Appendix C – Project Summaries

Olympic Peninsula Reinforcement

Background
During winter load conditions, the Olympic-Peninsula (Peninsula) is susceptible to voltage stability problems for single (N-1) and common-mode (N-2) outages. In order to delay the need date for reinforcing the Peninsula to cover for N-1 outages, BPA installed a capacitor group on the Fairmont 230-kV bus in 2003. Currently, the worst single contingency is loss of a transformer during extra-heavy winter load conditions.

Today, there are some N-2 outages that result in voltage stability problems for the Olympic Peninsula during normal winter load conditions. These include a double circuit line outage or a breaker failure.

The proposed reinforcement will solve both the N-1 and N-2 outages and reinforce the Olympic Peninsula region.

Project Description
In order to meet load growth and improve voltage stability performance, BPA plans to reinforce the Olympic Peninsula by constructing a 14-mile (22-km) double circuit 230-kV line and two new 230-kV line terminals at Shelton substation. The Olympia-Shelton No. 1, 115-kV line will be removed up to the Dayton Mason County Tap to allow the line to be built in its place. The Olympia-Satsop No. 3, 230-kV line will be split at a point approximately 6-miles (10-km) west of Olympia. The double circuit 230-kV line from Shelton substation will connect to the split ends of the Olympia-Satsop No. 3, 230-kV line to create the Olympia-Shelton No. 5, 230-kV and the Satsop-Shelton No. 1, 230-kV. The Olympia 230-kV bus will also be reconfigured. A new sectionalizing breaker will be added between bays 10 and 12 on the Olympia 230-kV bus which will create three sections: west, middle, and east. The low side of the Olympia 500/230-kV transformer will be moved from the west bus to the east bus. The Olympia-Kitsap No.3, 230-kV line will be moved from the east bus to the middle bus.

Limiting Outages Addressed
- N-1: Transformer or transmission line
- N-2: Double transmission line or breaker failure

Benefit - Load Area Service
This project will prevent these outages from impacting load service to the Peninsula and increase the load service capability to the Olympic Peninsula under non-outage conditions.

Business Case
This project provides the capacity to carry projected winter load conditions in the Olympic Peninsula area for compliance with NERC/WECC Planning Standards for Category A-C outages. For the purpose of this analysis**,** revenues are based on a 0.8% load growth. This corresponds to approximately 10 MW/year, reaching a project limit of 1500 MW in 2022 for N-1 outages. In the Table below, Alternative 1 is the 500-kV line from Paul to Shelton, and Alternative 2 is a 230-kV double circuit line to Shelton.

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV ($M)	Rev/C	In Service	Life
1	6.9	(50.8)	(40.9)	.14	2008	2043
2	6.9	(31.0)	(22.3)	.22	2008	2043
2a	8.6	(31.0)	(20.6)	.28	2008	2043
2b	6.9	(34.0)	(25.1)	.20	2008	2043
2c	3.5	(31.0)	(25.7)	.11	2008	2043

Risk

The following table qualitatively addresses various risk factors. Four are identified for evaluation.

Factor	Risk
Cost Overrun	**See sensitivity 2b**
ROW	1.8 miles new ROW
Funding	Requested - EIS/Preliminary Engineering
Load Growth	**See sensitivity 2a and 2c**

Alternatives Considered
1. 500-kV single circuit to Shelton
2. 230-kV double circuit to Shelton
3. Do Nothing - Curtail load in the event of one of the critical outages.
4. Non-transmission alternatives

Sensitivity 2a – In this case the load growth rate of 0.8% increases to 1%. This increases the Revenue/Cost ratio from 0.22 to 0.28.

Sensitivity 2b – This case represents an increase in project cost of 10%. The Revenue/Cost ratio for this case decreases from 0.22 to 0.20.

Sensitivity 2c – In this case the load growth rate of 0.8% decreases to 0.4%. This decreases the Revenue/Cost ratio from 0.22 to 0.11.

Alternative (#1)
For alternative #1 listed above the capital was $35.1M (loaded) compared to alternative #2 with $21.5M (loaded) capital.

