collapse. The essence of this "post-transient method" entailed modification of the power flow program to block all system adjustments that require human intervention, only allowing automatic adjustments to occur in the model. The Puget Sound voltage stability studies including determinations of present and future system capacity have been based on this methodology.

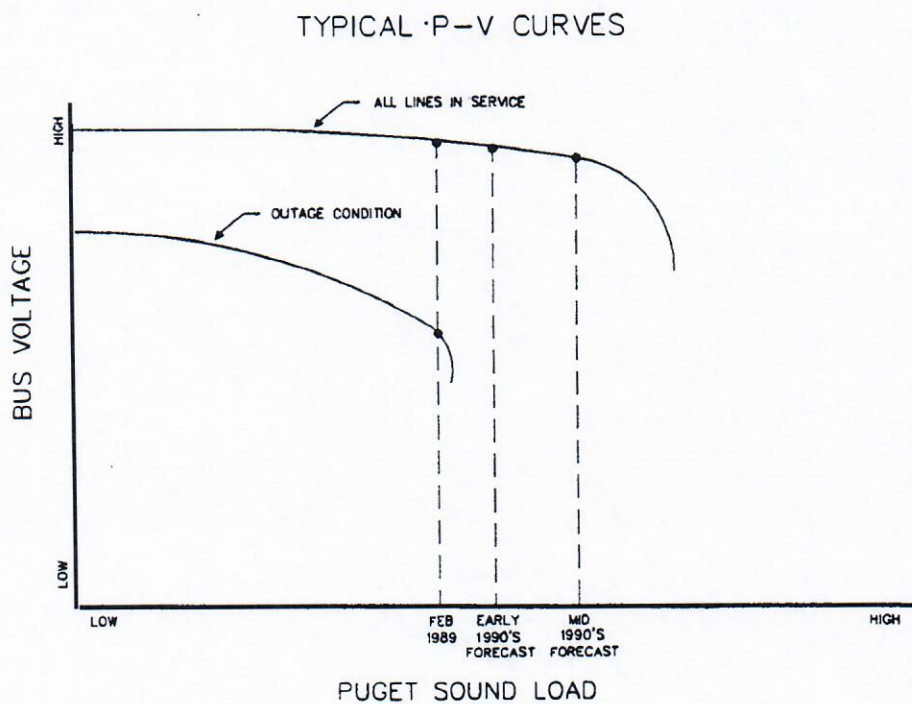
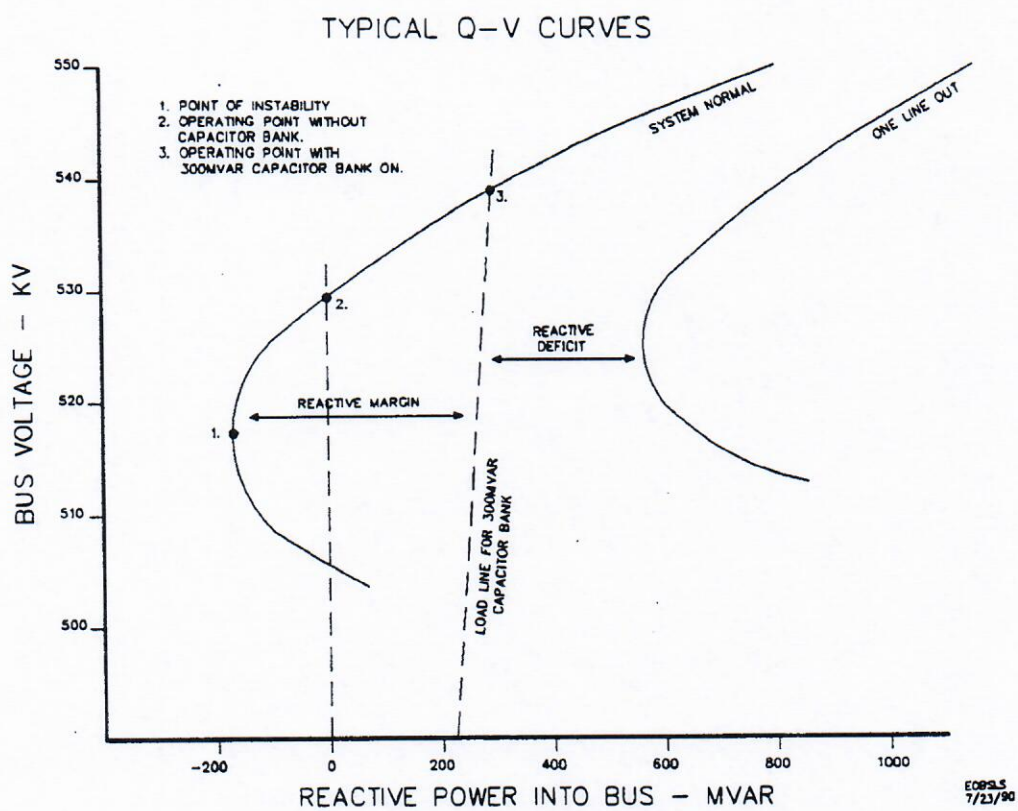
Q-V and P-V Analysis. Q-V (Reactive Power verses Voltage) and P-V (Real Power verses Voltage) analysis are techniques used as part of the post-transient methodology to determine how the system will respond to changes in real and reactive power flows and the vulnerability to voltage collapse.

A Q-V curve describes the relationship between voltage at a particular bus in the system and reactive power injection into the bus. A unique Q-V curve exists for each bus in the system for a given system state (loads, generation and network condition). A Q-V curve is generated by running series of power flow studies varying bus voltage incrementally over the range of interest to determine the reactive power injection required at each successive voltage level. Figure III-1 shows a typical Q-V curve for two different system states, system normal and after an outage of a line. The point at which the slope of the curve goes from positive to negative is called the point of instability. The horizontal distance from the instability point to the operating point is called the reactive margin. Normally the operating point is determined by the point of zero reactive injection. However if the bus has a reactive power source such as a capacitor bank connected to it, the operating point will be determined by the reactive power output of the capacitor bank. Determining system capacity for a given state of the transmission system entails generating Q-V curves at a number of critical buses for successively increasing loads to find the point where there is insufficient reactive margin above the point of instability.

P-V analysis is very similar to Q-V analysis except that P-V analysis looks at bus voltage response to variations in total real power load over the whole load area. Voltage stability studies rely principally on Q-V analysis with P-V analysis providing a consistency check. Much valuable qualitative information can be determined from the shape of the Q-V and P-V curves. For example a steep sloped curve means the system is in a state of high stress where small variations in system conditions will cause wide swings in system voltage.

Load Modeling. Properly representing how loads respond to voltage changes is the most formidable challenge in voltage stability studies. Reasonably good models of different types of loads have been developed and verified through EPRI sponsored research. It would be a fairly straight forward task to model a simple power system with a few known load types. However, it quickly becomes a task of enormous proportions for a system as extensive and diverse as that serving the Puget Sound area composed of hundreds of transmission lines, feeding thousands of distribution circuits connecting many millions of end-use loads each of which has unique daily and seasonal use patterns.

FIGURE III-1



PUGET SOUND REINFORCEMENT STUDY -- PLANNING FOR PEAK POWER NEEDS

Fortunately methods are available to greatly simplify the task by representing a distribution feeder and all the connected loads as a single element with approximately equivalent response. This equivalent load is composed of three components in varying proportion:

- o Constant power - no variation with voltage change
- o Constant current - varies linearly with voltage change
- o Constant impedance - varies as the square of the voltage

Some loads types are predominantly one component. Resistive space heating, a major factor for winter peak loads, is all constant impedance. Motor loads tend to be mostly constant power. An EPRI developed program called LOADSYN has become a utility standard tool for determining equivalent load models. Given data on sector mix (commercial, residential, etc) for a particular distribution feeder and data on typical load composition (resistance space heating, fluorescent lighting, motor type, etc), LOADSYN will calculate a single equivalent load model for the circuit.

The voltage stability studies up to this point have assumed that all loads are constant power. This is generally a conservative assumption that will produce "safe" results that underestimate actual system capacity. Transmission and Load Forecasting study teams have been working together over the last 9 months collecting detailed load data from Puget Sound and Portland area utilities to develop LOADSYN equivalent load models for all load buses in the Puget Sound and Portland area. These models should be completed and load response studies underway by early August.

Interpreting the results of load response studies will have to be done very judiciously because of the uncertainty in the data used to construct the load models. Most utilities do not have detailed data on load characteristics at each load bus and developing this level of detailed load data would be prohibitively expensive. The quality of data available varies from good to essentially an educated guess. Sanity checks of the load data are being made by comparing load class totals by utility against independently developed regional load composition data.

Another source of uncertainty in the load models is the effect of thermostat controls on resistive heat load. As voltage drops there is a significant immediate reduction in resistance space heat, water heat and cooking loads. Thermostats controlling these loads will try to counteract this loss of heat output resulting in an aggregate loss of load diversity for these loads. This effect could substantially reduce the apparent load relief that would otherwise result from voltage drop. How to account for this effect in load response studies has not yet been adequately resolved.

Until such time that more reliable load data can be developed, baseline voltage stability studies and system capacity determinations will continue to rely on constant power load models. Load response studies will be used to test the sensitivity of results to load assumptions. In addition, utilities will be conducting field tests to measure the actual response of the system to voltage changes.

Network Model. System models used in power flow studies represent the entire electrical network of the Western Systems Coordinating Council (WSCC) which covers ten western states and British Columbia and Alberta. To reduce the computational burden for Northwest regional studies, much of the detail outside the Northwest is reduced to simplified equivalent networks. Much of the subtransmission network at 115-kV and below within the Northwest is also reduced for conventional power flow studies of main grid performance.

Reactive losses in the Puget Sound subtransmission network could adversely affect voltage stability, yet are not fully accounted for in these reduced models. Because of this and the need to facilitate the detailed load model work discussed above, the Transmission Study Team is developing "super base cases" combining detailed network models from all the Puget Sound utilities plus lower British Columbia and the Portland area. This extended model also represents automatic voltage regulating transformers and more detailed models of local generation exciter response.

The super base case including detailed load models is being developed initially for 1993 studies and will later be extended to 1997. Super base cases with constant power loads are being developed for 1993, 1997, 2000 and 2004 studies. All future voltage stability studies will use these super base case models.

Study Assumptions. The following basic assumptions were used in Phase I studies to assess the performance of the transmission system under a variety of simulated conditions. Assumptions will be revised in future studies as needed to reflect changes in near term utility resource and transmission plans and refined technical information.

Resource Assumptions

1. Puget Sound area hydro generation performs at median water firm. Winter peaking levels prior to January 6 (reduced Skagit River generation.) Snoqualmie Falls frozen with no generation during abnormal cold.
2. PSP&L combustion turbines will be generating during abnormal cold except Whitehorn unit #3 and Shuffleton units are off.
3. PSP&L combustion turbines are off during normal winter peak load.
4. PGE's Beaver combustion turbine/combined cycle plant is off.
5. Coulee serves as a baseload generator with 4500 MW generation.
6. Snake River projects provide peaking generation.

Intertie Schedules

7. B.C. Hydro to Pacific Northwest (BCH-PNW) schedule is 250 MW during normal and abnormal cold. After the BCH to Washington Water Power (WWP) intertie is completed in the mid 1990s, total BCH-PNW schedule will be 850 MW. Phase shifters on the eastern BCH system will cause 600 MW to flow directly to WWP. The Nelway phase shifter will be adjusted to minimize inadvertent flow, assuring Ingledow to Custer power flow will consistently be about 250 MW.

