OLYMPIC PENINSULA STUDY OF NON-WIRES SOLUTIONS TO THE 500 KV TRANSMISSION LINE FROM OLYMPIA TO SHELTON AND A TRANSFORMER ADDITION AT SHELTON

Draft

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EXECUTIVE SUMMARY

This report provides an assessment of non-construction alternatives. Its purpose is to determine whether it is feasible to use these alternatives to defer a planned transmission line investment on the Olympic Peninsula to a later date. This study complements and does not replace existing transmission planning. The goals of this study are the following:

1. Evaluate a broad set of non-construction alternatives (NCAs);
2. Identify the most promising NCAs for the Olympic Peninsula Area;
3. Determine if it is feasible to deploy NCAs to defer transmission construction to a later date; and
4. Evaluate the sensitivity of the preliminary results of this report to the important input assumptions.

WHAT ARE NON-CONSTRUCTION ALTERNATIVES?

Non-construction alternatives encompass all activities unrelated to transmission facility construction that may allow for the deferral of that investment.

These include:

- Energy efficiency measures that reduce peak demand;
- Generation at or near loads;
- Loads selling back power at peak, either under contract or in response to periodic offers to pay a set amount for load reductions. This set of activities is referred to as "demand response;" and
- Actions taken by transmission operators that can squeeze more out of the existing transmission. (Not considered in this report.)

SUMMARY OF APPROACH

The approach of this study consists of four steps. Each of these steps is described briefly below, and in more detail in the main report.

Step 1: Collect local and system avoided cost data for the study area

The local and system cost data for the Olympic Peninsula includes forecasts of market prices of electricity, natural gas, and diesel; the avoided cost of the transmission line; number of customers; forecasted growth and area load pattern during the peak winter season; and other information. Each of these inputs is described in the report.

Whenever possible, public sources of information were used, such as the Northwest Power and Conservation Council's (NWPCC) data, rather than proprietary BPA data and assumptions.

We performed sensitivity analyses when key inputs were uncertain.

The Present Worth Method was used to determine the deferral value of the 500-kV transmission project. This approach measures the decrease in the Bonneville Power Administration's (BPA) Transmission Business Line (TBL) revenue requirement if the project is deferred.

The study measures the value of deferred investments in the transmission system and the opportunity costs of generation that otherwise would have been used to serve peak loads.

Step 2: Refine assumptions on cost and performance of NCAs

The cost and performance assumptions (heat rate, energy savings, etc.) from the database developed for a previous study done for BPA by Energy and Environmental Economics, Inc. (E3)[1] have been refined for this analysis. Again, the main sources of information are publicly available. The three main categories of NCAs that this study evaluates are:

1. Energy efficiency measures (EE)
2. Distributed generation (DG)
3. Demand response (DR)

The ability to add energy efficiency measures depends on how many have already been installed in homes, commercial buildings, and industrial plants. If all end-users are already at the cutting edge of efficiency, EE measures will offer no opportunities to defer the transmission investment.

Because this first draft is a scoping study, it is assumed that no conservation has been installed in homes. Since delay looks feasible under this assumption, we will be conducting a more detailed study of resources on the Olympic Peninsula. An estimate will be made as to what level of energy efficiency has already been accomplished on the Peninsula, and the remaining potential.

The DG input assumptions are taken from a set of recent National Renewable Energy Laboratory (NREL) studies for each main DG technology type; the EE measure costs and performance are taken from the NWPCC's Regional Technical Forum (RTF) database; and the DR costs are from a recent Xenergy report commissioned by BPA, along with BPA's experience with the Demand Exchange Program.

Step 3: Evaluate economics of each NCA from various stakeholder perspectives

With the input assumptions from Steps 1 and 2, the cost and benefits for each NCA alternative were calculated from the perspective of various stakeholders. Five different perspectives were used:

- Ratepayer Impact Measure (RIM) (Impact on rates)
- Participant Cost Test (PCT) (Net financial impact on customer with NCA)
- Total Resource Cost Test (TRC) (Net direct costs and benefits to all stakeholders)
- Utility Cost Test (UCT) (Impact on revenue requirement)
- Societal Cost Test (SCT) (Net social costs and benefits, including externalities)

The TRC and SCT are the only cost test perspectives that indicate whether the total system costs have been lowered. The other tests are measures of who pays and who benefits. That is, they measure how the costs and benefits of a cost-effective measure get allocated. These cost tests offer important information about how difficult it may be to implement the measures needed to defer the transmission project. For example, if cost-effective measures benefit both individuals and utilities,

[1] http://www2.transmission.bpa.gov/PlanProj/Non-Construction_Round_Table/NonWireDocs/KELReport.pdf.

it would be easier to enlist their help in implementing the NCAs. If individuals are harmed, even though the NCA might be best for the region, it might be difficult to get support for the measures.

A comment about the RIM test is in order. The RIM test measures the impact on rates, in this case to TBL's transmission rates. BPA has used the RIM test historically to choose between competing construction solutions for transmission improvement needs. The option that has the smallest impact on rates is the one pursued. In this context, the RIM test makes sense.

However, when considering NCA measures against supply side resources, such as transmission, distribution, and generation, the RIM test should not be used to make decisions about whether to implement the measures. Since transmission rates are generally costs divided by kW sold, any NCA measure that reduces transmission sales, even if it has no costs, will not pass the RIM test. If the RIM test is used in this way, few cost-effective measures, based on TRC or SCT perspective, would be deployed in the region.

In this report, the TRC test is used as the main cost test to screen NCAs. That is, measures that pass the TRC test are included in the package of NCAs that can be used to defer transmission construction. The other tests are a measure of who pays and who benefits. They offer important information including hints about reasonable cost allocations.

All of the alternatives have been screened using the five tests. A benefit-to-cost (B/C) ratio greater than 1.0 for the RIM, PCT, and UCT test would indicate that there may be partners willing to help implement the identified measures. For example, if the PCT benefit/cost ratio is greater than one, the participant would be better off by applying it, and therefore a willing collaborator. The same is true for the other "allocation" tests. The reverse might be true if the ratios are less than one, even if the measure is cost-effective from a total resource cost and a societal perspective.

Step 4: Evaluate sensitivities to key input variables

A sensitivity analysis was performed to determine how robust the results of the study were to changes in key inputs. Since this is a relatively high-level screening analysis, the sensitivities were designed to determine whether changing assumptions across a broad range would "flip" the answer, or whether it remained the same across the feasible range of assumptions. The sensitivity analysis evaluates changes in load growth, transmission capital costs, wholesale electricity prices, EE, DR & DG costs, and transmission loss savings that would occur if the new line were built. In order to reduce the number of combinations, three scenarios were created, each with a different set of assumptions:

1) The base case is the best and informed guess at the correct values for all inputs. The assumptions collectively favor neither the NCA nor construction of the transmission line.
2) Wires+ is a scenario containing a set of assumptions that collectively favor the construction alternative.
3) NCA+ is a scenario with a set of assumptions that collectively favors the NCA alternative.

SUMMARY OF PRELIMINARY FINDINGS

Preliminary findings for the NCAs that were analyzed are summarized below.

DISTRIBUTED GENERATION

In the base case, combined heat and power (CHP, also referred to as cogeneration) reciprocating engines are cost effective.

In Scenario 2, which favors the transmission line project, the reciprocating engine is marginally cost effective.

In Scenario 3, which favors NCA, microturbines with CHP, and stand-alone diesel generators are cost effective.

Renewable resources, fuel cells, and energy storage alternatives are not cost effective under any scenario.

ENERGY EFFICIENCY MEASURES

A broad range of EE measures are cost effective under all scenarios. The majority of these involve improvements to heating systems, lighting, and building shells.

Sensitivity analysis shows that the EE measures will be cost-effective even if no transmission line were being proposed. They should be done anyway.

A future study will develop a more detailed analysis of efficiency. Then we will determine whether the remaining uninstalled measures will still be cost-effective, and if there are enough measures left in aggregate to help defer the transmission line project.

DEMAND RESPONSE

In this study, DR initiatives are not cost-effective using the TRC and SCT tests. However, the RIM and PCT tests show that non-participating ratepayers and those participating in DR programs would, at least, be no worse off.

Thus, cost-effective DR programs should find eager partners to help make the initiatives succeed.

It was assumed that it would cost $150/MWh to buy back power under the DR program. There is not much confidence in this number, but better information should come out of the Demand Exchange Pilot Project being conducted on the Olympic Peninsula. This project should result in a clearer picture of how much DR will cost and how many MW of buy-back can be expected.

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Based on these preliminary results, it is possible to cost-effectively defer the proposed Olympic Peninsula line addition. This conclusion comes with the following caveats:

- Growth in the region will not be greater than what was used in these studies. This forecast should be refined.
- Good information is obtained from the Demand Response pilot project.

- Institutional barriers are worked through and local utilities enlisted to offer NCA programs that will defer construction.
- Although beyond the scope of this study, the NCA measures only address reliability concerns for single contingency events. Absent a transmission fix, low likelihood, multiple contingencies will need to be protected by a safety-net load-shedding scheme.

Having determined that NCAs are possible and cost effective, pilot initiatives will be designed and implemented. These pilots will allow better estimates to be made of the value of the avoided cost of capacity that is released to BPA, and how much transmission system investment has been reduced.

The final results will eventually have to be compared with the reliability and economics of transmission construction. That is, the NCA solution will ultimately have to be as reliable as construction.

FUTURE ANALYSIS

DETERMINE A BASE LINE FOR OLYMPIC PENINSULA EFFICIENCY

The ability to achieve sufficient capacity savings to defer the proposed transmission line with EE measures depends on the efficiency of Olympic Peninsula homes, commercial buildings, and industrial plants. If all end-users are already at the cutting edge of efficiency, EE measures will offer nothing more to TBL's ability to defer the transmission investment.

In order to provide an upper boundary of conservation potential, this study assumes that there have been no conservation programs on the Olympic Peninsula. This assumption results in enough potential value to defer the line. Consequently, the estimate of this potential will be refined through a future Olympic Peninsula detailed study.

EXPLORE POTENTIAL DISTRIBUTION CAPACITY VALUE

This analysis focuses on NCAs to the proposed Olympic Peninsula transmission line project. If NCAs reduce peak loads on the transmission system, they will necessarily reduce peak loads on the distribution system as well. By locating NCA alternatives in the right place, it may also be possible to defer capacity upgrades that the distribution utilities have planned. In subsequent analyses, distribution utilities will be worked with to explore the potential distribution capacity value.

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1.0 OLYMPIC PENINSULA PROBLEM DESCRIPTION

Area loads on Washington's Olympic Peninsula are served from BPA's Olympia substation via 230-kV and 115-kV transmission lines. During extra heavy winter load conditions, an outage of a major line to Olympia would result in a voltage collapse. A 500-kV upgrade from Olympia to Shelton is needed to solve this voltage collapse problem as early as 2003. A shunt capacitor group to be installed in 2003 will delay the need for this project until 2008. However, once the shunt capacitor has been added, the Olympic Peninsula transmission system will have reached the limit that can be supported by shunt capacitors. By that time, a total of 20 capacitor groups amounting to approximately 900 MVAR will have been installed.

Currently, a double-line outage or breaker failure at Olympia during normal winter weather will result in an inability to meet Olympic Peninsula loads. The proposed reinforcement will solve both the N-1 and N-2 problems[2] and reinforce the Olympic Peninsula region.

1.1 EXISTING CONDITIONS DESCRIPTION

The Olympic Peninsula's existing electrical system has several technical operating problems, whether the line is built or NCAs used to defer construction. Two are particularly important:

- Voltage stability problem
- Voltage collapse problem

The primary issue driving the base case construction project is serving area load. The base-case load growth forecast for the Olympic Peninsula is estimated to be 22 MW per year above today's estimated 1-in-20-year winter peak of 1,321 MW[3]. The maximum capability of the current system is 1,435 MW (which will be exceeded in 2008).

Non-weather-adjusted energy demand in the area has grown about 1 percent per year among retail customers served by the four public utilities supplied by BPA. Residential uses represent a full 50 percent of all electricity demand on the Peninsula, with industrial demand at 31 percent, and commercial demand at 18 percent, according to records for 2001.

Table 1 shows the aggregated type and number of retail accounts and sales for Clallam, Mason 1, Mason 3, and Port Angeles utilities.

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[2] Pronounced "en minus one"; N-1 contingencies are first order contingencies. That is they assume one critical piece of equipment is out of service. N-2 assumes two critical elements of the electric system have failed.

[3] The contents of Table 5, later in this report, show the importance of this forecast. We are considering construction to support loads that will exceed capacity during approximatley 6 hours in 2008, and during 70 hours in 2017, which is 14 years away.

Table 1: Public Utilities Retail Accounts and Sales

Olympic Peninsula Public Utility Retail Accounts and Sales								
EIA Form 412 Information; Source: Powerdat Database								
	Customer Accounts				Energy Sales (MWh)			
Year	Residential	Commercial	Industrial	Other	Residential	Commercial	Industrial	Other
1991	50,108	5,549	190	487	769,715	276,626	613,378	16,625
1992	51,718	5,501	200	435	726,684	267,794	602,038	16,284
1993	54,543	6,483	197	996	815,776	283,287	558,003	16,981
1994	56,224	6,354	199	203	808,196	285,748	547,619	17,260
1995	57,667	6,427	202	1,050	810,207	294,540	561,565	17,344
1996	58,960	6,476	205	1,069	881,336	313,100	562,764	16,778
1997	60,297	6,739	247	677	864,439	300,410	421,000	17,512
1998	60,811	6,734	212	675	862,042	314,736	416,188	15,252
1999	61,624	6,885	214	916	936,631	333,973	359,115	17,493
2000	61,042	5,966	229	607	943,085	351,751	560,048	18,676
2001	61,657	6,154	224	510	909,311	322,699	584,210	18,008
AAGR	2.1%	1.0%	1.7%	0.5%				
Average Energy Use per Account (MWh):					14.7	48.3	2,495	24.7
Share of Sales:					50%	18%	31%	1%

Missing from this table is the load served by Puget Sound Energy (Puget), which supplies customers in Kitsap and Jefferson Counties. A review of the Census of Households and Covered Employment data suggests that Puget serves 63 percent of housing units in the Olympia-Shelton upgrade area, 52 percent of the commercial accounts, and 50 percent of the industrial accounts. Thus, Puget accounts for about half of the loads on the Peninsula and, potentially, half of the opportunities for NCAs. Differences in energy use between Puget and the public utilities may be accounted for in rate structure, and to the presence of utility natural gas service—23 percent of housing units in Kitsap Country have utility natural gas service. In a more fundamental and structural sense, Kitsap County is the most urbanized of the counties on the peninsula, with a relatively large portion of households and businesses being connected to the Naval activities in the area.

Table 2 shows the number of manufacturing and commercial establishments on the Olympic Peninsula. To make the comparison easier, the data has been aggregated into Mason and Clallam Counties (served by the Public utilities) and Jefferson and Kitsap Counties (which are in the Puget service territory).

Lumber and wood products, along with pulp and paper, account for 37 percent of the 491 firms in the manufacturing sector. These two industries are relatively energy intensive, especially pulp and paper, which relies heavily on electricity for process energy. The dominance of the forest products industry on the Peninsula makes long-term load forecasts uncertain, given both the current restrictions on timber harvests and the real and likely sustained structural change in the soft lumber industry (due to competition from Canada) and competitive prices for pulp and paper (from Canada and Europe).

Table 2: Manufacturing and Commercial Establishments

Number of Firms (Covered Employment) on Olympic Peninsula in 2001			
	Mason & Clallam	Jefferson & Kitsap	Total
Total Firms:	3,971	7,433	11,404
Agriculture, Forestry and Fishing	170	240	410
Mining	6	5	11
Construction	509	1,055	1,564
Manufacturing	232	259	491
Transportation and Public Utilities	160	229	389
Wholesale Trade	161	227	388
Retail Trade	628	1,261	1,889
Finance, Insurance, Real Estate	210	474	684
Services	1,726	3,450	5,176
Government	230	195	425

Table 3 shows the Washington Department of Labor forecast of employment for Olympic counties. In the near term, manufacturing jobs are expected to decline and the most growth to occur in the services sector, followed by transportation, communications and utilities. Overall, employment is expected to grow between 1.2 and 1.4 percent. This is somewhat higher than, but consistent with, the growth in commercial accounts reported for the 1990s. Applying this growth rate for all sectors in Table 3, less manufacturing, an annual increase in commercial sales on the order of 4,700 MWhs to 4,800 MWhs can be expected for public utilities, based on the sales in Table 1.

