2.1 Description of the Proposed Action: Renewal of Right-of-Way

This subsection provides an overview of the system's major components, as well as projections for future use and maintenance. For purposes of this Environmental Report, the proposed action is renewal of the Federal Agreement and Grant of Right-of-Way for the Trans-Alaska Pipeline (Federal Grant). The Trans Alaska Pipeline System (TAPS) is defined in Stipulation 1.1.1.22 of the Federal Grant to include:

> "...all facilities located in Alaska used by Permittees in connection with the construction, operation, maintenance or termination of the Pipeline. This includes, but is not limited to, the Pipeline, storage tanks, Access Roads, communications site, airfields, construction camps, materials sites, bridges, construction equipment and facilities at the origin station and at the Valdez terminal. This does not include facilities used in connection with production or oil or gathering systems, nor does it include such things as urban administrative offices and similar facilities which are only indirectly involved."

Thus, Section 2.1 describes all of these elements of TAPS including facilities integral to TAPS but on fee-simple land and not part of the ROW (e.g., Valdez Marine Terminal, Pump Station 1) and other facilities used in operation such as access roads, the fuel gas pipeline, material sites, the Dalton Highway, etc. However, Alyeska operates the Ship Escort/Response Vessel System (SERVS) to provide spill prevention and response in support of the tanker trade, and discussion is provided in this section for convenience.

2.1.1 Trans Alaska Pipeline System

By J.D. Norton and J. Riordan

2.1.1.1 Description by Major Component

The Trans Alaska Pipeline System, which occupies 16.3 square miles in Alaska, consists of the pipeline, pump stations, Valdez Marine Terminal (VMT), and associated facilities (Table 2.1-1). The *Alyeska Design Basis Update* (DB-180) contains the approved design criteria and descriptions for all components of the pipeline system.

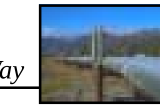
The Pipeline

The 800-mile, 48-inch-diameter crude oil pipeline begins about 6 miles from the Arctic Coast of Alaska and ends at the VMT on Port Valdez (Figure 2.1-1). The pipeline is elevated above ground for 420 miles of its length and buried for the other 380 miles. Eleven pump stations were built to move the oil through the pipeline (Table 2.1-1).

The pipe itself was specially engineered and manufactured for TAPS in two wall thicknesses (0.462 and 0.562 inches) with three grades of steel (with specified minimum yield strengths of 60,000, 65,000, and 70,000 pounds per square inch). The pipe is epoxy-coated and taped for protection from corrosion. To provide additional corrosion protection from defects in the coating or tape, zinc ribbons are buried parallel to the underground pipe and are galvanically coupled to it to provide a sacrificial anode (Figure 2.1-2). Most sections of below-ground pipe are protected by an impressed-current system.

At more than 800 river and stream crossings, the pipe either bridges the waterways or is buried beneath them. At most small streams, the pipe bridges the water channel on conventional supports. At 13 locations, however, special bridges were built: one highway bridge, nine standard plate-girder bridges, two special suspension bridges, and one tied-arch bridge (Photo 2.1-1). At critical locations where the pipeline crosses or parallels rivers, "river training structures" protect the pipeline from erosion of the river bank, riverbed, or floodplain. These structures are typically gravel embankments and riprap that deflect the river's flow.

The temperature of the composite crude oil leaving Pump Station 1 on the North Slope is around 115°F. At a flowrate of 1.0 million barrels per day (bbl/day), the oil is around 60°F when it arrives at Valdez — cooler with lower flow rates. About half of the pipeline corridor traverses ice-rich soil that becomes unstable if thawed. To avoid exposing these soils to the warm pipe, over half of the pipeline is



David Predeger

PS 1

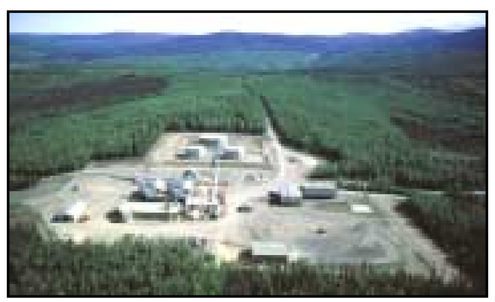
Pump Station 1 is located in the North Slope tundra lakes area. PS 1 receives and meters oil from the producers.

PS 3

Pump Station 3 provides pumping for the pipeline enroute to Atigun Pass. PS 3 has a heavy equipment maintenance facility.

PS 5

Pump Station 5 is a relief station and the first station south of Atigun Pass.



PS 7

Pump Station 7 is about 1.3 miles southeast of the Tatalina River in a wooded area. PS 7 is similar to PS 2 with two mainline pumps instead of three.

PS 9

Pump Station 9 is located in a flat area adjacent to the Richardson Highway and the adjoining Fort Greely Military Reservation.

PS 12

Pump Station 12 helps push oil over the Chugach Mountains located between PS 12 and the Valdez Marine Terminal.

Photos courtesy of Alyeska Pipeline Service Company

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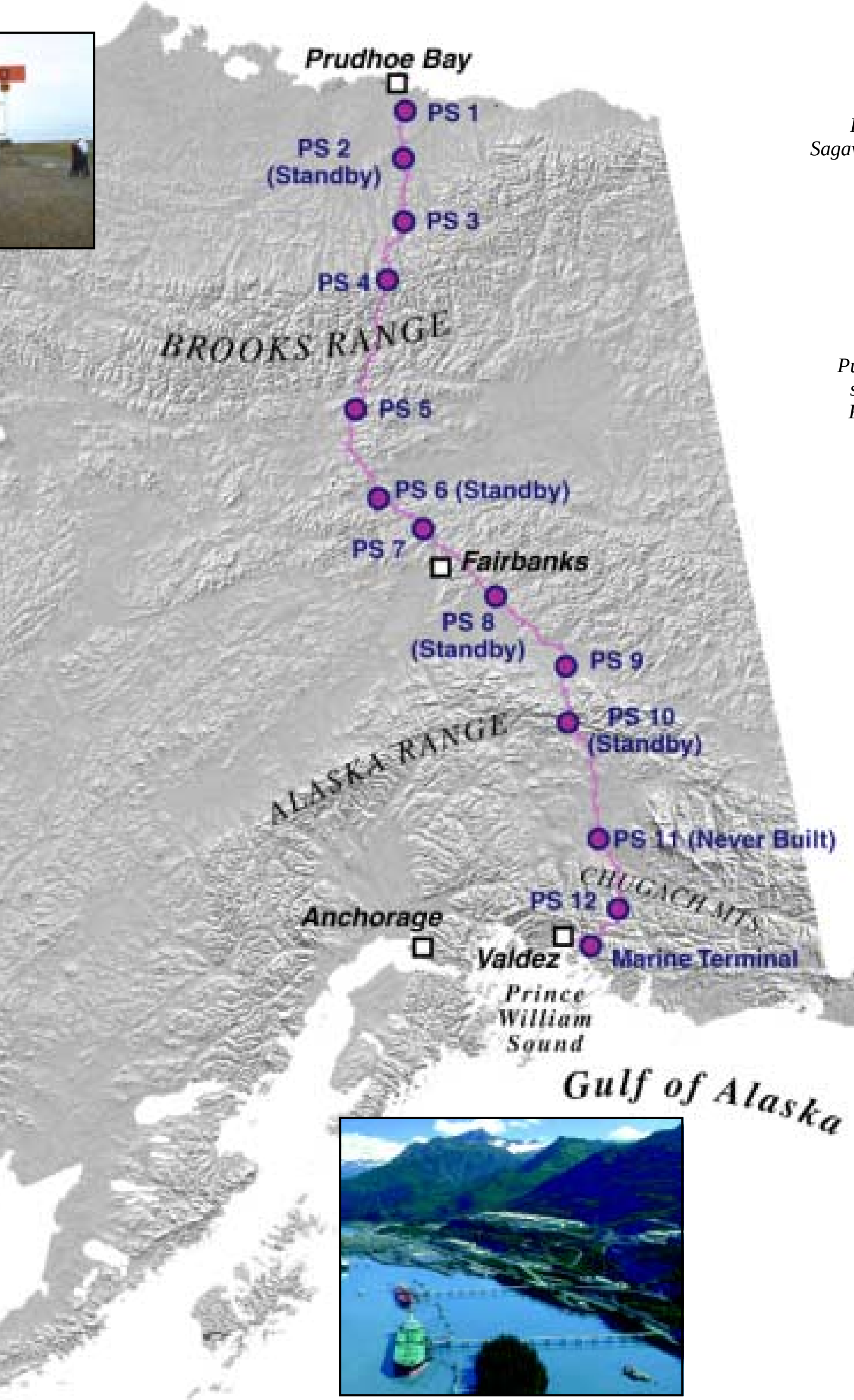
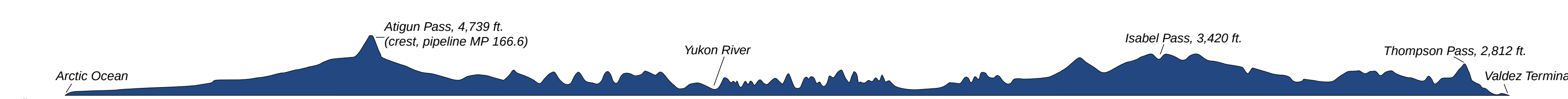


Valdez Marine Terminal.



PS 2 (currently on standby)

Pump Station 2 is west of the Sagavanirktok River and is fueled by North Slope natural gas.

