DOCKET NO. CP17-___-000

RESOURCE REPORT NO. 13

ENGINEERING AND DESIGN MATERIAL

(LIQUEFIED NATURAL GAS)

PUBLIC

DOCUMENT NUMBER: USAI-PE-SRREG-00-000013-000-B

RESOURCE REPORT NO.13 SUMMARY OF FILING INFORMATION[1]	
Filing Requirement	**Found in Section**
☒ Provide all the listed detailed engineering materials (§ 380.12(o)) These include:	
(1) Provide a detailed plot plan showing the location of all major components to be installed, including compression, pretreatment, liquefaction, storage, transfer piping, vaporization, truck loading/unloading, vent stacks, pumps, and auxiliary or appurtenant service facilities.	Appendix 13.A.1
(2) Provide a detailed layout of the fire protection system showing the location of firewater pumps, piping, hydrants, hose reels, dry chemical systems, high expansion foam systems, and auxiliary or appurtenant service facilities.	Appendix 13.S.10
(3) Provide a layout of the hazard detection system showing the location of combustible-gas detectors, fire detectors, heat detectors, smoke or combustion product detectors, and low temperature detectors. Identify those detectors that activate automatic shutdowns and the equipment that will shut down. Include all safety provisions incorporated in the plant design, including automatic and manually activated emergency shutdown systems.	Appendix 13.S.6
(4) Provide a detailed layout of the spill containment system showing the location of impoundments, sumps, subdikes, channels, and water removal systems.	Appendix 13.S.3
(5) Provide manufacturer's specifications, drawings, and literature on the fail-safe shut-off valve for each loading area at a marine terminal (if applicable).	Appendix 13.Q.5
(6) Provide a detailed layout of the fuel gas system showing all taps with process components.	Appendix 13.E.5
(7) Provide copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants.	Appendix 13.T
(8) Provide engineering information on major process components related to the first six items above, which include (as applicable) function, capacity, type, manufacturer, drive system (horsepower, voltage), operating pressure, and temperature.	Appendix 13.M
(9) Provide manuals and construction drawings for LNG storage tank(s).	Appendix 13.L
(10) Provide up-to-date piping and instrumentation diagrams. Include a description of the instrumentation and control philosophy, type of instrumentation (pneumatic, electronic), use of computer technology, and control room display and operation. Also, provide an overall schematic diagram of the entire process flow system, including maps, materials, and energy balances.	Appendix 13.E.5
(11) Provide engineering information on the plant's electrical power generation system, distribution system, emergency power system, uninterruptible power system, and battery backup system.	Appendix 13.N
(12) Identify all codes and standards under which the plant (and marine terminal, if applicable) will be designed, and any special considerations or safety provisions that were applied to the design of plant components.	Appendix 13.D
(13) Provide a list of all permits or approvals from local, state, Federal, or Native American groups or Indian agencies required prior to and during construction of the plant, and the status of each, including the date filed, the date issued, and any known obstacles to approval. Include a description of data records required for submission to such agencies and transcripts of any public hearings by such agencies. Also provide copies of any correspondence relating to the actions by all, or any, of these agencies regarding all required approvals.	Appendix 13.C
(14) Identify how each applicable requirement will comply with 49 C.F.R. part 193 and the National Fire Protection Association 59A LNG Standards. For new facilities, the siting requirements of 49 C.F.R. part 193, subpart B, must be given special attention. If applicable, vapor dispersion calculations from LNG spills over water should also be presented to ensure compliance with the U.S. Coast Guard's LNG regulations in 33 C.F.R. part 127.	Appendix 13.C
(15) Provide seismic information specified in Data Requirements for the Seismic Review of LNG facilities (NBSIR 84-2833, available from FERC staff) for facilities that will be located in zone 2, 3, or 4 of the Uniform Building Code Seismic Map of the United States.	Appendix 13.I, Appendix 13.J

[1] Guidance Manual for Environmental Report Preparation (FERC, August 2002). Available online at: http://www.ferc.gov/industries/gas/enviro/erpman.pdf.

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Agency	**Comment Date**	**Comment**	**Response/Resource Report Location**
FERC	12/14/2016	With the application version of Resource Report 13, please provide better organized electronic files. Provide only the combined version of Public, Privileged, and Critical Energy Infrastructure Information versions. Also provide individual files on the CD for each Appendix and Sub-Appendix with identifiable file labels (e.g., Appendix J.2).	FERC has a 40mb file size limit for uploading information onto eLibrary. As the combined public, P&C, and CEII files exceed this limit, they had to be broken into parts to allow the files to be filed with FERC. Individual files will be given to FERC staff on a CD for easier organization
FERC	12/14/2016	Draft Resource Report 11, section 11.10.4.3 indicates that tugs would be provided for assisting the LNG ships. Provide a marine vessel simulation study, and as public information, indicate the number of tugs that were determined to be needed based on this study.	Ship berthing/unberthing simulations demonstrate that LNGCs within the design range of 125,000 m^3 to 216,000 m^3 can safely be managed with three tugs, equipped with azimuth stern drives, of a minimum of 90 MT static bollard pull. Two azimuth stern drive tugs in the range of 120 MT static bollard pull for ice mitigation and towing work.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, the maximum design liquid capacity of the inner LNG storage tank and the available capacity in the space between the inner and outer tanks.	The maximum design liquid capacity of the 240,000 m3 tank is 259,000 m3. The outer tank can contain a volume of 301,427 m3. The LNG Storage Tank drawings in Appendix L.2 provide additional details and supporting information.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a description of the sizing of the trough system, including trough slope and the materials of its construction, including any areas of insulated concrete.	This information has been included in Resource Report 13.34.
FERC	12/14/2016	Several of the impoundments for ignitable fluids could cause thermal radiation in excess of 3,000 British thermal units per square foot per hour (Btu/ft2-hr) over equipment areas, which may prompt the use of fire water monitors and/or fixed water spray systems for cooling equipment in that same impoundment's liquid collection areas. Provide, for each ignitable fluid impoundment:	See below
FERC	12/14/2016	a. the fire water flow rate into that impoundment for a release and fire scenario; and	Based on the final design and equipment selection, a 3,000 BTU flux may or may not cause damages to plant equipment. The Hazard Analysis Report in Section H.3 includes a table illustrating the different heat flux and their corresponding potential damages. Nonetheless, the facility's fire protection system allows for firewater to be used for cooling of adjacent equipment in the event of a fire. Based on the heat coming from the fire, much of that firewater may be evaporated when used for cooling of equipment. Final details will be determined in detailed design.
FERC	12/14/2016	b. a detailed account of how this fire water volume is considered in the sizing of the impoundment.	The initial impoundment sizing was sized based on the requirements of

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			NFPA 59A which require sizing from the largest spill from any single accidental leakage source for 10 minutes. This sizing is conservative as it does not take into account active or passive mitigation systems which may be used to shorten the duration of a spill. In addition, in the event of a spill, a significant portion of the LNG will vaporize and not collect in the impoundment which is conservatively not taken into account when sizing the impoundments. Potential firewater volumes which may collect in the spill containment system will not be known until finalized equipment selection in detailed design.
FERC	12/14/2016	Draft Resource Report 13, section 13.4.2.8 provides the maximum channel current for the design of the marine facilities. Provide, as public information, the normal channel current.	The Applicant will address this comment after the FEIS but prior to construction start
FERC	12/14/2016	Draft Resource Report 13, section 13.4.4 defines the operating basis earthquake (OBE) and safe shutdown earthquake (SSE). The definitions are based on those provided in NFPA 59A-2001. Title 49 Code of Federal Regulations (CFR) 193 was updated in 2010 and now references NFPA 59A-2006 for determining the OBE and SSE. Revise section 13.4.4 so that it provides the definitions of the OBE and SSE consistent with NFPA 59A-2006 (i.e., OBE = 475 year return period and SSE = maximum considered earthquake [MCE] defined in American Society of Civil Engineers [ASCE] 7-05).	As described in section 1.5.1 of the final PSHA report, NFPA 59A-2006 was used to describe the OBE and SSE. This report is included in Appendix 13.I.1. Accordingly, OBE – 475 yrs and SSE is MCE per ASCE 7-05.
FERC	12/14/2016	Draft Resource Report 13, section 13.4.4 should provide a table of Spectral Acceleration Values versus period for the site-specific SSE and OBE to be used for the design of Seismic Category I structures, systems and components. Also, draft Resource Report 13, section 13.4.4 should provide the values of the site-specific seismic parameters SDS, SD1, and TL that are to be used for the design of Seismic Category II and III structures and nonstructural components.	Tables 5.9 and 5.10 of the PSHA report present site-specific OBE and SSE spectra of Seismic Category 1 structures for onshore locations. Tables 5.9 and 5.11 of the PSHA present site-specific OBE and SSE spectra of Seismic Category 1 structures for nearshore locations. The PSHA report is included in Appendix 13.I.1. The narrative (Section 13.3.1.4) has been updated to include site specific seismic parameters for seismic category II and III structures.
FERC	12/14/2016	Draft Resource Report13, section 13.4.4.2 provides a list of proposed Seismic Category structures, systems, and components. However, the current list is limited. Provide a more exhaustive list that includes the liquefaction trains, the dock and trestle, and flares.	The proposed Seismic Category for all pieces of equipment is listed as a column in the Equipment List located in Appendix M.3 of Resource Report 13.
FERC	12/14/2016	Draft Resource Report 13, section 13.4.4 should provide the maximum tsunami elevations at the shoreline of the site based on the values provided in section 3.4.5 of appendix J.1.	The tsunami analysis was updated in fall of 2016 and presented in Section 5 of Fugro's LNG Facilities Seismic Engineering Report. The update focused on the submarine landslide model, applying refined parameters

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			for the landslide materials and corrections for tidal currents. These refinements reduced the modeled wave heights by three to six feet. Maximum tsunami heights are listed in Table 5.2 for four observation points along the shoreline at the LNG site. Heights are shown for Lowest Astronomical Tide, Mean Sea Level, and Highest Astronomical Tide.
FERC	12/14/2016	Draft Resource Report 13, section 13.4.5.6 indicates that parts of the LNG Plant liquefying natural gas or transferring, storing, or vaporizing LNG, would be designed to withstand a sustained wind velocity of 150 miles per hour (mph), as per 49 CFR 193.2067. This section further indicates that structures, components, and systems not qualified as LNG facilities would be designed for a 3-second gust wind speed of 110 miles per hour, as per ASCE 7-05. In addition, the marine berth indicates an even lower design wind speed. Specify which hazardous fluid facilities, control buildings, emergency equipment (e.g. firewater pump buildings), and other critical components typically categorized as seismic 1 or 2, would not be designed to the 150 mile per hour sustained wind speed. Provide a safety justification for those that are not designed to the 150 mph sustained wind speed.	All Liquefaction Facilities and Marine Facilities associated with the LNG terminal would be designed to comply with 49 CFR Part 193.2067 which requires a sustained wind velocity of 150 mph.
FERC	12/14/2016	Draft Resource Report13, section 13.4.5.8 discusses storm surge heights and references a report DHI, 2014a. Provide the referenced report DHI, 2014a.	The reference to this report has been removed.
FERC	12/14/2016	In draft Resource Report 13, section 13.4.5.8 a 100-year storm surge height of 36.1 feet is indicated. Please provide the technical report on which that height is based. In addition, the storm surge height for a 500 year return period. Also, indicate the sea level rise that is included in the storm surge elevation values.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, section 13.5.1.2 indicates that there would be no need to construct or demarcate turning basins since there is ample sea room off the berths. Provide a bathymetry chart that depicts the depths available in the waterway.	Bathymetry charts for the LNG Plant area were provided under Fugro Marine Survey Report and is also provided under Appendix 13.J.9.
FERC	12/14/2016	Draft Resource Report 13, section 13.6.2 indicates for the current proposed ground improvements, the estimated total maximum settlement for the LNG tanks are in the range of 10 inches and differential settlements are 5 inches. Provide the calculations and assumptions that were used to determine these estimated settlements. These levels of settlement seem high and may warrant either additional ground improvement or use of deep foundations. Please revise proposed foundation recommendations in section 13.6.2 to provide foundation settlements for LNG tanks consistent with current practice.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, table 13.6.11-1 provides preliminary LNG storage tank seismic design values. Please provide in Resource Report 13, appendix L design calculations that were used to determine the values provided in table 13.6.11-1.	The Design Calculation Report, included in Appendix 13.L.3, explains the calculations used to determine the values presented in Table 13.11.1.24.

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FERC	12/14/2016	Draft Resource Report 13, section 13.9.6 indicates that condensate would be loaded onto trucks. Provide, as public information, a description of:	See below.
FERC	12/14/2016	a. the condensate truck station;	The condensate truck station will be a single load station capable of transferring up to 1,000 barrels per day of condensate
FERC	12/14/2016	b. the condensate truck loading and metering system;	It is estimated that condensate trucks up to 12,000-gallon capacity will serve the system. Final size of the trucks will be based on commercial agreements.
FERC	12/14/2016	c. method of operation;	The method of operation for the condensate truck station would be intermittent. Final details of operations will be determined in detailed design.
FERC	12/14/2016	d. safety features; and	Controls and monitoring systems are for the condensate loading would be illustrated on the P&IDs. Hazard detection, hazard control, and firewater features are illustrated on the drawings in Appendix S
FERC	12/14/2016	e. number of condensate trucks expected to be loaded per year.	Based on the estimated 1,000 barrels per day capacity, approximately 3-4 trucks per day at would be loaded at a 12,000 gallons size truck and approximately 5-6 trucks per day would be loaded at a 8,000 gallons size truck.
FERC	12/14/2016	Draft Resource Report 13, page 13-192 of the text indicates that the dock impoundment sumps would be sized based on a 1-minute duration spill from the 16-inch loading arm pipe downstream of the emergency shut down valve (ESDV). This is less than 10 minutes and should be based on demonstrable surveillance and shutdown provisions acceptable to the Authority Having Jurisdiction in accordance with NFPA 59A. Therefore, provide the following:	In accordance with Section 2.2.2.2 of NFPA 59A (2001), the project is preparing justification to support "demonstrable surveillance and shutdown provisions" to allow for a 1-minute spill duration for sizing of impoundment sumps. This justification will be submitted to DOT PHMSA for review. The results of the PHMSA consultation will be provided to FERC as a supplement to the application and will address the concerns raised by FERC.
FERC	12/14/2016	a. justification for why the portion of the line immediately upstream of this ESDV would not be considered to have potential for a release to the dock impoundment;	Answered above
FERC	12/14/2016	b. justification for a 1 minute duration spill, including detection and shutdown times, valve closure times, associated surge analyses, and reliability levels; and	Answered above
FERC	12/14/2016	c. concurrence from PHMSA on the appropriateness of using a 1 minute duration spill for sizing the dock impoundments.	Answered above

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FERC	12/14/2016	Draft Resource Report 13, section 13.13.1 provides descriptions of several of the hazardous fluid impoundments. For preparation of the environmental document, provide, as public information, the following details for all hazardous fluid impoundment sumps:	Resource Report 13, Section 13.34 has been updated to include this information
FERC	12/14/2016	a. the impoundment sump name;	Answered above.
FERC	12/14/2016	b. materials of construction, including any insulated concrete lining;	Answered above.
FERC	12/14/2016	c. Project areas and fluids served;	Answered above.
FERC	12/14/2016	d. usable dimensions (in feet), including the height below any trough or channel intersection and the height of the insulated concrete, if any;	Answered above.
FERC	12/14/2016	e. usable volume (in gallons);	Answered above.
FERC	12/14/2016	f. a full description of the sizing spill, including the fluid type, the pipe diameter and flow rate (or vessel capacity), and any pump run out and de-inventory considerations; and	Answered above.
FERC	12/14/2016	g. the liquid volume of the total sizing spill (in gallons).	Answered above.
FERC	12/14/2016	Draft Resource Report 13, section 13.1.15.2 indicates that the Project would have knock out drums. Provide the dimensions, materials of construction, and net usable volume of the liquid spill impoundments for the knock out drums. Also provide justification for the capacity of each of these impoundments, confirming that they would be adequate for the purpose.	Final dimensions, materials of construction, working volumes, and net useable volumes will be determined in final design. Appendix M.4 in Resource Report 13 includes data sheets which details all available information on the knock out drums. The spill containment drawings in Appendix S of Resource Report 13 show which areas will be served by each spill impoundment system. The design flow rate for each impoundment system is detailed in Section 13.34 of Resource Report 13. The design flow rate for each impoundment system is significantly greater than the volume which would be stored in each knock out drum.
FERC	12/14/2016	Draft Resource Report 13, pages 13-189 and 13-192 of the text indicate that the outer pipe of the pipe-in-pipe rundown and ship transfer lines would be used as part of the spill conveyance or containment system. Provide:	The Project is currently consulting with PHMSA on the use of pipe in pipe as a spill containment system and will address these items with PHMSA in the pipe in pipe equivalency letter. Once the PHMSA consultation is complete, this package will be filed with FERC addressing these comments.
FERC	12/14/2016	a. design and a plot plan layout of the pipe-in-pipe system, including identification of all conventional process lines extending from or attached to the pipe-in-pipe, as well as the locations of any reliefs, instrumentation or other connections along the inner or outer pipes;	Answered above.

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FERC	12/14/2016	b. fatigue cycling considerations for the pipe-in-pipe system;	Answered above.
FERC	12/14/2016	c. leak testing philosophy and pressures for the outer pipe;	Answered above.
FERC	12/14/2016	d. a description of the maintenance procedures that would be followed over the life of the facility to determine that the outer pipe would be continuing to adequately serve as spill containment;	Answered above.
FERC	12/14/2016	e. the method used and time needed to detect an inner pipe leak anywhere along the pipe-in-pipe system;	Answered above.
FERC	12/14/2016	f. plans for purging or draining LNG from the outer pipe;	Answered above.
FERC	12/14/2016	g. the impacts on the pipe-in-pipe system that could occur due to potential VCE overpressures, jet fires, and impoundment fires, evaluated in the draft Resource Report 13, appendix Q, and the amount of LNG that could potentially be released from the pipe-in-pipe in these scenarios; and	Answered above.
FERC	12/14/2016	h. a description of any features that would protect against external common cause failures of the inner and outer pipes, including heavy equipment accidents.	Answered above.
FERC	12/14/2016	Draft Resource Report 13, pages 13-189 and 13-192 of the text indicate that the outer pipe of the pipe-in-pipe rundown and ship transfer lines would be used as part of the spill conveyance or containment system. Provide a schedule for the following:	During detailed design, the EPC contractor will enter into an agreement with the selected pipe in pipe vendor. The pipe in pipe vendor will provide final design information on the pipe in pipe system. This information will be provided to FERC during detailed design.
FERC	12/14/2016	a. modeling to demonstrate that the outer pipe could withstand a sizing spill or any smaller release from the inner pipe, considering the combination of the sudden thermal shock and forces onto the outer pipe;	Answered above.
FERC	12/14/2016	b. an assessment of outer pipe bowing due to a sizing spill or any smaller release;	Answered above.
FERC	12/14/2016	c. an assessment of the vapor production and vapor handling capacities within the annular space during a sizing spill or smaller release into the outer pipe; and	Answered above.
FERC	12/14/2016	d. a stress analysis for the length of the pipe-in-pipe system, including at bulkheads.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a discussion of the planned use of pipe-in-pipe as spill containment for certain Project piping and the reliability of those systems. Also, provide a discussion of other features at the dock that would be relied upon to prevent LNG spills from entering the waterway, including an indication of what size LNG spills would be contained.	Information related to the pipe in pipe section has been included in Resource Report 13 Section 13.34
FERC	12/14/2016	Draft Resource Report 13, section 13.6.5 indicates that a stainless steel downcomer would direct LNG spills from the LNG storage tank top to the impoundment system below. Provide sizing calculations for the downcomer pipes, considering vaporization within the downcomers.	The Applicant will address this comment prior to the initiation of the EIS process

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FERC	12/14/2016	For preparation of the environmental document, provide, as public information, the flash points, lower flammability limits (LFLs), and upper flammability limits (UFLs) for all ignitable Project fluids, including the ranges for each ignitable mixture	Resource Report 11, Section 11.2.1 has been updated to contain this information
FERC	12/14/2016	For preparation of the environmental document, provide, as public information,	A Meteorological Report detailing the weather station, beginning and end dates of the weather data, and the selected conditions for thermal and vapor modeling is included in Resource Report 13, Appendix H.4.
FERC	12/14/2016	a. the weather station(s) used to select meteorological conditions for the hazard modeling;	Answered above.
FERC	12/14/2016	b. the beginning and end dates of the weather data;	Answered above.
FERC	12/14/2016	c. the temperature, humidity, and wind speed parameters selected for thermal radiation modeling; and	Answered above.
FERC	12/14/2016	d. the temperature, humidity, and wind speed parameters selected for flammable and toxic vapor dispersion modeling.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a list of the leakage source design spills used for hazard modeling, including the following parameters:	An updated Hazard Analysis Report is included in Appendix H.3. After the FERC application, the Project will prepare a Design Spill Package to submit to DOT PHMSA for their review. Following DOT PHMSA review, a Letter of No Objection along with any updates to the Hazard Analysis Report will be filed with FERC as a supplement. Resource Report No. 11, Section 11.3 includes the project's proposed design spills with their corresponding conditions. The Hazard Analysis Report also contains a list of all the leakage sources used as design spills for the hazard modeling.
FERC	12/14/2016	a. design spill number or scenario code;	Answered above.
FERC	12/14/2016	b. plant location;	Answered above.
FERC	12/14/2016	c. fluid type;	Answered above.
FERC	12/14/2016	d. line diameter (inches) or vessel capacity;	Answered above.
FERC	12/14/2016	e. hole diameter (inches);	Answered above.
FERC	12/14/2016	f. total mass flow rate (lb/hr); and	Answered above.
FERC	12/14/2016	g. liquid rainout (percent).	Answered above.

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FERC	12/14/2016	For preparation of the environmental document, provide, as public information, identification of the software used to model each hazardous scenario and the factor of safety applied to account for uncertainty in the model for each type of hazard.	This information is included in the Hazard Analysis Report in Appendix H.3.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a discussion of the ground surface roughness(es) used in the hazard modeling.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a discussion of any assumptions used in the dispersion modeling, including how any fan equipment was considered to contribute to vapor dispersion modeling scenarios and why that account is reasonable or conservative.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a depiction of the maximum distance of flammable vapor dispersion, considering uncertainty in the model, for all scenarios on generalized plot plans that identify any property lines and shore lines as well as the scale of the drawing.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a list of all the toxic components that would be extracted from the FEED gas into the heavier hydrocarbon streams, such as propane, butane, hexane, mercaptans, benzene, toluene, xylene, ethyl benzene, and any others. Also provide, as public information, a discussion of the method used to account for the potential additive toxic load of all toxic components in design spill releases of toxic mixtures, as well as any other assumptions made to provide a conservative or representative toxic dispersion analysis.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a discussion of the exposure times considered for the toxic dispersion endpoints and the averaging times used in the toxic modeling.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a list of the maximum distances, considering uncertainty in the model, to all three acute exposure guideline levels (AEGL) for all toxic dispersion scenarios. Also, provide a depiction of the maximum distances the AEGL-2 and AEGL-3 endpoints on generalized plot plans, identifying any property lines and shore lines as well as the scale of the drawing.	Answered above.
FERC	12/14/2016	If any of the three modeled AEGL distances extend offsite, provide, as public information, a discussion of the types of buildings and outdoor areas within the zones.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, the results of design spill dispersion modeling for the asphyxiant potential of the liquid nitrogen release and discussion of the placement of any oxygen sensors to protect operators.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a discussion of the overpressure scenarios, obstacle density, and any assumptions used in the overpressure modeling. Include discussion on the potential for flammable vapor underneath the LNG storage tanks to ignite and create significant overpressures and any measures that would be provided to prevent this scenario.	Answered above.

