POINT THOMSON PROJECT

POINT THOMSON DESIGN BASIS FOR PERMITTING - EXPORT PIPELINE

USPT-WP-YBDES-060001

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Revision 3

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A	09/15/09	Issued for Client Review	PAC	JAB		

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Attachment 1: Log of Changes

LIST OF ACRONYMS AND ABBREVIATIONS

AISC	American Institute of Steel Construction
API	American Petroleum Institute
APSC	Alyeska Pipeline Service Company
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
BPTA	BP Transportation Alaska
BSOP	Badami Sales Oil Pipeline
CCR	Centralized Control Room
CFR	Code of Federal Regulations
CP	Central Pad
CFP	Central Facilities Pad
CPF	Central Production Facility
CVN	Charpy V-Notch
DR&R	Dismantle, Remove, and Restore
EMPCo	ExxonMobil Pipeline Company
ESD	Emergency Shut Down
F	Fahrenheit
FBE	Fusion-Bonded Epoxy
FDS	Fire Detection System
g	Gravitational Acceleration
HAZOP	Hazardous Operations
HCA	High Consequence Areas
IBC	International Building Code
ICSS	Integrated Control and Safety System
MOP	Maximum Operating Pressure
MSL	Mean Sea Level
MTR	Material Test Report
OIMS	Operations Integrity Management System
PCS	Process Control System
PGA	Peak Ground Acceleration
PLC	Programmable Logic Controller
PTEP	Point Thomson Export Pipeline
PTU	Point Thomson Unit

SDV	Shut Down Valve
SIS	Safety Instrumented System
SMYS	Specified Minimum Yield Stress
TAPS	Trans Alaska Pipeline System
TVA	Tuned Vibration Absorbers
UHMWPE	Ultra-High Molecular Weight Polyethylene
VSM	Vertical Support Member(s)
WIV	Wind Induced Vibration
ZPA	Zero Period Acceleration

1. INTRODUCTION

1.1 Purpose

The purpose of this document is to provide design basis for Point Thomson Export Pipeline (PTEP) supporting the Pipeline Right-of-Way Lease Application.

1.2 Background

The Point Thomson field, a high-pressure gas liquid hydrocarbon reservoir discovered in 1977, is located approximately 60 miles east of the Prudhoe Bay field. The Point Thomson field is being developed as a gas cycling project. A single production well will be drilled from a Central Pad (CP). Additional wells may be drilled from two remote onshore well pads located along the coastline. All wells will extend to a vertical depth of approximately 13,000 feet and will use extended reach drilling to reach outlying targets.

Produced gas, water, and liquid hydrocarbons, will be gathered from the wells to the Central Processing facility (CPF), where the liquid hydrocarbons will be separated from the production stream, stabilized to meet sales quality specifications and shipped via the PTEP and existing downstream pipeline systems to the Trans Alaska Pipeline System (TAPS) Pump Station No. 1 (PS-01). The gas will be compressed and re-injected into the Point Thomson reservoir at the injection well pad located immediately adjacent to the CP.

Point Thomson CPF will be staffed with full-time operations and support personnel for routine operations and maintenance activities. Transportation of personnel and light equipment to and from the site will be via commercial and charter aircraft. Sea ice roads may be constructed for access by road during the winter but will only be built when their construction is justified by special activities (e.g., rig mobilization and demobilization and construction).

1.3 Subject Facilities

The facilities to which this design basis pertains (i.e., the subject facilities) consist of the PTEP commencing at the proposed Point Thomson CP and terminating at a point of connection to the 12-inch nominal diameter Badami Sales Oil Pipeline (BSOP) near the Badami Central Facilities Pad (CFP). The route is approximately 22 miles long and is illustrated in Figure 1.1. The pipeline facilities begin upstream of the inlet valves to the launcher barrel at the CP and end at the isolation valve adjacent to the tie-in to the BSOP. The PTEP will be insulated and installed aboveground on vertical support members (VSM) for its entire length.

The minimum design clearance between the surface of the tundra, streams and lakes and lowest point of any element being support by VSM (e.g., pipe insulation, pipeline attachments such as tuned vibration absorbers, electrical/communication cables, etc.) for the PTEP is seven feet. This criterion does not apply to the actual VSM where the bottom of the lowest structural elements will be less than seven feet from the surface of tundra, streams and lakes.

This design basis sets out the criteria and standards to which the subject facilities will be designed. The purpose of this document is to establish a design baseline to which supporting design information will be compared to verify that design requirements are met.

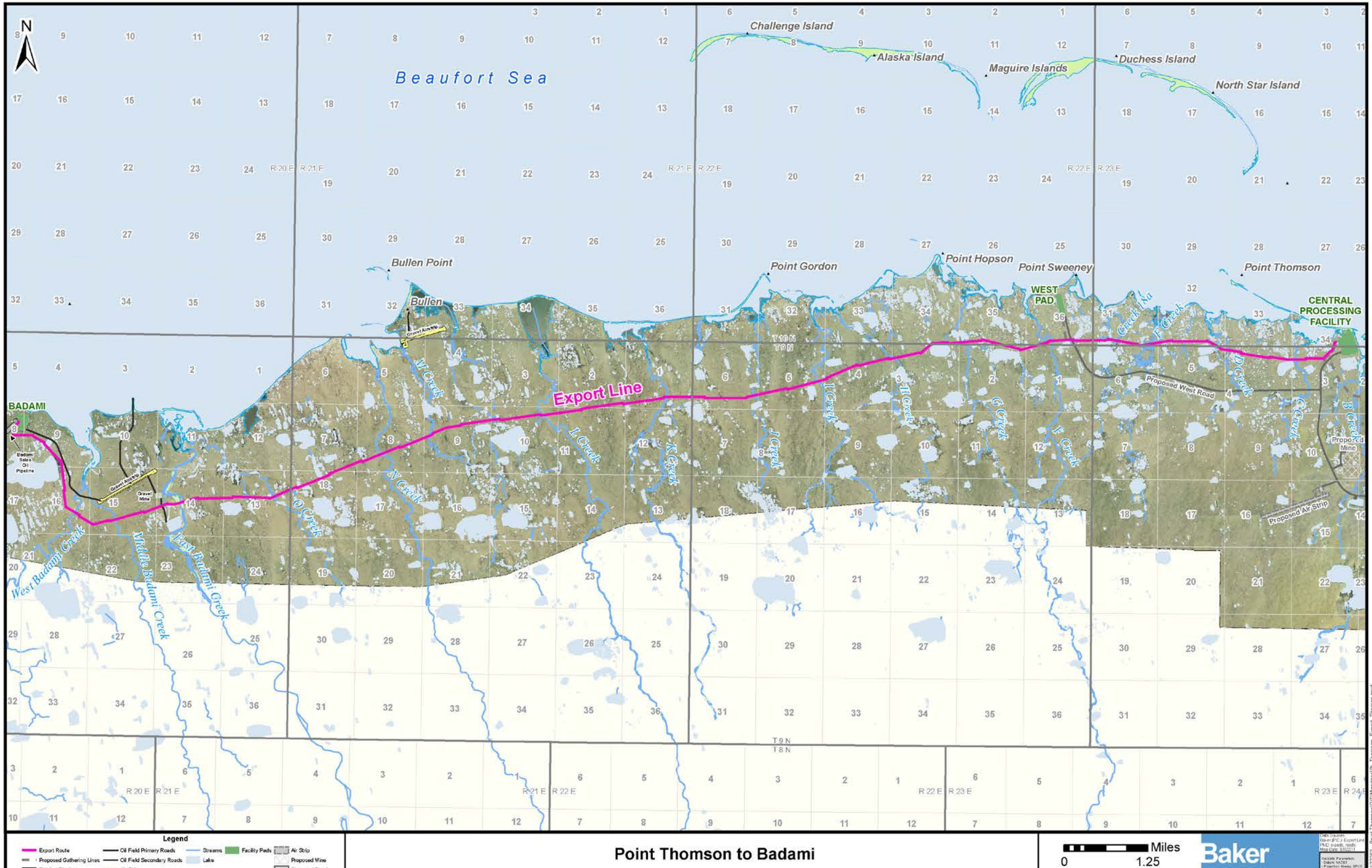


Figure 1.1 Export Pipeline Routing Map

2. GENERAL DESIGN AND CRITERIA

2.1 Liquid Hydrocarbon Properties and Characteristics

The composition of the Point Thomson liquid hydrocarbon is summarized in Table 2.1.

Table 2.1 Point Thomson Liquid Hydrocarbon Composition

Component	Mole Fractions
Nitrogen, N_2	0
Carbon Dioxide, CO_2	0.0007
Methane, C_1	0.0021
Ethane, C_2	0.0022
Propane, C_3	0.0054
I-Butane, iC_4	0.0032
N-Butane, nC_4	0.0087
I-Pentane, iC_5	0.0077
N-Pentane, nC_5	0.0108
C_6	0.0575
N-Heptane, C_7	0.0728
Octane, C_8	0.1001
Nonane, C_9	0.0832
Dodecane, C_{12}	0.3436
Heptadecane, C_{17}	0.2003
C_{27}	0.0817
C_{42}	0.0126
C_{65}	0.0031
C_{86}+	0
Water, H_2O	0.0043
TOTAL	1.00

The physical properties and characteristics of the Point Thomson liquid hydrocarbon are summarized in Table 2.2.

Table 2.2 Point Thompson Liquid Hydrocarbon Properties and Characteristics

PHYSICAL PROPERTY	VALUE @ STD CONDITIONS (0 PSIG & 60°F)	VALUE @ DESIGN OPERATING CONDITIONS (1000 PSIG AND 143°F)[1]
MW	170.4	176.0
Enthalpy (BTU/lb)	–966.9	–903
Cp (BTU/lbmole-°F)	73.39	83.39
Density (lb/ft^3)	52.46	51.4
Thermal Conductivity (BTU/hr-ft-°F)	0.08469	0.0789
Viscosity (cP)	5.046	1.94
Specific Gravity	0.841	
API Gravity	37	

[1] MOP conditions are 2035 psi and 200°F

Point Thomson liquid hydrocarbon has similar components as the fluids currently being transported through the Badami pipeline system, the Endicott pipeline system, and TAPS. The liquid hydrocarbon is therefore chemically compatible with the pipe material and has similar chemical and physical properties as the fluids being transported through the existing pipeline systems. Point Thomson liquid hydrocarbon will contain little or no sulfurous (i.e., sour) substances.

A provision in the TAPS Connection Agreement (3-06-03 revision) is that a party seeking to ship petroleum on the TAPS should provide to Alyeska Pipeline Service Company (APSC) sufficient data, petroleum sampling results, and other information to enable APSC to fully evaluate the suitability and compatibility of the petroleum stream proposed for delivery through TAPS.

PTEP Operations will ensure that the Point Thomson liquid hydrocarbon delivered through Badami pipeline system, and thence via Endicott pipeline system and TAPS will meet the BP Transportation Alaska (BPTA) connection agreement requirements for sampling result, delivery pressure, and delivery temperature.

2.2 Extent of Subject Facilities

The subject facilities design process will involve two major contractors; Michael Baker Jr., Inc. (MBJ) and WorleyParsons (WP). MBJ will design the cross-country pipelines, associated components and support structures. WP will be responsible for the integrated control and safety systems (ICSS), on-pad facilities including launcher, custody transfer meter, surveillance meter, meter prover and corrosion control and monitoring. MBJ and WP will coordinate with ExxonMobil Pipeline Company (EMPCo) to address operational needs.

The subject facilities will commence at a defined point (e.g., butt weld or flange connection), located downstream from the Point Thomson shipping pumps flow control and pressure relief facilities. The launcher barrel, its associated valves and piping; the inlet block valve on the export line, located on the Point Thomson CP; fiscal metering at the CPF; and leak detection metering at Badami are considered part of the subject facilities.

The subject facilities will terminate at a defined point (e.g., butt weld or flange connection) at the tie-in of the PTEP to the existing BSOP. The tie-in to the BSOP will be made through a piggable wye, which will be installed in the existing pipeline. Standalone PTEP supports and the portion of shared supports (i.e., supporting the PTEP and non-regulated infield gathering lines) that directly support the PTEP are considered to be part of the subject facilities. The subject facilities are illustrated schematically in Figure 2.1.

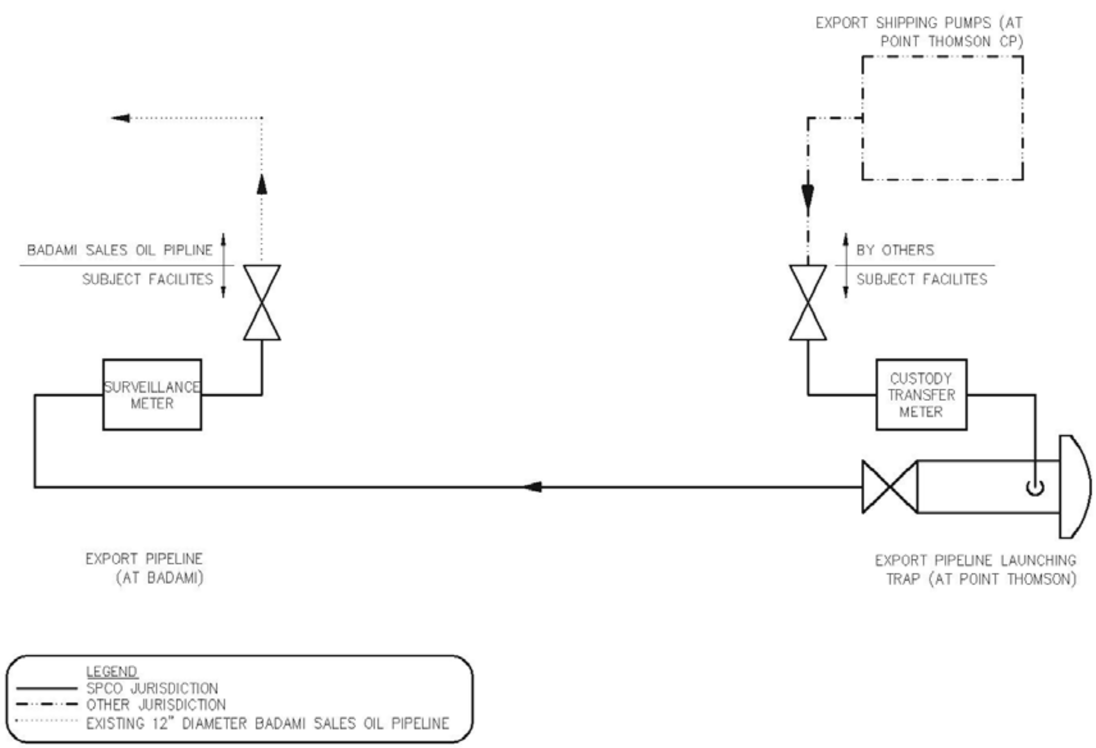


Figure 2.1 Point Thomson Export Pipeline Schematic Diagram

Leak detection meters, instrumentation, and associated signal processing systems will be installed at Point Thomson CP and at Badami. In addition, a leak detection programmable logic controller (PLC) will be installed at each end of the PTEP utilizing independent pressure signals and proprietary EMPCo software. Vertical loops will be employed as isolation devices at river crossings where applicable. The vertical loops, leak detection meters, and associated instrumentation are considered part of the subject facilities. Leak detection will be computed and monitored at the Point Thomson Centralized Control Room (CCR).