PS 4

Pump Station 4 is the last pump station upstream of the Brooks Range — the highest elevation along the pipeline.

PS 6 (currently on standby)

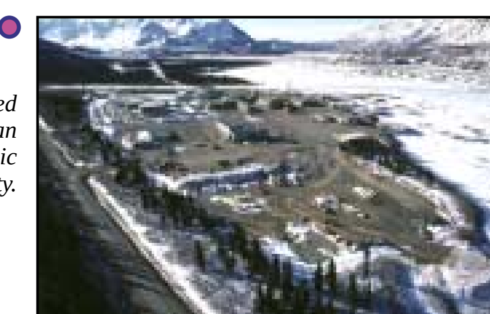
Pump Station 6 is located in a wooded area on the south bank of the Yukon River.

PS 8 (currently on standby)

Pump Station 8 is southeast of Fairbanks. The surrounding terrain is heavily wooded.

PS 10 (currently on standby)

Pump Station 10 is located near the Denali Fault in an area of high seismic probability.



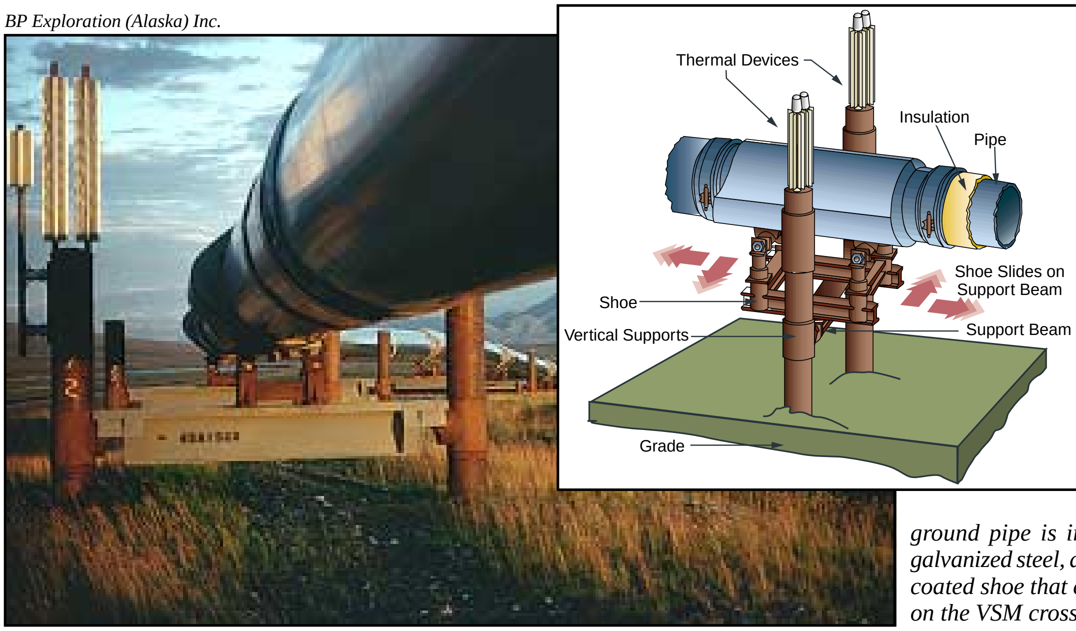
NOTE: PS 11 was never built

Figure 2.1-1.
Trans-Alaska Pipeline System.

Table 2.1-1. *Summary of major features of the Trans Alaska Pipeline System.*

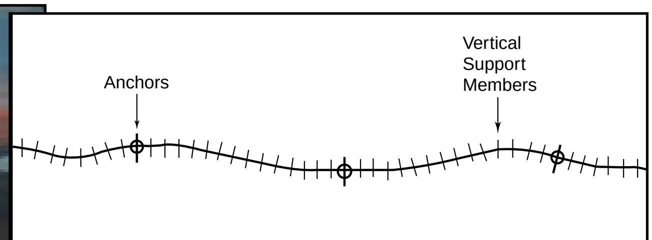
Component	Type	Data
Area Covered by TAPS	--	16.3 square miles (includes VMT)
Length of Pipeline	--	800 miles
Design Mode	Above-ground	420 miles
	Conventional below-ground	376 miles
	Refrigerated below-ground	4 miles
Typical Right-of-Way Width	Federal lands, buried pipe	54 feet
	Federal lands, elevated pipe	64 feet
	State lands	100 feet
	Private lands	54 to 300 feet
Vertical Support Members	Number	78,000
	Types	16 for different soil and permafrost conditions
	Diameter	18 inches
	Number with heat pipes	61,000
	Depth embedded	15 to 70 feet
Animal Crossings	Elevated	554
	Buried	23
	Buried (refrigerated)	2 (MP 645 and 649)
Bridges	Orthotropic box girder	1 (Yukon River: shared with Alaska Dept. of Transportation)
	Plate girder	9 (Atigun, Dietrich, Koyukuk [south and middle forks], Hammond, and Tatalina rivers; Unnamed, Hess, and Shaw creeks)
	Suspension	2 (Tanana and Tazlina rivers)
	Tied arch	1 (Gulkana River)
Pump Stations	Operating (1999)	PS 1, PS 3, PS 4, PS 7, PS 9, PS 12
	Stand-by	PS 2, PS 6, PS 8, PS 10
	Relief	PS 5
Pipeline Valves	Check valves	81
	Gate valves	95 (including pump station isolation valves)
	Ball valves	1
Fuel Gas Line	Buried natural gas pipeline	From PS 1 to PS 3 and PS 4; 8 to 10 inches diameter; approximately 144 miles long
Access Roads		Approximately 225 secondary roads (from 120 feet to 7.5 miles long) linking state roads with pipeline, pump stations, material sites, disposal sites, and airfields
Valdez Marine Terminal	Total area	1,000 acres
	Crude oil storage	9.18 million barrels total in 18 tanks (510,000 barrels each)
	Tanker berths	4 (1 floating, 3 fixed platform)
Ship Escort/Response Vessel System (SERVS)	Tugs	2 enhanced tractor tugs, 3 prevention/response tugs, 4 other
	Other vessels	10 workboats, 7 response barges, 48 mini-barges
	Skimmers	Over 70
	Containment boom	Over 42 miles
	Response centers	5 (Valdez, Cordova, Whittier, Chenega Bay, Tatitlek)
Communications Sites	Microwave stations	42 (operated by AT&T)
	Satellite earth stations	7 (operated by AT&T)
	VHF repeaters	22

BP Exploration (Alaska) Inc.

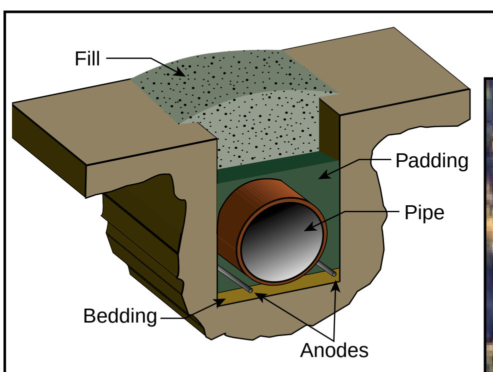


Vertical support members consist of crossbeams installed between vertical supports placed in the ground. The above-ground pipe is insulated, jacketed with galvanized steel, and mounted on a Teflon-coated shoe that can slide back and forth on the VSM crossbeams.

John Warden for BP Exploration (Alaska) Inc.



To allow for thermal expansion and contraction of the above-ground pipe, the pipeline was constructed in a flexible zigzag configuration. This design allows lengthwise expansion of the pipe to be translated into sideways movements. The photo at left shows the pipeline on the left and the Dalton Highway on the right.



Pipeline buried in the standard method lies on a layer of bedding material (well-drained sandy gravel without sharp rocks) covered with prepared gravel padding and soil fill material. The photo at right shows a transition between elevated and buried pipe.

Alyeska Pipeline Service Company

Figure 2.1-2. *Pipeline construction modes for the Trans Alaska Pipeline System.*

Photo 2.1-1. *The above-ground pipeline is carried across the Gulkana River on a tied-arch bridge (top), the Yukon River on the same bridge as the Dalton Highway (bottom left), and the Tanana River on a suspension bridge (bottom right). (Alyeska photos)*

above ground. In stable soils, where thawing would not result in disturbed terrain or pipe settlement, the line is buried. Several sections of pipe (about 4 miles total) are buried in thaw-unstable soils for big game passage and a highway crossing. These sections are mechanically refrigerated to maintain soil stability. Two sections of pipeline in Atigun Pass are buried in insulated boxes to keep the permafrost from thawing and to protect the pipeline from avalanches.

The 420 miles of above-ground pipeline are supported by vertical support members, or VSMs, located about every 60 feet (Figure 2.1-2). Anchor structures approximately every 800 to 1,800 feet hold the above-ground pipe in position. Between anchors, the pipe can move up to 170 inches side-to-side for thermal expansion and seismic movement. The pipeline crosses five seismic zones and is designed and constructed to withstand the most severe earthquake that could reasonably be expected within each zone. Most pump stations and the VMT are equipped with seismic instrumentation that detects, measures, and records earthquake-induced ground motion and processes the data to estimate the distribution of earthquake ground-shaking effects along the pipeline route.