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Agency	**Comment Date**	**Comment**	**Response/Resource Report Location**
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a depiction on generalized plot plans of the maximum distances to the 1 pound per square inch (psi) overpressure level from the overpressure scenarios. Include identification of any property lines and shorelines as well as the scale of the drawing.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a depiction on a generalized plot plan of the distances to 1,600 Btu/ft2-hr from all ignitable fluid impoundment sumps, as determined by LNGFIRE3 for these pool fires (or discuss the approval of a different model for siting). Include identification of any property lines and shorelines as well as the scale of the drawing.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a depiction on a generalized plot plan of the distances to the 1,600, 3,000, and 10,000 Btu/ft2-hr levels from the tank top fire. Include identification of any property lines and shorelines as well as the scale of the drawing. Also discuss, as public information, the flame base height and target height selected.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a depiction on a generalized plot plan of the maximum distances to the 1,600 Btu/ft2-hr level from design spill jet fires. Identify any property lines and shore lines as well as the scale of the drawing.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a detailed discussion of the measures that would be taken to prevent boiling liquid expanding vapor explosions (BLEVEs) or pressure vessel bursts due to thermal radiation from impoundment fires or jet fires. Include consideration of trucks at truck stations. Alternatively, provide a discussion of the impacts.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a discussion of the potential impacts and any mitigation from impoundment thermal radiation levels and from vapor cloud overpressures to fixed duty work locations, pipe-in-pipe containment systems, and any other Project components that could exacerbate the initial hazard.	Answered above.
FERC	12/14/2016	For preparation of the environmental document, provide, as public information, a depiction of the three zones of concern found in the Sandia Report, SAND2004-6258, for both accidental and intentional ship breaches. Also, include a description of the waterfront communities and structures, including industrial, commercial, residential, schools, hospitals, cultural centers, military installations, city centers, etc., that each zone would encompass. This information should be provided for the transiting LNG vessels.	This information is included in Resource Report No. 11, Section 11.2.3.2
FERC	12/14/2016	Draft Resource Report 13, section 13.14.4.2 indicates that flammable gas detectors would be provided in the air intakes of any occupied buildings, pressurized electrical rooms, or substation buildings within 200 feet of high or low leak potential equipment or where release scenarios and dispersion modeling indicate potential gas concentrations above ½ LFL. Provide:	See below.

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Agency	**Comment Date**	**Comment**	**Response/Resource Report Location**
FERC	12/14/2016	a. the set points at which this gas detection would trigger an alarm and at which it would trigger the Heating Ventilation (HV) or HVAC to switch to recirculation;	The final set points of the gas detectors will be determined in detailed design. However, the preliminary set points are at 20% alarm and 40 percent shutdown
FERC	12/14/2016	b. as public information, a description of any plant buildings that would not be provided with air intake gas detection capability, as well as an explanation of why this detection would not be needed;	During detailed design, an evaluation will be made to determine if there are any plant buildings which do not require gas detection on the air intakes along with an explanation of why this detection would not be needed.
FERC	12/14/2016	c. as public information, a description of any combustion air intake equipment and an explanation of why air intake gas detection would not be needed for these components; and	During detailed design, an evaluation will be made to determine if there is any combustion air intake equipment which do not require gas detection on the air intakes along with an explanation of why this detection would not be needed.
FERC	12/14/2016	d. an overall plot plan identifying the locations of the buildings and combustion air intake equipment discussed for items b. and c. above.	During detailed design, an overall plot plan will be developed which will identify the location of all buildings and combustion air intakes.
FERC	12/14/2016	Provide the following additional items needed to complete a FEED review of the facilities, which were either note as to be provided or were missing from the Preferred Submittal Format Guidance (PSFG) list being used:	See below.
FERC	12/14/2016	a. LNG storage tank drawings [PSFG 6.15];	LNG Storage Tank Drawings are included in Appendix L.2.
FERC	12/14/2016	b. electrical seal drawings [PSFG 11.3.5];	A drawing of the typical electrical seal arrangement is included in Resource Report No. 13, Appendix N.6.
FERC	12/14/2016	c. drawing of the layout of emergency shut down manual activation devices [related to PSFG 14];	The Applicant will address this comment after the FEIS but prior to construction start
FERC	12/14/2016	d. specifications for valves, rotating equipment, storage tanks and vessels, heat exchangers, and control system [PSFG Appendix M/T]; and	A list of all the specifications to be developed in detailed design is included in Appendix F. Preliminary specifications for certain components are included in Appendix F of Resource Report 13
FERC	12/14/2016	e. manufacturer's data for the shut off valves [PSFG Appendix S.3].	Preliminary information of manufacturers shutoff valves is included in Appendix Q.5.
FERC	12/14/2016	Indicate whether the following have been conducted or provide the schedule for the following:	See below.
FERC	12/14/2016	a. plant reliability, availability, and maintainability analysis;	A detailed RAM study will be developed in detailed design.
FERC	12/14/2016	b. road safety and reliability impact studies;	A road safety and reliability impact study will be developed in detailed design. A preliminary assessment

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Agency	Comment Date	Comment	Response/Resource Report Location
			of the hazards associated with roads are included in Resource Report No. 11, Section 11.2.4.
FERC	12/14/2016	c. crane and lifting impact studies;	A detailed crane and listing impact study will be developed in detailed design. A preliminary assessment of the hazards associated with cranes and lifting during construction is included in Resource Report No. 11, Section 11.2.5.
FERC	12/14/2016	d. security threat and vulnerability studies;	A detailed security threat and vulnerability study will be developed in detailed design. A preliminary discussion on the study is included in Resource Report No. 11, Section 11.2.8.
FERC	12/14/2016	e. simultaneous operations studies; and	A SIMOPS study will be developed in detailed design, if necessary
FERC	12/14/2016	f. waterway safety and reliability impact studies.	A waterway suitability assessment has been developed in accordance with USCG requirements and has been submitted to the USCG. Information on the waterway safety is included in Resource Report No. 11, Section 11.2.3.
FERC	12/14/2016	Draft Resource Report 13, appendix C.12, Rainfall Design Basis, page 12 indicates that 12 inches of snowfall height would be added at the bottom of spill conveyance to size conveyance depth. Draft Resource Report 13, appendix Q, Hydrocarbon Spill Containment Sizing Report, page 11 indicates that snow removal methods for the LNG channels/trenches would be developed during FEED. Provide a detailed and clear philosophy for handling snow volumes in the impoundment system, which explains:	During development of the operations and maintenance procedures, detailed requirements for operator snow removal would be developed. The initial philosophy is to provide snow clearing for access to critical equipment, components, and access points. Due to snow being lighter than LNG spills, it is not envisioned to send LNG operators into spill containment systems to remove snow.
FERC	12/14/2016	a. how all hazardous liquid spill channels/trenches would be assured to provide conveyance for the sizing spill at all times, including when snowfall accumulations exceed 12 inches;	The initial philosophy is to provide snow clearing for access to critical equipment, components, and access points. Due to snow being lighter than LNG spills, it is not envisioned to send LNG operators into spill containment systems to remove snow.
FERC	12/14/2016	b. how hazardous liquid spills into the areas under and around equipment would be assured to drain to any channels/trenches at all times; and	The initial philosophy is to provide snow clearing for access to critical equipment, components, and access points. Due to snow being lighter than LNG spills, it is not envisioned to send LNG operators into spill containment systems to remove snow.

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Agency	**Comment Date**	**Comment**	**Response/Resource Report Location**
FERC	12/14/2016	c. how the sizing spill volume in all of the hazardous liquid impoundments would be maintained available at all times.	The initial philosophy is to provide snow clearing for access to critical equipment, components, and access points. Due to snow being lighter than LNG spills, it is not envisioned to send LNG operators into spill containment systems to remove snow. The sizing of impoundments is done in accordance with 49 CFR Part 193 and NFPA 59A (2001) which does not require additional volume for snow accumulation.
FERC	12/14/2016	Draft Resource Report 13, appendix C.20, Design Basis – Waste Water Treatment document, page 8 of 18 indicates that 14 LNG and refrigerant sumps and the condensate and fractionation sumps would have storm water removal pumps in accordance with 49 CFR 193.2173. Confirm that storm water pumps, meeting the requirements of 49 CFR 193.2173, would be installed in all hazardous liquid impoundments, including the dock LNG impoundments and other hazardous liquid impoundments, such as liquid nitrogen, amine solutions, and oils.	Storm water pumps meeting the requirements of 49 C.F.R. 193.2173 would be installed in all hazardous liquid impoundments.
FERC	12/14/2016	Draft Resource Report 13, appendix C.20, Design Basis – Waste Water Treatment document, page 8 of 18 states that low temperature from LNG or refrigerant leakage would disable auto start of the storm water removal pumps instantly. Describe this system, and explain how it would have redundant automatic shutdown controls, in accordance with 49 CFR 193.2173.	The Applicant will address this comment after the FEIS but prior to construction start
FERC	12/14/2016	Draft Resource Report 13, appendix C.13, title of section 4.0 incorrectly spells the word Seismic. Please correct.	The Applicant will address this comment after the FEIS but prior to construction start
FERC	12/14/2016	51. Draft Resource Report 13, appendix C.13, section 4.1 defines the OBE and SSE. The definitions are based on those provided in NFPA 59A-2001. Title 49CFR193 was updated in 2010 and now references NFPA 59A-2006 for determining the OBE and SSE. Clarify or revise Section 13.4.4 so that it provides the definitions of the OBE and SSE consistent with NFPA 59A-2006 (i.e., OBE = 475 year return period and SSE = MCE defined in ASCE 7-05).	Please see response to RR11_13, #06: As described in section 1.5.1 of the final PSHA report, NFPA 59A-2006 was used to describe the OBE and SSE. This report is included in Appendix 13.I.1. Accordingly, OBE – 475 yrs and SSE is MCE per ASCE 7-05.
FERC	12/14/2016	Draft Resource Report 13, appendix C.13, section 5.1 references NFPA 59A-2001 for Seismic Category I structures, systems, and components. Title 49CFR193 was updated in 2010 and now references NFPA 59A-2006. Clarify or revise that reference to NFPA 59A-2006.	Please see response to RR11_13, #06
FERC	12/14/2016	Draft Resource Report 13, appendix C.13, section 8.0 should provide a table of Spectral Acceleration Values versus period for the site specific SSE and OBE to be used for the design of Seismic Category I structures, systems, and components. Also, section 13.4.4 should provide the values of the site-specific seismic parameters SDS, SD1, and TL that are to be used for the design of Seismic Category II and III structures and nonstructural components.	Please see response to RR11_13, #07: Tables 5.9 and 5.10 of the PSHA report presents site-specific OBE and SSE spectra of Seismic Category 1 structures for onshore locations. Tables 5.9 and 5.11 of the PSHA present site-specific OBE and SSE spectra of Seismic Category 1 structures for nearshore locations.

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Agency	Comment Date	Comment	Response/Resource Report Location
			The PSHA report is included in Appendix 13.I.1. The narrative (Section 13.3.1.4) has been updated to include site specific seismic parameters for seismic category II and III structures.
FERC	12/14/2016	Draft Resource Report 13, appendix C.14, section 3.1.2 should provide load combinations and factors that include load combinations with wind and seismic loads combined with self-straining loads.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	12/14/2016	Draft Resource Report 13, appendix D provides a pre-FEED list of codes and standards for the Project. Many codes and standards required under regulation by incorporations by reference and codes and standards commonly referenced were not included. Provide a revised list of codes and standards for the FEED design considering the specific codes and standards in attachment B to this document and/or a reason for not including each of the specific codes and standards.	A list of pre-FEED codes and standards for the Project is provided in Appendix D.1 Appendix D.1 also includes an additional list of Codes and Standards which the EPC contractor will follow for the detailed design engineering, procurement, and construction phase of the Project.
FERC	12/14/2016	Draft Resource Report 13, appendix D provides a pre-FEED list of codes and standards for the Project and indicates that the latest editions will be used except as noted. Indicate whether the versions of ASME VIII and ASME B31.3 being used for the Project would be compliant with the requirements of 49 CFR 193.	The Project will comply with all requirements in 49 CFR Part 193, including its references. It is known that 49 CFR Part 193 incorporates an older version of ASME code which the Project will comply with or follow any equivalency guidance from DOT PHMSA. Final decision on compliance or equivalency will be made in detailed design based on PHMSA guidance.
FERC	12/14/2016	The list of permits in draft Resource Report 13, appendix F includes the Federal Aviation Administration (FAA) Determination of No Hazard for Air Navigation. For preparation of the environmental document, provide as public information:	See below
FERC	12/14/2016	a. the distance to the nearest airport from the proposed liquefaction plant site;	Resource Report 11 Section 11.1.1.5 has been updated to include this information
FERC	12/14/2016	b. the distance to the nearest airport from the proposed LNG ship route;	Resource Report 11 Section 11.1.1.5 has been updated to include this information
FERC	12/14/2016	c. a discussion on whether the Project includes equipment and/or ships tall enough to require notification on the FAA under 14 CFR 77.9; and	Resource Report 11 Section 11.1.1.5 has been updated to include this information
FERC	12/14/2016	d. if any, provide the FAA aeronautical study number for each.	Resource Report 11 Section 11.1.1.5 has been updated to include this information
FERC	12/14/2016	Draft Resource Report 13, appendix G provides a Hazard Identification Study (HAZID) review. Provide responses to the HAZID recommendations and a schedule for the Hazard and Operability Study of the FEED design.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix I.1 should be stamped and sealed because it will be relied upon for design.	This can be stamped and sealed for the detailed design phase.

<table>
<tr><th colspan="4">Resource Report No. 13
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<tr><th>Agency</th><th>Comment Date</th><th>Comment</th><th>Response/Resource Report Location</th></tr>
<tr><td>FERC</td><td>12/14/2016</td><td>It is unclear how site response analysis and variability in site conditions were included in the determination of the recommended design spectra. All previous Fugro seismic hazard evaluations submitted to FERC for LNG facilities in the past 5 years explicitly considered these effects. Please revise appendix I.1 to follow the same approach as used previously by Fugro.</td><td>Site response analysis was not conducted to develop the final design spectra. PSHA spectra estimated at the ground surface, for Site Class D, were used to develop the site-specific design spectra in the final report.
Details are provided in Section 5.2 and Plates 22 to 24 of the PSHA report, included in Appendix 13.I.1).</td></tr>
<tr><td>FERC</td><td>12/14/2016</td><td>Draft Resource Report 13, appendix I.1, section 5.0 should provide the site-specific values of SDS and SD1 for the site. Draft Resource Report13, appendix I.1, section 5.0 should also provide procedures for adjusting the OBE and SSE response spectral for other damping levels.</td><td>The Applicant will address this comment prior to the initiation of the EIS process</td></tr>
<tr><td>FERC</td><td>12/14/2016</td><td>Draft Resource Report 13, appendix I.1, section 5.0 should provide additional linear-linear plots of the finally recommended OBE and SSE (both horizontal and vertical) and MCE and DE.</td><td>The PSHA report, included in Appendix 1.I.1 has log-log plots of recommended OBE and SSE (both horizontal and vertical) and MCE and DE.</td></tr>
<tr><td>FERC</td><td>12/14/2016</td><td>Draft Resource Report 13, appendix I.1, section 5.1 should provide the mapped seismic values of SS and S1 and the resulting seismic parameters SMS, SM1, SDS and SD1 and TL based on ASCE 7-05 for the representative locations based on Site Class D.</td><td>The following table presents the mapped seismic values and the resulting seismic parameters for one representative location for Site Class D.
<table>
<tr><th>Seismic Parameter</th><th>Va</th></tr>
<tr><td>TL (sec)</td><td>1</td></tr>
<tr><td>Ss (g)</td><td>1.</td></tr>
<tr><td>S1 (g)</td><td>0.</td></tr>
<tr><td>SMs (g)</td><td>1.</td></tr>
<tr><td>SM1 (g)</td><td>0.</td></tr>
<tr><td>SDs (g)</td><td>0.</td></tr>
<tr><td>SD1 (g)</td><td>0.</td></tr>
</table></td></tr>
<tr><td>FERC</td><td>12/14/2016</td><td>Draft Resource Report 13, appendix I.1, section 6.0 should provide additional linear-linear plots that demonstrate that the spectrally matched spectra satisfy section 16.1.3.2 of ASCE 7-05 for non-seismically isolated structures and section 17.3.2 for seismically isolated structures.</td><td>Please note that section 16.1.3.2 and 17.3.2 for ASCE 7-05 refer to scaling of motions. In our analyses, we have spectrally matched the motions based on the ASCE 4-98 criteria per AKLNG's requirements. We note that the ASCE 4-98 criteria, which is typically used for nuclear facilities, are more stringent than the ASCE 7-05 criteria for scaled motions. Various plots of comparisons and checks against ASCE 4.98 criteria for spectrally matched ground motions are presented in the final report. Please refer to Appendix E of PSHA report, included in Appendix 13.I.1</td></tr>
</table>

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Agency	**Comment Date**	**Comment**	**Response/Resource Report Location**
FERC	12/14/2016	Draft Resource Report 13, appendix J provides a list of 15 Fugro reports in table 1.1 that have been prepared for the Project including the Geologic Hazard Report and the LNG Facilities Onshore Geotechnical Data submitted as appendix J.2 in part 2 of 4. Provide these reports, including LNG Facilities Marine Geotechnical Data Report and LNG Facilities Seismic Engineering Report.	Please refer to Appendix 13.J where the LNG Facilities Marine Geotechnical Data Report and LNG Facilities Seismic Engineering Report have been included as public information. Other referenced Fugro reports which are not applicable to Resource Report 13 have not been included.
FERC	12/14/2016	Draft Resource Report 13, appendix J, section 3.4.5 should provide the maximum tsunami wave height at the shoreline for Maximum Considered Tsunami levels provided in chapter 6 in ASCE 7-2016 and should provide a discussion regarding how the site-specific Alaska LNG Tsunami Level compares to the ASCE 7-16 Maximum Considered Tsunami level at the site shoreline.	The comment requests that Fugro report the tsunami wave height for the Maximum Considered Tsunami (MCT) provided in Chapter 6 of ASCE 7-2016, and compare that with our site-specific tsunami wave height. Fugro is currently unable to provide this comparison as the ASCE 7-2016 has not yet been publicly released, thus the MCT values are not available. Our understanding of the tsunami MCT is based on summaries of ASCE 7-2016 available on the internet. However, it should be noted that ASCE MCTs are computed assuming the source is coseismic submarine fault displacement. Fugro's LNG site tsunami assessment found that a submarine landslide in the Cook Inlet would be capable of generating a much larger tsunami than coseismic fault displacement. Therefore, the maximum tsunami wave height determined by Fugro is expected to be larger than the ASCE MCT wave height.
FERC	12/14/2016	Draft Resource Report 13, appendix J.2 states that a separate report presenting results of field and laboratory test results performed for the 2014 G&G program was provided under Fugro Report No. 04.101400904.10140094-8 (USAL-FG-GRZZZ-00-000003-000 dated May 8, 2015. Please provide this report as a part of the Resource Report13 application submittal as well as the LNG Facilities Onshore Integrated Site Characterization and Geotechnical Engineering and LNG Facilities Marine Integrated Site Characterization and Geotechnical Engineering reports.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix J.2, page 4-3 states that "A brief summary of the location of these strata and their properties are summarized in Table 4.1." There is no table 4.1. Revise or clarify if table 4.2 should be relabeled as table 4.1.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix L.1, section 1.3 states that a full containment tank is the owners select type with an inner steel tank and a prestressed outer concrete tank. However, draft Resource Report 13, section 13.6.1 of the main text and in the drawings provided in appendix L.5 the tanks described are of a different type. Please either revise section 1.3 or the main text of	Resource Report No. 13, Appendix L.2 has been updated with design information on the Project's selected concrete LNG storage tanks.