Table 3: Forecast of Employment

Olympic Consortium Annual Average Nonagricultural Wage and Salary Employment 2005, 2010 Projections					
		Projected		Growth Rates	
INDUSTRY	**2000**	**2005**	**2010**	**2000-2005**	**2005-2010**
Total	102,700	108,600	116,100	1.1%	1.3%
Manufacturing	5,300	5,100	5,200	-0.8%	0.4%
Construction & Mining	6,100	6,300	6,700	0.6%	1.2%
Transportation, Comm., and Utilities	2,900	3,300	3,500	2.6%	1.2%
Wholesale and Retail Trade	24,300	25,400	27,000	0.9%	1.2%
Finance, Insurance, and Real Estate	3,600	3,900	4,200	1.6%	1.5%
Services	27,300	30,200	33,400	2.0%	2.0%
Government	33,200	34,400	36,100	0.7%	1.0%
Total Less Manufacturing	97,400	103,500	110,900	1.2%	1.4%

Table 4 shows Washington State's Office of Financial Management's population forecast for the Olympic Peninsula. The medium forecast is for population to grow by only 1.1 percent per year through 2010. This is half the growth rate of residential accounts in Table 1, and the growth rate in residential accounts may be more reflective of future growth.

Table 4: Population Forecast

Projections of the Total Resident Population for the Growth Management Act Intermediate Series: 2000 to 2025 (Released January 2002)							
High Forecast							
	2000	2005	2010	2015	2020	2025	AAG 2000-2010
Olympic	371,852	434,669	479,886	531,278	586,912	642,745	2.6%
Clallam	64,179	68,333	72,383	76,776	81,894	86,927	1.2%
Jefferson	26,299	30,195	33,793	38,197	43,055	47,990	2.5%
Kitsap	231,969	277,242	306,960	340,585	376,521	412,391	2.8%
Mason	49,405	58,899	66,750	75,720	85,442	95,437	3.1%
Intermediate Forecast							
	2000	2005	2010	2015	2020	2025	AAG 2000-2010
Olympic	371,852	383,469	415,091	450,726	488,580	525,215	1.1%
Clallam	64,179	64,969	67,754	70,769	74,349	77,749	0.5%
Jefferson	26,299	28,308	30,892	34,067	37,483	40,807	1.6%
Kitsap	231,969	236,403	257,841	281,883	307,113	331,571	1.1%
Mason	49,405	53,789	58,604	64,007	69,635	75,088	1.7%
Low Forecast							
	2000	2005	2010	2015	2020	2025	AAG 2000-2010
Olympic	371,852	357,876	375,864	395,564	415,137	431,557	0.1%
Clallam	64,179	61,442	62,781	64,225	66,059	67,598	-0.2%
Jefferson	26,299	26,421	27,989	29,935	31,913	33,626	0.6%
Kitsap	231,969	219,855	232,057	245,238	257,975	268,573	0.0%
Mason	49,405	50,158	53,037	56,166	59,190	61,760	0.7%

OFM/Forecasting 1/25/02

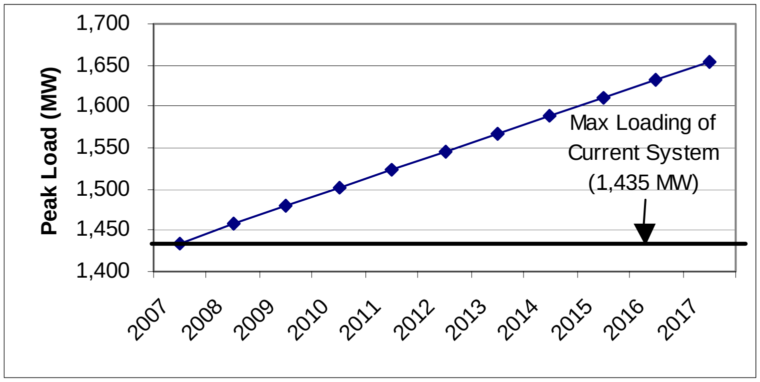
http://www.ofm.wa.gov/pop/gma/index.htm

Assuming economic conditions in the Seattle area improve over that of the past 2 years, there will likely be a rise in the number of vacation homes[4] and retirees who relocate to the Peninsula because of its proximity to Seattle. If residential accounts continue to expand at 2 percent per year, residential demand will grow by 19,000 MWhs per year. However, if the natural gas market share in Kitsap County is included in this projection, residential load growth in the Puget service territory may be somewhat less then 19,000 MWhs, depending on future growth of the natural gas infrastructure and its market penetration in the residential sector.

[4] The 2000 Census shows that 45 percent of vacant units in Clallam County and 79 percent of vacant units in Mason County are seasonal or vacation homes. In Mason County this is 20 percent of the total housing units but on 5 percent of all housing units in Clallam County.

Figure 1, below, shows the maximum load of the current system, and the forecast maximum load under 1-in-20-year extra-heavy weather conditions. It shows how far the load is expected to be above maximum capacity in each year.

Figure 1: Forecast of Peak Loads



The loads will exceed capacity in only a very few hours, as can be seen in Table 5. The table is based on historical load duration curves scaled to match the forecasted extra-heavy peak loads in each year.

Table 5: Forecast of Hours in Excess of System Capacity

Year	# of Hours Exceeding Max Load
2008	6
2010	18
2012	28
2017	70

1.2 TRANSMISSION BASE CASE SOLUTION

1.2.1 PROJECT TIMING AND COST

Based on the load growth forecast, the proposed transmission project would need to be constructed and in service by November 2007 to meet BPA's reliability criteria. The estimated project cost is $30 million, although $2 million of this amount represents land acquisition costs that would probably not be delayed even if the line itself were deferred, because of the risk of increased costs or limited availability. Consequently, the net expenditures to be deferred are $28 million.

The specific 500-kV plan for the Olympic Peninsula involves the following actions:

- Build approximately 13.8 miles of 500-kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to a new Shelton 500-kV yard. The line will be routed on the existing Olympia-Shelton right-of-way. Cut the Paul-Satsop 500-kV line at the corridor intersection and connect the Paul end to the new 500-kV line to Shelton.
- Remove Olympia-Shelton 115-kV line #1 from Olympia to Dayton Tap.

- Construct a 500-kV yard approximately one mile south of the existing Shelton substation, move Satsop 500/230-kV transformer to this location and connect it to Shelton 230-kV bus via 1-mile-long 230-kV line.
- Build approximately 6 miles of new 230-kV line from Olympia-Satsop and Olympia-Shelton corridor intersection to Olympia substation. Connect this new line to the Satsop end of the cut Paul-Satsop 500-kV line.

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1.2.2 TRANSMISSION LOSSES SAVED BY CONSTRUCTING THE 500-KV TRANSMISSION LINE

The construction of the new 500-kV transmission line and associated improvements on the Olympic Peninsula will result in reduced losses in the Northwest. Table 6 summarizes TBL's estimated loss savings. The table shows at projected 2008 normal winter peak load levels, the losses in the system will be reduced from 1120 MW to 1100 MW, a system savings of 20 MW on peak once the 500-kV line is in service.

Table 6: Estimated Loss Savings (500kV Upgrade)

	Change in Peak Losses in the Northwest (MW)		
Year	Today's System	500kV Upgrade	Savings
2008	1120	1100	20
2010	1150	1129	21
2012	1204	1181	23

If the new line is deferred, this reduction in losses will not occur. Therefore, the avoided loss savings are included as a cost in the analysis of the NCAs. TBL estimates an average loss savings of 5.2 aMW throughout the year if the proposed 500-kV line is built. These costs affect the ultimate energy cost to customers in the Northwest, but are not included in the TBL revenue requirement or rates. Therefore, they are included in the TRC and SCT tests, but not in the PCT, RIM, or UTC tests.

Although the loss savings from construction are measured on the entire grid, TBL has determined that most of these loss savings would be on the Olympic Peninsula. Therefore, this study assumes that all loss savings occur on the Olympic Peninsula.

Since the number of outages is not expected to be reduced as a result of the new transmission line, this consideration is not included in this analysis.

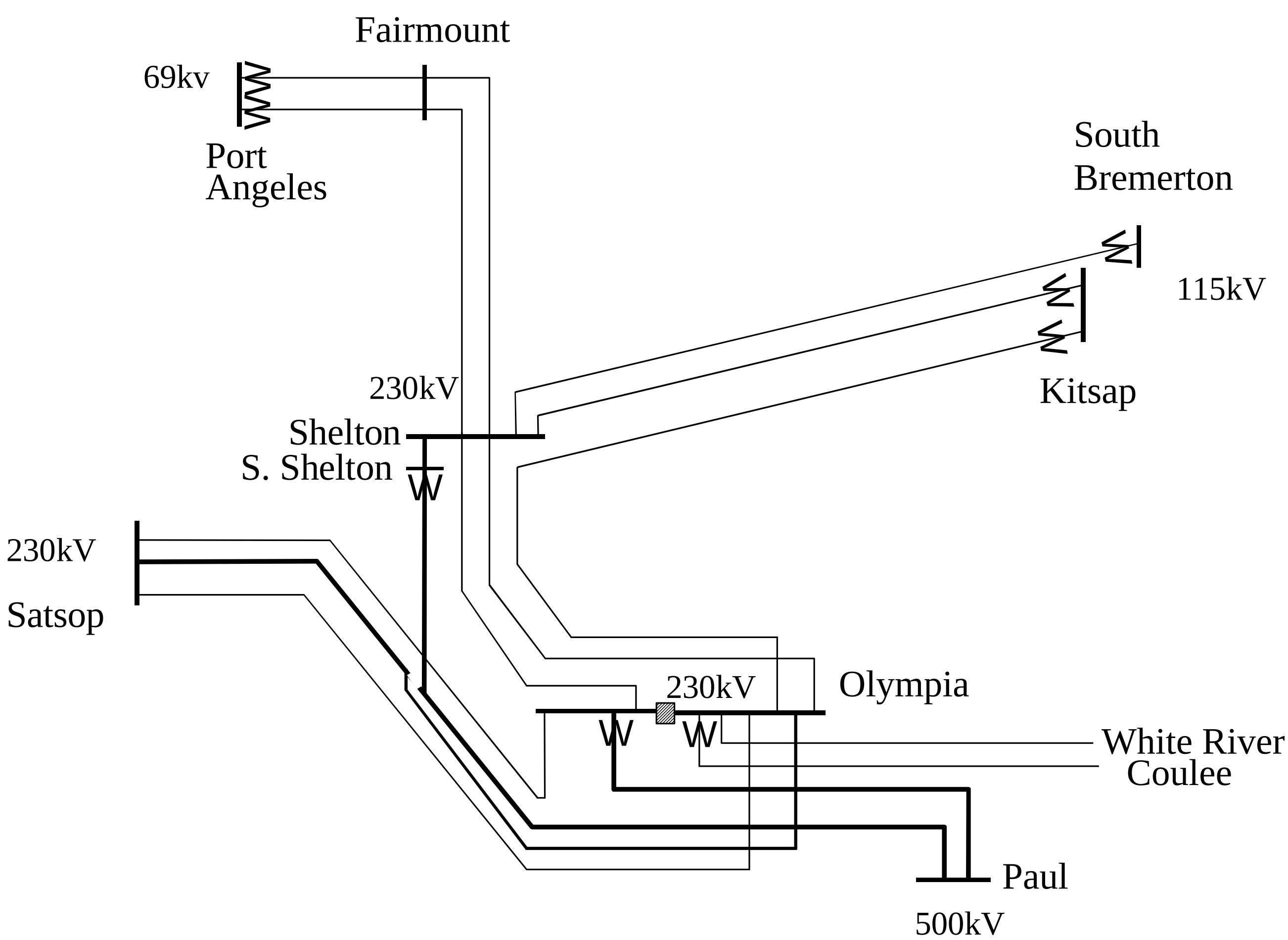
The O&M costs for the new transmission line are expected to be very small, with minimal impact on the results of the analysis. Therefore, they are not included.

1.3 ALTERNATIVE TRANSMISSION SOLUTIONS

BPA TBL engineers have also considered alternative transmission solutions. One alternative in particular could potentially meet the requirements of the Olympic Peninsula area. This alternative, the construction of a 230-kV transmission line rather than a 500-kV line, is estimated to cost approximately $13.6 million. Since the 230-kV solution is significantly less costly than the 500-kV plan, the NCA analysis uses the cost of the 230-kV plan as sensitivity to the transmission plan capital costs in the analysis.

The 230-kV transmission solution involves the following actions:

- Cut the Olympia-Satsop 230-kV line #3 at the corridor intersection and build a 230-kV double circuit from the intersection to the Shelton 230-kV bus. These two lines would be the Olympia-Shelton 230-kV line #5 and the Satsop-Shelton 230-kV line #1.
- Build a new bay at the Shelton 230-kV bus and finish the existing empty bay for termination of the two new lines.
- Remove Olympia-Shelton 115-kV line #1 from Olympia to Dayton Tap.
- Install a second sectionalizing breaker at the Olympia 230-kV bus.
- Re-terminate the Olympia 500/230-kV transformer from the Olympia 230-kV west bus to the east bus.



2.0 LOCAL AREA SPECIFIC INPUT DATA

2.1 NUMBERS AND SIZE OF CUSTOMERS

Customers on the Olympic Peninsula are served by one of five distribution utilities. The customer demographics are shown in Table 7. These numbers are approximations generated from the utilities' public filings, and are used in the screening analysis to estimate the potential savings from energy efficiency measures. The percentages in the last seven columns are applied to the number of buildings or assumed square footage, depending on the data. Table 8 contains further details about the commercial sector.

Table 7: Olympic Peninsula Customer Demographics

	# Customers	Sqft / Customer	Total Sq ft	Attic / Floor Space	Windows	Elec. Heat	Super Good Cents	Wall Space / Total Sq Ft	Pre-1990	Post-1990
Commercial	12,275	5,000	61,375,000							
Industrial	424	15,000	6,363,750							
Residential - Single Family	131,045	2,000	262,090,000	50%	10%	60%	5%		73%	27%
Residential - Manufactured	22,874	1,200	27,448,800	100%	10%	80%	5%			
Res - Multi-family	26,345	977	25,739,065	20%	10%			100%		
	# Installed									
Street Lights	10,000									
Laundromats / Multi-res Laundry	12,275									
Vending Machines	1,000									
5 Story or Greater	1									

Table 8: Commercial Class Demographics

Commercial Customers:	#	sq ft/customer	total sq ft	window %	attic %	floor %	wall %	Lighting Units/customer
Warehouse	170	20,000	3,400,000	10%	100%	100%	50%	20
Grocery	214	20,000	4,280,000	10%	100%	100%	50%	20
Restaurant	688	5,000	3,440,000	10%	100%	100%	50%	20
School	72	50,000	3,600,000	10%	100%	100%	50%	20
Health Services	605	20,000	12,100,000	10%	100%	100%	50%	20
Hospitality	127	50,000	6,350,000	10%	100%	100%	50%	20
Large Retail	325	20,000	6,500,000	10%	100%	100%	50%	20
Small Retail	1,036	5,000	5,180,000	10%	100%	100%	50%	20
Large Office	756	10,000	7,560,000	10%	100%	100%	50%	20
Small Office	1,864	3,000	5,592,000	10%	100%	100%	50%	20
Other	6,523	5,000	32,615,000	10%	100%	100%	50%	20
Total	12,380							

2.2 VALUE OF TRANSMISSION DEFERRAL

Using the local area information and the base case transmission construction plan, the value of load reduction and local generation were calculated using the Present Worth Method described below. This approach calculates the difference in present value revenue requirement between transmission construction and the set of NCAs that would be deployed to delay that investment, while maintaining a similarly reliable system.

The Present Worth Method divides the present value savings in revenue requirement from deferring the transmission project by the required load reduction from NCAs. This provides an estimate of how much can be paid for the NCAs in terms of $/MW. The value of transmission deferral is then the maximum incentive BPA/TBL could pay to in-area generators or customers for load reduction to replace construction and maintain reliability[5].

The maximum incentives are shown in Table 9, where:

- The value expressed as $/kW (PV of contract payments) is the total value over the life of the deferral per kW of load reduction.
- The value expressed as $/kW-yr (level annual payments) is the levelized annual value of the change in revenue requirement.
- The Maximum Incentive row shows the total change in revenue requirement for deferrals, the length of which is shown in the column headings of Table 5.

Table 9: Avoidable Costs over 5 Years

Avoidable Costs	1 Year	2 Year	3 Year	4 Year	5 Year
$/kW (contract)	$97.42	$93.96	$90.66	$87.51	$84.52
$/kW-yr (level)	$97.42	$48.71	$32.47	$24.35	$19.48
Maximum Incentive	$2,143,210	$4,134,036	$5,983,312	$7,701,103	$9,296,757

For example, the total present value of a 3-year deferral is $5,983,312[6]. This is the present value savings of BPA TBL revenue requirement if the base case transmission project is deferred for 3 years. If this amount is spent to achieve 66 MW (consistent with a 3-year deferral) of peak load reduction with NCAs, the present value revenue requirement will be the same as if the 500-kV transmission project were built. Therefore, this value is used as the maximum incentive payment. This amount is equivalent to $90.66/kW (calculated by dividing the maximum incentive line by 66 MW). The $90.66 equates to a maximum payment from TBL of $32.47/kW-year for each of 3 years. From another perspective, the whole region receives a benefit, which must be paid for. If the benefits are substantially larger than the costs, BPA could pay more than the value of the transmission deferral without affecting the societal tests.