Valves are strategically placed along the pipeline to isolate sections of the pipeline and minimize the size of potential spills in the event of a pipe rupture (Figure 2.1-3). Most of the gate or ball valves can be controlled from the Operations Control Center (OCC) at the VMT or from the pump stations. All valves can be operated manually for maintenance of the line or for spill isolation, if necessary. TAPS has 177 pipeline valves: 95 are gate valves (86 remote-controlled, 9 manually operated), 1 is a remote-controlled ball valve, and 81 are check valves that automatically prevent backflow when the pipeline shuts down. Eighty-five valves are above-ground and 92 are below-ground. Twenty-four of the gate valves are battery-limit valves that serve to isolate the pump stations.

Valve locations are based on environmental and resource considerations, as well as on construction and operating requirements. The valves are placed so as to limit the amount of a spill at any point to a maximum of 50,000 bbl from static drain-down. Check valves would limit backflow drainage in the event of a leak or break. Remotely operated valves are placed at major river crossings and other locations where quick closure would be necessary in an emergency. Power for each remote-control valve is provided by batteries that are kept charged by two propane-fired generators or by commercial electrical utilities where available. The batteries provide an uninterrupted power supply. Propane-fired systems serve as backup battery chargers where commercial power is the primary source.

TAPS was built from a gravel workpad ranging from 18

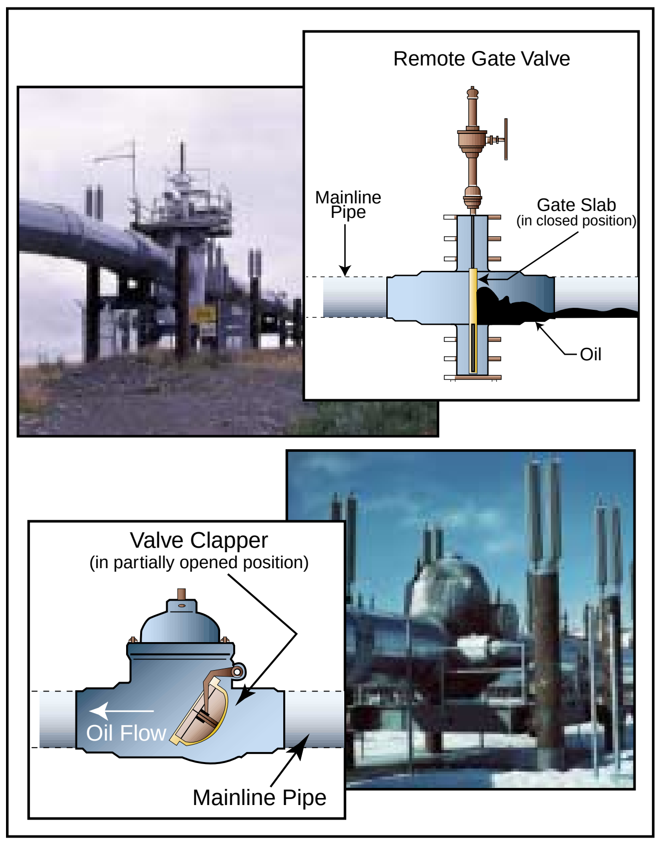


Figure 2.1-3. *TAPS gate valve (top) and check valve (bottom). (Alyeska photos)*

to 48 inches thick and designed to protect the underlying soils and provide a safe working surface for construction. The width of the workpad varies depending on the terrain, pipeline construction mode, soil conditions, and land ownership. The workpad occupies only a portion of the ROW. Typical ROW widths range from 54 feet for below-ground pipe on federal land to 100 feet on state land.

Construction actually took place on a construction zone width of up to 115 feet or more, which included the workpad as well as the pipeline itself and the spoils from the trench for the buried pipeline. This was wider than the permanent right-of-way but was permitted for use during construction. Following construction, the entire construction zone width was restored for erosion control, drainage, and revegetation. The workpad now provides access and a work platform for surveillance and maintenance and includes a 15-foot-wide drive lane along most of the pipeline.

Connections are provided from TAPS to three commercial oil refineries at North Pole and Valdez. These connections comprise offtake and return lines, isolation valves, and metering facilities. North Slope crude oil is delivered to TAPS by several feeder pipelines, including Endicott, Lisburne, Kuparuk, and Prudhoe Bay East and West (the Northstar pipeline is complete and is expected to be online in late 2001). These pipelines and the refinery delivery lines are not part of the TAPS ROW.

Pump Stations

The 11 pump stations are located at intervals of approximately 50 to 100 miles to boost crude oil pressure and provide relief tankage. Pump Station 5, however, does not have mainline pumps and serves to relieve pressure on the downslope side of Atigun Pass. TAPS was originally designed for 12 pump stations, but Pump Station 11 was not built because the development and use of drag reducing agent (DRA) allowed the numbers of downstream pump stations to be reduced (DRA is a long-chain hydrocarbon polymer injected into the oil to reduce the energy loss due to turbulence. See Section 2.1.1.2 for further discussion of DRA.)

The TAPS pump stations (Table 2.1-2, Figure 2.1-4) are similar in layout and function, although there are certain differences due to location and station tasks. The stations include pumps and turbine drivers (except PS 5), isolation valves, relief tanks with secondary containment, fuel handling facilities, station and pipeline control facilities, living facilities (except PS 1, 8, and 9), office buildings, shops/warehouses, and other facilities for pipeline operation and maintenance. A fence and round-the-clock security protect each station. Pump Station 1 has a vapor recovery system for the crude oil tanks. Pump Stations 1, 3, 4, 5, 7, 9, and 12 are currently operating (2000). Due to declining production and the use of DRA, Pump Stations 2, 6, 8, and 10 were placed on standby in 1996 and 1997 as part of the "rampdown" program. Pump Stations 7 and 12 may be placed on standby over the next 5 to 10 years, with the exact timing dependent on throughput and the economic balance between fuel and DRA costs. Table 2.1-2 summarizes the characteristics of TAPS pump stations.

The turbines at Pump Stations 1 through 4 are powered by Prudhoe Bay natural gas provided by a buried pipeline (the "fuel gas line") that parallels the TAPS crude oil pipeline from Pump Station 1 to Pump Station 4. Approximately the first 34 miles from Pump Station 1 south are 10-inch-diameter pipe, and the remainder is 8-inch-diameter pipe. Turbines at the other pump stations are powered with liquid turbine fuel, which is purchased from commercial fuel vendors who deliver the fuel in tanker trucks. If there is an interruption of natural gas supply, the turbines at Pump Stations 1, 2, 3, and 4 can be converted to operate on turbine fuel.

DRA injection facilities are located at Pump Stations 1, 7, and 9, and at Pipeline MP 238. DRA injected into the pipeline reduces the required pumping horsepower. As its name implies, DRA reduces drag, permitting more oil throughput at any given pumping horsepower.

In normal operating mode, most pump station functions are controlled from the OCC. If required, the pipeline controller at OCC can adjust pressure controls to increase or decrease the throughput, within capacity limits. Main pumps at the stations can be shut down locally or from the OCC by a single command. The speed of the turbines that drive the main pumps can be changed, and pressure controllers automatically vary pump speeds to keep line pressure within preset limits. Under emergency conditions, the OCC or the pump station control room can shut down the station and close remote gate valves (RGVs). All critical station equipment is fully automatic with local manual override capability.

Pressure relief systems at the pump stations are designed to keep the pressure from surges and other deviations from normal operations from exceeding 110 percent of the mainline pipe maximum allowable operating pressure at any point along the pipeline. The pump speed controllers keep pipeline pressure below the maximum allowable operating pressure during normal operations.

Valdez Marine Terminal

The Valdez Marine Terminal (Photo 2.1-2) is the southern terminus of the trans-Alaska pipeline and is located on

Table 2.1-2. *Trans Alaska Pipeline System pump station summary.*

Pump Station	Location (MP)	Elevation (ft)	Crude Tank Capacity (bbl)	Living Quarters (Y/N)	No. of Mainline Pumps	Turbine Fuel Capacity (bbl)	Crude Oil Topping Unit (Y/N)	Refrigerated Foundation (Y/N)	Significant Features
PS 1	0	39	420,000	N	3	10,000	N	Y	Meters; pig launcher
PS 2	58	602	55,000	Y	2	798	N	Y	Standby
PS 3	104	1,383	55,000	Y	3	20,000	N	Y	--
PS 4	144	2,763	55,000	Y	3	20,000	N	N	Pig receiver/ launcher
PS 5	275	1,066	150,000	Y	0	20,000	N	Y	Pressure relief station
PS 6	355	881	55,000	Y	3	40,000	Y	Y	Standby
PS 7	414	904	55,000	Y	2	40,000	N	N	--
PS 8	489	1,028	55,000	N	3	40,000	Y	N	Standby
PS 9	549	1,509	55,000	N	3	40,000	N	N	--
PS 10	586	2,392	55,000	Y	3	40,000	Y	N	Standby
PS 12	735	1,821	55,000	Y	3	40,000	N	N	--

NOTE: Pump Station 11 was never built. Y = yes; N = no.

