CIPL Cross Inlet Extension Project

Conversion of Service:

CIGGS A to CIPL Marine A 10

Basis of Design

Public Document

Hilcorp Alaska, LLC

HARVEST PIPELINE

Revision History

Rev	Date	Description	Author	Review	Approval
A	07/19/18	Issued for Review	W. Veelman	L. Bolling	T. SlatonBarker
B	07/26/18	Issued for Review	W. Veelman	L. Bolling	T. SlatonBarker
C	08/01/18	Issued for Review	W. Veelman	L. Bolling	T. SlatonBarker

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1.0 Abbreviations

AAC	Alaska Administrative Code
API	American Petroleum Institute
ARO	Abrasion Resistant Overlay
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
BBL	barrels
BPH	barrels per hour
CFR	Code of Federal Regulations
CIGGS	Cook Inlet Gas Gathering System
CIPL	Cross Inlet Pipeline
CP	Cathodic Protection
F	Fahrenheit
FBE	Fusion Bond Epoxy
lbs	pounds
MAOP	Maximum Allowable Operating Pressure
MOP	Maximum Operating Pressure
mil	one thousandth of an inch
mmscfd	Million Standard Cubic Feet Per Day
NACE	National Association of Corrosion Engineers
psi	pounds per square inch
psia	pounds per square inch atmospheric
psig	pounds per square inch gauge
SCADA	Supervisory Control and Data Acquisition
SDV	Shutdown Valve
USGS	United States Geological Survey

2.0 Project Overview

The CIGGS A pipeline is an existing 10" nominal marine pipeline that will be converted from natural gas service to crude oil service between Kaloa Junction and East Forelands. This work is part of an overall project, called the CIPL Cross Inlet Extension Project, that modifies the oil and gas pipeline systems in the Cook Inlet region in order to eliminate the need for Drift River Terminal and overwater transportation of crude oil.

The CIGGS A and CIGGS B pipelines are two parallel pipelines in what is commonly referred to as the Dual Marine CIGGS pipelines. The Dual Marine CIGGS are bi-directional, sub-sea 10-inch natural gas transmission pipelines.

As part of the CIPL Cross Inlet Extension Project, the existing CIGGS A pipeline, currently in natural gas service, will be converted to crude oil service and renamed the CIPL Marine A 10 pipeline.