2.3 OPTION VALUE OF CONSTRUCTION DEFERRAL

Beyond the value of avoided costs, as calculated above, there is inherent value in deferring construction as long as reliability is not compromised. Deferring construction gives BPA an option on construction at a later date, if needed. The value of deferral has not been included in the study, because it is beyond the scope of the project. It is only noted that it is potentially large. To the extent that load growth in an area is uncertain, deferring construction by one or two years gives BPA the time

[5] A successful outcome of resolving institutional barriers would free up monies from other beneficiaries.

[6] Note again that this value does not include any dollars for the deferral of distribution investments or the opportunity costs of capacity that is freed up.

to determine if a new line is definitely needed or if another solution would suffice that could potentially save BPA/TBL significantly more capital dollars than the actual deferral.

Specifically, the long-term viability of the pulp and paper industry in the Olympic Peninsula is uncertain. Since pulp and paper mills represent a large portion of area load (approximately 10%), major shifts in their production levels would have a direct impact on the total load and transmission required to serve the area. If an alternative to construction enables BPA to defer a large transmission line investment by a few years, or even just a year, this additional time has an "option value" to BPA. This is the value of BPA gaining more certainty about whether the pulp and paper industry will be able to rebound economically in the near term, or if these loads will be reduced or eliminated. If the loads decrease, a new transmission line would have been a poor investment, and the option value of deferral would be quite significant.

In addition, deferral allows time for promising new technologies to develop that could obviate the need for the line.

3.0 DESCRIPTION OF ALTERNATIVES TO CONSTRUCTION

The broad range of non-construction alternatives examined in this screening analysis include distributed generation (DG), energy efficiency measures (EE), and demand response (DR). This section provides an overview of each NCA category and discusses the specific data used for individual alternatives.

3.1 OVERVIEW OF GENERATION AND DISTRIBUTED GENERATION (DG)

Distributed generation (DG) is a subset of generation. A broad definition of DG is used in the analysis. As long as the generation is located in an area that can help reduce peak loads served by the proposed transmission line, the resource is considered "DG." Therefore, DG can encompass a wide variety of types and sizes of technologies. The analysis considered small generators ranging from 5-kW solar photovoltaic (PV) to a 5-MW internal combustion engine. In addition, large-scale generation technologies were studied, such as a new combined cycle gas plant and combustion turbine. Also evaluated were several energy storage technologies, such as lead-acid batteries and pumped hydro.

DG can substitute for investment in transmission or distribution circuits if a sufficient amount of distributed generation is operating during peak load periods. In addition to cost-effectiveness, the challenge for DG is to reliably provide sufficient capacity at the right time to mitigate overloads. The distributed generation technologies included in this analysis are listed in Table 10.

In addition to the new DG alternatives, the possibility of employing existing (primarily diesel) reciprocating engines in the region for peak period generation was explored. According to BPA estimates, these generators could potentially supply up to 20 MW. In evaluating existing DG, a relatively low cost to purchase this capacity was assumed, making existing DG in this study more cost effective than new DG.

Renewable generation, such as wind and solar, were also considered. However, their resource characteristics, such as intermittence, relatively low capacity factors, and poor coincidence with the winter peak load, are not a good match with the Peninsula's extreme weather-driven winter peaks, which often occur in calm winter early mornings.

Table 10: Generation Technologies Included in NCA Screening Analysis

Large Scale Generation	Internal Combustion Engines	Microturbines	Fuel Cells	Renewables	Storage Technologies
Combined Cycle Combustion Turbine	DE-K-30 (30 kW)	Capstone Model 330 – 30 kW w/ CHP	200 kW PAFC Fuel Cell	PV-5	Lead-acid Batteries (flooded cell)
Simple Cycle Combustion Turbine	DE-K-60 (60 kW)	IR Energy Systems 70LM – 70 kW w/ CHP	10 kW PEM Fuel Cell	PV-50	Lead-acid Batteries (VRLA)
Mobile Gas Turbine Generator (GE TM2500)	DE-K-500 (500 kW)	Bowman TG80 – 80 dW w/ CHP	200 kW PEM Fuel Cell	PV-100	Ni/Cd
	DE-C-7 (7.5 kW)	Turbec T100 – 100 kW	250 kW MCFC Fuel Cell	Bergey Windpower WD – 10 kW	Regenesys
	DE-C200 (200 kW)	Capstone Model 330 – 30 kW	2000-kW MCFC Fuel Cell		High Temp Na/S
	GA-K-55 (55 kW)	IR Energy Systems 70LM – 70 kW	100-kW SOFC Fuel Cell		Pumped Hydro
	GA-K-500 (500 kW)	Bowman TG80 – 80 kW	200-kW PAFC Fuel Cell CHP		Pumped Hydro Variable Speed
	MAN 150 kW – 100 kW	Turbec T100 – 100 kW	10-kW PEM Fuel Cell CHP		CAES
	Cummins GSK 19G – 300 kW		200-kW PEM Fuel Cell CHP		
	Caterpillar G3516 LE – 800 kW		250-kW MCFC Fuel Cell CHP		
	Caterpillar G3616 LE – 3 MW		2000-kW MCFC Fuel Cell CHP		
	Wartsila 5238 LN – 5 MW		100-kW SOFC Fuel Cell CHP		
	MAN 150 kW – 100 kW w/ CHP				
	Cummins GSK 19G – 300 kW w/ CHP				
	Caterpillar G3516 LE – 800 kW w/ CHP				
	Caterpillar G3616 LE – 3 MW w/ CHP				
	Wartsila 5238 LN – 5 MW w/ CHP				
	DEK 2100 (existing diesel)				

Although fuel cells and microturbines do not have the disadvantages of renewables, these emerging technologies are not commercially widespread, and their higher cost eliminates them as a viable alternative.

The capital cost and O&M assumptions for each DG technology are shown in Table A-12 of Appendix A.

Other important assumptions for DG technologies are presented in Table 11 and explained in the paragraphs that follow.

Table 11: DG Assumptions

Technology	Annual Load Factor	DG Interconnection Point	Behind the Meter	Customer Class (Res, Com, Ind, or Merchant Plant)	# Months of Peak Demand Reduction for Transmission Billing
CCGT	90%	Bulk System	No	Merchant	0
SCGT, Mobile Gas Turbine Generator	56	Bulk System	No	Merchant	0
Internal Combustion Engines (non-diesel)	90	Primary	Yes	Com	11
Diesel Combustion Engines	6	Primary	Yes	Com	11
Fuel Cells	90	Primary	Yes	Com	11
Microturbines	90	Primary	Yes	Com	11
Small Photovoltaic (PC-5)	30	Primary	Yes	Res	0
Large Photovoltaic (PV-50, PV-100)	30	Primary	Yes	Com	0
Wind	45	Primary	Yes	Com	0
Pumped Hydro	66	Bulk System	No	Merchant	0
CAES	50	Bulk System	No	Merchant	0
Other Storage Technologies	50	Primary	Yes	Com	11

The ***Annual Load Factor*** of each technology determines the amount of energy that will be available to sell into the wholesale market (for merchant generators) or to offset retail purchases from the distribution utility. The load factor of each technology is set at the level that maximizes the PCT results, but constrained by regulatory and technical considerations. Diesel generators, for example, are set to run only 500 hours because of emissions restrictions, while the load factor of photovoltaic, wind, and storage technologies is limited by technical issues. The generation of each technology is first allocated to higher value hours. For example, the SCGT operates 4,928 hours (56.26% load factor), and these hours are assumed to cover the super-peak and peak hours. This optimistic assumption improves the TRC, SCT, and PCT tests.

The ***DG Interconnection Point*** indicates where on the electricity grid the generator interconnects. Technologies that interconnect at the transmission or bulk system level would still pay for use of the transmission system and thus do not reduce the transmission company's revenues. Technologies that interconnect at the secondary or primary level, however, do reduce use of the transmission system and result in revenue losses for the transmission company. Larger technologies (CCGT, SCGT, mobile generator, pumped hydro) are assumed to interconnect at the transmission level on the Peninsula.

The DG technologies are considered ***Behind the Meter*** if residential, commercial, or industrial customers implement them to reduce the amount of electricity they purchase from the distribution utility. If a technology is "behind the meter", its energy output (based on the *Load Factor* assumption explained above) reduces the amount of electricity purchased from the distribution utility. Assuming that a technology is "behind the meter" improves its results in the PCT, because benefits of the energy generated are accounted for at retail rather than the lower wholesale electricity rates. Retail rates vary by end-user, with residential rates being the highest, followed by commercial, and then industrial.

The last column, ***# of Months of Peak Demand Reduction for Transmission Billing***, shows the number of months that the technology reduces peak loads on the transmission system. Most of the technologies interconnected at the secondary or primary level are assumed to reduce transmission peaks 11 months of the year[7], with 1 month downtime for maintenance. Photovoltaic and wind generators are not assumed to reduce transmission peaks, because their generation cannot reliably be made to occur at peak times.

3.2 OVERVIEW OF ENERGY-EFFICIENCY MEASURES

Energy efficiency (EE) measures are typically considered energy savers rather than capacity savers. However, certain measures such as heating efficiency, weatherization, and especially lighting, reduce loads in all hours and can have an impact on peak demand reduction.

The analysis looked at over 1,500 discrete DSM measures described in the Northwest Power Planning Council (NWPPC) Regional Technical Forum (RTF) Database[8], which includes market indicators and performance parameters (e.g., baseline technology alternative, costs, energy impacts, peak demand impacts, etc.) for each measure.

To constrain the analysis, the measures were first screened for applicability to transmission construction deferral on the Olympic Peninsula. Those measures were removed that would not contribute to winter peak reduction (e.g., air-conditioning efficiency upgrades), along with end uses that would not have significant penetration in the Peninsula (e.g., forced air furnace with central AC). Also screened out were end uses better suited to and analyzed under load control or demand response programs, such as water heating and industrial motors.

The remaining 815 measures were sorted according to end-use type and market segment (e.g., economic sector, building type, housing vintage, etc.), which resulted in 32 groups of measures.

Table 12 shows the EE measures by sector (residential, commercial, etc.) and end-use (heating, lighting, appliances, etc.). Finally, the cost-effectiveness of potential EE portfolios was analyzed by examining each measure and selecting the best from each group according to the following rules:

- "Best" defined by the most cost-effective measure in each group, based on the TRC test.
- "Best" defined by the largest demand reduction of any measure in each group that also passes the TRC test.

Other important assumptions related to EE measures are:

- The number of months per year that demand reduction occurs because of the measure. This will impact the estimation of lost revenues.
- Whether the measure is an early replacement or a failure replacement. Early replacement measures are assigned the full cost of the efficient device; failure replacement measures are only assigned the incremental cost over the less efficient alternative.
- Incentive levels. Higher incentive levels increase the participant benefits, but also increase costs.

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[7] They therefore free up BPA's capacity in 11 months of the year on peak and off-peak.

[8] http://www.nwppc.org/comments/default.asp

Table 12: Summary of Measures Groupings

Group	Rate Class	Market Segment	Measure Type	Application
1	Commercial	Mixed	Heating	Small HP
2	Commercial	Mixed	Heating	Weatherization
3	Commercial	Large Office	Lighting	
4	Commercial	Small Office	Lighting	
5	Commercial	Restaurant	Lighting	
6	Commercial	Large Retail	Lighting	
7	Commercial	Small Retail	Lighting	
8	Commercial	Grocery	Lighting	
9	Commercial	Warehouse	Lighting	
10	Commercial	School	Lighting	
11	Commercial	Health	Lighting	
12	Commercial	Hospitality	Lighting	
13	Commercial	Other	Lighting	
14	Commercial	Multi-family	Appliances	Clothes Washer
15	Commercial	Mixed	Exit Signs	
16	Commercial	Mixed	Vending Machines	
17	Other	Mixed	Traffic Signals	
18	Residential	Mixed	Lighting	
19	Residential	Mixed	Appliances	Oven
20	Residential	Mixed	Appliances	Dishwasher
21	Residential	Single-family	Appliances	Clothes-washer
22	Residential	Mixed	Appliances	Refrigerator
23	Residential	Single-family	Envelope	
24	Residential	New Mfd Homes	Envelope	
25	Residential	Existing Mfd Homes	Envelope	
26	Residential	Multi-family	Envelope	
27	Residential	New Hi-rise/Lo-rise	Envelope	
28	Residential	Pre '92 Single-family	Heating	Heat Pump
29	Residential	Post '93 Single-family	Heating	Heat Pump
30	Residential	Single Family	Heating	Ducts
31	Residential	Mfd Home	Heating	Heat Pump
32	Residential	Mfd Home	Heating	Ducts

3.3 OVERVIEW OF THE TYPES OF DEMAND RESPONSE (DR) PROGRAMS

DR programs provide a potential source of load reduction that can be exercised during extreme peak hours. These DR approaches include:

- Direct Load Control (DLC) (e.g., control devices directly installed on water heaters).
- Forward contracts with customers to reduce loads during peak.
- Demand bidding (e.g., the Demand Exchange) to reduce loads when needed during system peaks.

These approaches are potential NCAs because they focus on providing additional capacity to the area.

The DLC programs and capacity contracts are both forward contracts to interrupt loads based on interruptible rates, or to direct centrally-dispatched load reductions. DLC programs would contract with customers prior to the winter season to reduce loads during the system peak for a fixed price at BPA's request.

Demand bidding programs are price-based dispatch programs that offer customers incentives to voluntarily curtail load during the peak.

The two types of DR programs differ in their implementation and potential for providing load relief as discussed below.

3.3.1 Price-Based Dispatch

Price-dispatch programs are voluntary, market-based programs that allow for efficient load reduction during peak periods, emergencies, or when costs are highest for the load serving entities. The prices for curtailment or interruption are determined through a price convergence mechanism (i.e., auction, bidding system, etc.) between load-serving entities and customers. Customers can choose the point at which the price available to them is high enough to offset their productivity losses from reducing or shutting-off part of their load. The curtailment period can be specified for any appropriate period of time, e.g., real-time, day-ahead.

These programs tend to have low utility transaction costs once implemented, because individual contracts are not required for each curtailment. A large number of customers can participate, since the marginal cost of including additional customers is low. Additionally, the higher the penetration, the more likely the load serving entity would be to operate an efficient program that matched customer participation with available incentive payments. While price-based dispatch programs are a particularly efficient way to reduce loads, they do not provide firm or guaranteed reductions in system load when needed.

It is particularly important in considering alternatives to transmission construction to factor in the probability of achieving load reduction during the required time period. For example, during extreme weather it is unlikely that residential, commercial, and retail customers would curtail their heating load. Because there is no guarantee that the customer will reduce load, BPA cannot be certain that its demand reduction target will be met through a price-based dispatch program. More experience with these programs may reduce this uncertainty.

3.3.2 Interruptible/Curtailable and Demand Response Contracts

Interruptible/curtailable contracts differ from the price-based dispatch programs because the terms (i.e., number of times/year the customer can be curtailed, maximum hours per interruption, and notification period for interruption) and the price (fixed component) are pre-determined and bound with an enforceable contract. Since peak load relief is more certain under this type of program, it provides a good basis for planning and is generally better suited as an alternative to line construction.

As with price-based dispatch programs, the curtailment period and notification timeframe can be tailored to the needs of both the load serving entity and the customer. The price paid for interruption or curtailment is typically higher when there is less notification time. Since these contracts have higher transaction costs than the price-based dispatch contracts, they are better suited to customers with larger loads.

Over 30 utility DR programs were analyzed during the alternatives screening process. However, due to the individualized nature of these alternatives, only two programs were evaluated: the Conceptual DR Program and the Conceptual Water Heater DLC Program. Both programs were designed specifically for BPA. The cost-effectiveness results of the other programs was calculated to determine whether they might be useful to BPA.

3.4 DEMAND RESPONSE (DR) ASSUMPTIONS

The main assumptions for the Conceptual DR program are number of hours BPA has the right to curtail the customer, incentive payments, and whether the curtailments result in lost revenues to the transmission utility.

The base case analysis assumes that BPA curtails DR participants up to 50 hours per year. This number affects the results of the TRC, Societal, and Participant tests, because curtailment is assumed to cost the customer $150 per MWh in lost productivity. The load projections using the 1-in-20-year weather event predict that loads will exceed the technical capability of the system for 18 hours in 2010, for 28 hours in 2012, and for 70 hours in 2017. Because this analysis only considers a 3-year deferral of the transmission investment, 50 hours of curtailment is more than adequate to cover the critical hours during the 2008 to 2010 period.

All the cases studied assume that BPA pays out 50% of the transmission-avoided cost as an incentive to curtail participating customers for 50 hours per year[9]. The incentive payment affects the Participant and RIM tests, because they are a source of revenue for DR participants and, conversely, a cost for BPA. Higher incentive payments improve the results of the PCT and negatively affect the RIM test.