Do-Nothing Alternative (#3)

(a) The following information applies to for N-1 contingencies for winter if the transmission system is not reinforced:

- A 2-year MTBF for N-1 transmission line with average outage duration of 2.5 hours.
- A 100-year MTBF each phase of a transformer and a 4-week replacement time. This corresponds to a bank outage probability of:

  P(outage) = 1-(1-1/100)^(2x3) = 0.058, and a
  MTBF = 1/0.058 = 17 years.

- The required load curtailment for either outage increases by 10 MW yearly starting in 2015.

Since the outage time is quite different for the two events the societal costs are estimated separately. Voltage collapse is assumed to occur when the demand exceeds system capability following the outage by more than 5%. Area load is restored to the capability of the remaining system within one hour. The estimated present worth societal cost is $202K for a N-1 line outage. Since the forecasted load growth does not exceed system capability by more than 5% for a N-1 bank outage there is no societal cost in the ten-year window 2008-2017.

(b) The following information was used to estimate the probability of loss of load for N-2 contingencies if the transmission system is not reinforced:

- 9.3 year MTBF for N-2 outage of a double circuit transmission line. It is further assumed that one line can be restored within one hour and the second line within 24 hours.
- 0.018 breaker failures/year for each of eight breakers at a critical substation. It is assumed that full service is restored within one hour by moving the affected line over to the bus tie breaker. This corresponds to a bus outage probability of

  P(outage) = 1-(1-0.018)^8 = 0.14, and a
  MTBF = 1/0.14 = 7.4 years.

Again, the societal costs of the two events are treated separately. In each case it is assumed that the entire area load will be lost due to voltage collapse for the initial period of one hour. The estimated present worth societal cost is: $5.4M for the two-line outage and $502K for the breaker failure outages.

Overall the estimated present worth societal cost for a ten-year period of the do-nothing alternative is approximately $6.1M. This is calculated using the above MTBF estimates,

the previous load interruption cost figures inflated yearly by 2.64% and assuming the system exposure is 8 hours/day for two months/year. The present value savings of a ten-year delay in the project is expected to be greater considering deferred capital, financing and O&M costs**.**

Non-Wires Alternative (#4)
BPA is considering the implementation of a portfolio of non-wires solutions to reduce demand on the transmission system. These measures include energy efficiency programs, demand reduction initiatives (including direct load control), pricing strategies, and distributed generation.

In 2004, BPA piloted a demand exchange project on the Olympic Peninsula to determine its ability to reduce congestion on transmission lines by contracting with customers to voluntarily reduce transmission loads during times of critical peak demand. During the tests, BPA was able to purchase an average of 22 megawatts of peak demand reduction during each hour of a simulated event. This equated to about two year's load growth on the Peninsula. BPA is currently exploring a variety of technologies including:

- A direct load control pilot in Ashland, Ore.
- Load reduction and distributed generation in Richland, Wash.
- The use of small-scale power generation technology (known as distributed generation) to determine the feasibility of using standby generation to defer construction on the Olympic Peninsula.

These measures could potentially provide a cost-effective method of deferring the need under N-1 contingencies. However, these methods cannot address the N-2 problems.

