Polar LNG Feed Gas Pipeline

Basis of Design

Prepared for:

POLAR LNG
Green Fuel for Alaskans

Revision 1

September 03, 2013

Baker

Michael Baker Jr., Inc.

1400 West Benson Blvd., Suite 200
Anchorage, Alaska 99503
907-273-1600

124937-MBJ-DOC-001

Revision History

Rev	Date	Comments	Baker Approval	Polar LNG LLC Approval
A	09/14/2011	Draft		
B	09/21/2011	Updated per comments received. Updated section 5.3.1 to ASCE 7-10 previously was 7-05.		
C	10/13/2011	Removed reference to using existing VSM and updated route near the Halliburton Pad		
D	11/21/2012	Updated project personnel and incorporated comments from Client and SPCO		
E	01/08/2013	Incorporated SPCO comments dated December 21, 2012.		
0	02/08/2013	Issued For Public Comment		
1	09/03/2013	Updated Alignment at Polar Pad		

Title	Name	Signature	Date
Michael Baker Jr., Inc. *Project Manager*	Jason Gardner		
Michael Baker Jr., Inc. *Project Engineer*	Josh Greenhill		
Michael Baker Jr., Inc. *Civil Engineer*	Toby Lovelace, PE		
Polar LNG, LLC *Project Director*	Doug Smith, PMP		
Western Industrial Resources Company *Project Lead*	Eric Franklin, PMP		

Table of Contents

List of Tables

List of Figures

Appendices

List of Abbreviations and Acronyms

AISC	American Institute of Steel Construction
ANSI	American National Standards Institute
API	American Petroleum Institute
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
BOP	Bottom of pipe
BPXA	BP Exploration (Alaska), Inc.
CFR	Code of Federal Regulation
CVN	Charpy V-Notch
DF	Design factor
DOT	Department of Transportation (U.S.)
DS-12	Drill Site 12
FBE	Fusion bonded epoxy
FNG	Fairbanks Natural Gas, LLC
FS-1	Flow Station 1
g	Gravity
GPB	Greater Prudhoe Bay
HSM	Horizontal support member
IBC	International Building Code
ILI	In-line inspection
LNG	Liquefied natural gas
LRFD	Load and Resistance Factor Design
MAOP	Maximum allowable operating pressure
MMscfd	Million standard cubic feet per day
PBU	Prudhoe Bay Unit
pcf	Pounds per cubic foot
PPM	Parts per Million
psf	Pounds per square foot
SIP	Seawater Injection Plant
SMYS	Specified minimum yield strength
TOS	Top of Steel
TVA	Tuned vibration absorber
UHMW-PE	Ultra High Molecular Weight Polyethylene
VSM	Vertical support member
WIV	Wind induced vibration

1.0 Introduction

The Polar LNG, LLC (Polar LNG) program will construct a feed gas pipeline and a natural gas liquefaction plant in Deadhorse, Alaska, adjacent to the Prudhoe Bay Oil Field on Alaska's North Slope. The liquefied natural gas (LNG) will be transported by truck to Fairbanks, Alaska, where it will be stored and vaporized on demand. The LNG will provide Fairbanks Natural Gas (FNG) with a larger supply to increase gas service within its service area.

Polar LNG is planning to install the feed gas pipeline by the second quarter of 2014. The pipeline will tie into the Seawater Injection Plant (SIP) 10-inch nominal diameter fuel gas line at an existing flanged connection. From this tie-in, the pipeline will pass through a metering skid, to be designed by others. On the downstream side of the metering skid, the pipeline will proceed cross-country to the Polar LNG facility near Drill Site 12 (DS-12). The pipeline will be in compliance with DOT (49 CFR 192) regulations. The pipeline will be routed within a new right-of-way.

The new pipeline will be NPS 8 (8-inch nominal diameter), API 5L X65 carbon steel, and have a total length of approximately 18,600 feet. The pipeline capacity will be 32 million standard cubic feet per day (MMscfd) of feedstock gas. Table 1.1 shows the feed gas composition. The pipeline will be designed for a maximum allowable operating pressure (MAOP) of 1480 psig, with a normal operating pressure of approximately 650 psig. The pipeline will be coated with two layers (approximately 40 mils) of fusion bonded epoxy (FBE) for corrosion resistance. The pipeline will only be insulated for short distances at each anchor support. The pipeline will be installed on new vertical and horizontal support members (VSM/HSM).

A map of the project area is presented in Figure 1.1.

Table 1.1 Feed Gas Composition

Components	Design Gas (Mole %)	Rich Gas (Mole %)	Lean Gas (Mole %)
Methane, C_1	80.1	80.6	79.4
Carbon Dioxide, CO_2	12.05	12.4	11.8
Ethane, C_2	5.25	5.6	5.2
Propane, C_3	1.65	1.9	1.5
Nitrogen, N_2	0.61	0.64	0.58
Butane	0.28	0.35	0.26
Pentane	0.04	0.05	0.04
Hexane	0.02	1.02	2.02
Hydrogen Sulfide, H_2S	12 PPM	40 PPM	20 PPM
Water, H_2O	3 PPM	6 PPM	3 PPM
Note: Compositions are from the Polar LNG, Feed Gas Pipeline Design Basis, Rev B, received from Peak Oilfield Services.			