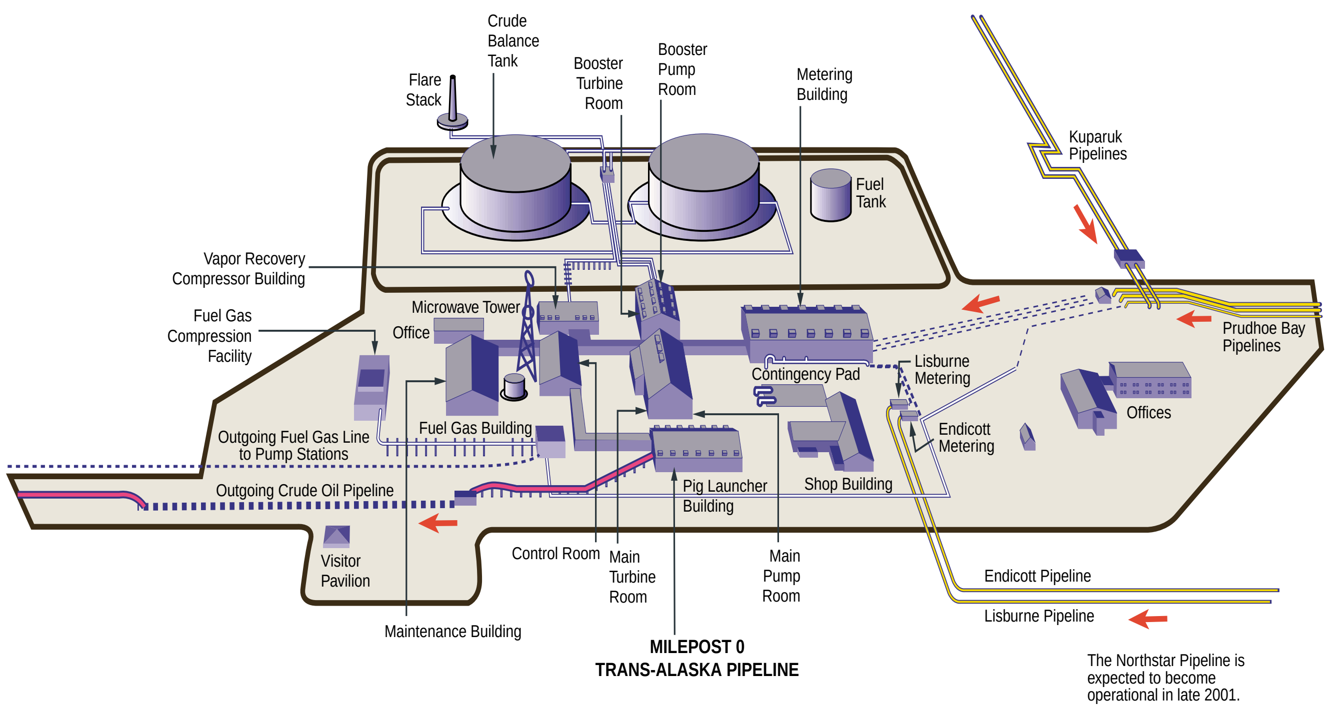


Figure 2.1-4. *Pump Station 1 at TAPS Milepost 0.*


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Photo 2.1-2. *Valdez Marine Terminal.*

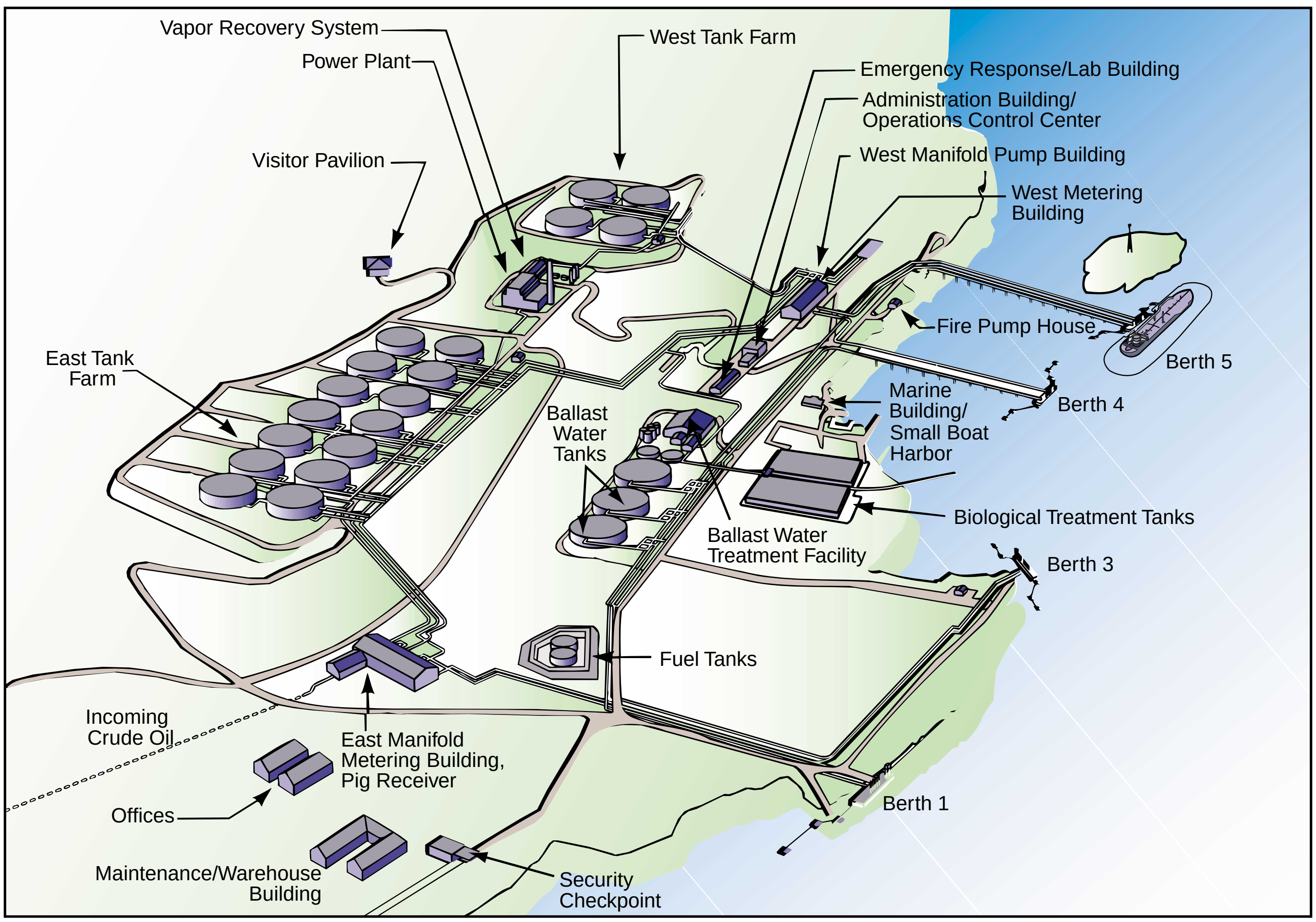


Figure 2.1-5. *Layout of Valdez Marine Terminal.*

ice-free Port Valdez at the northeastern end of Prince William Sound. The VMT site occupies approximately 1,000 acres on the southern shore of Port Valdez, extending from sea level to 538 feet in elevation at the West Tank Farm (Figure 2.1-5).

Table 2.1-3 summarizes the facilities located at the VMT, where oil is loaded onto tankers for shipment to markets. The vast majority has been shipped to the U.S. West Coast, with minor amounts to the Far East. The terminal has storage facilities for 9.18 million bbl of crude, and four loading berths. Berths 4 and 5 have vapor-control systems and will be the primary loading berths in the future. Berths 1 and 3 are not vapor-controlled but remain available for use in special situations. Future use of Berths 1 and 3 is under study.

Crude oil arriving at the VMT is measured at the East Metering Building and then goes to storage tanks or can be directly loaded onto tankers. Ballast water from incoming tankers is piped to the Ballast Water Treatment Facility for treatment before discharge to Port Valdez in accordance with state and federal permits. Vapor from tankers and crude storage tanks is piped to the vapor recovery system.

Table 2.1-3. *Valdez Marine Terminal facility summary.*

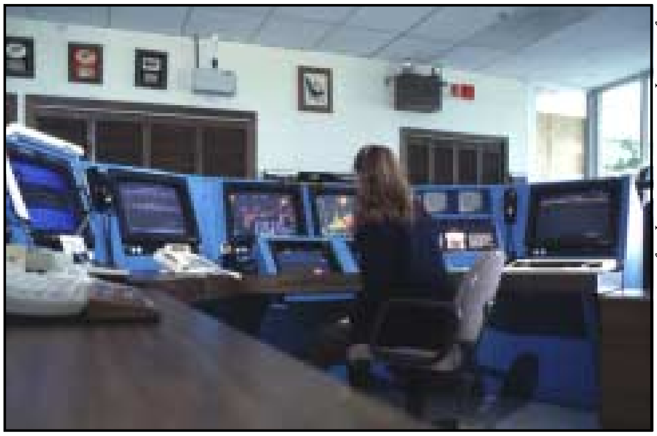
Facility	Function
Operations Control Center	• Controls entire pipeline. • Directs flow of oil to the tank farms and to vessels at the berths. • Monitors operation of the ballast water treatment system and the tanker loading berths.
18 Crude Oil Holding Tanks	• Four tanks at West Tank Farm, 14 at East Tank Farm. • Each tank has 510,000 barrels capacity; total capacity is 9.18 million barrels. • All tanks are within secondary containment and are connected to a vapor control system.
Two Manifold/Metering Buildings	• Measure incoming oil from the pipeline (East Manifold/Metering Building). • Pressure relief valves prevent incoming oil pressure from exceeding design limits and divert oil to relief tanks, if necessary. • Route oil to berth meters for loading onto tankers or to storage tanks (East Metering). • Measure oil loaded into tankers.
Four Tanker Loading Berths (1, 3, 4, and 5; 2 was never built)	• One (Berth 1) floating with up to 80,000 bbl/hr capacity. • Three fixed with up to 110,000 bbl/hr capacity each. • Two loading arms at Berth 1 can also offload fuel oil from tankers. • Berths 4 and 5 have tanker vapor collection systems.
Ballast Water Treatment (BWT) System	• All oily water collected in the VMT, including ballast water, is processed through the BWT system; handles an average of 400,000 bbl/day. • Recovered oil is returned to the crude oil system; recovers an average of 2,000 bbl/day of oil. • After treatment, ballast water is discharged into Port Valdez.
Major Support Systems	• Power generation and other utility systems • Maintenance • Security • Materials receiving and control • Emergency response (SERVS) • Tanker escort (SERVS) • Harbor facilities for support vessels • Tanker and tank farm vapor recovery

Operations and Control

Alyeska uses microwave, satellite, and radio technology for remote monitoring and control of pipeline operations. The TAPS voice communication system consists of a private telephone network and a mobile radio system. Two party-line channels on the microwave system are allocated for voice communications between all stations and Valdez. The mobile radio system consists of a VHF radio base and microwave repeater stations located at strategic sites, microwave control channels, and interconnecting links to the telephone network throughout the system.

