3.8 ENERGY AND NATURAL RESOURCES

This section discusses the anticipated energy and natural resources use of the proposed project, the sources and availability of energy for the cogeneration facility, the facility's impacts on energy and natural resources, and mitigation measures to be implemented. The analysis in this section is primarily based on information provided by the Applicant in the ASC (BP 2002, Section 3.8). Where additional information has been used to evaluate the potential impacts associated with the proposal, that information has been referenced. Information regarding water use and conservation is presented in Sections 3.3 and 3.4.

3.8.1 Existing Conditions

Energy Resources

Existing energy resources within the project vicinity primarily include electricity, natural gas, and a variety of petroleum products, including gasoline, diesel fuel, and lubricating oils. Figure 2-3 presents the existing electrical and natural gas infrastructure in the project vicinity.

<u>Electricity</u>

Project Area

Sources of electricity in the project vicinity include power provided by Puget Sound Energy (PSE) and Bonneville.

Two power plants are in the vicinity of the BP Cherry Point Refinery: the PSE Point Whitehorn Power Generation Plant and the Tenaska Cogeneration Plant. The PSE Point Whitehorn Plant is just west of the refinery. This 150-MW power plant can be fired by natural gas, diesel, or jet fuel and is primarily used to provide power during peak demand periods. Tenaska Power Partners operates a 249-MW gas-fired cogeneration power plant at the Conoco-Phillips Refinery, located a few miles south of the BP Cherry Point Refinery. A third power plant, the Sumas Energy 2 (SE2) project, is a 660-MW natural gas-fired power plant proposed in Sumas, Washington, approximately 25 miles east of the proposed cogeneration site. The SE2 plant has been permitted, but not yet constructed.

Electricity is supplied to the refinery by PSE through two 115-kV transmission lines that are routed within easements adjacent to Aldergrove and Blaine roads. The power lines enter the refinery area adjacent to Blaine Road and connect to a substation within the refinery boundaries.

Bonneville owns a substation at Custer, Washington (approximately 4 miles northeast of the refinery), from where two 230-kV transmission lines are routed west and then south to the Intalco substation at the Alcoa Intalco Works aluminum smelter. The Applicant has proposed the construction of a 0.8-mile-long 230-kV electrical transmission line (referred to throughout this EIS as the "transmission system") to provide a connection between the cogeneration facility and the Custer/Intalco Transmission Line No. 2.

In 1999, an earlier version of the transmission system was proposed by the Applicant to provide a means for supplying the refinery and other industrial customers in the area with electrical power from the Bonneville transmission system. That proposal received federal wetland permit and water quality certification approvals and has been partially constructed (two transmission line maintenance roads and three transmission tower gravel pads).

The transmission system element of the current cogeneration project proposal, which would supersede the original transmission line proposal, would use a portion of the original permitted transmission line design. Instead of using the new transmission line to supply power to the refinery and other customers from the Bonneville transmission system, the transmission line would normally be used to export power generated by the cogeneration facility to the Bonneville transmission system for distribution within the western power market. See Section 2 for additional discussion of the transmission system.

Northwest Region

Regional Demand. Based on data published by the Northwest Power and Conservation Council (NWPCC), electricity demand for the Council's four-state Pacific Northwest planning region (Washington, Oregon, Idaho, and Montana) was 20,080 average megawatts in 2000 (NWPCC 2003).

As shown below in Table 3.8-1, the Council's recently revised 20-year demand forecast projects that electricity demand in the region will grow from 20,080 average megawatts in 2000 to 25,423 average megawatts by 2025 (medium forecast), an average annual growth rate of just less than 1% per year. While the Council's forecast indicates that the most likely range of demand growth (between the medium-low and medium-high forecasts) is between 0.4 and 1.50% per year, the low to high forecast range used by the Council recognizes that growth as low as -0.5% per year, or as high as 2.4% per year, is possible although relatively unlikely (NWPCC 2003).

Table 3.8-1: Projected Pacific Northwest Electricity Demand, 2000-2025

Forecast Scenario	Electricity Demand (Average Megawatts)			Growth Rates (Percent Change)	
	2000	2015	2025	2000-2015	2000-2025
Low	20,080	17,489	17,822	-0.92	-0.48
Medium Low	20,080	19,942	21,934	-0.05	0.35
Medium	20,080	22,105	25,423	0.64	0.95
Medium High	20,080	24,200	29,138	1.25	1.50
High	20,080	27,687	35,897	2.16	2.35

Source: NWPCC 2003

Bonneville Transmission System. Bonneville owns and operates 15,000 miles of power lines that carry power from the dams and other power plants to utility customers throughout the Pacific Northwest. The Bonneville service area includes Oregon, Washington, Idaho, western Montana, and small portions of Wyoming, Nevada, Utah, California, and eastern Montana.

Generation resources typically require interconnection with a high-voltage electrical transmission system for delivery to purchasing retail utilities. Bonneville owns and operates the FCRTS, comprising more than three-fourths of the high-voltage transmission grid in the Pacific Northwest, including extra regional transmission facilities. Bonneville operates the FCRTS in part to integrate and transmit “electric power from existing or additional Federal or non-Federal generating units.” Interconnection with the FCRTS is essential to deliver power from many generation facilities to loads both within and outside the Pacific Northwest.

Public agencies get preference to power from Bonneville. About half the power Bonneville sells goes to Northwest public utility districts, city light departments, and rural electric cooperatives. An additional 15% of Bonneville's annual sales is to investor-owned utilities. Sales to Northwest aluminum companies and a few other large industries account for about one-fourth of Bonneville's annual revenues. After Northwest customers are served, Bonneville sells any surplus power to utilities outside the region.