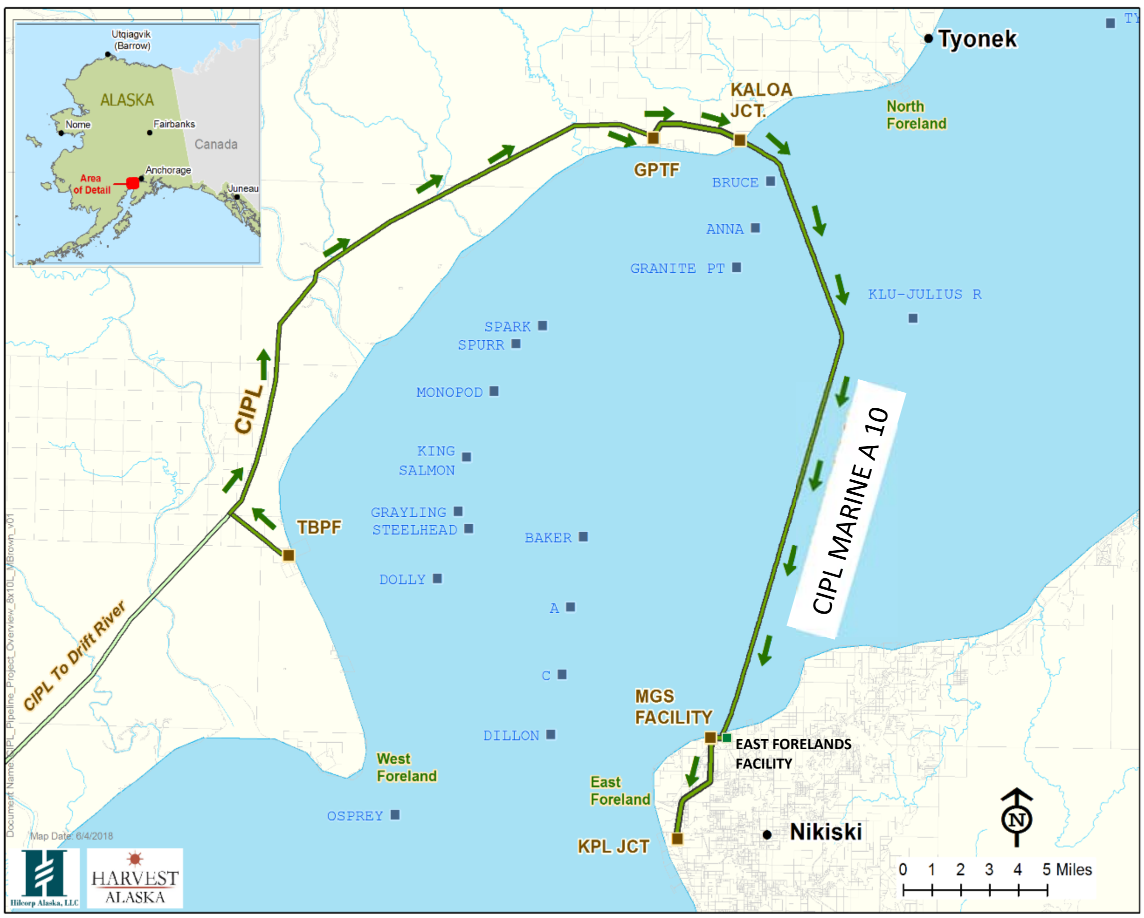

Figure 1: Location of CIPL Marine A 10 in Cook Inlet

2.1 System Design

The conversion of the CIGGS A to the CIPL Marine A 10 pipeline is required to provide a pipeline for crude oil produced on the West Side of Cook Inlet to be delivered to the Andeavor refinery without

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the use of barges. The existing pipeline will be connected to new on-shore crude oil pipelines at both Kaloa Junction and East Forelands to complete the pipeline circuit for crude oil to flow from the west side production facilities to Andeavor.

The CIPL Marine A 10 pipeline is designed to flow crude oil from west (Kaloa Junction) to east (East Forelands). Surface facilities at Kaloa Junction and East Forelands include shutdown valves, pig traps, and connections for facilitating emergency evacuation of the pipeline contents.

2.2 Pipeline Length

The on-shore section of pipeline from Kaloa Junction to the western beach is 720 feet (0.14 miles). The off-shore section of the pipeline from the beach near Kaloa Junction to the beach near East Forelands is 111,354 feet (21.1 miles). The on-shore section of pipeline from the eastern beach to East Forelands is 1,165 feet (0.22 miles). The overall CIPL Marine A 10 pipeline length between shutdown valves is 113,239 feet (21.5 miles) and has a volume of 56,472 cubic feet (422,412 gallons; 10,057 bbls) at standard pressure.

2.3 Pipeline Construction

The CIGGS A pipeline was constructed in 1972. The pipeline materials purchase documents (MTR's, construction specifications) indicate the existing CIGGS A pipeline material is 10.75" OD, 0.594" wall Grade X-52 Seamless Line Pipe that conforms to API Specification for High Test Line Pipe, API Std 5LX 18th Edition, dated April 1971, with added customer supplements for chemical composition and toughness. Product Specification Levels (PSL) were not included in the API specifications in 1971 - they were added in the late 1990's and after the specification was changed from 5LX to API 5L Specification for Line Pipe.

The pipe was ordered with supplemental requirements that provided limits on carbon, manganese, silicon, phosphorus and sulfur. Additional requirements for maximum yield, toughness, joint end roundness and heat treatment were also included. A comparison to modern PSL values is tabulated in Table 1 below:

Criteria	Existing Pipe Spec	API 5L PSL-2	API 5L PSL-1
Carbon % max	0.19	0.18	0.28
Manganese % max	1.40	1.40	1.40
Silicon % max	0.40	0.45	na
Phosphorus	0.03	0.025	0.03
Sulfur % max	0.035	0.015	0.03
Max Yield	68,000 psi	76,900 psi	na
Toughness	15 ft-lbs at 10F	20 ft-lbs at design temp	na

Table 1: Existing Pipeline Material Specifications

The pipe was supplied by British Steel Corporation. A review of the mill test certificates indicates the pipe conforms to the pipe specification. Charpy tests results indicate the toughness exceeds both the specification and PSL-2. In addition, the tensile strength range meets PSL-2 requirements.

The subsea portion of the pipeline is weight coated with concrete. The weight coating thickness is 1", 2" or 3-1/2", depending on the location. The weight coating thickness was designed for the variable currents along the pipeline route.