The incentive level must be set high enough to outweigh the cost of load curtailment for participating customers. BPA's preliminary discussions with industrials located on the Olympic Peninsula indicate that the minimum cost of curtailment is approximately $125 per MWh. The base case incentive level of $30.68 per kW for a 3-year contract averages out to $205 per MWh of curtailment, should BPA curtail the maximum of 50 hours per year. If BPA only curtails for 28 hours per year, the estimated number of critical hours in 2012, the $30.68 incentive payment is $365 per MWh curtailed.

Water heater load control could be applied as well. Practically all residences (180,000) have electric water heaters. There are some gas water heaters on the Kitsap Peninsula.

[9] This 50 percent incentive has importance for the RIM and Participant Cost Tests but is not a factor in the TRC or Societal Cost Tests.

4.0 SUMMARY COST-EFFECTIVENESS RESULTS – BASE CASE

This section summarizes the results for the DG, EE, and DR alternatives evaluated in this study. More detailed results, as well as a description of the methodology used, are provided in Appendix A.

Non-Construction Alternatives Analysis Test Perspectives

In the NCA analysis, alternatives are initially screened using the TRC test. Those alternatives that show a TRC benefit/cost (B/C) ratio greater than 1.0 are selected for further analysis.

The RIM test is used to determine if additional funding beyond the avoided costs from TBL's deferral of the transmission investment would be required to fund the selected alternative. If the alternative's RIM B/C ratio is greater than 1.0, then TBL's customers would be better off implementing the alternative, even if TBL pays the full estimated cost.

Finally, the Participant cost test indicates whether the programs will look attractive to the generation owners or the customers adopting the EE, DG, or DR measures.

The remaining cost test perspectives provide additional information about the potential viability of successfully implementing a non-construction alternative.

4.1 SUMMARY DG RESULTS

This section summarizes the cost-effectiveness of DG from each cost test perspective. Over 50 DG technologies were evaluated based on their estimated cost and performance characteristics. The DG alternatives included small internal combustion engines and microturbines, combined heat and power technologies, and energy storage. Throughout the analyses, the baseline incentive payments were set to 50% of the maximum incentive level shown in Table 9. The tables in this section present the specific B/C ratios for each DG alternative. Again, when the economic benefits of the alternative exceed the costs, the B/C ratio is greater than 1.0.

In general, most of the DG alternatives analyzed do not pass the cost tests because the capital and operating costs are high relative to the value of energy produced. The avoided energy loss savings are also a large cost. Since the incentive payment levels only account for a small percentage of the DG alternative benefits when compared to their total project costs, changes in the incentive payment levels do not have a large effect on the DG cost tests results.

However, the picture changes when an ability to run existing back-up generation is assumed. The TRC B/C ratio then increases to 0.99, well within the margin of error for a positive B/C ratio.

Table 13 shows the detailed cost test calculations for the Wartsila 5238LN (5 MW internal combustion engine). This technology had the best results of the DG alternatives. However, based solely on its value to the transmission system, it does not appear attractive to the Participant, and the RIM test suggests that additional cost offsets would be needed to make the project attractive. It does not pass the Participant test, because the operating costs outweigh the benefit of avoiding the distribution company's retail rates. The RIM test results are extremely low because of the high cost of transmission revenue losses. The cost tests would all be more positive for a pre-existing CHP installation.

Table 13: Detailed B/C Results for Wartsila 5238LN-5MW (No Capital Costs)

	Program Benefits	Program Costs	Net savings	B/C Ratio
RIM Test - Transmission Co.				
Transmission Capacity Savings	$61.35		$61.35	
Transmission Revenue Loss		$294.70	($294.70)	
Transmission Co. Incentive Payments		$30.68	($30.68)	
Transmission Co. Admin Costs		$0.00	$0.00	
Total	$61.35	$325.38	($264.03)	0.19
Utility Cost Test - Transmission Co.				
Transmission Capacity Savings (kW)	$61.350		$61.350	
Transmission Co. Incentive Payments		$30.68	($30.675)	
Transmission Co. Admin Costs		$0.00	$0.000	
Total	$61.35	$30.68	$30.68	2.00
TRC Cost Test				
Generation Capacity Savings (kW)	$0.000			
Generation Energy Savings (kWh)	$240.222			
Generator Energy Sales of Merchant Plant (kWh)	$0.000			
Transmission Capacity Savings (kW)	$61.350			
Distribution Capacity Savings (kW)	$0.000			
Reliability Benefits	$52.215			
Transmission Co. Admin Costs		$0.00		
Distribution Co. Admin Costs		$0.00		
Avoided Energy Loss Savings (by deferral)		$76.482		
DG Capital Costs		$0.00		
DG Fuel Costs		$204.75		
DG Fixed O&M		$61.65		
DG Variable O&M		$15.41		
Total	$353.79	$358.29	($4.51)	0.99
Societal Cost Test				
Generation Capacity Savings (kW)	$0.00			
Generation Energy Savings (kWh)	$266.14			
Transmission Capacity Savings (kW)	$63.10			
Distribution Capacity Savings (kW)	$0.00			
Reliability Benefits	$77.23			
Transmission Co. Admin Costs		$0.00		
Distribution Co. Admin Costs		$0.00		
Avoided Energy Loss Savings (by deferral)		$78.805		
DG Capital Costs		$0.00		
DG Fuel Costs		$360.44		
DG Fixed O&M		$102.97		
DG Variable O&M		$25.74		
Total	$406.47	$567.96	($161.48)	0.72
Participant Cost Test				
Transmission Co. Incentive Payments	$30.68			
Distribution Co. Incentive Payments	$0.00			
Energy Sales (merchant plant)	$0.00			
Revenue Reduction (behind the meter installation)	$152.18			
Equipment Rebate	$0.00			
Reliability Benefits	$52.21			
DG Capital Costs		$0.00		
DG Fuel Costs		$204.75		
DG Fixed O&M		$61.65		
DG Variable O&M		$15.41		
Total	$235.07	$281.81	($46.74)	0.83

Table 14 shows the B/C ratios for the large-scale generation technologies analyzed. These include a generic combined cycle combustion turbine (base load >100 MW), a simple cycle combustion turbine (peaking >50 MW), and a mobile gas turbine generator (22 MW). None of these technologies pass either the TRC or Participant cost tests, primarily because the capital and operating costs are too high relative to the value of energy generated.

Table 14: Benefit Cost Ratios for Large Scale Generation

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.
Combined Cycle Combustion Turbine	0.83	0.84	**1.05**	**2.00**	**2.00**
Simple Cycle Combustion Turbine	0.61	0.62	0.73	**2.00**	**2.00**
Mobile Gas Turbine Generator (GE TM2500)	0.61	0.62	0.67	**2.00**	**2.00**

Table 15 illustrates the B/C ratios for 17 internal combustion engine (ICE) configurations, ranging from 7.25 kW to 3 MW capacity ratings. Several engines were analyzed using a combined heat and power configuration, which adds the benefit of waste heat use. Three of the ICE technologies in CHP configurations passed the TRC test. These alternatives have better cost test results because their waste heat increases their efficiency.

Table 15: Benefit Cost Ratios for Internal Combustion Engines

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.
Caterpillar G3616 LE -3MW w/CHP	**1.11**	0.94	0.92	0.22	**2.00**
Wartsila 5238 LN - 5MW w/CHP	**1.10**	0.93	0.91	0.22	**2.00**
Caterpillar G3516 LE - 800kW w/CHP	**1.07**	0.90	0.89	0.22	**2.00**
Wartsila 5238 LN - 5MW	0.85	0.71	0.67	0.22	**2.00**
Caterpillar G3616 LE -3MW	0.81	0.68	0.64	0.22	**2.00**
MAN 150 kW - 100 kW w/ CHP	0.79	0.66	0.67	0.22	**2.00**
DEK 2100 (existing diesel)	0.77	0.62	0.61	0.19	**2.00**
Caterpillar G3516 LE - 800kW	0.77	0.64	0.60	0.22	**2.00**
GA-K-500 (500kW)	0.70	0.58	0.56	0.22	**2.00**
Cummins GSK19G - 300kW	0.70	0.58	0.54	0.22	**2.00**
GA-K-55 (55kW)	0.66	0.55	0.52	0.22	**2.00**
MAN 150 kW - 100 kW	0.59	0.49	0.47	0.22	**2.00**
DE-K-500 (500kW)	0.42	0.31	0.37	0.19	**2.00**
DE-C-200 (200kW)	0.38	0.28	0.34	0.22	**2.00**
Cummins GSK19G - 300kW /w CHP	0.34	0.28	0.26	0.22	**2.00**
DE-C-7 (7.5kW)	0.33	0.23	0.30	0.19	**2.00**
DE-K-60 (60kW)	0.27	0.19	0.25	0.19	**2.00**
DE-K-30 (30kW)	0.20	0.14	0.20	0.19	**2.00**

Table 16 displays the B/C ratios for fuel cell technologies. Those included in the screening analysis are phosphoric acid, proton exchange membrane, molten carbonate and solid oxide. Although all calculations include the benefit of waste heat recovery, none of these technologies pass the required cost test screening. While fuel cells can operate relatively efficiently, their extremely high capital costs make it nearly impossible for them to compete economically with the base case transmission project.

Table 16: Benefit Cost Ratios for Fuel Cells

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.
2000kW MCFC Fuel Cell CHP	0.48	0.40	0.49	0.22	**2.00**
100kW SOFC Fuel Cell CHP	0.46	0.38	0.48	0.22	**2.00**
200kW PEM Fuel Cell CHP	0.45	0.37	0.47	0.22	**2.00**
2000kW MCFC Fuel Cell	0.44	0.36	0.43	0.22	**2.00**
100kW SOFC Fuel Cell	0.42	0.34	0.43	0.22	**2.00**
200kW PAFC Fuel Cell CHP	0.38	0.32	0.41	0.22	**2.00**
200kW PEM Fuel Cell	0.38	0.31	0.38	0.22	**2.00**
200kW PAFC Fuel Cell	0.33	0.27	0.34	0.22	**2.00**
250kW MCFC Fuel Cell CHP	0.32	0.27	0.34	0.22	**2.00**
10kW PEM Fuel Cell CHP	0.31	0.26	0.33	0.22	**2.00**

250kW MCFC Fuel Cell	0.30	0.25	0.31	0.22	**2.00**
10kW PEM Fuel Cell	0.27	0.22	0.28	0.22	**2.00**

Table 17 shows the B/C ratios for microturbines. Four models were screened, ranging from 30-kW to 100-kW turbines. The analysis for each microturbine used both standard and combined heat and power configurations. As can be seen in the table, none of the microturbine technologies pass the TRC test. As with fuel cell technologies, their capital costs were too high. Even with CHP configurations, their efficiency cannot be increased enough to outweigh the effect of the high capital costs.

Table 17: Benefit Cost Ratios for Microturbines

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.
Turbec T100 - 100kW w/ CHP	0.70	0.58	0.69	0.22	**2.00**
Bowman TG80 - 80kW w/ CHP	0.66	0.55	0.66	0.22	**2.00**
IR Energy Systems 70LM - 70kW w/ CHP	0.64	0.54	0.64	0.22	**2.00**
Capstone Model 330 - 30kW w/ CHP	0.56	0.47	0.58	0.22	**2.00**
Turbec T100 - 100kW	0.52	0.43	0.49	0.22	**2.00**
IR Energy Systems 70LM - 70kW	0.51	0.43	0.48	0.22	**2.00**
Bowman TG80 - 80kW	0.49	0.41	0.46	0.22	**2.00**
Capstone Model 330 - 30kW	0.41	0.34	0.39	0.22	**2.00**

Table 18 presents the B/C ratios for both solar photovoltaic (PV) and wind power DG technologies. Three different sizes of solar PV technologies were analyzed, along with a small wind turbine. Since no detailed local area renewable resource information was available, the economics are estimated assuming optimistic conditions for both solar and wind energy. The annual capacity factor used for PV is 30%, and for wind 45%. Even with the optimistic assumptions, these alternatives do not pass the initial screening—again because of their high capital costs.

Table 18: Benefit Cost Ratios for Renewable Energy Technologies

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.
PV-100	0.27	0.17	0.36	2.00	2.00
PV-50	0.27	0.17	0.36	2.00	2.00
Bergey Windpower WD -10kW	0.25	0.19	0.31	2.00	2.00
PV-5	0.21	0.09	0.27	2.00	2.00

Table 19 shows the B/C ratios for several energy storage technologies. Due to their high capital costs, none of the storage solutions were a cost-effective alternative to transmission line investment.

Table 19: Benefit Cost Ratios for Energy Storage Technologies

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.
Pumped Hydro Variable Speed	0.65	0.66	0.90	**2.00**	**2.00**
Pumped Hydro	0.65	0.65	0.88	**2.00**	**2.00**
Lead-acid Batteries (flooded cell)	0.60	0.53	0.51	0.32	**2.00**
Regenesys	0.59	0.46	0.47	0.22	**2.00**
CAES	0.58	0.59	0.74	**2.00**	**2.00**
High Temp Na/S	0.44	0.34	0.38	0.22	**2.00**
Lead-acid Batteries (VRLA)	0.24	0.22	0.24	0.36	**2.00**
Ni/Cd	0.23	0.17	0.22	0.22	**2.00**

4.2 SUMMARY OF ENERGY EFFICIENCY RESULTS

This section summarizes the cost-effectiveness results for energy efficiency NCAs. Since a large number (800+) of EE measures were evaluated, only the results of the best measure from each of the 32 EE groups in Table 12 are given here. The measures selected are those from each group that passed the TRC and had the highest peak kW impact.

In general, many energy efficiency measures pass the TRC test because they offer a significant amount of energy savings relative to their cost.

Table 20 shows the detailed cost test calculations for a Single Family Heat Pump (PTCS Duct Sealing and System O&M). This measure had one of the highest peak kW reduction potentials under the penetration assumptions used in the analysis. It passes the TRC test because it results in significant energy savings.

Table 20: Detailed B/C Results for Single Family Heat Pump (PTCS Duct Sealing and System O&M)

	Program Benefits	Program Costs	Net savings	B/C Ratio
RIM Test - Transmission Co.				
Transmission Capacity Savings	$37.02		$37.02	
Transmission Revenue Loss		$250.35	($250.35)	
Transmission Co. Incentive Payments		$342.79	($342.79)	
Transmission Co. Admin Costs		$0.00	$0.00	
Total	$37.02	$593.14	($556.12)	0.06
Utility Cost Test - Transmission Co.				
Transmission Capacity Savings (kW)	$37.02		$37.02	
Transmission Co. Incentive Payments		$342.79	($342.79)	
Transmission Co. Admin Costs		$0.00	$0.00	
Total	$37.02	$342.79	($305.76)	0.11
TRC Cost Test				
Transmission Capacity Savings (kW)	$37.02		$37.02	
Generation Capacity Savings (kW)	$0.00		$0.00	
Generation Energy Savings (kWh)	$1,322.56		$1,322.56	
Distribution Capacity Savings (kW)	$0.00		$0.00	
Cost of Original Device	$0.00		$0.00	
Transmission Co. Admin Costs		$0.00	$0.00	
Distribution Co. Admin Costs		$0.00	$0.00	
Avoided Energy Loss Savings (by deferral)		$46.16	($46.16)	
Cost of Replacement Device		$685.57	($685.57)	
Total	**$1,359.59**	**$731.73**	**$627.86**	**1.86**
Societal Cost Test				
Transmission Capacity Savings (kW)	$38.08		$38.08	
Generation Capacity Savings (kW)	$0.00		$0.00	
Distribution Capacity Savings (kW)	$0.00		$0.00	
Generation Energy and Environmental Savings (kWh)	$1,788.21		$1,788.21	
Cost of Original Device	$0.00		$0.00	

	Program Benefits	Program Costs	Net savings	B/C Ratio
Transmission Co. Admin Costs		$0.00	$0.00	
Distribution Co. Admin Costs		$0.00	$0.00	
Avoided Energy Loss Savings (by deferral)		$47.56	($47.56)	
Cost of Replacement Device		$685.57	($685.57)	
Total	**$1,826.29**	**$733.13**	**$1,093.16**	**2.49**
Participant Cost Test				
Transmission Co. Incentive Payments	$342.79		$342.79	
Distribution Co. Incentive Payments	$0.00		$0.00	
Distribution Energy Savings (kWh)	$1,024.30		$1,024.30	
Cost of Original Device	$0.00		$0.00	
Cost of Replacement Device		$685.57	($685.57)	
Total	**$1,367.09**	**$685.57**	**$681.52**	**1.99**

Table 21 shows that a number of measures offering significant peak reduction potential passed the TRC test. The "Number of Measures" shown in the last column refers to the number of energy efficiency groups that have at least one measure in the group that passes the costs test (for example, 30 out of 32 groups had measures that passed the TRC test). According to the table, a total peak load reduction of 72 MW can be obtained from measures that passed the TRC test. The total peak kW impact numbers are derived by taking the "best" measure from each EE grouping and assuming 100% saturation of that end use in the applicable customer sector, based on the customer demographics shown in Table and Table . It is assumed that there has been 0% historical penetration of the measure in the sector, and a 20% future penetration[10].