System Constraints. Bonneville has indicated that portions of the Northwest transmission system are approaching gridlock, resulting in chronic congestion on a number of critical transmission paths, which has curtailed firm power deliveries. One effect of these constraints is that they limit wholesale power trading, which in turn drives up prices for all consumers in the West. As of 2001, approximately 1,000 MW of generation projects under construction had contracted for wheeling (transferring power) over the Bonneville system. An additional 3,000 MW of new generation is proposed by 2004, and developers for nearly 30,000 MW of generation have requested interconnection. While many of the proposed generation projects will not be built, Bonneville has determined that a transmission capacity shortfall of approximately 3,000 MW will occur by 2004 (Bonneville 2001d).

Planned Generation Projects. As of April 2003, there were 39 new merchant power generation projects proposed in the State of Washington, representing in excess of 10,000 MW of additional generation capacity (see Table 3.8-2). While not all of these will be constructed, it is likely that additional generation capacity will continue to be added in the Northwest during the next two to three years. In 2002, over 1,100 MW of additional capacity has become operational in the region, with gas-fired facilities comprising a majority of the newly installed capacity (see Table 3.8-3). Table 3.8-4 lists four additional plants currently under construction in Washington with their expected commercial operation dates (PSE 2003).

Table 3.8-2: Proposed Generation Projects in Washington

Facility	Developer	Facility Type	Size (MW)
Bickleton	PacifiCorp Power Marketing, Inc.	Wind	200
Big Horn	PacifiCorp Power Marketing, Inc.	Wind	200
BP Cherry Point Refinery	BP Cherry Point Refinery	Combined Cycle/Cogen	720
Columbia River 1	Nordic Electric, Llc	Combust Turbine	100
Columbia River 2	Nordic Electric, Llc	Combust Turbine	100
Cowlitz Cogneration	Weyerhaeuser Co.	Combined Cycle/Cogen	405
Darrington	National Energy Systems Co.	Boiler/Cogen	15
Everett Delta Power Project	FPL Energy, Inc.	Combined Cycle	248
Frederickson (USGECO)	PG&E Generating Co.	Combust Turbine	100

Table 3.8-2: Continued

Facility	Developer	Facility Type	Size (MW)
Frederickson (Tahoma)	Tahoma Energy	Combined Cycle	270
Frederickson 2	EPCOR	Combined Cycle	290
Goldendale Smelter	Westward Energy Llc	Combined Cycle	300
Horse Heaven	Washington Winds Inc.	Wind	150
King County Fuel Cell Plant	Fuel Cell Energy Inc	Other	1
Kittitas Valley	Sagebrush Power Partners (Zilkha)	Wind	250
Klickitat	Columbia Wind Power	Waste	80
Longview (MIR)	Mirant Corp.	Combined Cycle	286
Moses Lake	National Energy Systems Co.	CC/Cogen	306
Plymouth Energy LLC	Plymouth Energy Llc	Combined Cycle	306
Port Of Washington	Continental Energy Services, Inc.	Combust Turbine	290
Rainier	National Energy Systems Co.	Combined Cycle	306
Richland (COMPOW)	Composite Power Corp.	Combust Turbine	2600
Roosevelt (SEENGR)	SeaWest Energy Group, Inc.	Wind	150
Roosevelt Landfill	PUD No. 1 of Klickitat County Intern	Combustion	13
Seattle (Globaltex)	Globaltex Industries Inc.	Coal	249
Six Prong	SeaWest Energy Group, Inc.	Wind	150
Stateline Wind Project (Wash)	FPL Energy, Inc.	Wind	40
Sumas Energy 2, Inc.	Sumas Energy 2, Inc.	Combined Cycle	530
Sumas Energy 2, Inc.	Sumas Energy 2, Inc.	Duct Firing	130
Sumner (PG&E)	PG&E Dispersed Generating Co.,	Combust Turbine	87
Tacoma (Mscg)	Morgan Stanley Capital Group, Inc.	Combust Turbine	324
Underwood	PacifiCorp Power Marketing, Inc.	Wind	70
Waitsburg	SeaWest Energy Group, Inc.	Wind	50
Wallula	Newport Northwest	Combined Cycle	1000
Wallula	Newport Northwest	Duct Firing	300
Washington (Elcap)	El Cap I	Combust Turbine	10
Wild Horse Wind Power	Wind Ridge Power Partners (Zilkha)	Wind	250

Source: PSE 2003; Makarow, pers. comm., 2003

Table 3.8-3: Washington/Oregon Generation Facilities Online in 2002

Facility	Developer	Facility Type	Size (MW)	On-Line Date
Boulder Park	Avista Corp	Intern Combust	25	5/31/2002
Centralia (TRAENE)	TransAlta Energy Corp.	Comb Cycle	248	8/12/2002
Frederickson Power	Frederickson Power (EPCOR)	Comb Cycle	248	8/19/2002
Hermiston	Calpine	Comb Cycle	630	6/1/2002
Klondike	Northwest Wind Power	Wind	25	4/30/2002
Nine Canyon Wind Project	Energy Northwest	Wind	50	9/25/2002

Source: PSE 2003

Table 3.8-4: Washington Generation Facilities Currently Under Construction

Facility	Developer	Facility Type	Size (MW)	On-Line Date
Chehalis Power Station	Tractebel Power, Inc.	Comb Cycle	520	Qtr. 3/2003
Coyote Springs 2	Avista	Comb Cycle	260	Qtr. 3/2003
Goldendale	Calpine Corp.	Comb Cycle	248	Qtr. 2/2004
Satsop CT Project	Duke Energy	Comb Cycle	650	Construction Suspended

Source: PSE 2003

Planned Transmission Projects. Bonneville has determined that there is a need to upgrade portions of the Northwest transmission grid, and has identified nine high priority projects in Washington and Oregon that would improve Bonneville's ability to maintain reliable service to loads, integrate new generation, and restore or enhance transfer capability across key transmission paths. While none of the projects is in Whatcom County, three projects (G1, G6, and G8) would address north-south transmission capacity along the I-5 corridor. The identified priority projects are summarized below (from Bonneville 2001d).