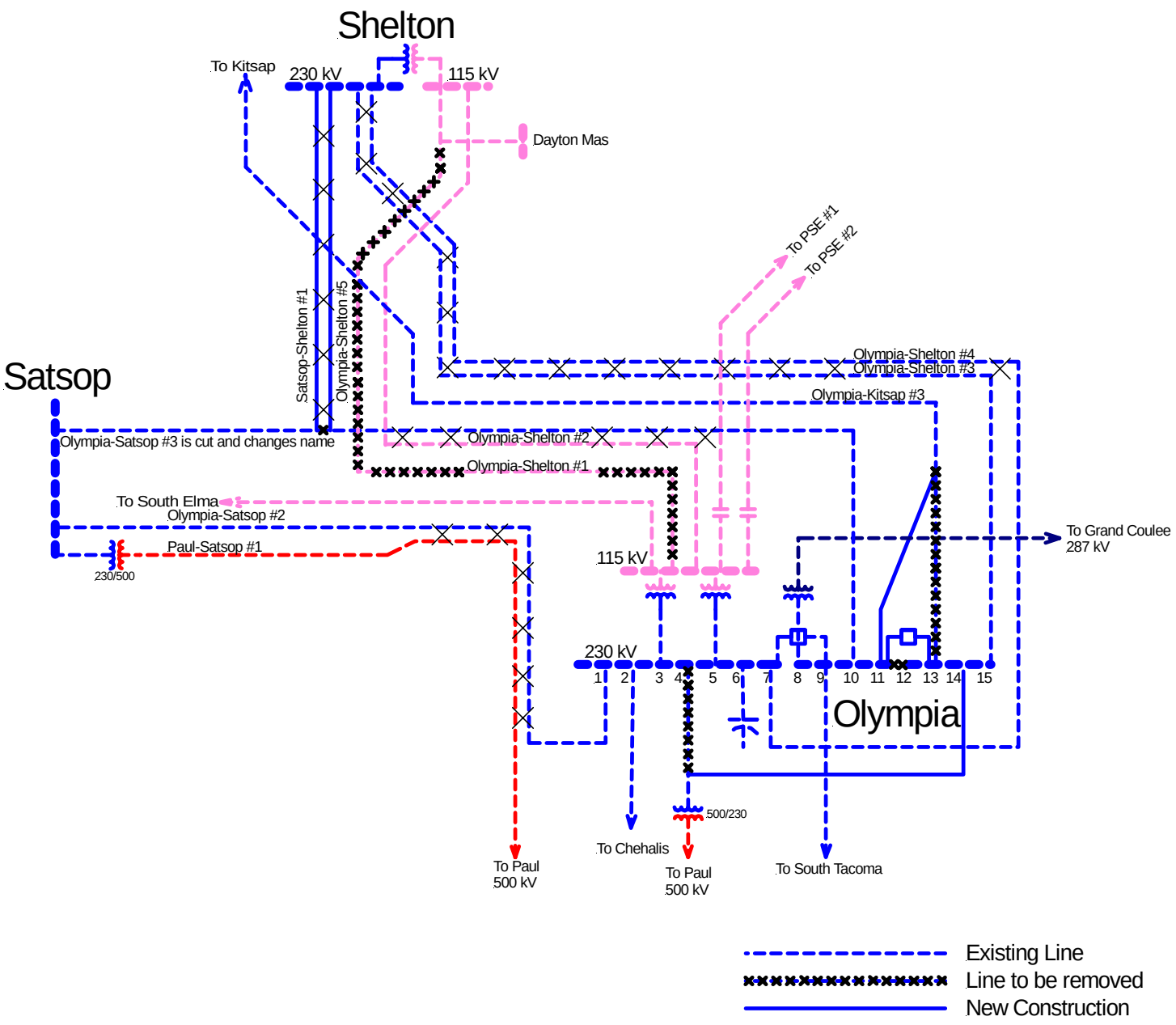
BPA will further consider non-transmission solutions before proceeding with this project. Cost information is not available at this time to allow presentation of an economic analysis.

Analysis
BPA is considering Alternative #2 based on the following:

- Technical performance
- Lowest up-front and present worth cost to BPA

Energization Date: Fall 2007
Estimated Cost: $21.5 M (loaded)

Olympic Peninsula 230-kV Reinforcement Project



Lower Valley Area Reinforcement Project

Background
A 345/161-kV transformer at PacifiCorp's Goshen Substation currently serves the Lower Valley area. Three transmission lines serve the loads out of Goshen.

1. The Goshen-Drummond 161-kV line serves mostly Fall River loads and provides back-up service to Lower Valley.
2. The Goshen-Swan Valley 161-kV line serves most of the Lower Valley load.
3. The Goshen-Palisades 115-kV line serves the Palisades Generating Plant and some Lower Valley load.

BPA constructed a second Swan Valley-Teton line in 2000 and upgraded the Goshen-Drummond line to 161-kV in 2002. These upgrades increased the reliability of the Fall River system and helped support load growth in the Jackson Hole area, but did little to support the southern part of Lower Valley's system. Capacitor banks have been installed at Targhee, Tincup, Teton, and Madison Way. Additional capacitor banks were ruled out as a solution to voltage stability issues due to the nature of the Lower Valley system (long transmission lines with comparatively low loads).

The projected load growth in the Lower Valley and Fall River area has averaged around 3% per year for the past 8 years. The load forecast assumes 3% growth per year leveling off to 1.5% in 2010.