PUGET SOUND REINFORCEMENT STUDY -- PLANNING FOR PEAK POWER NEEDS

8. BCH is using two Burrard units as synchronous condensers for normal and and four units for abnormal winter loads. Zero reactive is generated prior to a contingency.
9. PNW-PSW interchange is zero during abnormal cold if PNW resources are sufficient to meet the cold weather load.
10. PNW imports from the PSW on the DC intertie if PNW resources are insufficient to meet the assumed cold weather load.
11. PNW-PSW interchange during normal peak is 1000 MW DC and 2000 MW AC export to PSW in 1996. Export in later years decreases to allow PNW resources to meet the assumed normal load.
12. Canadian Entitlement return will not be included in base cases. Sensitivity studies will assess the Puget Sound voltage stability impacts for a range of capacity schedules (up to 1400 MW) to Canada during winter peak loads.

System Design

13. The operating point will be planned to provide 500 MVAR shunt reactive margin from the voltage instability point.
14. The newly revised Reliability Criteria are applied. (See Table III-1)
15. The system will be designed to restore full load immediately following the contingency unless a detailed system study shows the load cannot be fully restored with a 95 percent voltage level at BPA delivery points. The system will not be designed to use the direct load trip scheme now installed at Intalco and Kaiser.

Load Level Assumptions

16. The normal and extreme winter peak load forecasts displayed in Table II-2, are assumed for transmission studies. Sensitivity to load growth assumptions will be tested using the loads from Table II-4 and II-5. The power factor for abnormal is the same as normal weather.

System Addition Assumptions

Prior to Winter 1992-1993:

- Raver 500-kV shunt capacitors (brings total to 952 MVAR)
- Columbia series capacitor upgrade (2400 A, 22.5 percent)
- Olympia-Port Angeles 230-kV loop-in at Shelton
- Shelton-Port Angeles 230-kV loop-in at Fairmount
- Port Angeles 115-kV terminals in advance of added Daishowa load
(assumed schedule: phase 1 - fall 1993, phase 2 - fall 1995)
- Olympia 230-kV shunt capacitors (2-150 MVAR banks, remove old 100 MVAR bank)
- Custer-Bellingham 230-kV #2 line
- BCH Nelway phase shifter
- BCH Nicola-Meridian series capacitors (50 percent)
- BCH Nicola-Ingledow series capacitors (50 percent)
- TCL shunt capacitors at Southwest (100 MVAR), Pearl (60 MVAR), Northeast (80 MVAR) and Cowlitz (60 MVAR)

PUGET SOUND REINFORCEMENT STUDY -- PLANNING FOR PEAK POWER NEEDS

Prior to Winter 1995-1996:

Cowlitz-Olympia 230-kV line
Cowlitz Falls Integration (Mayfield-Mossyrock 230-kV loop-in)
Port Angeles 115-kV shunt capacitors (Daishowa phase 1, 2-23.7 MVAR banks)
Shelton 230-kV shunt capacitors (Daishowa phase 1, 1-114 MVAR bank)
Fairmount-Port Angeles 230-kV line (3rd line, Daishowa phase 1)
Shelton-Fairmount 230-kV line (3rd line, Daishowa phase 2)
Olympic Peninsula Reinforcement with 500-kV to Shelton
Allston 500/230-kV transformer #2
Ostrander 500-kV shunt capacitors (1-312 MVAR bank)
Keeler 500-kV shunt capacitors (1-312 MVAR bank)
BCH Williston-Kelly Lake 500-kV #3 line with series capacitors
BCH Kelly Lake-Cheekye 500-kV #2 line with series capacitors
BCH Ingledow static var device (150 MVAR)
BCH-WWP intertie (600 MW added import assumed for both normal and abnormal)

Prior to Winter 2003-2004:

No assumed additions after 1996.

IV. MEASURE CATEGORIES

Introduction. This chapter describes the results of the scoping process in each of the four measure categories: conservation & load management, local generation, transmission, and load curtailment. It begins with a description of the screening criteria that were applied to measures within each category. Separate sections for each of the measure categories list all options identified and describe in more detail the measures that passed the initial screening process. These are the measures that the study teams propose for use when developing alternative strategies in Phase II of the study. The descriptions include estimates of cost, quantity, and availability for each measure.

Screening Criteria. The evaluation team developed screening criteria for the study teams to assess which measures merit further analysis. These criteria were used as rough guidelines for the teams to consider when deciding which components of the measure categories to include in their lists. The screening criteria were not considered as absolute; judgment complemented the criteria where appropriate.

Table IV-1 lists the screening criteria. These criteria received public review at the March technical review group meeting.

TABLE IV-1

SCREENING CRITERIA

Market Factors

Commercially Available Technology

Commercially Proven Technology/ Confirmed Resource

Acceptable to the Market

Resource Characteristics

On-line date no later than 1999

Available during cold weather from November through March

Located within the Puget Sound area

Costs should be reasonable relative to the estimated cost of transmission (approximately \$100 per kW), the estimated cost of a single cycle combustion turbine (approximately \$650 per kW), and the regional cost-effectiveness limit of 50 mills per kWh

Environmental Criteria

Meets state and federal environmental quality laws and standards (e.g., air quality standards, water quality standards, etc.)

Avoids protected sites and environmentally unique habitats (e.g., the Council's Protected Areas, wetlands, national parks, etc.)

A. CONSERVATION & LOAD MANAGEMENT

Background. Conservation and load management are frequently referred to as demand-side management. These types of actions may be designed to influence customer use of electricity in ways that would reduce the peak load stress on the transmission system in the Puget Sound area. The types of demand-side management actions are illustrated in Figure IV-A-1. Of these actions, conservation and load shifting were emphasized in this analysis.

Utilities in the Pacific Northwest are more familiar with conservation than with load management for satisfying the requirements of growing loads. Conservation is defined as the more efficient use of electricity in any of the consuming sectors: residential, commercial, industrial, or irrigation. As illustrated in Figure IV-A-1, conservation typically reduces the level of electricity use at all hours of the day, and therefore can help reduce transmission requirements.

Load management is the demand side option most frequently associated with peak load problems. It is also the area with which utilities in the Pacific Northwest have the least experience, since the Pacific Northwest generating system is energy-constrained and not capacity constrained. Utilities in this part of the country typically have few problems meeting peak demand. Load management emphasizes the management of electricity use during a day (i.e., rescheduling some uses for other than peak times). This is illustrated in Figure IV-A-1 where electricity use during peak hours is shifted to off-peak hours. Load management does not typically reduce overall electricity use. As with conservation, load management can be applied to all sectors.

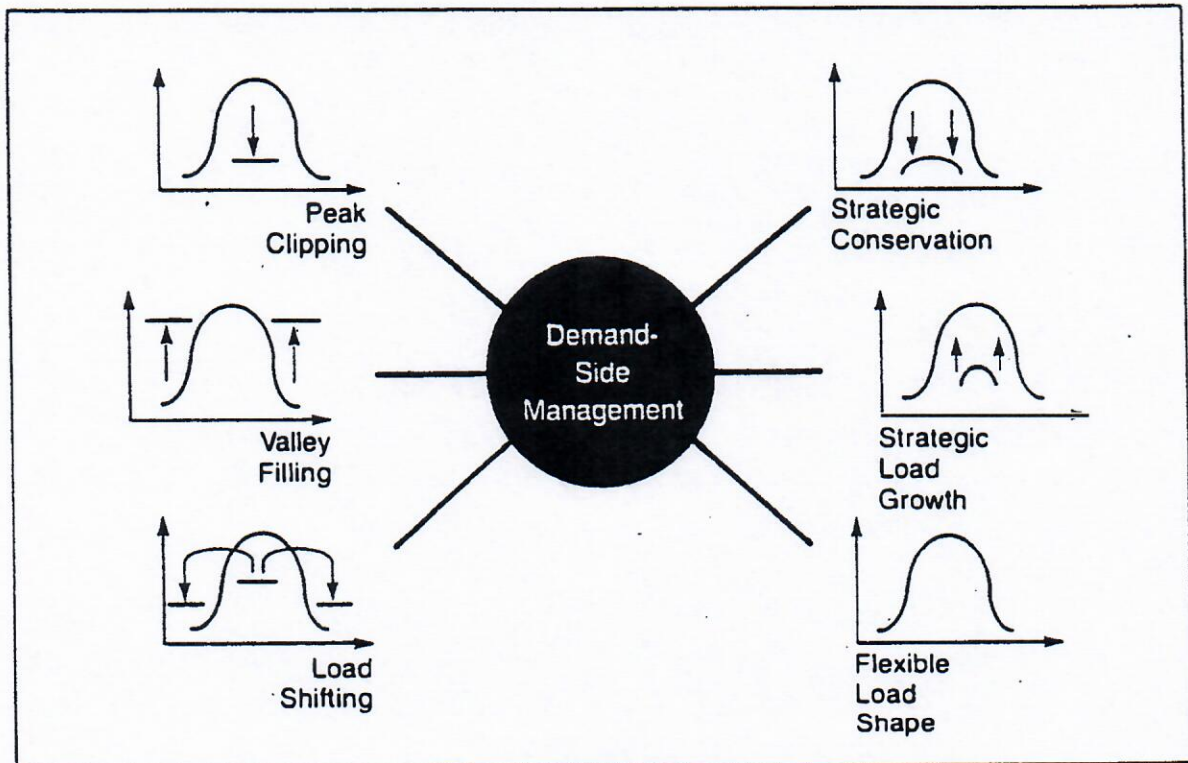
Conservation & Load Management Options. The conservation and load management team's first task was to develop a list of conservation and load management options which may have the potential to reduce Puget Sound area peak loads on an average and extremely cold winter day. The identification of these options was based on the team's understanding of the peak load problem and level of knowledge about various demand-side management program impacts. The list of potential options was reviewed with the technical review group and was refined several times. The screening criteria described earlier in this chapter were used as guidelines for selection of options. Around 20 options were considered for analysis. The options that passed the screening are shown in Table IV-A-1. Those not recommended for further analysis are listed in Table IV-A-2.

Methodology. The team estimated the maximum achievable peak reduction potential in the Puget Sound area: conservation beyond what is currently planned, load management options, and each option's associated costs. Estimates were developed for a normal winter peak day as well as an extreme winter peak day. System load shape impacts were projected for both day types.

The estimates of conservation and load management potential were developed using the same methods that were used to develop the estimates of conservation

FIGURE IV-A-1

DEMAND-SIDE MANAGEMENT



Source: Electric Power Research Institute

TABLE IV-A-1

CONSERVATION AND LOAD MANAGEMENT OPTIONS THAT REMAIN
 AFTER INITIAL SCREENING
 BY SECTOR

SECTOR	CONSERVATION	LOAD MANAGEMENT	OTHER
Residential	Weatherization <u>1/</u> Low flow shower heads	Space heat controls Water heater package <u>4/</u> Whole house demand control Thermal heat shortage Time-of-Use (TOU) rates	Fuel switching
Commercial	Existing <u>2/</u> New <u>2/</u>		
Industrial	Energy Savings Plan conservation <u>3/</u>		

1/ Includes insulation; water heater wraps; double or triple pane windows; more efficient water heaters.

2/ Includes insulation; efficient lights, HVAC systems and refrigeration.