A fiber-optic communication system has been installed along the TAPS ROW; however, its reliability has not yet proven sufficiently high for critical control-system communications. It is anticipated that the existing analog microwave system, which has demonstrated extremely high reliability in over 20 years of operation, will be upgraded to a more modern and technically superior digital microwave system for such communications. The fiber-optic network may ultimately be used for non-critical voice and data communications.

The OCC (Photo 2.1-3) continually monitors the status of all pump stations and valves using supervisory control and data acquisition (SCADA) systems with remote sensors. Data such as pressures, flow rates, temperatures, tank levels, and valve positions are recorded and analyzed for abnormal operations or any indication of a pipeline leak.



Alyeska Pipeline Service Company

Photo 2.1-3. *Operators at the Valdez Operations Control Center monitor the performance of all aspects of pipeline operation via modern communications and computer technology.*

The pipeline controller at the OCC can rectify any abnormal operation by changing settings for pump speed or relief valves or by issuing idle or stop commands to the mainline pumps. The OCC controller can also activate remote control valves. The monitoring and analysis systems include backup communications equipment and computers.

Leak detection for the pipeline consists of three independent systems: line volume balance (LVB) compares the volume of oil entering the line with the volume leaving the line; transient volume balance (TVB) compares reported flow with calculated flow and can identify the probable location of a leak by pipeline section; and alarms will signal deviations in pressure, flow, or flow rate balance.

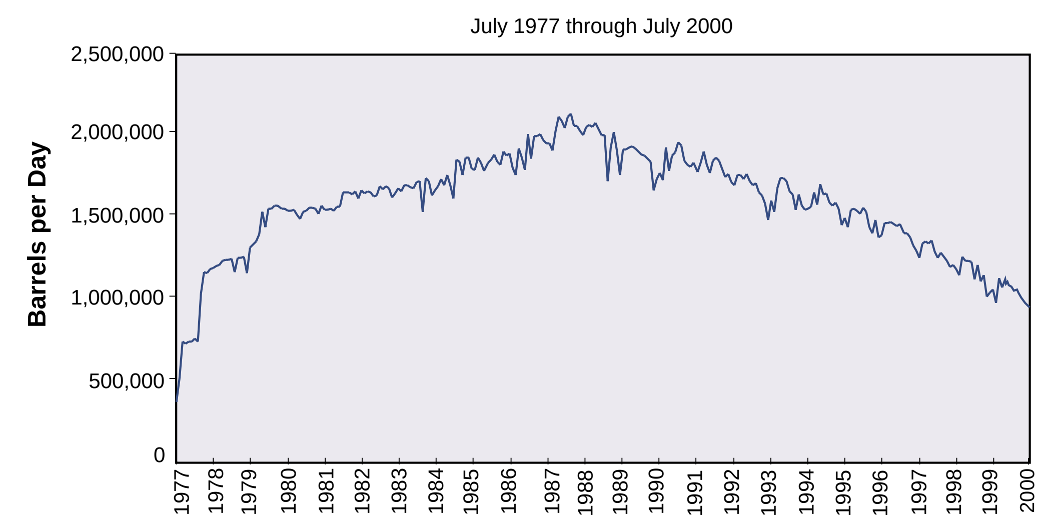
If emergency conditions occur, the pipeline controller can shut down an entire pump station and isolate it from the line, or shut down the entire pipeline. Pressure relief systems are in place to prevent overpressure during each type of shutdown.

2.1.1.2 Projected Use

The projected use of TAPS is a continuation of its current use as an oil pipeline linking the North Slope to in-state refineries and the VMT. The TAPS design was based on crude oil from Sag River State Well #1, which represented the Sadlerochit zone, the major producing zone in the Prudhoe Bay oil reservoir (APSC, 1973), but other crude oils or hydrocarbons may be safely transported. By design, crude oils from the different fields are blended at Pump Station 1. The composite crude oil is known as Alaska North Slope (ANS) crude. Since TAPS startup in 1977, additional North Slope oil fields have been discovered and developed.

Not all North Slope oil fields share processing facilities, but all use TAPS for transportation to Valdez. Consequently, TAPS allows North Slope petroleum to be marketed by providing the critical land transportation link between the North Slope oil fields and in-state refiners and waterborne tankers. Figure 2.1-6 shows the daily average oil throughput for TAPS since startup, while Appendix A addresses projected throughput estimates.

Although the projected use of TAPS is essentially a continuation of its current use, some physical changes to TAPS are anticipated during the ROW renewal period. These changes would be in response to throughput decline, re-



Source: Alyeska Pipeline Service Company

Figure 2.1-6. *Daily average TAPS throughput since startup.*

quired maintenance and repairs, and future system upgrades, and would be subject to regulatory oversight. Some of the more significant changes are discussed in the following sections.

Future TAPS Pipeline Hydraulic Configuration

Changes in TAPS to accommodate lower throughputs are expected. These changes will include standby pump stations and DRA equipment/injection enhancements to optimize the hydraulic performance. Pump Stations 1, 3, 4, and 9 are critical to moving oil though TAPS and cannot be shut down while TAPS operates. Pump Stations 7 and 12 will likely be put on standby as throughput continues to decline. At lower throughputs, slackline conditions must be managed for leak detection and DRA optimization.

Slackline occurs when the pressure exerted on the crude oil falls below its vapor pressure. This is most common on the downhill side of a slope where the leading edge of the fluid pulls away from the trailing edge. The liquid between the leading and trailing edges vaporizes to fill the void. This condition remains until the exerted pressure increases to the vapor pressure of the fluid, at which point the vapor returns to the liquid state at the slackline/tightline interface. The terms *tightline* or *packed line* refer to a pipeline that is operating at a pressure above the vapor pressure of the fluid and is completely filled with liquid (i.e., no vapor).

Slackline operation can be helpful in reducing hydraulic pressure quickly, but on the other hand, it can degrade the effectiveness of DRA. Leak detection is less sensitive under slackline conditions; therefore, more sophisticated leak detection is required for slackline operation. TAPS was designed for slackline operation, and depending on throughput, there could be as many as three slackline areas on TAPS: Atigun Pass (MP 166.7-175.6), Isabel Pass (MP 610.3-628.1), and Thompson Pass (MP 775.0-775.8) (Baskurt et al., 1998; Tonkins et al., 1998). A backpressure-control system at the VMT mitigates pipe vibrations from slackline operation at Thompson Pass (Norton et al., 1998).

Hydraulic gradient is the change in pressure of a fluid over distance. It is a function of the energy gained (e.g., from a pump) or lost (due to friction) as the fluid travels down the pipeline. The hydraulic gradient is typically represented as a saw-tooth pattern between the elevation and the maximum allowable pressure (converted to head of liq-