2.4 Pressure Test

The CIGGS A and B pipelines were successfully hydrostatically tested after construction in 1972, and again in 1987. Both tests were performed for a period of 24 hours, and neither test experienced any failures. Test records indicate that both CIGGS A and CIGGS B pipelines were tested simultaneously.

The minimum test pressure recorded during the 1972 test was 2,400 psig. The minimum pressure during the 1987 test was 2,000 psig. The hydrostatic tests both support the established MAOP of 1,440 psig.

Prior to conversion to liquid service, the CIGGS A (CIPL Marine A 10) pipeline, from Kaloa Junction to East Forelands, will be hydrotested per CFR 195 and ASME B31.4 to at least 1,800 psig (1.25 x design pressure) for 8 hours to confirm mechanical integrity.

2.5 Pipeline Integrity History

There are no records of any pipeline leaks on either the CIGGS A or CIGGS B pipelines. There have been multiple integrity assessments performed on both pipelines, including hydrostatic testing and multiple in-line inspection (ILI) assessments. The following studies have been reviewed:

- Original engineering study outlining span criteria, baseline storm events, pipeline design criteria, and proposed span lengths.
- Additional engineering study based on developed pipeline plan. Includes analysis of final pipeline design criteria, final design currents.
- Re-assessment of span criteria based on 25-years of operating history.
- Detailed span and fatigue analysis for a specific span length of 132 feet.
- Multi-beam and sidescan survey data providing mapping for lateral displacement of CIGGS A and B pipelines.
- Analyses of the displaced pipelines using membrane and bending strain techniques as well a finite element analysis.
- Follow-up study including full scale pipeline model, testing, destructive testing, and finite element analysis.
- CIGGS ILI Data Review, based on the following ILI’s that have been completed:
    - 1998 MFL
    - 2007 MFL
    - 2011 Caliper
    - 2014 Caliper/MFL

These studies have addressed known integrity threats and provided mitigation recommendations for continuing to operate these pipelines safely.

2.6 MAOP Verification

In August of 2017, the Hilcorp Alaska Integrity Group performed a review of the Maximum Allowable Operating Pressure (MAOP) for the CIGGS A and B pipelines. Based on a review of all available information, the established MAOP value of 1,440 psig was reasonably verified by comparing multiple, complimentary records, most of which were developed for Harvest over the past year. Pipe specification data was consistently documented on numerous sources including hydrotest records and ILI reports. The established MAOP of the 10-inch CIGGS A and B pipelines was thus verified to be 1,440 psig, based on the limiting factor of the 1,440 psig fittings.

2.7 Normal Operating Pressure

The pressure source of the pipeline is the GPTF booster pumps, which will be normally operated between 300 psig and 600 psig. Due to hydraulic pressure losses in the pipeline system, the pipeline will experience pressures less than the booster pump pressure range. The normal operating pressure will not exceed 600 psig.

Based on the CIPL pipeline system hydraulic calculations, the typical operating pressure at the design high flow range will be about 400 psig at the Kaloa Junction end of the pipeline.

3.0 Jurisdiction and Criteria

The pipeline is used for transportation of crude oil, so falls under the Office of Public Safety regarding design criteria for evaluation of the existing pipeline for the new service condition.

The Office of Public Safety, references 49 CFR Part 195 – Transportation of Hazardous Liquids by Pipeline, revised as of October 1, 2011 for crude oil transmission pipelines.

In addition to pressure loads covered in the CFR, this pipeline is subject to external loads from ocean current and spans. CFR Part 195 references ASME B31.4 – Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids, October 2006, for design of pipelines subject to external loads. B31.4 has been updated since 2006, and this evaluation uses the 2012 Edition.

4.0 Pipe Properties

4.1 Offshore Segment

The offshore pipeline segment between the Mean High High Water (MHHW) at Kaloa Junction and MHHW at East Forelands is shop coated with 1/8" coal tar enamel and concrete weight coat varying from 1" to 3-1/2" thick. Pipeline joints are double random. Offshore pipeline properties are summarized in Table 2 below.