2.3 Design Life

The minimum design life of the PTEP will be 30 years and will be incorporated into applicable design criteria for the pipeline. Time-sensitive parameters (e.g., VSM creep rate) are selected based on a 30-year design life.

2.4 Regulations, Standards and Codes

The subject facilities will be designed in accordance with, but not limited to, the following regulations, standards and codes.

- Code of Federal Regulations Title 49, “Transportation,” Part 195, “Transportation of Hazardous Liquids by Pipeline,” October 1, 2008.
- Alaska Administrative Code (AAC) 18 AAC 75, Oil and Hazardous Substances Pollution Control
- American Institute of Steel Construction (AISC-303-05), “Code of Standard Practice for Steel Buildings and Bridges.”
- AISC, Manual of Steel Construction, 13th Edition
- American Welding Society (AWS) D1.1/D1.1M:2006, Structural Welding Code—Steel
- API 5L, Specification for Line Pipe, 2004
- API 6D, Pipeline Valves, Edition 22, 2002
- API 1104, Welding Pipelines and Related Facilities, 2005
- API 1130, Computational Pipeline Monitoring for Liquid Pipelines, 2002
- API RP 1102 Steel Pipelines Crossing Railroads and Highways, 7th Edition
- ASCE 7-05, Minimum Design Loads for Buildings and Other Structures, 2005
- ASME B31.4, “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids,” 2006.
- ASME B16.5-2003, Pipe Flanges and Flanged Fittings: NPS 1/2 through 24
- ASTM International A572/A572M-07, Standard Specification for High-Strength Low-Alloy Columbium-Vanadium Structural Steel
- Federal Highway Administration (FHA). 2001. Evaluating Scour At Bridges. Hydraulic Engineering Circular No. 18. Publication No. FHWA NHI 01-001. Fourth Edition. U.S. Department of Transportation. May 2001
- International Building Code, 2006

- 2008 National Electrical Code (NEC)
- NFPA 30, Flammable and Combustible Liquids Code, 2008 edition
- Alaska Safety Handbook, 2010
- North Slope Environmental Field Handbook (NSEFH), February 2005

3. PHYSICAL FEATURES/CIVIL

3.1 Topography/Oceanography

The project area is located on the Arctic Coastal Plain situated between the Beaufort Sea and the Brooks Mountain Range. The PTEP traverses the coastal zone of the Ancient Canning River Alluvial Fan, a broad, relatively flat, treeless area. The coastal zone is located within 2 to 3 miles of the coastline and at elevations of up to 25 to 30 feet above mean sea level (MSL). A poorly defined terrace face marks the transition from the coastal zone to the relatively higher, better-drained inland zone. Surface drainage in the coastal zone is characterized as channel flow, which consists of a network of shallow lakes and streams while surface drainage in the inland zone is generally not confined to defined channels and is characterized as sheet flow.

The PTEP route is located in the coastal zone and passes close to numerous shallow lakes and crosses several defined stream channels. Between lakes and streams, drainage is poor due to impermeable underlying permafrost. Runoff and water from summer thaw of the near surface soils accumulates above the permafrost table resulting in slow run-off into small streams and in the swampy character of much of the tundra during the summer.

Wind-oriented thaw lakes dominate the landscape in the coastal zone. The thaw-lake basins originate in areas of restricted drainage where shallow ponding results in a warmer surface temperature that causes the underlying ground ice to thaw resulting in subsidence. Most of the ponds and lakes are relatively shallow. The thaw lakes go through a cycle of development, expansion, drainage, and revegetation.

Topography along the PTEP route is relatively flat with the landform between drainages dominated by patterned ground. Sharp topographic breaks and features are uncommon although low ridges exist at lake and stream edges and adjacent to ice wedges. Small (e.g., typically less than one foot) seasonal variation in local tundra elevation due to freezing and thawing of the active layer is common. Other than a few remaining gravel exploration pads built and used in the 1970s, the Point Thomson area is essentially undeveloped.

The principal marine environment in the Point Thomson area is a relatively shallow marine lagoon that is situated south of a barrier island complex with water depths typically between 7 and 12 feet. Sea level variation due to tide action during the open water season is less than one foot.

The barrier island complex parallels the coast and extends approximately 18 miles from Challenge Island on the west to Flaxman Island on the east. Documents prepared for the Liberty Development Project indicate that the barrier island complex partially protects much of the lagoon in the Point Thomson area from exposure to storm waves generated in the Beaufort Sea during the open-water periods. Based on this information, it is expected that storm surges in the Point Thomson area will be generally less than 3 feet. During extreme storms, surges may reach up to 7 feet above MSL.

3.2 Climate/Meteorology

Based on Prudhoe Bay temperature normals by month between 1971 and 2000, the mean annual ambient temperature is approximately 10.7°F. Ambient temperature ranges from a highest daily average of 53.9°F to a lowest daily average of –35.8°F. The record maximum temperature is 83°F (June 21, 1991) and the record minimum temperature is –62°F (January 1989). The area annually experiences approximately 9,291 degree days °F freezing and approximately 960 degree days °F thawing.

Winds are generally from the northeast (N70°E at Prudhoe Bay to N79°E at Barter Island), but wind shifts to the west or northwest is common throughout the summer. Strong westerly and southwesterly winds periodically occur during storms. Wind data was collected at Point Thomson and Flaxman Island during the summers of 1997 and 1999 (URS 2000) and is generally consistent with the wind speed and direction recorded at Deadhorse during the same periods. Wind speed varies from a low of 11.4 mph to a high of 12.9 mph. Maximum instantaneous recorded wind speeds vary from 38 mph in early summer to 81 mph in winter.

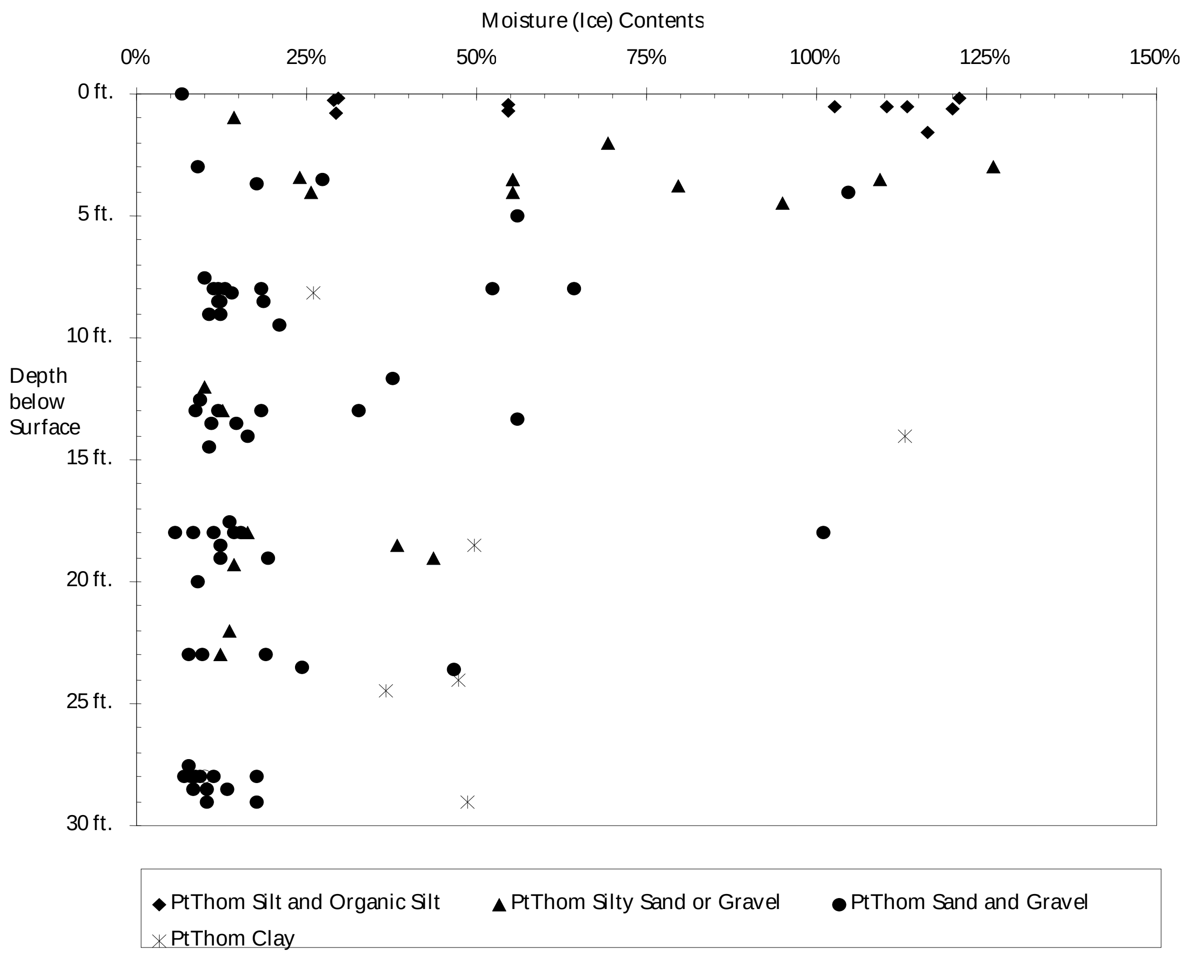
Prudhoe Bay mean annual precipitation is approximately 4 inches per year with total annual snow accumulation estimated to be approximately 4 inches.

3.3 Geotechnical

The entire onshore area on which the Point Thomson facilities will be developed is underlain by permafrost. Permafrost extends almost to the ground surface except for thaw pockets that are typically located beneath deep lakes and large river channels. By the end of summer thaw, the permafrost depth (i.e., the active layer thickness) under the undisturbed tundra surface is less than 3 feet.

Soil profiles in the Point Thomson area and along the export pipeline route consist of an ice-rich surface layer of organic and silty soils that generally extend to depths of less than 8 feet. Sand and gravel are found below the icy surface soils and extend to depths of 50 feet or more. The exception to this typical profile is a localized clay deposit found in a single boring from 14 to 31 feet below ground surface near the Point Thomson Central Pad. This clay deposit is not expected to adversely affect pipeline VSM design.

A comparison of the moisture (ice) contents and distribution of soil types in the Point Thomson area is presented in Figure 3.1. The typical moisture (ice) content values in the organic and silt surface soil unit range from about 10 percent to over 100 percent by weight. Thawed, moderately compact silt may have a moisture content around 25 percent. Frozen silts with moisture (ice) contents above this value are said to have “excess ice” and are prone to strength loss and consolidation if allowed to thaw.



Notes:

1. Moisture (Ice) content is defined by the ratio of weight of water (ice) to the weight of dry soil in a given sample.
2. A few samples exceeding 150 percent moisture content are not shown to facilitate the presentation of Firgure 3.1.

Figure 3.1 Comparison of Moisture (Ice) Contents

The underlying outwash material is composed primarily of sandy gravel and gravely sand with traces of silt. While the outwash material is ice bonded, the ice content is generally small. Massive bodies of segregated ice are found in the gravel, the shallower of which are probably associated with ice wedge development. Massive ice was encountered beneath the Central Pad gravel fill in five out of the six borings drilled in 2008. Approximately seven feet of massive ice was encountered in one of the borings. Outside of the massive ice zones, the typical moisture (ice) content in the outwash ranges between 10 and 25 percent to a depth of at least 50 feet.

During the construction process, the contractor will be required to observe VSM holes during the drilling to note any unusual subsurface conditions such as significant ice or water. The holes will be logged to include date drilled, soil conditions, hole diameter, and depth. An ExxonMobil representative will also complete a drilling log for each hole and observe the piles. The pile log will be used to report soil materials, ice, snow, thawed ground, water, etc. by hole elevations, finish grade, plumbness, diameter, and depth.

If unusual conditions or ice lenses are encountered during boring for piles or VSM, an ExxonMobil representative will determine the additional length of pile or VSM penetration needed to meet the actual strength requirement of the conditions encountered. The contractor will lengthen the hole to the additional depth and sign drilling logs for all pile holes at the completion of the construction of each hole and before moving the drilling rig away from the immediate area.

Permafrost temperatures vary locally and seasonally depending on surface characteristics including seasonal air temperature swings, solar gain related to type of surface cover (i.e., tundra or gravel), proximity to anomalies such as drainages or lakes, and insulation provided by snow cover. Permafrost temperatures also vary locally with depth below the ground surface depending on soil type, salinity, and soil moisture content.