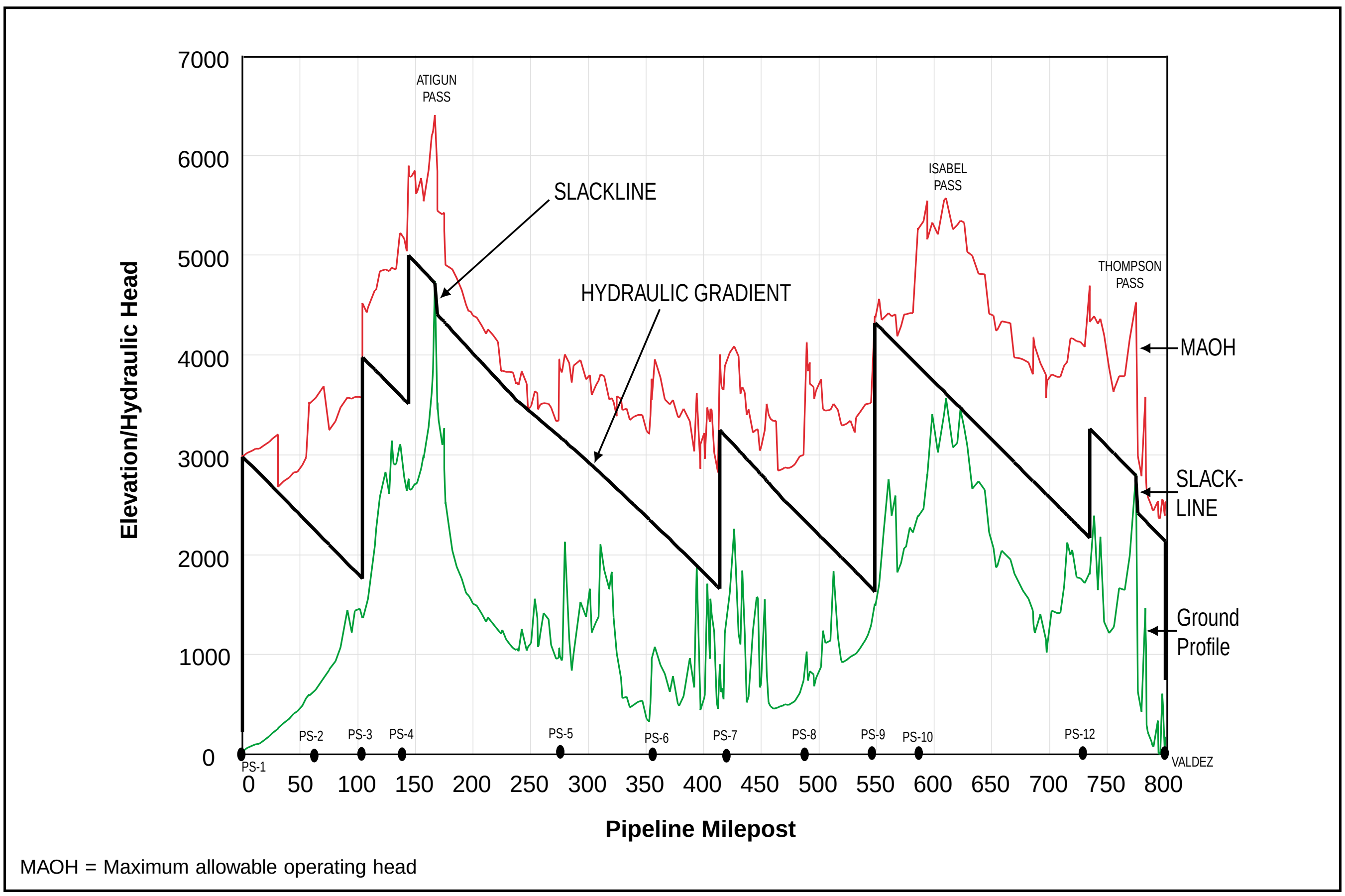


Figure 2.1-7. *Hydraulic gradient graph for operating condition of 1.1 million bbl/day with Pump Stations 1, 3, 4, 7, 9, and 12 operating; Pump Stations 2, 6, 8, and 10 on standby; and Pump Station 5 as a pressure relief station.*

uid) profiles on an hydraulic gradient graph (Figure 2.1-7). TAPS must be configured so that the combination of pumps and pipeline friction losses always maintain the hydraulic gradient between the ground profile and the maximum allowable operating head.

Drag reducing agent, or DRA, is a chemical which, when added to the crude oil stream, reduces the loss of energy due to friction as fluid travels through the pipeline (Photo 2.1-4). DRA is made of a long-chain polymer that uncoils in crude oil. DRA is believed to stretch out into stringers, reducing the friction loss between the crude oil and the pipe wall. Since slackline conditions or passage through a mainline pump easily destroys these stringers, DRA is useful only for non-slackline operation between pump stations. A flattening of the hydraulic gradient slope is evidence of the effect of DRA. DRA allows higher throughput without additional pumps and allows earlier rampdown of pump stations as throughput declines.

Projected Maintenance, Repairs, and Upgrades

Changes to TAPS due to lower throughput are anticipated to involve additional standby pump stations and equipment changes for hydraulic optimization. Other changes may include leak detection improvements or modifications necessitated by cooler crude oil. During the past 20 years of operation, changes to TAPS have already occurred as throughput increased and then decreased after 1988. Therefore, the pipeline has successfully operated at the throughput levels anticipated in the future. However, some changes are anticipated as technology improves and the pipeline matures.

Future TAPS Reconfigurations: In the future, reconfigurations of physical TAPS facilities will allow the flexibility to adapt to changes in the crude oil transported through TAPS, throughput decline, technology improvements, and optimization of support infrastructure and resource utilization.

TAPS was originally designed to transport 2 million bbl/day using 48 mainline pumps at each of 12 pump stations (3 operational and 1 spare at each pump station). During TAPS construction, DRA was introduced and eliminated the requirement for mainline pumps at Pump Stations 5 and 11. Consequently, Pump Station 5 was constructed for pressure relief purposes only and Pump Station 11 was never built. Moreover, high reliability of turbine-driven pumps eliminated the requirement for a fourth spare unit at operating pump stations, and reduced the requirement at Pump Stations 2 and 7 to two online pumps. In 2000, TAPS transports approximately 1 million bbl/day using 7 mainline pumps at 5 pump stations with 10 online spare pumps.

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Photo 2.1-4. *Drag reducing agent (DRA).*

At throughputs less than 830,000 bbl/day, only 4 pumps at 4 pump stations are required. In that case, a potential system configuration in 2010 could include Pump Stations 1, 3, 4, and 9 operating with one mainline pump unit each and Pump Station 5 operating as relief facility and cold restart contingency. Pump Stations 7 and 12 would be kept on standby with provisions for cold restart. In this configuration, most of the buildings and equipment at Pump Stations 2, 6, 8, 10, and VMT Berth 1 would be removed (Pomeroy, 2000, pers. comm.).

Reconfiguration of TAPS may also require upgrades to communications systems and pipeline control systems, as well as initiatives to further automate remaining pump stations.

- Many pump station activities that currently require manual intervention, data collection, interpretation, or decision making are suitable for automation, and upgrades to these systems could occur with reconfiguration efforts.
- TAPS voice and data communications systems are undergoing significant changes. A fiber-optic network intended to provide for higher data and voice transmission speed and capacity has been installed primarily along the TAPS ROW. The reliability of the system has not proved sufficient for critical-control system communications; however, non-critical voice and data communications capability along TAPS would be enhanced by use of the fiber-optic network. It is anticipated that the existing highly reliable analog microwave system will be upgraded to a digital microwave system. With its backup satellite capabilities, the microwave system will continue to be used for critical control-system communications. The fiber-optic network may ultimately be used for non-critical voice and data communications. Communications systems will continue to be evaluated to ensure that

the systems continues to provide a very high degree of reliability and service.

- Significant advances in pipeline control have been made in the decade since the current TAPS control system was installed. Alyeska expects to upgrade this system with reconfiguration efforts to take advantage of faster, higher-volume, better-quality information. Moreover, new-generation control systems offer improved sharing of data that is projected to increase efficiency of operation.

Mainline Pipe Repair: An instrumented internal inspection of the pipeline is performed every three years to measure corrosion or wall thinning. Based on the corrosion data, repair areas are identified and prioritized, thus allowing pipeline repairs to be performed on a schedule that ensures pipeline safety.

Over the past five years, excavations of mainline pipe have averaged 14 digs per year. This may continue and possibly will increase to 20 digs per year over the next 30 years (Flanders, 2000, pers. comm.) (see Section 4.1.1.1). However, depending on the performance of the new impressed-current cathodic-protection systems installed along the pipeline, the number of pipeline excavations may remain constant or possibly decline.

Mainline Refrigeration: Three sections of TAPS approximately 4 miles in total length near Gulkana are buried in thaw-unstable permafrost. These sites are mechanically refrigerated to prevent thawing of the soil surrounding the warm pipeline and possible settlement of the pipeline. The pipeline was buried and mechanically refrigerated rather than being built above-ground to allow for animal crossings. Wildlife data available at the time of construction were inconclusive as to whether big game animals would cross under elevated sections of pipe. Mechanical refrigeration systems may require replacement or upgrade for improved performance and durability during the ROW renewal period.

Mainline Valves: The TAPS mainline valves are periodically tested and, as necessary, repaired or replaced. Future valve replacements may include upgrades to improve functionality or durability. The work on mainline valves is scheduled to minimize impact on pipeline throughput.

Mainline Pumps: Since the mainline pumps are centrifugal and driven by turbines on variable speed control, they perform efficiently across a wide range of flow rates. During the rampup years, the number of spare pumps decreased to virtually zero as pumps were brought online to increase throughput. Moreover, modifications were made to the pumps to gain increased performance at peak throughputs. Similarly, the pumps may be modified in the future to maintain optimum performance at the lower throughputs. As throughput declines, the number of spare pumps increases.

Projected Crude Characteristics

Initially, ANS crude consisted primarily of one crude type from the Sadlerochit zone of the Prudhoe Bay oil field. As new fields were developed, the characteristics of the composite crude oil changed. TAPS was designed to handle this change. Overall, the composite crude stream has become lighter as the amount of natural gas liquids introduced immediately upstream of Pump Station 1 has increased. In addition, crude oil temperature in the line is decreasing with decreased throughput (Figure 2.1-8).

Crude composition and temperature changes may result in increased wax content, which, if not addressed, could affect the sensitivity of detection capability by smart pigs, as well as the sensitivity of the leak detection system. Waxing problems are typically handled by increased scraper pig runs, which remove wax from the internal pipe wall.

Pump Station Rampdown

A pump station becomes a candidate for *rampdown* status when the cost of adding DRA is less than cost of operating the pump station. Once ramped-down stations are isolated from the pipeline, they are placed in a standby condition that would allow restarting within 180 days in the event of unanticipated throughput increase or a contingency event at an adjacent station.