Grade	5L-X52 seamless	Charpy 15 ft-lb at 10F
Outside Diameter, Do	10.75"	
Inside Diameter, Di	9.562"	
Wall thickness, t	0.594"	
Area, A	18.95 in2	
Elastic Section Modulus, Z	45.62 in3	
Weight / foot (empty)	66.5 lb/ft	Includes 2.0 lb/ft coating
1" Weight Coat		
Weight / foot (empty)	116 lb/ft	Includes 49.7 lb/ft wt coat
Weight / foot (full of oil)	143 lb/ft	Includes 27.1 lb/ft oil
Weight / foot (full of water)	147 lb/ft	Includes 31 lb/ft water
Outside Diameter	13.0"	
Displacement (Buoyancy)	57.5 lb/ft	
2" Weight Coat		
Weight / foot (empty)	175 lb/ft	Includes 107.8 lb/ft wt coat
Weight / foot (full of oil)	202 lb/ft	Includes 27.1 lb/ft oil
Weight / foot (full of water)	206 lb/ft	Includes 31 lb/ft water
Outside Diameter	15.0"	
Displacement (Buoyancy)	76.6 lb/ft	
3-1/2" Weight Coat		
Weight / foot (empty)	277 lb/ft	Includes 210.4 lb/ft wt coat
Weight / foot (full of oil)	304 lb/ft	Includes 27.1 lb/ft oil
Weight / foot (full of water)	308 lb/ft	Includes 31 lb/ft water
Outside Diameter	18.0"	
Displacement (Buoyancy)	110.3 lb/ft	

Table 2: Offshore Pipeline Properties

4.2 Onshore Segment

The onshore pipeline segments between Kaloa Junction and MHHW and MHHW and East Forelands is shop coated with 1/8" coal tar epoxy. Pipeline joints are double random. Onshore pipeline properties are summarized in Table 3 below.

Grade	5L-X52 seamless	Charpy 15 ft-lb at 10F
Outside Diameter, Do	10.75"	
Inside Diameter, Di	9.562"	
Wall thickness, t	0.594"	
Area, A	18.95 in2	
Elastic Section Modulus, Z	45.62 in3	
Weight / foot (empty)	66.5 lb/ft	Includes 2.0 lb/ft coating
Weight / foot (full of oil)	93.6 lb/ft	Includes 27.1 lb/ft oil
Weight / foot (full of water)	97.6 lb/ft	Includes 31 lb/ft water
Outside Diameter (Coated)	11.0"	Includes coatings

Table 3: Onshore Pipeline Properties

5.0 Pipeline Design

5.1 Structural Pipeline Design

For conversion from natural gas to crude oil service, the existing CIGGS A (CIPL Marine A 10) pipeline has been evaluated using design criteria from 49 CFR 195 and ASME B31.4. The evaluation determined the existing pipeline will remain within allowable stress through the range of operating loads that are expected and prescribed by the codes. See Section 6.0 for the loading scenarios for the design of the pipeline.

5.2 Geotechnical

The documentation for the pipeline construction indicates the bottom conditions along the route range vary from gravel, cobbles, and boulders toward the west shoreline to primarily sand and gravel between Middle Ground Shoal and the east shoreline. The bottom conditions are typical of the Inlet and common to other pipelines.

5.3 Scour and Erosion Mitigation Measures

Scour and erosion from currents within the Cook Inlet can affect the subsea section of the pipeline by seafloor material being displaced across the pipeline surfaces and by movement of seafloor material resulting in loss of support under the pipeline. The movement of material can also be beneficial if it results in partial or complete burial of the pipeline as it provides additional stabilization.

The documentation for the pipeline construction indicates the entire subsea pipeline is concrete weight coated. In addition to stabilizing the pipeline, the concrete weight coat mitigates erosion of the pipeline from materials passing across the surface of the pipe. The coating is resistant to abrasion and is applied over the entire length of the pipeline, including the field welded joints.

The pipeline monitoring and maintenance program provides the mitigation for loss of material under the pipeline. Annual pipeline surveys are conducted to determine the pipeline position and support conditions, and if necessary support is reestablished through pinning if spans develop that exceed the maximum allowed.

5.4 Trenching Design and Ice Hazard Mitigation

To avoid the hazard of ice hitting the pipeline, the existing pipeline is installed below grade in the transition zone from onshore to offshore. The pipelines were installed to transition from buried to exposed at about 10 feet below mean low low water level, a distance of about 500 feet. Therefore, the existing pipeline has not experienced damage from ice movement.

5.5 Pinning of Subsea Pipeline

Hilcorp's sub-sea Integrity Program builds on the previous operator's practice to perform annual multi-beam surveys, identify spans over 50 feet in length, and to remediate by pinning the pipeline to the seafloor using concrete sacks. In addition to the subsea considerations, Hilcorp's integrity management plan includes risk assessments conducted after each ILI, wherein engineers and operators evaluate potential threats to the pipeline and then develop custom tailored mitigative considerations/actions to implement.