- G1. Kangley - Echo Lake 500 kV line

  - Build approximately 9 miles of new 500-kV line from Echo Lake to a point on the Schultz-Raver 500-kV line (near the community of Kangley).
  - Move the existing Monroe-Sammamish-SnoKing 230-kV tap to the Monroe-Echo Lake 500-kV line and add a new 500/230-kV transformer at SnoKing.
  - Tap the Bothell-Sammamish 230-kV line into SnoKing.
  - Remove the Horse Ranch tap from the Monroe-Snohomish 230-kV lines and reterminate the Horse Ranch line directly to the Snohomish 230-kV bus.
  - Reconfigure Bothell substation to add fifth bus section.
  - Add another transformer bank in the Puget Sound area in 2005-2006. Possible locations are Covington or Maple Valley.

- G6. Schultz series capacitors

  - Add two 500-kV series capacitors at Schultz substation in the Schultz-Echo Lake #2 and Schultz-Raver #1 500-kV lines.

- G8. Monroe - Echo Lake 500 kV line

  - Construct approximately 32 miles of a new single-circuit 500-kV line between Bonneville's Echo Lake substation and Monroe substation.
  - Add terminal facilities at Monroe and Echo Lake substations to terminate the new line.
  - To meet the Western System Coordinating Council reliability criteria for simultaneous multiple-circuit outages, it is recommended that this line be constructed on a separate ROW, at least 1,200 feet from the existing 500-kV ROW.

Natural Gas

Transmission Facilities

Approximately 80% of the natural gas used in the Northwest comes from Canada. Natural gas exported from Canada to the Northwest and other western states uses either the Duke Energy, Inc. pipeline that transports gas through British Columbia to the border at Sumas, Washington, or through Alberta on the Alberta Natural Gas Pipeline (TransCanada) to the border at Kingsgate, British Columbia. Two interstate natural gas transmission pipelines, the Northwest Pipeline operated by the Williams Company and the Gas Transmission, Northwest (GTN) Pipeline operated by PG&E National Energy Group (PG&E), supply natural gas to the Pacific Northwest and other western states from Canada and the Rocky Mountain region. The two transmission lines interconnect just south of the Washington border near Hermiston, Oregon. Natural gas from either pipeline can be delivered to any point in the state currently served by a natural gas distribution system (Washington State Office of Trade and Economic Development [OTED] 2001a).

<u>Northwest Pipeline</u>. The Northwest Pipeline Corporation (a subsidiary of Williams Company) owns and operates a natural gas transmission system from interconnections with El Paso Natural Gas Company and Transwestern Pipeline Company near Blanco, New Mexico. Northwest Pipeline can deliver gas to northwest Washington from both the Rocky Mountains and Canada. The Northwest Pipeline connects with West Coast Energy and Sumas International Pipeline near the Canadian border in Sumas. The pipeline is a bi-directional pipeline that relies on a combination of physical and displacement capacity to meet firm contract commitments. Northwest Pipeline is a one-third owner of the Jackson Prairie Storage Project in Lewis County, Washington, and also owns and operates the Plymouth LNG facility in Benton County, Washington, both used by Northwest Pipeline to provide contract storage services. Northwest Pipeline also has contracted for underground natural gas storage capacity from Questar in the Clay Basin Field in Utah (OTED 2001b). Total firm delivery capacity of the Northwest Pipeline at the receipt point is 2,580 MDth/day (million decatherms per day).

Capacity on Northwest Pipeline is fully subscribed, although some capacity is sold under short-term arrangements. Because of the design and physical capacity of the system, under certain conditions capacity on the system becomes constrained and displacement must be used to meet contract demand (OTED 2001b).

<u>Gas Transmission, Northwest Pipeline</u>. The GTN pipeline is owned and operated by PG&E, a subsidiary of PG&E Corporation, which also owns Pacific Gas and Electric Company of San Francisco. The GTN pipeline is routed across the southeast corner of the state, interconnecting with TransCanada at Kingsgate, British Columbia; Northwest Pipeline at Spokane and Palouse, Washington, and Stanfield, Oregon; and Pacific Gas and Electric Company and Tuscarora Gas Transmission Company at Malin, Oregon (OTED 2001b). GTN also connects with Avista Utilities and Cascade Natural Gas. The GTN pipeline is a dual pipeline system consisting of approximately 630 miles of 36-inch-diameter gas transmission pipeline, and approximately 590 miles of 42-inch transmission pipeline. The GTN natural gas transmission pipelines can transport a total of 2,700 MDth/day to the Pacific Northwest, of which more than 1,800 MDth/day can be sent on to California and Nevada. In 2000, typical deliveries to the Pacific Northwest from the GTN system averaged 522 MDth/day in the winter and 300 MDth/day in the summer (OTED 2001b).

GTN has 2,732 MDth of firm transportation capacity under contract, or 100% of its nominal transportation capacity. Nearly all of these contracts have expiration dates in 2005 or later. The majority of gas transported by large customers like Pacific Gas & Electric Company is passing through the GTN system en route to California. The exceptions are Avista Corporation, Northwest Natural Gas Company, Puget Sound Energy, Pan-Alberta Gas (US), Inc., PanCanadian Energy Services, Duke Energy, and Chevron USA Inc., all of which deliver to points in Washington and Oregon (OTED 2001b).