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Agency	**Comment Date**	**Comment**	**Response/Resource Report Location**
		Resource Report 13 and drawings provided appendix L.5 so they are consistent.	
FERC	12/14/2016	Draft Resource Report 13, appendix L.1, section 4.1 should provide a table of Spectral Accelerations versus period for SSE and OBE site-specific earthquake motions in addition to referencing sections 2.8 and 2.10.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix L.1, section 4.2.2 should specify the design wind velocity in addition to referencing the Wind Design Basis.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix L.1, section 4.2.4.6 should revise or clarify why ASCE 7-10 is referenced instead of ASCE 7-05.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix L.1, section 4.2.4.7 should provide more specifications regarding the seismic monitoring instrument and indicate that in addition to measuring accelerations in the free field, one set for tri-axial accelerometers will be located on the LNG tank.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix M.2, Firewater Equipment List indicates certain information as TBD. Provide a revised list that includes the equipment capacities.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix M.4, Hazard Control and Safety Equipment List includes entries for a helipad. Provide a drawing depicting the location of the helipad with respect to the Project facilities and buildings	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix N.1, Cause and Effect diagrams appear to be missing the diagrams for the liquefaction train, and the diagrams provided did not clarify alarm conditions. Provide a set of Cause and Effect diagrams that covers all areas handling process fluids and include the alarm conditions.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hydrocarbon Spill Containment Sizing Report Page 17 of 69 indicates that the outer concrete walls of the LNG storage tanks would contain 110 percent of the inner tank's maximum design liquid capacity. Provide calculations to demonstrate this.	The inner tank's maximum capacity is 259,000 m3. 110% of this volume is 285,000 m3. The outer tank diameter is 361 feet and the height is 104 feet yielding a volume of 301,427 m3 which would be able to contain more than 110% of the inner tank volume.
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hydrocarbon Spill Containment Sizing Report, page 17 of 69 indicates that no tertiary containment would be provided for the full-containment LNG storage tanks. While no tertiary "impoundment" is required by the federal regulations, FERC consistently recommends a tertiary berm around full-containment tanks to prevent LNG from flowing offsite in the unlikely event of a breach of both the inner and outer tank walls. For the recommended tertiary berm, provide layout drawings, along with capacity calculations in relation to the maximum design capacity of one LNG tank. For preparation of the environmental document, provide, as public information, a description of the recommended tertiary berm, including its capacity.	The Project did not consider a tertiary berm as it was not required under federal regulations. As this is a FERC requirement, the Project is working with Chiyoda to determine the best way to incorporate a tertiary containment into the LNG facility design. Details on the proposed tertiary containment will be filed with a FERC once finalized.
FERC	12/14/2016	Draft Resource Report 13, appendix Q includes the sizing spills for the impoundment sumps. The sizing should account for the potential contributions from all installed pumps at pump run out rates unless interlocks or other acceptable measures would	See below

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		prevent simultaneous operation of the additional pumps. This is consistent with PHMSA's FAQ DS12, found at http://primis.phmsa.dot.gov/lng/faqs.htm. Provide, explain, or revise the following:	
FERC	12/14/2016	a. revise the sizing spill calculations for the impoundment sumps to account for the flow from all installed pumps, or explain in detail how the additional pumps would be prevented from operating simultaneously; and	The Project will include electronic interlocks for pumps where additional pumps would accidentally be "turned on" to exceed the design spill rates.
FERC	12/14/2016	b. provide justification that the pump run out capacity in each case would not be expected to exceed 20 percent of the pump rated capacity, as indicated in the Hydrocarbon Spill Containment Sizing Report in the draft Resource Report 13 Appendix Q.	The final runout capacity will be determined based on final vendor selection for each pump. Based on typical pump curves, an initial consideration for runout was estimated to be 20%. In the event that the final design selects a pump with a higher runout flow than 20%, the impoundment system design would be updated in final design to account for the higher runout from the pump.
FERC	12/14/2016	Draft Resource Report 13, appendix Q provides sizing spills for impoundments. For all potentially-governing sizing spills from piping provide the following:	As part of the Design Spill Package, the piping and equipment inventory list includes information related to piping inventories to demonstrate the sufficiency of the sizing spill for impoundments. This information is provided in Appendix 13.H.3.
FERC	12/14/2016	a. the pipe length between automatic shutoff valves and between isolation valves around the release locations;	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	b. calculations for the largest amount of liquid inventory between automatic shutoff valves or isolation valves around the sizing spill release location, considering all release locations along a pipe, and provide calculations to determine how long it would take to release this volume at the sizing spill release rate; and	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	c. any excess inventory volume in the total sizing spill size, considering the inventory volume that would not be released during the sizing spill time minus the estimated detection, shutdown, and valve closure times.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix Q includes a Hydrocarbon Spill Containment Sizing Report. Provide impoundment sizing spills for hazardous liquids that were not included in this report, including liquid nitrogen, amine solutions, all hazardous oils, and any other hazardous liquids. Also, clarify whether the amine solutions and various oils would be handled above their flashpoints.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hydrocarbon Spill Containment Sizing Report lists vessel capacities. Provide calculations for the maximum design liquid capacities given for the hazardous liquid vessels, as well as for other hazardous liquid vessels to be considered for impoundment sizing, such as liquid nitrogen.	Final dimensions and capacities will be determined in final design. Appendix M in Resource Report 13 includes data sheets which details all available information on the vessels. The spill containment drawings in Appendix S of Resource Report 13 show which areas will be served by

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			each spill impoundment system. The design flow rate for each impoundment system is significantly greater than the volume which would be stored in each vessel.
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hydrocarbon Spill Containment Sizing Report provides “working depths” for impoundments, but it’s not clear what these depths represent. The “LNG Spill Containment Trench and Sump Sections and Details Layout” drawing in the appendix U.14 indicates that both a spill trench and a storm water culvert may intersect the impoundment walls at different heights. For each hazardous liquid impoundment, specifically provide:	See below
FERC	12/14/2016	a. the depth between the impoundment floor and the lowest penetration of the impoundment wall; and	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	b. the depth of any insulated concrete.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hydrocarbon Spill Containment Sizing Report indicates that certain tanks would be located within their impoundment.	See below
FERC	12/14/2016	a. Provide the volumes of any equipment foundations, insulated concrete, or other items that would need to be subtracted from each impoundment volume to find its net usable volume.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	b. Explain why a potential fire in the Condensate and Diesel Storage Area Dike would not cause the need for this impoundment sump to be sized for the total liquid volume in all three tanks located within it or separate impoundments for each tank sized for at least 110 percent of the tank.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix Q presents the weather parameters used for hazard modeling. Provide hourly weather data, in Excel format for at least 3 recent years, to support the selection of the ambient temperatures, humidities, and wind speeds for the hazard modeling.	A Meteorological Data Report is included in Resource Report 13, Appendix H.4. This report includes the weather data available which meets the requirements of 49 CFR Part 193.
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hydrocarbon Spill Containment Sizing Report indicates that weather data from the Metocean and Ice Design Basis (which was not found in the draft Resource Report 13 Appendix C) was used to determine weather parameters for modeling. Draft Resource Report 13, appendix C.12, Rainfall Design Basis table 3 indicates that the data in the Metocean and Ice Design Basis was collected from the Kenai airport. The Nikiski buoy station NKTA2 – 9455760 would be closer to the terminal site than the Kenai airport weather station. Provide a comparison of the wind data from this buoy station to the wind data used from the Kenai airport.	A Meteorological Data Report is included in Resource Report 13, Appendix H.4. This report includes the weather data available which meets the requirements of 49 CFR Part 193.
FERC	12/14/2016	NFPA 59A (2001) section 2.2.3.2, as incorporated by 49 CFR 193.2051, requires the use of LNGFIRE3 to model thermal radiation from impoundments unless an alternative model is validated and found acceptable. LNGFIRE3 can be used to conservatively model fires from hydrocarbons heavier than LNG. The Hydrocarbon Spill Containment Sizing Report in the draft Resource Report 13 appendix Q provides thermal radiation	An updated Hazard Analysis report is included in Appendix H of Resource Report 13 which uses LNGFIRE3 to conservatively model all impoundment sumps

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		results for the fractionation and condensate impoundments using PHAST, while the Hazard Analysis Report in the draft Resource Report 13 appendix Q provides results for these impoundments using LNGFIRE3. Confirm that the LNGFIRE3 results for the fractionation and condensate impoundments are being considered for siting, or provide the results of consultation with PHMSA on the use of PHAST for this modeling.	
FERC	12/14/2016	Draft Resource Report13, appendix Q indicates that LNGFIRE3 and PHAST were used to model thermal radiation from impoundments containing ignitable fluids. LNGFIRE3 input/output print outs were provided for several impoundments. Provide print outs of the LNGFIRE3 input/output files used to determine the 10,000, 3,000, and 1,600 Btu/ft2-hr zones for all impoundments that could contain ignitable fluids, including the LNG tank concrete outer wall fire and all others. Also, provide the electronic PHAST files for the thermal radiation modeling results provided in the Hydrocarbon Spill Containment Sizing Report.	An updated Hazard Analysis report is included in Appendix H of Resource Report 13 which uses LNGFIRE3 to conservatively model all impoundment sumps
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hazard Analysis Report, page 10 of 52 indicates that a thermal radiation analysis is not required for the dock impoundment sumps due to consideration of NFPA 59A (2001) section 2.2.3.1. However, the USDOT addressed this issue in a March 2010 letter of interpretation and determined that an exclusion zone analysis of the marine cargo transfer system is required. FERC staff would also recommend this thermal radiation analysis of the dock impoundment sumps. Therefore, provide a thermal radiation analysis using LNGFIRE3 for the dock impoundment sumps.	An updated Hazard Analysis report is included in Appendix H of Resource Report 13 which uses LNGFIRE3 to conservatively model all impoundment sumps
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hazard Analysis Report, section 4.3.3 discusses the method used to interpolate for the 3,000 Btu/ft2-hr zones from the default LNGFIRE3 results. Provide justification for the validity of the interpolation method used to calculate the 3,000 Btu/ft2-hr zones instead of directly modeling the 3,000 Btu/ft2-hr zone. Alternatively, provide print outs of the LNGFIRE3 input/output files for the cases that identify the distance to 3,000 Btu/ft2-hr for each scenario.	An updated Hazard Analysis report is included in Appendix H of Resource Report 13
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hazard Analysis Report, figure 3 provides a generalized plot of the 1,600 Btu/ft2-hr zones from most ignitable fluid impoundments. For analysis, provide detailed thermal radiation result plots for all impoundments that could contain ignitable fluids (and similar plots for design spill jet fires), depicting the 10,000, 3,000, and 1,600 Btu/ft2-hr hazard or exclusion zones, and identifying:	See below.
FERC	12/14/2016	a. any plant property lines, including any easements within;	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	b. any shorelines;	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	c. the measurement scale of the drawing; and	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13

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FERC	12/14/2016	d. plant components within the hazard or exclusion zones, such as:	An updated Hazard Analysis report is included in Appendix H of Resource Report No. .13
FERC	12/14/2016	e. equipment items;	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	f. LNG tank outer concrete containment walls;	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	g. elevated spill containment troughs;	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	h. pipe-in-pipe, with outer pipe as containment;	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	i. berthed ships;	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	j. truck transfer stations; and	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	k. occupied buildings or fixed duty work locations.	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hazard Analysis Report, figure 3 indicates that the 1,600 Btu/ft2-hr from the LNG tank tops would extend offsite. Further modeling of other hazards may produce offsite hazard or exclusion zones as well. Identify any areas outside of the plant property line, including beach/shoreline areas that would be within an exclusion or hazard zone. Provide concurrence from PHMSA on whether these areas meet the requirements in 49 CFR 193.2051, 193.2057, 193.2059 and incorporated siting sections of NFPA 59A (2001).	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hydrocarbon Spill Containment Sizing Report thermal radiation figures indicate that thermal radiation from impoundment fires may extend over plant components. Provide an analysis of the potential for this thermal radiation to cause BLEVEs, pressure vessel bursts, or other significant cascading impacts. Consider the impacts from a 2-hour duration fire, unless the sizing spill would not produce that duration of a fire. Provide passive protection measures where BLEVEs or pressure vessel bursts may be possible, or provide modeling of the impacts.	The project's firewater system and drawings as detailed in Appendix S illustrate complete and overlapping coverage of firewater monitors. These monitors can be used to cool plant components to prevent a BLEVE. Final details on the cooling impacts of firewater will be determined in detailed design when vendor details are available for all vessels including materials, inventory, and process conditions along with final determination of firewater system flow rates.
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hazard Analysis Report, table 5 lists the design spill flow rate considered for one LNG tank withdrawal header. Provide:	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	a. calculations demonstrating that the listed flow rate considers all of the LNG tank's installed pumps to be operating	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13

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		simultaneously at pump run out rates, unless interlocks or other measures would prevent this;	
FERC	12/14/2016	b. the pipe lengths between automatic shutoff valves and between isolation valves around potential release locations, including a guillotine at the connection to the ship loading header line;	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	c. calculations for the largest amount of inventory between automatic shutoff valves or isolation valves around the potential design spill release locations;	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	d. calculations to determine how long it would take to release the maximum de-inventory volume at the design spill release rate; and	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	e. revised design spill dispersion modeling, if needed, to represent the final calculated spill rate and to include any excess de-inventory volume released after the 10 minute spill time, considering any inventory volume that would not be released during the design spill time (at the design spill rate) minus the estimated valve closure time.	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	Draft Resource Report 13, appendix Q, Hazard Analysis Report overpressure scenario accounted for cloud positions and ignition locations that would demonstrate the maximum potential overpressures from a congested area to the LNG storage tanks. Provide additional overpressure scenarios, considering the cloud and ignition locations that would demonstrate the maximum potential overpressures onto:	See below
FERC	12/14/2016	a. any fixed duty work locations, including consideration of the trestle guard house;	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	b. the pipe-in-pipe systems;	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	c. any elevated troughs; and	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	d. other components that could exacerbate the hazard.	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	Draft Resource Report 13, appendix Q provides a toxic dispersion analysis for certain individual toxic components in the heavier hydrocarbon streams, and an analysis for hydrogen sulfide (H2S) in the reflux stream. Additional analyses are needed. Provide:	See below
FERC	12/14/2016	a. a revised toxic dispersion analysis for the heavier hydrocarbon stream that accounts for the potential additive toxicity of all toxic components dispersing simultaneously, such as propane, butanes, hexanes, mercaptans, benzene, ethyl-benzene, toluene and xylene;	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	b. a toxic dispersion analysis for propane leakage sources; and	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13

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Agency	**Comment Date**	**Comment**	**Response/Resource Report Location**
FERC	12/14/2016	c. an analysis of the maximum distances to asphyxiant or oxygen deprivation effects from a liquid nitrogen leakage source release and the need for oxygen sensors to alert onsite personnel.	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	Preliminary flammable vapor dispersion results in draft Resource Report 13, appendix Q indicate that flammable vapor could reach the LNG storage tanks. Provide an analysis of the potential overpressures from ignition of flammable vapor underneath the LNG storage tanks, and/or provide details of any prevention measures.	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13
FERC	12/14/2016	Provide all dispersion, overpressure, and jet fire modeling software files for the hazard modeling results presented in Resource Report 13, appendix Q. Be sure to organize these electronic files in a way that clearly identifies the scenario being modeled in each case.	An updated Hazard Analysis report is included in Appendix H of Resource Report No. 13. All software files will be provided to FERC staff electronically.
FERC	12/14/2016	Revise or clarify why ASCE 7-10 is referenced instead of ASCE 7-05 in draft Resource Report13, appendix R.2, section 6.1.1.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix R.2, section 13.6.1 and the drawing provided in appendix L.5 appears to show that the tank selected by the owner is a C3T tank. Please provide explanations on how each of the 16 issues raised in section 6.5.3 regarding C3T tanks have been resolved or would be resolved.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix T.1, section 3.0, Building Specifications should reference Seismic, Structural and Wind Design Basis documents. Also indicate how for each building, the Seismic Category and Wind Criteria (whether 150 mph sustained or ASCE 7-05 wind) will be identified (e.g., table added to the specification).	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report13, appendix U.1, provides most, but not all, unit plot plans shown on the Area Plot Plan Drawing Index. Provide a full set of unit plot plans, including the missing liquefaction train unit plot.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix U.3 provides Heat and Material Balance sheets for the Average Case in summer and winter. Provide the lean and rich bounding design cases, in addition to the Average Case.	Based on the Projects preliminary assessment of gas compositions, it is not expected that the composition will vary over the course of the operating season. The only parameters expected to change are ambient conditions and flow rates which are reflected in the summer and winter cases.
FERC	12/14/2016	Draft Resource Report 13, appendix U.4, provides Piping and Instrumentation Diagrams that contained a majority of the information needed, but did not include items such as some smaller line sizes. Provide Piping and Instrumentation Diagrams, ensuring that they contain all of the following information:	The Project's Piping and Instrumentation Diagrams are included in Appendix E.5. The P&IDs include the majority of the information requested by FERC as detailed in items a through p. Some of the information requested by FERC will not be available until final vendors are selected and their information is incorporated into the P&IDs. Any of the outstanding items will be developed in detailed design

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			and provided to FERC in detailed design.
FERC	12/14/2016	a. equipment tag number, name, size, duty, capacity and design conditions;	See above.
FERC	12/14/2016	b. piping with line number, piping class spec, size and insulation;	See above.
FERC	12/14/2016	c. LNG tank pipe penetration size or nozzle schedule;	See above.
FERC	12/14/2016	d. piping spec breaks and insulation limits;	See above.
FERC	12/14/2016	e. vent, drain, cooldown and recycle piping;	See above.
FERC	12/14/2016	f. isolation flanges, blinds and insulating flanges;	See above.
FERC	12/14/2016	g. valve type, in accordance with the piping legend symbol;	See above.
FERC	12/14/2016	h. all control valves numbered;	See above.
FERC	12/14/2016	i. all valve operator types and valve fail position;	See above.
FERC	12/14/2016	j. instrumentation numbered;	See above.
FERC	12/14/2016	k. control loops including software connections;	See above.
FERC	12/14/2016	l. shutdown interlocks;	See above.
FERC	12/14/2016	m. relief valves numbered, with set point;	See above.
FERC	12/14/2016	n. relief valve inlet and outlet piping size;	See above.
FERC	12/14/2016	o. car sealed valves and blinds; and	See above.
FERC	12/14/2016	p. equipment insulation.	See above.
FERC	12/14/2016	Draft Resource Report 13, appendix U. 14 trench cross-section drawings did not contain the trench dimensions. Provide trench/channel/ditch sizing calculations to demonstrate that all portions of the hazardous liquid conveyance system would be sized to carry the sizing spills.	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	Draft Resource Report 13, appendix U.14, LNG Spill Containment Trench and Sump Plan drawings provide general area extents and flow paths for hazardous liquids. Provide the following:	The Applicant will address this comment prior to the initiation of the EIS process
FERC	12/14/2016	a. detailed drawings of the hazardous spill containment system, allowing for equipment identification in each area and clarifying the impoundment system design and flow paths for other hazardous liquids, including liquid nitrogen, amine, all hazardous oils, and any others; and	The Applicant will address this comment prior to the initiation of the EIS process

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FERC	12/14/2016	b. as public information, spill containment system descriptions clarifying that all piping, vessels, and equipment that would handle hazardous liquids would be located within curbed or other impoundment areas. Also, describe any curbing provided at the extent of the spill containment areas.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	12/14/2016	Draft Resource Report13, appendix U.14, LNG Spill Containment Trench and Sump Plan drawings provide the layout and flow paths for the LNG spill containment system for onshore terminal areas. Provide:	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	12/14/2016	a. a drawing depicting the dock area spill containment system and flow paths; and	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	12/14/2016	b. as public information, a detailed explanation of what size LNG releases on the dock would be prevented from entering the waterway and a description of the measures used to keep this LNG on the dock.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	12/14/2016	Draft Resource Report 13, appendix U.14, LNG Spill Containment Trench and Sump Plan drawings depict both insulated and non-insulated concrete trenches and impoundments. Draft Resource Report 13, appendix Q, LNG Hazard Analysis Report, page 8 of 52 states that only regular concrete would be used in the impoundment system. Resolve this discrepancy, and provide the thermal conductivity and diffusivity of any insulated concrete. Also, revise the impoundment vapor dispersion modeling if not accurate for the Project design.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	12/14/2016	Draft Resource Report 13, appendix U.14, LNG Spill Containment Trench and Sump Sections and Details Layout drawing includes the depiction of a weir wall and sluice gate within the impoundment. Provide:	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	12/14/2016	a. an explanation of the purpose of the weir wall;	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	12/14/2016	b. dimensions of the space between the weir wall and the impoundment wall in each hazardous liquid impoundment;	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	12/14/2016	c. whether the culvert beyond the sluice gate and/or the weir wall spacing would create a confined space for flammable vapors with respect to overpressure generation;	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	12/14/2016	d. whether and how redundant low temperature detection would control of the opening of the sluice gate; and	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	12/14/2016	e. concurrence from PHMSA on whether the weir wall, sluice gate, and culvert would meet the requirements of 49 CFR 193.2167 as well as NFPA 59A (2001) section 2.2.2.3, as incorporated by 49 CFR 193.2101(a).	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	12/14/2016	Draft Resource Report 13, appendix U.14, LNG Spill Containment Trench and Sump Plan drawings do not clearly depict whether there would be any significant elevation drops in the spill conveyance system (other than for the LNG tank top) and any other downcomers, pipes, or other covered or confined areas of the spill containment system. Clarify whether any of these situations exist in the spill containment system.	The Applicant will address this comment prior to the initiation of the EIS process.

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FERC	12/14/2016	Draft Resource Report 13, appendix U.14, LNG Spill Containment Trench and Sump Plan drawings indicate that there would be areas where hazardous liquid piping and the spill conveyance system would extend over an in-plant roadway. Provide the clearance height of the system, and explain how these systems and their structural supports would be protected from impacts due to vehicle accidents and mobile equipment.	Isometrics and clearance heights will be developed in detailed design based on the final plot plan and spill containment systems. The final design will include considerations for accidental damage to adjacent road crossing structures and may include the installation of bollards, barriers, or other protective devices alongside of roadways to prevent vehicular damage.
PHMSA	12/14/2016	RR13 – Engineering and Design Material (Liquefied Natural Gas) - PHMSA Comment: LNG design must follow 49 CFR 193.2013 documents or standards incorporated by reference. Other standard versions (different dates) than what is in 49 CFR 193.2013 are not Code approved and would require a special permit, if used by the Developer/Owner/Operator.	Comment acknowledged
PHMSA	12/14/2016	RR13 – Engineering and Design Material (Liquefied Natural Gas) - PHMSA Comment: For LNG information from PHMSA, please ask the Developer/Owner/Operator to contact Kenneth Lee, kenneth.lee @ dot.gov	Comment acknowledged
SOA	12/14/2016	none - Green House Gas (GHG) regulation and fugitive emissions. Comment: In the North Slope NGL plant or the Nikiski terminal, are anticipated regulations covering GHG emissions and fugitive emissions considered? These issues will have the least cost impact if they are considered early in design? Do they need to be considered? Do they belong in a resource report?	The Applicant will address State of Alaska comments during required permitting activities.
SOA	12/14/2016	13.1.8.1, 13.1.21.1, 13.1.21.2, 13.4.2.8, 13.4.1.4, 13.456, & 13.6.1.1 - Storage, Currents and Ice. Comment: The design current is listed as 4.1 knots. The net LNG production is listed as 2.6 mmscfd. The total storage volume is listed as 480,000 cubic meters. The Holding Mode and the Loading Mode are described. Design sustained wind speed is listed as 150 mph. However, this location has large tides, ice, inclement weather, and strong cross-shore currents. Is there any analysis or information on the allowable loading conditions or the likelihood of delay in loading due to weather? Is there is sufficient storage capacity to avoid shutting down the AKLNG process and pipeline?	The Applicant will address State of Alaska comments during required permitting activities.