Figure 1.1 Polar LNG Pipeline between Seawater Injection Plant (SIP) Pad and Polar LNG Facility

2.0 Project Overview

2.1 Pipeline Route

The pipeline will follow the alignment shown in Figure 1.1. A new pipeline right-of-way will be obtained by Polar LNG. The pipeline alignment will start near the origin of the SIP 10-inch nominal diameter fuel gas line, travel to the metering skid, and head south along a new right-of-way until turning east at a location north of the Halliburton Pad. The pipeline will turn south toward DS-12, remaining east of Halliburton Pad, until reaching the north shore of McDermott Lake. The pipeline will then follow the northern and eastern shores of the lake to its terminus at the Polar LNG Pad near DS-12.

To support the construction of the new pipeline, an ice road approximately 30 feet wide will be required. Work and turnaround areas, roughly 120 by 120 feet, will be spaced along the route. A minimum 7 feet of clearance will be maintained between the tundra surface and the bottom of pipe, except at road crossings where the pipeline will descend before entering a steel casing.

A metering skid will be installed at the SIP Pad to determine the volume of gas purchased by Polar LNG. The portion of the line between the tie-in and the metering skid is outside the jurisdiction of the U.S. Department of Transportation (USDOT) and therefore is not governed 49 CFR 192. This section will be designed in accordance with ASME B31.8. Polar LNG will be the responsible party for the operation and maintenance, and the emergency response for this section of the line.

The pipeline will terminate at the Polar LNG Facility pad as shown in Figure 2.1. Receiver barrel connections will be installed at this location.

Figure 2.1 Termination at Polar Pad

2.2 Pipeline Configuration

2.2.1 Expansion Loops

To account for the effects of thermal expansion, "Z" style expansion loops will be used, shown in Figure 2.2. Two 90-degree bends will be used in typical sections. Stresses and displacements calculated will govern the allowable distance between anchors.

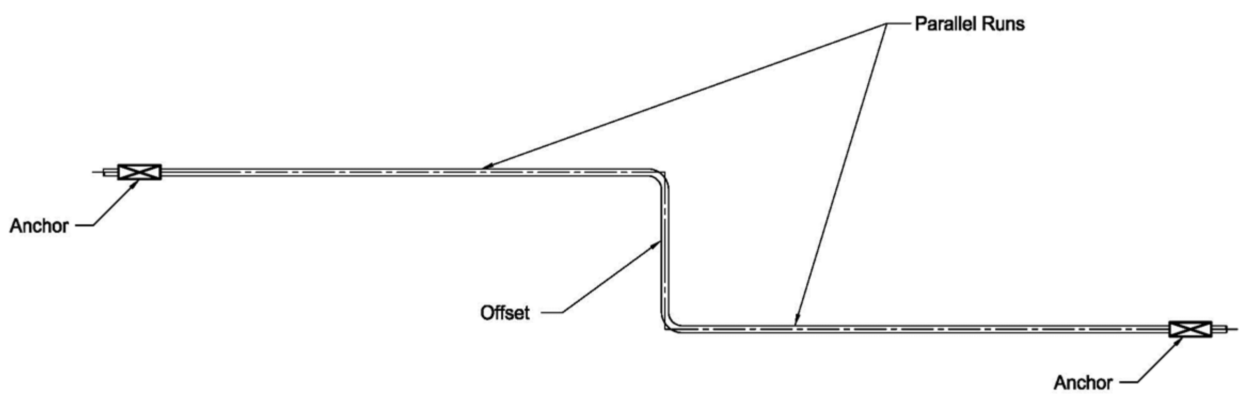

Figure 2.2 Typical Z Loop Configuration

Pipe bends used at expansion loops and piping intersections will be pre-fabricated induction bends. Routing and configuration optimization will be conducted to minimize the number of induction bends. All pipe bends will have a minimum radius requirement of three times the nominal pipeline diameter (3D) to accommodate the use of in-line inspection (ILI) tools.

2.2.2 Supports

A minimum spacing of 3.5 feet will be maintained between the ends of the existing HSM beams and the new pipe support beams in the area near the SIP pad.

Typical support spacing will be approximately 55 feet. Consideration will be given to accommodate field changes up to 5 feet resulting from massive ice or other conditions encountered during installation of the supports, variations in survey information, and avoidance of any natural or manmade structures not previously addressed.

North Slope Borough regulations require a minimum clearance of 7 feet from bottom of pipe to the tundra surface. The saddles each will provide additional elevation to the bottom of pipe and will raise the pipeline to an elevation to allow the mid-span sag of the pipeline to exceed the clearance requirement. This eliminates the need for caribou crossings along the alignment.

2.3 Launcher and Receiver Barrels

The pipeline will be designed to accommodate connection of temporary/portable launcher and receiver barrels to allow deployment of in-line inspection (ILI) and maintenance tools. The launcher barrel connections will be located downstream of the metering skid and receiver barrel connections will be located at the Polar LNG facility for use by operations.

3.0 Design Parameters

3.1 Pipeline Data

The Polar LNG pipeline will be designed according to the codes, standards, and specifications as outlined in Appendix A of this report. The pipeline will not be insulated for the majority of the alignment. The pipeline will instead be coated with two layers of FBE coating, approximately 40-50 mils thick. As FBE is not UV resistant, this thickness will allow for the outer surface of the pipe to "chalk" while still affording adequate corrosion protection of the pipe steel. The pipeline will be insulated for short distances at each anchor support. This will allow a typical anchor saddle design that clamps around the insulation to be used.

The pipeline design parameters are summarized in Table 3.1.