Ferndale Pipeline. Within the Cherry Point industrial area, the Applicant and Alcoa jointly own the proprietary Ferndale gas pipeline that transports natural gas from the Sumas gas-trading hub to the BP Cherry Point Refinery and the Alcoa Intalco Works aluminum smelter. Arco and Alcoa constructed the Ferndale pipeline in 1990 to provide natural gas service to the BP (formerly Arco) Cherry Point Refinery and the Alcoa Intalco Works facility. The 16-inch pipeline extends for approximately 31 miles.

The Ferndale pipeline has a nominal design capacity of approximately 104 million standard cubic feet per day, or approximately 104,000 decatherms per day (Dth/d), with a supply pressure of 500 psig at Sumas and a minimum delivery pressure of 350 psig at Cherry Point. Current demands on the Ferndale pipeline typically range from approximately 6,000 to 38,000 Dth/day, with average demand typically in the 15,000 to 20,000 Dth/day range. An 8-inch lateral line continues south from the BP Cherry Point Refinery to supply Alcoa Intalco Works (Torpey, pers. comm., 2002).

Cascade Natural Gas Pipeline. Cascade Natural Gas owns a second distribution pipeline in the Cherry Point industrial area that parallels Grandview Road adjacent to the refinery and provides gas to the PSE Point Whitehorn generation facility. This pipeline previously transported natural gas to the refinery until the Ferndale pipeline was constructed in 1990.

Georgia Strait Crossing Pipeline (Proposed). A third natural gas pipeline has been proposed within the Cherry Point industrial area. BC Hydro and the Williams Company have formed a joint venture to construct the GSX pipeline. The proposed project would include 32 miles of 20-inch pipeline from an interconnection station at Sumas, Washington, to a new compressor station to be constructed near Cherry Point. From the compressor station, approximately 53 miles of 16-inch onshore and offshore pipeline would be constructed to extend the pipeline to Vancouver Island, British Columbia. Within the immediate cogeneration project vicinity, the proposed pipeline corridor runs east-west along the north side of Grandview Road and would connect to a new compression station to be constructed on the west side of Jackson Road. From there, the pipeline would run south to the Strait of Georgia along the west side of Jackson Road.

The proposed pipeline would provide natural gas to Vancouver Island, and would have an initial design capacity of 95,700 Dth/d. Although providing natural gas to customers in Whatcom County is not specifically part of the GSX proposal, the project would include the installation of a tap valve assembly at the Cherry Point compression station to facilitate the potential future addition of a major industrial customer in the area (FERC 2002). See Section 3.10.5 for additional discussion of this planned project.

Transmission System Outlook. A 2001 survey of the Pacific Northwest natural gas industry prepared by the OTED concluded that the natural gas transmission system supplying Washington State is severely constrained. Among its findings, the report noted:

- The Northwest and GTN pipelines are currently operating at or near their capacity;
- There is no firm capacity available and as the load factor on the pipelines grow, the availability of non-firm capacity is likely to be limited;

- The existing pipelines are not sized to meet large new demands for natural gas;
- Demand for gas has increased at a much faster rate than expected by pipeline companies and major shippers largely because of greatly increased use of natural gas for electric generation necessitated by higher electric demand and lower hydroelectric production;
- Recent price volatility and large price differentials at various points on pipelines serving West Coast markets have demonstrated that even the existing level of gas consumption for electric generation during low water years is not sustainable with current infrastructure; and
- Meeting new demand will require major investments in pipeline capacity (OTED 2001b).

However, the report also noted that pipeline expansion activities are under way, and that these expansions will likely ease some of the constraints on the existing pipelines. The report concluded that expansions on upstream pipelines such as TransCanada and Westcoast would be required to bring additional Canadian gas supplies to the region.

Transmission System Expansion Projects. Interstate natural gas providers serving Washington have identified plans for expansion of their transmission facilities to meet current and future demand in the region. These planned projects are listed in Tables 3.8-5 and 3.8-6.

Table 3.8-5: Northwest Pipeline/Williams Expansion Plans

	Capacity (MDth/day)	Cost (million $)	Compression (horsepower)	New Pipe (miles)	Service Commencement
Columbia Gorge Expansion	50	35.5	14,600	6	Completed Nov. 1, 1999
Sumas to Chehalis Expansion	224	N/A	N/A	N/A	June 2003
Opal to Stanfield Displacement Replacement	175	125	24,000	90	Nov. 2003
Georgia Strait Pipeline	94	159	9,400	85	Nov. 2003
Grants Pass Lateral Expansion	136	64.9	14,300	45.4	Project postponed

Source: OTED 2001b

Table 3.8-6: GTN Pipeline Expansion Plans

	Capacity MDth/day	Cost (million $)	Compression (horsepower)	Pipeline (miles)	Timeline
2002 Expansion – Kingsgate to Malin	200	115	75,000	21 (looping)	June 2002
2003 Expansion – Kingsgate to Malin	200-500	--	--	--	--
(depends on interest)	TBD	TBD	TBD	Late 2003	--
Phase 2 – Vantage Pipeline	300-500 (speculative)	More than Phase 1	Much less than Phase 1	260-270 (new)	2004
Phase 3 – Alaskan and MacKenzie Delta Pipeline	6,000 – 7,000	unknown	unknown	unknown	2008

Source: OTED 2001b

Canadian Expansion Plans

Expansion of the GTN and Northwest pipelines would not result in additional ability to deliver gas to consuming areas in Washington unless pipeline capacity from producing fields in northern British Columbia and Alberta to interconnection points at Sumas and Kingsgate is also expanded. At least two options for expanding this capacity are under consideration.