The minimum BPA-recorded temperature in the Jackson area is –58 degrees Fahrenheit. The normal winter temperature is –30 degrees Fahrenheit. Obviously, temperatures this low make reliable service imperative since the job of restoring load service is difficult at best.

Project Description
Negotiated arrangements are tentative – No contracts have been signed.
Alternative 3:

- PacifiCorp to finance, design, and rebuild PacifiCorp's Caribou Substation near Soda Springs, Idaho. The modifications would include a new 345-kV interconnection with Idaho Power and a 345/138-kV substation – Fall 2007 or 2008
- BPA to finance, design, and construct an adjacent Caribou 138/115-kV Substation – Fall 2008
- Lower Valley Energy to design, construct (and pay for half) of a 20-mile, 115-kV, double circuit line from BPA's Caribou Substation to Lower Valley's Lanes Creek-Valley 115-kV line segment – Fall 2008
- BPA to install approximately 25 MVAR shunt capacitors near Drummond – Fall 2008
- Rebuild the Goshen-Palisades 115-kV line to 161-kV – Fall 2027

Limiting Outages Addressed
Based on the current load forecast, three outages could cause voltage instability in the Fall River/Lower Valley area within the next few years.

- Critical outage #1 could cause voltage instability by winter 2009.
- Critical outage #2 could cause voltage instability by winter 2010.
- Critical outage #3 could cause voltage instability by winter 2012.

Benefit – Load Service
This project will increase the reliability of maintaining load service to the Lower Valley area. Without this project it would be necessary to trip off load to relieve voltage stability problems during normal cold winter peaks for any of the three outages mentioned above. Such action could cause loss of life due to extreme winter weather conditions.

PacifiCorp has determined that a second 345/161-kV transformer is needed at Goshen Substation by summer 2007 or 2008 at an estimated cost of $11.4M (unloaded). This project is necessary in addition to either alternative 1 or alternative 2. However, alternative 3 off-loads the Goshen transformers and eliminates the need for the project. This investment, if made, would be recovered through increased charges under the GTA administered by BPA's PBL.

This plan also benefits PacifiCorp by providing much needed support to an existing potassium mining plant and blast furnaces as well as to residential loads located near the proposed Caribou Substation.

Business Case

Alternative	PV Revenue ($M)	PV Costs ($M)	Net PV ($M)	Rev/C	In Service	Life
1	4.1	(65.8)	(55.3)	.06	2008	2043
2	4.1	(72.6)	(63.4)	.06	2008	2043
3	4.1	(33.5)	(27.2)	.12	2008	2043
3a	6.4	(33.5)	(24.9)	.19	2008	2043
3b	4.1	(36.4)	(30.0)	.11	2008	2043
3c	1.9	(33.5)	(29.5)	.06	2008	2043

Risk Factors

The following table qualitatively addresses various risk factors:

Factor	Risk
Cost Overrun	**See 3b**
Contract	Contract not signed (low probability)
Funding	Requested
Load Growth	**See 3a and 3c**

Alternatives Considered

1. Goshen-Palisades Rebuild
   Phase 1:
   - Rebuild the Goshen-Palisades 115-kV line to 161-kV – Fall 2008
   - Add shunt Caps at Snake River substation – Fall 2010

   Phase 2:
   - Build Goshen-Lanes Creek 161-kV line (52-miles) – Fall 2014
2. Goshen-Lanes Creek
   Phase 1:
   - Build a new Goshen-Lanes Creek 161-kV line (52 miles) – Fall 2008
   - Add shunt caps near Madison Way – Fall 2013

   Phase 2:
   - Rebuild the Goshen-Palisades 115-kV line to 161-kV – Fall 2022
3. Caribou Loop In (*see Project Description on page C-9*)
4. Do Nothing - Curtail load in the event of one of the critical outages.
5. Non-transmission alternatives.

Sensitivity 3a – In this case the load growth rate of 3% is increased to 6%. This increases the Revenue/Cost ratio from 0.12 to 0.19.

Sensitivity 3b – This case represents an increase in project cost of 10%. The Revenue/Cost ratio for this case dropped from 0.12 to 0.11.

Sensitivity 3c – This case the load growth rate decreases from 3% to 1.5%. The Revenue/Cost ratio for this case dropped from 0.12 to 0.06.