Table 3.1 Pipeline Parameters

Parameter	Tie-in to Meter	Cross Country	Halliburton Pad to Polar LNG Pad
Product	Feed Gas	Feed Gas	Feed Gas
Governing Codes	ASME B31.8	CFR 49 Part 192	CFR 49 Part 192
Location Class	2	1	3
Code Design Factor (DF)	0.60	0.72	0.50
Nominal Pipe Diameter	8-inch	8-inch	8-inch
Minimum Wall Thickness	0.226 inch	0.199 inch	0.259 inch
Design Wall Thickness	0.322 inch	0.322 inch	0.322 inch
Corrosion Allowance	0.0625 inches	0.0625 inches	0.0625 inches
Material Grade	API 5L X65	API 5L X65	API 5L X65
Specified Minimum Yield	65,000 psi	65,000 psi	65,000 psi
ASME B16.5 Rating	Class 600	Class 600	Class 600
Maximum Allowable Operating Pressure (MAOP)	1480 psig	1480 psig	1480 psig

All bends will have minimum radii of three times the nominal diameter to facilitate passage of ILI and maintenance tools.

3.2 Design Loads

Detailed industry requirements regarding allowable internal pressure and other loads, loading combinations, or limitations on combined states of stress are presented in ASME B31.8, ASCE 7-10, and project design specifications.

The design operating conditions are defined to include all normal operating conditions and environmental loadings. Design loads include internal pressure, temperature differential, dead and live loads, wind load, hydrostatic test loads, and loads imposed by earthquakes. Pipeline design loadings are summarized in Table 3.2.

Table 3.2 Design Loading

Operational Loadings for Pipeline	
MAOP	1480 psig
Maximum Operating Temperature	100°F
Minimum Temperature	–50°F
Tie-In Temperature	25°F
Insulation Thickness	None
Specific Gravity of Contents (Air = 1.00)	0.72
Pipe Guide Saddle Friction Coefficient (UHMW-PE liner and FBE)	0.25[1]
Pipe Slide Saddle Friction Coefficient (PTFE and Stainless Steel)	0.10[1]
Dead Loads	
Pipe Steel Unit Weight	489 pcf
Occasional Loads	
Wind	110 mph
Snow Load (ground)	50 psf
Earthquake Acceleration	0.213g
[1]Actual friction coefficients reported by the manufacturer(s) are lower (0.18 for guides and 0.04 for slides). Analysis will be run for each set of friction values to determine controlling case.	

3.2.1 Internal Design Pressure

The pipeline will be designed to 1480 psig (based on ASME B16.5 Class 600 flange rating) which is greater than the MAOP of the PBU Field Fuel Gas pipeline (1440 psig). The operating pressure of the PBU Field Fuel Gas pipeline is 575-650 psig.

3.2.2 Hydrostatic Test Loads

The pipeline will be tested to at least 1.5 times the MAOP. One hydrostatic test will be performed from the flange connection off the 10-inch SIP fuel gas line to the metering skid, and the other will be performed from the metering skid to the Polar LNG pad. The southern portion of the pipeline will be Location Class 3. The maximum hoop stress during hydrostatic testing will be less than 95% of the specified minimum yield strength (SMYS). The pipeline design is expected to accommodate the test conditions as a contingency load. The load combination for modeling hydrostatic testing on installed pipe typically includes internal pressure, gravity, thermal differential (during testing), and $^{1}/_{3}$ wind speed (approximately 37 mph).

3.2.3 Temperature Differential

Pipe stresses from temperature differential will be calculated per minimum design temperature and the maximum pipe wall temperature.

Pipe stresses from temperature differentials will be calculated per ASME B31.8. The operational range for the pipeline is –50°F to 100°F, which has been verified with Polar LNG. The operative paragraph of ASME B31.8 states:

> The total range in temperature from minimum design temperature to the maximum design temperature shall be considered, whether piping is cold-sprung or not. Should installation, start-up, or shutdown temperatures be outside of the design temperature range, additional analysis will be required. In addition to expansion of the line itself, the linear and angular movements of the equipment to which it is attached shall be considered.

Forces and moments acting on pipeline supports will be calculated based on a cold spring temperature of 25°F. These forces will be determined using a temperature range specified from 25°F to –50°F (contraction) and 25°F to 100°F (expansion).

3.2.4 Gravity Loads

The gravity loads include the weight of the pipe, contents, and external coating. The highest fluid weight that the pipeline will experience will occur during hydrostatic testing.

3.2.5 Snow Load

A minimum design ground snow load of 50 psf per Polar LNG design criteria will be converted to a comparable design snow load as per ASCE 7-10. It is assumed that snow loading only applies to locations identified by field operations where significant snow drift is expected. Typically, snow drift accumulates adjacent to pads and roads, and anywhere the pipeline is not adequately elevated from the tundra (at least 5 feet approximately).

3.2.6 Wind Load and Wind Induced Vibration (WIV)

Design wind speed for aboveground pipelines is 110 mph. The design wind pressure will be calculated using ASCE 7-05 as required by the International Building Code (IBC). The design wind exposure is “C,” the importance factor is 1.00, and the topographic factor “K_{zt}” is equal to 1.00. The force coefficient is taken to be 0.8. The gust effect factor is taken as 0.85. The velocity pressure exposure coefficient “K_z” is defined as 0.85. The pipelines are anticipated to be between 7 and 15 feet above grade for the majority of the alignment. This results in a wind pressure of approximately 18 pounds per square foot on the pipeline.