<u>Westcoast Pipeline</u>. Westcoast has identified approximately 300 MDth/day of additions on its main line from the British Columbia gas fields to Sumas. These would involve a slightly higher delivery rate than the current pipeline transportation tariff. In February 2001, Westcoast announced that shippers had fully renewed all firm service on its Southern mainline transportation facilities. This means that all available annual contractible firm service on Westcoast's mainline north of Compressor Station 2 (with the exception of certain facilities in the Fort St. John area) and on Westcoast's Southern mainline from Compressor Station 2 to Sumas are fully contracted on a firm basis. Westcoast is now assessing options for expanding capacity on its Southern mainline to meet growing demand in traditional markets and new gas-fired generation in the Pacific Northwest.

<u>Southern Crossing/IPC Pipeline</u>. BC Gas is planning an extension of its existing Southern Crossing Pipeline to Sumas. The Southern Crossing Pipeline, completed in November 2000, connects the TransCanada system to the BC Gas distribution system in the southern interior of British Columbia. The current capacity is 250 MDth/day, which is used to displace capacity on Westcoast, which formerly served the southern interior areas.

The project would involve 150 miles of 24-inch pipe and additional compression, and would bring up to 350 MDth/day of new capacity to Sumas. The project is expected to cost around $300 million (U.S.), resulting in a transportation toll of approximately 34 cents per MMBtu. BC Gas is currently in discussion with TransCanada about a matching expansion of that system upstream of the interconnection point at Yahk, British Columbia. BC Gas is targeting an in-service date of November 2003.

Natural Gas Supply

In 2001, total demand for natural gas in the U.S was approximately 22.7 trillion cubic feet (tcf). Between 2001 and 2025, annual natural gas demand in the West (including Alaska, western Canadian and most of the offshore Gulf of Mexico) is projected to increase by 2.1 tcf. The U.S. Energy Information Administration estimates that national demand will increase by an average annual rate of 1.8% between 2001 and 2025, resulting in an annual consumption of 34.9 tcf by 2025 (U.S. Energy Information Administration 2003).

Projected future demand is expected to be largely driven by rapid growth in the demand for electricity generation. Most new electricity generation capacity is expected to be fueled by natural gas, and natural gas consumption in the electricity generation sector is projected to grow rapidly as electricity consumption increases. Demand by electricity generators is expected to account for 33% of total end-use natural gas consumption in 2025 (U.S. Energy Information Administration 2003).

The U.S. Energy Information Administration estimates that the lower 48 states and Canada have approximately 230 tcf of proven natural gas reserves (OTED 2001b). Total foreign and domestic natural gas supplies are projected to grow by 11.4 tcf between 2001 and 2025. Domestic natural gas production is expected to increase by 7.3 tcf, accounting for 64% of the total growth in supply, and net imports are projected to increase by 4.1 tcf, accounting for the remaining 36%.

The largest increase in domestic natural gas production from 2001 through 2025 is projected to come from the Rocky Mountain region, predominantly from unconventional sources. Rocky Mountain natural gas production is projected to increase by 2.7 tcf between 2001 and 2025. Another large increase in domestic production is projected to come from Alaska, primarily as a result of the expected completion of a pipeline from the North Slope. Alaskan natural gas production in 2025 is expected to be 2.2 tcf above its 2001 level. Other production regions, both onshore and offshore, are projected to collectively increase domestic natural gas production by a projected 2.4 tcf between 2001 and 2025.

Net imports of Canadian natural gas are projected to provide 15% of total U.S. supply in 2025, about the same as in 2001 (U.S. Energy Information Administration 2003). Canada's natural gas reserves are found primarily in the Western Canada Sedimentary Basin of British Columbia, Alberta, and Saskatchewan. A recent report from the Canadian National Energy Board estimated that 271 tcf of this resource is recoverable. At current rates of production in Canada, this is approximately a 50-year supply (BP 2002, Section 3.8).

Petroleum Products

Several petroleum fuel pipelines are located within the general vicinity of the proposed cogeneration facility; however, the project would not be connected to these pipelines. A number of petroleum products, including vehicle, equipment gasoline, and diesel fuels, and machinery lubricants are available from numerous commercial outlets in the project vicinity.

Other Nonrenewable Resources

Other nonrenewable resources in the project vicinity are primarily sand and gravel that are extracted from local sources and used locally. Primary consumption of these resources is related to construction projects (sand, gravel, and other mineral resources as used in steel, aluminum, concrete, and other building products).

Washington State is ranked seventh in the nation in annual tonnage of sand and gravel extracted and six of the top 100 producers of sand and gravel in the U.S. operate facilities in or adjacent to Whatcom County. The largest gravel mines in Whatcom County account for approximately 68 million tons of gravel, including one deposit of 12.8 million tons that is currently not permitted. Total gravel resource reserves in the County equal approximately 105 million tons. Total gravel resources that have been permitted for extraction in the County equal approximately 55.2 million tons. See Section 3.1 for additional discussion regarding the distribution of sand and gravel resources in Whatcom County (BP 2002, Section 3.8).

Renewable Resources and Conservation

Renewable resources are materials that can be regenerated, such as wood, other fibers, wind, and sunlight. Neither wind nor sunlight is present at this location in sufficient quantifiable amounts to make them usable for bulk electricity generation, given the current state of technology.

Hybrid poplar trees used for making pulp have been planted at the BP Cherry Point Refinery and approximately half an acre of these trees would be affected by the project. No specific schedule for harvesting these trees has been established by the Applicant.