Temperature profiles taken at borings located inland from Point Thomson in April 1982 and August 1998 are presented in Figure 3.2. The 1982 temperature profiles represent the “cold” side of the seasonal ground temperatures. Note that the 1982 temperature profile extends near vertical (at about 16.5 °F) below about 35 feet below the ground surface. The 1998 temperature profiles represent the “warm” side of the seasonal ground temperatures. The 1998 temperature profiles extend at constant temperatures (from 16.2 to 19.2 °F) below about 35 feet depth. The PTEP VSM will typically be embedded 15 feet below the ground surface so will be located in the zone of seasonal temperature variations.

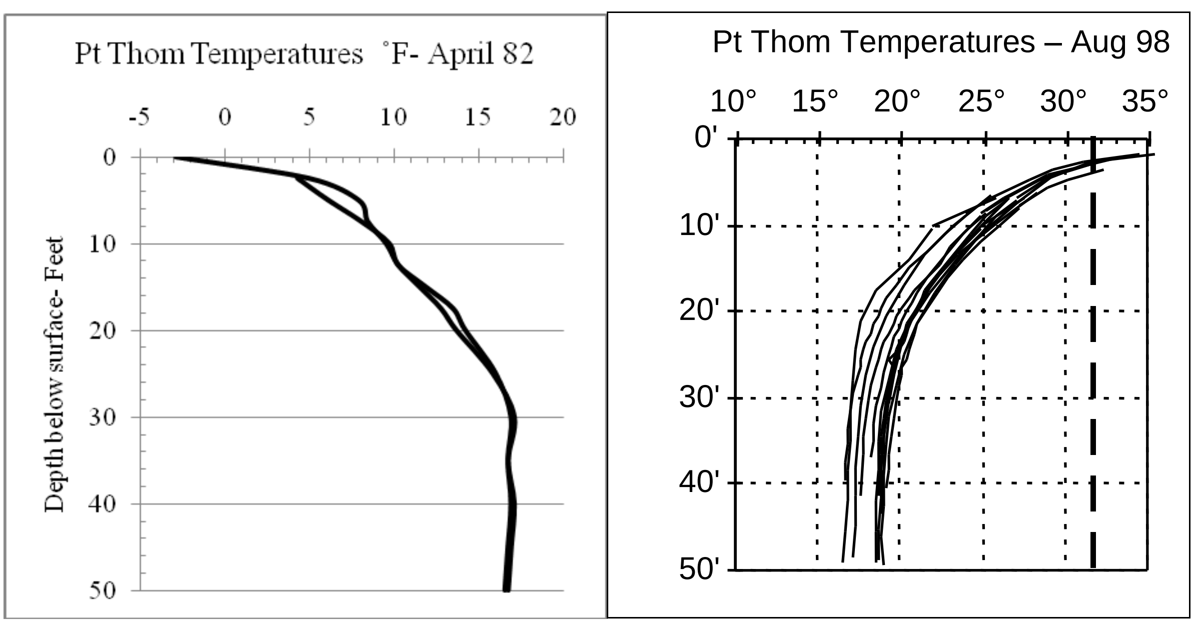


Figure 3.2 Comparison of Ground Temperatures

Permafrost temperatures may also vary from year to year due to short-term or long-term climate change. The PTEP temperature records summarized in Figure 3.2 are insufficient to determine whether there is a long-term temperature trend in the stable portion of the profile (i.e., below 35 feet depth). However, geotechnical explorations underway in 2010 are expected to generate new temperature data that will facilitate further analysis of temperature trends. At a minimum, the 2010 field program should generate sufficient new temperature data to establish the depth to the stable, constant temperature zone and also establish the upper bound temperature representing existing conditions. Note that the 2010 temperature profiles will correspond with the “cold” side of the temperature profile in the zone of seasonal variation. The characteristic shape of the PTEP 1998 profiles can be used with the 2010 temperature data to extrapolate the “warm” temperature values that should be used for VSM design.

The potential for climate change can also be addressed using soil temperatures measured in undisturbed tundra near Deadhorse, Alaska (Figure 3.3), which indicate a period of warming since at least 1993 (Osterkamp 2003[1] and Romanovsky et al. 2007[2]). The data show warming at all depths measured up to 50 meters. Osterkamp chose the Deadhorse monitoring site to represent tundra areas that were not influenced by producing wells, rivers, lakes, creeks, roads, pipelines, etc. The trends measured follow the pattern one would expect for soils responding to warming ambient temperatures: more rapid change near the ground surface, lower rates of change at depth.

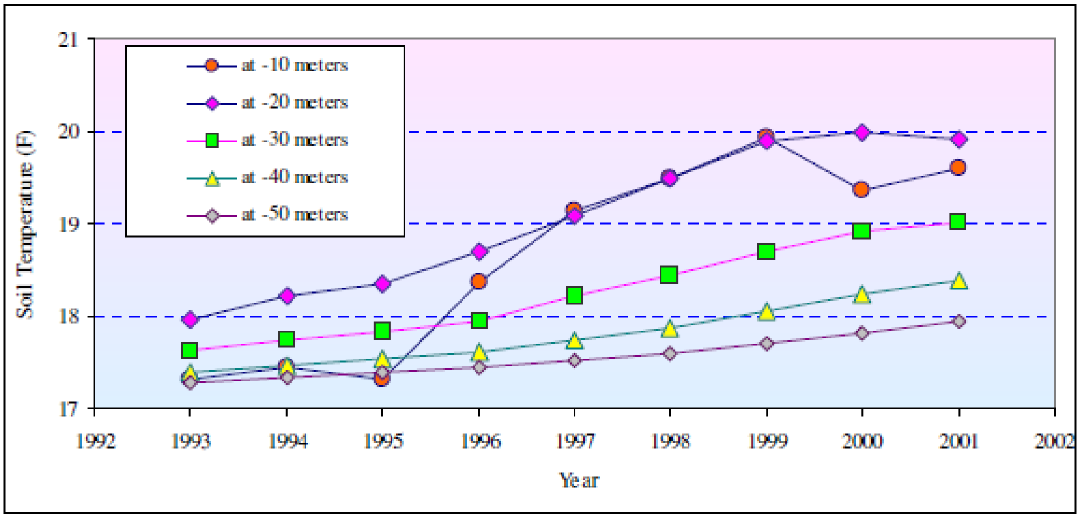


Figure 3.3 Measured Ground Temperatures for Undisturbed Tundra, Deadhorse, Alaska (Osterkamp 2003)

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[1] Osterkamp, T.E. 2003. A Thermal History of Permafrost in Alaska. University of Alaska, Fairbanks. Proceedings of the Eighth International Conference on Permafrost. July 2003. Zurich, Switzerland.

[2] Romanovsky, V.E., S. Gruber, A. Instanes, H. Jin, S.S. Marchenko, S.L. Smith, D. Trombotto, and K.M. Walter. 2007.Global Outlook for Ice and Snow. Earthprint. UNEP/GRID. Arendal, Norway. pp. 181-200. 2007.

Linear trends fitted to data from the Deadhorse site show warming rates ranging from 0.08 F/year at 50 meters depth to 0.28 °F/year at 20 meters depth (Hazen 2009[3]). These correspond to warming from 2.4 °F to 8.4 °F at their respective depths over a 30-year service life for the PTEP. Interpreting trend behavior from shallow depth data, however, is complicated by inherent year-to-year variability.

Rising subsoil temperatures could lead to increased active layer thickness and increased frost jacking force with a corresponding reduction in VSM adfreeze resistance. This situation can be addressed by offsetting the temperature profile to account for possible warming (which essentially results in a deeper VSM embedment) or by designing the VSM to existing ground temperatures and monitoring for possible temperature changes over time. For this scenario, if ground temperatures rise above a design threshold value, mitigation is needed to stabilize the ground temperatures at that threshold or to increase the VSM embedment.

3.4 Hydrology

The project area is located on the Arctic Coastal Plain, which is generally poorly drained because of the underlying impermeable permafrost and the low slope of the terrain. Most streams in the project area are poorly developed because the frozen ground resists erosion. Small drainages form when near-surface ground ice melts, often along ice wedge polygon boundaries. Drainage channels are largely formed by the subsidence of soils due to the melting of ground ice. As the drainage channels join and grow larger toward the coast, they attain sufficient energy to erode beds and banks and to transport sand and gravel. Frozen ground hinders lateral bank erosion of small streams. Erosion of frozen banks is a process of frozen slumping where blocks of frozen soil are undercut and slump into the river to thaw and erode away.

Most of the five inches of average annual precipitation falls in the form of snow. A substantial portion of the precipitation is lost to sublimation. An average of about three inches of snow generally remains on the ground throughout the winter in small drainage areas. The actual amount available in a particular small drainage basin can vary widely depending on the ability of the local relief to trap snowdrifts.

The first run-off in early spring occurs as sheet flow over the ground surface. Infiltration is practically nonexistent due to the underlying frozen ground. When break-up commences, the first snowmelt runs along the frozen surface of small streams and ponds behind snowdrifts. As break-up progresses, these small snowdrift dams are breached and the accumulated melt water is released to flow downstream until it again ponds behind a larger snowdrift. The storage and release process results in a highly peaked run-off hydrograph with flow during break-up being unsteady and non-uniform.

Once the break-up crest passes, recession is rapid. Typically, the flow on a small stream two weeks after the break-up crest will be less than 1 percent of the peak flows, and the smallest

[3] Hazen, B. 2009. The Potential Influence of Climate Change on Subsoil Temperatures at the Nigliq Channel (Draft). Prepared for Michael Baker Jr., Inc.

drainages can be completely dry within two weeks. During break-up, the bed and banks of the small drainage channels tend to remain frozen, and erosion is limited.

During the winter, sheets of ice form on streams that sustain winter flow, and smaller streams that are normally dry in winter become blocked by snowdrifts. These winter snow and ice blockages play three important roles during break-up:

- Collection and release of run-off with increased rate of discharge.
- Decrease of available channel area to convey water, thus increasing the water elevation for a given discharge. The increased water causes more area to be flooded and may increase the freeboard requirements.
- Diversion of flow to adjacent stream channels.

Floods on small streams have historically occurred solely as a result of snowmelt, which responds to a rapid seasonal increase in temperature. As a result, snowmelt floods on a given stream tend to occur at about the same time each year. Rivers originating in the Brooks Range flood about the first week of June while smaller Arctic Coastal Plain streams crest about one week later than the large rivers. The largest floods tend to be associated with later break-ups. Small streams near the coast tend to be the last to break up.

Summer floods are not anticipated to produce design floods for the Arctic Coastal Plain streams. Rainfall intensity is low and tundra and thaw lakes have a relatively large capacity to absorb summer storm run-off.

Watersheds within the Point Thomson project area range in size from approximately one to 100 square miles. The larger watersheds, those over about 10 square miles, are typically long and narrow. The largest watershed crossed by the PTEP route, which contains East Badami Creek, is about 34 miles long and has a maximum width of about 6 miles.

The break-up of most of the streams crossed by the PTEP route was monitored in 1998. The 1998 spring flood peak flow return period was estimated to be on the order of 2 to 10 years. Snowmelt progressed from south to north during the early stages of break-up and then combined with a general melt 5 to 10 miles from the coastline. The narrow shape of many of the watersheds resulted in a concentrated run-off hydrograph exhibiting rapid rise and recession.

Most of the streams crested on May 29 or 30, 1998. The peak water surface elevation and the peak discharge typically did not occur simultaneously. At the peak water surface elevation, the flow areas of the channels were 10 to 50 percent blocked by snow. The peak discharge occurred at a lower water surface elevation once the snow blockages melted.

3.5 Seismicity

The Point Thomson project area is considered an area of low earthquake activity. In the general vicinity of Point Thomson approximately 200 earthquakes were recorded between August 1965 and December 1993. These included a magnitude of 5.3 on the Richter scale, offshore near Barter Island in 1968, and a 5.1 event about 100 miles southwest of the area in 1969.

Most seismicity in the area is shallow (less than 20 miles deep), indicating near-surface faulting, but no active faults are recognized at the surface. Studies by the United States Geological Survey (USGS) estimate a 15.4 percent probability of exceeding 0.06g earthquake-generated peak ground acceleration (PGA) in bedrock during a 50-year period (300-year return interval) in this area (where g = acceleration due to the earth's gravitational field), and a 3.3 percent probability in a 50-year period (1,500-year return interval) of exceeding 0.14g. Thick permafrost, which underlies the project area, will cause the earthquake response of the alluvial sediments to act more like bedrock, limiting amplification and tending to prevent earthquake-induced ground failure such as liquefaction.

The project area is in the North Slope seismic region, 70.1 to 70.3 N Latitude and 146.1 to 147.1 W Longitude. This region was classified a Design Seismic Zone 1, under the previous governing code, the Uniform Building Code. The current governing code is the International Building Code (IBC 2006), which requires that design be based on the mapped spectral accelerations for the proposed site location. The following are the North Slope design spectral response acceleration values for maximum earthquake ground motion with 5 percent damping and for site class B (site coefficients, F_a and F_v of 1.0).

The actual mapped spectral accelerations for the Point Thomson area were calculated following USGS guidelines for 300-year and 1,500-year return intervals using 2007 USGS data. Mapped spectral accelerations (S_a); adjusted spectral accelerations, incorporating site class (S_M); design spectral accelerations (S_D); and zero period accelerations (ZPA) are presented in Table 3.1.

Table 3.1 Spectral Response Accelerations

Return Interval	Mapped Spectral Acceleration		Adjusted Spectral Acceleration		Design Spectral Acceleration		Zero Period Acceleration
	S_S	S_1	S_{MS}	S_{M1}	S_{DS}	S_{D1}	S_S
300-yr	0.125g	0.035	0.125g	0.035	0.125g	0.035	0.050g
1,500-yr	0.332g	0.095	0.332g	0.095	0.332g	0.095	0.133g

3.6 Export Pipeline Routing

The PTEP commences at the proposed Point Thomson CP and terminates at a point of connection to the BSOP near the Badami CFP. The route is approximately 22 miles long. The PTEP may be installed with infield gathering pipelines on common VSM for the first five miles of the route. For the remainder of its route, the PTEP is standalone and runs across undeveloped tundra. The PTEP route is illustrated in Figure 1.1.