The new pipeline will be evaluated for susceptibility to wind induced vibration. Segments identified as susceptible will be mitigated using tuned vibration absorbers (TVA), reducing distance between VSM, or other suitable techniques. Baker will perform a simplified screening analysis to determine the susceptibility of the pipeline to WIV. If susceptibility is confirmed by this calculation, SSD, Inc. will be consulted to use refined analysis techniques to determine the proper TVA configuration to dampen the predicted vibrations.

3.2.7 Loss of Support

The design load analysis will include scenarios involving loss of support due to frost jacking or settling of at least one VSM. This will ensure the pipeline will not buckle or rupture if one support is no longer contacting the pipeline.

3.2.8 Earthquake Loads

The North Slope is considered a low seismic risk zone; therefore, simplified static earthquake loads are used in the analysis.

Seismic criteria for pipeline design are based on mapped spectral acceleration values with an estimated 2 percent probability of exceedance during a 50-year return interval (2500-year return interval), and Site Class B soils. Based on USGS data, the project area has approximate maximum short period and 1-second spectral accelerations of S_S=0.319g and S_1=0.109g, respectively. ASCE 7-10, Table 11.4-1, gives the site coefficient for Site Class B as 1.00 for short period spectral accelerations of less than 0.50. Design spectral acceleration is specified to be 2/3 of the factored spectral acceleration, which results in design short-period and 1-second spectral accelerations of 0.213g and 0.073g, respectively. The short-period spectral acceleration will be used in pipe stress analyses of the aboveground pipelines.

3.2.9 Load Combinations

Loads on the pipelines and supports will be analyzed for the load combinations presented in Table 3.3.

Table 3.3 Load Combinations

Load Type	Description	Pipeline Load Combinations								
		Testing		Operating						Contingency
		1	2	3	4	5[5]	6	7[4]	8	9
Primary	Internal Pressure (Hoop)			X					X	X
Primary	Internal Pressure (Longitudinal)				X	X		X	X	X
Primary	Hydrostatic Test Pressure	X	X							
Primary	Gravity Loads		X[1]		X	X		X	X	X
Primary	Occasional Load (Wind, Seismic, Etc.)		X[2]			X		X		
Secondary	Temperature Differential (–50°F to 100°F)		X[3]				X		X	X
Primary	Loss of Support									X
Secondary	Temperature Differential (–50°F to 25°F, 25°F to 100°F)							X		

[1]Gravity load for hydrostatic test includes the weight of the hydrostatic test fluid.
[2]One-third of the design wind speed is included.
[3]Temperature differential for hydrostatic test is based on an assumed hydrostatic test temperature of 60°F.
[4]Combination 7 is applied towards forces, moments, and displacements only and does not apply towards internal pipeline stress.
[5] Stress resulting from worst case occasional load will be reported.
Reference: ASME B31.8, *Gas Transmission and Distribution Piping Systems*

4.0 Pipe Stress

ASME B31.8 addresses detailed industry requirements for gas pipelines. Based on the nature and duration of the imposed loads, pipeline stresses are categorized as primary or secondary stresses. The primary and secondary 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 it is not self-limiting. The stresses caused by the following loads are considered as primary stresses: internal pressure, external pressure including overburden, and dead and live loads.
- **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. The stresses caused by the following loads are considered as secondary stresses: temperature differential, differential settlement, and earthquake motion.
- **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.

4.1 Allowable Stress Criteria

Circumferential, longitudinal, shear, and effective stresses are typically calculated taking into account stresses from all relevant load combinations. Calculations consider flexibility and stress concentration factors of components other than straight pipe. Allowable stresses for aboveground pipeline are presented in Table 4.1.

Table 4.1 Allowable Stress for Aboveground Pipelines

Criterion	Value	Basis	Load Comb.
Testing			
Hoop Stress (hydrostatic test pressure)	0.95 SMYS	Project Defined[1]	1
Longitudinal Stress (hydrostatic test pressure, hydrostatic test temperature, hydrostatic test live, gravity load and the occasional load)	0.95 SMYS	Project Defined[1]	2
Primary			
Hoop Stress (design pressure)	(DF) SMYS[2]	B31.8, 805.2.3	3
Longitudinal Stress (design pressure, gravity load)	0.75 SMYS	B31.8, 833.6	4
Longitudinal Stress (design pressure, gravity load, and other occasional loads)	0.75 SMYS	B31.8, 833.6	5
Secondary			
Expansion Stress (temperature differential)	0.75*T SMYS	B31.8, 833.6, 841.1.8, 841.1.8-1	6
Combined			
Effective Stress (sustained loads, i.e., pressure, gravity, and temperature differential)	0.90 SMYS	Project Defined	8
Effective Stress (sustained loads, i.e., pressure, gravity, temperature differential, and loss of support)	0.90 SMYS	Project Defined	9

[1] Since test pressure is stipulated as 1.25 times the design operating pressure, the minimum test pressure for the majority of the line would correlate to 0.90 SMYS (1.25 × 0.72); therefore the project defined value of 0.95 SMYS was chosen to account for hydrostatic head effects due to elevation changes along the pipeline route.

[2]DF=0.50, 0.72

4.2 Pipeline Stress Analysis

A complete stress analysis will be performed to assure that the design will perform in accordance with specifications, codes, and standards to cover each Pipeline Load Combination (Table 3.3) and Allowable Stresses for Aboveground Pipelines (Table 4.1).