Table 21: Number of Energy Efficiency Groups that Passed the Cost Test and Associated Demand and Energy Reductions

	Annual Expected kW Reduction	Annual Expected MWh Reduction	Number of Measures
RIM Test - Transmission Utility	-	-	-
Utility Cost Test - Transmission Utility	202	777	1
TRC Cost Test	72,561	481,409	30
Societal Cost Test	82,582	528,530	31
Participant Cost Test	60,951	441,745	30

[10] There are offsetting errors in this analysis that must be resolved in detailed program designs. For example, we know that some energy efficiency measures have been installed, so the zero historical penetration is wrong. On the other hand, we also know that we can achieve closer to 80% future penetration with a concerted effort.

Table 22 gives the B/C ratios for the energy efficiency measures with the highest kW impact potentials. As mentioned above, these kW impacts are based on assumptions of end use saturation and measure penetration.

Table 22: Energy Efficiency Measures Passing TRC with Highest kW Impact

Name	Peak kW Impact from Measures Passing TRC	Sector	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.
LIGHTING - Other - Lamp and Ballast Retrofit	23,486	Commercial	**3.04**	**2.77**	**3.88**	0.09
HEATING - Single Family Heat Pump - PTCS Duct Sealing, System O&M and Weatherization	23,115	Residential	**1.02**	0.81	**1.41**	0.10
LIGHTING - Small (<=20,000 ft2) Retail, Gas Heat - Lamp and Ballast Retrofit	4,794	Commercial	**3.00**	**2.77**	**3.83**	0.11
LIGHTING - Large (>20,000 ft2) Office, HtPmp Heat - Lamp and Ballast Retrofit	3,499	Commercial	**3.00**	**2.77**	**3.83**	0.11
HEATING - Manufactured Home NonSGC Forced Air Furnace w/CAC - PTCS Duct Sealing and Weatherization	3,401	Residential	**5.80**	**4.80**	**8.00**	0.14
HEATING - Post79/Pre93 Single Family Construction Convert FAF w/oCAC to HP w/PTCS - Heat Pump rated HSPF 8.0 or higher and SEER 12 or higher w PTCS	3,153	Residential	**1.95**	**1.78**	**2.31**	0.18
LIGHTING - Restaurant, Gas Heat - Lamp and Ballast Retrofit	2,426	Commercial	**3.04**	**2.77**	**3.89**	0.11
LIGHTING - Health, Gas Heat - Lamp and Ballast Retrofit	2,150	Commercial	**3.04**	**2.77**	**3.88**	0.09
ENVELOPE - Manufactured Home Weatherization - Floor Insulation R0 to R11 (Cost and savings are per square foot of floor insulated) - Existing floor insulation must be less than R-11. Floor insulation must be installed in substantial compliance with WeatherWise specifications for manufactured homes	1,764	Residential	**1.36**	0.99	**1.87**	0.16
LIGHTING - Grocery, HtPmp Heat - Lamp and Ballast Retrofit	863	Commercial	**3.02**	**2.77**	**3.86**	0.15
HEATING - Post92 Single Family Construction Convert FAF w/oCAC to HP w/PTCS - Heat Pump rated HSPF 8.0 or higher and SEER 12 or higher w PTCS	862	Residential	**1.66**	**1.53**	**1.92**	0.18
LIGHTING - Hospitality, Gas Heat - Lamp and Ballast Retrofit	504	Commercial	**3.02**	**2.77**	**3.86**	0.10
ENVELOPE - Single Family Dwellings w/Electric Heat - Home Must Certified under the Long Term Super Good Cents Program & Specifications	479	Residential	**1.51**	**1.18**	**2.28**	0.10
ENVELOPE - Small Retail Weatherization Attic Insulation - R4> R38 blown	460	Commercial	**1.86**	**1.33**	**2.73**	0.14
HEATING - Commercial Small Heat Pump - Heat pump rated HSPF 8.0 and SEER 13 or higher	439	Commercial	**1.18**	**1.12**	**1.27**	0.25
LIGHTING - Residential Lighting - Energy Star CFL Weighted Average - Whole House Savings	359	Residential	**1.75**	**1.71**	**2.19**	0.07
LIGHTING - School, Gas Heat - Lamp and Ballast Retrofit	313	Commercial	**3.01**	**2.77**	**3.84**	0.11
ENVELOPE - New manufactured homes built under HUD standards w/Electric Heat - Certified Super Good Cents under Northwest Energy Efficient Manufactured Home Program	151	Residential	**1.37**	**1.07**	**2.00**	0.11
TRAFFIC SIGNALS - Existing and new traffic signals - LED Traffic Signals - Replace 12 inch Red Incandescent Left Turn Bay with 12 inch Red LED module	137	Industrial	**1.31**	**1.77**	**1.58**	0.30
EXIT SIGNS - Building or structure where exit signs are required - Energy Star Electro-luminescence (EL) Exit Sign - Incandescent Exit Sign Base Case Fixture	109	Commercial	**1.01**	0.93	**1.28**	0.16
VENDING MACHINES - Existing and new vending machines with illuminated fronts - Vending Machine Controller-Large Machine w/Illuminated Front	50	Commercial	**1.96**	**1.89**	**2.46**	0.07
APPLIANCES - Residential - Energy Star Dishwasher (EF58) - PNW DHW Fuel Average	16	Residential	**1.60**	**1.57**	**2.00**	0.08
APPLIANCES - Multifamily common area or commercial laundrymat w/Electric Dryer and Electric Water Heat - Energy Star Clothes Washer - Commercial Laundry - Electric Water Heater & Dryer	16	Commercial	**1.02**	**1.00**	**1.14**	0.01
APPLIANCES - Residential - Energy Star Clothes Washer (MEF 1.27) - Weighted Average DHW & Dryer	8	Residential	**2.14**	**1.85**	**2.79**	0.01
APPLIANCES - Residential - Energy Star Refrigerator with Side-by-Side Model - No Ice	6	Residential	**2.06**	**1.63**	**2.76**	0.04
ENVELOPE - Multifamily Weatherization - R0 - R19 Attic insulation (Cost & Savings are per square foot of attic area insulated) - Existing attic insulation must be less than R-11. Insulation must be installed in substantial compliance with WeatherWise Specifications	1	Residential	**1.58**	**1.24**	**2.31**	0.12
ENVELOPE - New Low Rise (Less than 5 Stories) Multifamily Dwellings w/Electric Heat - Long Term Super Good Cents Program & Specifications	0	Residential	**3.08**	**2.52**	**4.64**	0.10

4.3 SUMMARY DR & DLC RESULTS

This section summarizes the cost effectiveness of the Demand Response (DR) and Direct Load Control (DLC) program alternatives analyzed in this study.

The Conceptual DR Program and DR-DLC programs implemented by other utilities perform well in some cost tests because reductions in energy usage only occur when they are needed to mitigate peak load. The assumed cost of curtailment used in this analysis is $0.15 per kWh of curtailment. Of course, the true cost of curtailment will be different for every customer, so this is simply an approximation to determine the potential cost-effectiveness of DR as an alternative solution.

Table 23 shows the detailed cost test calculations for the Conceptual DR Program.

Table 23: Detailed B/C Results for the Conceptual DR Program

	Program Benefits	Program Costs	Net savings	B/C Ratio
RIM Test - Transmission Co.				
Transmission Capacity Savings	$61.35		$61.35	
Transmission Revenue Loss		$0.00	$0.00	
Transmission Co. Incentive Payments		$30.68	($30.68)	
Transmission Co. Admin Costs		$0.00	$0.00	
Total	**$61.35**	**$30.68**	**$30.68**	**2.00**
Utility Cost Test				
Transmission Capacity Savings (kW)	$61.35		$61.35	
Transmission Co. Incentive Payments		$30.68	($30.68)	
Transmission Co. Admin Costs		$0.00	$0.00	
Total	**$61.35**	**$30.68**	**$30.68**	**2.00**
TRC Cost Test				
Transmission Capacity Savings (kW)	$61.35		$61.35	
Generation Capacity Savings (kW)	$0.00		$0.00	
Generation Energy Savings (kWh)	$15.75		$15.75	
Distribution Capacity Savings (kW)	$0.00		$0.00	
Transmission Co. Admin Costs		$0.00	$0.00	
Distribution Co. Admin Costs		$0.00	$0.00	
Avoided Energy Loss Savings (by deferral)		$76.48	($76.48)	
Cost of Dropped Load		$18.65	($18.65)	
Total	**$77.10**	**$95.13**	**($18.03)**	**0.81**
Societal Cost Test				
Transmission Capacity Savings (kW)	**$63.10**		$63.10	
Generation Capacity Savings (kW)	$0.00		$0.00	
Distribution Capacity Savings (kW)	$0.00		$0.00	
Generation Energy and Environmental Savings (kWh)	$17.24		$17.24	
Transmission Co. Admin Costs		$0.00	$0.00	
Distribution Co. Admin Costs		$0.00	$0.00	
Avoided Energy Loss Savings (by deferral)		$78.81	($78.81)	
Cost of Dropped Load		$18.65	($18.65)	
Total	**$80.34**	**$97.46**	**($17.11)**	**0.82**

	Program Benefits	Program Costs	Net savings	B/C Ratio
Participant Cost Test				
Transmission Co. Incentive Payments	$27.85		$27.85	
Distribution Co. Incentive Payments	$0.00		$0.00	
Distribution Energy Savings (kWh)	$3.83		$3.83	
Cost of Original Device			$0.00	
Cost of Dropped Load		$18.65	($18.65)	
Total	**$31.68**	**$18.65**	**$13.03**	**1.70**

The Conceptual DR Program does not pass the TRC test because the avoided energy loss savings far outweigh the transmission capacity and generation energy savings of the transmission project. It passes the Participant test because the incentive payments are high compared to assumed productivity costs. It passes the Utility and RIM test because the energy loss benefits of the transmission contribution project are not captured as financial benefits.

Table 24 displays the B/C ratios for the Conceptual DR Program and the Conceptual Water Heater DLC Program designed specifically for BPA. The Conceptual DR Program is tailored to meet the specific criteria needed by BPA to achieve a deferral. The Conceptual Water Heater DLC Program is a direct load control program for water heaters curtailed for 50 hours per year.

Table 24: Cost Test Results of Conceptual DR-DLC Programs

Name	Utility	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.
Conceptual DR Design	**None**	0.81	**1.70**	0.82	**2.00**	**2.00**
Conceptual Water Heater DLC	**None**	0.49	**1.71**	0.50	0.66	0.66

The Conceptual Water Heater DLC program does not pass the TRC test because of the avoided energy loss savings and substantial program administration costs (ongoing maintenance, upfront capital costs, and marketing costs).

Table 25 shows the results for 30 measures that are based on actual utility programs.

Table 25: Summary Benefit Cost Ratios for DR & DLC Programs

Name	Utility	Firm Capacity Reduction?	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.
Demand Buy Back	Portland General Electric	**N**	0.82	**1.21**	0.84	**1.32**	**1.32**
Energy Exchange Program	PacificCorp	**N**	0.81	0.87	0.82	**4.67**	**4.67**
Voluntary Load Reduction	Exelon - ComEd	**N**	0.82	**1.21**	0.84	**1.49**	**1.49**
The Alliance Option A - Interruptible	Exelon - ComEd	**Y**	0.82	0.67	0.85	**2.69**	**2.69**
The Alliance Option B - Curtailable	Exelon - ComEd	**Y**	0.81	0.93	0.83	**3.46**	**3.46**
The Alliance Option C - Curtailable	Exelon - ComEd	**Y**	0.81	0.94	0.82	**4.06**	**4.06**
Energy Cooperative (Curtailment Service Cooperative)	Exelon - ComEd	**Y**	0.84	**2.14**	0.88	0.40	0.40
Interruptible Service	Exelon - ComEd	**Y**	0.83	**3.50**	0.87	0.15	0.15
Demand Relief Program	CAISO	**Y**	0.82	**9.09**	0.84	0.17	0.17
Emergency Demand	NYISO	**Y**	0.82	**3.54**	0.84	0.45	0.45

Name	Utility	Firm Capacity Reduction?	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.
Response Program							
Day-Ahead Demand Response Program	NYISO	**N**	0.82	0.75	0.84	**2.77**	**2.77**
Demand Bidding Program	CA - SCE	**N**	0.82	0.44	0.84	**6.40**	**6.40**
Com/Ind. Base Interruptible Program	CA - SCE	**Y**	0.82	**4.87**	0.85	0.27	0.27
Scheduled Load Reduction Program	CA - SCE	**N**	0.82	0.87	0.86	**1.17**	**1.17**
Emergency Response Program	PJM	**N**	0.82	**3.54**	0.84	0.45	0.45
Capacity Program - Interruptible Tariff	Wisconsin Power & Light	**Y**	0.83	**1.23**	0.87	0.48	0.48
Economy Program - Interruptible Tariff	Wisconsin Power & Light	**N**	0.82	0.81	0.86	**1.24**	**1.24**
Reliability Program Rider	Wisconsin Power & Light	**N**	0.82	**3.01**	0.85	0.36	0.36
Demand Exchange	BPA	**N**	0.82	**1.12**	0.84	**1.63**	**1.63**
Demand Response Program	ISO-NE	**Y**	0.82	**8.42**	0.86	0.10	0.10
Voluntary Load Response Program	Baltimore Gas & Electric	**N**	0.82	0.74	0.84	**2.80**	**2.80**
Voluntary Load Response Program - Rider 24 Firm Capacity Initiative	Baltimore Gas & Electric	**N**	0.82	0.74	0.84	**2.80**	**2.80**
Discretionary Load Curtailment Program	CAISO	**N**	0.82	**2.54**	0.84	0.64	0.64
Participating Load Program	CAISO	**N**	0.82	0.87	0.84	**2.24**	**2.24**
Price Response Program	ISO-NE	**N**	0.82	0.87	0.84	**2.24**	**2.24**
Economic Load Response Program	PJM	**N**	0.82	0.87	0.84	**2.24**	**2.24**
Call Option	Cinergy	**N**	0.82	0.87	0.84	**2.24**	**2.24**
Quote Option	Cinergy	**N**	0.82	0.87	0.84	**2.24**	**2.24**
Market Valued Reduction Program	Entergy	**N**	0.82	0.87	0.84	**2.24**	**2.24**
Experimental Energy Reduction Program		**N**	0.82	0.87	0.84	**2.24**	**2.24**

None of the options based on utilities' existing DR and DLC programs passed the TRC test, due to the high cost of avoided energy loss savings. Some pass the Participant and RIM tests. In general, DR-DLC programs will pass the Participant test if the incentive offered by the utility is higher than the cost of curtailed load. DR-DLC programs will pass the RIM test if the avoided transmission costs are high relative to the incentive payments and lost transmission revenues. Many of the DR-DLC programs in the table have excellent results in the RIM test, because of the assumption that DR-DLC programs do not reduce the transmission company's revenues.

5.0 SENSITIVITY ANALYSIS

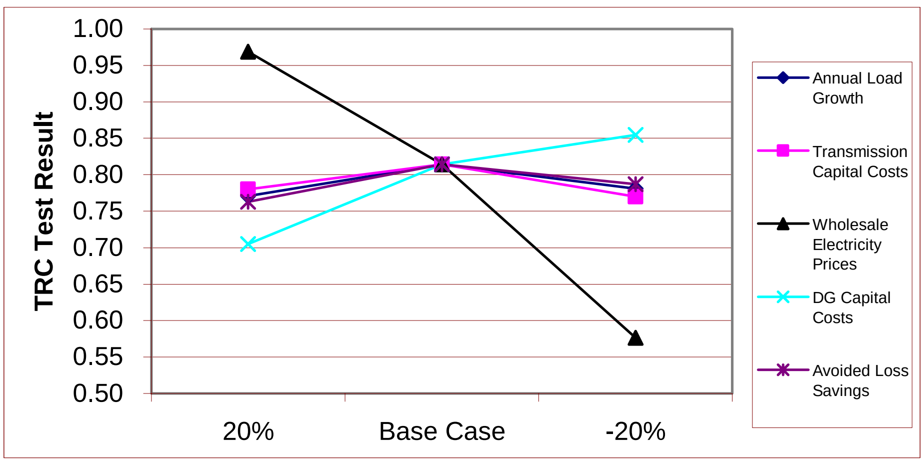
A number of scenarios were evaluated in which key economic inputs were systematically tested to determine to what extent different base case assumptions would change the conclusions. This section first tests the sensitivity of the TRC test results to individual assumptions. It then describes the development of alternative scenarios. Finally, it looks at the cost effectiveness of transmission alternatives with assumptions either more or less favorable to DG, DR, and EE than the base case.