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ACRONYMS AND ABBREVIATIONS

Abbreviation	Definition
Abbreviations for Units of Measurement	
°C	degrees Celsius
°F	degrees Fahrenheit
ft	feet
g	grams
gpm	gallons per minute
ha	hectare
hp	horsepower
in	inches
m3	cubic meters
Ma	mega-annum (millions of years)
mm	millimeters
MMSCFD	million standard cubic feet per day
Mol%	molar proportion
MMTPA	million metric tons per annum
MSCFD	thousand standard cubic feet per day
MT	metric tonne
ng	nanograms
NM	nautical mile
ppm	parts per million
ppmv	parts per million by volume
psia	pounds per square inch absolute
psig	pounds per square inch gauge
µg	microgram
µPa	micropascals
VAC	voltage alternating current
VDC	voltage direct current
Other Abbreviations	
§	section or paragraph
ADAS	Analyzer Data Acquisition System
ADEC	Alaska Department of Environmental Conservation
Air Products	Air Products and Chemicals Inc.
Applicant's Plan	Applicant's Upland Erosion Control, Revegetation, and Maintenance Plan
Applicant's Procedures	Applicant's Wetland and Waterbody Construction, And Mitigation Procedures
ALE	Aftershock Level Earthquake
APE	Area of Potential Effect
API	American Petroleum Institute
ASCE	American Society of Civil Engineers
ASD	Azimuth Stern Drive

Abbreviation	Definition
ASME	American Society of Mechanical Engineers
ATWS	additional temporary workspace
BFW	boiler feed water
BOG	boil-off gas
BTEX	benzene, toluene, ethylbenzene and xylene
CCR	Central Control Room
CCTV	closed circuit television
CEMS	Continuous Emission Monitoring System
C.F.R.	Code of Federal Regulations
CIP	Corrugated Inclined Plate
CMMS	Computerized Maintenance Management System
CO	carbon monoxide
CO_2	carbon dioxide
CPI	Corrugated Plate Interceptor
DAF	Dissolved Air Floatation
DGF	Dissolved Gas Floatation
DOS	Declaration of Security
ECMS	Electrical Control and Management System
EDP	Emergency Depressurization Valve
EIS	Environmental Impact Statement
EO	Executive Order
EOC	Emergency Operations Center
EPC	Engineering Procurement and Construction
ERP	Emergency Response Plan
ESD	Emergency Shut Down
F&G	Fire and Gas
FACP	Fire Alarm Control Panel
FE	United States Department of Energy, Office of Fossil Energy
FEIS	Final Environmental Impact Statement
FEMA	United States Department of Homeland Security, Federal Emergency Management Agency
FERC	United States Department of Energy, Federal Energy Regulatory Commission
FERC Plan	FERC Erosion Control, Revegetation, and Maintenance Plan
FERC Procedures	FERC Wetland and Waterbody Construction and Mitigation Procedures
FGS	Fire and Gas System
FR	Federal Regulation
GAN	Gaseous Nitrogen
GIS	Geographic Information System
GTG	Gas Turbine Generator
GTP	Gas Treatment Plant
H&MB	Heat and Material Balance

Abbreviation	Definition
H_2S	hydrogen sulfide
HART	Highway Addressable Remote Transducer
HEA	Homer Electric Association
HHV	Higher Heating Value
HIPPS	High Integrity Pressure Protection System
HLV	Heavy Lift Vessel
HMI	Human Machine Interface
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning
I/O	input/output
IAMS	Instrument Asset Management System
IBC	International Building Code
ICS	Incident Command System
ICSS	Integrated Control and Safety System
IP	Individual Permit
IR	infrared
ISA	International Society of Automation
ISO	International Organization for Standardization
JT	Joule-Thomson
KO Drum	Knock-Out Drum
KOP	Key Observation Point
LAN	Local Area Network
LED	Light-Emitting Diode
LER	Local Equipment Room
LFL	lower flammable limit
LHV	lower heating value
Liquefaction Facility	natural gas liquefaction facility
LIN	liquid nitrogen
LNG	liquefied natural gas
LNGC	liquefied natural gas carrier
LOA	Letter of Authorization
LP	Low Pressure
LPG	liquefied petroleum gas
Mainline	an approximately 807-mile-long, large-diameter gas pipeline
MAOP	maximum allowable operating pressure
MARSEC	Maritime Security
MCD	Marine Construction Dock
MCE	Maximum Considered Earthquake
MCHE	Main Cryogenic Heat Exchanger
MHHW	Mean Higher High Water

Abbreviation	Definition
MHW	Mean High Water
MICC	Main Instrument and Control Systems Contractor
MLA	Mineral Leasing Act
MLBV	Mainline block valve
MLLW	Mean Lower Low Water
MLW	Mean Low Water
MOF	material offloading facility
MP	Mainline Milepost
MR	mixed refrigerant
MSL	main sea level
N_2O	nitrous oxide
NAS	Nonindigenous Aquatic Species
NCC	National Certification Corporation
NEMA	National Electrical Manufacturers Association
NFPA	National Fire Protection Agency
NGA	Natural Gas Act
Ni	the element nickel
NID	Negligible Impact Determination
NIMS	National Incident Management System
NMS	Nikiski Meter Station
NO_2	nitrogen dioxide
NOAA	National Oceanographic and Atmospheric Administration
North Slope	Alaska North Slope
NRTL	National Recognized Testing Laboratory
NTP	Network Time Protocol
O&M	Operations and Maintenance
O_3	Ozone
OBE	Operations Basis Earthquake
OD	Outside Diameter
OSHA	Occupational Safety and Health Administration
OTS	Operator Training Simulator
OU	operating unit
P&ID	Process and Instrument Diagrams
PAC	Potentially Affected Community
PAGA	Public Address/General Alarm
Pb	the element lead
PBTL	Prudhoe Bay Gas Transmission Line
PBU	Prudhoe Bay Unit
PCS	Process Control System
PCSW	potentially contaminated stormwater
PFD	Process Flow Diagrams

Abbreviation	Definition
PHMSA	United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration
PIMS	Process Information Management System
PiP	Pipe-in-Pipe
PLC	Programmable Logic Controller
PMC	Piping Material Class
Project	Alaska LNG Project
PRV	pressure relief valve
PSD	process shutdown
PSV	pressure safety valve
PTTL	Point Thomson Gas Transmission Line
PTU	Point Thomson Unit
PTZ	Pan-Tilt-Zoom
Q&A	Question and Answer
RCA	Regulatory Commission of Alaska
RCRA	Resource Conservation and Recovery Act
RFSU	Ready for Start-up
RO	Reverse Osmosis
RTD	Resistance Temperature Detector
SDV	shutdown valve
SIL	Safety Integrity Level
SIS	Safety Instrumented System
SO_2	sulfur dioxide
SS	stainless steel
STG	steam turbine generator
TBD	to be determined
TDH	total dynamic head
TÜV	Global Testing, Certification, and Inspection Laboratory
TWIC	Transportation Worker Identification Credential
UEHM	Upstream Equipment Health Monitoring System
UFD	Utility Flow Diagram
UIC	Underground Injection Control
UKC	under keel clearance
UPS	uninterrupted power supply
U.S.	United States
U.S.C.	United States Code
USCG	United States Coast Guard
UV	ultraviolet
VOC	volatile organic compound
VRV	vacuum relief valve

13.0 RESOURCE REPORT NO. 13 – ENGINEERING AND DESIGN MATERIAL

13.1 GENERAL BACKGROUND AND PROJECT MANAGEMENT

The Alaska Gasline Development Corporation (Applicant) plans to construct one integrated liquefied natural gas (LNG) Project (Project) with interdependent facilities for the purpose of liquefying supplies of natural gas from Alaska, in particular from the Point Thomson Unit (PTU) and Prudhoe Bay Unit (PBU) production fields on the Alaska North Slope (North Slope), for export in foreign commerce and for in-state deliveries of natural gas.

The Natural Gas Act (NGA), 15 U.S.C. § 717a(11) (2006), and Federal Energy Regulatory Commission (FERC) regulations, 18 Code of Federal Regulations (C.F.R.) § 153.2(d) (2014), define "LNG terminal" to include "all natural gas facilities located onshore or in State waters that are used to receive, unload, load, store, transport, gasify, liquefy, or process natural gas that is ... exported to a foreign country from the United States." With respect to this Project, the "LNG Terminal" includes the following: a liquefaction facility (Liquefaction Facility) in Southcentral Alaska; an approximately 807-mile gas pipeline (Mainline); a gas treatment plant (GTP) within the PBU on the North Slope; an approximately 63-mile gas transmission line connecting the GTP to the PTU gas production facility (PTU Gas Transmission Line or PTTL); and an approximately 1-mile gas transmission line connecting the GTP to the PBU gas production facility (PBU Gas Transmission Line or PBTL). All of these facilities are essential to export natural gas in foreign commerce and will have a nominal design life of 30 years.

These components are shown in Resource Report No. 1, Figure 1.1-1, as well as the maps found in Appendices A and B of Resource Report No. 1. Their proposed basis for design is described as follows.

The new Liquefaction Facility would be constructed on the eastern shore of Cook Inlet just south of the existing Agrium fertilizer plant on the Kenai Peninsula, approximately 3 miles southwest of Nikiski and 8.5 miles north of Kenai. The Liquefaction Facility would include the structures, equipment, underlying access rights, and all other associated systems for final processing and liquefaction of natural gas, as well as storage and loading of LNG, including terminal facilities and auxiliary marine vessels used to support Marine Terminal operations (excluding LNG carriers [LNGCs]). The Liquefaction Facility would include three liquefaction trains combining to process up to approximately 20 million metric tons per annum (MMTPA) of LNG. Two 240,000-cubic-meter tanks would be constructed to store the LNG. The Liquefaction Facility would be capable of accommodating two LNGCs. The size of LNGCs that the Liquefaction Facility would accommodate would range between 125,000–216,000-cubic-meter vessels.

In addition to the Liquefaction Facility, the LNG Terminal would include the following interdependent facilities:

- Mainline: A new 42-inch-diameter natural gas pipeline approximately 807 miles in length would extend from the Liquefaction Facility to the GTP in the PBU, including the structures, equipment, and all other associated systems. The proposed design anticipates up to eight compressor stations; one standalone heater station, one heater station collocated with a compressor station, and six cooling stations associated with six of the compressor stations; four meter stations; 30 Mainline block valves (MLBVs); one pig launcher facility at the GTP meter station, one pig receiver facility at the Nikiski meter station, and combined pig launcher and receiver facilities at each of the compressor stations; and associated infrastructure facilities.

Associated infrastructure facilities would include additional temporary workspace (ATWS), access roads, helipads, construction camps, pipe storage areas, material extraction sites, and material disposal sites.

Along the Mainline route, there would be at least five gas interconnection points to allow for future in-state deliveries of natural gas. The approximate locations of three of the gas interconnection points have been tentatively identified as follows: milepost (MP) 441 to serve Fairbanks, MP 763 to serve the Matanuska-Susitna Valley and Anchorage, and MP 807 to serve the Kenai Peninsula. The size and location of the other interconnection points are unknown at this time. None of the potential third-party facilities used to condition, if required, or move natural gas away from these gas interconnection points are part of the Project. Potential third-party facilities are addressed in the Cumulative Impacts analysis found in Appendix L of Resource Report No. 1;

- GTP: A new GTP and associated facilities in the PBU would receive natural gas from the PBU Gas Transmission Line and the PTU Gas Transmission Line. The GTP would treat/process the natural gas for delivery into the Mainline. There would be custody transfer, verification, and process metering between the GTP and PBU for fuel gas, propane makeup, and byproducts. All of these would be on the GTP or PBU pads;

- PBU Gas Transmission Line: A new 60-inch natural gas transmission line would extend approximately 1 mile from the outlet flange of the PBU gas production facility to the inlet flange of the GTP. The PBU Gas Transmission Line would include one-meter station on the GTP pad; and

- PTU Gas Transmission Line: A new 32-inch natural gas transmission line would extend approximately 63 miles from the outlet flange of the PTU gas production facility to the inlet flange of the GTP. The PTU Gas Transmission Line would include one-meter station on the GTP pad, four MLBVs, and pig launcher and receiver facilities—one each at the PTU and GTP pads.

Existing State of Alaska transportation infrastructure would be used during the construction of these new facilities including ports, airports, roads, railroads, and airstrips (potentially including previously abandoned airstrips). A preliminary assessment of potential new infrastructure and modifications or additions to these existing in-state facilities is provided in Resource Report No. 1, Appendix L. The Liquefaction Facility, Mainline, and GTP would require the construction of modules that may or may not take place at existing or new manufacturing facilities in the United States.

Resource Report No. 1, Appendix A, contains maps of the Project footprint. Appendices B and E of Resource Report No. 1 depict the footprint, plot plans of the aboveground facilities, and typical layout of aboveground facilities.

Outside the scope of the Project, but in support of or related to the Project, additional facilities or expansion/modification of existing facilities will be needed to be constructed. These other projects may include:

- Modifications/new facilities at the PTU (PTU Expansion project);
- Modifications/new facilities at the PBU (PBU Major Gas Sales [MGS] project); and
- Relocation of the Kenai Spur Highway.

13.1.1 Project Facilities

13.1.1.1 Number of Marine Docks, and With Both Rated and Maximum Export and Import Rates, Million Standard Cubic Feet Per Day (MMscfd) and Million Tons Per Annum (MTPA);

Two marine berths, each with three 16-inch LNG liquid loading arms (FAY691871/2/4 (includes one hybrid arm) and one 16-inch vapor return arm (FAY691873 and FAY691883) will be provided on each berth. The maximum annual LNG export rate will be nominally 20 MMTPA. The Liquefaction Facility will be capable of loading LNGCs at a rate up to 12,500 cubic meters per hour. The expected loading frequency will be 16–21 times per month depending on the size of the LNGCs in the fleet mix at the time.

13.1.1.2 Number of LNG Storage Tanks, and With Both Net and Gross Storage Capacity per Tank, Gal and Cubic Meter (m3) and Equivalent Billion Standard Cubic Feet (Bscf) Of Natural Gas;

Two full containment LNG storage tanks (ABJ691810/20), each with a capacity of 63,401,293 gallons (240,000 cubic meters, 5.2 bcf), will store the LNG product from the liquefaction units. Total storage will be 126,802,585 gallons (480,000 cubic meters, 10.5 bcf). Note that the tank capacity quoted represents the net working volume; excluding minimum liquid level for pump operation and any additional height required for high alarm level and sloshing height. The tanks have a 68,420,562 gallon (259,000 cubic meter, 5.9 bcf) maximum liquid capacity.

13.1.1.3 Number of Liquefaction Trains, and With Both Rated And Anticipated Maximum Liquefaction Capacity Per Train, MMscfd and MTPA;

The AP-C3MR™ LNG Process designed and licensed by Air Products and Chemicals, Inc., (Air Products) has been selected for the Project. This process is based on the principle of precooling the feed gas with a closed propane refrigerant circuit and then condensing and subcooling the feed gas within a closed mixed refrigerant circuit.

The Liquefaction Facility contains three identical 6.7 MMTPA liquefaction trains. The net LNG production is approximately 2,600 MMscfd (about 870 MMscfd for each LNG train).

13.1.1.4 Number of LNG Vaporizers, and With Both Sustained and Anticipated Maximum Vaporization Capacities, MMscfd

Not Applicable

13.1.1.5 Number of Feed Gas Pipelines and Interconnects, and with Both Rated and Anticipated Maximum Capacities, MMscfd, and Pressures, psig

A new 42-inch-diameter natural gas pipeline approximately 804 miles in length will extend from the GTP in the PBU to the Liquefaction Facility. The proposed design anticipates up to eight compressor stations; one standalone heater station, one heater station collocated with a compressor station, and six cooling stations associated with six of the compressor stations; four meter stations; 30 Mainline block valves (MLBVs); one pig launcher facility at the GTP meter station, one pig receiver facility at the Nikiski meter station, and combined pig launcher and receiver facilities at each of the compressor stations; and associated infrastructure facilities.

Along the Mainline route, there will be at least five gas interconnection points to allow for future in-state deliveries of natural gas. The approximate locations of three of the gas interconnection points have been tentatively identified as follows: milepost (MP) 441 to serve Fairbanks, MP 763 to serve the Matanuska-Susitna Valley and Anchorage, and MP 804 to serve the Kenai Peninsula. The size and location of other interconnection points are unknown at this time. None of the potential third-party facilities used to condition, if required, or move natural gas away from these gas interconnection points are part of the Project.

Feed gas maximum capacity is 2,793 MMscfd with an arrival pressure between 1,050–1,250 psig at the inlet of the Nikiski Meter Station.

13.1.1.6 Number of Sendout Pipelines and Interconnects, and With Both Rated and Anticipated Maximum Sendout Rates, MMscfd

Not Applicable

13.1.1.7 Fractionation Products, and with Both Rated and Anticipated Maximum Capacity Rates, gpm and MMscfd

The Fractionation System will be common for the three liquefaction trains. The feed to the Fractionation System is the bottoms stream from the Scrub Column in each LNG train. The Fractionation System will produce refrigerant (ethane/propane) make-up for the refrigerant circuits, liquefied petroleum gas (LPG) reinjection for the liquefaction system, and a condensate byproduct. The Fractionation System consists of a Deethanizer, a Depropanizer, a Debutanizer, and associated equipment.

The fractionation unit will produce a maximum capacity of 31.5 gpm (6,201 ft3/day) of condensate.

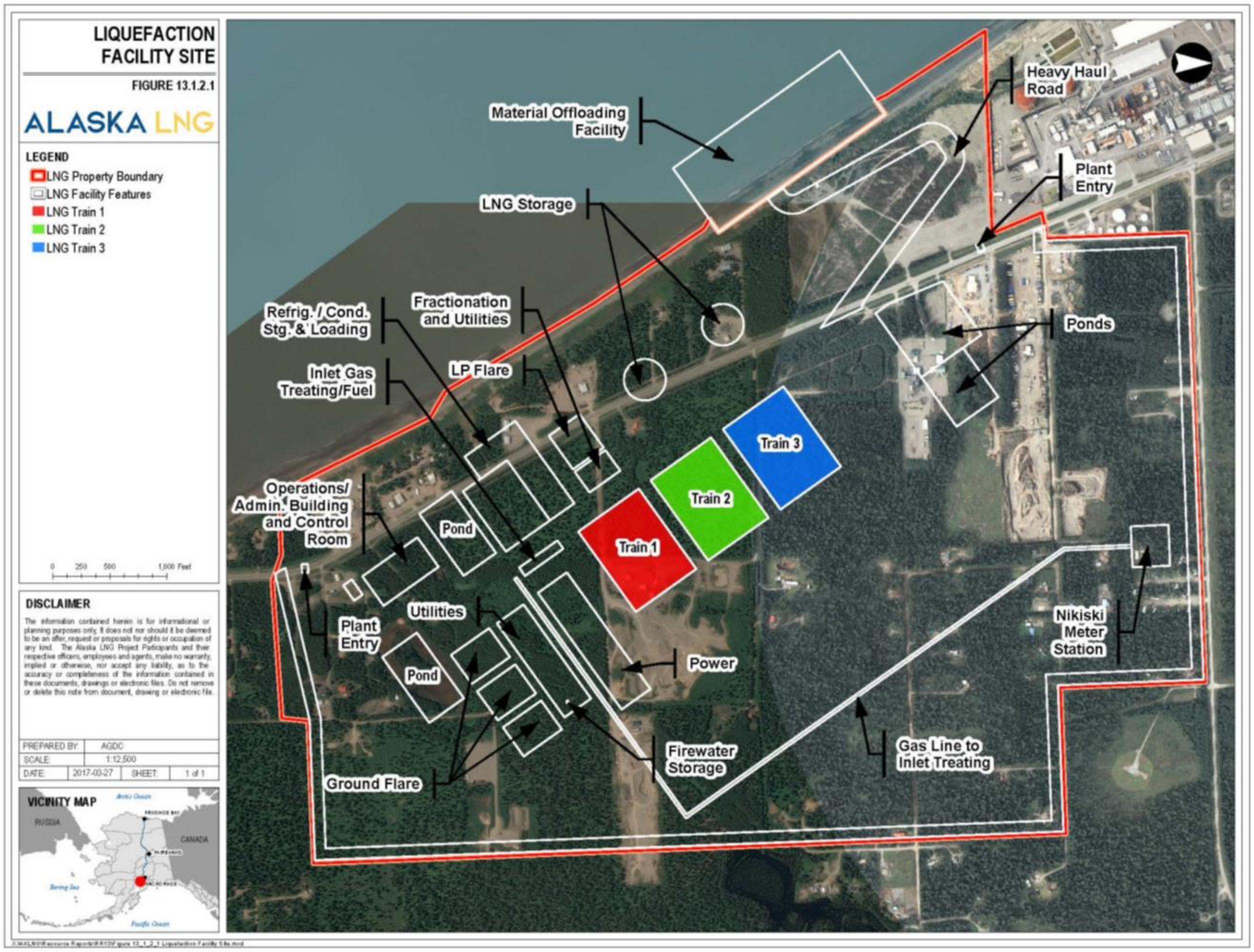
13.1.2 Location

13.1.2.1 Owned and Leased Property Boundaries, Options, Easements, and Rights Of Way With Reference to Site Location Maps and Drawings in Appendix 13.A.1

The Nikiski site lies on the north-central coast of the Kenai Peninsula on a low relief plain of glacial and glaciofluvial deposits, referred to as the Kenai Lowland. The Liquefaction Facility will be composed of the LNG Plant and associated Marine Terminal and located in the Nikiski area on the Kenai Peninsula in

East Cook Inlet. The LNG Plant, including utilities, will be designed to occupy the optimum footprint needed and be located within the approximately a 901-acre area shown notationally in Figure 13.1.2.1.

FIGURE 13.1.2.1 Liquefaction Facilities Overview



13.1.3 Owner, Principal Contractors, and Operator

13.1.3.1 Owner of the facilities with reference to the Organizational Structure in Appendix 13.A.2

The entity or entities that will own the Project facilities has yet to be determined. AGDC is currently the sole applicant. A preliminary organization chart is included in Appendix 13.A.2.

13.1.3.2 Principal Contractors identified for design, engineering, procurement, and construction of the facilities with reference to any preliminary Construction Workforce Organizational Chart or Work Breakdown Structure (if available) in Appendix 13.A.3*

A joint venture between CBI/Chiyoda was responsible for the engineering development included in Resource Report 13 for the Liquefaction Facility and Marine Terminal. The principal Engineering, Procurement & Construction (EPC) contractor(s) for Final Design have not yet been selected. A Construction Workforce Organization Chart will be developed during the Final Design Phase.

13.1.3.3 Operating Company of the facilities with reference to a preliminary Operating Workforce Organizational Chart in Appendix 13.A.4

The entity or entities that will operate the Project facilities has yet to be determined. A Workforce Organization Chart will be developed during the Final Design Phase.

13.1.4 Feed and Sendout Product(s)

13.1.4.1 Natural Gas Pipeline(s) Sending Out To

Not Applicable.

13.1.4.2 Natural Gas Pipelines Feeding From

The source of feed gas for the Project will be the PBU and PTU fields. Gas from the PBU and PTU will be processed on the North Slope in a purpose-built GTP that will remove carbon dioxide (CO_2) and hydrogen sulfide (H_2S) down to the levels acceptable to the Liquefaction Facility.

13.1.4.3 Fractionation Product Pipelines Sending Out To

No fractionation pipelines are included in the Project. Condensate product will be loaded into truck trailers and sent out from the Project.

13.1.4.4 Liquefaction Product Shipped To

LNG will be loaded onto LNG Carriers for transport. Off-takers and capacity holders will be determined in the Final Design Phase.

13.1.5 Project Schedule

It is to be requested that FERC issue authorization to site, construct, and operate the Project no later than late 2018, with construction scheduled to commence late 2019. It is anticipated that construction and commissioning of the facilities will take approximately eight years to complete. Construction activities will be divided into phases. The first phase is planned to last from 2019–2025 and will include construction related to the first LNG and GTP trains, marine facilities, Mainline, PBTL, and PTTL, resulting in first production of LNG. After 2024, the installation of the remaining Project facilities needed for full production will take place. The proposed Project schedule is included in Appendix 13.A.5.

13.2 SITE INFORMATION

13.2.1.1 Site Conditions

The Nikiski site lies on the north-central coast of the Kenai Peninsula on a low relief plain of glacial and glaciofluvial deposits, referred to as the Kenai Lowland. North of the site is an area of low ridges up to 310 feet elevation with intervening bands of kettle lakes. Topography becomes more gentle and planar toward the Project site, where the surface is covered with glacial outwash fans. The main onshore facilities area is relatively flat, varying between El. +140 feet to north/northwest to about El. +120 feet south/southwest indicating gently south-sloping coastal plain of glacial outwash. Additionally, the terrain near the Project site consists of closed depressions (the largest of which include Bernice Lake and Island Lake) that indicate elevations as low as El. +80 feet. These lower elevation bands of kettle holes and lakes within the outwash plain are aligned with former glacial ice fronts and are prominent on the south side of the site. Two additional low lying areas that are privately owned gravel pits (one toward the north and one centrally located) also include existing low elevations of El. +80 feet. The site is bounded on the west side by coastal bluffs that rise to about El. +140 feet on the north and El. +100 feet to the south with the toe of the bluff at an approximate elevation of El. +20 feet.