5.0 Pipeline Supports

New pipe supports will be evaluated in accordance with the Load and Resistance Factor Design (LRFD) method presented in AISC Steel Construction Manual, 13th Edition. The stresses in the supports will be evaluated using the interaction formulae presented in Chapter H of AISC 360-05 within the Steel Construction Manual.

5.1 Support Descriptions

Typically, three varieties of pipe supports are used in aboveground arctic pipelines: sliding, guided, and anchor supports.

Sliding supports allow lateral and longitudinal movement of the pipeline (to relieve stresses due to thermal expansion (and contraction). Sliding supports are most often used near bends. For this project, sliding supports will be designed as a single VSM (typically pipe) with a welded cap plate, to which is bolted an HSM (typically a wide-flanged beam). A slide bearing plate (PTFE, e.g., Teflon®) is welded via a carbon steel mounting plate to the top surface of the HSM. The pipeline saddle is fixed to the pipeline and free to slide on the bearing plate (polished stainless steel strips welded to the bottom of the saddle further reduce friction on the bearing plate). See Figure 5.1

Guided pipe supports allow longitudinal movement of the pipeline, but restrict lateral movement, and are used in straight runs of the alignment. Constructed of a single VSM and HSM with cap plate similar to the sliding support, the guided saddle is attached to the beam and the pipeline rests on a liner (UHMW-PE, e.g., Tivar®) within the saddle. See Figure 5.2.

Anchor supports have the primary function of resisting the longitudinal movement of the pipeline, but are also designed to resist rotations and lateral movement. Due to the fixed boundary condition the anchor support provides for the pipeline, anchors require more strength; as such, they are designed to be constructed of two VSM and cap plates connected to a single HSM. Typical moment resistance required necessitates an HSM able to resist torsion. Since wide-flanged beams do not economically resist torsion and rectangular tube shapes are not able to meet low temperature Charpy impact requirements, a “built-up beam” usually consisting of a wide-flanged beam with plate steel boxing in the flanges, is used instead. See Figure 5.3.

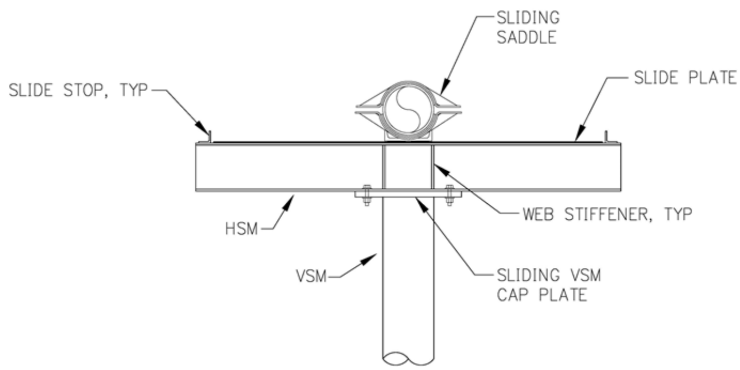

Figure 5.1 Typical Sliding Support

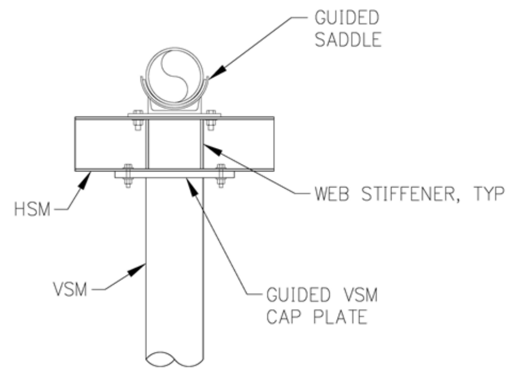

Figure 5.2 Typical Guided Support

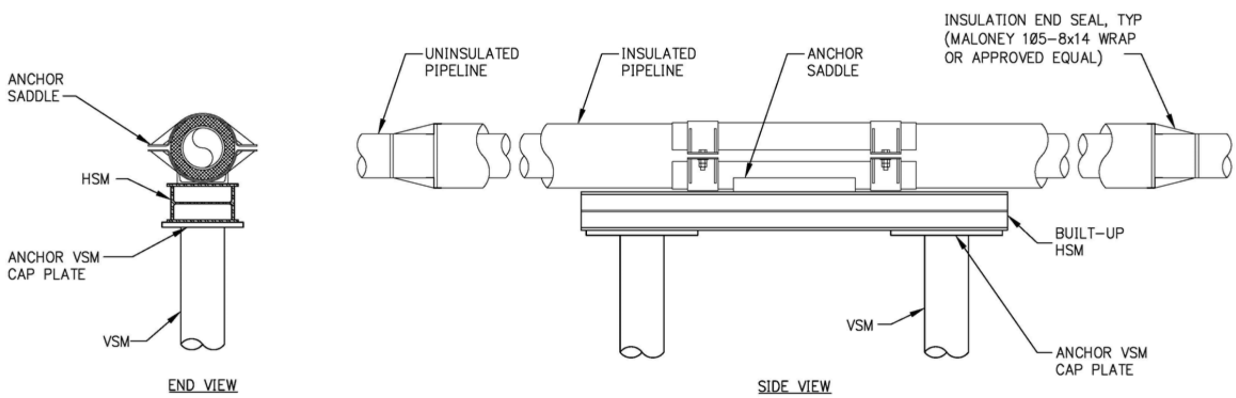

Figure 5.3 Typical Anchor Support

5.2 Support Design

VSM will be installed vertically in oversized, drilled holes and backfilled with dense sand-water slurry. The VSM design will include evaluation of the thermal regime and geotechnical conditions.