Alternatives (#1) and (#2)
Alternatives 1 and 2 listed above have capital costs of $57.6 M (loaded) and $53.9M (loaded), respectively as compared to $24.1M (loaded) for alternative 3.

Do-Nothing Alternative (#4)
The "no build" alternative represents a risk of load interruption for the following first contingency outages:

- Critical Outage #1
- Critical Outage #2

- Critical Outage #3

The amount of interrupted load ranges from 177 MW in 2008 to 233 MW in 2020. Based on historical information, one of these outages has occurred an average of 4.1 times every winter over the past 10 years. The risk that one of these outages will occur during winter peak loading is very high.

The outage mean time between failures (MTBF) is estimated as follows:

TRANSFORMER BANK OUTAGES:

P(no outage) = (1-1/100)^(2x3 banks)
P(no outage) = 0.941
P(outage) = 1-0.941 = 0.058
MTBF = 1/0.058 = 17 years

While the revenues for the do-nothing alternative can be assumed to be the same assuming load can be carried under the no-outage condition, the societal cost of any of these outages would be significant. Assuming that load is curtailed to the outage limit for a period of 4 weeks until a new transformer unit is installed the present worth of the societal cost over ten years of service is estimated to be about $5.5M. If a spare transformer bank was available the present worth of the societal cost would reduce to $1.4M assuming that the load is curtailed to the outage limit for one week. The societal cost was calculated using the above MTBF estimate, the following load interruption cost figures inflated yearly by 2.64% and assuming the system exposure is 8 hours/day for four months/year.

Load Type	**Composition**	**$/kWHr (2004)**
Residential	56.0%	$1.75
Commercial	38.0%	$19.49
Industrial	6.0%	$29.03

TRANSMISSION LINE OUTAGES:

Transmission Line	**Initial Outage Time**	**Events**	**MTBF**	**Restoration Time**
	(Minutes)	**(10-Year Span)**	**(Years)**	**(Minutes)**
Critical Line Outage #1	30	9	1.11	107.3
Critical Line Outage #2	30	17	0.59	38.9
Critical Line Outage #3	30	24	0.42	307.3

For a transmission line outage we assumed that load is curtailed to the outage limit for the initial outage time plus the restoration time (based on historical data) for each line. The totalized present worth of the societal cost over ten years of service is estimated to be about $3.3M. This is calculated using the above MTBF estimates, the previous load

interruption cost figures inflated yearly by 2.64% and assuming the system exposure is 8 hours/day for four months/year.

TOTAL SOCIETAL COST (all contingencies):

Total societal cost for all contingencies was calculated by simply summing the societal costs for loss of the transformers with loss of the transmission lines. This brings the totalized present worth of the societal cost over ten years of service to approximately $8.8M.

Non-Wires Alternative (#5)

BPA is considering the implementation of a portfolio of measures to reduce demand on the transmission system. These measures include energy efficiency programs, demand reduction initiatives (including direct load control), pricing strategies, and distributed generation Included in this consideration were the results of a report entitled "Non-Wires Solutions to Lower Valley Power and Light Transmission System Reinforcement Project," dated January 12, 2004 available at:

http://www.transmission.bpa.gov/PlanProj/Non%2DWires%5FRound%5FTable/default.cfm?page=key

In conjunction with the Caribou Project, Lower Valley Energy has tentatively agreed to fully evaluate, design and implement a load management program to selectively control loads (like water heating) in order to reduce peak hour transmission use.