Additional site information including the Site Topographic Map can be found in Appendix 13.E.6

13.2.1.2 Elevation reference, North American Vertical Datum of 1988 (NAVD88) or National Geodetic Vertical Datum of 1929 (NGVD29)

The elevation reference is North American Vertical Datum of 1988 (NAVD88).

13.2.1.3 Marine Platform Elevation, ft

Refer to Table 13.2.1.3 for the marine trestle and platform elevations.

TABLE 13.2.13

Project Loading Platform Elevation and Air Gap Summary

Marine Facility Structure	Top of Pile Cap Elevation (feet)		Depth of Pile Cap (feet)	Minimum Soffit Elevation (feet MLLW)	Top of 100-year Return Period Wave Crest (feet MLLW)	Minimum Air Gap Provided (feet)	
	Min	Max				Substructure Soffit	Pipelines
Onshore Interface Point	109.5	109.5	5	104.50	36.1	63.5	68.5
East West Trestle	50.0	109.5	5	45.0	36.1	8.9	13.9
Marine Operation Platform	50.0	50.0	5	45.0	36.1	8.9	13.9
North South Trestle	50.0	50.0	5	45.0	36.1	8.9	13.9
Loading Platform	50.0	50.0	8	42.0	36.1	5.9	13.9

13.2.1.4 LNG Storage Tank Inner Tank Bottom Elevation, feet

Storage tank bottom is at an elevation of 132 feet (Approximate elevation based on adjacent final grade at 124 ft).

13.2.1.5 Process Areas Foundation Elevation, ft

Process area foundation elevations are 125.15 feet

13.2.1.6 Impoundment Floor Elevation, feet

Impoundment sump elevation will vary for each impoundment based in the facility.

13.2.1.7 Utilities Foundation Elevation, feet

The foundation elevation for Utilities will vary as they are located in multiple areas of the facility

13.2.1.8 Buildings Foundation Elevation, feet

The foundation elevation for Buildings will vary as they are located in multiple areas of the facility

13.2.1.9 Roads Elevation, feet

The patrol road elevation are between 116 – 135.70 feet while the primary road elevation is between 116.90 – 129.40 feet.

13.2.2 Shipping Channel

The Marine Terminal is located in the East Cook Inlet, not a shipping channel. The Cook Inlet is an elongated body of water oriented in a southwest-northeast direction in Southcentral Alaska. It is long and narrow, with shoals toward its head in Upper Cook Inlet where it separates into two branches – the Knik and Turnagain Arms.

13.2.2.1 Channel Width

Not applicable to this proposed Project. The Inlet is approximately 150 nautical miles long, and its width ranges from about 10 nautical miles between the East and West Forelands, toward the north, to approximately 80 nautical miles in Lower Cook Inlet.

13.2.2.2 Channel Depth, ft

A dedicated navigation channel is not required for LNGC maneuvering to/from the berths. However, for the LNGCs to depart at all tidal states, the approach to the berths will be located in water depths greater than -53 feet MLLW.

13.2.2.3 Berth Depth, ft

LNGC berths at the Marine Terminal will be located in water depth of approximately -53 feet MLLW.

13.2.2.4 Tidal Range Elevations, ft

Cook Inlet experiences large tidal variations. The National Oceanic and Atmospheric Administration (NOAA) has established a tidal datum at Nikiski Tide Station No. 9455760 (60° 41.8’ N, 151° 23.9’ W). At the Nikiski tide gauge, the mean tide range is 17.72 feet, defined as the difference in height between mean high water and mean low water. The diurnal range is 20.58 feet, defined as the difference between Mean Higher High Water (MHHW) and Mean Lower Low Water (MLLW).

Table 13.2.2.4 documents the various tidal planes at this station for the tidal epoch spanning 2007–2011. Note that NOAA calculates tidal planes in certain regions with anomalous sea level changes (e.g., Alaska and the Gulf of Mexico) based on a Modified 5-Year Epoch, instead of the normally used 18.6-year period.

TABLE 13.2.2.4

Tidal Datum at Nikiski Station

Tidal Datum	Abbreviation	Value (feet MLLW)
Highest Observed Water Level (26-Dec-76)	-	28.40
Highest Astronomical Tide	HAT	25.61
Mean Higher High Water	MHHW	20.58
Mean High Water	MHW	19.86
Mean Sea Level	MSL	11.29
Mean Tide Level	MDTL	11.0
North American Vertical Datum 1988	NAVD88	7.32
Mean Low Water	MLW	2.14
Mean Lower-Low Water	MLLW	0.0
Lowest Astronomical Tide	LAT	-5.78
Lowest Observed Water Level (14-Dec-08)	-	-6.32

13.2.2.5 Channel current (normal, maximum), knots

The average flood current is approximately 4 to 5 knots but can be as high as 6 to 7 knots on spring tides

13.2.3 Climactic Conditions

Details regarding the weather conditions expected at the site are described in the Multidiscipline Design Basis (USAKL-PT-BBFDB-40-0001) included in Appendix 13.B.22.

13.2.3.1 Temperature Design Basis (minimum, average, maximum), °F

The absolute minimum ambient design temperature will be -30 °F the annual average is 37 °F and the maximum ambient design temperature will be 84 °F.

13.2.3.2 Barometric Pressure Design Basis (minimum, average, maximum), inches mercury (Hg)

The average barometric pressure will be 29.77 inches Hg. The minimum barometric pressure is 28.35 inches Hg and maximum pressure is 30.98 inches Hg.

13.2.3.3 Barometric Pressure Rate of Increase Design Basis (minimum, average, maximum), inHg/h

The barometric pressure rate of change will be 0.15 inches Mercury per hour (3.39 mbar per hour).

13.2.3.4 Barometric Pressure Rate of Decrease Design Basis (minimum, average, maximum), inHg/h

The barometric pressure rate of change will be 0.15 inches Mercury per hour (3.39 mbar per hour). Based on recorded values, the typical range associated with strong low pressure systems is in the range of 0.02 to 0.11 inches Hg per hour.

13.2.3.5 Prevailing Wind with Seasonal Wind Rose or Charts with 16 Radial Directions and Wind Speeds, mph

The prevailing wind direction will be northeast during the late fall, winter, and early spring months. During the late spring and summer months, the pattern switches to an up-inlet flow and winds normally blow from south and southwest. The Multidiscipline Design Basis (USAKL-PT-BBFDB-40-0001) included in Appendix 13.B.22, illustrates the Average Annual Wind Rose.

13.2.3.6 Rain Fall Rates Design Basis (100-year return period, 50-year return period, 10-year return period), inches per hour

Rainfall during the 100-year storm data generates the following per hour and per day rain criteria: a) 0.836 inches per hour and b) 3.91 inches per day.

13.2.3.7 Snow Fall Rates Design Basis (100-year return period, 50-year return period, 10-year period), inches per hour

Snowfall for Civil Design is as follows:

- 13.8 inches per month (max)
- 61.2 inches per year (max)

13.2.3.8 Frost Line Depth, ft

The frost line is seven feet deep below finished grade.

13.2.3.9 Visibility Frequency and Distances, No. fog alerts per year, visibility ft

In addition to restricted visibility due to darkness, Cook Inlet can experience thick fog and whiteout snow conditions. Table 13.2.3.9 presents data on the percentage of time that visibility is reduced at the airports at Homer and Kenai. In winter, visibility decreases to less than a mile more often because precipitation often falls as snow, which is much more opaque. Most low-visibility periods in the winter are due to snow.

When visibility is decreased due to marine fog, airport sensors may understate the visibility reduction. Marine fog dissipates quickly over land, where solar warming increases the dew point. Thus the values reported in Table 13.2.3.9 are likely lower than what will be experienced on the water, especially in spring and summer.

Table 13.2.3.9 **Percentage of Time that Visibility is Less than One or One-quarter Mile at Kenai and Homer Airports**

Visibility	Homer Airport			Kenai Airport		
	Spring and Summer	Fall and Winter	Year Around	Spring and Summer	Fall and Winter	Year Around
Less than one mile	0.8%	1.8%	1.3%	1.3%	3.1%	2.2%
Less than ¼ mile	0.4%	0.3%	0.3%	0.6%	0.6%	0.6%

13.2.3.10 Lightning Strike Frequency, No. per year

The frequency of lightning strikes will be determined in detailed design.

13.2.4 Geotechnical Conditions

The Liquefaction Facility is located on the northeastern shore of the Cook Inlet Basin. This gently sloping lowland was buried by ice and subsequently flooded by proglacial lakes several times during the Pleistocene era, leaving behind fine-textured lacustrine deposits ringed by coarse-textured glacial tills and outwash throughout the region (Nowacki et al., 2001). Deposits and landforms associated with Naptowne glaciation include ground and recessional moraines composed of glacial till and outwash plains of gravelly sandy alluvial fan deposits that fan toward the south, away from the glacial front. Kettle holes, filled with small lakes and muskegs (bogs with shallow to deep accumulations of organic material), dot the till and outwash plains between the moraine ridges. Underlying bedrock is composed of oil and gas-bearing continental deposits, including sandstone, siltstone, claystone, conglomerate, and coal beds (ADNR Division of Geological & Geophysical Surveys [DGGS], 2011).

Detailed description of the geotechnical conditions are addressed in Appendix 13.J.

13.2.4.1 Groundwater Conditions

Based on the monitoring well records the groundwater levels within the upper aquifer vary between elevations El. 96 feet (NAVD88) to El. +75 ft. (NAVD88). Groundwater is present below existing grade in the two main geologic formations encountered during the field investigation. The Killey unit (also referred to herein as the Upper Aquifer) contains coarser grained Killey age glacial outwash deposits consisting of sands; laminated sands and silts; coarse sands and rounded gravels. The Moosehorn unit (also referred to herein as the Lower Aquifer) contains mainly clayey sands with gravel, silty sands, sandy silts, silts, lean clays and silty clays extending below the Killey unit.

Additional description of the groundwater conditions are presented in the LNG Facilities Onshore Hydrogeologic Report (USAL-FG-GRZZZ-00-002016-007) included in Appendix 13.J.6.

13.2.4.2 Soil/Rock Layer Description

Three main strata have been identified in the areas that correlate with three main geologic units:

- Organic mat (or described as “top soil” in the boring logs) is comprised of a web of plant roots and humus just beneath the ground surface. These top soils generally extend to a maximum depth of 2.5 feet below the existing ground surface.

- The Killey unit contains coarser grained Killey age glacial outwash deposits consisting of sands; laminated sands and silts; coarse sands and subrounded to rounded gravels.

- The Moosehorn unit contains mainly clayey sands with gravel, silty sands, sandy silts, silts, lean clays and silty clays extending below the Killey unit, to a maximum depth of about 150 ft.

Additional details on the field and laboratory results are presented in Geotechnical Data Report Onshore LNG Facilities (USAL-FG-GRZZZ-00-002017-001) included in Appendix 13. J.2.

13.2.4.3 Geotechnical Cross-Sections

Geotechnical cross-section profiles are presented in the Geotechnical Data Report Onshore LNG Facilities (USAL-FG-GRZZZ-00-002017-001) included in Appendix 13. J.2.

13.2.4.4 Soil and Rock Parameters

Soil and Rock Parameters used in hazard calculations are addressed in the LNG Facilities Geologic Hazard Report (USAL-FG-GRHAZ-00-002015-002) included in Appendix 13.J.1.

13.3 NATURAL HAZARD DESIGN CONDITIONS

13.3.1 Earthquakes

13.3.1.1 Seismic Design Basis and Criteria for Seismic Category I, II, and III Structures, Systems and Components

The "Draft Seismic Design Guidelines and Data Submittal Requirements for LNG Facilities" (FERC 2007), dated January 23, 2007, has been followed for the seismic analysis discussed herein. The designs for critical safety-related structures are based on existing rules and procedures found in NFPA 59A 2006, ASCE 7-05, and Title 49 C.F.R. 193. The 2009 edition of the International Building Code ("IBC") are used as a basis for design of all structures, systems, and components not specifically addressed in NFPA 59A.

NFPA 59A defines two levels of earthquake motions: Operating Basis Earthquake (OBE) and Safe Shutdown Earthquake (SSE). OBE and SSE ground motions are determined by site-specific evaluations and are defined in terms of 5 percent damped response spectra.

OBE ground motions are defined as the motion represented by an acceleration response spectrum having a 10 percent probability of exceedance within a 50-year period (mean return interval of 475years).

SSE ground motions are defined as maximum considered earthquake (MCE) defined in American Society of Civil Engineers (ASCE) 7-05.

Seismic Category I structures, as defined by the "Draft Seismic Design Guidelines and Data Submittal for LNG Facilities," are designed for OBE and SSE ground motions. Seismic Category I structures are designed to remain operable during an OBE event. Seismic Category I structures will consider an importance factor:

$$Ip=1.0$$

ASCE 7-05 defines the Design Earthquake (DE). Seismic Category II and III structures are to be designed for DE ground motions.

Structures, components, and systems not included in Seismic Category I structures that are required to maintain safe plant operations are classified as Seismic Category II Structures. Seismic Category II Structures will consider an importance factor:

$$Ip=1.5$$

Structures, components, and systems not included in Seismic Categories I and II are classified as Seismic Category III Structures. Seismic Category III Structures will consider an importance factor:

$$Ip=1.0$$

13.3.1.2 Identification of Structures, Systems and Components Classified as Seismic Category I, II, and III

The following structures, components, and systems are classified as Seismic Category I:

- LNG storage containers and their respective impounding systems;
- System components required to isolate the LNG container and maintain it in a safe shutdown condition; and
- Structures or systems, including fire protection systems, the failure of which could affect the integrity of (1) or (2) above.

The following structures, components, and systems are classified as Seismic Category II:

Structures, components and systems not included in Category I are classified as Seismic Category II. This category includes all other equipment (most mechanical equipment is in this category). This category includes:

- Inlet facilities;
- Pre-treatment area;
- Power generator area;
- Fuel gas system;
- Interconnecting piping systems;
- Metering system;
- LNG pumps;
- LNG recirculation system;
- Instrument and utility air system; and
- Electrical and main control buildings.

The following structures, components, and systems are classified as Seismic Category III:

All other structures, components and systems of the Liquefaction Facility that will not be included in Categories I and II are classified as Seismic Category III. This category includes:

- Administration buildings;
- Dock service equipment; and
- Wastewater treatment plant.

13.3.1.3 Maximum Considered Earthquake (MCE) Site-Specific Ground Motion Spectral Values for 5% Damping

The Maximum Considered Earthquake (MCE) is described in the LNG Facilities Probabilistic Seismic Hazard Analysis (PSHA) Report (USAL-FG-GRHAZ-00-002015-001), provided in Appendix 13.I.1.

13.3.1.4 Design earthquake (DE) Site-Specific Ground Motion Spectral Values for 5% Damping and Ground Motion Parameters, S_{DS}, S_{D1}, S_{MS}, S_{M1}, T_L

The Design Earthquake (DE) is described in the LNG Facilities Probabilistic Seismic Hazard Analysis (PSHA) Report (USAL-FG-GRHAZ-00-002015-001), provided in Appendix 13.I.1.

The following table provides the site-specific seismic parameters for Seismic Category II and III structures.

TABLE 13.3.1.4

Site-specific Seismic Parameters for Seismic Category II and III Structures

Seismic Parameter	Onshore	Nearshore
TL (sec)	16	16
SDs (g)	1.00	1.02
SD1 (g)	0.64	0.69

13.3.1.5 Safety Shutdown Earthquake (SSE) Site-Specific Ground Motion Spectral Values for 5% Damping

The Safety Shutdown Earthquake is described in the LNG Facilities Probabilistic Seismic Hazard Analysis (PSHA) Report (USAL-FG-GRHAZ-00-002015-001), provided in Appendix 13.I.1.

13.3.1.6 Operating basis earthquake (OBE) Site-Specific Ground Motion Spectral Values for 5% Damping

The Operating Basis Earthquake is described in the LNG Facilities Probabilistic Seismic Hazard Analysis (PSHA) Report (USAL-FG-GRHAZ-00-002015-001), provided in Appendix 13.I.1.

13.3.1.7 Aftershock level earthquake (ALE) Site-Specific Ground Motion Spectral Values for 5% Damping

The Aftershock level earthquake is described in the LNG Facilities Probabilistic Seismic Hazard Analysis (PSHA) Report (USAL-FG-GRHAZ-00-002015-001), provided in Appendix 13.I.1.

13.3.1.8 At Locations Crossing Active Faults, Design Surface Fault Offsets (Horizontal and Vertical) and Fault Orientations

Active faults are described in the LNG Facilities Probabilistic Seismic Hazard Analysis (PSHA) Report (USAL-FG-GRHAZ-00-002015-001), provided in Appendix 13.I.1.

13.3.1.9 At Locations Where Crossing Growth Faults, Design Offsets For Growth Faults: Provide Design Fault Offsets For Growth Faults (Horizontal and Vertical) For The Facility Design Life And Fault Orientations

Active faults are described in the LNG Facilities Probabilistic Seismic Hazard Analysis (PSHA) Report (USAL-FG-GRHAZ-00-002015-001), provided in Appendix 13.I.1.

13.3.1.10 Ground Motions and Frequencies of Earthquakes At Site Location

Significant major and great earthquakes in the study region are described in the LNG Facilities Probabilistic Seismic Hazard Analysis (PSHA) Report (USAL-FG-GRHAZ-00-002015-001), provided in Appendix 13.I.1.

13.3.1.11 Sloshing Freeboard

Minimum freeboard for the LNG Storage Tanks is 1 feet as described in the Storage Tank Data Sheet (USAL-CB-PTTDS-80-ABJ691810) included in Appendix 13.L.1.

The storage tank foundation will consist of a seismically isolated double concrete slab supported on grade. The two slabs will be designed to ACI 376 and ACI 318, and will be separated by plinths that rest on friction pendulum isolators.

Seismic isolation is required due to nearby faults and high accelerations for Operating Basis Earthquake (OBE) and Safe Shutdown Earthquake (SSE) cases. Friction pendulum bearings will be engineered products that reduce the horizontal acceleration imparted to the structure utilizing two mechanisms:

Extending the response time over a longer duration has the effect of reducing the peak acceleration force; and inserting the seismic isolators has the effect of absorbing the shock and thus reducing the amount of horizontal force that is transmitted. Seismic isolation reduces the base shear by 88 percent, while the pile foundation reduces the base shear by approximately 40 percent (as allowed by code). Note that the vertical acceleration cannot be reduced with any of the foundation options and remains close to peak- ground acceleration for wall uplift. Due to the large footprint of the low profile tank, the combination of overturning moment and seismic vertical acceleration still does not cause any uplift of the inner wall of the tank on base isolation even under SSE. Uplift and shear of the external wall can be handled with seismic tendons in combination with shear bars, if needed.

13.3.1.12 Ground Motion Detection Systems That Alarm and Shutdown

A seismic accelerometer capable of recording free field ground motion was installed on the site and began operations in October of 2015. It has operated continuously since that date. The installed system is a broadband dual-sensor, dual-acquisition system that records ground accelerations from local and regional earthquakes. This instrument will allow assessment of seismic activity versus the design level OBE and SSE, and could be used as the ground motion detection system that alarms and shuts down critical components of the proposed LNG project facilities in response to an earthquake.

The seismograph station is located in a forested area north of the main facilities and away from major structural foundations. The data are automatically collected and transmitted electronically to a data storage server, and are regularly retrieved and processed. In addition, the data can be processed and analyzed immediately after major seismic events for comparison to OBE and SSE.

A detailed description of the seismograph station is provided in the Seismograph Station Operations and Maintenance Manual (Report #AKLNG-USAL-FG-CMZZZ-00-000001-000 Rev.0)

13.3.2 Tsunamis and Seiche

13.3.2.1 Tsunami and Seiche Design Basis and Criteria

A deterministic tsunami hazard study was conducted as a preliminary assessment of maximum tsunami wave heights at the site. The study considered the three tsunamigenic sources judged most likely to produce the largest tsunami at the site: (1) a submarine landslide in Cook Inlet, (2) a subduction zone earthquake such as the 1964 **M** 9.2 Great Alaskan Earthquake, and (3) a volcanic flank collapse and debris flow at Augustine Volcano. The maximum wave height at the site was calculated or estimated for each of the three sources.

The Augustine volcano flank collapse scenario was evaluated based on published results from previous studies. Because this scenario has already been modeled through numerical analysis in at least six published studies, it was not modeled during this analysis. Instead, the results from the preceding studies were analyzed and applied to this study. Previous models are all in agreement that tsunami waves are attenuated to wave heights of about 1-meter or less during passage from Augustine Volcano into the central portion of the Cook Inlet where the site is located. Based on this analysis, the elevation of maximum tsunami wave heights at the site shoreline from the Augustine Volcano source are likely to be about 27 feet (8 m) MLLW at highest astronomical tide.

Tsunami wave height from the 1964 event was evaluated using numerical modeling. The 1964 **M** 9.2 Great Alaskan Earthquake is the defining tsunamigenic event for the Cook Inlet region. This tsunami source was simulated to provide model validation. The model was adjusted to best represent actual tsunami wave heights and arrival times observed in 1964 at Yakutat, Seward, and Kodiak, Alaska. The simulated results from the 1964 Great Alaskan Earthquake created a maximum wave height at the site shoreline of about 2.6 feet (0.8 meter), which at a HAT will rise to an elevation of about 27 feet (8 m) (MLLW), similar to the results for the Augustine Volcano source. No records were available of the observed tsunami height in Nikiski in the 1964 earthquake for comparison to these model results.

The submarine landslide scenario produced the highest wave heights at the Site. For this scenario, a hypothetical landslide mass was defined based on interpretation of bathymetric data. A deep submarine channel exists in central Cook Inlet about 7 km northwest of the site at the constriction between the West and East Forelands. Along the western margin of the channel, a 3.3-mile long by ~0.6-mile wide east-facing segment of submarine slope was selected as the modeled landslide mass. The overall volume of the modeled landslide mass is estimated as ~.03 mi^3 (0.12 km^3). This channel margin was identified as an area with landslide-prone slopes based on a geomorphic assessment of NOAA bathymetric data. Significant uncertainties are associated with realistic estimation of submarine landslide parameters; thus the results should be considered approximate.

The modelled maximum landslide-induced tsunami wave crest elevation along the proposed marine trestle is everywhere lower than the pile cap on the trestle. At the proposed marine loading berth area, located approximately 3,900 feet offshore, the modelled peak crest elevation of 28.9 ft. MLLW is 13 feet lower than the bottom of the trestle pile cap elevation of 42 feet MLLW. At the shoreline end of the trestle, the modeled peak crest elevation of 39 feet MLLW is 46 feet lower than the bottom of the pile cap at about 85 feet MLLW.