5.1 TRC COST TEST SENSITIVITIES

The sensitivity of the TRC test results to isolated changes in load growth, project costs, market electricity prices, and avoided energy losses was tested. One DG, one DR-DLC, and one EE measure were chosen and each assumption varied, while keeping all other assumptions at the base case values. Each assumption was both increased and decreased by 20%.

For DG, the Caterpillar G3616LE in a CHP configuration was chosen, because it showed the best TRC test results in the base case. The TRC test result sensitivities are presented in Figure 2.

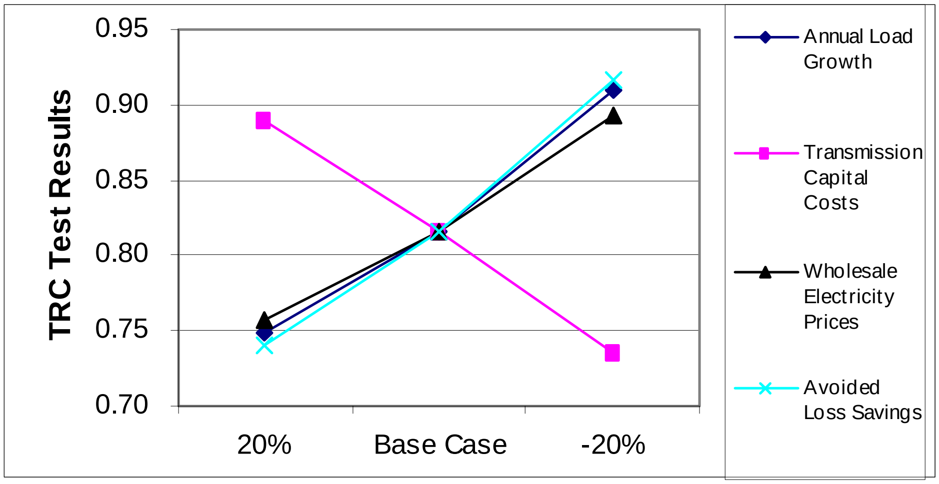
Figure 2: DG (Caterpillar G3616LE w/CHP) TRC Test Result Sensitivities



As Figure 2 shows, the TRC test results are most sensitive to changes in wholesale electricity prices followed by changes in DG capital costs. Changes in incentive payment levels caused by changes in load growth and project costs barely affect the TRC test results for this, and most other DG alternatives.

The sensitivity of the TRC test results for the Conceptual DR Program was also evaluated. The results are shown in Figure 3.

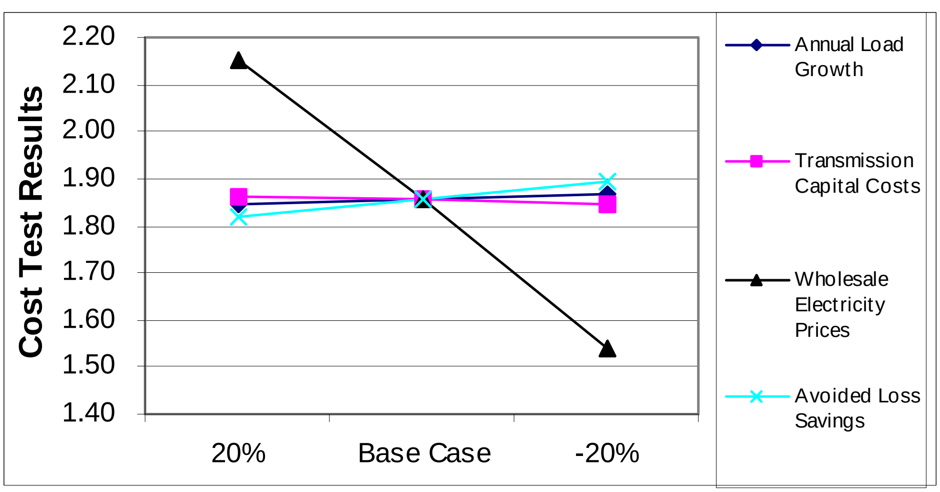
Figure 3: DR (Conceptual DR Program TRC Test Result Sensitivities



The Conceptual DR Program's TRC test results are sensitive to all of the variables. An important point to note is that the TRC test results do not approach 1.0 for any of the sensitivities. This is because the cost of the avoided loss savings is sufficiently large that it outweighs any increases in benefits or decreases in costs caused by changes in the other assumptions.

The Single Family Heat Pump (PTCS duct sealing and system O&M) was the EE measure chosen to test TRC test result sensitivities. The results are shown in Figure 4.

Figure 4: EE (Single Family Heat Pump: PTCS duct sealing and system O&M) TRC Test Result Sensitivities



The TRC test results are extremely sensitive to wholesale electricity prices, while barely changing when the other assumptions are varied. This is because this EE measure saves a large amount of energy, the value of which far outweighs any other benefits or costs.

5.2 ALTERNATIVE SCENARIOS

Two alternative scenarios were developed, each of which varied load growth, project costs, electricity market prices, DG capital costs, and avoided energy loss savings relative to the base case. The "wires +" scenario incorporates assumptions more conducive to the transmission project, while the "NCA+" scenario incorporates assumptions more favorable to the non-wires alternatives. The assumptions used in each case are shown in Table 26.

Table 26: Alternative Scenario Assumptions

	NCA+ Scenario	Base Case	Wires+ Scenario
Annual Load Growth	9.4 MW	22 MW	34 MW
Transmission Capital Costs	$35.6 MM	$30 MM	$13.6 MM
Wholesale Electricity Prices	All-in costs of SCGT	NWPPC	MC of CCGT
DG Capital Costs	-10%	NREL	+10%

The following sections describe the development of the assumptions under each scenario, followed by a summary of the cost test results under the two scenarios.

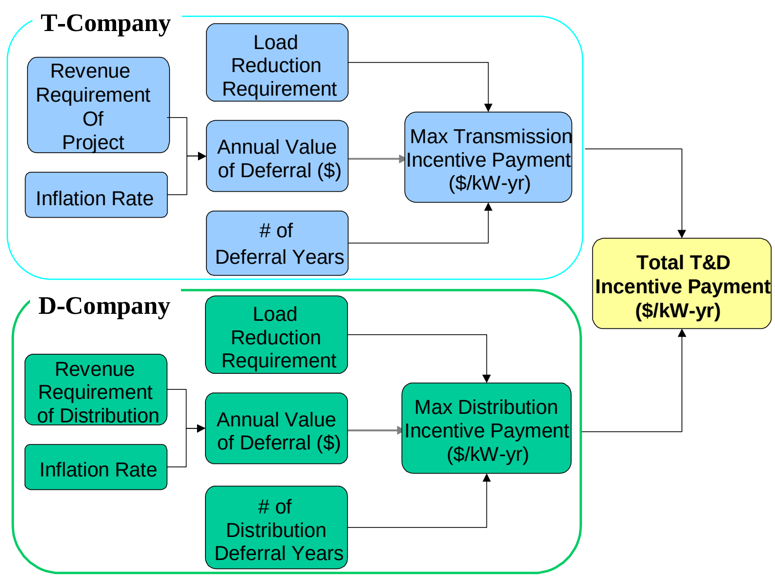
5.2.1 MAXIMUM INCENTIVE PAYMENT SCENARIOS

The capital costs of the proposed transmission investment and load growth are the primary determinants of the maximum incentive payments for TBL. Other stakeholders, especially distribution utilities, may also see benefits from the peak load reduction resulting from DG, DR, or EE alternatives. If all stakeholders contribute program incentive payments approximating the benefits they receive from the peak load reduction, this can result in increased incentive levels and higher program penetration, as well as the likelihood of achieving the intended peak load reduction.

This analysis sets the distribution system avoided cost to zero. Avoided distribution costs are area-specific, and utility experience throughout North America has shown that the majority of distribution areas have excess distribution capacity, and thus zero avoided capacity costs. However, many distribution feeders are overextended and require significant investments to effectively serve customers. This bi-modal overinvestment/underinvestment pattern is common. Where needed, avoidable distribution investment costs are commonly $80/kW. Should a distribution company identify an area with avoidable distribution capacity costs, it would present an opportunity for a combined TBL/distribution company program in which both companies would contribute to the program incentive payments.

The calculation of total incentive payments from a transmission company (TBL) and distribution company is summarized pictorially in Figure 5. The maximum $/kW-year incentive payment is calculated by determining the total yearly avoided cost and dividing by the required yearly load reduction for project deferral. This section develops scenarios for both the proposed project revenue requirement and the required load reduction levels, and then calculates ranges of potential incentive levels.

Figure 5: Maximum T&D Incentive Payment Calculation



5.2.1.1 Transmission Project Costs

Two additional scenarios were developed for the capital costs of the transmission investments. The high cost scenario assumes that $28 million of the base case scenario increases by 20% to $33.6 million, resulting in a total project cost of $35.6 million. The low cost scenario assumes that the 230-kV option is constructed at $13.6 million. The annual benefit for a 3-year deferral is shown in Table 27.

Table 27: Revenue Requirement Scenarios

Scenario	Revenue Requirement (Construction Cost)	Annual Deferral Benefit PV Revenue Requirement
Base Case	$30 million	$1.3 million
Low Cost	$13.6 million (230 kV)	$0.6 million
High Cost	$35.6 million	$1.6 million

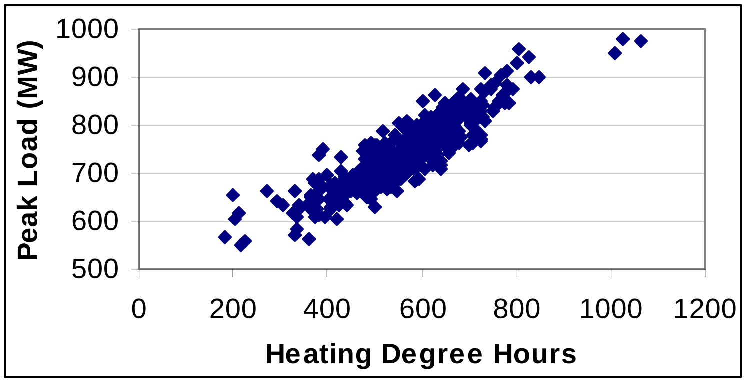
5.2.1.2 Load Reduction Requirement Scenarios

An alternative load forecast was developed using hourly Olympic Peninsula load data for non-holiday, weekdays in the months of November through February for the years 1997 to 2002. This forecast was used to develop an alternative load growth scenario. This scenario is based on the average growth in the weather-adjusted peak load for the winter seasons between 1997 and 2002.

The weather-adjusted peak load is the peak load for each winter season adjusted to eliminate the effects of year-to-year weather variations. The steps for calculating the weather-adjusted peak loads are:

1. **Use regression analysis to quantify the effects of weather on daily peak load**. Daily *Heating Degree Hours* and *Lagged Heating Degree Hours* are the endogenous variables in the regression. The *Heating Degree Hours* for each day is calculated as the sum of Max (0, 65° - hourly temperature) for each hour. The *Lagged Heating Degree Hours* for each day is calculated as a weighted average of the *Heating Degree Hours* for the last three days, with weights equal to 1/2 for day t-1, 1/3 for day t-2, and 1/6 for day t-3. Figure 6 plots daily historical peak temperatures and Heating Degree Hours for the observed period.

Figure 6: Relationship of Heating Degree Hours to Daily Peak Temperatures



The results of the regression analysis are shown in Table 28 below.

Table 28: Regression Analysis Results

Regression Statistics	
Multiple R	0.90
R Square	0.81
Adjusted R Square	0.81
Standard Error	31.46
Observations	401.00

	Coefficients	Standard Error	T Stat	P-value
Intercept	4.17.15	8.98	46.43	0.00
Heating Degree Hours	0.47	0.02	29.61	0.00
Lagged heating Degree Hours	0.11	0.02	6.00	0.00

2. **Find the peak load and corresponding *Heating Degree Hours* and *Lagged Heating Degree Hours* for each winter season.**

3. **Normalize each of the peak loads to the planning temperature.** Historical peak loads for each winter are adjusted by using "normalized" figures for *Heating Degree Hours* and *Lagged Heating Degree Hours*. After statistical adjustment, peak loads occurring during days colder than the "normalized" day are adjusted downward, while peak loads occurring on warmer days are adjusted upwards. For this scenario, the average peak day cold temperatures

were used to establish the planning temperature. Note that this value is not nearly as cold as the "extra heavy" 1-in-20-year temperature used in the base case forecast.

Table 29 shows the results of the analysis. The historical peaks in each winter season are adjusted using normalized *Heating Degree Hours* and *Lagged Heating Degree Hours*, along with the coefficients calculated from the regression analysis. The average growth in peak load for the five winters between 1997 and 2002 was **9.4 MW**. This is the growth figure used in the alternative load forecast in the optimistic case sensitivity.

Table 29: Normalized Peak Load

Period	Actual Peak (MW)	Actual Heating Degree Hours	Actual Lagged Heating Degree Hours	Normalized Heating Degree Hours	Normalized Lagged Heating Degree Hours	Adjusted Peak (MW)	Increase from Prior Year
Winter 97-98	901.7	849.7	653.6	842.0	640.9	896.7	
Winter 98-99	980.6	1,028.1	622.5	842.0	640.9	895.1	(1.6)
Winter 99-00	913.7	780.3	685.3	842.0	640.9	937.9	42.8
Winter 00-01	956.9	805.5	676.1	842.0	640.9	970.3	32.3
Winter 01-02	881.3	746.4	567.3	842.0	640.9	934.2	(36.0)
					Average Increase		**9.4**

To make the scenarios symmetrical around the base case, a growth rate of 34 MW per year is assumed for the high load growth case. The load growth scenarios are shown in Figure 7.

Figure 7: Load Growth Sensitivity Cases

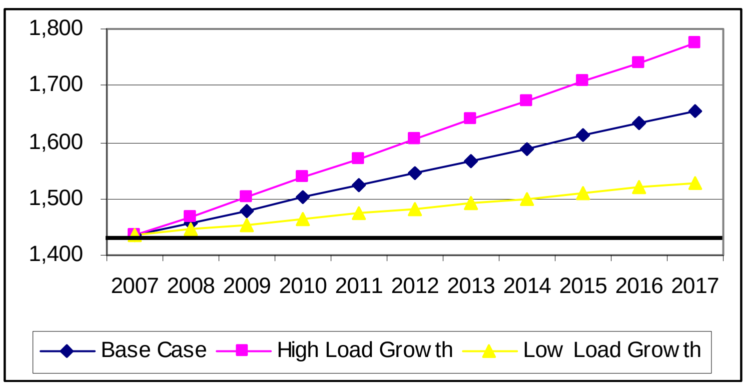


Table 30 summarizes the values of the three scenarios shown in Figure 7 (base case, plus the high and low variations).

Table 30: Required Load Reduction (MW)

	Base Case		Low Growth		High Growth	
Winter	Annual Growth (MW)	Cumulative Required Deferral (MW)	Annual Growth (MW)	Cumulative Required Deferral (MW)	Annual Growth (MW)	Cumulative Required Deferral (MW)
2007-2008	22.0	22.0	9.4	9.4	34.0	34.0
2008-2009	22.0	44.0	9.4	18.8	34.0	68.0
2009-2010	22.0	66.0	9.4	28.2	34.0	102.0
2010-2011	22.0	88.0	9.4	37.6	34.0	136.0
2011-2012	22.0	110.0	9.4	47.0	34.0	170.0
2012-2013	22.0	132.0	9.4	56.4	34.0	204.0
2013-2014	22.0	154.0	9.4	65.8	34.0	238.0
2014-2015	22.0	176.0	9.4	75.2	34.0	272.0
2015-2016	22.0	198.0	9.4	84.6	34.0	306.0
2016-2017	22.0	220.0	9.4	94.0	34.0	340.0
2017-2018	22.0	242.0	9.4	103.4	34.0	374.0

5.2.2 Scenario Results for Incentive Payments

The maximum incentive that BPA could offer on a per kW basis differs as both load growth and project costs change.

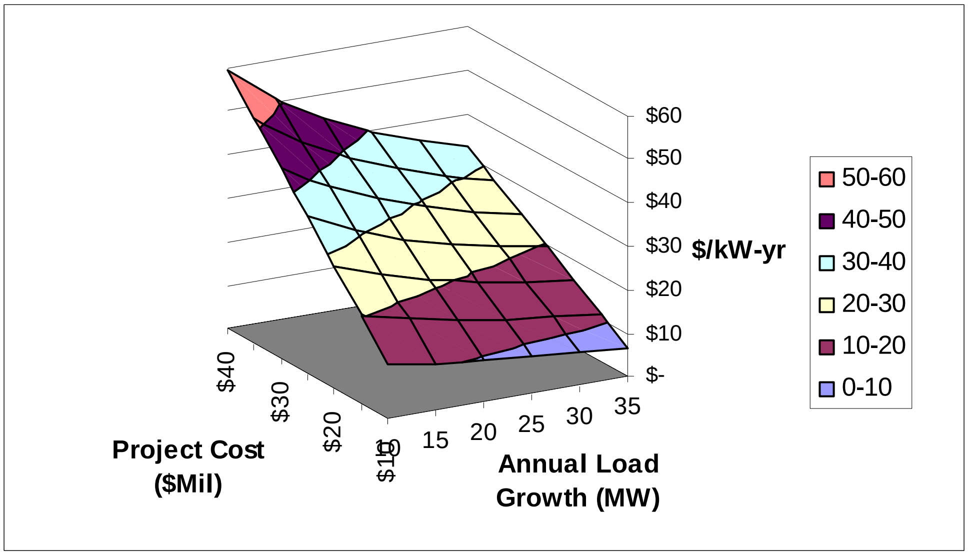
Table 31 shows the spread of maximum incentive payments for the complete range of sensitivities of load growth and construction revenue requirement. The table is highlighted with different colors to indicate contours of the avoided cost curves. Each contour covers $10/kW-year of potential avoided transmission cost.