3/ Includes lighting, HVAC, process heating, pumping, compressed air, motors.

4/ Includes water heater controls, low flow shower heads, and larger, more efficient tanks.

TABLE IV-A-2

OPTIONS DELETED FROM CONSIDERATION BY
INITIAL SCREENING
BY SECTOR

SECTOR	OPTION	REASON FOR SCREENING
Residential	Space heat set-back controls	May increase peak
Residential	Water heater replacement	Limited peak reduction
Residential	Lighting effic. and controls	Limited peak reduction
Residential	Solar augmntn. for water heaters	Appears unreliable
Residential	Gas back-up for heat pumps	Expensive
Residential	Portable gas generators	Environmental issues
Commercial	Lighting controls	Incl in commercial conservation
Commercial	Street lighting efficiency	Affects off-peak load
Commercial	Whole building controls	Considered as load curtailment
Comm & Indl	Dual fuel boilers	Limited potential
Comm & Indl	Fuel switching	Limited potential
Comm & Indl	TOU rates	Can increase energy use
Comm & Indl	Interruptible rates	Considered as load curtailment

supply for BPA's 1990 Resource Program and the Northwest Power Planning Council's 1990 Power Plan. These methods were developed during extensive public involvement processes and are the result of consensus among experts in the region. In addition, the data used for assessing conservation potential have also been reviewed by a regional panel. The methods and data used for the conservation analysis are described in BPA's draft 1990 Conservation Resources Supply Document. BPA continues to take comments on its conservation supply estimates and will continue research in the area. Reviews of data and assumptions to date indicate that these estimates are still reasonable. As research progresses and new information is developed, it will be incorporated into future Puget Sound studies.

Technical Potential. In general, the method begins with projections of numbers of units (for example, numbers of electrically heated single-family dwellings) from the load forecast, and costs and savings per unit from an inventory of available conservation and load management measures. The combination of this information yields an estimate of technical potential savings, savings that could be achieved if market constraints did not exist. Market constraints include such factors as unwillingness of some consumers to accept measures regardless of program incentives or delivery mechanism.

Market-Achievable Savings & Penetration Rates. Given that market constraints do exist, and that some installed measures do not achieve all the intended savings, the technical potential estimates are reduced to arrive at estimates of market-achievable savings. The market-achievable savings represent maximum saturation of the market for each option. Penetration rates were developed to estimate how much of the market achievable savings could be accomplished by the years 1995, 2000, 2005, and 2010.

Base case. It is important to account for the current conservation plans of each of the four major Puget Sound utilities and the remaining utilities in the area so as not to overstate total Puget Sound area conservation potential. The potential savings that were estimated as available to address the transmission problem reflect the conservation savings that can be accomplished by either accelerating existing utility plans, or instituting plans above and beyond what is currently planned. The existing utility plans define the base case and largely reflect the directions BPA laid out in the 1990 Resource Program. Base case savings estimates are provided in Table IV-A-3.

Peak Estimates. Estimates of daily load shapes for normal and extreme peak days were developed for several of the options, taking advantage of BPA's extensive hourly end-use data. These data are collected as part of the End-Use Load & Consumer Assessment Project (ELCAP) and provide actual metered data on the most important end-uses in the residential and commercial sectors. In general, the peak estimates were developed from estimates of annual energy savings, and daily load shapes are estimated based on ELCAP data.

Conservation & Load Management Potential. Table IV-A-3 lists the preliminary peak savings for the conservation and load management options listed in Table IV-A-1. There are several notes of caution when reading Table IV-A-3.

TABLE IV-A-3

CONSERVATION & LOAD MANAGEMENT POTENTIAL
IN THE PUGET SOUND AREA

	Cumulative MW (aMW) Saved in the year: <u>1/</u>											
	1995			2000			2005			2010		
	Nor MW	Ext MW	(aMW)	Nor MW	Ext MW	(aMW)	Nor MW	Ext MW	(aMW)	Nor MW	Ext MW	(aMW)
<u>Base Line (Planned Conservation Savings) 2/</u>												
Res Weatherization	99	130	(23)	165	217	(37)	206	271	(47)	228	300	(52)
Exstng Commercial	40	44	(25)	74	84	(46)	106	119	(66)	130	146	(81)
New Commercial	30	34	(19)	78	88	(49)	128	144	(80)	167	188	(104)
Industrial	20	21	(20)	51	52	(50)	80	82	(79)	93	95	(91)
<u>Conservation Savings Potential Above Base Line 3/</u>												
Res Weatherization	19	25	(4)	71	95	(16)	31	41	(7)	9	12	(2)
Res Lo Flow Shower Heads <u>4/</u>	6	6	(5)	12	12	(11)	12	12	(11)	12	12	(11)
Exstng Commercial	0	0	(0)	38	43	(24)	62	70	(39)	94	106	(59)
New Commercial <u>5/</u>	0	0	(0)	0	0	(0)	0	0	(0)	0	0	(0)
Industrial	36	37	(35)	43	44	(42)	14	14	(13)	1	1	(1)
<u>Load Management 6/</u>												
Res Water Htr Pckg	153	111	(6)	372	269	(16)	533	385	(23)	534	385	(21)
Res TOU Rates	93	101	(0)	126	137	(0)	128	140	(0)	131	143	(0)

1/ Nor MW = normal year MW savings; Ext MW = extreme year MW savings; aMW = average MW (energy) savings per year. Cumulative savings in each reported year reflect the savings in that year occurring from units installed in prior years.

2/ Base line savings projections based on current utility plans and BPA's Resource Program; assumed to be accounted for in the forecast.

3/ Calculated by subtracting base line projected savings from accelerated program savings. BPA Supply Curves and utility projections used to calculate accelerated program savings.

4/ Market for low flow shower heads includes only existing homes; assumes few existing homes have low flow shower heads. Base line assumed to be zero.

5/ Aggressive planned new commercial conservation savings already captures 100% of market potential; therefore, no potential exists beyond base line.

6/ Load management data come from EPRI, Snohomish PUD pilot programs, vendors, etc. Some load management results still being developed.

First, the estimates provided are the result of preliminary scoping efforts by the conservation and load management team. Although team members have significant experience with conservation, there is little familiarity with load management in the Northwest. Second, conservation options may interact with load management options, and as a result, they are not additive.

Load management options have the most potential for peak reduction. For example, residential time-of-use rates, if structured properly, could provide up to 143 MW of extreme peak day savings by the year 2010, at low cost. In addition, conservation options are largely already planned; the increment of peak savings due to conservation above current plans therefore tends to be small.

Load Management. Load management options generally operate by causing loads to shift from peak hours to off-peak hours during the day. The challenge is to avoid creating another peak by shifting too much load. The team developed a rule of thumb which constrained the maximum amount of "shiftable" load to 500 MW shifted from the morning peak to the mid-morning valley. The 500 MW accounts for the peak to valley difference on the Puget Sound area system load shape and also for electricity use by appliances when they are turned back on. Table IV-A-3 presents savings for two load management control options. However, it is recognized that other options such as space heat controls, thermal energy storage, etc., can be pursued to shift peak loads. Because of the 500 MW maximum shiftable load constraint and other issues related to these options, it was determined that water heat load management would be emphasized. Other options will be addressed further in Phase II of the study.

Costs. The costs of each option displayed in Table IV-A-4 and Table IV-A-5 include capital, incentive, administrative, and annual costs. These costs have been levelized to account for different measure lives and to make the savings estimates more consistent with the costs. For example, the costs in the year 2005 reflect the costs of the measures installed through 2005. This is consistent with the savings estimates for 2005 in Table IV-A-3 which result from installation of measures through 2005.

The costs for load management options are expressed in dollars per peak kW saved. These costs have been developed from a combination of regional experiences and research documents, primarily from EPRI. The costs in Tables IV-A-4 vary by year and by peak day type even though the levelized costs are constant. The costs change because the peak savings themselves change by peak day type and between years.

The costs for the conservation options are expressed in mills per kWh. These costs were developed from a combination of recent utility experiences and from data obtained from BPA's Resource Program document. The costs of the conservation options are all below the regional cost effectiveness ceiling of 50 mills/kWh. They provide a cost effective energy resource apart from any peak benefits they can provide. In Phase II more emphasis will be placed on how to develop the conservation costs associated with peak savings.

TABLE IV-A-4

LEVELIZED COSTS FOR LOAD MANAGEMENT PROGRAMS 1/
BY DAY TYPE \$/PEAK KILOWATT

PROGRAM	1995	2000	2005	2010
Hot Water Controls <u>2/</u> - Normal Day Type	\$57.20	\$57.10	\$57.10	\$57.30
Hot Water Controls - Extreme Day Type	\$78.80	\$79.00	\$79.10	\$79.50
Residential Time of Use Rates <u>3/</u> - Normal Day Type	\$56.40	\$56.40	\$59.00	\$63.40
Residential Time of Use Rates - Extreme Day Type	\$52.00	\$52.00	\$54.20	\$58.10

1/ Levelized at 3 percent over equipment life. Levelized costs are annual costs comparable to annual peak savings.

2/ Equipment costs are \$358 per hot water heater. Annual costs are \$28 per tank for incentives and administrative costs.

3/ Equipment costs are \$115. Annual costs are \$22 per year for incentives and administrative costs.

TABLE IV-A-5

LEVELIZED COST OF CONSERVATION PROGRAMS 1/
MILLS/KWH

Residential Weatherization	40
Low-flow Shower Heads	19
Existing Commercial	21
New Commercial	14
Industrial	15

1/ Costs are levelized at 3 percent over equipment life and divided by expected average annual energy savings. Cost data are from the Draft 1990 Conservation Resources Supply Document published by BPA. Program evaluation reports were also used.

Fuel Switching. The switching of electricity loads to other fuels, termed "fuel switching," is another option that has attracted attention. While fuel switching might appear to have a large potential for peak reduction, some of this results from market forces and thus is already reflected in the load forecast described in Chapter II.

Fuel switching presents a number of concerns, including regulatory policy issues, fuel availability, reliability, distribution and price issues, and environmental impacts. The significance of these concerns will be addressed in Phase II.

Preliminary estimates indicate that there are approximately 600 MW of peak savings potential available from fuel switching residential space and water heat. This estimate is based on moderate assumptions about gas availability, the emphasized market niche, and market saturation.

As this subject receives more regional attention and the many uncertainties are discussed further, some fuel switching issues may be resolved in other forums. The topic of fuel switching will continue to be addressed in the context of the Puget Sound study. The extent to which it is considered as a solution is dependent on the resolution of a number of issues and on the further development of estimates of gas availability, fuel switching costs, and MW potential.

Remaining Conservation and Load Management Issues. Several factors limit the accuracy of the conservation and load management estimates. These include:

- 1) Lack of data on the capacity impacts of various conservation and load management programs;
- 2) Lack of experience in load management and rates programs, which make it difficult to judge customer response (Estimates of penetration and saturation rates are conservative.);
- 3) Dimensions of the transmission problem not yet fully understood (Does a problem occur frequently, every year, or infrequently, once every 20 years?);
- 4) Lack of resolution of several issues that could significantly change the impact of conservation and load management options on peak reduction (Most important of these is the issue of how programs will be funded. Another is the accounting for costs of conservation programs pursued to meet energy requirements.);
- 5) Policy issues surrounding fuel switching which make it difficult to quantify as an option for peak reduction.

In Phase II it may be necessary to reconsider the assumptions underlying these estimates, both in examining new technologies and in estimating penetration and market saturation rates. This could result in less conservative estimates of conservation and load management potential.