The capacity of a VSM to support long-term loads in adfreeze is temperature and soil property dependent. A lower temperature below freezing corresponds to higher adfreeze strength. A design temperature profile to full embedment will be based on typical active layer depth measurements, VSM skin melt allowance, and in-situ soil temperature. The design soil strength values applied to resist VSM loads, both long term and short term, will be for ice-rich soils and will be dependent on the soil temperature profile.

The VSM design is limited by the strength of the VSM steel, the strength of the steel/sand adfreeze bond, and the strength of the in situ soils. Design adfreeze capacity for VSM is calculated assuming the bond strength profile presented in Table 5.1. Minimum embedment will be 15 feet. No adfreeze strength is allowed for embedment in massive ice. Embedment will be increased 1 foot per foot of massive ice encountered, if ice in excess of 3 feet is encountered (the base design provides for up to 3 feet of massive ice).

Table 5.1 Allowable Adfreeze Stresses for VSM

Depth (Feet)		Design Adfreeze
From	To	
Land Surface	3	40 psi jacking (upward)
3	9	12.5 psi
9	14	18.75 psi
14	25	25 psi
25	Bottom of VSM	31.25 psi

5.3 Structural Analysis of Pipeline Supports

The typical descriptions of new pipeline supports are assumed based on previous experience. New pipeline supports will be categorized into groups based on similar stick-up heights (from tundra to TOS), depth of active layer, support type, and magnitude of pipeline operating forces. A model of each support group will be created using RISA© Structural Analysis software. A structural analysis of each model will verify compliance with AISC 360-05 code requirements.

The structural connections for each type of support will be designed to adequately resist the applied loadings, also in accordance with AISC 360-05.

VSM foundation design is typically based on strength as well as deflection requirements. In addition to the strength requirements of AISC 360-05, the VSM will be designed to resist lateral deflections due to environmental forces, and long term creep under operational loading associated with the relaxation of the soil VSM interface. As detailed geotechnical investigation of each VSM location is not practical, standard assumptions will be used to determine the design deflection due to each of these effects; as such, the deflections calculated will not be field verifiable.

5.3.1 Support Loading

Pipeline supports will be analyzed with consideration to loading per ASCE 7-10 and this section. Seven load combinations are listed in section 2.3.2 of ASCE 7-10, for use with the LRFD method.

Several load types do not apply to pipeline supports, such as flood load, lateral earth pressure load, roof live load, and rain load. Gravity loads from the pipeline contents are treated as dead loads; therefore, live loads also do not apply. Fluid load is considered part of dead load and therefore is included wherever dead load is included per ASCE 7-10.

Loading from thermal effects on the pipeline is not specifically addressed in ASCE 7-10. Load case “T” refers to self-straining loads, which are equivalent to thermal effects on structural members, but do not pertain to external loads applied to the structure. Section 2.3.5 of ASCE 7-10 elaborates on the application of self-straining loads, effectively leaving the application of thermal loads to the engineer’s discretion. For the purpose of pipeline supports, thermal loading from the pipeline will be applied as a dead load with the corresponding load factors. This assumption is based on the high probability of thermal effects and the sustained nature of thermal loading during pipeline operation.

Removing loads that do not apply and other assumptions leaves the following load combinations from ASCE 7-10:

1. 1.4 D
2. 1.2 D + 0.5 S
3. 1.2 D+ 1.6 S + 0.5 W
4. 1.2 D + 1.0 W + 0.5 S
5. 1.2 D + 1.0 E + 0.2 S
6. 0.9 D + 1.0 W
7. 0.9 D + 1.0 E

Load combinations 6 and 7 will not be included in the analysis as they are intended to consider wind and earthquake load on a structure with reduced weight. To accomplish this in a more conservative manner, load combinations 4 and 5 will be modified to have a dead load corresponding to that of empty pipelines.

Hydrostatic test loading is not specifically addressed in ASCE 7-10; however, since it is a transient event, it is assumed that equation 4 is the most appropriate load combination. In this case, dead load is based on water with a specific gravity of 1 and will not include thermal loading from the pipeline. Thermal effects are considered negligible since it is assumed the hydrostatic test medium will be at ambient temperature. Wind loading is reduced since hydrostatic tests are not conducted during high wind events. It is also assumed the hydrostatic test will occur during the summer season, and therefore snow loading, S, does not apply. Based on these assumptions, the load combination for the hydrostatic test is:

4a. 1.2 D + 1.0 ((1/9) W)

Operating, thermal, test, earthquake, and dead loads will be determined from the results of the pipeline stress analysis.

Snow loading will be determined as previously described in Section 3.2.5.

Wind loading will be determined by the formula

$$F = q_Z * G * C_f * A_f$$

Where: q_Z = Velocity pressure evaluated at the elevation of the pipe (Equation 29.3.1 of ASCE 7-10)
G = Gust-effect factor
C_f = Force Coefficient
A_f = Projected area normal to the wind

6.0 Civil Design

6.1 Road Crossings

The current route has three road crossings. Typically, casings are a minimum of two standard diameters greater than the pipeline. Casing-isolators will be installed around the insulated pipe and will serve to electrically isolate the pipeline from the casing. Wall thickness of casings will be based on commercially available materials and fit for purpose.

Spacing between new casings and existing casings will be based on the anticipated compaction equipment and compaction testing methods. Typically, new casings are spaced 18 inches from outside of new casing to outside of existing casing; however, the exact spacing will be evaluated on a case by case basis.