Table 31: Transmission Avoided Costs ($/kW-year)

		Project Cost ($millions)						
		$ 40	$ 35	$ 30	$ 25	$ 20	$ 15	$ 10
Annual Load Growth (MW)	10	$ 59	$ 52	$ 44	$ 36	$ 28	$ 20	$ 12.51
	15	$ 51	$ 44	$ 38	$ 31	$ 24	$ 17	$ 10.72
	20	$ 45	$ 39	$ 33	$ 27	$ 21	$ 15	$ 9.38
	25	$ 40	$ 34	$ 29	$ 24	$ 19	$ 14	$ 8.34
	30	$ 36	$ 31	$ 26	$ 22	$ 17	$ 12	$ 7.51
	35	$ 32	$ 28	$ 24	$ 20	$ 15	$ 11	$ 6.82

Figure 8 illustrates the results from Table 31 in graphical form.

Figure 8: Transmission Avoided Costs ($/kW-year)



As the load growth decreases and the project costs increase, the transmission avoided costs and related maximum incentive payments increase.

5.2.3 Market Price Sensitivity

To test the sensitivity of the cost-effectiveness results to market electricity prices, low and high market electricity forecasts were developed, keeping natural gas prices unchanged. Varying the market price without changing the assumption of natural gas price results in sensitivity to the "spark spread" for natural gas-fired generation. A larger "spark-spread" makes DG options more cost-effective, since it increases their revenues relative to operating costs. Even though the natural gas and electricity markets generally move together, the fuel cost and the electricity price were not varied together because these scenarios would not materially change the results. As discussed in the sensitivity analysis above, changes in market price also have a significant effect on the cost-effectiveness of EE.

Table 32 lists the assumptions used to develop the base, high, and low electricity price scenarios. Under the low forecast it is assumed that wholesale electricity prices are equal to the marginal operating costs (fuel costs and variable O&M) of a large-scale combined cycle power plant fueled by natural gas, with a heat rate of 7,618 HHV MMBtu per kWh. This case results in an average electricity price of $33.61 per MWh over the forecast period. Such a case is unlikely to persist for long, since these electricity prices do not allow any margin to recover fixed operating costs. Hence, the average electricity price ($33.61/Mwh) in the low case probably understates electricity prices in the Pacific Northwest over the long term.

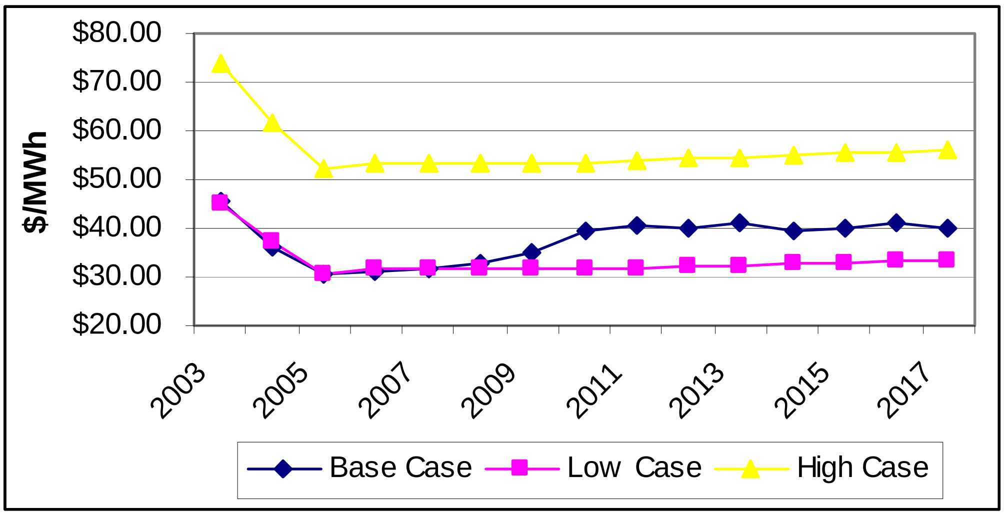
The high forecast assumes that electricity prices are equal to the fully allocated cost of a simple cycle combustion turbine fueled by natural gas, with a heat rate of 11,380 HHV MMBtu per kWh. This assumption results in a levelized electricity price of $56.56 per MWh during the forecast period.

Table 32: Electricity Price Scenario Assumptions

	Base Case	Low Case	High Case
Technology/Source	NWPPC	Combined Cycle Combustion Turbine	Simple Cycle Combustion Turbine
Lifetime (yrs)	Not Applicable	25	10
Fuel	Not Applicable	Gas	Gas
Avg. Fuel Cost	Not Applicable	$4.35	$4.35
Capacity Factor	Not Applicable	90%	90%
Plant Costs Recovered in Power Prices			
Initial Cost ($/kW)	Not Applicable	$523.06	$369.90
Heat rate	Not Applicable	7,618	11,380
Total Fixed Annual	Not Applicable	$0.00	$11.14
Fixed O&M ($/kW-yr.)	Not Applicable	$0.00	$7.44
Property Tax ($/kW-yr.)	Not Applicable	$0.00	$3.70
Variable O&M ($/MWh)	Not Applicable	$0.60	$0.12
Average Electricity Price	$39.58	$33.61	$56.56

Figure 9 shows power prices under the three scenarios.

Figure 9: Electricity Price Scenarios



5.3 BENEFIT/COST TESTS FOR ALTERNATIVE SCENARIOS

In addition to the base case, cost tests were performed for two alternative scenarios. The assumptions for these scenarios are shown in Table 26, above.

The NCA+ scenario is conducive to non-construction alternatives because of the assumed lower load growth, higher transmission capital costs, higher electricity prices, and lower DG capital costs. The Wires+ scenario is favorable to the transmission project because of the assumed higher load growth, lower transmission capital costs, lower electricity prices, and higher DG capital costs.

The cost test results for DG alternatives vastly improved under the NCA+ scenario because of the increase in electricity prices and the decrease in capital costs. Where only three measures passed the TRC test in the base case, 11 pass in the NCA+ scenario. Those that passed are the CCGT, one microturbine, and nine internal combustion engines. The Participant test results also improved, with three large-scale generators and six internal combustion engine technologies passing. The TRC and Participant test results for DG measures are extremely sensitive to changes in electricity prices, fuel prices and capital costs, because these are large components of the total benefits and costs in the tests. Increased incentive payments do not affect the cost test results greatly, since they only comprise a small portion of the total benefits for DG.

Of the three DG technologies that passed the TRC test in the base case, only one still passes under the Wires + scenario. In general, the TRC and Participant test results were negatively impacted by the lower electricity prices and higher capital costs.

The TRC test results decreased for the Conceptual DR-DLC option in NCA+ scenario, because the higher electricity prices caused the avoided energy loss savings to increase substantially. This increase in avoided loss savings actually overshadowed the increased incentive payments from higher transmission capital costs and lower load growth.

The TRC test results improved for the Conceptual DR-DLC program in Wires+ scenario, because of the decrease in avoided energy loss savings. However, the Participant test result dropped below 1, due to the significant decrease in incentive payments.

6.0 CONCLUSIONS AND RECOMMENDATIONS

Several conclusions can be drawn from this analysis of the Olympic Peninsula expansion.

6.1 CHP AND ENERGY EFFICIENCY EMPHASIZED WITH TRC

The use of the TRC test screening criteria changed the types of NCA measures that are economic from prior studies, such as that for the Kangley-Echo Lake Line. With the TRC approach, the full benefit is emphasized. Consequently, CHP-type applications that typically run a large percentage of the time, and energy efficiency conservation measures which save predominantly energy, become cost-effective. Demand response is not cost-effective from the TRC perspective for the Olympic Peninsula because of the high level of avoided loss savings. The results for the Kangley-Echo Lake study, which emphasized the RIM test, favored DR because of the small amount of associated revenue loss, although the study found no alternatives cost-effective due to both the cost-test perspective and the fundamental difficulty in solving the Kangley-Echo Lake issues through non-construction alternatives.

6.2 LOAD GROWTH REMAINS IMPORTANT

Some of the same issues arose in this study as in that for Kangley-Echo Lake. In particular, the load growth forecast can change the results significantly. Preparing a “solid” load growth forecast for extreme winter peak conditions presents a number of challenges. These include the fact that the region has not experienced extremely cold weather in the last 10 years or so, which leaves a great deal of uncertainty about the load profile under such conditions. There are also institutional challenges, since forecasts are prepared by summing projections from a number of different utilities, each with their own objectives, internal resources, and experience.

In addition to the uncertainties of forecasting load growth, the NCA assessment methodology now in use puts more emphasis on the load forecast than in the past. With the NCA approach, capacity is added to the system in very small increments, literally one light bulb replacement at a time in the extreme case. While a difference of 5 MW in the forecast would not significantly affect the design or timing of a new 500-kV line, it could make or break the success of a NCA project to reduce peak loads.

6.3 NON-CONSTRUCTION ALTERNATIVES ARE POSSIBLE FOR THE AREA

The results of this screening study indicate that it is possible to cost effectively defer the planned Olympia-Shelton transmission line. In particular, if growth does not follow the projected trend based on new data or reassessment of existing load data, if the revenue loss issue can be managed so that EE and CHP options are promoted as part of the solution, and if the demand response pilot achieves success in reducing critical peak loads, then deferring the line and maintaining area reliability is a real possibility.

The following set of actions are recommended to continue to pursue NCAs in the area:

(A) Continue to refine the load forecasting process used to estimate the peak loads, recognizing the critical importance of the forecast on the results of the NCA solution.

(B) Assess the magnitude of the potential revenue loss that would be created by implementing measures that pass the TRC test, but not the RIM. Without knowing the magnitude of the lost revenues, how significant this problem is cannot be known, nor how much rates would be increased with solutions that pass the TRC test.

(C) Develop a more detailed EE implementation program for the Olympic Peninsula to refine the assessment of the potential winter peak load reduction.

(D) Continue to pursue the Demand Exchange and other pilot programs on the Olympic Peninsula and work with customers in gathering information on the potential for load reductions during the critical system peak loads.

APPENDIX A

A.1 METHODOLOGY

The goal of this analysis was to conduct a high-level screening of potential alternatives to a proposed transmission construction solution (the wires solution) for a specific need on BPA's system. This process is useful because there are a very large number of potential alternatives available to BPA. These alternatives include combinations of distributed generation technologies, demand response programs, and demand side management measures, all of which have varying characteristics and costs. It would be extremely expensive to conduct a detailed analysis of each alternative to determine if it could contribute to a non-construction alternative. Thus, the analytical process described below is designed to identify which alternatives have the greatest potential for successful implementation. Those alternatives that pass through this high-level screen can then be analyzed further to determine their potential penetration and feasibility for successful implementation.

The screening criterion used in this analysis to identify cost-effective alternatives was that a cost-effective alternative must have a benefit/cost (B/C) ratio greater than one. A B/C ratio greater than one indicates that the non-wires alternative has a benefit greater than its cost, and therefore is a potentially cost-effective alternative to transmission construction. Suggesting that a measure is "cost-effective," however, immediately raises the question, "Cost effective to whom?"

To answer that question, each alternative was analyzed from five different stakeholder perspectives. Obtaining results from numerous perspectives allows for a greater understanding of the decision whether to build the transmission improvement or implement a non-construction alternative. However, there are competing views about what is the appropriate criterion for determining cost effectiveness. The principal debate is between the Ratepayer Impact Measure (RIM) and the Total Resource Cost (TRC) test. RIM compares the alternative's cost impact on BPA's rates versus the capital and maintenance costs of a proposed solution. TRC compares the costs and benefits of alternatives with all the costs and benefits of a proposed solution. TRC includes energy and generation benefits

A.2 COST-EFFECTIVENESS TESTS

Since BPA's ratepayers are not the only stakeholders in a transmission line expansion, cost effectiveness needs to be evaluated from a number of different perspectives: Total Resource Cost, Societal, Participant, and Local Utility. The purpose of including a number of perspectives is to find solutions that are cost effective, or "winners," for all stakeholders. Looking at all perspectives also aids in program design. For example, one of the costs in the RIM test is the incentive paid by BPA to the provider of the non-wires solution, which could be contractual payments to a local generator to be available to operate during the heavy load hours, or to an industrial customer to curtail load during such hours. A win-win program design is one that would set the incentive level payment such that both BPA's ratepayers and the program participant are better off, i.e., the RIM and Participant B/C ratios are both greater than 1. If such a balance is found, it would indicate a program that warrants further investigation as a potential alternative to transmission construction.

RATEPAYER IMPACT MEASURE (RIM) - TRANSMISSION COMPANY

This benefit/cost test measures the impacts on BPA's rates. The benefits included are the transmission cost savings from the deferral of the line and changes in O&M costs. The costs included are the incentive payments paid by TBL to the providers of the non-wires solution(s), BPA's administrative costs, and BPA's lost revenues due to reduced sales. If the program benefit/cost ratio is less than one, this program would tend to increase the per unit rates that BPA would charge to collect its revenue requirement. Measures that have a high reduction in sales relative to peak load reductions, such as conservation, are generally not cost-effective from the RIM perspective.

UTILITY COST TEST - TRANSMISSION COMPANY

This test measures the impacts on BPA's revenue requirement. The benefits included for this test are the avoided transmission costs including O&M savings. The costs included are the BPA incentive payments and BPA administrative costs. If the program benefit/cost ratio is less than one, the program will increase the revenue requirement. This test is different than the RIM test because the lost sales due to any measures that reduce BPA energy sales will generally not alter the transmission company revenue requirement.

TOTAL RESOURCE COST TEST (TRC)

The TRC test measures the costs and benefits from a broader perspective, and includes all of the direct cash costs associated with the non-wires alternative. The benefits include the avoided costs of transmission, distribution, generation capacity and energy, including losses. The costs include the lifecycle costs of the measure, O&M costs, program administrative costs, and the lost opportunity to realize a reduction in transmission losses from building the line. Transfers such as incentive payments between BPA and its customers, as well as bill savings, are not included from this perspective, since the net cost of transfers between BPA and customers is zero.

SOCIETAL COST TEST

The societal cost test includes the broadest set of costs and benefits. In addition to the direct cash costs accounted for in the TRC test, any environmental externalities such as reduced air emissions are included as a benefit.

PARTICIPANT COST TEST

The participant cost test measures the lifecycle net benefits for the participant. The participant is the customer that installs the energy efficiency, curtails their load, or owns the DG. The benefits included in this test are the incentives paid to the customer and the customer's bill savings due to the measure. The costs included are the life-cycle costs of the measure to the participant. This cost test is a good indicator of how acceptable a program will be to individual customers who might participate in the program.

RATEPAYER IMPACT MEASURE (RIM) - DISTRIBUTION COMPANY

This benefit/cost test measures the impacts on the rates of the distribution utilities that BPA TBL serves with their transmission system. The benefits included for this test are the transmission avoided costs, while the costs included are the incentive payments by the utility to the providers of the non-wires solution(s), the utility's administrative costs, and the lost revenues due to reduced sales. If the program benefit/cost ratio is less than 1, the program would tend to increase the per unit rates that the utility charges to meet its revenue requirement. Measures that significantly lower sales relative to peak demand reductions, such as conservation, generally are not cost-effective from the RIM perspective.

Table A-1 outlines the program costs and benefits assigned to each test perspective.