There may also be opportunities to combine options to create programs that will result in greater savings. For example, pairing time-of-use rates with residential thermal heat storage may provide better results than either option alone. Such strategies may also allow expansion into other approaches which alone may not show much potential for reducing peak or being accepted by customers. Combinations of options will be addressed in Phase II.

B. LOCAL GENERATION

Background. Sufficient generating resources exist within the Pacific Northwest region to meet both peak and energy requirements in the Puget Sound area. However, the bulk of these resources are located east of the Cascade Mountains and require long distance transmission to serve loads in the Puget Sound area. As explained in Chapter I, the existing transmission system delivering power to the area is increasingly strained as peak loads continue to grow.

"Local" generation is defined for the purpose of this study as any power source located within the Puget Sound area, extending north to the Canadian border, east to the Cascade Mountains, south to Chehalis, and west to the Pacific Ocean. New local generation offers several distinct advantages that relate directly to the peak delivery problem: peaking capacity and reactive voltage support. In addition, generation alternatives have value associated with their energy component.

Information Sources. Major sources used to develop the information in this section were: the material being prepared for the Northwest Power Planning Council's 1990 Power Plan; BPA's Draft 1990 Generating Resource Supply Document; BPA's "Assessment of Commercial and Industrial Cogeneration Potential in the Pacific Northwest"; the Northwest Hydro Database; and an assessment of standby generation performed by a contractor. These sources of information along with the data developed by the technical review group provided the information from which the local generation supply was developed.

Projections of future resource acquisitions from the utility members of the study team were used to corroborate BPA and Northwest Power Planning Council estimates. The Puget Sound area utilities, as well as others in the region, are actively seeking resource development options. At this point, most plans are in the preliminary stages, so continuing changes in resource prospects should be expected.

Methodology. BPA and the Northwest Power Planning Council have collaborated in assessing potential generating resources for the region. These assessments, which have been refined through numerous public involvement processes, formed the foundation of the analysis of local generation for the Puget Sound area.

The estimates for Puget Sound area cogeneration were developed by breaking out sub-regions in BPA's cogeneration study. The methodology for developing the cogeneration potential within the subregion is identical with that used in the cogeneration study.

The potential for small hydro was developed in a similar manner. A subregion consisting of the Puget Sound area was developed and then the hydro potential for that region was projected using the Northwest Hydro Database.

Standby generation is a rough estimate of the amount of resource that might be available in the Puget Sound area based on the experiences of utilities in other parts of the country. Several technical and institutional issues would have to be investigated more thoroughly to assess the proper role of this resource.

Combustion turbines are a known technology with predictable capital costs. The capacity that can be installed does not have an inherent limit, but rather is constrained by siting and fuel delivery factors. Further study is required to assess the application of combustion turbines in the Puget Sound area.

WNP-3 costs and performance figures are taken from BPA's 1990 Resource Program documentation. Although WNP-3 is located at the southern end of the Puget Sound area under study, it has potential benefit for both capacity and reactive support. Further study will be required to determine its likely contribution.

A coal resource using advanced technologies (i.e. atmospheric fluidized bed or gasification) has been included for further analysis. These technologies can be developed in relatively small increments and have reduced emissions compared to conventional coal conversion technologies. They can also be developed in cogeneration applications.

Local Generation Supply. The results of Phase I generating resource analyses are displayed in Tables IV-B-1 through IV-B-5 on the following pages. The "universe" of generic generation alternatives identified during Phase I is shown in Table IV-B-1. This list of resources was then subjected to the screening criteria described in Table IV-B-3. The technologies that passed the initial screening are listed in Table IV-B-2. These technologies will be analyzed further and evaluated as components of alternative strategies in Phase II. Table IV-B-3 summarizes the results of the screening and identifies those resource technologies that were eliminated.

Table IV-B-4 displays operating characteristics of the resource types recommended for further consideration. The data were developed from the references cited earlier. These data are not based on site-specific studies in the Puget Sound area, but are thought to be representative of potential Puget Sound area resource development.

Table IV-B-5 shows energy characteristics, levelized costs (in 1988 \$) and construction lead times for each of the resource types recommended for further study. These data were developed from the same sources.

No detailed information on the technologies that did not pass screening is presented here. However, all source materials and documentation are available for review upon request. It should also be pointed out that local generation options that were not found suitable for solving the Puget Sound peak load problem may still warrant further consideration in utility energy resource programs.

UNIVERSE OF GENERATION ALTERNATIVES

Oil and Gas Combustion

- Steam
- Combustion Turbines
- Combined Cycle

Coal

- Conventional Coal
- Advanced Coal (FBC, Gasification)

Nuclear Fission - Completion of WNP-3

Nuclear Fusion

Geothermal

Hydroelectric

- Conventional
- Pumped Storage
- Water Supply (Pressure Reduction)

Biomass Fired - Direct Combustion or Gasification

Municipal Solid Waste - Mass Burn, RDF or Gasification

Cogeneration

Wind

Solar Thermal Electric

Photovoltaics

Ocean - Wave and/or Tidal

Hydrogen

Fuel Cells

Storage Systems - Compressed Air

- Utility Batteries
- Superconducting Magnetic Energy

Standby Generation

Table IV-B-2

GENERATION TECHNOLOGIES RECOMMENDED FOR FURTHER STUDY

Oil and Gas Combustion

- Steam
- Combustion Turbines
- Combined Cycle

Hydroelectric - Conventional

- Pumped Storage
- Water Supply (Pressure Reduction)

Biomass Fired - Direct Combustion or Gasification

Municipal Solid Waste - Mass Burn, RDF or Gasification

Cogeneration

Standby Generation

Nuclear - WNP-3

Advanced Coal

Table IV-B-3

GENERATION TECHNOLOGIES EXCLUDED FROM FURTHER CONSIDERATION

Generation Technologies Excluded from Further Consideration	Exclusion Based on Not Meeting the Screening Criteria(*)
Conventional Coal (**)	5
Advanced Nuclear	1, 2, 4 & 5
Geothermal	2
Wind	2, 3
Solar Thermal Electric	1, 2 & 4
Photovoltaics	2, 3 & 4
Ocean - Wave and/or Tidal	1, 2, 3 & 4
Hydrogen	1, 2, & 4
Fuel Cells	1, 2 & 4
Storage Systems	1, 2, & 4
- Compressed Air	
- Utility Batteries	
- Superconducting Magnetic Energy	

- (*)
1. Technology maturity
 2. Commercially available technology/Confirmed resource
 3. Available during winter and any other critical outage condition
 4. Competitive cost (50 mills/kWh or less) levelized real (1988 \$)
 5. On line by 2002.

(**) Conventional coal may be feasible but cannot meet the 2002 on-line date. Advanced coal technologies are included for further consideration.

Table IV-B-4

PEAK POTENTIAL AND OPERATING CHARACTERISTICS

Resource	Winter Peak Day Project Output (MW)		Energy (% of Annual)		
	Normal	Extreme	Winter <u>1/</u>	Shoulder <u>2/</u>	Summer <u>3/</u>
Cogeneration <u>4/</u> (Total potential)	1,100	<u>5/</u>	- - - - - Flat - - - - -		
Combustion Turbines (Per unit)					
Simple Cycle	160 <u>6/</u>	<u>5/</u>	- - - - - As Required - - - - -		
Combined Cycle	420+ <u>6/</u>	<u>5/</u>	- - - - - As Required - - - - -		
Hydroelectric (Total potential-New)	240	<u>5/</u>	25%	30%	45%
Standby Generation	20	<u>5/</u>	- - - - - Not Applicable - - - - -		
WNP-3 <u>7/</u>	1,240	<u>5/</u>	40%	40%	40%
Advanced Coal	200	<u>5/</u>	- - - - - Flat - - - - -		

1/ Winter includes November, December, January and February

2/ Summer includes May, June, July and August

3/ Shoulder includes September, October, March and April

4/ Includes municipal solid waste and biomass-fired opportunities

5/ Winter peak day project output is assumed to equal installed capacity.
(More study is required.)

6/ These are typical sizes for single and combined cycle installation. The actual amount installed depends on specific factors such as siting constraints and fuel arrangements.

7/ Although WNP-3 is located at the southern end of the Puget Sound area under study, it has potential benefit for both capacity and reactive support. Further study will be required to determine its likely contribution.

Table IV-B-5

ENERGY, LEVELIZED COST, AND LEAD TIMES

Resource	Installed Capacity (MW)	Energy (aMW)	Levelized Cost (mills/kWh, 1988\$)	Lead Time (Years)
Cogeneration <u>1/</u>	1,100	950	35-55	2-4
Combustion Turbines				
Simple Cycle	160 <u>3/</u>	—	<u>2/</u>	3-4
Combined Cycle	420+ <u>3/</u>	—	<u>2/</u>	4-5
Hydroelectric (New)	240	100	16-55	3-6
Standby Generation	20	—	52-61	<1
WNP-3	1,240	806	34	8
Advanced Coal	200 <u>3/</u>	170	40-50	7

1/ Includes municipal solid waste and biomass-fired opportunities

2/ Combustion turbine (CT) cost depends on how they are used. When displaced by nonfirm hydro power, combined cycle CT's have a cost of 26-34 mills/kWh. If installed for capacity only, simple cycle CT's have a capital cost of 400-500 \$/KW. CT's are considered to be a viable option for the Puget Sound area. Actual application and the verification of cost will require further study.

3/ These are typical unit sizes. The actual number of units installed depends on specific factors such as siting constraints and fuel arrangements.

C. TRANSMISSION

Background. Thirty-nine transmission options were studied during Phase I using constant power load models. Six options, listed in Table IV-C-1, are considered technically and economically feasible. Since the five transmission line options are similar, only one is described here. A transmission line option and a reactive option will be carried forward in the planning EIS process.

Options such as 765-kV double circuit and \pm 500-kV direct current (DC) are technically feasible, but are too costly. In addition, 28 other 500-kV alternating current (AC) options, listed in Table IV-C-2, were found to be infeasible or technically inferior.

Upgrade of existing single circuit 345-kV lines to 500-kV is not practical since audible noise and EMF considerations require a minimum of 3-conductor bundles. The existing towers are not capable of supporting the increased weight. It may be feasible to convert a double circuit 345-kV line to single circuit 500-kV, but the capacity increase would be limited.

A complete rebuild of an existing circuit is possible. This would allow the replacement of a lower capacity line (or lines) with a higher capacity circuit(s) using existing right-of-way or minimizing the need for new right-of-way. However, the capacity of the replaced circuit is lost and it may be difficult to operate the system reliably during construction when the old line is taken out of service. Also, rebuildable lines may not be located where transmission reinforcement is needed or would best be placed. Rebuild options will be explored in greater detail in Phase II.

Determinations of feasibility were based on assumptions and information available at the time. Any of the options not being carried forward into Phase II could be re-evaluated if further engineering or environmental studies provide information that could affect their feasibility.

Viable Transmission Alternatives

1. Cross-Cascade 500-kV AC Double-Circuit Line

Puget Sound Area Voltage Stability Performance. With a new line added, the three critical outages for the Puget Sound area are 1) loss of one Coulee-Raver 500-kV line during abnormally cold weather, 2) loss of the Trojan nuclear plant with one Centralia unit previously out of service, also during abnormally cold weather, and 3) simultaneous loss of both Coulee-Raver 500-kV lines during normal winter peak loads.