Remediated spans through the subsea integrity program, since Hilcorp began operation of the CIGGS A pipeline in 2013, is reflected below. Annual surveys and remediation will continue for the CIPL

Marine A 10 pipeline after the conversion of service from natural gas to crude oil.

Year of Remediation	# of Spans Identified over 50 ft	# of Spans Remediated
2017	11	11
2016	6	6
2015	11	11
2014	13	13
2013	0	0

Table 4: Subsea Pinning of Spans (Over 50ft)

5.6 SCADA, Communications and Control System

The CIPL Marine A 10 pipeline will be monitored and controlled through Hilcorp's existing SCADA system. The primary control and operations center for the pipeline is located at the Kenai Gas Field facility. The backup control room is located at KPL Junction.

The SCADA system will enable pipeline operators to efficiently and effectively supervise pipeline operations in real time. Data acquisition and storage will be provided, along with provision for report generation using historical data. Data retention and management will comply with applicable federal and state regulatory requirements. Additionally, some control functions will be provided through the system to allow for manual operational control and testing when necessary.

The SCADA system scan rate will be fast enough to minimize overpressure conditions, provide very responsive abnormal operation indications to controllers and detect small leaks within technology limitations.

The SCADA system will incorporate a real-time database and historian. The information on these databases will be used to generate operations reports and trends.

The SCADA system will send necessary information to a business database/historian. The information on this historian will be used to file reports to outside entities such as government regulators and provide information for business analysis.

The SCADA system will collect measurements and data along the pipeline, including flow rate through the pipeline, operational status, pressure, and temperature readings. This information may all be used to assess the status of the pipeline. The SCADA system will provide pipeline personnel with real-time information about equipment malfunctions, leaks, or any other unusual activity along the pipeline.

5.7 Operating Philosophy and Valve Configuration

Flow of crude oil is introduced into the CIPL Marine A 10 through the pipeline booster pumps located at Granite Point Tank Farm (GPTF). The pipeline pressure downstream of the pumps and pig trap at GPTF is monitored by pressure transmitters located at GPTF and Kaloa Junction that have high (500 psig), high high (800 psig), low (80 psig) and low low (50 psig) alarms. A high high pressure condition results in a shutdown of the pipeline by closing automated shutdown valves located at Kaloa Junction and East Forelands, which isolates the CIPL Marine A 10 pipeline segment.

5.8 Leak Detection Systems

The CIPL Marine A 10 leak detection system will include two separate leak detection technologies consisting of a statistical mass balance leak detection system and a wave rarefaction model leak detection system.

5.8.1 Mass Balance

Atmos Pipe leak detection system is a statistical volume balance leak detection system that provides a very accurate method of detecting smaller leaks over a longer period of time or larger leaks over a short period of time. Operational experience at other Alaska oil pipelines using the Atmos Pipe system has verified it provides a highly reliable and accurate method of leak detection on crude oil pipelines in similar oil production service.

Flow Meters carefully monitor inlet and outlet flows of the pipeline system for comparison of these values. Differences would indicate possible leaks. A statistical mass balance leak detection computer modeling system ties into the SCADA system that monitors the pipeline flow and generates predictable flow patterns over time. Disturbances such as those caused by temperature variations or varying flow or operating pressure are measured and masked out as "noise."

5.8.2 Wave Refraction

Complementing this, Atmos Wave is suited to identify larger leaks in a shorter period of time and is also able to identify the leak location. The Atmos Wave Leak Detection System is based on the detection of the negative pressure waves associated with the onset of a leak or theft. These rarefaction waves propagate out from the location of the release in both directions and can be sensed by high performance pressure meters at the ends or along the pipeline. The basic principle is simple, and it is used to detect and locate very large leaks using normal pressure meters. Unfortunately, when this principle is applied to very small leaks, the sensors detect not only the leak but also the large number of pressure changes that are part of normal pipeline operations and this causes a large number of false alarms on this type of system.