The preferred mode for the PTEP is insulated pipe installed aboveground on standard North Slope VSM. Criteria used in development of the PTEP route include:

- Avoid locating VSM in lakes and cross streams at locations that minimize the need for VSM in active channels and ensures long term integrity of VSM adjacent to the streams;
- Straight pipeline sections wherever possible and minimize overall length;
- The use of standard anchor-to-anchor configurations wherever possible; and

- Minimize impact on environmentally sensitive areas and valuable habitat such as salt marshes and drained lake basins as much as possible.

An aerial photograph interpretation expert and ExxonMobil's hydrological consultant participated in the development of the preliminary PTEP route in 2003. The routing maps produced in 2003 and current aerial photography were used as guidance in determining the current, optimized PTEP route.

A proposed infield road runs parallel with the PTEP from the CP in Section 34, Township 10N, Range 23E to Section 34, Township 10N, Range 22E, a distance of approximately six miles. The PTEP also runs parallel with the Badami airstrip and access road in Sections 9, 15, and 16 in Township 9N, Range 20E, a distance of approximately three miles.

3.7 Road Crossings

The PTEP will cross two roads and one small pad. One road crossing will be through the proposed infield road between the Point Thomson CP and the west well pad and is located in Section 36, Township 10N, Range 22E. The other road crossing will be through the existing Badami water source access road and is located in Section 14, Township 9N, Range 20E. The small pad crossing will be approximately 40 feet wide and located roughly 450 feet south of the Badami CFP. The purpose for this crossing is to allow future ice road access from south of the pipelines to the pad facilities. It is located in Section 9, Township 9N, Range 20E.

Road crossing design criteria include:

- Preservation of pipeline integrity particularly through minimization of accumulation of water around the pipeline;
- Minimization of settlement that induce additional loading on the pipeline;
- Non-interference with adjacent pipelines;
- Protecting the underlying tundra from damage and thaw settlement; and
- Promoting long term integrity of the road surface.

Casings will be designed in accordance with API 1102. Oversized casings with casing-carrier pipe isolators, carrier pipe coating beneath insulation and additional insulation beneath casings will be incorporated into road crossing design. A typical road crossing is illustrated in Figure 3.4.

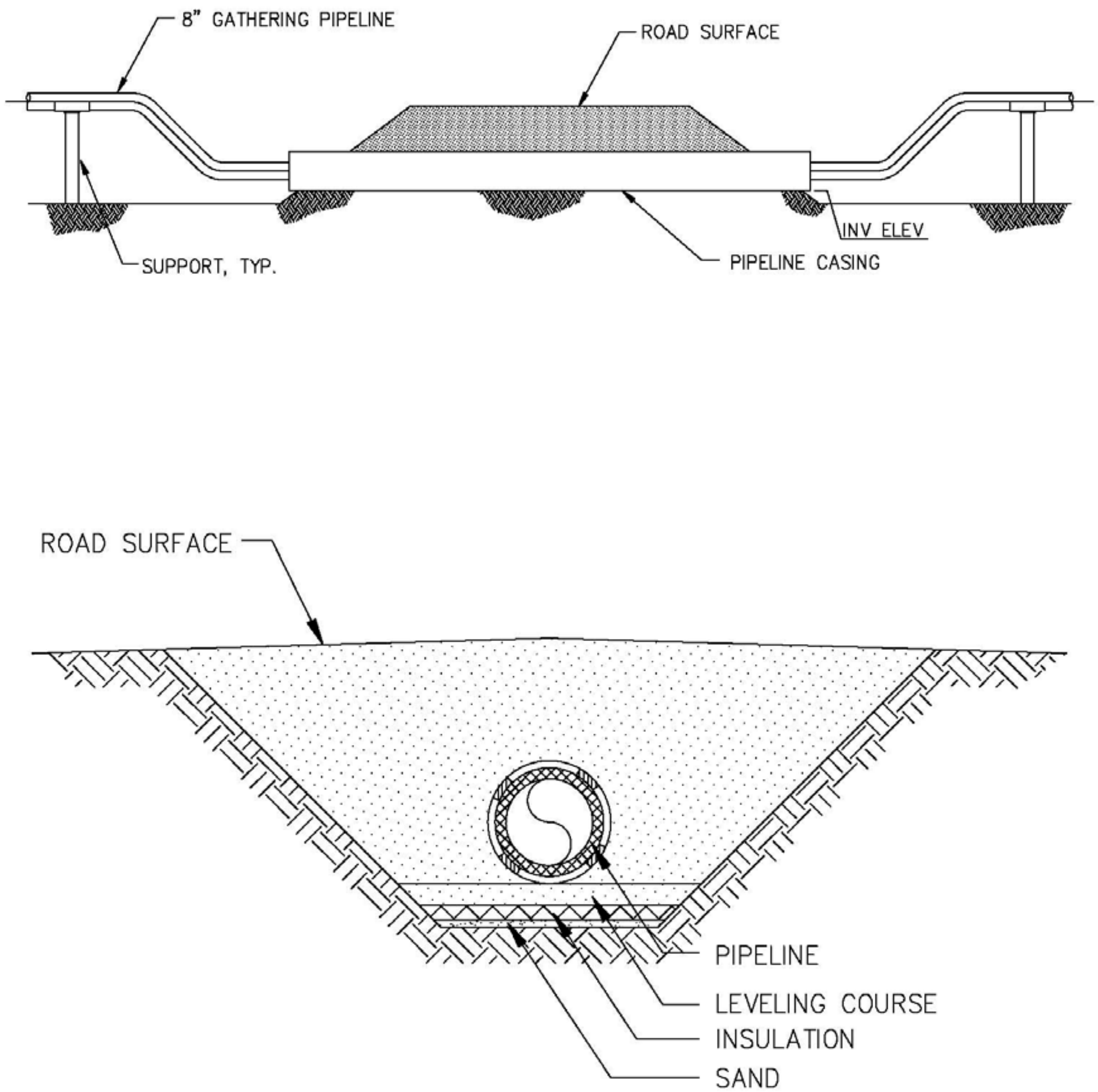

Figure 3.4 Typical Road Crossing Elevation and Section

The invert of the casings should be set a minimum of 1 foot above the 50-year flood event unless otherwise specified in the design drawings.

Whenever the natural drainage pattern is interrupted and a bridge is not required, culverts will be provided set at original tundra grade and large enough to carry the maximum flood flow conditions to assure that the pipeline casing at no time acts as a drainage culvert.

3.8 High Consequence Area Evaluation and Selection

High consequence areas (HCA) that could be affected by the pipeline will be identified and evaluated according to the requirements of Federal Regulation 49 CFR 195.452 "Pipeline Integrity Management in High Consequence Areas." Data available from the Office of Pipeline Safety and generated during the detailed design phase of the pipeline will be used to determine the presence of any HCA along the proposed pipeline alignment. HCA will be identified and used to develop an integrity management plan. An HCA evaluation and risk assessment procedure will be prepared to assist identification of any potentially affected areas.

If the pipeline is determined to affect an HCA, then that fact will be identified and a baseline integrity assessment completed before product enters the pipeline. A written integrity management program addressing the risks on the pipeline segments identified as possibly affecting an HCA will be completed within one year after pipeline operation begins only if the pipeline is determined to probably affect any HCA. Re-inspection intervals for integrity assessments will be based on federal regulatory requirements.

4. STRUCTURAL

4.1 Vertical Support Members

The PTEP will be installed on typical North Slope support structures. The supports will consist of a horizontal steel beam connected to a steel pipe pile or vertical support member (VSM). VSM will be fabricated with API 5L X65 steel while crossbeams and plates will be fabricated from normalized ASTM A572 steel.

A general fracture control philosophy has been developed which establishes acceptance criteria based on current procurement practice for Charpy toughness-tested steels in low-temperature service. Examples of steel shapes and temperatures that may apply are listed in Table 4.1.

Table 4.1 Steel Shapes and Grades Typically Meeting Charpy V-Notch (CVN) Testing Criteria at Rated Temperatures (1)

Shape	15/12 foot-pounds @ CVN Test Temperature	
	–20°F	–50°F
Wide Flange Beams (Hot Rolled)	A572 A992(S5)	A572 normalized (2) A992(S5)
Plate Girders (Fabricated)	A572	A572 (3)
Plate (Smooth)	A572	A572 / A588
Channel 8" & Larger (Hot Rolled)	A572 / A588	—
Channel (Formed)	—	A572 (4)
Box Beams	—	A572 (5)
Pipe	A333 Grade 6	A333 Grade 6 API-5L-X65
Box Columns	—	A537 Class 1

Notes:

(1) Certified Material Test Reports (MTRs) are required to confirm CVN test results on each individual heat.
(2) Normalized steels require special processing and are not usually stocked. Check with suppliers for pricing and availability
(3) Plate girders (similar to wide flange beams) can be custom fabricated to nearly any size and or shape from plate steels meeting CVN low-temperature requirements. Consult fabrication shops for limitations.
(4) Channel beams can be custom formed (by bending) to nearly any size and shape from plate steels meeting CVN low-temperature requirements. Consult fabrication shops for limitations.
(5) Box Beams (similar to square or rectangular tube) can be custom fabricated to nearly any size and shape from plate steels meeting CVN low-temperature requirements. Consult fabrication shops for limitations.

The VSM will be embedded and slurried at a specified depth in the ground. Design of the supports will be in accordance with appropriate codes and standards, and information received from the geotechnical and hydrology reports.

4.2 Design Loads

Pipeline supports will be designed to accommodate the following loads:

- Dead Load (D): to include equipment and piping
- Operating Loads (F): to include fluid in pipes, and other long-term loads which result from the operation of the facility (including pipeline anchor, guides, and slide loads)
- Live Loads (L)
- Thermal Load (T): as determined from the pipeline stress analysis
- Wind Load (W): per IBC, and as follows:
  - Basic Wind Speed = V = 110 mph
  - Exposure Factor = D
  - Importance Factor = II
  - Total lateral wind force per foot on the supported pipeline will be considered
- Seismic Load (E): as determined from the pipeline stress analysis
- Frost Jacking Force or Frost Heave (J): per Table 4.2
- Snow Load (S): as determined from the pipeline stress analysis
- Ice Load Forces (L_{ice}): as determined in the MBJ Water Crossing Study (USPT-WP-YRZZZ-060008)

The design basis for the PTEP is that the minimum distance between the surface of the tundra, streams, and lakes and lowest point of any element being supported by VSM (e.g., pipe insulation, including pipeline attachments such as tuned vibration absorbers, electrical/communication cables, etc.) is seven (7) feet.

4.3 Foundation Design

The soil and geothermal conditions in the Point Thomson area consist of an upper layer of icy silt and organics overlying outwash material consisting largely of sand and gravel. The outwash is generally encountered at a depth of 6 to 8 feet along the pipeline route. Thaw depths (i.e., active layer thickness) measured in August 1998 in the Point Thomson area were found to be in the range of 1.4 feet to 3 feet with an average of about 2 feet.

In general, the pile foundation design will be based on:

- The tangential adfreeze bond strength at the pile to slurry interface to resist the vertical loads
- The resistive strength between the slurry and native soil to resist frost jacking (heave) forces. The required depth of pile embedment will be dependent on these forces.

Typical adfreeze and frost jacking (heave) stresses for North Slope VSM is shown in Table 4.2.

Table 4.2 Typical Adfreeze Stresses for VSM

Depth Below Top of Tundra (feet)		Compressive or Tensile Loading (psi)	
From	**To**	**Summer**	**Winter**
0	3	0	–40 (upward)
3	6	5.8	5.8
6	9	11.6	11.6
9	12	16.5	16.5
12	Bottom of VSM	20.3	20.3

Notes:

1. The "Depth Below" shown in the above table applies to the undisturbed tundra case or the gravel pad case, for other conditions substitute -3 with the appropriate case dependent depth of active layer as presented in Table 4.2.
2. The capacity of a VSM to resist frost heave shall be the lesser of the following:
   - The summation of the allowable adfreeze bond stresses between VSM and slurry.
   - The summation of the allowable stresses between the slurry and the native soil or ice.
3. Adfreeze stresses are at pile/slurry interface.
4. For wind and seismic loadings plus short term vertical loads, stress may be increased by 33%.
5. Piles/VSM installed by the drilled and slurried method shall be calculated for all sizes. In no case shall the embedment be less than 15 ft below top of tundra.
6. Adfreeze stresses based on Department of the Army TM5-852-4 "Arctic and Subarctic Construction Foundations for Structures" October 1983
   Includes a factor of safety of 2 on sustained loading conditions.
7. Design temperature profile consistent with general 2010 measured ground temperatures.

The adfreeze values set out above in Table 4.2 are based on controlling creep related vertical deflection (i.e., settlement) under long term loads. The Point Thomson VSM, Piling and Sheet Pile specification is based on the Prudhoe Bay guideline specification but has been tailored to reflect existing conditions encountered in the 2010 geotechnical exploration program. Final design for PTEP foundations will be based on this site-specific specification.

The minimum embedment for VSM design is typically controlled by the need to resist frost heave forces. Based on a design active layer of 3 feet and a frost heave stress of 40 psi, the frost heave force is calculated to be 17.3 kips per foot of the pile's perimeter. In areas of upland tundra without massive ice, an embedment of 12.9 feet below the tundra surface provides sufficient adfreeze bond between the sand-slurry and the steel pipe to resist this force. Massive ice is treated as a no-load zone for resistance to frost jacking and/or structural loads. The baseline design provides for up to three feet of massive ice at each VSM location before site-specific adjustments are needed. Therefore, VSM will be designed using 15 feet below tundra surface as the minimum embedment. If ice thickness in excess of 3 feet is encountered when drilling pilot holes for VSM installation, the VSM is extended an additional 1 foot for each additional 1 foot of ice. The design basis for the Point Thomson export pipeline VSM follows this approach, but uses adfreeze values updated to reflect 2010 geotechnical conditions.

In addition to adjusting VSM embedment where massive ice is encountered, other conditions such as proximity to water bodies (ponds or drainages) or deeper snow drifting could result in a warmer ground condition and result in deeper embedment being necessary as determined on a site specific basis.