A new Cross-Cascade 500-kV AC double circuit line alone will not fully solve the Puget Sound voltage/stability problem and provide the required reactive margins for the critical outages. The 500/230-kV transformer project in North Seattle will also help reduce the reactive deficit, but will still not provide the necessary reactive margin. A 300 MVAR Static VAR Compensator (SVC) is also needed in the Puget Sound area at the Maple Valley Substation to provide this margin.

PUGET SOUND REINFORCEMENT STUDY -- PLANNING FOR PEAK POWER NEEDS

This SVC will need to be increased to 500 MVARs in later years to keep up with the expected load growth. Also, additional 500-kV shunt capacitors will be needed at Monroe and Snoqualmie Substations between 2000 and 2004.

Puget Sound Area Thermal Overload Requirements. If the Cross-Cascade line is added, numerous problems are aggravated in the North Seattle area during winter conditions. These would require local reinforcement.

Portland Area Voltage Stability Performance. The critical outage for the Portland area is loss of the Trojan nuclear plant with one Centralia generating unit previously out of service during abnormally cold weather loads. The addition of the new line into the Puget Sound area will not provide the necessary margins in the Portland area by itself. A 300 MVAR SVC is needed at Keeler substation. This SVC will need to be increased to 500 MVARs in later years to keep up with the load growth. Also, additional 500-kV shunt capacitors will be needed at Ostrander and Pearl Substations between the years 2000 and 2004.

Coulee/Chief Joseph Area Performance/Effects. Loading increases on the 500/230-kV transformers with a new cross mountain line. A second Chief Joe 500/230-kV transformer is needed to prevent overloads following outages of the existing Chief Joe 500/230-kV transformer, Coulee 500/230-kV transformer, or Coulee-Chief Joe 500-kV line during spring with 1800 MW Custer to Ingledow power flow.

Transmission Line Option Summary.

- 1994 Add 300 MVAR SVC on Maple Valley 230-kV bus,
 Add 300 MVAR SVC on Keeler 230-kV bus,
 Add Snoqualmie Switching Station, and
 Eight line upgrades.

- 1996 Add Chief Joseph-Snoqualmie/Monroe 500-kV double circuit line; Add
 Snoking 500/230-kV transformer tapping Monroe-Snoqualmie 500-kV
 Line and using existing 500-kV constructed line into Snoking;
 Add Snoking-Bothell 230-kV line #2; add Snoqualmie 500-kV shunt
 reactor; and
 Eight line upgrades.

- 2000 Upgrade Maple Valley SVC to 500 MVAR; and
 Upgrade Keeler SVC to 500 MVAR;
 Add 500-kV shunt capacitor bank at Monroe;
 Add 500-kV shunt capacitor bank at Pearl; and
 Add 500-kV shunt capacitor bank at Ostrander.

- 2004 Add 500-kV shunt capacitor bank at Snoqualmie
 Add 500-kV shunt capacitor bank at Ostrander

- 2005 Add Monroe-Snohomish 500-kV line, operate at 230-kV initially.

- 2010 Add Snohomish 500/230-kV 1800 MVA transformer;
 Loop Bothell-Diablo 230-kV line into Snohomish; and
 Convert Monroe-Snohomish line to 500-kV operation.

2. Reactive Option

Puget Sound Area Voltage Stability Performance. Assumed voltage stability criteria can be achieved in 1996 with the addition of four 300 MVAR SVC's (Snohomish, Maple Valley, Covington, and Keeler) and two series capacitor stations (1 on each Coulee-Raver 500-kV line about 50 miles from Raver, 20 percent 2600A).

In 2000, load growth and system design for the simultaneous loss of both Coulee-Raver 500-kV lines requires three additional series capacitor stations on the other three existing cross Cascades 500-kV lines (25 percent 3200A midline on Chief Joe-Monroe 500, 35 percent 2300A on each Naneum-Raver 500 line). Another 324 MVAR 500-kV shunt capacitor bank is needed at Monroe.

By 2004, load growth causes the need for all the series capacitors to be in service with no outage during abnormal cold weather. Three more series capacitor stations need to be added for planning contingencies (25 percent more compensation on Chief Joe-Monroe and 35 percent more compensation on each Naneum-Raver line). Two 500-kV 324 MVAR shunt capacitor banks are needed at Snoqualmie.

Portland Area Voltage Stability Performance. A 300 MVAR SVC is needed at Keeler in 1996 and an additional 300 MVAR SVC is needed at Ostrander in 2004 to satisfy voltage stability criteria for a Trojan outage during abnormal cold with one Centralia unit down.

Reactive Option Summary

- 1994 300 MVAR SVC on Maple Valley 230-kV bus,
 300 MVAR SVC on Keeler 230-kV bus,
 Add Snoqualmie Switching Station, and
 Eight Line Upgrades.
- 1996 300 MVAR SVC at Snohomish
 300 MVAR SVC at Covington
 20 percent more series comp on Coulee-Raver #1 and #2 between
 Columbia and Raver
- 2000 25 percent series comp on Chief Joe-Monroe midline
 35 percent series comp on Naneum-Raver #1 & #2 between Naneum and
 Raver
 3rd parallel circuit from Monroe Tap to Sedro Tap
 Add 500-kV shunt capacitor banks at Monroe, Pearl, and Ostrander
- 2004 Add 2-500-kV shunt capacitor banks at Snoqualmie
 Add 500-kV shunt capacitor bank at Ostrander
 25 percent more series comp on Chief Joe-Monroe
 35 percent more series comp on Naneum-Raver #1 and #2
 2nd Maple Valley 500/230-kV transformer
 2nd Raver-Snoqualmie 500-kV line
 300 MVAR SVC at Ostrander

PUGET SOUND REINFORCEMENT STUDY -- PLANNING FOR PEAK POWER NEEDS

Costs and Transmission Efficiency Benefits of Viable Alternatives.

COST COMPARISON
(All Costs in Millions, 1990 \$)

	1990-1995	1996-2000	2001-2005	2006-2010
Transmission Line Option	60	242	18	14
Reactive Option	60	105	76	0

LOSS SAVINGS COMPARISON
(Peak MW)

	1996	2000	2004(1)	2004+(1)
Transmission Line Option	73.9	86.1	77.1	84.9
Reactive Option	2.4	10.1	-0-	-0-

1/ The loss savings for 1996 and 2000 are referenced against the base transmission system for each year. The loss savings for 2004 are referenced against the Reactive Plan.

Table IV-C-1

TRANSMISSION OPTIONS CONSIDERED TECHNICALLY & ECONOMICALLY FEASIBLE

1. Chief Joe-Monroe 500-kV double circuit line.
 2. Chief Joe-Snoqualmie 500-kV double circuit line.
 3. Chief Joe-Snoqualmie/Monroe 500-kV double circuit line.
 4. Hanford-Snoqualmie 500-kV double circuit line.
 5. Sickler-Snoqualmie 500-kV double circuit line and Naneum Switchyard.
 6. Reactive Alternative
-

Table IV-C-2

TRANSMISSION OPTIONS NOT CARRIED FORWARD INTO PHASE II

1. Chief Joe-Raver 500-kV double circuit line.
2. Chief Joe-Raver 500-kV double circuit & Raver-Snoqualmie 500-kV #2 lines.
3. Coulee-Raver 500-kV double circuit line.
4. Ashe-Snoqualmie 500-kV double circuit line.
5. Chief Joe-Monroe/Snoqualmie 500-kV double circuit, add Raver-Snoqualmie #2 and use with one existing Coulee-Raver line to form Coulee-Snoqualmie 500-kV line.
6. Chief Joe-Coulee 500-kV single circuit line.
7. Monroe-Raver-Paul 500-kV single circuit line.
8. Monroe-Raver-Olympia 500-kV single circuit line.
9. Naneum Switchyard (tie Coulee-Raver lines, Vantage-Raver, and Sickler-Raver lines together near Ellensburg)
10. Naneum Switchyard and Grand Coulee-Naneum 500-kV double circuit line.
11. Naneum Switchyard with shunt capacitors.
12. Naneum Switchyard with series capacitors within station.
13. Naneum Switchyard, Naneum-Snoqualmie 500-kV double-circuit line.
14. Naneum Switchyard, Naneum-Monroe 500-kV double-circuit line.
15. Naneum Switchyard, 500-kV single circuit tap line to Hanford-Grand Coulee.
16. Naneum Switchyard, Naneum-Hanford 500-kV single circuit line.
17. 500-kV single circuit tap line from Sickler to existing Grand Coulee-Hanford 500-kV line.
18. Sickler-Monroe 500-kV double circuit line.
19. Sickler-Monroe 500-kV double circuit line, 500-kV single circuit tap line from Sickler to existing Grand Coulee-Hanford 500-kV line.
20. Sickler-Snoqualmie 500-kV double circuit line.
21. John Day-Paul 500-kV double circuit line.
22. John Day-Allston 500-kV double circuit line.
23. John Day-Allston 500-kV double circuit line, Monroe-Raver-Olympia 500-kV single circuit line.
24. Lower Monumental-Hanford 70 percent Series Compensation - 136 MVAR.
25. Raver-Snoqualmie 500-kV single circuit line, Snoqualmie switchyard.
26. Raver-Snoqualmie 500-kV single circuit line, Raver-Covington 500-kV single circuit line.
27. Raver-Snoqualmie, Raver-Covington, and Raver-Tacoma 500-kV single circuit lines.
28. Covington-Maple Valley 500-kV single circuit line, Covington and Maple Valley switchyards.

D. LOAD CURTAILMENT

Background. Load curtailment is a reduction in the amount of electricity consumed by an end user. Load curtailment for purposes of this study needs to be differentiated from conservation and load management. There are generally three methods that can be used to reduce the amount of electrical demand and energy consumed by an end user. The first method is to reduce the amount of electricity used through energy conservation measures, potentially reducing both peak and energy loads. The second method is to shift the pattern of energy use from a specific point in time to another, reducing demand while holding total energy consumption relatively constant. The third method is to limit the amount of electricity and simply forego its use. The first two methods, for this analysis, are being defined as conservation and load management alternatives. The third is load curtailment.

For purposes of this study, load curtailment is defined as a reduction of demand during times of system stress that is limited to a short, nonrecurring period during which a utility has identified a need to reduce demand temporarily. However, curtailment was studied for use on a planning basis rather than as a short term method for dealing with a temporary operating problem. Long term load reductions accomplished through capital investment incentives or focused toward a reduction of energy consumption would not be considered curtailment.

Various methods of curtailing demand were identified and studied to determine whether they would be of value in effecting a net reduction in demand in the Puget Sound area. As new options were suggested, the load curtailment study team coordinated with the load management study team to assure that overlap and omission were avoided. Options suggested included voluntary curtailment, rotating "rolling" blackouts (involuntary curtailment), voluntary industrial curtailment without affecting production, multi-utility curtailment, curtailment cooperatives (co-op), industrial contractual curtailment, and curtailment rates. BPA's existing DSI contracts were also studied to determine what potential might exist.

After more thorough analysis, the study team narrowed the curtailment options to three different types--voluntary, involuntary, and contractual. Voluntary curtailment includes curtailment which could be achieved in the residential, commercial, and industrial sectors at the request of utilities and government agencies. Involuntary curtailment would be implemented through rolling blackouts by utilities without any action by end-use consumers. Contractual curtailment includes both industrial curtailment contracts and curtailment co-ops. Multi-utility curtailment was thought to be a special case of contractual or voluntary curtailment. Curtailment rates were not studied as a separate type of curtailment because the rate would be an implementation mechanism under both industrial and co-op curtailment contracts. Each of these types is discussed in detail later in this section.