Invert elevations for new casings will be located to achieve the minimum cover determined by design, typically 12 inches. If necessary, the existing road surface will be raised to provide the minimum cover, using pit run gravel on secondary roads or crushed rock finishing course on high traffic roads. Material requirements for gravel and finishing course will be specified on the drawings and will be determined based on what is available at the permitted pit source and prior experience with the materials. The minimum cover at each road crossing will be evaluated specifically when gravel fill is required, based on the type of road and the expected traffic and design vehicle.

Minimum cover and wall thickness requirements for casings at road crossings will be evaluated per API RP 1102, with loading from a design vehicle determined by information provided by the PBU Operator. Typically, the design vehicle is the most recent and heaviest drill rig in use at the time of design. Currently, Doyon 14 and Parker Drilling 272L and 273L drill rigs are the controlling design vehicles.

Appendix A Codes, Standards and Specifications

Pipeline and pipeline support design will be performed in accordance with the codes, standards, specifications, and recommended practices listed below.

- 49 CFR 192, Transportation of Natural and Other Gas by Pipeline: Minimum Safety Standards
- Alaska General Safety Code (AGSC), Occupational Safety and Health Standards
- ASCE Standard 7, Minimum Design Loads for Building and Other Structures
- American Institute of Steel Construction (AISC), Allowable Stress Design (ASD) / Load and Resistance Factor Design (LRFD), Steel Construction Manual, 13th Edition
- American Petroleum Institute (API) 5L, Specification for Line Pipe, 44thEdition, 2007
- API 6D, Specifications for Pipe Line Valves
- API 1102, Steel Pipelines Crossing Railroads and Highways, 6th Edition
- API 1104, Welding Pipeline and Related Facilities, 20th Edition
- API 1163, Qualification Systems Standards
- ASME B16.5, Pipe Flanges and Flanged Fittings – NPS ½ through NPS 24
- ASME 31.8, Gas Transmission and Distribution Piping System
- ASTM A572/A572M-07 – Standard Specification for High-Strength Low-Alloy Columbium-Vanadium Structural Steel
- ASME BPV Section VIII – Boiler and Pressure Vessel Code Section VIII – Pressure Vessels
- IBC, International Building Code, as adopted as Alaska Building Code
- IMC 2006, International Mechanical Code, as adopted as Alaska Building Code
- NFPA 70 National Electrical Code

The following table is applicable for the design and engineering of the pipeline tied into a BPXA system.

2009 PROJECT DIRECTORATE PROJECTS TECHNICAL SPECIFICATIONS DOCUMENT INDEX WITH REVISION NUMBER/DATE AS OF OCTOBER 27, 2009			
Number	**Title**	**Revision**	**Date of Latest Revision**
GENERAL			
CRT-GA-00004	National Codes and Standards Design	1	8/23/2004
CRT-GA-00005	PE Stamping	0	1/31/2003
SPC-GA-00003	Specification Style Guide	0	7/16/2002
SPC-GA-00004	BPXA Engineering Drawing and Document Requirements	4	5/00/2007
SPC-PR-NSS-00007-001	BPXA As-Built Drawing Procedures	0	2/15/2006
ARCTIC			
CRT-AK-04-02	General Site Conditions Design	0	9/14/2007

2009 PROJECT DIRECTORATE PROJECTS TECHNICAL SPECIFICATIONS DOCUMENT INDEX WITH REVISION NUMBER/DATE AS OF OCTOBER 27, 2009			
Number	**Title**	**Revision**	**Date of Latest Revision**
HSE			
CRT-AK-76-02	Health, Safety & Environmental Protection Design	0	9/2/2008
CIVIL/STRUCTURAL			
CRT-AK-04-20	Civil Engineering	0	6/2/2008
CRT-AR-00001	Architectural Design	1	8/23/2004
CRT-SS-00001	Structural Design	2	10/5/2006
SPC-AK-04-902	Material Toughness Requirements for Structural Steel	0	6/2/2008
SPC-CE-00001	Civil Material and Construction	0	3/25/2002
SPC-SS-00001	Structural Steel Welding	1	1/15/2002
SPC-SS-00003	VSM and Pile Installation	1	10/27/2010
SPC-SS-00008	Beam and Pile Cap Fabrication	0	12/20/2001
SPC-SS-00013	Structural Steel Fabrication, Detailing and Erection	1	7/23/2002
SPC-SS-00014	Structural Low Temperature Steel Plates Specification for Pipeline Supports	1	1/15/2002
SPC-SS-00015	Module Pile Materials and Fabrication	1	1/15/2002
SPC-SS-00016	Structural Pipe for Support Piling	1	1/15/2002
CORROSION AND COATING			
SPC-MA-00002	External Coatings for Moderately Corrosive Service	0	9/22/2004
SPC-MA-00004	External Pipe Coating - Application of Fusion Bonded Epoxy	0	2/20/2003
GP 06-70	Corrosion Monitoring	ETP	8/29/2005
MECHANICAL EQUIPMENT			
CRT-AK-43-35	Valves for Pipelines	0	4/12/2007
CRT-AK-62-01	Valves	0	4/12/2007
CRT-AK-62-02	Valve Specification and Procurement	0	4/12/2007
SPC-AK-62-012	API 608 Metal Ball Valves (NPS 1/4 to NPS 20 up to Class 800)	0	8/10/2007
SPC-AK-62-013	API 6D Ball Valves	0	5/9/2007
SPC-AK-62-015	API 602 Gate, Globe, and Check Valves up to NPS 2	0	5/9/2007
SPC-AK-62-016	Ball, Plug, and Other Quarter-Turn Valves – Common Material	0	5/9/2007