Table A-1: Description of B/C Tests

Tests and Perspective	Program Costs	Program Benefits
RIM Test BPA TBL	TBL Incentive TBL Revenue Loss Admin Costs	T Avoided Cost
Utility Cost Test BPA TBL	TBL Incentive Admin Costs	T Avoided Cost
TRC Cost Test	Measure / Program Costs Admin Costs Avoided Loss Savings	Gen Capacity Savings Energy Savings T Avoided Cost D Avoided Cost
Societal Cost Test	Measure / Program Costs Admin Costs Avoided Loss Savings Environmental Externalities	Gen Capacity Savings Energy Savings T Avoided Cost D Avoided Cost
Participant Cost Test Distribution Utility Customers	Participant Measure / Program Costs	TBL Incentive Dist. Utility Incentive Dist. Revenue Loss
RIM Test Distribution Utility	Dist. Utility Incentive Dist. Revenue Loss Utility Admin	Gen Capacity Savings Energy Savings TBL Revenue Loss D Avoided Cost

A.3 TRANSMISSION AVOIDED COST DEFINITION

As stated above, the basic benefits of non-traditional alternatives on the transmission system are measured as the change in BPA's revenue requirement that can be achieved by the deferral of a transmission line (or other wires) investment. Calculating the avoided costs of this project is a way of estimating the forward-looking incremental cost of transmission construction. If the construction can be avoided or deferred for a year or longer, this will result in a reduction of BPA's future revenue requirements. The avoided transmission cost is just one component of the total system benefits of implementing an alternative solution; however, from the BPA perspective, it is the only benefit of reducing peak loads. Therefore, the focus in this section is on the calculation of the transmission avoided cost component; however the method is similar for the other components of avoided cost.[11]

This method of calculating the long run incremental costs is also referred to as the "differential revenue requirement" method, because it is based on the difference in revenue requirements before and after deferral of the transmission project.

[11] For more detail, see *Costing Methodology for Electric Distribution System Planning*, prepared by E3 and Fred Gordon of Pacific Energy Associates for the Energy Foundation.

Step 1: Estimate the Revenue Requirement and Timing of the Planned Transmission Investment.

Table A-2 shows the revenue requirements for the planned traditional project. The costs are shown at revenue requirement levels (direct investment dollars have been scaled up to account for administrative and general costs, debt repayment, tax effects, and operations and maintenance expenses) so that the economic savings to the BPA rate base can be estimated.

Table A-2: Revenue Requirement of Planned Expenditures

A	*B*	*C*	*D*	*E*
Energized Year	**Investment**	**Constant Base Year Dollars ($000)**	**Base Year / Inflation**	**Revenue Requirement in nominal Dollars ($000)**
			2008	
2008	Olympic Peninsula Project	28,000	1.25%	29,314

Step 2: Evaluate the Load Reduction Required on the Transmission Path to Defer the Project

Table A-3 shows the forecast of load reduction requirements. If this amount of load reduction can be achieved during the critical load periods, BPA can maintain its system reliability criteria and defer the project.

Table A-3: Overload of the Olympic Peninsula System

Year	Peak Load Reduction (MW)
2008	22
2009	44
2010	66
2011	88
2012	110
2013	132
2014	154
2015	176
2016	198
2017	220

Step 3: Calculate the Change in Revenue Requirement per kW of Load Reduction

Table A-4 shows the calculation of the reduction in revenue requirement from postponing the traditional transmission line project, if the alternatives can achieve the required amount of load reduction.[12] Column A shows the revenue requirement of the expenditures (from Table A-2). Column B is the required annual load reduction from TableA-3. Column C shows the assumed amount of load reduction. Column D shows the deferral length in years achieved by the load reductions in column C. This deferral length can vary by year, depending on the load growth in each year. Column E shows the value of the deferral for each year. The deferral value is calculated as the difference in the present value of revenue requirement under the original and deferred schedule.[13]

The method for calculating the deferral value is based on the concept that the value of a load change is equal to the difference between the present value of the original investment plan and the present value of the deferred plan.[14] The cost of a deferred investment increases with the inflation rate, but decreases by the cost of capital (discount rate). Since the discount rate is higher than the inflation rate, this results in a net present value savings:

$$\text{Deferral Value} = \text{Nominal Cost in Year (i)} \times (1 - ((1+\textit{Inflation Rate})/(1+\textit{Discount Rate}))\text{^}\Delta t)$$

Where Δt is the deferral length in years.

Table A-4: Calculation of Olympic Peninsula Transmission Deferral Value

Year	A Scaled Nominal Cost ($000)	B Incremental Load Reduction (MW)	C Deferral Length (yrs)	D Deferral Value ($000)	E Marginal Cost ($/kW)
	(See prior table)		*(Col E/ Col D)*	*(A * (1-((1+inflation)/ (1+discount rate))^C))*	*(Col D/ Col B)*
2008	29,314	22.0	1.00	1,314	59.71
2009	0	22.0	1.00	0	0.00
2010	0	22.0	1.00	0	0.00
2011	0	22.0	1.00	0	0.00
2012	0	22.0	1.00	0	0.00
2013	0	22.0	1.00	0	0.00
2014	0	22.0	1.00	0	0.00
2015	0	22.0	1.00	0	0.00
2016	0	22.0	1.00	0	0.00
2017	0	22.0	1.00	0	0.00

[12] This load reduction could be due to distributed generation, curtailable load, ENERGY EFFICIENCY or other strategy.

[13] The inflation rate and weighted average cost of capital (WACC) used in the calculation of Column E are 2.7% and 9%, respectively.

[14] See Area Specific Marginal Costing for Electric Utilities: "A Case Study of Transmission and Distribution Costs", R. Orans Ph.D. Dissertation, 1989.

Step 4: Adjust for Changes in O&M Costs

If avoided O&M costs can be associated with deferring the traditional transmission project, then they are added to the total deferral value prior to calculating the total transmission marginal cost in $/kW. Dividing the total deferral value by the amount of load reduction required, gives the value per kW of load reduction.

Step 5: Calculate the Total Transmission Avoided Costs

These calculations suggest the maximum that BPA could pay without increasing the revenue requirement. Table A-5 shows the value of additional load reduction to achieve additional years of deferral. For each consecutive year after the initial expenditure is made, the incentive level in present value terms would be discounted further because the inflation rate is lower than the discount rate.

Table A-5: Base Case Incentive Levels Using $28 Million Dollar Avoided Investment Cost

Minimum Contract Length	1 Year	2 Year	3 Year	4 Year	5 Year
Minimum Total MW Required	22.0	44.0	66.0	88.0	110.0
Maximum Incentive	$1,313,580	$2,568,297	$3,766,789	$4,911,574	$6,005,060
$/kW (PV Contract Payments)	$59.71	$58.37	$57.07	$55.81	$54.59
$/kW-yr (Level and Annual Payments)	$59.71	$29.85	$19.90	$14.93	$11.94

A.4 SYSTEM INPUT DATA

A.4.1 Financing and Inflation Assumptions

The inflation, discount, and financing rates applied throughout the economic screening analysis were developed by BPA and are shown in Table A-6.

Table A-6: Financing and Inflation Assumptions

Applied Rates	Percentages
BPA Discount Rate (Real prices)	4.69%
Real Societal Discount Rate	3.00%
Financing Rate of Generator (DG)	12.50%
Customer Discount Rate	10%
Distribution Utility WACC	4.69%

A.4.2 Environmental Adders

Throughout the economic analysis, only tangible financial impacts that are applicable to each measure are included in the benefit-cost model. An estimation of tangible financial impacts for environmental externality effects is not readily available for the Olympic Peninsula region. However, many of the alternatives analyzed have positive environmental effects for each measure within the Societal Cost test perspective. Consequently, to reflect the environmental benefits of the measures tested, the Regional Technical Forum's (RTF) recommended environmental monetary estimate of $15/ton of carbon dioxide emissions was used. This estimate stems from the conclusion by the RTF that there exists "a risk that serious damage will result from continued increases in greenhouse gas concentrations in the atmosphere." Thus, $15/ton of carbon dioxide represents the reduction in this risk.

The environmental externality value is only used during the calculation of the Societal Cost test and is not applied to any other cost test perspective in the economic analysis.

Table A-7: Environmental Externalities

Environmental Externalities	$/MWh
Super-Peak	$ 6.00
Peak	$ 6.00
Off Peak	$ 6.00

A.4.3 Utility Rates

For the economic screening analysis, average rates were used for the three major customer classes: residential, commercial, and industrial. While average rates do not exactly match the rates in each distribution utility's territory, they do provide a reasonable approximation for a screening study. A more detailed program design (for implementing a cost-effective program) would use the utility-specific rates. Table A-8 outlines the average $/kWh rates used in the analysis. The rates used are intended to be representative of current posted rate schedules, and are not to accurately reflect billing rates for particular customers.

Table A-8: Distribution Utility Rates for 5 Years

Year	1	2	3	4	5
Distribution Utility Residential Rate $/MWh	$59.08	$49.70	$43.78	$44.56	$45.08
Distribution Utility Medium Commercial Rate $/MWh	$57.89	$48.51	$42.59	$43.37	$43.89
Distribution Utility Industrial Rate $/MWh	$45.03	$35.65	$ 29.73	30.51	$31.03

The unavoidable components of rates are also averages, and are shown in Table A-9.

Table A-9: Unavoidable Components of Distribution Utility Rates

	1	2	3	4	5
Residential Unavoidable Component $/MWh	$18.36	$18.36	$18.36	$18.36	$18.36
Commercial Unavoidable Component $/MWh	$4.26	$4.26	$4.26	$4.26	$4.26
Industrial Unavoidable Component $/MWh	$6.46	$6.46	$6.46	$6.46	$6.46

A.4.4 Loss Factors

The energy loss factors for the transmission and distribution systems for the various TOU periods are shown in the Tables A-10 and A-11.

Table A-10: Average Losses to the Generator

Average Marginal Energy Losses by TOU Period	Customer Meter to Generator	Distribution Sub to Meter	Primary Transmission Sub to Generator	Bulk Transmission to Generator
Super-Peak	15%	8%	8%	8%
Peak	15%	8%	8%	8%

Table A-11: Allocation of Capacity Costs

	Dist Cap Losses (meter to dist constraint)	Trans Cap Losses (meter to trans constraint)	Gen Losses (meter to gen)
Capacity Losses at Peak Hour	8%	8%	15%

A.4.5 DG Technology Cost and Performance

Table A-12 contains the capital and operating cost assumptions for the DG alternatives.

Table A-12: DG Capital and Operating Cost Assumptions

Technology	Captial Cost $/kW	Heat Rate (Net Heat Rate for CHP Applications) or Efficiency (for storage options)	Fixed O&M $/kW-yr	Variable O&M $/kWh
Combined Cycle Combustion Turbine	$523	7,618	$23.23	$0.0006
Simple Cycle Combustion Turbine	$370	11,380	$11.14	$0.0001
Mobile Gas Turbine Generator (GE TM2500)	$250	10,940	$2.78	$0.0010
200 kW PAFC Fuel Cell	$4,500	10,428	$6.50	$0.0290
10 kW PEM Fuel Cell	$5,500	12,507	$18.00	$0.0330
200 kW PEM Fuel Cell	$3,600	10,725	$6.50	$0.0230
250 kW MCFC Fuel Cell	$5,000	8,723	$5.00	$0.0430
2000-kW MCFC Fuel Cell	$2,800	8,162	$2.10	$0.0330
100-kW SOFC Fuel Cell	$3,500	8,338	$10.00	$0.0230
200-kW PAFC Fuel Cell CHP	$4,500	5,346	$6.50	$0.0290
10-kW PEM Fuel Cell CHP	$5,500	7,007	$18.00	$0.0330
200-kW PEM Fuel Cell CHP	$3,600	5775	$6.50	$0.0230
250-kW MCFC Fuel Cell CHP	$5,000	6,303	$5.00	$0.0430
2000-kW MCFC Fuel Cell CHP	$2,800	5,720	$2.10	$0.0330
100-kW SOFC Fuel Cell CHP	$3,500	5,731	$10.00	$0.0230
Capstone Model 330 – 30 kW w/ CHP	$2,604	5573	$0.00	$0.0200
IR Energy Systems 70LM – 70 kW w/ CHP	$1,929	7640	$0.00	$0.0110
Bowman TG80 – 80 dW w/ CHP	$1,962	6,598	$0.00	$0.0130
Turbec T100 – 100 kW	$1,765	6,166	$0.00	$0.0150
Capstone Model 330 – 30 kW	$2,201	1,5443	$0.00	$0.0200
IR Energy Systems 70LM – 70 kW	$1,663	13,544	$0.00	$0.0110
Bowman TG80 – 80 kW	$1,692	14,103	$0.00	$0.0130
Turbec T100 – 100 kW	$1,485	13,127	$0.00	$0.0150
DE-K-30 (30 kW)	$1,290	11,887	$26.50	$0.0000
DE-K-60 (60 kW)	$864	11,201	$26.50	$0.0000
DE-K-500 (500 kW)	$386	10,314	$26.50	$0.0000
DE-C-7 (7.5 kW)	$627	10,458	$26.50	$0.0000
DE-C200 (200 kW)	$416	9,944	$26.50	$0.0000
GA-K-55 (55 kW)	$970	12,997	$26.50	$0.0000
GA-K-500 (500 kW)	$936	12,003	$26.50	$0.0000
MAN 150 kW – 100 kW	$1,030	11,780	$0.00	$0.0184
Cummins GSK 19G – 300 kW	$771	10,967	$0.00	$0.0128
Caterpillar G3516 LE – 800 kW	$724	10,246	$0.00	$0.0097
Caterpillar G3616 LE – 3 MW	$702	9,492	$0.00	$0.0093
Wartsila 5238 LN – 5 MW	$727	8,758	$0.00	$0.0093
MAN 150 kW – 100 kW w/ CHP	$1,491	4,717	$0.00	$0.0184
Cummins GSK 19G – 300 kW w/ CHP	$1,172	4,687	$0.00	$0.1280
Caterpillar G3516 LE – 800 kW w/ CHP	$971	4,771	$0.00	$0.0097
Caterpillar G3616 LE – 3 MW w/ CHP	$864	4,857	$0.00	$0.0093

A.4.6 Fuel Prices

Natural gas and distillate oil prices are inputs to the running costs of DG and other generation resources. These prices are also used in the forecasts of electricity market prices. For this analysis, the fuel forecasts are taken from draft natural gas and distillate oil price forecasts supplied by the Northwest Power Planning Council in its *5th Power Plan* of April of 2003.[15] The Council forecasts U.S. wellhead prices through 2025, and then adjusts these prices to reflect the costs of delivering power to end-users. This study uses the Council's forecast of delivered natural gas prices for Eastside electricity generators and utility distillate oil prices, adjusted for inflation to 2003 dollars. Fuel price forecasts are shown graphically in Figures A-1 and A-2.

Figure A-1: Natural Gas Prices

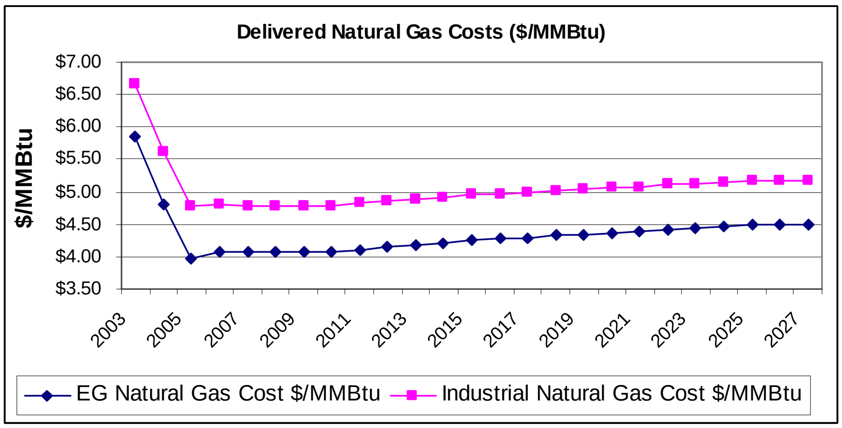
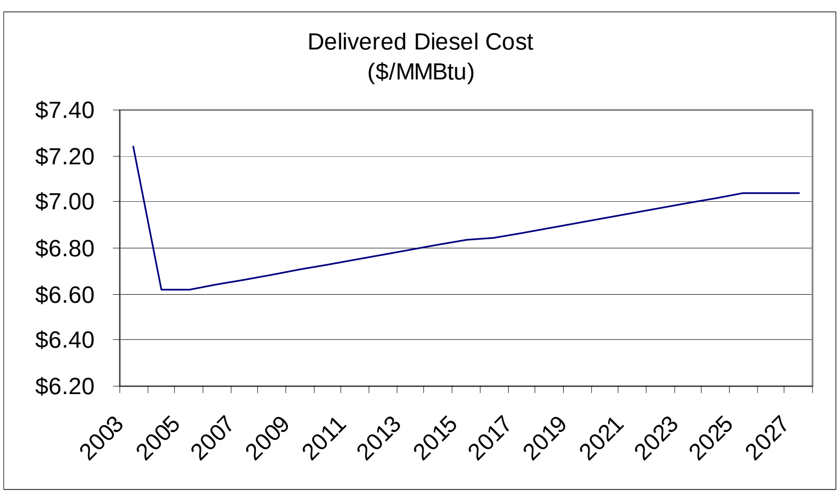


Figure A-2: Diesel Prices



[15] Northwest Power Planning Council, *Draft Fuel Price Forecasts for the 5th Northwest Conservation and Electric Power Plan*, April 25, 2002, p. F-1.