Methodology. To estimate the amount of potential for curtailment in the Puget Sound Area, information from utilities outside the region was reviewed, and a survey was distributed to various industrial customers of the four large utilities in the Puget Sound area. The industrial sector was chosen because

large blocks of load might be available, and the smaller number of consumers made it easier to obtain survey results. These customers were asked to identify their typical peak January load and the amount of load they might be willing to make available for curtailment at three different rates ranging from \$3/kW-yr to \$25/kW-yr. The assumptions in the survey were that curtailment would be called for no more than once a winter season with 30 minutes advance notice and that the interruption would last for no more than four hours. Some survey recipients also identified loads that could be curtailed for up to twelve hours.

Curtailment programs from other utilities throughout the country with experience in load curtailment were reviewed to gain a better understanding of the local potential for curtailment and its associated issues. Some of the utilities whose programs were reviewed included Potomac Electric Power Company (PEPCO), Boston Edison Company (BECO), and Sacramento Municipal Utility District (SMUD). Although these utilities are located in other parts of the country and are subject to different load characteristics and conditions than those which exist in the Puget Sound area, the team felt that similar curtailment resources might be developed in the Puget Sound area.

Curtailment Potential. The results of the survey identified the following potential industrial load curtailment resources:

<u>Curtailment Rate</u>	<u>Curtailment Potential</u>
\$ 3/kW-yr	125 MW
\$10/kW-yr	162 MW
\$25/kW-yr	302 MW

As a check against the compensation offered by other utilities in their curtailment programs a limited analysis was performed to determine what type of rate structure might be appropriate for a curtailment program. That analysis suggested that curtailment rates should be established somewhere between BPA's value of DSI reserves and the cost of the next least-cost alternative solution. The range of suggested rates was similar to the rates proposed in the industrial survey, lending credibility to the survey data.

After analyzing all the information gathered during the study, the study team concluded that there are four basic kinds of curtailment resources that could be used to help avoid a voltage collapse in the Puget Sound area. These include voluntary curtailment, contractual curtailment, curtailment co-ops, and involuntary curtailment or rolling blackouts. The consensus of the study team was that only the first three would be considered good candidates for an overall package to be used as a long term solution for the voltage collapse problem. A summary of curtailment potential of the four kinds of resources is shown in Table IV-D-1. Delivery mechanisms will be addressed during Phase II.

Rolling blackouts were considered to be an emergency or short term type of resource. If implemented, it is likely that additional control equipment would need to be installed by utilities to make rolling blackouts an effective curtailment resource. The duration of the blackout would need to be precisely controlled in order to avoid recovery peak problems. If the electrical system in the Puget Sound area were in imminent danger of a voltage collapse, rolling

Table IV-D-1

CURTAILMENT POTENTIAL IN THE PUGET SOUND AREA

Curtailment Resource	Sector	Cost to Utility	Amount
Voluntary	Residential	No Cost	0.1 - 10 % (10 - 860 MW)
	Commercial		
	Industrial		
Contractual	Industrial	\$3 - 100 /kW-yr	100 - 900+ MW
Curtailment Co-ops	Commercial	\$3 - 25 /kW-yr	50 - 300 MW
	Industrial		
Rolling Blackouts (Involuntary)	Residential	Control Cost	Amount needed but limited by recovery peaks
	Commercial		
	Industrial		

blackouts could provide adequate load reduction to avoid a widespread outage, but the impacts it would create make it unsuitable as a long term solution. Industries would be thrown into chaos if they were subjected to half-hour to hour outages repeated every one or two hours. Such a scheme would effectively curtail the entire load of many industries for the duration of the system problem. Workers might also be subjected to unacceptable dangers associated with production processes. The general public would also face various hazards associated with the sudden interruption of electricity, and in general, safety problems arising from rolling blackouts would be great enough to cause this option to be eliminated as a longer term resource.

Of the three remaining kinds of curtailment resources, the study team concluded that the following amounts of load curtailment might be achieved in the Puget Sound area, depending on how actively they were pursued:

Voluntary Curtailment. The study team estimated that between a 0.1 and 10 percent (10 - 860 MW) reduction in demand could be achieved with a voluntary load curtailment program. Under such a program, businesses and the general public would be notified by radio and/or television of a need to reduce electricity use. This type of program could be implemented with a minimum of preparation and cost. The amount of reduction would depend on various conditions at the time.

Factors which would reduce the amount of load curtailed include the frequency with which curtailment is called upon, the duration of the load reduction, weather conditions, and market conditions. The team felt that, as load grew to the point where curtailment were needed more and more often, the amount of curtailment achievable on a voluntary basis would diminish. However, there may be some individuals or businesses that would always be willing to curtail use no matter how often it was asked; thus there would always some amount of curtailment available. Weather would also play a big factor in determining the amount of voluntary curtailment that could be achieved. Residential customers would be less likely to turn off electric heaters if the risk of freezing pipes was great due to extremely cold weather conditions. Market conditions would especially affect the amount of voluntary curtailment which might be achievable from the commercial and industrial sectors. If companies were in financial stress they would be less likely to curtail voluntarily.

This type of curtailment resource would generally be available to utilities without direct compensation cost, however it was recognized that individual customers may be subjected to other costs and impacts associated with their decision to curtail use. Utilities would need to devote staff resources to working out implementation details with local media and to educate the general public regarding how to respond to the utility's call for curtailment.

Members of the study team also determined that voluntary curtailment may not be as effective in combating a voltage collapse problem because of the length of time it would take to achieve the needed reduction. In a scenario where a key transmission line was suddenly taken out of service causing a voltage drop, a reaction would be needed in a matter of minutes to prevent system collapse. The time required for the media to ask for voluntary curtailment

might be too long. By the time the public could react, the situation would have already been resolved by either stabilizing or collapsing.

This may be used more effectively as a preventative resource called upon either prior to an actual system problem or as a fill-in measure after immediate steps are taken to stabilize the system but before other resources can be put into place. A drawback of using voluntary curtailment in this manner is that utility customers may begin to doubt the need for curtailment over a longer period of time. If utilities call for voluntary curtailment as a preventative measure too frequently, without demonstrating to the public an actual need, customers might eventually curtail less or not at all. The utilities could soon be viewed as "crying wolf."

Contractual Curtailment. Based on the results of the utility survey, it is estimated that between 100 and 900 MW of curtailment could be achieved over a 2-year phase-in period by contracting with individual industrial customers in the Puget Sound area. This is in addition to existing curtailment contracts within the area. Under a curtailment contract, a utility would negotiate with interested industrial customers in its service area for specific amounts of curtailment based on various warning, frequency, and duration parameters. If there were a need for curtailment, the utility would implement the curtailment resource in one of a number of ways. In turn, the utility would compensate the industry in the form of a rate reduction.

Implementation methods include manual interruption by either the customer or utility, undervoltage load dropping, transfer trip load dropping, and a method of load dropping based on the Supervisory Control And Data Acquisition (SCADA) system. The method to be used would be established in each contract, allowing flexibility in addressing specific concerns and impacts for each customer. Contracts allowing for automated interruption would provide a more responsive resource. However, in the case of processes which could not tolerate automated interruptions or where such an interruption would create dangerous health or safety problems, the load could be interrupted manually by either the customer or serving utility.

The survey indicated a willingness on the part of some industrial customers to consider between 100 MW and 300 MW of contractual curtailment at incentive amounts of between \$3/kW-yr and \$25/kW-yr. The total peak demand of the customers responding to the survey was approximately 451 MW out of a total 1990 estimated Puget Sound area peak industrial demand of 1,449 MW. Extrapolating the data suggests that approximately 900 MW of curtailment might be available if the industrial customers were compensated at a rate of \$100/kW-yr. The \$100/kW-yr is at the upper end of compensation rates that have been used in other parts of the country. Combining the low and high estimates indicates that between 100 MW and 900 MW of industrial contractual curtailment might be available in the Puget Sound Area at compensation rates between \$3/kW-yr and \$100/kW-yr.

Under existing BPA DSI contracts, approximately 650 MW of Puget Sound area peak load can be interrupted for a period of 15 minutes to provide capacity reserves. Under the contract half of the interrupted load must be restored after 15 minutes and the remainder must be restored after an additional 30 minutes. Any continuing curtailment after that point would be arranged

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informally between BPA and the affected DSI. Other Puget Sound area utilities can curtail smaller amounts of load but only during hours of the day that would be less useful in alleviating a potential voltage collapse. As these contracts expire and are renegotiated, it may be possible to increase curtailment rights. However, BPA's existing DSI contracts don't expire until the year 2001 and may not provide any additional near term curtailment potential. There is also no assurance that the DSI's will agree to additional curtailment provisions because of operational impacts.

Curtailment Cooperatives. The study team estimated that between 50 MW and 300 MW of curtailment could be achieved over a 3-year phase-in period through curtailment co-ops in the Puget Sound area. Co-ops are groups of commercial and industrial customers who join together to provide contracted amounts of curtailment when called for under an interruptible rate. The co-op members agree to limit their collective demand, upon utility request, to pre-established firm service levels. The estimate is based on results in other parts of the country for similar sized load bases. The actual amount achieved would depend on how the co-op was structured and how aggressively area utilities sought this type of curtailment.

Co-ops in other areas of the country have required significant utility staff effort to seek out co-op participants and to establish reasonable firm service levels. In many cases the utility provides a number of customer service engineers whose function is to analyze each interested participant and establish potential load reduction strategies and amounts. In order to establish a curtailment base in the Puget Sound area, staff would need to be allocated to identify the potential. Whether the staff would be provided by individual utilities or a regional entity is an open question.

Other utilities have based compensation on the avoided cost of the least cost alternative replacement resource. A preliminary look at compensation based on BPA's costs and alternative pricing structures indicates that compensation to co-ops would range between \$3 and \$25/kW-yr. The avoided costs for Puget Sound area utilities would vary, but are assumed to be similar to BPA's.

Study team members expressed concern that, although some amount of curtailment could fit into an overall strategy, load curtailment is not preferred as the primary long term solution. Historically, the Pacific Northwest has been accustomed to an abundant supply of electricity available on demand. Recent changes in the price and availability of electric power may make it economic to look toward increasing contractual rights to interrupt service as a supplement to other resources in achieving load-resource balance. When asked to compare the limitation of electricity supply (curtailment) to other approaches, most study participants preferred to use load curtailment as a last resort. It was viewed primarily as an emergency resource or short term measure to be used only until the implementation of a long term solution. However, curtailment could be incorporated into long-term planning as a tactic for use in response to low-probability contingencies, such as extreme weather, where the cost of system additions would be uneconomic based on infrequent use.

Most customers, including the larger industries in the Puget Sound area, would be willing to curtail some load to help local utilities keep the electrical

system on line in an emergency, but would be less willing to participate if load curtailment was used as the primary solution to a longer term problem. Thus, the study team concluded that load curtailment would best be used as a short term measure or as part of a more comprehensive solution strategy.