The Applicant has a conservation program in place at the refinery and has conducted both energy and water audits to find ways to conserve these resources. In addition, the Applicant has a pollution prevention plan that identifies areas where it can conserve or reduce the amount of hazardous and other materials it uses at the refinery. The Applicant has committed to a resource conservation plan similar to that in existence at the refinery and would continue to seek ways to minimize the use of both nonrenewable and renewable resources.

3.8.2 Impacts of the Proposed Action

Construction

<u>Cogeneration Facility, Refinery Interface, and Other Project Components</u>

Construction of the cogeneration facility, systems, and components that interface with the refinery, construction laydown areas, wetland mitigation areas, facility access roads, and industrial water supply modification at Alcoa Intalco Works would require the use of both nonrenewable and renewable resources. Required resources would include such materials as gravel, sand, steel, glass, concrete, asphalt, paper products, and wood. The demand for these materials would primarily be associated with project construction; large quantities of these materials would not be required on an ongoing basis during operation of the proposed project. The approximately half-acre of existing hybrid poplar trees on the project site would be removed as part of cogeneration project site preparation.

Construction would also consume various forms of energy, including electricity, natural gas, and petroleum products. The use of these resources would continue after the cogeneration facility is operational. A discussion of the impacts related to the use of energy and materials during the construction phase of the project follows below.

Energy Resources

<u>Electricity</u>. During construction, electricity would be used for lighting and heating in construction offices, temporary lighting at the facility, and to power various pieces of construction equipment. During non-working hours, electricity consumption would include lighting for security purposes. The estimated peak electrical demand during construction is 2.5 million volt amps at 480 volts.

Natural Gas. Natural and propane gas would be consumed in very small quantities during the construction process. Typical uses would include the operation of construction equipment and heaters.

Petroleum Products. During construction, diesel fuel and gasoline would be delivered to the project site by trucks and would be consumed by portable generators, vehicles transporting workers and materials, and other construction equipment. It is estimated that construction of the proposed project would consume 592,000 gallons of petroleum products.

Other Nonrenewable Resources

Other natural resources that would be used in the construction of the project include imported fill, sand, gravel, concrete (from aggregate, sand, cement quarries, and pits), and steel (from iron ore). Table 3.8-7 lists estimated quantities of materials to be used during construction of the proposed project. This list does not include bulk materials included in equipment packages or systems purchased from equipment suppliers.

Table 3.8-7: Construction Materials and Commodities Consumed

Material	Quantity
Imported Fill	126,000 cubic yards
Sand	7,500 cubic yards
Gravel	18,150 cubic yards
Concrete	25,200 cubic yards
Steel	1,050 tons

Source: BP 2002, Section 3.8

Acquisition of fill material, sand, and gravel would be the responsibility of the construction contractor, who would be required to obtain these materials from an approved source. In Whatcom County, total gravel resources that have been permitted for extraction equal approximately 55.2 million tons. Based on estimates developed for construction of the cogeneration facility, approximately 27,000 tons of gravel would be required. This amount of gravel represents a small percentage (less than 0.05%) of the permitted local supply; therefore, the construction of the cogeneration project is not expected to significantly affect local availability of this resource.

Transmission Facility and Custer/Intalco Transmission Line No. 2

Aluminum, steel, wood, gravel, sand, concrete, and other nonrenewable material would be used to construct the transmission line's tower structures and foundations, conductors, insulators, and other transmission line components. Aluminum and steel would be obtained from mills and fabrication facilities. Sand, gravel, and crushed rock would be obtained from approved local sources. Some petroleum-based fuels would be used for construction vehicles and equipment.

Operation

<u>Cogeneration Facility, Refinery Interface, and Other Project Components</u>

Energy Resources

The cogeneration facility design includes high efficiency natural gas combustion turbines, heat-recovery steam generators, a steam turbine generator, and an integrated steam system to supply the BP Cherry Point Refinery. In addition to generating electrical energy, the cogeneration facility would generate steam for use at the refinery. The cogeneration facility is projected to export approximately 4,200 million pounds (MMlb) of steam per year to the refinery based on a rate of approximately 510 thousand pounds per hour (kpph) and a pressure of 600 pounds per square inch (psi). The Applicant anticipates that the cogeneration facility and the refinery would execute an operating agreement that would specify the terms and conditions under which the cogeneration facility would provide the refinery with electrical power and steam to ensure a reliable supply of these energy sources for the refinery (Torpey, pers. comm., 2003). See Section 2.2 Description of the Proposed Action for an operational overview of the proposed facility.

Cogeneration offers efficiency and environmental benefits because it turns otherwise wasted heat into a useful energy source. The main benefit of cogeneration is the more efficient use of fossil fuels when used for the generation of electricity and production of steam. The efficiencies arise from the use of the latent heat of the steam in the refinery. This heat would otherwise be lost in the steam turbine condenser. Thus, cogeneration eliminates the need to burn additional fuels for the sole purpose of providing steam. This normally reduces the overall costs of producing electricity and heat because less fuel is consumed.

<u>Electricity</u>. The primary purpose of the cogeneration facility would be to generate electrical power and steam for the refinery. The projected electrical power that would be produced by the facility's four generators (three gas turbines and one steam turbine) is shown in Table 3.8-8. The power output estimate reflects the maximum annual electrical energy output, and assumes 94% availability of the cogeneration facility to allow for routine scheduled maintenance activities that would require taking the facility's generators off-line temporarily from time to time. The actual output may be less depending on market conditions, but in all cases would include provision of electrical power to the refinery.