4.4 Stream Crossings

The streams that will be crossed by the pipeline are predominantly smaller drainages that are expected to be underlain by frozen soil similar to the upland areas. Deep snow drifts in the stream channels could result in warmer ground conditions and subsequently require slightly deeper VSM.

Location of VSM within active stream channels will be avoided wherever possible. The active channel is defined as the portion of streams containing flowing water or ice all year round. The active channel for small streams with poorly defined channels and/or those that are seasonally dry is that portion of the stream in which ice or water resides longest.

The PTEP route crosses 17 drainages. For more detail on hydrologic characteristics of the drainages along the proposed PTEP route, refer to Export Pipeline Water Crossing Study USPT-WP-YRZZZ-060008, Export Pipeline Water Crossing Study, USPT-WP-CRENV-002008, 2010 Breakup Report, USPT-WP-CRENV-002009, 2010 Hydraulics Report and USPT-WP-YRHYD-060001, Stream Crossing Design Report. Nine of the streams drain an area greater than 10 square miles. These eight streams are listed in Table 4.3.

Based on the proposed pipeline routing, it was determined that VSM at East Badami Creek represent the design case (i.e., have maximum imposed loads) for VSM design within the flood plain area.

Isolation devices in case of a leak within the East Badami Creek Drainage area will consist of a vertical loop system.

Table 4.3 Data for Export Pipeline Streams with Drainage Areas Greater than 10 Square Miles

Stream name	Drainage Area ($mile^2$)	Peak Stream Flow (ft^3/sec) 100-year
West Badami Creek	51.5	3600
Middle Badami Creek	23.5	1900
East Badami Creek	93.0	5500
“N” Creek	16.5	1300
“L” Creek	31.0	2200
“I” Creek	22.0	1600
“G” Creek	16.5	1300
“F” Creek	19.0	1500
“D” Creek	12.0	1050

4.4.1 Scour

Scour design uses current survey data and is based on the methods described in the Federal Highway Administration, Hydraulic Engineering Circular No. 18 (FHA 2001). Local pier scour calculations were performed on all VSM located within the 100-yr floodplain.

Both clear water and live bed contraction scour calculations were performed for those VSM subject to pier scour. In all cases, contraction scour was determined not to be a factor, based on a range of estimated mean diameter of bed material (D50) values. Eight VSM are subject to local pier scour, as presented in Table 4.4

Table 4.4: VSM Scour Locations and Estimated Maximum Scour Depth

Stream Name	VSM Number	VSM Diameter (NPS)	Maximum Scour Depth (ft)
"E" Creek	5300	12	2.4
"L" Creek	6239	18	4.3
East Badami Creek	6807	12	3.5
	6808	18	4.7
	6809	12	3.5
	6810	8	2.6
	6811	18	4.8
	6812	18	4.7

Table note: VSM numbers are based on current layout and may change prior to final design

4.4.2 Freshwater Ice

Several factors affect the magnitude of the ice forces exerted on a VSM. For PTEP and gathering line design, several factors including the depth of water at the VSM, the velocity at which the ice is moving, and the length, width and thickness of the ice are considered. The preliminary hydraulic analysis provided area of inundation, water surface elevations, depth, and average velocities in the active channel and the overbank floodplain for open channel conditions during a 100-year recurrence interval flood event.

With regard to the length, width, and thickness of the ice likely to reach the pipeline during a large flood event, the following will be considered:

- Broken ice pans can be generated by ice on the river or lakes within the flood plain.
- At freeze-up, the amount of water flowing in the coastal plain streams is relatively low.
- Many of the streams freeze to their beds in the winter.
- When the river ice freezes to the riverbed, and the riverbed is frozen, the ice might not lift off the riverbed during an average flood.
- During the 1998 spring monitoring of streams along the alignment, only slush floes were observed.
- Additional observations were performed during 2009 and 2010 breakup events comprising the following observations (reference 2010 Breakup Report, USPT-WP-CRENV-002008):
  - Slush floes were observed on the majority of streams and can be utilized for design of all streams unless specifically noted otherwise.
  - Broken ice pans were observed in East Badami Creek. The majority of pans were less than 30 square feet. Some larger pans of up to 1000 square feet were also observed, but theses pans were stationary.

Ice pan sizes were established in the 2010 Water Crossing Study conducted by MBJ in an effort to delineate impacts from breakup ice on pipeline support members. Maximum ice width, thickness, and lengths from that report at each stream crossing are presented in Table 4.5.

Table 4.5 Ice Parameter Summary

Stream Name	Maximum Ice Width (ft)[1]	Maximum Ice Thickness (ft)[2]	Maximum Ice Length (ft)[3]
West Badami Creek	17	3.4	51
Middle Badami Creek	17	3.4	51
East Badami Creek	14	3.4	42
"O" Creek	8	1.5	23
"N" Creek	11	2.2	33
"M" Creek	8	1.6	23
"L" Creek	13	3.4	39
"K" Creek	6	1.2	18
"J" Creek	4	0.7	11
"I" Creek	15	2.9	44
"H" Creek	3.5	0.7	10.5
"G" Creek	16	3.2	49
"F" Creek	10	2.0	30
Creek 18a	4	0.8	12
"E" Creek	5	1.1	15
"D" Creek	8	1.7	25
"C" Creek	9	1.9	28

Notes:
1. Maximum Ice Width is half of the water top width as measured from July 2009 aerial imagery.
2. Maximum Ice Thickness is the average of measured flow depth at historically monitored channels during spring events or is an estimate of flow depth based on similarities in drainage characteristics with measured channels.
3. Maximum Ice Length is three times the ice width for the given channel.

The following preliminary stream ice criteria will be used for design of VSM located within an active channels and floodplains:

- Maximum Ice Crushing Strength is 200 psi
- Maximum Ice Width
  - In-channel VSM: Maximum ice width estimated to be one half of the water top width as determined from July 2009 aerial imagery;
  - VSM within 100-yr flood overbank but outside active channel: Maximum ice width estimated as five times the maximum ice thickness

Maximum Ice Thickness - Determined as the minimum of the following:
  - Ice thickness calculated using average freezing degree days (AFDD) (U.S. Army Corps of Engineers [USACE] 2002), which assumes an infinite freeze depth regardless of physical availability of water; or
  - Freeze-up ice thickness using the 2-yr flood depth, (a conservative approach considering low precipitation and shallow gradient contribute to little available water present in the channel prior to seasonal freezeup); or

    - Ninety percent of the 100-yr flood depth, considering the density of ice and its capacity for buoyancy.
- Maximum Ice Length
    - Estimated to be three times the ice width.
- Maximum Velocity
    - Determined based on HEC-RAS modeling for 100-yr flood values.
- The estimates for ice floe dimensions are considered to be conservative, but appropriate for design values. It is generally accepted that water surface elevations, and therefore flow depth and flow width, are lower at fall freeze-up than what is estimated based on the Q2 discharge. Furthermore, observations during the 1998 and 2010 breakup events indicated mostly slush floes were observed in the drainages.

4.4.3 Bank Migration

Based on preliminary hydrologic data, bank migration is not expected to be significant at most crossing locations. Design will include consideration for placement of stream centerline near the center of the VSM spans to maximize the distance between channel banks and out-of-channel VSM. In those locations where bank migration is considered to be more of an issue, out-of-channel VSM located closest to the channel will be designed based on in-channel design criteria.

The foregoing scour criteria as discussed in section 4.4.1 will be employed where VSM are placed in stream channels.

4.4.4 Pipe Elevation

The bottom of pipe elevation is a minimum three feet above the highest water surface elevation that is likely to occur during a 100-year flood.

4.5 Storm Surges and Sea Ice Run-up

The PTEP is designed and sufficiently set back from the coastline (i.e., generally 2,000 feet or more) to ensure that it is not significantly impacted by extreme summer storm surges, anticipated to reach as high as seven feet above mean sea level, or sea ice run-up.

5. MECHANICAL

5.1 Steady State Hydraulics

Anticipated production from the Point Thomson Project is nominally 10,000 barrels per day (bpd); however, the PTEP has been sized to accommodate potential full field development which may be in excess of 70,000 bpd.

For hydraulic purposes, the maximum inlet pressure of the PTEP will be 2,035 psig and the maximum outlet pressure will be 1,415 psig. The MOP of the PTEP from Point Thomson to the Badami sales oil pipeline tie-in point will be 2,035 psig.

The normal operating temperature of the liquid hydrocarbon entering the PTEP at Point Thomson will be 143°F. The maximum operating temperature of the fluid entering the PTEP at Point Thomson will be 200°F. The maximum operating temperature of the fluid exiting the PTEP (i.e., at the point that the pipeline connects to the BSOP) will be 150°F.

Pipe design parameters for hydraulic analysis are summarized in Table 5.1; pressure drop from Point Thomson to Badami and normal pipeline outlet temperatures are shown in Table 5.2

Table 5.1 Pipe Design Parameters for Hydraulic Analysis

Outside Diameter (in)	Wall Thickness (in)	Specified Minimum Yield Strength (SYMS) (psi)	Normal Liquid Hydrocarbon Operating Temperature (ºF)	Maximum Liquid Hydrocarbon Operating Temperature (ºF)	Maximum Inlet Pressure (psig)	Maximum Outlet Pressure (psig)
12.75	0.406[1]	65,000	143	200	2,035	1,415

[1] Wall thickness includes a 0.125-inch corrosion allowance; minimum wall thickness for pressure containment is 0.281 inches.

Table 5.2 Pipe Pressure Drop and Outlet Temperature

Flow Rate (bpd)	Pressure Drop (psi)	Outlet Temperature	
		Summer (F)	Winter (F)
10,000	11	114	58
70,000	320	145	135

The normal operating pressure of the pipeline will be dependent on the back pressure of the common use pipeline systems downstream of Badami due to other pipeline users' export rates and crude properties along with Point Thomson Unit (PTU) export. With a PTU export rate of 10,000 bpd, the inlet pressure is only marginally above the system back pressure due to the low pressure drop. This will enable operation well below the Badami design pressure of 1415 psig. At 70,000 bpd, the higher pressure drop contribution of PTU fluids may require inlet pressures above 1415 psig depending on the export rates of downstream contributors; this may require pressure protection equipment to protect the BSOP.

The pipeline outlet temperatures are always above freezing for all cases. The water hold up fraction in low points of the line is less than 10% for the lowest flow rates and does not change significantly after shutdown. Freeze protection is therefore not required on shutdown. Operability of downstream sections of pipeline, however, may require more aggressive removal of water from the export stream which would eliminate freeze considerations.

Pipeline outlet temperatures are below the wax appearance temperature, which means wax can form on the pipe walls. Wax deposition modeling shows that the deposition rates are low and that regular wax pigging programs are not required above the normal pipeline maintenance pigging frequencies. Wax properties are predicted to be soft and gel-like and are not predicted to cause difficulties in pigging operations.

5.2 Surge Analysis

The PTEP will be analyzed from a surge perspective in conjunction with the downstream connecting pipeline system. Pipeline surge scenarios that will be verified are those associated with actuated valve closures and pump trips. The surge analysis will consider all pipeline block valves that are proposed for the PTEP system. In accordance with 49 CFR 195, surge pressure must be controlled to ensure it does not exceed 110% of the internal design pressure at any location. However, the PTEP surge pressure will be limited to 100% of the internal design pressure.

Isolation valves are located at Point Thomson CP downstream of the launcher and at Badami upstream of the piggable wye tie-in to the BSOP. Vertical loops will be employed as isolation devices at river crossings where applicable. The surge analysis will consider the proposed vertical loops in the system.

The potential surge pressures for the export pipeline for different flow rates are shown in Table 5.3. This represents the initial “water hammer” pressure spike based on a simple surge analysis assuming instantaneous valve closure. These momentum surge pressures are very low relative to the design and operating pressures and are likely workable without any relief devices or accumulators at 10 kbd. Alternate surge scenarios may have the potential to overpressure the system depending on control system response times and dynamics. These scenarios will be analyzed during detailed design once control systems, valve and pump dynamics are available and any surge specific modifications recommended accordingly.

For a potential future 70 kbd case the real surge pressure is also likely to be lower than 10% of the MOP once valve dynamics are modeled. The operating pressure at Badami will be less than 1400 psi due to the Badami design pressure limits; therefore, since the export line design pressure is higher than 1400 psi, there is significant surge capacity before 100% of MOP is reached. This will be further analyzed as part of future phases of the project to increase the flow rate beyond 10 kbd. Nominal tie-in points and space are available at the BSOP tie in for possible future surge protection equipment requirements.

Table 5.3 Peak Potential Surge Pressure

Flow Rate (kbd)	Peak Surge (psi)
10	41
70	285

5.3 Pipe Wall Thickness Considerations

5.3.1 Design Factor

The design factor used for wall thickness calculations will be 0.72 for the pipeline located outside of the facilities. Where piping is inside of the facilities such as the pig launcher or the meter skid the design factor will be 0.6.

5.3.2 Corrosion Allowance

Results of the latest flow assurance study predict the potential for water drop out in the PTEP. Based on this prediction, the pipeline design will include a 0.125-inch (3 mm) corrosion allowance.

5.3.3 Accidental Bullet Impact

The PTEP is routed within local off-shore hunting grounds and therefore the design must consider the potential for accidental bullet strikes where the pipeline is located near the coastline. The design has considered rifle calibers and ammunition typically utilized in the area for caribou hunting. The potential for penetration was analyzed using established ballistic limit formulae.

The first 4.9 miles of the PTEP will have an additional 0.094-inch allowance applied to the wall thickness to reduce the likelihood of damage from incidental bullet strikes during subsistence hunting activities. These activities typically occur in bays and inlets along the coast.

5.4 Export Pipeline Design Loading Categories

Two general categories of design loading conditions are the design operating condition and the design contingency condition.