The tsunami hazard analysis is presented in two Fugro reports. The elevations obtained in the initial tsunami analysis are presented in the *LNG Facilities Geologic Hazard Report* (USAL-FG-GRHAZ-00-002015-002, October 2016). The modeling of the submarine landslide scenario was updated and refined in Section 5 of the *LNG Facilities Seismic Engineering Report* (USAL-FG-GRZZZ-00-002016-008, December 2016).

Table 3.4: **Tsunami Modeling Results**

Tsunami Source	**Maximum Wave Height (MSL)**	**Maximum Wave Height (HAT)**	**Exceeds Site Elevation?**
Submarine landslide	16-20 feet (5-6 meters)	30-33 feet (9-10 meters)	No
Augustine volcano	<3 feet (1 meter*)	~16 feet (5 meters*)	No
1964 **M** 9.2 Great Alaskan Earthquake	<3 feet (1 meter)	~16 feet (5 meters)	No

**Estimated from published literature*

13.3.2.2 Tsunami and Seiche Design Inundation and Run-Up Elevations and Corresponding Return Periods For All Structures, Systems, and Components

Additional studies will be needed to determine design inundation and run-up elevations and corresponding tsunami return periods for all structures.

13.3.2.3 Maximum Considered Tsunami (MCT), MCT Inundation and Run-Up Elevations for Project Site, Including The MCE Level Ground Motions At The Site If The MCE Is The Triggering Source Of The MCT

Additional studies will be needed to determine Maximum Considered Tsunami (MCT), MCT inundation and run-up elevations for the project site resulting from the MCE.

13.3.2.4 Discussion of Inundation and Run Up Elevations and Frequencies of Tsunamis and Other Natural Hazards at Site Location

Additional studies will be needed to determine tsunami elevations and frequencies.

Additional studies will also be needed to determine the magnitudes and frequencies of other natural hazards, for example, volcanic ash-fall magnitudes and frequencies and establishment of a design ash-fall event.

13.3.2.5 Design Sea Level Rise: Elevation Change to be Used in Design to Account for Sea Level Rise at Project Site for The Facility Design Life

Section 13.3.2.6 addresses both sea level rise and regional subsidence.

13.3.2.6 Design Regional Subsidence: Elevation Change to be Used in Design to Account for Regional Subsidence At Facility Site For The Facility Design Life

Significant sea level rise or fall over the 50-year life of the plant could adversely affect marine terminal operations. Global climate change, tectonic uplift, subsidence, isostatic rebound, changes in wind direction, and other processes may cause changes in sea level.

A study of sea level trends across the United States by NOAA (2012) shows that relative sea levels in southern Alaska are falling. Rates of sea level fall for the Kenai Peninsula are shown by NOAA (2012) to be 3 to 4 feet per 100 yrs (9-12 mm/ yr). The Nikiski tide gage shows a steady rate of sea level fall of 0.034 ft./yr (10.5 +/-1 mm/yr) since about 1973 (NOAA, 2016c). This phenomenon is attributed to a combination of tectonic and isostatic land uplift. Over the 50-year life of the plant, a continuation of this trend will result in a net drop in sea level of (50 yrs x 10.5 mm/yr) 525 mm, or 1.7 feet.

This net result quoted above assumes no significant changes occur over the next 50 years in the rates of uplift, climate-induced sea level rise, wind direction, or other factors. Additional studies will be needed to assess the probability and magnitude of any future changes in these rates.

13.3.2.7 Discussion of Co-Seismic Subsidence/Uplift

The 1964 **M** 9.2 Great Alaskan earthquake caused 0.9 feet of co-seismic subsidence recorded at a standard U.S. Coast and Geodetic Survey tide-gage station near Nikiski (Foster and Karlstrom, 1967). Most of the Kenai Peninsula experienced subsidence from this earthquake, with the magnitude of subsidence increasing to the southeast. Co-seismic subsidence of the Kenai Peninsula during the 1964 earthquake occurred on the southeast limb of a synclinal warp located in the hanging wall of the Aleutian megathrust (Plafker, 1969).

However, as described above, past and present-day measurements by NOAA (2012) indicate that land uplift rather than subsidence is currently occurring in the Nikiski area. The observed tectonic uplift is thought to be a steady post-1964 earthquake elastic response that is part of the normal earthquake cycle.

13.3.2.8 Discussion of Expected Settlement Over The Design Life Of The Facilities

Liquefaction-induced reconsolidation settlements are in the range of approximately 0 to 0.5 inches during both the OBE and the SSE / MCE shaking level, with negligible estimated settlements at most locations.

Details regarding the tsunami analysis and results are included in the LNG Facilities Onshore Integrated Site Characterization and Geotechnical Engineering Report Report (USAL-FG-GRZZZ-00-002016-009) included in Appendix 13.J.7.

13.3.3 Hurricanes and Other Meteorological Events

13.3.3.1 Wind and Storm Surge Design Basis

Storm surge refers to the increase in water level above daily tidal fluctuations during a storm event. Surge may include effects from barometric pressure, wind stress, and dynamic wave setup. Measured water level and predicted tide time-series from the NOAA tide station at Nikiski were used to extract a surge a time-series for a time period between October 2, 1996, and November 1, 2014.

Table 13.3.3.1 summarizes predicted positive and negative surges for various return periods at the Nikiski station.

TABLE 13.3.3.1

Summary of the Extreme Surge at NOAA Nikiski Station No. 9455760

Return Period (years)	Positive Surge (feet)	Negative Surge (feet)
1	2.7	-2.3
5	3.1	-2.7
10	3.3	-2.9
20	3.4	-3.1
30	3.5	-3.3
60	3.7	-3.5
100	3.8	-3.7

13.3.3.2 Identification of Design Wind Speeds (Sustained and 3-Second Gusts) sand Corresponding Return Periods, Wind Importance Factors, And Storm Surge Design Elevations For All Structures, Systems, And Components

The Liquefaction Facility defined as parts of the LNG Plant liquefying natural gas or transferring, storing or vaporizing liquefied natural gas, will be designed to withstand a sustained wind velocity of 150 miles per hour as per 49 C.F.R. 193.2067. This equates to an ultimate 3-second gust wind speed of 183 miles per hour. Structures, components and systems not qualified as LNG facilities will be designed for a 3-second gust wind speed of 110 miles per hour as per ASCE 7-05. Additionally, the mooring and breasting structures will be designed to withstand winds up to 60 knots (design maximum of 30-second gust, as recommended by OCIMF) and 40 knots (maximum operating condition) combined with other metocean (current and waves) parameters. Refer to Metocean and Ice Design Basis, Document No. USAL-PM-JBDES-90-000002-000 provided in Appendix 13.B.23.

13.3.3.3 Sea Level Rise: Elevation Change to Be Used To Account for Sea Level Rise at the Site for the Design Life

See Section 13.3.2.6 for details on sea level rise.

13.3.3.4 Regional Subsidence: Elevation Change to Be Used to Account for Regional Subsidence at the Site for the Design Life

See Section 13.3.2.7 for details on regional subsidence.

13.3.4 Tornadoes

13.3.4.1 Wind Speed Design Basis

The Liquefaction Facility defined as parts of the LNG Plant liquefying natural gas or transferring, storing or vaporizing liquefied natural gas, will be designed to withstand a sustained wind velocity of 150 miles per hour as per 49 C.F.R. 193.2067. This equates to an ultimate 3-second gust wind speed of 183 miles per hour. Structures, components and systems not qualified as LNG facilities will be designed for a 3-second gust wind speed of 110 miles per hour as per ASCE 7-05. Additionally, the mooring and breasting structures will be designed to withstand winds up to 60 knots (design maximum of 30-second gust, as recommended by OCIMF) and 40 knots (maximum operating condition) combined with other metocean (current and waves) parameters. Refer to Metocean and Ice Design Basis, Document No. USAL-PM-JBDES-90-000002-000 in Appendix 13.B.23.

13.3.4.2 Identification of Design Wind Speeds (Sustained and 3-Second Gusts) and Corresponding Return Periods, and Wind Importance Factors for All Structures, Systems, and Components

Refer to Metocean and Ice Design Basis, Document No. USAL-PM-JBDES-90-000002-000 in Appendix 13.B.23.

13.3.5 Floods

Due to the elevated site location, flooding is not considered credible for the Project.

13.3.5.1 Flood Design Basis

Not Applicable.

13.3.5.2 Stream Flows and Flood Design Elevations and Corresponding Return Periods For All Structures, Systems, And Components

Not Applicable

13.3.5.3 Discussion of Streamflows and Flood Design Elevations Frequencies Of Floods And Other Natural Hazards At Site Location

Not Applicable

13.3.6 Rain, Ice, Snow, and Related Events

13.3.6.1 Rainfall Design Basis and Criteria

Rainfall during the 100-year storm data generates the following per hour and per day rain criteria: a) 0.836 inches per hour and b) 3.91 inches per day.

13.3.6.2 Ice Load Design Basis and Criteria

Sea ice (first year ice only) occurs in the central and northern Cook Inlet from late fall to early spring. Refer to Metocean and Ice Design Basis, Document No. USAL-PM-JBDES-90-000002-000 in Appendix 13.B.23.

13.3.6.3 Snow Load Design Basis and Criteria

According to the Structural Design Criteria, Document No. USAL-CB-NBDES-000004-000, included in Appendix 13.B.14, structures will be designed considering a ground snow load of 70 psf.

Snowfall for Civil Design:

- 13.8 inches per month (max)
- 61.2 inches per year (max)

The Rainfall Design Basis (USAL-CB-CBDES-00-000005-000) included in Appendix 13.B.12 also include snowfall design data.

13.3.6.4 Identification of Snow and Ice Loads Corresponding Return Periods For All Structures, Systems, And Components, Including Snow Removal For Spill Containment Systems

Refer to Metocean and Ice Design Basis, Document No. USAL-PM-JBDES-90-000002-000 in Appendix 13.B.23 for ice loads and the Rainfall Design Basis (USAL-CB-CBDES-00-000005-000) in Appendix 13.B.12 for snow return periods.

13.3.6.5 Identification of Stormwater Flows, Outfalls, and Stormwater Management Systems For All Surfaces, Including Spill Containment System Sump Pumps

During a storm, “first flush” water from the paved and unpaved surfaces that may contain oil will be collected in potentially contaminated stormwater (PCSW) sumps for visual inspection. First flush capture is defined as the first inch of rainfall. Each sump will be equipped with an underflow/overflow weir arrangement to contain the potentially oil contaminated water, while allowing excess stormwater beyond the first flush to overflow to the stormwater pond.

The first flushwater, if confirmed to be oil contaminated, will be pumped to the oily water treatment system to remove oily contaminants. Otherwise, it will be pumped to a stormwater pond, where clean stormwater will be then sent to the permitted outfall.

Each PCSW sump will be equipped with two 2 x 50 percent sump pumps. When two pumps are operating, the sump contents can be pumped out within 6 hours to prepare for the next rainfall/storm event.

The Utility Flow Diagram for the Oily Wastewater/Process Spill Collection and Treatment System, Drawing No USAL-CB-PDUFD-70-000997-001, and Utility Flow Diagram for the Oily Wastewater/Stormwater Collection and Treatment System, Drawing No USAL-CB-PDUFD-70-000997-002, are included in Appendix 13.E.

13.3.6.6 Discussion of Snow and Ice Formation and Frequencies Of Blizzards and Other Snow and Ice Events At Site Location

Refer to Metocean and Ice Design Basis, Document No. USAL-PM-JBDES-90-000002-000 in Appendix 13.B.23 for ice loads and the Rainfall Design Basis (USAL-CB-CBDES-00-000005-000) in Appendix 13.B.12 for snow return periods.

13.3.7 Other Natural Hazards

Not Applicable - There are no un-mitigatable hazards associated with landslides, wildfires, volcanic activity, geomagnetism, or other natural hazards applicable to the project.

13.3.7.1 Design basis and criteria

Not Applicable.

13.3.7.2 Identification of loads and corresponding return periods for all structures, systems, and components

Not Applicable.

13.3.7.3 Discussion of natural hazards and frequencies of natural hazards at site location

Not Applicable.

13.4 MARINE FACILITIES

A Waterway Suitability Assessment (WSA) has been prepared for the Project and is included in Resource Report 11. The WSA purpose is to:

- Provide a basis for an assessment of the suitability of Cook Inlet for the proposed Project from a maritime safety and security standpoint.

- Identify credible navigational safety hazards and security threats associated with the additional LNG marine traffic related to the Project, along with appropriate risk management strategies, mitigation measures, and resources necessary to mitigate those risks.

- Consider the transportation of LNG through Cook Inlet by LNGCs for both inbound (unladen, in-ballast) and outbound (laden) voyages to and from the proposed Marine Terminal, as per the requirements of 33 CFR 127.007 and NVIC 01-2011.1

- Provide the local COTP Western Alaska with the information necessary to advise the federal agencies involved in the permitting process that the Liquefaction Facility is appropriate for Cook Inlet.

- Provide the basis for developing/updating safety and security plans for the transportation of LNG into and out of Cook Inlet and for determining resources required for LNGC transport and operations.

13.4.1 LNG Vessels

The LNG loading berths will be designed to accommodate the majority of LNGCs of both principal containment types (spherical and membrane) in the size range of 125,000 cubic meters to 216,000 cubic meters. Table 13.4.1 presents the LNGC dimensions.

TABLE 13.4.1

LNGC Dimensions

LNGC Code	Containment Type	Gross Liquid Capacity (cubic meter)	Approximate Displacement (MT)	LOA (meter)	Beam (meter)	Laden Draught (meter)	Longitudinal Ballast Windage (square meter)
125S	Spherical	125,500	92,163	283.0	44.6	11.3	7,893
216M	Membrane	216,200	149,341	315.0	50.0	12.0	8,300

13.4.1.1 Shipping Route Within U.S. Waters

LNGCs transiting between the Gulf of Alaska and proposed Marine Terminal location in Nikiski, Alaska, will pass through roughly 142 nautical miles of Cook Inlet, depending on the route used. An entrance route is also available through the Shelikof Strait, which will add an additional 150 nautical miles to the transit from the boundary of the U.S. Territorial Sea. Upon entering the Inlet, LNGCs will embark a marine pilot at the Homer Pilot Station. The vessel will then proceed to the Liquefaction Facility under the direction of the pilot.

13.4.1.2 Ship Traffic

A recent analysis of vessel traffic through Cook Inlet (Eley & Nuka Research, 2012) indicates that for vessels greater than 300 gross tons, there are approximately 490 vessel calls (one inbound and one outbound) annually in Cook Inlet with an additional 100 transits by tugs and barges.

13.4.1.3 Ship Simulations

Ship, pilotage, berthing and unberthing simulations demonstrated that LNGCs within the design range of 125,000 cubic meters to 216,000 cubic meters could be safety managed with four to five tugs, assuming three with 90 metric tonne ballard pull and one or two with 120 metric tonne ballard pull.

13.4.1.4 Tug Services, owned/leased

Project representatives will determine during detailed design whether the tug services should be provided through ownership of the tugs or by lease of the tugs.

13.4.1.5 Tug Services, full time/as requested

The recommended number of tugs stationed at Nikiski to meet the expected frequency of ship arrivals/departures at AKLNG Marine Terminal, especially during the busy winter period, is four Azimuth Stern Drive ASD tugs. A fifth tug may be stationed at Homer to be available to provide support when an LNGC is in the lower parts of Cook Inlet, but also to support operations at Nikiski when required (e.g., to perform ice management duties), so that operations can continue under the maximum operating parameters of the port.

13.4.1.6 Aids to Navigation

Aids to navigation will be provided with the Marine Terminal.

13.4.1.7 LNG Vessel Size

The LNG loading berths will be designed to accommodate the majority of LNGCs of both principal containment types (spherical and membrane) in the size range of 125,000 cubic meters to 216,000 cubic meters. Table 13.4.6-1 presents the LNGC dimensions.

TABLE 13.4.1.7

LNGC Dimensions

LNGC Code	Containment Type	Gross Liquid Capacity (cubic meter)	Approximate Displacement (MT)	LOA (meter)	Beam (meter)	Laden Draught (meter)	Longitudinal Ballast Windage (square meter)
125S	Spherical	125,500	92,163	283.0	44.6	11.3	7,893
216M	Membrane	216,200	149,341	315.0	50.0	12.0	8,300

13.4.1.8 LNG Vessel Draft

See section 13.4.1.7 for Vessel Draft.

13.4.1.9 LNG Vessel Cargo Design and Operating Conditions and Specification for Loading and Vapor Recovery

Table 13.4.1.9 lists the expected Molecular weight, higher heating value (HHV), lower heating value (LHV), Wobbe, specific gravity, equilibrium temperature (°F) and cargo pressure (psig), composition.

TABLE 13.4.1.9

LNG Product Characteristics

Characteristics	**Value**
Real Mixture High Heating Value	1095 British thermal units per standard cubic foot minimum +/- 10 British thermal units per standard cubic foot
Nitrogen Content	≤ 1 mol%
Methane Content	≥ 85 mol%
Butanes and Heavier Content	< 1 mol%
Pentanes and Heavier Content	< 0.1 mol%
Benzene Content	< 4 parts per million by mole
H2S Content	< 5 milligrams per cubic meter
Total Sulfur	< 30 milligrams per cubic meter
Delivery Pressure to the LNGC Loading Manifold	44 pounds per square inch absolute

13.4.1.10 LNG Vessel Cargoes Design and Operating Conditions and Specifications for Unloading and Vapor Recovery

Not Applicable

- **Cargoes' molecular weight, HHV, LHV, Wobbe, specific gravity, equilibrium temperature (°F) and cargo pressure (psig), composition**

Not Applicable

- **LNG vessel pump design pressure range, psig**

Not Applicable

- **LNG vessel pump design rates, gpm**

Not Applicable

13.4.2 Marine Platform Design

LNGCs will be moored at the loading berths, consisting of mooring and breasting dolphins and interconnecting catwalks. The loading berths will be located in natural water depths greater than -53 feet MLLW and will be approximately 1,600 feet apart (the distance measured between the centerline of each berth). The direction of the berth orientation will be with the predominant peak current direction. Each berth will include:

- Four breasting dolphins that include marine fenders. The breasting dolphins protect the platform during LNGC docking. Breasting dolphins assist in the berthing of vessels by taking up some berthing loads, keep the vessel from pressing against the pier structure, and serve as mooring points to restrict the longitudinal movement of the berthing vessel. The breasting dolphin structures will be supported by pile supported structures. The breasting dolphins will have a precast concrete deck (platform) with railings for personnel engaged in the mooring process;
- Six mooring dolphins (three forward and three aft) with fenders to allow a vessel to be secured alongside the berth for cargo discharge operations. Mooring dolphins will be used for mooring and securing the vessel. The mooring dolphins will each be supported by pile structures with a precast concrete platform with railings, and a bull-nose; and
- Catwalks for personnel access loading and the mooring dolphins.

The loading platform will be a steel-jacketed, pile-supported platform(s) that will be located adjacent to each berth, with a surface area of 150 feet by 145 feet, on which the loading system package, gangway, substation, and safety systems will be located. The loading platforms will be connected to each other and to the shore by means of a trestle.

The jetty access trestle will be a pile-supported trestle structure that will interconnect the onshore storage tanks with the loading platforms at the offshore end of the trestle. The trestle supports the pipe rack modules and a single-lane roadway from the shoreline to the loading platforms. The trestle will be approximately 3,260 feet long and trestle support piles will be spaced 120 feet apart. This corresponds to the maximum spacing practicable based on current engineering design. The roadway will be 15 feet with bypass bays (roadway width of 30 feet) at three locations along the trestle.

The Marine Operations Platform will be a pile-supported platform that will support the Marine Terminal Building, electrical substations, and supporting piping, cabling, and equipment used to monitor the loading operations. The Marine Operations Platform will have a preliminary design size of approximately 0.4 acre in surface area (approximately 200 feet by 60 feet) and the deck will be capable of supporting a variety of vehicles.

13.4.2.1 Wave Crests and Periods, ft

In the protected waters of Cook Inlet and Shelikof Strait, waves are usually smaller than 5 feet, but buoys have recorded waves greater than 15 feet, especially in winter months. In the open ocean at Portlock Bank, the median winter wave height is around 10 feet, and rare waves above 30 feet have been recorded.

13.4.2.2 Prevailing Currents (Normal, Maximum), knots

See Section 13.2.2.5 for Current Conditions.

13.4.2.3 Tidal Range Elevations, ft

See Section 13.2.2.4 for Title Range Elevations.

13.4.2.4 Water Depth at Berth and in Approach Channel, ft

See Section 13.2.2.2 for Water Depth.

13.4.2.5 LNG Carrier Capacity Range, m3

See Section 13.4.1 for Carrier Capacity Range.

13.4.2.6 LNG Carrier Approach Velocity, knots

Navigation simulations performed during detailed design will determine appropriate approach velocities for the LNG Carriers.

13.4.2.7 LNG Carrier Approach Angle, degrees

Navigation simulations performed during detailed design will determine appropriate approach angle for the LNG Carriers.

13.4.2.8 LNG Carrier Unloading Frequency, per year

Not Applicable

13.4.2.9 LNG Carrier Unloading Duration, hours

Not Applicable

13.4.2.10 LNG Carrier Loading Frequency, per year

The LNGC loading frequency is a function of LNGC size and LNG sales destination; both of which are currently not fixed. However, for a representative portfolio of LNG sales destinations, the following ship sizes have approximate annual loading frequencies:

TABLE 13.4.2.10

LNG Carrier Loading Frequency based on Carrier Size

LNGC Capacity (cubic meters)	Annual Frequency
125,000	360
176,000	252
216,000	204

13.4.2.11 LNG Carrier Loading Duration, hours

The loading duration is expected to be 12 to 18 hours depending on the carrier capacity.

13.4.2.12 LNG Carrier Port Time, Pilot on to Pilot off, hours

Approximately one to two days, which includes 12 to 18 hours of loading for the LNGCs at berth.

13.4.2.13 Barge Capacity Range, m3

Not Applicable

13.4.2.14 Barge Approach Velocity, knots

Not Applicable

13.4.2.15 Barge Approach Angle, degrees

Not Applicable

13.4.2.16 Barge Unloading Frequency, per year

Not Applicable

13.4.2.17 Barge Unloading Duration, hours

Not Applicable

13.4.2.18 Barge Loading Frequency, per year

Not Applicable

13.4.2.19 Barge Loading Duration, hours

Not Applicable

13.4.2.20 Turning Basin Depth and Radius, ft

Depending on the direction of the current at the time of berthing, LNGCs will berth either portside alongside or starboard side alongside, whichever will be deemed safer by the Pilot(s) and LNGC Master taking into consideration the prevailing metocean conditions at the time, and the capabilities of the tugs to operate in those conditions. There will be no need to construct or demarcate turning basins since there is ample sea room off the berths.

13.4.2.21 Marine Platform Location/Spacing

The LNG loading berths will be spaced 1,600 feet apart (Loading Platform center-to-center), which positions each berth outside of the predicted flammable gas vapor clouds or fire heat radiation of the other berth in case a hazardous event occurs.

13.4.2.22 Jetty/Trestle Configuration

The elevation of the trestle will angle down from the bluff at nominally 3 percent (3 feet per 100 feet) and transition to the loading berths at approximately +50 MLLW as measured at the top of the pile headstock.