2009 PROJECT DIRECTORATE PROJECTS TECHNICAL SPECIFICATIONS DOCUMENT INDEX WITH REVISION NUMBER/DATE AS OF OCTOBER 27, 2009			
Number	**Title**	**Revision**	**Date of Latest Revision**
SPC-AK-62-017	Rising Stem (Gate and Globe) Valves – Common Material	0	5/9/2007
SPC-PP-00081	Valve Data Sheet Index	6	4/3/2006
MECHANICAL PIPING			
CRT-AK-43-00	Pipeline Systems (Overview Document)	0	5/9/2007
CRT-AK-43-01	Criteria for Onshore Pipeline Design and Project Execution	0	4/12/2007
CRT-AK-43-04	QA & QC for Pipeline Projects	0	6/2/2008
CRT-AK-43-07	Selection of the Design Basis for Pipelines	0	4/12/2007
CRT-AK-43-08	Selection and Use of Pipeline Codes and Standards	1	9/28/2007
CRT-AK-43-09	Hydraulic Design of Pipeline Systems	0	5/9/2007
CRT-AK-43-17	Pipeline Risk Management	0	8/10/2007
CRT-AK-43-20	Onshore Pipeline System Design	2	9/28/2007
CRT-AK-43-22	Aboveground Pipeline Facilities	1	9/28/2007
CRT-AK-43-28	Pipeline Crossings	0	12/5/2007
CRT-AK-43-31	Line Pipe Material Selection and Procurement	0	12/20/2006
CRT-AK-43-32	Pipe Handling and Logistics for Pipelines	0	4/12/2007
CRT-AK-43-40	Onshore Pipeline Construction	0	5/9/2007
CRT-AK-43-46	Criteria for Pipeline Hydrotest and Pre-commissioning	0	4/03/2009
CRT-AK-43-47	Pipeline Commissioning and Handover to Operations	0	6/2/2008
CRT-AK-43-92	Wind-induced Vibration (WIV) Assessment and Design	0	12/17/2007
CRT-AK-43-94	Assessment of Pipe Spans Deformed by Extreme Snow Loads	1	9/27/2007
SPC-AK-42-201	Low-yield Carbon Steel Pipe, Flanges and Fittings	0	11/18/2007
SPC-AK-42-203	Gasket Procurement	0	8/10/2007
SPC-AK-42-204	Stud Bolting Procurement	0	8/10/2007
SPC-AK-43-311	Manufacture of Longitudinal or Helical Seam SAW Linepipe in Grades up to X80	1	5/9/2007
SPC-AK-43-312	Manufacture of HFI or ERW Linepipe in Grades up to X70	1	5/9/2007
SPC-AK-43-313	Seamless Line Pipe in Grades up to X80	2	9/14/2007
SPC-AK-43-317	Manufacture of Carbon Steel Induction Bends for Pipelines to ISO 15590 in Grades up to X80	0	8/10/2007

2009 PROJECT DIRECTORATE PROJECTS TECHNICAL SPECIFICATIONS DOCUMENT INDEX WITH REVISION NUMBER/DATE AS OF OCTOBER 27, 2009			
Number	**Title**	**Revision**	**Date of Latest Revision**
SPC-AK-43-317A	Induction Bends (ASME B16.49)	0	5/9/2007
SPC-AK-43-401	Above-grade Arctic Pipeline Construction	0	5/9/2007
SPC-AK-43-411	Pipeline Support Saddles	0	9/28/2007
SPC-AK-43-412	Pipeline Supports	0	9/28/2007
SPC-AK-43-413	Teflon Slide Plates	0	9/28/2007
SPC-AK-43-414	Pipeline Support Anchors	0	9/28/2007
SPC-AK-43-901	Pipeline Materials and Line Classes	0	9/11/2007
SPC-AK-43-927	High-yield Carbon Steel Flanges and Forged Fittings	0	9/28/2007
SPC-AK-43-928	High-yield Carbon Steel Fittings	0	9/28/2007
SPC-AK-52-102	Shop Applied Insulation	1	9/27/2007
SPC-AK-52-103	Preformed Insulation	0	8/10/2007
SPC-AK-52-104	Foam-in-Place Insulation	1	9/18/2007
PROCESS SAFETY			
CRT-AK-48-02	Hazard and Operability (HAZOP) Study	1	4/15/2009
GP-48-01	HSSE Review of Projects (PHSSER)	1	6/8/2009
GP-48-04	Inherently Safer Design (ISD)	1	5/5/2009
GP-48-05	Hazard Identification (HAZID) Study	1	2/13/2009
CRT-AK-43-54	Depressurization and Repressurization of Pipeline Systems	0	6/2/2008
WELDING AND FABRICATION		-	
CRT-AK-18-01	Welded Fabrication and Construction	0	6/2/2008
CRT-AK-18-02	Storage and Control of Welding Consumables	0	6/2/2008
CRT-AK-43-33	Welding of Pipelines	0	9/14/2007
SPC-AK-18-012	In-Service Welding	0	6/2/2008
SPC-AK-42-103	Branch Connection Welding	0	5/9/2007
SPC-AK-42-104	Hot Tapping	0	12/5/2007