Atmos Wave is the result of several years of research and development directed at producing pressure-based leak detection system that is based on state-of-the-art hardware and telecommunication technology. A thorough review of the performance problems of the traditional systems leads to the decision to develop a completely new approach. This new approach is extremely successful. It examines all aspects of the negative pressure wave front and its propagation through the entire pipeline length. Three comprehensive algorithms filter out noise, arrange the analog pressure data into a detailed 3-dimensional map that allows the system to differentiate true leak/theft events from the pressure changes caused by transient operation. Extensive performance evaluation and field trials have proven that Atmos Wave consistently differentiates opening and closing leak/theft signals during transients. These remarkable algorithms have been rigorously tested in operational pipelines with great success.

In combined mode, Atmos Pipe acts as the primary leak detection system aided by Atmos Wave. Both leak detection systems run independently of each other. If one system fails, the other system will continue leak detection. Atmos Wave provide the Atmos Pipe System with the ability to detect leaks more quickly and provide a more accurate leak location.

5.8.3 Control Room Monitoring

In addition, the Harvest Kenai Control Room is manned 24 hours per day and the operator on duty constantly monitors pipeline transfer operations via the SCADA system. In addition, the controller takes readings to compare the accumulated totals for CIPL and compares with what has been received at MGS. These readings are recorded by the SCADA historian.

5.9 Corrosion Control and Monitoring

The CIPL Marine A 10 has a corrosion control system, provided by protective coatings and cathodic protection (CP). The pipeline coatings used are coal tar epoxy, as discussed in Section 4.0. Cathodic protection is provided to the CIPL Marine A pipeline by two impressed current cathodic protection systems. These systems are located at East Forelands in Nikiski, Alaska and at the Kaloa facility on the west side of Cook Inlet.

In June and July 2016, a CP survey was completed on the two 10-inch Dual Marine CIGGS pipelines. The cathodic protection survey consisted of field-testing, visual examinations, and minor repairs. The rectifiers were operating properly and no adjustments were made. Test results indicated that the existing cathodic protection systems were providing adequate levels of protection to the pipelines at the established test station locations, as defined by NACE International Standard: SP0169-2007 “Control of External Corrosion on Underground or Submerged Metallic Piping Systems.” During the survey, all test stations were meeting NACE (National Association of Corrosion Engineers) criteria.

Alternating Current (AC) pipe-to-soil potential measurements were obtained in 2016 at all test point locations. The AC potentials that were obtained were minimal, and no concerns were identified.

6.0 Pipeline Loading Scenarios

Loads on the CIPL Marine A 10 pipeline include both pressure loading cases and other loading cases. Loads are combined as prescribed by code and sound engineering practice.

6.1 Pressure Load Scenarios

The pipeline stress evaluation was performed for various pressure loadings summarized as follows:

- Normal Operating Pressure: 400 psig (based on pipeline hydraulic calculations for design high flow range)
- Design Internal Pressure (Maximum Operating Pressure): 1,480 psig (based on existing fitting ratings the published MOP will be 1,440 psig, however calculations are accomplished using 1,480 psig which is ANSI Class 600)
- Hydrostatic Test Pressure: 1,850 psig (1.25 * Design Internal Pressure)

6.2 Offshore Pipeline Segment – Other Loading Scenarios

The offshore pipeline will be subject to non-pressure loading conditions, including:

6.2.1 Residual Load from Installation

The pipeline was installed by lay-barge and has been in service since 1972, and thus residual installation loads are considered inconsequential.

6.2.2 External Pressure:

14 psia to 80 psia (surface to 150 feet maximum water depth). External pressure loading is considered inconsequential, as the operating pressure of the pipeline is about 400 psig to 100 psig across its length. External pressure is ignored in the hoop stress calculations (conservative).

6.2.3 Thermal Loads (Operational Load):

These loads result from a change in temperature in the pipeline walls. This pipeline will be located in a temperature stable environment as it is exposed on the seafloor and Cook Inlet water temperature is relatively stable. Additionally, the oil in the pipeline is ground temperature as there is no heat added from process that effects the temperature of this pipeline. The installation method will result in the pipeline temperature equalizing with the water temperature before operating pressure is introduced. The pipeline that is exposed on the seafloor is treated as unrestrained.

6.2.4 Current Loads (Hydrotest Load and Operational Load):

The pipeline is located on the surface of the seafloor to the transition zones near shore at Kaloa Junction and East Forelands, then buried through the transition zone and onshore to the facilities. The subsea section is subject to water current loading from tides and wind events. Studies in Cook Inlet have been previously accomplished that establish the range of current velocities used for design of the exposed pipeline. The current velocity used for evaluation is 7 ft/sec at the seafloor.