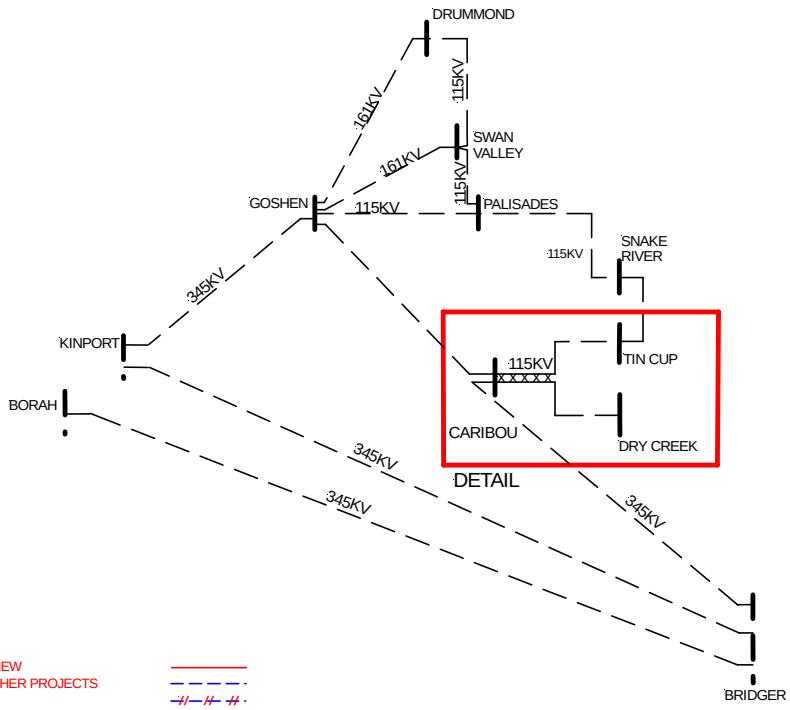
Analysis

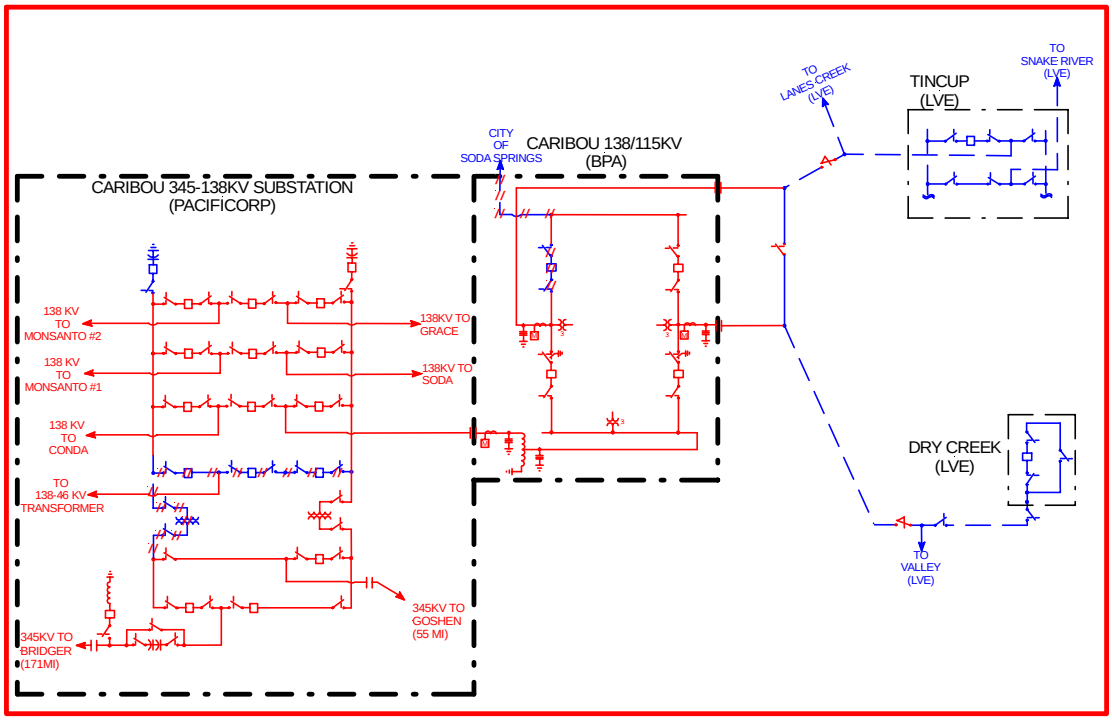
BPA chose the Alternative 3 for the following reasons:

- Strongest Plan Technically
- Most reliable since it is the only option that provides a second source.
- Less reliance on Goshen Substation
- Lowest up-front and present worth cost to BPA
- Lower environmental impact than other options (20-mile line versus 52-mile line)
- Cost Sharing from PacifiCorp and Lower Valley Energy

Energization Date: Fall 2008
Estimated Cost: $24.1M (loaded) – BPA Portion

LOWER VALLEY AREA REINFORCEMENT





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