Due to declining pipeline throughput, Pump Stations 8 and 10 were placed on rampdown status in 1996, and Pump Stations 2 and 6 in 1997. Depending on economic factors, Pump Station 12 may be a candidate for rampdown when throughput declines below about 1.1 million bbl/day, and Pump Station 7 when below about 900,000 bbl/day.

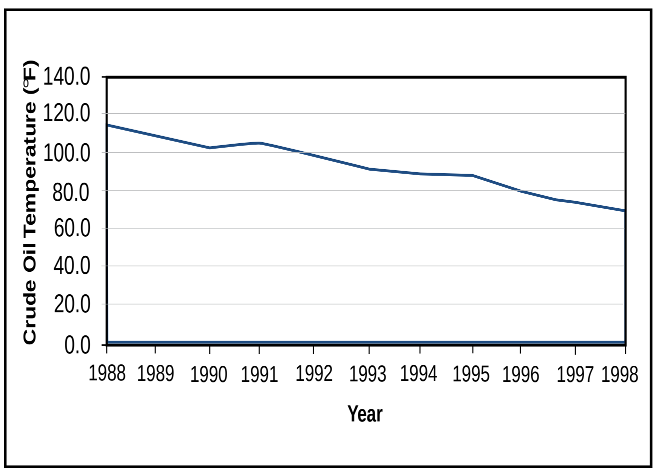

Figure 2.1-8. *Average incoming crude-oil temperature at Valdez.*

Rampdown of Pump Station 5 could occur when throughput declines below approximately 380,000 bbl/day. Pump stations are taken off-line in a different order than they were started up because of cost savings and DRA enhancements that were realized after TAPS startup.

The maximum throughput of TAPS without DRA, using the original pumping facilities and original ANS crude composition, is approximately 1.4 million bbl/day. Throughputs above this amount require DRA, whereas throughputs below this amount require less horsepower or fewer facilities. As throughput declines to the point that an upstream pump station using DRA can compensate for the hydraulic requirements for a downstream station, then the downstream station becomes a candidate for rampdown. Once the station pumps no longer operate, additional horsepower and DRA are added at the upstream station to make up for the loss in power.

TAPS is designed such that Pump Stations 1, 3, 4, and 9 are necessary to move any amount of oil. Additional stations are required with increased throughput.

Rampdown of Crude Oil Topping Units

Some pump stations have crude oil topping units (COTU), which are small refineries formerly used to produce turbine fuel from crude oil to power mainline pumps on TAPS. Although all COTUs on TAPS have already been ramped down, it is illustrative to discuss the effect of the changes to address issues relating to future configuration changes, oil spill risk from fuel hauling, and the effect of residual oil from commercial refineries that is reinjected back into the TAPS crude stream.

TAPS was originally designed for COTUs at all pump stations south of the Brooks Range (those not fueled by natural gas) due to the lack of commercially available fuel in the remote interior. During construction, it was decided that topping units would be eliminated at Pump Stations 5, 9, and 12 and the COTUs at Pump Stations 6, 8, and 10 would fuel these stations and the VMT. Consequently, TAPS mainline units representing most of the fuel needs were supplied from startup until 1997 using fuel distilled at Pump Stations 6, 8, and 10 topping plants. The topping units received crude oil from the pipeline and removed the diesel fuel portion and returned the residual oil to the pipeline. The relatively small quantity of residual oil was blended with the crude oil stream.

Since construction of TAPS, commercial refineries built in Fairbanks and Valdez have provided another source of fuel for the pump stations. When the pipeline hydraulics indicated that DRA could offset the need for fuel-burning mainline pumps at certain stations and that commercial sources of fuel could replace COTU-produced fuel, the cost of fuel produced by topping units became comparable to commercial sources. A risk assessment was also conducted that concluded that commercial purchases of fuel reduced the potential for spills from trucking accidents due to shorter distances between refineries and the TAPS fuel-burning equipment. That is, the total number of truck/tanker-miles for hauling fuel from commercial sources was less than for hauling from the TAPS topping units. Since the pump stations north of Pump Station 5 use fuel gas instead of liquid fuel for mainline pumps, only minor amounts of liquid fuel for ancillary purposes are required at those locations. Consequently, the COTUs were placed in standby status along with the rampdown of Pump Stations 6, 8, and 10, and commercial fuel purchases replaced the topping units.

The commercial refineries at North Pole and Valdez operate similarly to the TAPS topping units in that they are supplied with crude oil from the pipeline and return residual oil to a downstream location on the pipeline. Therefore, the effect on the composite crude quality due to idling of the TAPS topping units was largely displaced by the increased production from the commercial sources. In the case of fuel purchases from refineries not connected to TAPS, the effect on the composite crude oil stream is to theoretically improve it slightly due to reduced volumes of residual oil, although the effect is virtually not discernible due to the small volumes involved.

As TAPS throughput decreases, the effect of the residual oil on the composite stream will increase and will require monitoring to ensure that it does not adversely affect TAPS operations.

Cold Restart

Station facilities and insulation on the above-ground sections of the pipeline are designed to permit restarting after a prolonged winter shutdown. A 21-day shutdown was selected because it is the estimated maximum time required to make major repairs to the pipeline system. The design criteria involve a 21-day shutdown with an ambient air temperature of -40°F and a wind velocity of 20 mph.

The primary concern is the impact from gelled crude oil in the pipeline at low temperatures. Gelling results when high-molecular-weight hydrocarbons such as waxes and asphaltenes crystallize and precipitate out of solution. Since it is necessary to pump nongelled crude into the upstream end of a pipeline segment to displace the gelled crude, the hydraulic profile of the segment will develop a two-part characteristic separated by a change in slope as the injected slug moves down the line. An essential aspect of this process is the gradual increase in throughput in each segment over many hours as the high-resistance gelled crude is cleared from the segment and liquefied by friction along the wall of the pipe and from passing through the pumps at the downstream pump station.

2.1.2 Pipeline-Associated Marine Transportation

By L.D. Maxim

2.1.2.1 Tanker Traffic

Oil tankers loaded with ANS crude oil at the VMT in Port Valdez deliver crude oil to various markets. All tankers pass through Prince William Sound en route to the Gulf of Alaska, and then alter course in accordance with their destination (Figure 2.1-9).

The primary market for ANS crude is the U.S. West Coast. Small shipments also have been sent to Kenai, Alaska, and the Hawaiian Islands. On November 28, 1995, President Clinton signed legislation [30 USC 1859(s)] that authorized the export of ANS crude oil when transported in U.S.-flagged tankers. The President found that such exports were in the national interest, and in May 1996, the first shipment went to the Asia Pacific market. Laden tankers proceeding there are required to remain over 200 miles offshore, outside the U.S. Exclusive Economic Zone.

Several classes of tanker, ranging in size from 50,000 to 262,000 deadweight tons, have been involved in the Valdez trade. Cargo capacities have ranged from 660,000 to 2,000,000 bbl.

The size and composition of the tanker fleet serving TAPS will be changing over the next several years. Section 4115 of the Oil Pollution Act of 1990 (OPA 90; 33 CFR 157.10d) imposes certain requirements on tankers calling at U.S. ports and specifies which vessels are permitted to use U.S. ports by year, size of vessel (gross tons), hull design (single hulls, double bottoms, or double sides), and age of vessel. By the year 2015, all tankers calling on U.S. ports must have double hulls (double bottoms and sides). OPA 90 contains a schedule with eligibility requirements.

The current fleet serving the VMT consists of 26 tankers (NRC, 1991) — three with double hulls and 13 with double sides. However, the composition of the fleet must change in the future to stay in compliance with OPA 90. Figure 2.1-10 shows the planned phaseout schedule for existing Prince William Sound tankers based on U.S. Maritime Administration estimates published in a recent U.S. Government Accounting Office study (GAO, 1999). According to this schedule, the last of the present tankers will be phased out by the end of the year 2013, and the fleet will consist exclusively of double-hulled tankers beginning in 2014. Double-hulled tankers offer environmental advantages in terms of a reduced likelihood and volume of oil spills (NRC, 1991; NRC, 1998).

There are substantial economies of scale in the construction and operation of tankers (GAO, 1999; NRC, 1998), whether constructed in the U.S. or abroad. This consideration alone argues for construction of relatively large tankers. However, determining the optimal size for tankers serving the VMT is more complex, because draft constraints at many ports limit the utility of large tankers.