Factors which were found to affect the industries' willingness to participate in any load curtailment program included the amount of warning, the frequency of curtailments, the duration of each curtailment, and the price utilities would be willing to pay. More warning would allow processes to be shut down safely and economically and decisions to be made regarding process schedules. Most industries agreed that as curtailment was used more often and for longer periods of time, fewer customers would be willing to participate. The survey also confirmed that the more utilities offered to pay for curtailment, the more willing customers would be to participate. However, some customers indicated unwillingness to participate regardless of the level of compensation. A few indicated that the amount of curtailment they could provide would not increase with greater compensation. Most responded that the effects of less warning, greater frequency, and longer duration of curtailments would tend to cancel out the incentive of higher compensation. Some industries stated that if they were asked to curtail load too often, they would not be willing to participate no matter what price incentive was offered.

Implementation issues that would need to be addressed include:

1. Priority, duration, frequency, & amount of notice needed.
2. The means by which load curtailment would be implemented. (undervoltage, transfer trip, SCADA based)
3. Load curtailment as a reduction of reliability and if/how existing rate structure for some classes of customers would need to be changed. Some utilities don't feel existing rates would allow for curtailment on a planned basis.
4. The health and safety problems various types of load curtailment resources would create, including public safety problems.
5. How companies served by multiple utilities would be affected by each utility asking for curtailment. Would they be able to choose what they would curtail even though it meant possible curtailment to only one utility?
6. How do the utilities keep from "crying wolf", especially with voluntary curtailment, so that the needed amount of curtailment is realized?
7. Public awareness, education, and communications problems. Does the public know how to react when curtailment is in effect? (turning off electrical appliances, lights, etc.)
8. How existing curtailment rights with DSI's apply to a load curtailment alternative. Some DSI's don't think the existing contracts were meant to solve the problem being studied.

Table IV-D-2

LOAD CURTAILMENT SUPPLY CURVE

Program	Sector	Quantity (MW)	Cost to Utility (\$/kW-yr)
<u>Year: 1992</u>			
Voluntary Curtailment	All	10 - 860	0
Curtailment Co-ops	Commercial/Industrial	0	0
Contractual	Industrial	0	0
Rolling Blackouts	All	(1)	0
<u>Year: 1993</u>			
Voluntary Curtailment	All	10 - 860	0
Curtailment Co-ops	Commercial/Industrial	20 - 100	3 - 25
Contractual	Industrial	50 - 450	3 - 100
Rolling Blackouts	All	(1)	0
<u>Year: 1994</u>			
Voluntary Curtailment	All	10 - 860	0
Curtailment Co-ops	Commercial/Industrial	40 - 200	3 - 25
Contractual	Industrial	100 - 900	3 - 100
Rolling Blackouts	All	(1)	0
<u>Year: 1995 and Beyond</u>			
Voluntary Curtailment	All	10 - 860	0
Curtailment Co-ops	Commercial/Industrial	50 - 300	3 - 25
Contractual	Industrial	100 - 900	3 - 100
Rolling Blackouts	All	(1)	0

(1) Resource could provide whatever MW requirements necessary but may be limited by recovery peak problems.

V. EVALUATION METHODOLOGY

Introduction. This chapter describes the methodology for evaluating alternative strategies that address the Puget Sound area peak load problem. It will be used in the Environmental Impact Statement (EIS) being prepared for this project.

Following quantification of the supply and cost of the measures available to address the peak load problem, as discussed in the previous chapter, a key step in the evaluation process will be the construction of alternative strategies. (See Chapter VI) It is likely that these strategies will include components from more than one measure category. Evaluation and ranking will then be performed on these strategies for each of eight evaluation factors, as shown in the example evaluation matrix (Table V-1). Each evaluation factor is described in detail later in this chapter.

The evaluation factors represent a range of concerns that utility decision makers may consider. Some factors, such as system costs, can often be quantified while others, such as environmental impacts, lend themselves more to qualitative comparisons. Evaluation factors dealing with utility costs treat the Puget Sound area as if it were served by a single utility. Issues of who will pay for what portion of an alternative strategy will not be dealt with in the EIS. Since the evaluation factors represent different concerns and are measured in different ways, the evaluation methodology ranks alternative strategies according to each factor individually rather using a single score that combines ranks from all factors. The methodology therefore does not weight the relative importance of each evaluation factor.

Among the alternative strategies considered, it is unlikely that the same strategy will rank highest on all evaluation factors. For example, the strategy with the lowest near-term revenue impacts may not be the strategy with the lowest present value of system costs. Eventually, tradeoffs must be made when searching for the best strategy.

Study Framework. The evaluation factors include measures of economic impacts and risk. Each of these factors focuses on the Puget Sound area as if it were served by a single utility. This single utility perspective means that no distinction is made between private and public utilities or load served by BPA and load served by utility-owned generation. The evaluation factors that consider revenue impacts include only the costs to utilities. In addition, the present value of total system costs and the measure of economic risk includes consumer costs and benefits as well as those of the utilities. For the latter factors, the perspective is that of society as a whole in the Puget Sound area.

The base case for this study assumes medium load growth in the Puget Sound area and will also account for currently planned generation, conservation, load management, and transmission additions. The study period for decisions will begin in winter 1993-94 and extend until winter 2002-03. End effects after 2003 will be accounted for. Table V-2 contains the proposed economic and financial assumptions for the evaluation of the alternative strategies.

TABLE V-1

EXAMPLE EVALUATION MATRIX

Evaluation Factor	Strategy A	Strategy B	Strategy C	Strategy D	Strategy E
Minimize Net Present Value	2	4	1	3	5
Ability to Meet High Loads	1.5	3	5	1.5	4
Minimize Economic Risk	5	2.5	1	2.5	4
Minimize Near-Term Revenue Rqmts	4	5	1	2.5	2.5
Minimize Long-Term Revenue Rqmts	5	4	3	1.5	1.5
Minimize Environmental Impacts	2	4	1	5	3
Maximize Deliverability	3	3	1	3	5
Maximize Reliability	3	4	5	1.5	1.5

Notes

These examples are for illustration purposes, and are not intended to represent particular strategies

Ranking: 1 = high, 5 = low

Ties indicate rankings that are close together

TABLE V-2

ECONOMIC & FINANCIAL ASSUMPTIONS

Discount Rate	3 percent real
Inflation Rate	5 percent
Cost of Capital	4 percent real
Percent Debt Financing	100 percent

After the base case is established and the eight evaluation factors are assessed, sensitivity studies will be performed where appropriate. Three likely candidates for variables to study are the discount rate, fuel prices, and the penetration rates assumed for conservation and load management programs. This latter parameter is particularly important for assessing the uncertainty of the amount of conservation and load management available. Sensitivity analysis will be performed only on the economic evaluation factors.

Evaluation Factors. The following paragraphs describe each of the evaluation factors in detail. Of the eight evaluation factors, the first seven have been applied by utilities in the region for various resource planning exercises and have previously received public review. The eighth factor is new for this project and specifically addresses the issue of power system reliability. Methods of measurement have been designed to address the issues important to power system reliability in the Puget Sound area.

Minimize the Present Value of Total System Costs. For this evaluation factor, quantifiable costs and benefits of both energy and capacity, for resource and transmission actions, are used to calculate the net present value of total system costs for each alternative strategy. The present value includes costs and benefits to BPA, Puget Sound area utilities, and consumers. An expected value of three load paths: low, medium, and high will be used. Each proposed alternative strategy that solves the peak load problem in the Puget Sound is ranked according to this evaluation factor. The strategy with the lowest system cost then is ranked first for this factor.

System costs for this calculation include capital costs for actions that require construction, and debt service, operating and maintenance costs, regardless of whether these costs are paid by utilities or consumers. Benefits include the energy and capacity saved or generated that benefit the power system. Marginal costs of energy and capacity will be used to value these benefits.

Ensure that Puget Sound Area Utilities are Able to Meet High Peak Loads from 1996-1998, if Necessary. Every utility faces uncertainty about what its future power needs will be. Even if load growth moderates in the Puget Sound area, utilities will need to initiate action in order to ensure that the criteria for system planning are met to serve peak loads safely and reliably. If, however, load growth continues over the next few years at the current pace, the risk of blackouts or other load interruptions becomes unacceptable if no actions are taken. For this factor, each alternative strategy will be evaluated in terms of its ability to meet forecasted high peak loads in the Puget Sound area on average from 1996 to 1998. This ability will be expressed in MW of capacity surplus or deficit. These years were chosen to allow enough time for utilities to implement reasonable actions to address the peak load problem once they realized they were experiencing continued high load growth. Using an average of 3 years ameliorates the "lumpiness" of large measures (such as transmission lines and combustion turbines) that arrive all at once in a particular year.

Minimize Exposure to Economic Risks of Adjusting to Unplanned Changes in Load Growth, Resource Availability, and Costs. In addition to the risk of not serving peak loads, utilities and consumers run the risk of experiencing the economic impact of having chosen the wrong strategy to solve the Puget Sound area peak load problem. Two major areas of risk exist: (1) the cost of building or acquiring an expensive resource and/or transmission line that is not needed because load growth does not occur as anticipated (overbuilding); and (2) the high cost of acquiring expensive short lead-time resources because of greater load growth than planned (underbuilding). Economic risk for each alternative strategy will be measured by calculating the expected present value of total system costs assuming low and high load growth when the strategy has been designed for medium load growth.

Minimize Near-Term Revenue Requirements. Resource and transmission actions paid for by utilities require funding that must be recovered through revenues from rates charged to consumers. For this analysis, in keeping with the single utility perspective, funding sources will not be distinguished. Maintaining low and stable rates to customers is important to all utilities in terms of maintaining competitiveness and supporting the economic health of their customers. This factor will be measured by considering the average impact on utility revenue requirements for the representative years 1996-1998 required to pay for each alternative strategy.

Minimize Long-Term Revenue Requirements. Long-term revenue requirements are also important for decision makers to consider. Strategies with the least impact on near-term revenue requirements may have large adverse impacts on long-term revenue requirements. This factor will be measured in a manner similar to that used for the near-term revenue requirement impacts. It will consider the average impact on revenue requirements for the representative years 2006-2008.

Minimize Local and Global Environmental Impacts. For each alternative strategy, the costs of mitigation actions, such as installing scrubbers on coal plants, are included in total system costs. In contrast, this factor focuses on the nonquantifiable local and global environmental impacts of each alternative strategy, such as impacts on endangered species, wetlands, anadromous fish, air quality, and water quality. This factor will be a major focus of the EIS. It is discussed more thoroughly in the following chapter.

Maximize Deliverability in View of Social and Political Factors. In every decision process, factors other than economic or financial impacts affect the final decision. These influences are largely political and/or social and can strongly affect whether or not an alternative strategy is practical and achievable. For example, a technology or action may be well known and proven, but not publicly acceptable, and therefore would be difficult to implement. This factor attempts to assess the impact of elements such as regulatory influences, institutional complexity, and public acceptability on the ability to implement each alternative strategy. There likely will be some overlap between this evaluation factor and the environmental impact factor, as well as others. However, in addition to the actual environmental impacts, this factor assesses how the perception of environmental impacts may affect the feasibility, or deliverability, of a particular alternative.

It does not necessarily follow that the alternative with the fewest or most benign environmental impacts will be the most deliverable. Finally, in contrast to the other evaluation factors, this factor is largely the result of judgment.

Maximize Power System Reliability. Reliability is a measure of the capability of the power system to meet consumer demands over a period of time. It is typically measured in terms such as how often outages occur, how long they last, and how much load is affected. The goal is to maximize reliability to the extent possible.