6.2.5 Seismic Loads (Operational Load):

The pipeline is located in Cook Inlet, an area of high seismicity. The pipeline route does not cross any USGS mapped faults. The pipeline does cross the Granite Point fold about ½ mile from the shore. The pipe will be exposed on the seafloor in this area. No specific seismic loads are applied to the pipeline for design.

6.2.6 Accidental Loads (Operational Load):

The pipeline route does traverse the main transportation routes in Cook Inlet, but is not in a vessel mooring area, so anchor loads are not expected. There is a potential for personal watercraft anchors or set net tender vessel anchors to impact the pipeline. These loads are considered improbable and are not included in the stress analysis.

6.2.7 Dynamic Induced Soil Loads (Operational Load):

The pipeline has been in operation since 1972 and has not been subject to soil displacement events. The pipeline route does not traverse areas with slopes of steepness to be prone to soil displacement.

6.2.8 Ice Loads (Operational Load):

The pipeline is buried through the transition zone, so ice loading is not applied to the pipeline for design.

6.3 On-shore Pipeline Segment – Other Loading Scenarios

The onshore pipeline segments will be subject to non-pressure loading conditions, including:

6.3.1 Installation Load

Pipeline was installed by conventional trenching / cover methods. No unusual installation loads are included.

6.3.2 External Pressure Load (Operational Load)

14 psia to 22 psia (surface to 10 feet maximum soil cover). External pressure loading is considered inconsequential, as the operating pressure of the pipeline is about 400 psig to 100 psig, depending on location. External pressure is ignored in the hoop stress calculations.

6.3.3 Thermal Loads (Operational Load)

Thermal loads result from a change in temperature in the pipeline walls. This pipeline is buried and considered to be restrained. The stresses are evaluated for winter installation (0F) and summer installation (70F) and an operating temperature of 35F to cover the range of time allowed for construction. The oil in the pipeline is ground temperature as there is no heat added from process that effects the temperature of this pipeline.

6.3.4 Seismic Loads (Operational Load)

The pipeline is located in Cook Inlet, an area of high seismicity. The pipeline route onshore does not cross any USGS mapped faults or folds. No specific seismic loads are applied to the pipeline for design.

7.0 Design Results

The pipeline meets the 49 CFR 195 requirements for hoop stress, summarized in Table 5.

Location	P per CFR	$P_{Operating}$	P_{Design}	P_{Hydro}
All	4,137 psig	400 psig	1,480 psig	1,850 psig

Table 5: 49 CFR 195 Design Results

7.1 Offshore Segment

The offshore pipeline segment is evaluated using B31.4, Section 402. B31.4 calculations take into account hoop stress, longitudinal stress from pressure and bending loads, and torsion stress. Since the offshore pipeline is not buried, the pipeline is considered unrestrained.

Free Span Condition

The offshore pipeline has some areas of free spans. The pipeline is evaluated for pressure and longitudinal stress conditions due to internal pressure and bending load from maximum current and gravity at free spans. At free spans, the current sheds around the pipe so no torsion is created. The pipeline has been previously inspected and the free spans are limited through maintenance work to 50 feet maximum. Per Harvest, the 50 feet span limitation will be maintained in the future. The pipeline stresses for a 50 feet free span for each weight coat thickness are summarized in Table 6.

Pipeline Pressure Condition	Internal Pressure	Pressure (Hoop) Stress, S_H	Longitudinal Stress, S_L
1” Weight Coat			
Normal Operation	400 psig	3,420 psi	9,550 psi
Design (600# ANSI)	1,480 psig	12,652 psi	12,013 psi
Hydrotest (1.25 * Design)	1,850 psig	15,815 psi	13,651 psi
2” Weight Coat			
Normal Operation	400 psig	3,420 psi	12,683 psi
Design (600# ANSI)	1,480 psig	12,652 psi	14,534 psi
Hydrotest (1.25 * Design)	1,850 psig	15,815 psi	16,181 psi
3-1/2” Weight Coat			
Normal Operation	400 psig	3,420 psi	18,207 psi
Design (600# ANSI)	1,480 psig	12,652 psi	19,028 psi
Hydrotest (1.25 * Design)	1,850 psig	15,815 psi	20,682 psi
ASME Allowable Stresses		37,440 psi	39,000 psi

Table 6: 50 Feet Free Span Stress Summary

The hoop and longitudinal stresses are all well within allowable stresses for a 50 feet free span. Since the pipeline is unrestrained, thermal stress and combined stress are not considered.