Table 3.8-8: Estimated Maximum Annual Electrical Energy Output

Component	Each Train (MWh/yr)	Total (Three Trains) (MWh/yr)
Combustion gas turbine gross output (172.5 MW ea.)	1,418,787	4,256,361
Steam turbine generator gross output (214 MW ea.)	1,827,213	1,827,213
Gross power output	3,246,000	6,083,574
Auxiliary power used by cogeneration project		146,325
Net power output		5,937,249

Source: BP 2002, Section 3.8
Notes: Basis - Average ambient conditions at 50^0F, 44% relative humidity and lower heat value fuel, 94% capacity factor.

The cogeneration facility is projected to consume approximately 146,325 MWh of electrical power annually during operation at 94% capacity factor and would supply its own electrical energy from its own generators. For initial startup power or to restart the entire cogeneration unit, power would be back-fed from the Bonneville system via the 230-kV transmission system. The general cogeneration facility components that consume power are shown in Table 3.8-9.

Table 3.8-9: Cogeneration Facility Power Demand

Cogeneration Facility Component	Power Demand
Station power (cogeneration facility auxiliary load)	17.8 MW
Natural gas compression station	3.5 MW
Total project auxiliaries	21.3 MW

Source: BP 2002, Section 3.8

Electrical energy produced in excess of the operating needs of the refinery and the cogeneration facility (up to approximately 635 MW) would be exported from the site to the Northwest power grid through the 230-kV transmission system to the Bonneville transmission system. Electrical power transmitted to the Northwest power grid is sold to public utility districts, city light departments, and rural electric cooperatives from within the region. Regional power customers include public agencies, investor-owned utilities, and a number of large industrial concerns. After Northwest customers are served, Bonneville sells any surplus power to utilities outside the region.

Bonneville has determined that modifications would need to occur to the Bonneville system to accommodate the cogeneration facility's interconnection. Two interconnection options have been identified.

Option 1 – Remedial Action Scheme. Under Option 1, a RAS would install additional electrical equipment within the Custer and Intalco substations, which would automatically reduce the load at Alcoa Intalco Works if thermal operating limits were to be exceeded on the Bonneville transmission lines. This option would require an operating agreement among the Applicant, Alcoa Intalco Works, and Bonneville.

Option 2 – New Transmission Line. Under Option 2, a second 230-kV transmission line would be installed between the Custer substation and the cogeneration facility's interconnection to increase transmission capacity along this segment of the Bonneville transmission system. Refer to Chapter 2 for additional discussion of the Bonneville transmission system's interconnection options.

Natural Gas. The cogeneration facility would use natural gas as its only source of fuel to generate electrical power. The source of natural gas for the project would be the Sumas gas-trading hub. Although the Applicant has not made a commitment to purchase natural gas from a particular provider, it is anticipated that natural gas would be supplied by the Sumas hub via the existing Ferndale and/or Cascade pipelines that are routed through the refinery in the utility corridor immediately east of Blaine Road. A new natural gas pipeline interconnection would be installed within the refinery at the existing Ferndale pipeline metering station. At this time, the Applicant has not determined who would design, construct, own, or operate the proposed pipeline interconnection.

Natural gas would be delivered to the project at a pressure of approximately 250-300 psig. The cogeneration facility and some refinery operations require a higher fuel pressure, so a natural gas compressor station would be constructed in the refinery to raise the pressure of the gas to approximately 500 psig. At this time, it has not been determined who would design, construct, own, or operate the natural gas compressor station.

The annual natural gas consumption for operation of the cogeneration facility would be approximately 42,457,356 MMBtu, or approximately 43 MDth as shown in Table 3.8-10. This projection reflects 94% availability of the cogeneration facility because of the need for scheduled routine maintenance shutdowns. The consumption estimates also depend on actual cogeneration facility output, which may be less depending on market circumstances.

The cogeneration facility's projected annual natural gas consumption would be relatively small in comparison to the region's existing and projected future supply, and would not be expected to significantly affect the overall supply for other users in northwest Washington.

The proposed project would, however, have an effect on the transmission capacity of the Ferndale pipeline. Although a new compression station would need to be installed in the refinery to provide “end of the line” compression that would increase the capacity of the pipeline to approximately 130,000 Dth/d, there may be periods when the combined demands of the cogeneration facility and the refinery exceed the pipeline's increased delivery capacity. During periods of peak demand, the Applicant estimates that up to about 40,000 Dth/d of additional capacity of may be needed. The Applicant anticipates that the additional natural gas would be supplied by a third party in the area with extra capacity (Torpey, pers. comm., 2002).

The cogeneration facility would not have an alternative or emergency source of fuel if natural gas were not available. In the unlikely event that gas supplies are curtailed, the cogeneration facility would go through a series of steps to reduce power and steam production. If the natural gas supply were completely curtailed, the cogeneration facility and the refinery would not be able to operate.

Table 3.8-10: Estimated Maximum Annual Natural Gas Energy Consumption

Natural Gas Energy Consumption by Facility Component	MMBtu/year (lower heat value)	
	One Train	Total (Three Trains)
Combustion gas turbine (1,613.7 MMBtu/hr lower heat value)	13,287,840	39,863,520
HRSG duct burners (105 MMBtu/hr lower heat value)	864,612	2,593,836
Total fuel (natural gas)	14,152,452	42,457,356

Source: BP 2002, Section 3.8

Notes: Basis - Average ambient conditions at 50^0F, 65% relative humidity, and 94% capacity factor.