Planners use a set of rules, such as the BPA Reliability Criteria, to establish reliability requirements for the power system. The criteria specify contingencies that must be examined, such as the loss of a key transmission line or generating station, and define acceptable performance, in this case serving extreme winter peak loads. At this point, no explicit measure of reliability is made. However, the criteria reflect a balance between the cost of upgrading the power system to provide a given level of service and the benefits to the consumer in terms of reduced outage impacts, based on the experience of system planners.

All proposed strategies must meet the tests specified in the criteria. However, even after meeting the tests, each strategy may provide a different level of reliability. For example, two transmission circuits on a single tower pose a greater risk than if they are routed on separate corridors, but they both satisfy the reliability criteria.

Existing transmission reliability models are not capable of examining the Puget Sound peak load problem because of the complexity of the system and the difficulty of detecting voltage collapse. Therefore, a simplified analysis will be performed for this evaluation factor. Power flow studies performed by the transmission study team will determine the amount of load that can be served with a major facility, such as a 500-kV cross-mountain line, out of service.

Load and system capability information will be combined to determine the likelihood and severity of system problems, similar to a generation capacity study. Daily and seasonal load variation will be considered, as well as higher loads resulting from cold weather. The measure of reliability for this evaluation factor is expected MW-hours unserved.

VI. NEXT STEPS: PHASE II

Introduction. This chapter describes the next phase of the technical and environmental components of the analysis. It also discusses the interim steps being taken to address operating concerns while a longer term solution is sought. Upcoming public involvement opportunities are discussed in Part A of this report.

Development of Alternative Strategies. The first task in Phase II of the study will be to develop alternative strategies from among the measure categories. This aggregation will allow planners to balance costs and risks, and to take advantage of the relatively short lead times required to develop some alternatives. Some strategies may consist of only one measure category, but most will probably include elements of two or more categories.

Chapter IV presented cost and quantity data for options within each measure category. Where appropriate, taking into account cost and lead times, these elements will be aggregated into logical groups to simplify the analysis. For generation, groups of resources such as small hydro or cogeneration may be aggregated. Conservation, load management, and curtailment measures may be grouped into blocks of related programs or technologies where appropriate. One transmission measure representing line construction and a second measure using only reactive sources will be considered. To be considered for further analysis, an aggregate strategy must pass the tests specified in the reliability criteria.

Examination of the strengths and weaknesses of each measure should provide guidance in assembling the alternative strategies. For example, a transmission line may completely fix the problem for 10 years, but it requires about 6 years to site and build. As a result, any alternative strategy that includes transmission line construction needs to include measures that address the peak load problem in the years prior to the completion of the line, such as load curtailment. On the other hand, load management may be cost effective for deferring a transmission line for some period of time, thus delaying or avoiding the need for the line. These examples illustrate the types of tradeoffs to be considered as these alternative strategies are formed. In this way, four to six alternative strategies, representing the range of possible actions, will be developed for analysis in the planning EIS.

Environmental Analysis - Planning Phase EIS. Environmental analysis is planned on four levels. The first level is the application of environmental screening factors. These factors recognize unique habitats and protected sites as well as environmental quality standards that any proposal must meet to be approved.

The environmental screening factors differ from the screening factors discussed in Chapter IV in that they constitute absolutes, and no alternative would be considered viable if it violated a legal requirement. Table VI-1 is a list of the environmental screening factors.

The second level is a generic assessment of environmental impacts, to be based largely upon published findings for similar projects. Impacts associated with each alternative will be listed in matrix form to allow comparison.

The third level is a locational impact assessment. In the absence of a proposed site (as in this planning phase EIS) little can be said about how an action will affect actual environments. This analysis provides a geographical context to the impact analysis. The locational assessment is based on a geographical data base composed of natural resource and cultural resource data. Data within the data base have been used to build impact sensitivity models for each of the measure types being considered for the Puget Sound area. The result of the locational assessment will be a series of impact advisory maps that predict environmental sensitivity as high, moderate, or low. This technique is most commonly attributed to Ian McHarg, and has been described as an ecologically based approach to urban and regional planning.

Finally, once the impacts of each measure are analyzed and understood, a yet-to-be-developed method of providing environmental advice on alternative strategies will be developed. It is expected that the final method will extrapolate findings at the component level and reflect relative environmental differences among strategies. It may be useful to use strictly environmental factors to assemble what might be the strategy with the least environmental impact, and compare all other strategies to it. The specifics of this fourth level of analysis will be developed during Phase II.

Near Term Actions. BPA and the Puget Sound utilities have worked through the Northwest Power Pool to develop a "Winter Operating Plan" to deal with possible near term system emergencies. Under the plan, measures are to be implemented by each of the parties when loads reach specified levels or when a system disturbance occurs. Measures include "arming" the system to curtail direct service industrial load automatically; operating thermal generation to support system stability before it would be economically justified; and, as a last resort, instituting utility curtailment by geographical area ("rolling blackouts"). The plan was put into effect during winter 1989-90 and is being refined for 1990-91.

The group is also investigating low cost, environmentally benign actions that can be taken now but will fit into the long term strategy. Such actions might include adding capacitor banks and static VAR devices and installing under-voltage load shedding equipment.

ENVIRONMENTAL SCREENING FACTORS

1. AVOIDS PROTECTED SITES AND ENVIRONMENTALLY UNIQUE HABITATS

ENVIRONMENTALLY PROTECTED SITES

Federally Protected Areas

- Wilderness Areas (Designated)
- Wilderness Areas (Proposed by BLM/FS)
- Wilderness Study Areas (Status Undefined)
- Primitive Areas
- Federal Wild and Scenic Rivers
- Old Growth Habitat (Spotted Owl)
- Research Natural Areas (RNA)
- Botanical and Natural Areas
- Outstanding Natural Areas
- Scenic Landmarks
- Experimental Forests
- Areas of Critical Environmental Concern (BLM)
- Unique Geologic Sites
- Historic Landmarks, Districts & Sites (National Registry)
- National Recreation, Scenic & Historic Trails
- Paleontologic Sites (National Register)
- Natural Landmarks (National Register)
- National Recreation Areas
- National Scenic Areas

Other Protected Areas

- Protected Areas (Northwest Power Planning Council)
- National Parks
- State Parks
- State Designated Wild Rivers
- Cultural Areas/Sites
- National Wildlife Refuges
- State Wildlife Refuges
- National Fish Hatcheries
- National Natural Landmarks
- State Research Natural Areas
- Critical Habitat for Endangered Species
- Wetlands

Restricted Land Use Types

- Military/Department of Defense/DOE Installations
- Classified Areas (Missiles, Command Centers, DOE Nuclear Areas)
- Ammo Storage Areas
- Firing Ranges
- Airports, Airfields, and Associated Controlled Airspace
- Indian Reservations
- Active Mining Sites & Mineral Resource Areas

2. MEETS ENVIRONMENTAL QUALITY STANDARDS

CHECKLIST OF 16

Environmental Policy (NEPA, SEPA)
Endangered and Threatened Species and Critical Habitat
Fish and Wildlife Conservation
Heritage Conservation
State, Areawide, and Local Plan and Program Consistency
Coastal Management Program Consistency
Floodplains
Wetlands
Farmlands
Recreation Resources
Global Warming
Permit for Structures in Navigable Waters
Permit for Discharges into Waters of the United States
Permit for Right-of-Way on Public Lands
Energy Conservation at Federal Facilities
Pollution Control at Federal Facilities
Prevention, Control, and Abatement of Environmental Pollution
Contract Compliance with the Clean Air and Water Acts
Air
Water
Solid and Hazardous Waste
Safe Drinking Water
Noise
Pesticides
Toxic Substance Control Act (TSCA)
Asbestos
CERCLA
Radon

(VS11-T-1449f)

APPENDIX

LETTER AGREEMENT

Management of Puget Sound Reinforcement Project

Under certain conditions, the East-West Main Grid Transmission System is no longer able to support the increasing electrical loads in the Puget Sound Area due to rapidly increasing load growth. In response to this growing problem, the Bonneville Power Administration (BPA) has initiated a Federal NEPA process to evaluate potential solutions.

BPA and various Puget Sound area utilities, including Public Utility District Number 1 of Snohomish County, Puget Sound Power & Light Company, Seattle City Light, and Tacoma City Light (collectively, the "Puget Sound Utilities") have agreed to cooperate at several organizational levels in further defining the problem of voltage instability in the Puget Sound area, and evaluating potential solutions. Currently, under conditions of peak winter demand, the system might not adequately withstand failure of a major line or the Centralia power plant.

BPA and the Puget Sound Utilities agree that the Puget Sound Reinforcement Project, which BPA has initiated to address the voltage instability issue, should be an effort that adequately addresses the NEPA and SEPA needs of all parties to the extent applicable. The potential results of voltage instability in Puget Sound are not yet fully known, but BPA and the Puget Sound utilities seek to jointly explore the existence and extent of the problem as well as cost-effective environmentally sound solutions to this problem to the extent possible. This letter reflects the commitment by the undersigned to coordinate on this planning effort. It is the intent that the decisions of the 5 utilities will be by consensus.

1. Steering Committee. A Steering Committee, composed of a single representative from Bonneville and each of the Puget Sound Utilities, is established. The purpose of the Steering Committee, through a Project Management Team and various study teams, is to:

- provide organizational support for the completion of studies addressing the voltage instability problem;
- coordinate the NEPA/SEPA process, including the preparation of any environmental documents;
- analyze the evaluation criteria for alternatives;
- analyze the alternatives;
- coordinate with other Federal, State, and local agencies; and
- coordinate public involvement efforts.

BPA, consistent with its lead role in the Federal EIS, will chair the Steering Committee. Members are the signatories to this letter.

2. Project Management Team. BPA and each of the Puget Sound Utilities will designate a Project Manager. The purpose of the Project Management Team will be to conduct the studies and carry out the tasks established by the Steering Committee. The BPA representative will chair the Project Management Team. The Project Management Team will conduct work through various study teams which will address subjects including, but not limited to, load forecasting, local generation, load curtailment, conservation/demand side management, transmission studies and evaluation criteria.

3. Technical Review Group. A Technical Review Group is established as an advisory group to the Project Management Team. Membership in the Technical Review Group will be open to interested utilities, interest group leaders, State and Federal agency representatives, and others interested in providing specific technical input on studies, options and alternatives, and decision criteria. The BPA Project Manager will provide leadership for this group, including the setting of meetings and agendas and arranging for input to the Project Management Team.

4. Funding. BPA and the participating utilities will separately fund their participation in the planning process described in this letter. Nothing in this letter precludes BPA or the Puget Sound Utilities from seeking rate relief for costs associated with this project through their respective rate processes.

5. Impact. BPA and the Puget Sound Utilities agree that the process described in this letter is intended solely as a coordinating vehicle and is not itself intended to replace, impact, or prejudice any existing or future individual utility efforts.

6. Termination. BPA and the Puget Sound Utilities agree that any member of this planning process may terminate its participation upon notice to the other participants.

(Letter Agreement - contd.)

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PUBLIC UTILITY DISTRICT #1 OF SNOHOMISH COUNTY

By Charles R. Earl

Date 3/22/90

BONNEVILLE POWER ADMINISTRATION

By A.O. Clark

Date 3/9/90

PUGET SOUND POWER & LIGHT COMPANY

By H.J. Finnegan

Date 3/13/90

SEATTLE CITY LIGHT

By [Signature]

Date 3/15/90

TACOMA CITY LIGHT

By [Signature]

Date 3/19/90