The design operating condition is defined to include all normal operating conditions and environmental loadings. The ASME B31.4 Piping Code establishes these loadings. The stresses produced in the pipeline by these loadings are to be within the design criteria limits established by conventional engineering practices and B31.4. The loadings for the design operating condition on the aboveground pipeline are:

- Internal design pressure
- Surge pressure
- Dead and live loads
- Temperature differential
- Wind load
- Snow and ice load
- Operating Design Earthquake

The design contingency condition is defined to include the sustained loadings for normal operating conditions combined with occasional loadings from extreme environmental events. Design contingency conditions will occur rarely, if at all, during the lifetime of the system. The stresses produced in the pipeline by these loadings will remain within design criteria limits. When environmental loadings reach the design contingency condition levels; the pipeline system will be inspected and may be shut down for maintenance purposes. The loadings for the design contingency condition on the aboveground pipeline are:

- Internal design pressure
- Dead and live loads
- Temperature differential
- Contingency Design Earthquake
- Loss of a support

The contingency design earthquake and loss of support are not considered to occur concurrently.

5.4.1 Internal Design Pressure

The internal design pressure for the PTEP is 2035 psig.

5.4.2 Surge Pressure

Surge pressure will be controlled and will not exceed 100% of the internal design pressure at any location. Pipeline surge scenarios that will be verified are those associated with automated valve closures and pump trips.

5.4.3 Hydrostatic Testing

All pipes will be tested to at least 1.50 times the design pressure. The maximum hoop stress during hydrostatic testing will be less than 95% of the Specified Minimum Yield Stress (SMYS). The test pressure is combined only with dead and live loads, thermal expansion at test fluid temperature, and 1/3 wind design speed.

5.4.4 Dead and Live Loads

The dead loads include pipe weight, insulation weight, and insulation jacket weight. Additional dead loads include the weight of tuned vibration absorbers (TVA) where required along the pipeline.

Due to the long term constant application, the weight of export liquid hydrocarbon is also considered a dead load and will be based on a specific gravity of 0.841.

5.4.5 Snow and Ice Loads

Typically ice and snow loads on North Slope pipelines can be neglected unless the topography is such that consideration is warranted (i.e., pipelines in gulleys, areas of extreme drifting, or that may be affected by snow removal operations). Where snow loads are to be considered, adjusted snow and ice loads for an elevated pipeline will be based on a snow density of 20 lbs/ft^3.

5.4.6 Wind Load

Design operating wind speed is 110 mph. The design wind pressure will be calculated using ASCE 7-05 as required by the IBC. The design wind exposure is “D”, the importance category is II, and the topographic factor “k” is equal to 0.85 for heights up to 15 feet. The maximum pipe height above tundra is generally less than 15 feet for a majority of the cross-country alignment (typical pipeline height is 7 to 8 feet). This results in a wind pressure of approximately 19 pounds per square foot on the pipeline.

5.4.7 Temperature Differential

The temperature differential is based upon a minimum ambient temperature (–50°F) and the maximum pipe wall temperature of 200°F.

5.4.8 Earthquake Loads

Earthquake loads for the operating design earthquake are based on the 300-year return interval accelerations; while loads for the contingency design earthquake are based on the 1500-year return interval accelerations. Accelerations are considered the same for the three orthogonal directions.

5.4.9 Loss of Support

The loss of support is defined as settling of one support such that the pipeline completely free spans between the two adjacent supports. In addition, the case of up to 18 inches of frost heave at a single support is also considered. This loss of support is evaluated as a design contingency condition. The PTEP and gathering lines will be designed to ensure that loss of a support will not result in a buckle or rupture of the pipeline.

5.4.10 Wind Induced Vibration

The current design mitigates all segments of the pipeline against Wind Induced Vibration (WIV) using Tune Vibration Absorbers (TVA).

A more detail review of pipeline susceptibility to WIV will be conducted during detailed design using current state of the art analysis techniques.

5.5 Pipe Stress Criteria

The PTEP is subject to the requirements of 49 CFR 195. This federal regulation places limitations on the allowable internal pressure but does not specify other loads, loading combinations, or limitations on combined states of stress. The ASME Code for Pressure Piping B31.4 – *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*, addresses detailed industry requirements for loads and stress criteria.

Based on the nature and duration of the imposed loads, pipeline stresses are categorized as primary, secondary, and combined (effective) stresses. The general stress criteria are summarized as follows:

- Primary Stresses - Primary stresses are stresses developed by imposed loads with sustained magnitudes that are independent of the deformation of the structure. The basic characteristic of a primary stress is that is it not self- limiting, meaning that no redistribution of load occurs as a result of yielding. Therefore, if the primary stress in the pipe exceeds the yield strength of the pipe, the pipe will continue to yield until failure of the pipe or removal of the load causing the stress, whichever occurs first. The stresses caused by the following loads are considered as primary stresses: internal pressure, dead and live loads, surge (water hammer), earthquake motion, and wind.
- Secondary Stresses - Secondary stresses are stresses developed by the self-constraint of the structure. Generally, they satisfy an imposed strain pattern rather than being in equilibrium with an external load. The basic characteristic of a secondary stress is that it is self-limiting, meaning that local yielding and minor distortions can relieve the stress imposed by the application of the load. Once stress relief has occurred, the pipe will not yield any further despite continued application of the secondary load. The stresses caused by the following loads are considered secondary stresses: temperature differential and loss of support.
- Combined Stresses - The three principal stresses acting in the circumferential, longitudinal, and radial directions define the stress state in any element of the pipeline. Limitations are placed on the magnitude of primary and secondary principal stresses and on combinations of these stresses in accordance with acceptable strength theories that predict yielding.

5.5.1 Allowable Stresses

Allowable stress criteria are shown in Table 5.4. As stated by ASME B31.4 code, stresses due to wind and earthquake are not considered to occur concurrently. Circumferential, longitudinal, shear and equivalent stresses will be calculated considering stresses from all relevant load combinations. Calculations will consider flexibility and stress concentration factors of components other than straight pipe.

Table 5.4 Export Pipeline Stress Criteria

Criterion	Allowable	Basis[2]	Load Combination
Hydrostatic Test Stresses			
Hoop Stress (pressure)	0.95 SMYS[1]	USPT-WP-YSPDS-000007	1
Effective Stress (test pressure, dead and live loads, 1/3 wind speed, and temperature differential between tie-in and test fluid)	1.00 SMYS	USPT-WP-YSPDS-000007	2
Primary Stresses			
Hoop Stress (pressure)	0.72 SMYS	402.3.1	3
Longitudinal Stress (pressure, dead and live loads)	0.54 SMYS	419.6.4	4
Longitudinal Stress (pressure, dead, live, and occasional operating loads, i.e., wind, snow and ice, and operating earthquake)	0.80 SMYS	419.6.4	5 6 7
Secondary Stresses			
Longitudinal Stress Range (temperature differential, tie-in to operating)	0.72 SMYS	419.6.4	8
Combined Stresses			
Effective Stress (sustained loads, i.e., pressure, dead and live loads, and temperature differential)	0.90 SMYS	419.6.4	9
Effective Stress (sustained and occasional operating loads)	1.00 SMYS	Project Design	10 11 12
Effective Stress (sustained and contingency loads)	1.00 SMYS	Project Design	13 14
Surge Stresses			
Hoop Stress (surge pressure)	0.79 SMYS	402.2.4	15
Effective Stress (surge pressure, live and dead loads, temperature differential, and transient loads due to surge pressure wave)	1.00 SMYS	Project Design	16

1. SMYS = Specified minimum yield strength
2. Basis refers to sections of ASME B31.4-2006 code unless otherwise noted.

5.5.2 Load Combinations

The load combinations presented in Table 5.5 will be analyzed during design of the pipeline and the resulting stresses will be compared to the allowable stresses in Table 5.4. The pipeline design will ensure that the stresses in all load combinations are below the allowable stress criteria.

Table 5.5 Export Pipeline Load Combinations

Load Type	Load	Description	Testing		Operating										Contingency		Surge	
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Primary	A	Internal Pressure			X	X	X	X	X		X	X	X	X	X	X		
Primary	B	Hydrostatic test Pressure	X	X														
Primary	C	Surge Pressure															X	X
Primary	D	Dead Load		X		X	X	X	X		X	X	X	X	X	X		X
Primary	E	Live Load		X[1]		X	X	X	X		X	X	X	X	X	X		X
Primary	F	Wind Load		X[2]			X					X						
Primary	G	Snow and Ice Load						X					X					
Primary	H	Operating Earthquake							X					X				
Primary	I	Contingency Earthquake													X			
Secondary	J	Temperature Differential		X[3]						X	X	X	X	X	X	X		X
Primary	L	Loss of Support														X		

1. Live load for hydrostatic test is the loading from the hydrostatic test fluid
2. Wind load for hydrostatic test is based on 33% of the design wind speed
3. Temperature differential for hydrostatic test is based on the difference between the tie-in temperature and the hydrostatic test temperature.

5.6 Configuration

The PTEP will be constructed aboveground and supported by VSM. Thermal expansion will be accommodated by including offsets in a "Z" configuration with pipeline anchors between each offset. The length of the offsets and thermal expansion stresses will govern the maximum distance between anchors. The "Z" configuration is illustrated in Figure 5.1.

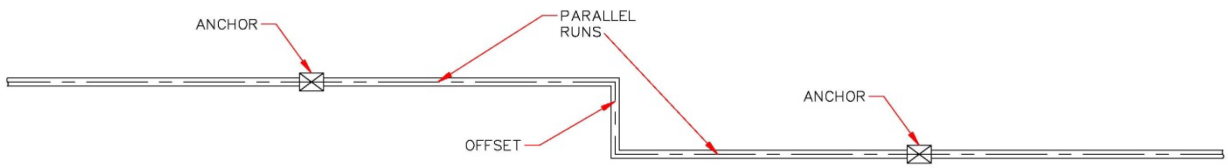

Figure 5.1 Z-Offset Configuration

In cases where a change in direction is required, expansion loops may consist of one 90-degree angle and second wider angle to accommodate the new direction as shown in Figure 5.2. These cases may further limit the maximum distance between anchors and the design will ensure that the allowable stress requirements are met.

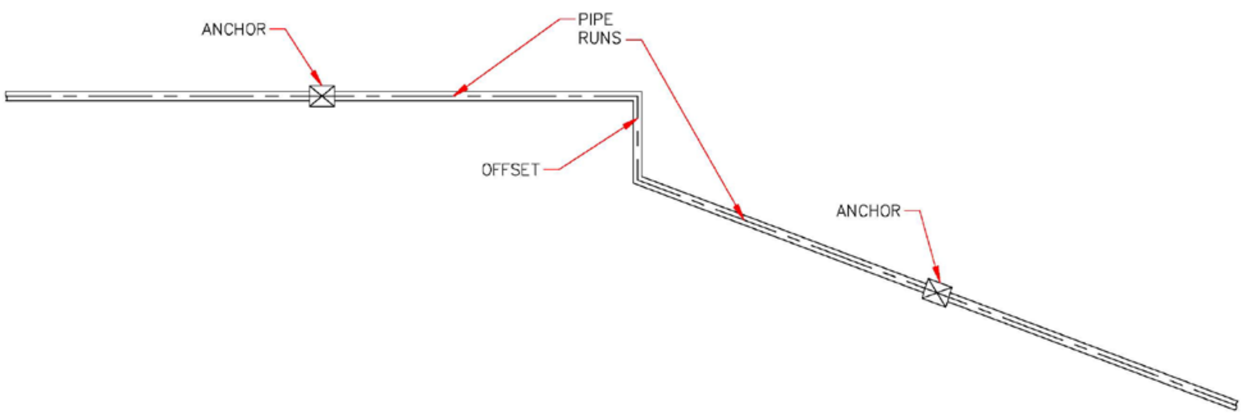

Figure 5.2 PI-Configuration

5.7 Facilities

Valve locations will be evaluated and determined in accordance with federal regulatory requirements. At a minimum, valves will be placed at the ends of the pipeline to isolate the pipeline from the Point Thomson process facility and the BSOP. Vertical loops will be installed on the east and west sides of the East Badami Creek as isolation devices for the creek. A typical vertical loop configuration is presented in Figure 5.3.

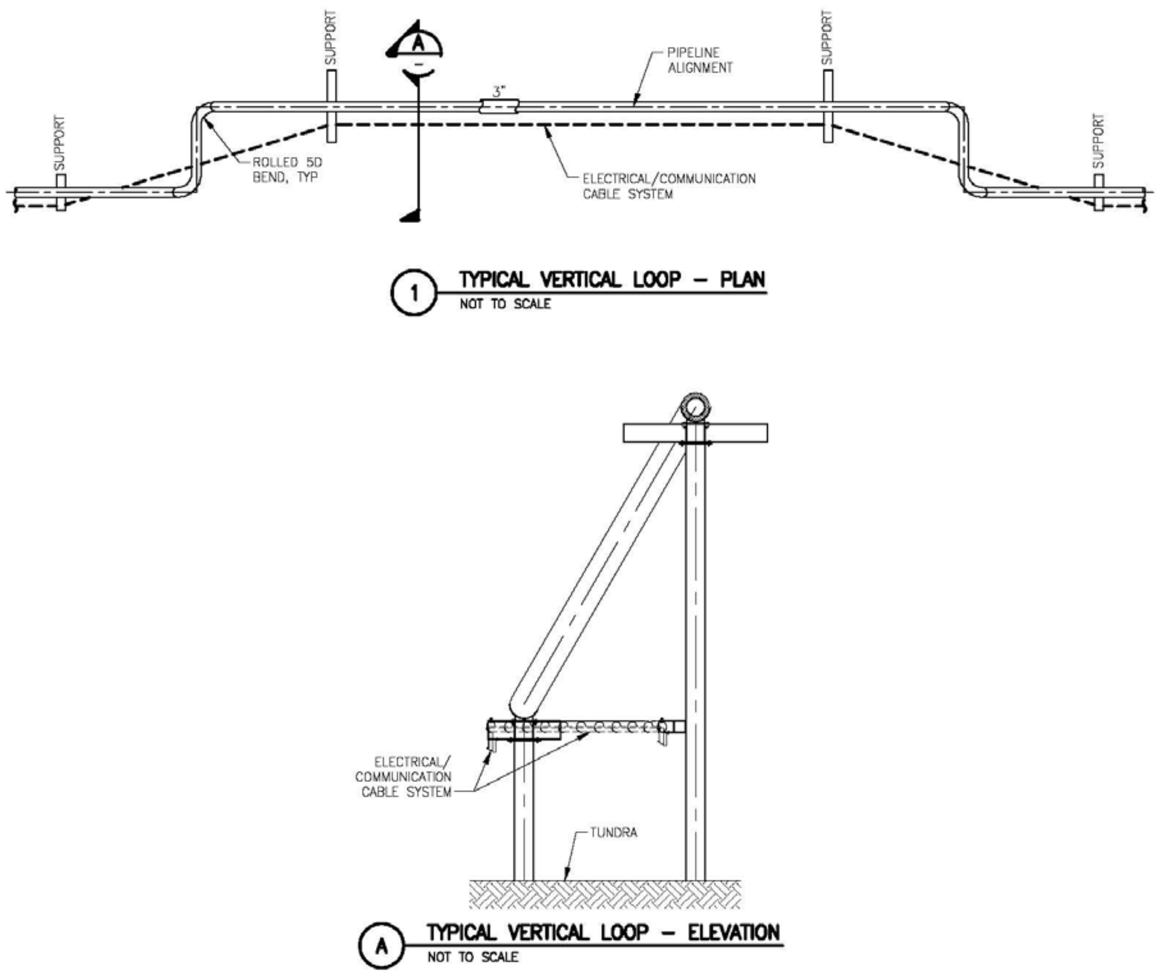

Figure 5.3 Vertical Loop

The launcher will be located in the line at the Point Thomson CP. The launcher barrel will be operated "dry" and will have a double block and bleed valving system for isolating the barrel from the main pipeline when required. The trapping systems will be protected by a safety system or operating procedure so that the trap cannot be over pressured and the access door cannot be opened when the barrel is under pressure. All of the loading and unloading areas will be indoors and will be protected with a fire detection and suppression system.