13.4.2.23 Number and Design of Berths

Two

13.4.2.24 Number and Design of Hooks, Quick Release Hooks

Marine detailed design will determine appropriate number of quick release hooks for the LNG Carriers.

13.4.2.25 Number and Design of Capstans

Marine detailed design will determine appropriate number of capstans for the LNG Carriers.

13.4.2.26 Number and Design of Fenders

Marine fenders are included in the four breasting and six mooring dolphins.

13.4.2.27 Number, Arrangement, and Design of Breasting Dolphins

Four breasting dolphins to protect each platform

13.4.2.28 Number, Arrangement, and Design of Mooring Dolphins

Six mooring dolphins to secure the vessel at each platform.

13.4.2.29 Current Monitors

The need for current monitors will be determined in detailed design.

13.4.2.30 Vessel Approach Velocity Monitors

The need for vessel approach velocity monitors will be determined in detailed design.

13.4.2.31 Tension Monitors

Tension monitors will be provided.

13.4.2.32 Marine Platform Other Safety Features

The Marine Terminal Building will be located along the trestle and will also be outside of the predicted flammable gas vapor clouds or fire heat radiation from either berth in case a hazardous event occurs.

With this spacing arrangement, occupants from one berth can evacuate primarily via the trestle that connects midway between the loading berths, if a hazardous event occurs in the other berth. Occupants from the Marine Terminal Building can also escape via the trestle, if a hazardous event occurs on either berth.

13.4.3 Marine Transfer Design

13.4.3.1 LNG Arms or Hoses and Size per Dock, No., in

Two 16-inch LNG liquid loading arms (FAY691871/2/4) will be provided on each berth

13.4.3.2 Vapor Arms or Hoses and Size per Dock, No., in

One 16-inch vapor return arm (FAY691873 and FAY691883) will be provided on each berth

13.4.3.3 Hybrid Arms or Hoses and Size per Dock, No., in

One 16-inch hybrid arm (FAY69187/4) will be provided on each berth

13.4.3.4 LNG Arms or Hoses Operating and Design Flow Rate Capacities (Minimum, Normal, Maximum), gpm

Three LNG loading arms in liquid service will be used to meet the loading rate of 55,035.gpm (12,500 m^3/h). The two liquid and one hybrid arm will be rated at 5,000 m3/h LNG loading capacity.

13.4.3.5 LNG Arms or Hoses Operating and Design Pressures (Minimum, Normal, Maximum), psig

The design pressure for the arms and piping will be 300 psig. The minimum loading pressure at the ship manifold will be 44 psia. The maximum loading pressure at the ship manifold will be determined later and will consider surge to confirm maximum pressure on activation of powered emergency release couplings (PERCs).

13.4.3.6 LNG Arms or Hoses Operating and Design Temperatures at Ship Manifold (Minimum, Normal, Maximum), °F

The maximum design temperature for the LNG Arms is 150 °F. The minimum design temperature for the LNG Arms is -274 °F. The operating temperature for the LNG Arms is estimated to be -258 °F.

13.4.3.7 Vapor Arms or Hoses Operating and Design Flow Rate Capacities (Minimum, Normal, Maximum), lb/hr

The design flow rate for the Vapor Arms is 47,717.5 lb/hr (19,303 m3/hr).

13.4.3.8 Vapor Arms or Hoses Operating and Design Pressures at the Ship Manifold (Minimum, Normal, Maximum), psig

The estimated BOG return conditions from the carrier for the Vapor Arms is 21.2 psig.

13.4.3.9 Vapor Arms or Hoses Operating and Design Temperatures at Ship Manifold (minimum, normal, maximum), °F

The maximum design temperature for the Vapor Arms is 150 °F. The minimum design temperature for the Vapor Arms is -274 °F. The operating temperature for the Vapor Arms is estimated to be -112 °F.

13.4.3.10 Marine Transfer Startup and Operation

13.4.3.10.1 Marine Transfer Custody Transfer

Custody transfer will occur at the LNG Carrier flange.

13.4.3.10.2 Marine Transfer Measurement and Analysis

Flow measurement is provided in the marine transfer line as well as the recirculation line back to the LNG storage tanks.

13.4.3.10.3 Unloading and/or Loading

Non-combustibles relieved during the initial phase of an inerted (i.e., nitrogen full) LNGC cool-down and loading will be routed to the LP Flare.

Blow down of the LNG loading arms after LNG transfer will be accomplished by applying nitrogen pressure at the apex of each arm. LNG on the vessel-side of the apex will be drained back into one or more of the LNGCs. LNG on the side of the Liquefaction Facility will be forced back to the loading line or Loading Arm Drain/Surge Drum (MBD691876/86) and the Loading Arm Drain/Surge Drum Blowcase (MAB691877/87) through drain valves at the low point on each LNG arm lead line. A heel of LNG will be maintained in the drum to keep it at cryogenic temperatures to avoid thermal shock and minimize vapor production when LNG will be routed into the drum.

13.4.3.10.4 Recirculating System

During Holding Mode, LNG will be recirculated from the LNG Storage Tanks to the loading berths and back.

13.4.3.10.5 Vapor Return Handling

BOG generated during LNGC loading will be collected into the BOG Header, which also accepts BOG from the LNG Storage Tanks before going into the BOG Compressor Drums (MBD691815/25/35). Any liquids in the BOG Header will be separated and the overheads will be compressed to 470 psig by the three LP and HP BOG Compressors (CAE691841/51/61 and CAE691842/52/62), and then cooled in the BOG Compressor After-Coolers (HFF691843/53/63). Refer to LNG Storage and Loading System, Drawing No. USAL-CB-PDPFD-80-000691-001/2/3, included in Appendix 13.E.

The amount of BOG generated during various operating modes is shown in Table 13.4.22-1.

TABLE 13.4.22-1 Boil-off Gas Generation Rates, pounds per hour					
Holding Mode					**Loading Mode**
Case 1 Average Gas Winter Ambient	**Case 2 Average Gas Average Ambient**	**Case 3 Average Gas High Ambient**	**Case 4 100% PBU Average Ambient**	**Case 5 100% PTU Average Ambient (single train)**	**Case 6 Average Gas Average Ambient Loading Mode**
300,050	297,834	308,314	296,356	102,770	404,551

13.4.3.10.6 Vapor Return Desuperheating

LNG will be used to quench warm vapors coming from warm LNGCs to cool BOG to a suction temperature of -238 ˚F.

13.4.3.11 Marine Transfer Shutdown

Marine transfer shutdown is included in the Cause and Effect Diagram System 691 LNG Storage and Loading (USAL-CB-PDZZZ-80-000001-001), included in Appendix 13.Q.1.

13.4.3.12 Marine Transfer Piping, Vessel, and Equipment Specifications Design and Marine Transfer Isolation Valves, Vents, and Drains

Isolation valves will be provided in the loading lines and loading arms. These valves will be used during maintenance when isolation will be required between the LNG Plant and the loading berths. These valves will also be used to isolate the individual LNG loading lines and vapor return lines. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.4.3.13 Marine Transfer Basic Process Control Systems

Marine Transfer operations shall be remotely operated through the plant DCS or through the Ship to Shore Communications Link System. Plant alarms shall alert operations both onshore and offshore to out of bound conditions set by the equipment manufacturer or EPC. Further information is found in Appendix 13.E.5 and 13.N.1

13.4.3.14 Marine Transfer Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the loading operation as described in Appendix 13.E.5 and 13.N.1.

13.4.3.15 Marine Transfer Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogens can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.4.3.16 Marine Transfer Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.4.3.16.1 Safe Working Envelope of Transfer Arms

The working envelope of the transfer arms will be determined by vendor during the detailed design phase of the project.

13.4.3.16.2 Powered Emergency Release Coupling Valves

All of the arms will be provided with PERC and full bore Powered Emergency Release Coupling (PERC) valves.

13.4.3.16.3 Ship/Shore Communication and Shutdown Capability

Ship/shore communications will be included in the final design phase. The design will allow shutdown of transfer from shore side or on the ship.

13.5 FEED GAS

13.5.1 Feed Gas Design

The feed gas will be received at normal operating pressure of 1,050 to 1,250 pounds per square inch gauge (psig) and in the temperature range of 25 to 44 degrees Fahrenheit (°F). The feed gas flow and pressure will be measured at the Nikiski Meter Station (NMS) located within the LNG Plant boundary. Within the NMS the flow will be split for delivery to local in-state customers with the primary flow going to the Liquefaction Facility.

The Inlet Treating, Mercury Removal, and Dehydration Systems will be common systems for the three liquefaction processing trains. The feed gas will flow through the Inlet Gas Filters (MAJ623503A/B/C) and then be heated as needed in Inlet Gas Heater (HBG623501). The Inlet Gas Heater will be designed to avoid hydrate or condensate formation downstream of the pressure letdown station.

Additional details on the Feed Gas and Inlet System are presented in the Inlet Treatment, Mercury Removal and Dehydration Design Basis (USAL-CB-PBDES-50-000001-000), provided in Appendix 13.B.

Refer to the Inlet Facilities and Gas Treatment Area Process Flow Diagrams listed below and found in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPFD-50-000623-001	Process Flow Diagram Inlet Receiving and Treatment System

13.5.1.1 Feed Gas Battery Limit Operating and Design Flow Rate Capacities (Minimum, Normal, Maximum), MMscfd

TABLE 13.5.1.1

Liquefaction Facility Feed Gas Flow Rate Variations

Gas Case		**Flow Rate (MMSCFD)**
Average Gas	Case 1 (Winter Pipeline Delivery)[a]	2,793
	Case 2 (Average Ambient)[b]	2,700
	Case 3 (High Ambient)[c]	2,550
	Case 6 (Ship Loading)[b]	2,700
100% PBU	Case 4 (Average Ambient)[b]	2,700
100% PTU	Case 5 (Average Ambient)[b]	900

Notes:
[a] Winter air temperature 23 ºF.
[b] Average air temperature 37.4 ºF.
[c] High air temperature 59 ºF.

13.5.1.2 Feed Gas Battery Limit Operating and Design Pressures (Minimum, Normal, Maximum), psig

Feed Gas Minimum Operating/Design Pressures (psig)	Feed Gas Normal Operating/Design Pressures (psig)	Feed Gas Maximum Operating/Design Pressures (psig)
1,050/--	1,250/--	1,945/--

13.5.1.3 Feed Gas Battery Limit Operating and Design Temperatures (Minimum, Normal, Maximum), °F

The arrival temperature will vary based on the season.

Feed Gas Minimum Operating/Design Temperature (°F)	Feed Gas Normal Operating/Design Temperature (°F)	Feed Gas Maximum Operating/Design Temperature (°F)
24/--	27/--	44/--

13.5.1.4 Feed Gas Operating and Design Inlet Gas Compositions (Minimum/Lean/Light, Normal/Design/Average, Maximum/Rich/Heavy), %-Vol and/or Parts Per Million (Ppm)

Table 13.5.1.4 shows the Feed Gas Compositions for Inlet Treatment System.

TABLE 13.5.1.4

Natural Gas Composition

	Average Gas at PBU:PTU = 3:1	**100% PBU**	**100% PTU**
Component (molar proportion [mol%]): dry basis			
Nitrogen	0.765	0.6928	1.0108
Methane	91.0914	90.9186	92.1425
Ethane	5.7636	6.2487	4.1704
Propane	1.9739	1.9098	1.7372
i-Butane	0.134	0.0683	0.2965
n-Butane	0.175	0.1024	0.3804
i-Pentane	0.037	0.0114	0.1172
n-Pentane	0.035	0.0114	0.1069
2-Mpentane	0.001	0.0023	0.0
n-Hexane	0.004	0.0014	0.0
Mcyclopentane	0.001	0.0009	0.0
Cyclohexane	0.003	0.003	0.003
n-Heptane	0.003	0.0028	0.0
Mcyclohexane	0.001	0.0015	0.0
n-Octane	0.001	0.0012	0.0
n-Nonane	0.0	0.0005	0.0
n-Decane	0.0	0.0001	0.0
C6 Pseudo	0.0	0.0056	0.0
C7 Pseudo	0.0	0.0043	0.0
C8 Pseudo	0.0	0.0013	0.0
C9 Pseudo	0.0	0.0005	0.0
C10 Pseudo	0.0	0.0001	0.0
PTU C6	0.0	0.0	0.0214
PTU C7	0.0	0.0	0.0025
PTU C8	0.0	0.0	0.0001
Contaminants (maximum expected values)			
CO_2 (parts per million by volume)	50		
H_2S (parts per million by volume)	3		
Carbon Sulfide (parts per million by volume)	1		
Methyl Mercaptan (parts per million by volume)	1		
Ethyl Mercaptan (parts per million by volume)	1		
Dimethyl Sulfide (parts per million by volume)	1		
Carbon Disulfide (parts per million by volume)	1		
Total Sulfur Containing Species (gr/100 standard cubic feet)	1		
Water (pounds per million standard cubic feet)	0.2		
Mercury (micrograms per cubic meter)	20 (Assumed)		

TABLE 13.5.1.4

Natural Gas Composition

	Average Gas at PBU:PTU = 3:1	100% PBU	100% PTU
p-Xylene (parts per million by volume)	1		
Cyclohexane (parts per million by volume)	30		
Benzene (parts per million by volume)	20		
Neopentane (parts per million by volume)	5		
o-Xylene (parts per million by volume)	1		
m-Xylene (parts per million by volume)	1		
Ethylbenzene (parts per million by volume)	1		
Toluene (parts per million by volume)	10		
Methanol	Nil		
Triethylene Glycol	As per equilibrium in vapor phase		
Oxygen (parts per million by volume)	10 (assumed)		

13.5.1.5 Feed Gas Filters

Three Inlet Gas Filters (MAJ623503A/B/C) are included in the design.

13.5.1.6 Feed Gas Booster Compressor(s) Type

There are no Feed Gas Booster Compressors.

13.5.1.7 Feed Gas Booster Compressor (s), Operating and Spare

Not Applicable.

13.5.1.8 Feed Gas Startup and Operation

The feed gas will flow through the Inlet Gas Filters (MAJ623503A/B/C) and then be heated as needed in Inlet Gas Heater (HBG623501). The Inlet Gas Heater will be designed to avoid hydrate or condensate formation downstream of the pressure letdown station.

13.5.1.9 Feed Gas Metering

Feed Gas Metering occurs at the Nikiski Meter Station located outside the LNG Plant.

13.5.1.10 Feed Gas Analysis and Measurement

Flow, pressure, and composition will be monitored at the Nikiski Meter Station located just inside the northern fence line of the LNG Plant.

13.5.1.11 Feed Gas Shutdown

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the vapor handling operation as described in Appendix 13.E.5 and 13.N.1. The HIPPS system will provide additional shutdown capabilities.

13.5.1.12 Feed Gas Piping, Vessel, and Equipment Design and Specifications

Equipment Design and Specifications for the Feed Gas and Inlet System are presented in the Inlet Treatment, Mercury Removal and Dehydration Design Basis (USAL-CB-PBDES-50-000001-000), provided in Appendix 13.B.

13.5.1.13 Feed Gas Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.5.1.14 Feed Gas Basic Process Control Systems

The system shall be remotely operated through the plant DCS Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.5.1.15 Feed Gas High Integrity Pressure Protection Systems

A High Integrity Pressure Protection System (HIPPS) is included in the Feed Gas System. This high integrity safety system is as additional protection layer designed to prevent over-pressurization of the plant. This system is completely independent from the plant.

13.5.1.16 Feed Gas Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.5.1.17 Feed Gas Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.6 FEED GAS PRETREATMENT

Because the feed gas to the Liquefaction Facility will have been pretreated in the GTP on the North Slope to contain less than 50 parts per million CO_2 and 3 parts per million H_2S, further pretreatment for removal of these substances will not be necessary at the Liquefaction Facility.

13.6.1 Acid Gas Removal Design

Not Applicable

13.6.1.1 Acid Gas Removal System Type

Not Applicable

13.6.1.2 Acid Gas Removal Operating and Design Inlet Flow Rate Capacities (Minimum, Normal, Maximum), Mmscfd

Not Applicable

13.6.1.3 Acid Gas Removal Operating and Design Inlet Gas Compositions (Minimum/Lean/Light, Normal/Design/Average, Maximum/Rich/Heavy), Parts per Million (ppm)

Not Applicable

13.6.1.4 Acid Gas Removal Operating and Design Inlet Pressures (Minimum, Normal, Maximum), psig

Not Applicable

13.6.1.5 Acid Gas Removal Operating and Design Inlet Temperatures (Minimum, Normal, Maximum), °F

Not Applicable

13.6.1.6 Acid Gas Removal Operating and Design Outlet Flow Rate Capacities (Minimum, Normal, Maximum), MMscfd

Not Applicable

13.6.1.7 Acid Gas Removal Operating and Design Outlet Gas Compositions (Minimum/Lean/Light, Normal/Design/Average, Maximum/Rich/Heavy), ppm

Not Applicable

13.6.1.8 Acid Gas Removal Operating and Design Outlet Pressures (Minimum, Normal, Maximum), Psig

Not Applicable.

13.6.1.9 Acid Gas Removal Operating and Design Outlet Temperatures (Minimum, Normal, Maximum), °F

Not Applicable.

13.6.1.10 Acid Gas Disposal Operating and Design Compositions, ppm

Not Applicable.

13.6.1.11 Acid Gas Disposal Operating and Design Pressures (Minimum, Normal, Maximum), psig

Not Applicable.

13.6.1.12 Acid Gas Disposal Operating and Design Outlet Temperatures (Minimum, Normal, Maximum), °F

Not Applicable.

13.6.1.13 Acid Gas Removal Startup and Operation

Not Applicable.

13.6.1.14 Normal Startup and Operation

Not Applicable.

13.6.1.15 Regeneration Startup and Operation

Not Applicable

13.6.1.16 Acid Gas Removal Shutdown

Not Applicable

13.6.1.17 Acid Gas Removal Piping, Vessel, and Equipment Design and Specifications

Not Applicable

13.6.1.18 Acid Gas Removal Isolation Valves, Drains, and Vents

Not Applicable

13.6.1.19 Hydrogen Sulfide Removal/Disposal

Not Applicable

13.6.1.20 Carbon Dioxide Removal/Disposal

Not Applicable

13.6.1.21 Acid Gas Removal Safety Instrumented Systems

Not Applicable

13.6.1.22 Acid Gas Removal Relief Valves and Discharge

Not Applicable

13.6.1.23 Acid Gas Removal Other Safety Features

Not Applicable

13.6.2 Mercury Removal Design

The feed gas will be fed to 3 x 33 percent Mercury Adsorber (MBA669501/2/3) beds. The Mercury Adsorbers will be designed to remove the mercury, if present, from the feed gas (to below 0.01 microgram per cubic meter) to avoid corrosion of and damage to downstream aluminum equipment. The mercury-free gas will then be filtered through the Mercury Adsorber After-Filters (MAJ669504A/B/C) to remove carbon dust particles before being sent to the Dehydration System. Three x 50 percent Mercury Adsorber After-Filters will be provided such that two filters are always online while the other will be either on standby or having the elements changed.

Additional details on the Feed Gas and Inlet System are presented in the Inlet Treatment, Mercury Removal and Dehydration Design Basis (USAL-CB-PBDES-50-000001-000), provided in Appendix 13.B.

Refer to the Inlet Facilities and Gas Treatment Area Process Flow Diagrams listed below and found in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPFD-50-000669-001	Process Flow Diagram Gas Treatment and Conditioning Mercury Removal System

13.6.2.1 Mercury Specifications, ppm

The Mercury Removal System is designed to reduce the feed gas mercury content before sending the feed gas to the dehydration beds. The treated gas mercury content will be <0.01µg/Nm^3.

13.6.2.2 Mercury Removal Type

The Mercury Adsorbers remove potential elemental mercury by direct contact with a bed of sulfur impregnated activated carbon.

13.6.2.3 Mercury Removal Operating and Design Inlet Flow Rate Capacities (Minimum, Normal, Maximum), lb/hr

The Mercury Adsorber After Filters (MAJ669504A/B/C) are sized for 2,711,162 each, based on 50% flow for each filter.

13.6.2.4 Mercury Removal Operating and Design Inlet Gas Compositions (Minimum/Lean/Light, Normal/Design/Average, Maximum/Rich/Heavy), ppm

A maximum inlet Mercury concentration of 20 micro-g/Nm^3 is considered for the Mercury Removal system feed gas.

13.6.2.5 Mercury Removal Operating and Design Inlet Pressures (Minimum, Normal, Maximum), psig

		Mercury Removal Minimum Operating/Design Pressures (psig)	Mercury Removal Normal Operating/Design Pressures (psig)	Mercury Removal Maximum Operating/Design Pressures (psig)
MBA669501/2/3	Mercury Adsorbers	--/--	912/--	--/1087
MAJ669504A/B/C	Mercury Adsorber After Filters	--/--	900/--	--/1087

13.6.2.6 Mercury Removal Operating and Design Inlet Temperatures (Minimum, Normal, Maximum), °F

		Mercury Removal Minimum Operating/Design Temperature (°F)	Mercury Removal Normal Operating/Design Temperature (°F)	Mercury Removal Maximum Operating/Design Temperature (°F)
MBA669501/2/3	Mercury Adsorbers	--/-50	16/--	--/130
MAJ669504A/B/C	Mercury Adsorber After Filters	--/-50	14.5/--	--/130

13.6.2.7 Mercury Removal Operating and Design Outlet Flow Rate Capacities (Minimum, Normal, Maximum), lb/hr

The Mercury Adsorber After Filters (MAJ669504A/B/C) outlet conditions are the same as the inlet conditions presented in Section 13.6.2.3.

13.6.2.8 Mercury Removal Operating and Design Outlet Gas Compositions (Minimum/Lean/Light, Normal/Design/Average, Maximum/Rich/Heavy), ppm

The Mercury Removal System is designed to reduce the feed gas mercury content before sending the feed gas to the dehydration beds. The treated gas mercury content will be <0.01μg/Nm^3.

13.6.2.9 Mercury Removal Operating and Design Outlet Pressures (Minimum, Normal, Maximum), psig

	Mercury Removal Maximum Pressure Drop Across Equipment (psig)
Mercury Adsorbers (MBA669501/2/3)	10
Mercury Adsorber After Filters (MAJ669504A/B/C)	5

13.6.2.10 Mercury Removal Operating and Design Outlet Temperatures (Minimum, Normal, Maximum), °F

Design and Operating Outlet Temperatures are the same as inlet temperatures presented in 13.6.2.6.

13.6.2.11 Mercury Removal Startup and Operation

From the NMS, feed gas flows 5000 feet in a 42-inch belowground flowline to the Inlet Receiving and Treatment area, where it will be filtered to remove any scale and particles, and then heated by Inlet Gas Heater (HBG623501) if and when needed. When required, heating the feed gas will prevent the formation of condensate and hydrate when the pressure will be reduced in the pressure letdown station, upstream of the Mercury Removal System. During normal operation, heating will not be expected to be required.

With reduced pressure, the feed gas flows to the Mercury Adsorbers (MBA669501/2/3).