The costs of new double-hulled tankers are likely to be

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Photo 2.1-5. *Escort vessels accompany a tanker through Prince William Sound.*

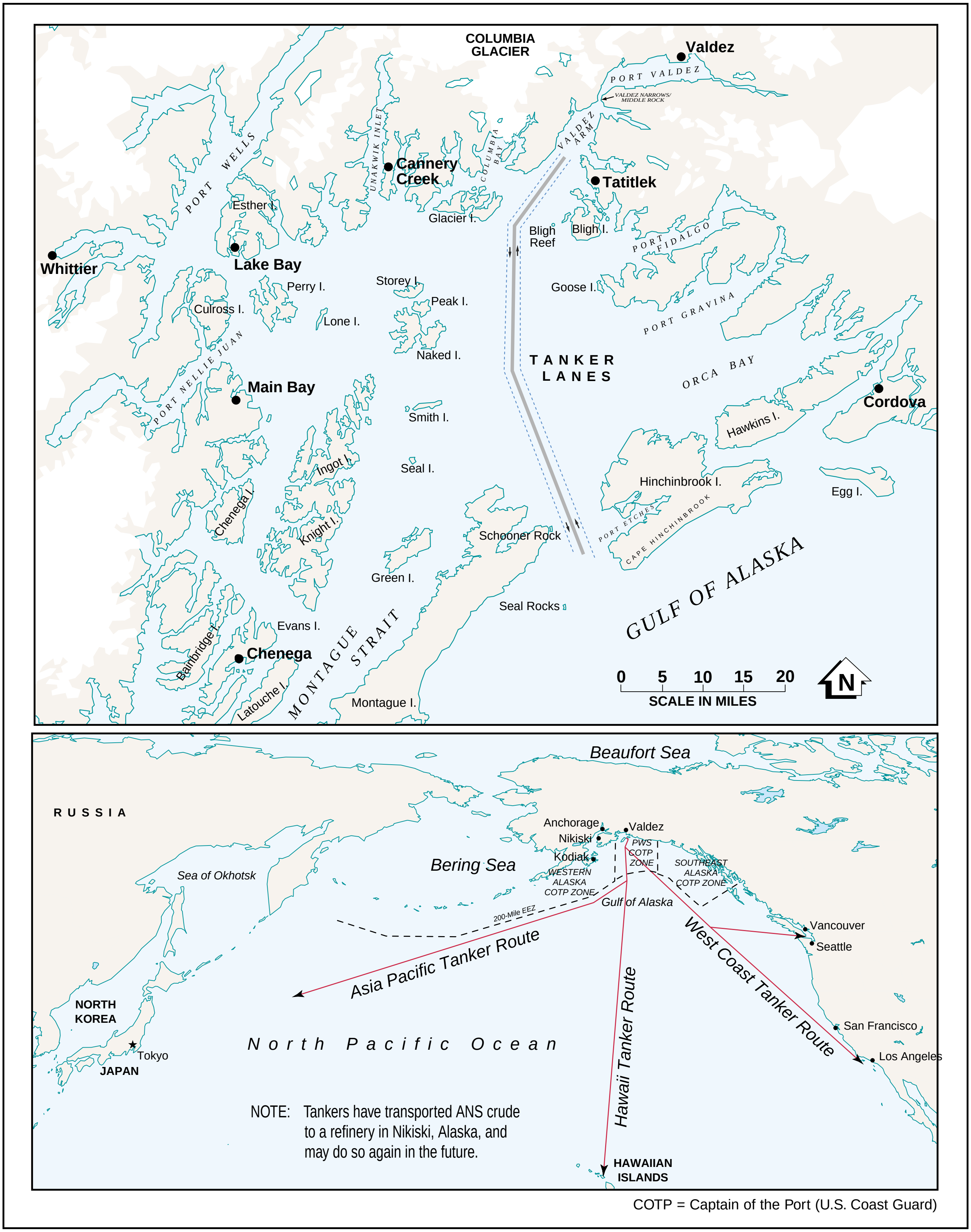
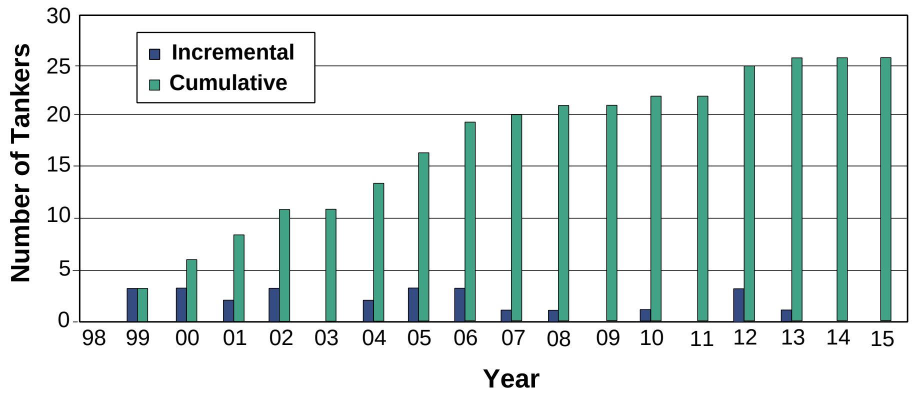
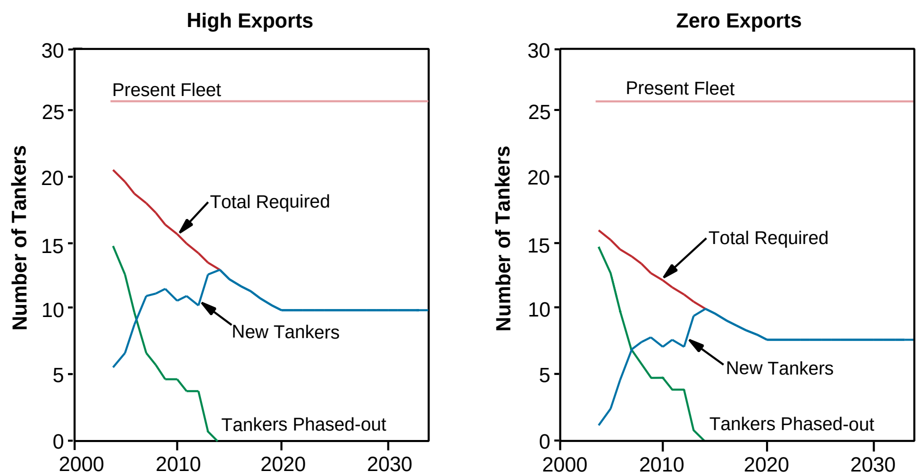


Figure 2.1-9. *Routes from Valdez for tankers carrying Alaska North Slope crude.*



Source: GAO (1999).

Figure 2.1-10. *Planned phaseout for existing TAPS-related tankers.*



Source: ECA (1999a).

Figure 2.1-11. *Tanker projections.*

comparable to those for the Phillips Millennium Class tankers currently under construction at $166 million each. Thus, the total cost of the 8 to 10 new tankers will be from $1.3 billion to $1.7 billion — a substantial investment in future marine transportation.

The number of tankers will decrease substantially from the present 26 tankers to 8 to 10 tankers by 2020 (Figure 2.1-11). Fewer tanker transits and the use of double-hulled tankers and other improvements will substantially reduce annual accident and oil spill probabilities.

A smaller tanker fleet will require fewer berths at the VMT. There are four berths at present — one floating and three fixed-platform berths. One or two of these berths may be shut down in the future. The two berths with tanker vapor control facilities will remain in operation.

Alyeska manages the largest spill response equipment stockpile in the world, including more than 70 oil-skimming systems, 7 storage barges, and 35 miles of containment boom. Equipment is stationed in Port Valdez and at five Response Centers across the Sound. In addition, Alyeska has contracts with over 300 fishing-vessel owners to respond to a potential spill. Fishermen also provide local knowledge to help identify at-risk areas and provide protection methods.

Other improvements made in the wake of the *Exxon Valdez* oil spill include:

- Regular oil spill drills and training exercises are conducted at a variety of locations along the pipeline and

in Prince William Sound.

- The Prince William Sound Regional Citizens Advisory Council was formed in accordance with the Oil Pollution Act of 1990. This citizens group has participated actively in issue related to the VMT and to spill prevention and response in Prince William Sound.

Alyeska spends $60 million annually on an organization with over 200 people engaged in prevention and response activities in Prince William Sound.

2.1.2.2 Ship Escort/Response Vessel System

Prevention and cleanup of oil spills have always figured in the design and operation of TAPS; however, in the aftermath of the *Exxon Valdez* oil spill in 1989, Alyeska, the TAPS Owners, regulators, and Congress conducted a comprehensive examination of ways to improve oil spill performance. Among other things, this resulted in the passage of OPA 90, which includes requirements for spill prevention and response.

Significant improvements have been made in spill prevention and response capability for Prince William Sound, including the creation of Alyeska's Ship Escort Response Vessel System (SERVS). SERVS is responsible for the safe transit of oil tankers from the VMT to international waters. Its duties are primarily related to spill prevention and spill response.

A study by Det Norske Veritas et al. (1996), which did not consider future benefits of double-hulled tankers, estimated that the risks of a large oil spill were reduced by 75 percent with the creation of SERVS and related measures.

SERVS has nine vessels assigned to escorting, docking, and response duties, and at least two escort vessels are required for each laden tanker transiting the sound. Tethered escort is required through Valdez Narrows. In the northern sound, the escort vessels will be within one-quarter nautical mile of the tanker when not tethered. In the central sound, a conventional tug or a prevention and response tug (PRT) will maintain close escort, while the second escort vessel goes on sentinel duty to provide response coverage to a larger area. A vessel is on sentinel duty in the Hinchinbrook Entrance area. A third escort vessel may be added, depending on weather conditions. Additional vessels are available if needed for a response or to fill in during scheduled and unscheduled maintenance.

- Currently, the three PRTs and two enhanced tractor tugs (ETTs) are designated to fill escort and response duties. These vessels carry response equipment such as boom and skimmers. The escort vessels accompanying each laden tanker monitor the vessel's actions and will radio the escorted tanker to question or alert the tanker of atypical behavior. The tanker notifies the escort vessels upon recognition of a loss of steering and/or propulsion or suspected equipment malfunction.
- The vessel stationed in the Hinchinbrook area (including Port Etches) to provide sentinel assistance to tankers in Hinchinbrook Entrance is also used as a close escort vessel for laden tankers and has open-ocean rescue capabilities.
- The two ETTs were built specifically for service in the sound and were both deployed in 1999.
- The three 140-foot, 10,000-horsepower PRTs were deployed in 2000. They have twice the horsepower and are more maneuverable than the escort/response vessels they replaced.