Petroleum Products. Operation of the cogeneration facility would consume petroleum products, primarily lubricants associated with the operation of equipment and a minor amount of gas and diesel fuel for vehicles around the facility. A 1,500-kW diesel-powered emergency generator would consume diesel fuel in the event of a total grid power failure at the cogeneration facility. In addition, a 265-horsepower (hp) diesel-powered fire suppression water pump would consume diesel fuel in the event of a power failure or low water supply situation. Onsite storage capacities for the emergency generator and fire suppression water pump would be approximately 1,500 gallons and 460 gallons, respectively. The use of petroleum products at the cogeneration facility is not expected to have a significant impact on the availability of petroleum products locally.

Other Nonrenewable Resources

The demand for nonrenewable materials such as sand, gravel, and other minerals used in the manufacture of steel, aluminum, and other building products would primarily be associated with project construction. Significant quantities of these materials would not be required on an ongoing basis during operation of the cogeneration project.

The cogeneration facility would use various chemicals during operation to facilitate desired chemical reactions, control water quality, and for other facility operational purposes. See Table 3.16-5 for an estimate of the chemicals that would be used during operation and maintenance of the facility.

Transmission Facility and Custer/Intalco Transmission Line No. 2

The new 230-kV transmission system and the modifications to Custer/Intalco Transmission Line No. 2 would be permanent additions to the Bonneville transmission network. Over the life of the transmission line, relatively small quantities of fuel for maintenance vehicles and helicopters engaged in transmission line surveillance and monitoring would be consumed. Small amounts of electricity would be consumed to maintain and operate equipment at the Custer substation. Road maintenance activities would require the use of crushed rock, gravel, and sand over the years on an as-needed basis. Periodic replacement of conductor wires, ground wires, fiber-optic cables, insulators, and structural elements may be required over time. The quantities of fuel and materials required for operation and maintenance activities would not be sufficient to create impacts on the availability of fuel and materials locally, regionally, or nationally.

3.8.3 Impacts of No Action

Under the No Action Alternative, the cogeneration facility, refinery interface, 230-kV transmission facility, and other project components would not be constructed and the consumption of energy or natural resources associated with construction and operation of the project would not occur. The Applicant would likely continue to meet the electrical power needs of the refinery with a combination of onsite generation and purchase of electrical power from other sources. The existing refinery boiler system would continue to be used to meet the refinery's steam demand.

Under this alternative, the cogeneration facility would not generate and transmit electrical power for use on the Northwest power grid. The No Action Alternative would not remove the need for power production; it would potentially transfer the impacts to another site and potentially another technology. There would be no increase in the power supply reliability for the BP Cherry Point Refinery and no contribution to new electrical generation required to meet increasing power demands in the Pacific Northwest and adjoining regions.

3.8.4 Secondary and Cumulative Impacts

The project would consume 42,457,356 MMBtu (approximately 43 MDth) of natural gas annually in the production of electrical energy and steam. The proposed project would result in an incremental contribution to the regional demand for natural gas, however, and given existing natural gas transmission system capacity in the region, would represent an additional increment of demand on the system.

The project would use 146,325 MWh of electrical power annually in the generation of electricity and steam. However, the overall impacts of electrical energy use would not be significant compared to the total amount of energy being produced by the proposed facility. Operation of the cogeneration facility would cumulatively add to the availability of energy in the Pacific Northwest by generating up to 635 MW of electrical power for distribution on the Northwest power grid.

Approximately 176,850 cubic yards of sand, gravel, fill dirt, and concrete, and 1,050 tons of steel would be used to construct the cogeneration facility, representing an incremental contribution to the regional consumption of these resources. Total permitted gravel resources in Whatcom County are estimated to be approximately 55.2 million tons. The proposed project would use less than 0.05% of the total permitted gravel sources in Whatcom County and would not result in a significant cumulative impact on these resources.

3.8.5 Mitigation Measures

Construction

The Applicant has proposed the following mitigation measure to minimize impacts on natural resources and energy associated with the construction of the project:

- Conservation of energy and natural resources during construction of the cogeneration facility could take place through the implementation and use of industry standard BMPs by the selected contractor. These BMPs may include using energy-efficient lighting, lighting only critical areas during non-working hours, encouraging carpooling, scheduling construction crews efficiently, minimizing idling of construction equipment, recycling used motor oils and hydraulic fluids, and installing signs to remind construction workers to conserve energy and other resources.

Although not proposed by the Applicant, the following mitigation measure could be implemented to minimize impacts on natural resources and energy associated with the construction of the project:

- Construction could be coordinated with energy and natural resource providers to ensure that other users in the area would not experience any service interruptions. For example, as part of the proposed project, modifications to the natural gas pipeline that supplies Alcoa Intalco Works are proposed at the Ferndale metering station. This work could be coordinated with Ferndale pipeline staff and the management of Alcoa Intalco Works to ensure that the required piping modifications do not disrupt natural gas service to Alcoa Intalco Works or that any necessary disruptions are minimized.

Operation

The Applicant has identified the following mitigation measures to reduce potential impacts on energy and natural resources during operation and maintenance of the project:

- Because the cogeneration facility would produce enough steam to meet the operating needs of the refinery, the existing boilers currently providing steam to the refinery would be taken out of service.
- The cogeneration design of the facility would provide for a more efficient use of natural gas by using the residual steam from the cogeneration facility to meet the needs of the refinery, as compared with a combined-cycle plant without cogeneration capability.

3.8.6 Significant Unavoidable Adverse Impacts

The proposed project would consume approximately 42,457,356 MMBtu (approximately 43 MDth) of natural gas annually in the production of electricity and steam for the BP Cherry Point Refinery and electrical power for distribution on the Bonneville transmission system. However, the project design features high efficiency natural gas combustion turbines used in a cogeneration facility design. This design provides for a more efficient use of fossil fuels in the generation of electricity and production of steam.