Due to the operating procedure which will leave the trap dry when not in use and a relatively small volume of the barrel when isolated (<240 gallons), a thermal relief system is not required. The system will be provided with instrumentation to signal the departure of the pig at the launching station.

Consistent with the recommendation of in-line inspection (ILI) service providers, the portions of the PTEP system to be subjected to ILI will have bends with a minimum radius equivalent to five times the nominal diameter of the pipe (5D bends). The launcher will be designed to handle all the anticipated inspection tools (see section 11.2), as well as a full range of pipeline cleaning tools.

5.8 Material Selection

The PTEP material will conform to API 5L, Specification for Line Pipe. API 5L X65 line pipe material has been selected, is compatible with the process fluid and has good low temperature properties for the service. The wall thickness of the pipe was determined using the design calculations provided by both 49 CFR 195 and ASME B31.4 and increased to the nearest API 5L standard wall thickness. The selected pipe material will be adequate for the pipeline design temperature range from –50°F to 200°F. Line pipe procurement will be in accordance with project specifications for onshore line pipe requirements. For liquid service, the minimum full size average CVN transverse energy shall be 59 ft-lbs and 53 ft-lbs minimum as tested at -50°F.

Pipe insulation and jacketing will be specified and selected to ensure pipeline operating performance within the design flow and temperature limits. Insulation will be selected mainly on the basis of continuous performance at design temperatures (–50°F to 230°F). Outer jacketing will be specified and selected mainly on the basis of protection of the pipe insulation from damage and degradation from the elements of the arctic environment.

The design basis for shop-applied insulation for the PTEP consists of polyurethane foam insulation covered with roll formed, interlocked, bonderized sheet metal jacket. This insulation-jacketing system has a proven North Slope track record of preventing moisture ingress.

The initial K value for insulation as prescribed by ASTM standards C177 or ASTM C518 should not exceed 0.0125 Btu/(ft hr °F) at 74°F. With time the insulation K value increases. A conservative insulation K value of 0.018 Btu/(ft hr °F) should be used for design purpose.

Field joints are the locations at which most North Slope external corrosion occurs. The design basis for the PTEP incorporates the current field joint coating, insulation, sealing, and jacketing system, including recent enhancements currently in use on North Slope pipelines. External corrosion monitoring and inspection, particularly at field joints, will be conducted during periodic pipeline inspections and surveillance.

The weld pack currently used on the North Slope consists of two half-shells of preformed insulation that match the outer diameter of the shop-applied pipeline insulation, but leave a small gap between the inner surface of the weld pack and the outer surface of the pipeline. The ends of the shop-applied insulation are sealed from water intrusion using a silicon sealant similar to GE Silpruf, effective for a temperature range of –50°F to 230°F. The sealant is installed to overlap the insulation jacket on the outside and the pipe surface at the insulation-to-pipe interface. Foam-in-place PUF field joint insulation will also be considered. This method may be preferred over the pre-formed half-shells because of the chemical bond between field joint insulation and factory-installed insulation is stronger than silicon sealant.

Weld pack insulation and jacketing will be selected during final design. Recent and ongoing weld pack enhancements will be considered and incorporated as appropriate during detailed design.

5.9 Guides, Slides, and Anchors

Slide and anchor saddles will be strapped firmly to the pipe over the insulation jacket. Slides have stainless steel sliding surfaces attached to the bottom of the saddle. This rests on a polytetrafluoroethylene (PTFE) sliding surface, such as Teflon®, that will be installed on the top surface of the support. Anchor saddles will be welded directly to the top of the supports which will prevent any differential movement between the pipe and the support.

Guided saddles are the common bolted-in-place style used for recent North Slope pipeline projects (e.g., Badami and Alpine) and most of the other infield pipelines recently installed on the North Slope. A sliding surface such as ultra-high molecular weight polyethylene (UHMWPE) placed on the inside of the saddle protects the pipeline insulation jacket from wear. Tivar® is an example of several equal options that will be considered for use in the guided saddles.

The friction coefficient between the pipeline and supports can range from 0.10 to 0.25. Stress analyses will be conducted considering these bounding values.

5.10 Wind Induced Vibration Prevention and Mitigation

Preliminary wind induced vibration (WIV) analysis was conducted for the PTEP. A generic AutoPipe model was developed from the preliminary PTEP configuration and design data contained in this Design Basis. The maximum pipeline span (i.e., distance between VSM) used for the WIV analysis was 55 feet. Prudhoe Bay wind data was used for the preliminary WIV analysis. Comparison of the Prudhoe Bay data with wind data collected in the Badami area confirmed that the Prudhoe Bay wind data adequately represents wind conditions prevailing across the North Slope.

The preliminary WIV analysis concluded that significant segments of the PTEP may be exposed to narrow band vortex shedding; the most severe WIV condition the pipeline is likely to experience, under laminar and turbulent wind conditions. Maximum displacement and stress expected due to WIV are 2.3 inches and 8.5 ksi, respectively.

A wind fan was developed for facilities in the Kuparuk field to assess the effects of wind on pipeline orientation. The Kuparuk wind fan, encompassing azimuths from N35°E through N50°W, is a broadly used tool on the North Slope for indicating pipeline orientations that are generally subject to WIV. An initial review of wind rose information from Milne Point, Deadhorse, and Badami as presented in OCS Study MMS 2007-011, Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis Project indicated azimuths from N30°E to N65°W may be more appropriate for the Point Thomson Project. Additional review and analysis will be conducted during detailed design.

6. WELDING

6.1 Welding Criteria

Welding and inspection requirements will comply with 49 CFR 195 Subpart D, API 1104, and project specifications for onshore pipeline welding.

Welding specifications and welder and welding operator qualifications will meet these requirements. All welding consumable materials will meet API 1104 and project specifications for onshore pipeline welding and be compatible with the line pipe materials.

Project specific welding and inspection specifications will be based on API 1104 and ExxonMobil Global Practices for onshore pipeline welding.

7. HYDROSTATIC TESTING

Hydrostatic testing of the pipeline will exceed the requirements of 49 CFR 195 and ASME B31.4, in that the minimum test pressure will be 150% of the maximum operating pressure (MOP) rather than 125% as prescribed by the codes. General requirements include:

1) A strength test of at least 4 continuous hours at a minimum pressure equal to 150% of the design pressure.
2) A leak test of at least 4 continuous hours at a minimum pressure equal to 150% of the design pressure.

8. CLEANING AND DRYING

The entire pipeline system will be thoroughly cleaned prior to hydrostatic testing. Following testing, the line will be completely evacuated and dried prior to commissioning. Drying will be adequate to ensure the dew point within the pipeline system will be at or below –20°F. Following cleaning and drying, the pipeline will have blind flanges with taps installed and the line will be inerted with nitrogen with a nominal positive pressure.

9. INTEGRATED CONTROL AND SAFETY SYSTEM (ICSS)

9.1 General Description of ICSS

The Point Thomson facilities will be operated and controlled by an Integrated Control and Safety System (ICSS). Design codes applicable to the ICSS are the IBC; NFPA 30, Flammable and Combustible Liquids Code, 2000; and NFPA 70, National Electric Code, 2002. The portions of the ICSS that falls within the scope and jurisdiction of the above Codes will meet all applicable requirements contained in the Codes. Documentation demonstrating such compliance will be provided, as required, during detailed final design.

The Point Thomson ICSS is comprised of the following major systems.

9.1.1 Process Control System (PCS)

This system will serve as the primary means to control and monitor all operations of the facilities from a fully-manned, centralized control room (CCR) at the Central Pad. It will be used to control not only the Central Pad equipment, but also the remote wellheads located at the edges of the field, control and monitoring of the PTEP, and the 12-inch nominal diameter BSOP tie-in. The PCS will be a distributed control system relying on a redundant ethernet communication backbone to connect all of its components. The operator, engineering, and application computers will all be industry standard personal computers and servers.

9.1.2 Safety Instrumented System (SIS)

The Safety Instrumented System (SIS) at Point Thomson will be a high integrity system to provide safety shutdown and annunciation of all critical processes. This system, completely independent of the PCS, will serve to protect equipment and personnel from process upset and emergency conditions and the unexpected release of hazardous hydrocarbon vapors. This safety system, while functioning separately, will have data links to the PCS for purposes of monitoring from the CCR Operator Stations.

9.1.3 Fire Detection System (FDS)

An independent, State of Alaska compliant fire detection and alarm system will provide early and reliable detection of fire hazards, prompt notification of a fire condition, and activation of the fire suppression system. It will have hard-wired interface to the SIS for shutdown coordination and gas accumulation alarming. Dual serial links to the PCS will serve to provide integrated monitoring of the fire system with all operations.

9.1.4 Third Party Equipment

In addition to remote control and monitoring from the CCR, certain major equipment will be provided with their own, standalone measurement/control system such as fiscal and leak detection metering, meter provers, and SCADA PLC. This equipment will be connected to the PCS via serial communication link. These panels will provide local control during normal operation, and assist Operations during equipment startup and system troubleshooting. Certain remote control functions will also reside in the PCS to allow start/stop, set point changes, valve and pump control, and data monitoring from the CCR.

9.2 Communication System

The Point Thomson pipeline will have multiple communication links including a radio system and telecommunications system. Communication links will be established between the Point Thomson Control Center, the Badami Control Center, the Endicott Pipeline Control Center, the ExxonMobil Pipeline Control Center in Houston, and the TAPS PS-01 facilities. This will include appropriate communications for a quick response should an emergency situation arise. In addition, a connection to ExxonMobil's electronic mail system will be provided.

9.3 Leak Detection System

The PTEP will include two computational leak detection systems in accordance with federal and state requirements and API 1130, Computational Pipeline Monitoring for Liquids Pipelines, 2002.

Due to the importance of detecting spills, there are two independent leak detection systems being implemented to monitor the PTEP.

The primary leak detection system will be a statistical based system using data from the custody meter flow computers, e.g., ATMOS Pipe system. This system will require flow, density, pressure, and temperature measurements at CPF and Badami. The leak detection software will run on a dedicated computer located in the Point Thomson Central Control Room (CCR).

The secondary leak detection system is based on EMPCo's proprietary leak detection software run on a RTO2 PLC. This technology utilizes pressure waves from pressure transmitters located inside the automated shutdown valves (SDV) at both ends of the pipeline. The program runs on an Allen Bradley L32E CompactLogix processor, and data will be transmitted directly to the CCR.

Neither leak detection system initiates an automatic shutdown of the facility. Leak detection will alert the operator to take appropriate action.

In addition to leak detection systems, PTEP leak monitoring will also be combined with periodic surveillance. Periodic surveillance of the PTEP will be conducted in accordance with CFR Title 49, Part 195 and ASME B31.4 requirements. The surveillance will also be consistent with the Point Thomson Corrosion Management Program and in accordance with the Alaska Department of Environmental Conservation Regulations (18 AAC 75).

9.4 Fire Detection and Suppression System

A fire detection and suppression system will be installed throughout the Point Thomson facilities including the Central Pad and the Badami meter station. In general, all enclosed process areas, equipment rooms, and living/office quarters will be continuously monitored for smoke and/or fire. All fire panels will be interfaced with the PCS so that any detection of fire will be annunciated to the control room operators who have the ability to immediately shutdown and de-pressure the process.

Fire suppression, in general, will be accomplished by the use of a fine water mist system. At the Central Pad, the fine water mist system will be an interconnected system with centrally located water pumps and control system. At the well pads and the Badami meter station, the fine water mist system will be accomplished through the use of pressurized vessels.

9.5 Gas Detection System

Gas detection monitors, located throughout the Point Thomson facilities, will be connected to the fire and gas detection system for alarm annunciation and shutdown activities. Full detection, suppression and ventilation of 6 air changes per hour for normal and 12 air changes per hour for emergency will be provided. The ventilated air will be heated.

10. OPERATIONS

10.1 Flow Control

At the Central Pad, liquid hydrocarbon will be pumped using shipping pumps. These pumps will raise the pressure in the pipeline as required to achieve the target flow rate.