Grounded Condition

The offshore pipeline is grounded on the seafloor for a majority of the corridor. The pipeline is designed to be stable on the seafloor through the use of weight coat. With the conversion from gas to oil, the pipeline operating weight increases further, resulting in increased stability. The grounded pipe is not subject to bending or torsion from current loading since it is self-stable.

The grounded sections of the pipeline are evaluated for pressure and longitudinal stress conditions due to internal pressure, with no added stress from bending or torsion.

Pipeline Pressure Condition	Internal Pressure	Pressure (Hoop) Stress, S_H	Longitudinal Stress, S_L
All Weight Coat Thicknesses			
Normal Operation	400 psig	3,420 psi	1,512 psi
Design (600# ANSI)	1,480 psig	12,652 psi	5,594 psi
Hydrotest (1.25 * Design)	1,850 psig	15,815 psi	6,992 psi
ASME Allowable Stresses		37,440 psi	39,000 psi

Table 7: Grounded Span Stress Summary

The hoop and longitudinal stresses are all well within allowable stresses for the grounded pipeline. Since the pipeline is unrestrained, thermal stress and combined stress are not considered.

7.2 Onshore Segments

The onshore (includes transition zone) pipeline segments (buried segments) are evaluated using B31.4, Section 402. B31.4 calculations take into account hoop stress, longitudinal stress from thermal, pressure and bending loads, and torsion stress. Since the onshore pipeline is buried, the pipeline is considered restrained.

As-Installed Stress Evaluation:

The onshore pipeline segments are fully supported and restrained by soil backfill. The onshore pipeline stress is summarized in Table 8 (winter install) and Table 9 (summer install).

Pipeline Pressure Condition	Internal Pressure	Hoop Stress	Thermal Stress	Longitudinal Stress	Combined Stress
Normal Operation	400 psig	3,420 psi	-7,540 psi	-6,024 psi	9,444 psi
Design (600# ANSI)	1,480 psig	12,652 psi	-7,540 psi	-1,932 psi	14,584 psi
Hydrotest (1.25*Design)	1,850 psig	15,815 psi	-7,540 psi	-530 psi	16,346 psi
ASME Allowable Stresses		37,440 psi	46,800 psi	46,800 psi	46,800 psi

Table 8: Onshore Stress Summary – 0F Install Temp, 40F Operating

Pipeline Pressure Condition	Internal Pressure	Hoop Stress	Thermal Stress	Longitudinal Stress	Combined Stress
Normal Operation	400 psig	3,420 psi	7,540 psi	9,056 psi	7,920 psi
Design (600# ANSI)	1,480 psig	12,652 psi	7,540 psi	13,148 psi	12,907 psi
Hydrotest (1.25*Design)	1,850 psig	15,815 psi	7,540 psi	14,550 psi	15,222 psi
ASME Allowable Stresses		37,440 psi	46,800 psi	46,800 psi	46,800 psi

Table 9: Onshore Stress Summary – 70F Install Temp, 30F Operating

The hoop, thermal, longitudinal, and combined stresses are all well within allowable stresses for the onshore and transition pipeline segments.

7.3 Minimum Wall Thickness Summary

The CIPL Marine A 10 pipeline onshore and subsea segments have wall thickness in excess of that required by code. A corrosion allowance is not required per CFR or ASME, however excess wall thickness provides some additional reservice strength to allow for some wall loss and still meet code. The exterior of the pipeline is coated and protected by cathodic protection, so external wall loss is risk is mitigated.

For the subsea portion, the minimum wall is based on the design pressure of 1,480 psig and a 50’ free span condition with 3-1/2” of weight coat, which results in the highest longitudinal and combined stress loading.

For the onshore segment, the minimum wall is based on the hoop stress due to the design pressure of 1,480 psig since longitudinal stresses and combined stresses are comparatively insignificant for the buried condition.

Pipeline Segment	Nominal Wall Thickness	Minimum Wall Thickness
Subsea (50’ free span)	0.594”	0.27”
Onshore and Subsea Grounded	0.594”	0.21”

Table 10: Minimum Wall Thickness Summary

7.4 Design Summary

After the conversion of service from natural gas to crude oil, the CIPL Marine A 10 Pipeline will remain within allowable stresses defined in 49 CFR 195 and ASME B31.4 through the range of loads that are expected and prescribed by code.

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