10.2 Pipeline Isolation

The pipeline actuated isolation valves will be installed at Point Thomson CP downstream of the launcher and upstream of the piggable wye at the Badami BSOP tie in.

These valves will be remotely operated from the Control Center, will have a manual override, and be part of the Emergency Shut Down (ESD) system. Vertical loops along the PTEP will be installed on the east and west sides of the East Badami Creek as isolation devices for the creek. A typical vertical loop is presented in Figure 5.2.

The launcher will be located at the Point Thomson Central Pad. The launcher barrel will be operated "dry" and will have a double block and bleed valving system for isolation from the main pipeline when required. The trapping systems will be protected by a safety system or operating procedure so that the trap cannot be over pressured and the access door cannot be opened when the barrel is under pressure. The launcher will be outdoors and designed to –50ºF

Due to the operations procedure which leaves the traps dry when not in use, the relatively small volume of the barrel when isolated (<240 gallons), and the higher than ambient temperature of the fluid, a thermal relief system is not required. The system will be provided with instrumentation to signal the arrival of the pig at the launching or receiving station.

The portions of the PTEP system to be subjected to in-line inspection (ILI) will have bends with a minimum radius equivalent to five times the nominal diameter of the pipe (5D bends). The launcher will be designed to handle all the anticipated inspection tools, as well as a full range of pipeline cleaning tools.

10.3 Pressure Monitoring and Relief

ExxonMobil's Operations Integrity Management System ("OIMS") will be implemented to ensure effective and safe operation of the pipeline system. A principal requirement for operation will be that the chain of communication and command and operator protocol for the entire PTEP system will be clearly and thoroughly documented, understood, and tested.

The current Point Thomson Central Processing Facility operations plan is to be attended 24 hours a day, 7 days a week. Part of the daily responsibilities of Point Thomson Operators will be to monitor the operating parameters, and to make process adjustments on the PTEP.

The pressure on the liquid hydrocarbon shipping pumps discharge will be monitored at the CP. The shipping pumps discharge or shutoff pressure is lower than pipeline design pressure; therefore, it will not over-pressure the pipeline.

Local and remote commands to stop pumps or close Shutdown Valve (SDV) will be allowed.

10.4 Start-up

Initial start up will be made using production liquid hydrocarbon. The start-up procedures will be developed during the detailed design of the system.

10.5 Flow Constraints

Flow constraints that must be mitigated by design or by becoming operating restrictions will be determined based on connection agreements currently being negotiated.

10.6 Normal Operations

The steady state conditions for normal flow rates, temperatures, and pressures for the PTEP will be monitored and controlled from the control room at the Central Pad at Point Thomson.

10.7 Planned and Unplanned Shutdown of Liquid Hydrocarbon Line

The liquid hydrocarbon pipeline to Badami can be shutdown at any time for planned or unplanned events without additional work. The line would only need to be de-inventoried to make repairs.

Laboratory testing demonstrated that Point Thomson liquid hydrocarbon flows at –20°F. Furthermore, given the properties and characteristics of liquid hydrocarbon, it is expected that Point Thomson fluid will flow at –50°F. Cold restart will be accomplished by slowly increasing the fluid production rate. Hot liquid hydrocarbon will begin to move within the annulus between the pipe wall and the core of cold liquid hydrocarbon along the axis of the pipeline. Over time the warm liquid in the annulus will mix with the cold core of the liquid hydrocarbon; resulting in warmer pipeline temperature, decreased viscosity and increased flow rate. This gradual process will continue until normal liquid hydrocarbon throughput is achieved.

10.8 Maintenance

Pipeline valves will be inspected, serviced where necessary and partially operated every 7.5 months and at least twice each calendar year to verify proper operation. All pipeline valves will be designed and located to facilitate the inspections.

A wax deposition study and pigging frequency analysis were performed by ExxonMobil Upstream Research Company in February 2010 for the PTEP system. Regular wax pigging of the PTEP to Badami is not required as significant wax drop out does not occur until below -50°F.

Due to dehydration during initial production, hydrate issue for the PTEP is not anticipated as the stabilized liquid hydrocarbons will have insufficient hydrate forming gas molecules or water to form hydrates, let alone a hydrate blockage.

Based on the PTEP Flow Assurance studies on wax deposition and hydrate formations, the cleaning tools (pigs) frequency during the initial production of 10,000 BPD is once every 3 months (4 times per year) during normal operation. A more frequent cleaning may be required during winter season, if the PTEP is operated at turndown for significant periods of time. This situation will be address during operations on the case by case basis.

10.9 Dismantle, Remove, and Restore

Dismantle, remove, and restore (DR&R) activities will be consistent with lease terms, permit conditions, and other applicable regulatory requirements. Detailed abandonment procedures will be developed at the time of project termination. Specific plans will depend on the facilities in place and the specific requirements applicable to those facilities at the time of abandonment.

10.10 Surveillance

Periodic surveillance of the PTEP and Lease will be conducted in accordance with federal regulatory and ASME B31.4 requirements and in accordance with the Alaska Department of Environmental Conservation Regulations (18 AAC 75).

Visual surveillance of the pipeline and right of way will typically be conducted weekly by aerial surveillance, unless precluded by safety or weather conditions.

11. CORROSION CONTROL AND MONITORING

11.1 Corrosion Control Measures

11.1.1 Internal Corrosion

Internal corrosion will be mitigated using corrosion inhibitor and a 0.125-inch corrosion allowance. The corrosive effects of the liquid hydrocarbon will be monitored through the use of corrosion coupons installed in the flow path and examined once every 7.5 months and at least twice each calendar year.

11.1.2 External Corrosion

External corrosion will be controlled in accordance with federal regulations. The design basis for factory-installed insulation for the PTEP consists of polyurethane foam insulation covered with roll formed, interlocked, bonderized sheet metal jacket. This insulation-jacketing system has a proven North Slope track record of preventing moisture ingress.

Dual layer fusion-bonded epoxy anti-corrosion coating will be applied beneath the pipeline insulation. Total dry film thickness will range between 20 and 32 mils with a minimum average thickness for the FBE anti-corrosion (e.g., 3M, Scotchkote®: 226N/6233) coating of 24 mils. The anti-corrosion coating will be sufficient for the operating conditions of the pipeline in Table 5.1. FBE field joint coating will be compatible with the factory-applied FBE anti-corrosion coating.

Field joints will be coated with field applied FBE to the maximum extent possible. Two-part paint on epoxy coating is allowed where use of FBE is not practicable, e.g., tie-in welds, etc. An insulation, sealing, and jacketing system will be installed based on best available North Slope practices.

11.2 In-Line Inspection

The PTEP will be designed to allow passage of in-line inspection (ILI) and maintenance and cleaning tools. The frequency of inspection is currently undetermined, but will be developed during detailed design to be consistent with the Point Thomson Corrosion Management Program.

12. RISK ASSESSMENTS

EMPCo's Index Based Risk Assessment (IBRA) program TIARA will be utilized. Additionally, transient hazardous operations (HAZOP) reviews will be required by EMPCo and will be conducted during the FEED and subsequent design stages as considered necessary.

ATTACHMENT 1: LOG OF CHANGES

Change Log

Document Number	Title	Rev	Comment No	Page / Section	Company Comments	Commentor
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	1	General	Updated abbreviations/acronyms for consistency through out.	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	2	5 & 6	Updated List of Acronyms and Abbreviations to reflect current usage in the Design Basis.	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	3	7/1.2	Removed discussion of next design phase, as we are moving into final design.	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	4	7/1.3	In second paragraph replaced "include" with "apply to" in reference to the VSM being exempt from the minimum 7 feet clearance to tundra.	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	5	11/2.2	Removed reference to pig receiver.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	6	12/2.1	Replaced "LLC" with "Operations" and "make sure" with "ensure" in last paragraph.	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	7	12/2.2	Removed pig receiver from Figure 2.1	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	8	13/2.2	Updated description of BSOP tie-in to include piggable wye. Removed reference to incorporating leak detection in to BSOP and Endicott Pipeline. Removed reference to surge protection being considered in detail design.	C. Watters P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	9	14/2.4	Updated Alaska Safety Handbook from 2006 to 2010 edition.	M. de la Pena
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	10	15/3.1	Changed typical water depths to betweeen 7 and 12 feet.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	11	22/3.5	Removed "previously" in reference to the Design Seismic Zone 1 used in UBC.	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	12	23, 24/3.7	Road Crossing details have become generic and a section detail has been added.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	13	23/3.6	Removed reference to avoidance of lakes during final design.	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	14	23/3.7	Updated description of small pad crossing near the Badami CFP	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	15	23/3.6	Capitalized first letters on sales oil pipeline to match general project terminology. Added "(BSOP)"	P. Carson/C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	16	26/4.2	Update text in Design Loads section.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	17	27/ 4.3	Table 4.2 was updated.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	18	28/Table 4.2	Updated notes section to correspond with Pile Spec	M. Mollenkopf
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	19	28/4.3	Updated description of VSM design.	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	20	28/4.4	Stream crossing text has been updated.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	21	28/4.4	Flow values in Table 4.3 have been updated. "K" Creek has been removed because its drainage area dropped below 10 sq mi and "D" Creek has been added.	C. Watters

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Document Number	Title	Rev	Comment No	Page / Section	Company Comments	Commentor
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	22	29/4.3	Updated minmum embedment as calculated to resist heave	M. Mollenkopf
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	23	29/4.4	Updated wording in reference to the design case for VSM in streams.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	24	29/4.4.1	Scour text has been modified and Table 4.4 has been added.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	25	29-31/4.4.2	Renamed section to "Freshwater Ice" and updated text.	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	26	30/Table 4.4	Updated table to reflect latest support numbers and convert VSM diameters to NPS from feet	M. Mollenkopf
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	27	33,34/5.3.2	Update Accidental Bullet Impact section.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	28	33/5.1	Changed "modelling" to "modeling"	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	29	33/5.2	Updated Surge Analysis section. Added Table 5-3 to show Peak Potential Surge Pressures.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	30	33/5.2, 5.4.2	Changed maximum surge to be less than 100% rather than 110%.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	31	33/5.3.1	Added section 5.3.1 Design Factor.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	32	35,45/5.4.3, 7	Increased hydrostatic test pressure to 1.5 MOP.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	33	35/5.1	Changed "in the range of 10,000 to 20,000" to "nominally 10,000"	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	34	35/5.4.6	Changed wind pressure to 19 psf rather than 18 psf. Also, added reference to typical pipeline height being 7 to 8 feet.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	35	36/5.4.10	WIV section updated. May need to be updated once final WIV analysis is completed.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	36	36/5.4.9	Loss of Support section updated	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	37	36/5.5	Add title of ASME B31.4. "Pipeline Transportation Systems for Liquid hydrocarbons and Other Liquids"	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	38	39/5.6	Added Figure 5.2 showing PI-Configuration. Also update text for Configuration section	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	39	40/5.7	Remove reference to pig receiver at Badami and add piggable wye. Also, added reference to operating procedure which will leave the trap dry when not in use.	C. Watters/P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	40	41, 60/5.8, 11.1.2	Used "bonderized sheet metal" instead of "galvanized metal" for the insulation jacketing.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	41	41/5.8	Added reference to ASME B31.4 in addition to 49 CFR 195 for wall thickness calculations.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	42	41/5.8	Raised design insulation temperature to 230 deg F.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	43	41/5.8	Removed redundant paragraph discussing PTEP insulation system.	P. Carson

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USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	44	41/5.8	Raised design insulation temperature to 230 deg F for the weld packs.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	45	42/5.9	Change "relative motion" to "differential movement" in reference to Anchor Saddles.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	46	42/Table 5.2	Updated B31.4 reference to include edition of the code.	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	47	48/5.10	Changed "should" to "will" in reference to additional WIV review and analysis during detailed design. Removed reference to preliminary WIV analysis.	P. Carson C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	48	48/9.3	Updated Leak Detection/Metering.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	49	50/10.1	Document has been updated to show two shipping pumps rather than one.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	50	50/10.2	Pipeline Isolation text has been updated. Also, remove reference to receiver at Badami.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	51	51/10.8	Maintenance text has been updated.	C. Watters
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	52	52/11.1.2	Updated FBE coating thicknesses and added reference to epoxy coating. Also corrected text in reference to installation of the jacketing system.	C. Watters P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	53	58/11.1.1	Changed "0.125 inch" to "0.125-inch" in reference to the corrosion allowance.	P. Carson
USPT-WP-YBDES-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2A	54	34, 36/ Table 5.2 & 5.3	Removed reference to 20 KBPD in Table 5.2 and Table 5.3, as well as from the body of the Text.	T. Bunnell
SPCO Exhibits: NO UPDATES HAVE BEEN MADE TO FIGURES						
USPT-WP-SDZZZ-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	1	SHT 001	PTEP alignment needs to be updated based on IFQ design. IPS layout needs to be updated.	P. Carson
USPT-WP-SDZZZ-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	2	SHT 002	PTEP alignment needs to be updated based on IFQ design. Alignment from CPF to fourth change in direction is significantly different. IPS layout needs to be updated. CP and road configuration has changed significantly.	P. Carson
USPT-WP-SDZZZ-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	3	SHT 006	PTEP alignment needs to be updated based on IFQ design. Alignment from furthest east change in direction to change in direction west of stream crossing is significantly different. Road crossing has moved south several hundred feet. IPS layout needs to be updated. West Pad and road configuration has changed.	P. Carson
USPT-WP-SDZZZ-060001	Point Thomson Design Basis for Permitting - Export Pipeline	2	4	SHT 022	PTEP alignment and gravel layout at Badami need to be updated based on piggable wye	P. Carson
USPT-WP-SDZZZ-060004	Point Thomson Design Basis for Permitting - Export Pipeline	2	5		Remove second future gathering line and move power/FOC to other side of 8" future gathering.	P. Carson
USPT-WP-SDZZZ-060005	Point Thomson Design Basis for Permitting - Export Pipeline	2	6		Remove power/FOC.	P. Carson

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USPT-WP-SDZZZ-060006	Point Thomson Design Basis for Permitting - Export Pipeline	2	7		Remove power/FOC.	P. Carson