Three Mercury Adsorbers (3x33 percent) will operate in parallel to remove any potential elemental mercury present in the feed gas by direct contact with a bed of sulfur impregnated activated carbon. Although mercury will not be expected, if present in trace quantities, it will be tightly and irreversibly bound to the adsorbent and will not desorb so the beds will need replacement if they become saturated. Bed life is expected to be at least five years.

Feed gas exiting the Mercury Adsorbers then passes through the Mercury Adsorber After-Filters (MAJ669504A/B/C), to remove any carbon dust particles from the gas before entering the Dehydration System

13.6.2.12 Mercury Removal Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.6.2.12.1 Mercury Removal Disposal

Although mercury will not be expected, if present in trace quantities, it will be tightly and irreversibly bound to the adsorbent and will not desorb so the beds will need replacement if they become saturated. Bed life is expected to be at least five years. The beds will be replaced by a specialized vendor.

13.6.2.13 Mercury Removal Shutdown

The Mercury Removal System itself does not include any moving parts to shutdown.

13.6.2.14 Mercury Removal Piping, Vessel, and Equipment Design and Specifications

Equipment Design and Specifications for the Mercury Removal System are presented in the Inlet Treatment, Mercury Removal and Dehydration Design Basis (USAL-CB-PBDES-50-000001-000), provided in Appendix 13.B.

13.6.2.15 Mercury Removal Basic Process Control Systems

The vapor handling system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.6.2.16 Mercury Removal Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the vapor handling operation as described in Appendix 13.E.5 and 13.N.1.

13.6.2.17 Mercury Removal Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.6.2.18 Mercury Removal Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.6.3 Water Removal Design

The mercury-free and filtered gas will then be fed to the Dehydration System, which will consist of six Molecular Sieve Dryers (MBA661502/3/4/5/6/7). At any one time, five of the Molecular Sieve Dryers will be treating the process gas for removal of moisture, and one dryer will be thermally regenerated or will be in standby mode. The treated dry gas will exit the bottom of the molecular sieves and then pass through Molecular Sieve Dryers After-Filters (MAJ661510A/B/C). The filters will remove any particulate matter that may have been picked up by the gas stream while flowing through the molecular sieves. Three filters will be provided such that two filters are always online while the other will be either standby or having the elements changed.

The Molecular Sieve Dryers will use gas from Low Pressure (LP)/High Pressure (HP) boil-off gas (BOG) Compressors (CAE691841/51/61)/(CAE691842/52/62) as the main source of regeneration gas. If this flow rate will not be sufficient for regeneration, the dehydrated feed gas from the Molecular Sieve Dryer outlet will be used as a supplement. The regeneration gas will be heated by Regeneration Gas Heaters (NAP661513/4) and passed through the dryer bed that will be in regeneration. The regeneration gas will then be cooled by the Regeneration Gas Cooler (HFF661509) and the free water will be separated in a Regeneration Gas Knockout (KO) drum (MBD661512). The regeneration gas will then be sent to the HP fuel gas system.

The treated gas will then be split and fed equally to the three liquefaction processing trains. A side stream from the feed gas to each train can be sent to Defrost Gas Heater (NAP661113). The Defrost Gas Heater will heat the feed gas to dry the equipment prior to plant start up or as-needed for maintenance.

Additional details on the Feed Gas and Inlet System are presented in the Inlet Treatment, Mercury Removal and Dehydration Design Basis (USAL-CB-PBDES-50-000001-000), provided in Appendix 13.B.

Refer to the Inlet Facilities and Gas Treatment Area Process Flow Diagrams listed below and found in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPFD-50-000661-001	Process Flow Diagram Gas Treatment and Conditioning Gas Dehydration and Regeneration Gas System

13.6.3.1 Water Specifications, ppm

The Dehydration System will lower the moisture content of the feed gas to 0.1 ppmv.

13.6.3.2 Dehydration System Type

Dehydration is achieved by molecular sieve dryers heated by regeneration gas. The dryers are operated with 5 in operation while one is in regeneration mode.

13.6.3.3 Dehydration Operating and Design Inlet Flow Rates (Minimum, Normal, Maximum), lb/hr

The Molecular Sieve Dryer After Filters (MAJ661510A/B/C) are sized for 2,711,162 each, based on 50% flow for each filter.

13.6.3.4 Dehydration Operating and Design Inlet Compositions Capacities (Minimum, Normal, Maximum), ppm

A maximum inlet water concentration of 0.2lbMMscf is considered for the Dehydration system feed gas.

13.6.3.5 Dehydration Operating and Design Inlet Pressures (Minimum, Normal, Maximum), psi

		Dehydration Minimum Operating/Design Pressures (psig)	Dehydration Normal Operating/Design Pressures (psig)	Dehydration Maximum Operating/Design Pressures (psig)
MBA661502/3/4/5/6/7	Molecular Sieve Dryers	--/--	870/-- (during adsorption) 435/-- (during regeneration)	--/1087
MAJ661510A/B/C	Molecular Sieve Dryer After Filters	--/--	875/--	--/1087

13.6.3.6 Dehydration Operating and Design Inlet Temperatures (Minimum, Normal, Maximum), °F

		Dehydration Minimum Operating/Design Temperature (°F)	Dehydration Normal Operating/Design Temperature (°F)	Dehydration Maximum Operating/Design Temperature (°F)
MBA661502/3/4/5/6/7	Molecular Sieve Dryers	--/-50	14/-- (during adsorption) 482/-- (during regeneration)	--/650
MAJ661510A/B/C	Molecular Sieve Dryer After Filters	--/-50	13/--	--/130

13.6.3.7 Dehydration Operating and Design Outlet Flow Rates (Minimum, Normal, Maximum), lb/hr

The Molecular Sieve Dryer After Filters (MAJ661510A/B/C) outlet conditions are the same as the inlet conditions presented in Section 13.6.3.3.

13.6.3.8 Dehydration Operating and Design Outlet Gas Compositions (Minimum/Lean/Light, Normal/Design/Average, Maximum/Rich/Heavy), ppm

The Dehydration System will lower the moisture content of the feed gas to 0.1 ppmv for all operating modes.

13.6.3.9 Dehydration Operating and Design Outlet Pressures (Minimum, Normal, Maximum), psig

	Mercury Removal Maximum Pressure Drop Across Equipment (psig)
Molecular Sieve Dryers (MBA661502/3/4/5/6/7)	10
Molecular Sieve Dryer After Filters (MAJ661510A/B/C)	5

13.6.3.10 Dehydration Operating and Design Outlet Temperatures (Minimum, Normal, Maximum), °F

Design and Operating Outlet Temperatures are the same as inlet temperatures presented in 13.6.3.6.

13.6.3.11 Regeneration Gas Operating and Design Flow Rates (Minimum/Lean/Light, Normal/Design/Average, Maximum/Rich/Heavy), lb/hr

		Regeneration Minimum Operating/Design Flow Rate (lb/hr)	Regeneration Normal Operating/Design Flow Rate (lb/hr)	Regeneration Maximum Operating/Design Flow Rate (lb/hr)
NAP661513/4	Regeneration Gas Heaters	--/--	49,848/-- (2 x 50%)	--/--
HFF661509	Regeneration Gas Cooler	--/--	1,440/--	1,491/--
MBD661512	Regeneration Gas KO Drum	--/--	49,929/1,440 (operating vapor/liquid)	--/--

13.6.3.12 Regeneration Gas Operating and Design Temperatures To/From Adsorber (Minimum, Normal, Maximum), °F

The regeneration system provides warm gas to the Molecular Sieve Dryers not the Adsorbers. Therefore, the information presented below is temperature details for regeneration equipment.

		Regeneration Minimum Operating/Design Temperature (°F)	Regeneration Normal Operating/Design Temperature (°F)	Regeneration Maximum Operating/Design Temperature (°F)
NAP661513/4	Regeneration Gas Heaters	--/-50	45/536 (operating in/out of heater)	--/650
HFF661509	Regeneration Gas Cooler	--/-50	536/--	--/650
MBD661512	Regeneration Gas KO Drum	--/-50	81	--/550

13.6.3.13 Regeneration Gas Operating and Design Pressures To/From Adsorber (Minimum, Normal, Maximum), psig

		Regeneration Minimum Operating/Design Pressures (psig)	Regeneration Normal Operating/Design Pressures (psig)	Regeneration Maximum Operating/Design Pressures (psig)
NAP661513/4	Regeneration Gas Heaters	--/--	445/--	--/650
HFF661509	Regeneration Gas Cooler	--/--	433/--	--/650
MBD661512	Regeneration Gas KO Drum	--/--	428/--	--/650

13.6.3.14 Dehydration and Regeneration Startup and Operation

The regeneration gas will be taken off the compressed and cooled BOG stream. The regeneration gas will then be heated by the electric Regeneration Gas Heaters (NAP661513/4) to reach the regeneration temperature. The regeneration gas will then flow through the Molecular Sieve Dryers (MBA661502/3/4/5/6/7). Refer to Gas Dehydration and Regeneration Gas System, Drawing No. USAL-CB-PDPFD-50-000661-001, included in Appendix 13.E.

The regeneration gas from the Molecular Sieve Dryers (MBA661502/3/4/5/6/7) will be routed to the Regeneration Gas Cooler (HFF661509), and Regeneration Gas KO Drum (MBD661512). The regeneration gas will then be routed to the HP Fuel Gas Mixing Drum (MFG966503).

13.6.3.15 Dehydration and Regeneration Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.6.3.16 Dehydration and Regeneration Basic Process Control Systems

The vapor handling system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.6.3.17 Dehydration and Regeneration Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the vapor handling operation as described in Appendix 13.E.5 and 13.N.1.

13.6.3.18 Dehydration and Regeneration Relief Valves and Discharge

The relief valves on the dehydration beds and relief/blowdown/vent streams from the regeneration section of the Dehydration Unit will be routed to the wet flare header.

13.6.3.19 Dehydration and Regeneration Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.7 NATURAL GAS LIQUIDS (NGL) REMOVAL, STORAGE, AND DISPOSITION

13.7.1 NGL Removal Design

Dry feed gas enters the Scrub Column (MAF695104) to remove aromatics and other high-boiling hydrocarbons to avoid freezing out in the cold end of the Liquefaction System. The vapor overhead from the Scrub Column (MAF695104) is partially condensed in the MCHE (HBA695108) to initiate NGL removal. The gas is then phase-separated in the Scrub Column Reflux Drum (MBD695107). The overhead vapor from the Scrub Column Reflux Drum is then directed to the MCHE (HBA695108), while liquids are pumped back to the Scrub Column (MBD695107). The bottom stream from the Scrub Column is sent to the Deethanizer Column to begin the fractionation process.

The Fractionation Design Basis (USAL-CB-PBDES-50-000002-000), provided in Appendix 13.B, establishes a design for the Fractionation System.

The following Process Flow Diagrams associated with the LPG Fractionation System are included in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPFD-50-000631-001	Deethanizer and Depropanizer
USAL-CB-PDPFD-50-000631-001	Debutanizer

The following Piping and Instrumentation Drawings associated with the LPG Fractionation System are included in Appendix 13.E

Drawing Number	Description
USAL-CB-PDPID-50-000631-501	Piping & Instrumentation Diagram LPG Fractionation System Fractionation Feed Separator
USAL-CB-PDPID-50-000631-502	Piping & Instrumentation Diagram LPG Fractionation System Deethanizer Column
USAL-CB-PDPID-50-000631-503	Piping & Instrumentation Diagram LPG Fractionation System Deethanizer Reboiler And Condensate Pot
USAL-CB-PDPID-50-000631-504	Piping & Instrumentation Diagram LPG Fractionation System Deethanizer Condenser
USAL-CB-PDPID-50-000631-505	Piping & Instrumentation Diagram LPG Fractionation System Deethanizer Reflux Drum And Pumps
USAL-CB-PDPID-50-000631-511	Piping & Instrumentation Diagram LPG Fractionation System Depropanizer Column
USAL-CB-PDPID-50-000631-512	Piping & Instrumentation Diagram LPG Fractionation System Depropanizer Reboiler And Condensate Pot
USAL-CB-PDPID-50-000631-513	Piping & Instrumentation Diagram LPG Fractionation System Depropanizer Condenser And Reflux Pumps
USAL-CB-PDPID-50-000631-514	Piping & Instrumentation Diagram LPG Fractionation System Depropanizer Reflux Drum And Reinjection Pumps
USAL-CB-PDPID-50-000631-521	Piping & Instrumentation Diagram LPG Fractionation System Debutanizer Column

USAL-CB-PDPID-50-000631-522	Piping & Instrumentation Diagram LPG Fractionation System Debutanizer Reboiler And Condensate Pot
USAL-CB-PDPID-50-000631-523	Piping & Instrumentation Diagram LPG Fractionation System Debutanizer Condenser And Reflux Pumps
USAL-CB-PDPID-50-000631-524	Piping & Instrumentation Diagram LPG Fractionation System Debutanizer Reflux Drum And Reinjection Pumps
USAL-CB-PDPID-50-000631-525	Piping & Instrumentation Diagram LPG Fractionation System LPG Reinjection Cooler
USAL-CB-PDPID-50-000631-526	Piping & Instrumentation Diagram LPG Fractionation System LPG Reinjection KO Drum And Reinjection Pumps
USAL-CB-PDPID-50-000631-527	Piping & Instrumentation Diagram LPG Fractionation System Debutanizer Condensate Product Cooler
USAL-CB-PDPID-50-000661-501	Piping & Instrumentation Diagram Gas Dehydration System Molecular Sieve Dryers Inlet/Outlet

13.7.1.1 NGL removal type (Demethanizer, Deethanizer, Depropanizer, Debutanizer

The Fractionation System is common for the three liquefaction trains. The Fractionation System will produce refrigerant (ethane/propane) make-up for the refrigerant circuits, liquefied petroleum gas (LPG) reinjection to the Liquefaction System, and a condensate byproduct. The Fractionation System will consist of a Deethanizer, a Depropanizer, a Debutanizer, and associated equipment.

13.7.1.2 Number of NGL Removal Columns

The following table lists the columns and vessels for NGL removal located inside each liquefaction train:

Gas Liquefaction System	
MAF695104	Scrub Column
MBD695107	Scrub Column Reflux Drum

The following table lists the columns and vessels for the NGL removal and LPG fractionation process located outside the trains in a common area:

LPG Fractionation System	
MBD631522	Fractionation Feed Separator
MAF631501	Deethanizer Column
MBD631504	Deethanizer Reflux Drum
MAF631506	Depropanizer Column
MBD631509	Depropanizer Reflux Drum
MAF631512	Debutanizer Column

13.7.1.3 NGL Removal Columns Inlet Operating and Design Flow Rate Capacities (minimum, normal, maximum), gpm

Quantities listed correspond to feed line operating conditions into each vessel. Since not all feed streams are liquid, the flow rates are listed in lb/hr rather than gpm to ensure consistency with data sheets or heat and material balances.

		Minimum Flow Rate Capacity Operating (lb/hr)	Normal Flow Rate Capacity Operating (lb/hr)	Maximum Flow Rate Capacity Operating (lb/hr)
MAF695104	Scrub Column	1,604,120/--	1,798,817/--	1,798,817/--
MBD695107	Scrub Column Reflux Drum	1,842,521/--	1,657,602/--	1,953,140/--
MBD631522	Fractionation Feed Separator	8,078/--	20,088/--	66,347/--
MAF631501	Deethanizer Column	51,788/--	64,850/--	66,347/--
MBD631504	Deethanizer Reflux Drum	54,239/--	86,504/--	95,121/--
MAF631506	Depropanizer Column	44,211/--	52,682/--	56,630/--
MBD631509	Depropanizer Reflux Drum	49,033/--	59,358/--	67,986/--
MAF631512	Debutanizer Column	21,992/--	32,696/--	40,443/--
MBD631515	Debutanizer Reflux Drum	20,308/--	54,677/--	211,836/--

13.7.1.4 NGL Removal Column Operating and Design Inlet Compositions (minimum/lean/light, normal/design/average, maximum/rich/heavy), %-vol

The compositions listed below are associated with the greatest mass flow rate for the feed stream into each vessel.

	Scrub Column	Scrub Column Reflux Drum	Fractionation Feed Separator	Deethanizer Column	Deethanizer Reflux Drum	Depropanizer Column	Depropanizer Reflux Drum	Debutanizer Column	Debutanizer Reflux Drum
Nitrogen	0.7	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H2S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Methane	91.0	89.9	12.9	12.6	19.8	0.0	0.0	0.0	0.0
Ethane	5.7	6.4	16.0	16.0	79.3	0.0	0.1	0.0	0.0
Propane	1.9	2.5	25.0	25.2	0.9	35.2	95.5	0.5	0.6
Isobutane	0.1	0.7	10.1	10.2	0.0	14.3	4.2	20.1	24.0
Butane	0.1	0.2	18.2	18.3	0.0	25.7	0.1	40.3	48.2
Isopentane	0.0	0.0	7.9	8.0	0.0	11.3	0.0	17.7	20.5
Pentane	0.0	0.0	7.4	7.5	0.0	10.5	0.0	16.5	6.5
Neopentane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
C6+	0.0	0.0	1.9	1.9	0.0	2.7	0.0	4.2	0.0

13.7.1.5 NGL Removal Columns Operating and Design Pressures (minimum, normal, maximum), psig

		Minimum Operating/Design Pressures (psig)	Normal Operating/Design Pressures (psig)	Maximum Operating/Design Pressures (psig)
MAF695104	Scrub Column	--/--	854/--	--/1087
MBD695107	Scrub Column Reflux Drum	--/--	791/--	--/1087
MBD631522	Fractionation Feed Separator	--/--	400/--	400/550
MAF631501	Deethanizer Column	--/--	400/--	401/550
MBD631504	Deethanizer Reflux Drum	--/--	390/--	--/550

		Minimum Operating/Design Pressures (psig)	Normal Operating/Design Pressures (psig)	Maximum Operating/Design Pressures (psig)
MAF631506	Depropanizer Column	--/--	143/--	--/200
MBD631509	Depropanizer Reflux Drum	--/--	132/--	--/200
MAF631512	Debutanizer Column	--/FV	31/--	--/150
MBD631515	Debutanizer Reflux Drum	--/FV	22/--	--/150

13.7.1.6 NGL Removal Columns Operating and Design Temperatures (minimum, normal, maximum), °F

		Minimum Operating/Design Temperatures (°F)	Normal Operating/Design Temperatures (°F)	Maximum Operating/Design Temperatures (°F)
MAF695104	Scrub Column	--/-220	-28/--	--/220
MBD695107	Scrub Column Reflux Drum	--/-220	-70/--	--/150
MBD631522	Fractionation Feed Separator	--/-150	45/--	--/170
MAF631501	Deethanizer Column	--/-150	54/--	--/290
MBD631504	Deethanizer Reflux Drum	--/-150	-14/--	--/290
MAF631506	Depropanizer Column	--/-50	162/--	--/290
MBD631509	Depropanizer Reflux Drum	--/-50	82/--	--/290
MAF631512	Debutanizer Column	--/-30	130/--	--/260
MBD631515	Debutanizer Reflux Drum	--/-30	85/--	--/260

13.7.1.7 NGL Removal Column Operating and Design Products Flow Rates (minimum, normal, maximum), gpm

Quantities listed correspond to bottoms from each vessel. Flow rates are listed in lb/hr to ensure consistency with data sheets or heat and material balances.

		Minimum Flow Rate Capacity Operating/Design (lb/hr)	Normal Flow Rate Capacity Operating/Design (lb/hr)	Maximum Flow Rate Capacity Operating/Design (lb/hr)
MAF695104	Scrub Column	18,429/--	20,023/--	66,347/--
MBD695107	Scrub Column Reflux Drum	183,708/--	295,480/--	333,638/--
MBD631522	Fractionation Feed Separator	51,788/--	59,606/--	66,103/--
MAF631501	Deethanizer Column	41,598/--	52,682/--	56,630/--
MBD631504	Deethanizer Reflux Drum	44,216/--	71,473/--	74,160/--
MAF631506	Depropanizer Column	21,992/--	32,696/--	40,443/--
MBD631509	Depropanizer Reflux Drum	33,852/--	35,810/--	51,799/--
MAF631512	Debutanizer Column	7,853/--	12,094/--	11,282/--
MBD631515	Debutanizer Reflux Drum	9,375/--	31,031/--	179,246/--

13.7.1.8 NGL Removal Column Operating and Design Products Compositions (minimum/lean/light, normal/design/average, maximum/rich/heavy), %-vol

The compositions listed below are associated with the greatest mass flow rate for the bottoms stream from each vessel.

	Scrub Column	Scrub Column Reflux Drum	Fractionation Feed Separator	Deethanizer Column	Deethanizer Reflux Drum	Depropanizer Column	Depropanizer Reflux Drum	Debutanizer Column	Debutanizer Reflux Drum
Nitrogen	0.0023	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2	0.0066	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H2S	0.0014	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Methane	12.9996	70.3	12.6	0.0	16.4	0.0	0.0	0.0	0.0
Ethane	16.0365	15.7	16.0	0.0	82.6	0.0	0.0	0.0	0.0
Propane	25.0400	11.2	25.2	35.2	1.0	0.5	0.1	0.0	0.6
Isobutane	10.1374	1.0	10.2	14	0.0	20.1	95.5	0.0	24.0
Butane	18.1764	0.0	18.3	25.6	0.0	40.3	4.3	0.1	48.2
Isopentane	7.9764	0.0	8.0	11.3	0.0	17.7	0.1	14.9	20.5
Pentane	7.4363	0.0	7.5	10.5	0.0	16.5	0.0	20.9	6.5
Neopentane	0.0277	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1
C6+	1.8979	0.0	1.9	2.7	0.0	4.2	0.0	56.2	0.0

13.7.1.9 NGL Removal Column Operating and Design Products Pressures (minimum, normal, maximum), psig

The columns and vessels product operating and design pressures are the same as those listed in 13.7.1.5.

13.7.1.10 NGL Removal Column Operating and Design Products Temperatures (minimum, normal, maximum), °F

The removal column design pressures are the same as those listed in 13.7.1.5, therefore, the table below presents the outlet operating temperatures only.

		Normal Operating Temperatures (°F)
MAF695104	Scrub Column	170
MBD695107	Scrub Column Reflux Drum	-70
MBD631522	Fractionation Feed Separator	54
MAF631501	Deethanizer Column	27
MBD631504	Deethanizer Reflux Drum	-14
MAF631506	Depropanizer Column	214
MBD631509	Depropanizer Reflux Drum	81
MAF631512	Debutanizer Column	84.7
MBD631515	Debutanizer Reflux Drum	81

13.7.1.11 NGL Removal Reboilers Operating and Design Flow Rate Capacities (minimum, normal, maximum), gpm

Quantities listed correspond to inlet line operating conditions into each reboiler. Flow rates are listed in lb/hr to ensure consistency with data sheets or heat and material balances.

		Product Minimum Flow Rate Capacity (lb/hr)	Product Normal Flow Rate Capacity (lb/hr)	Product Maximum Flow Rate Capacity (lb/hr)
NAP695105	Scrub Column Reboiler	31,787/--	36,283/--	142,795/--
HBC631502	Deethanizer Reboiler	156,103/--	220,210/--	229,858/--
HBC631507	Depropanizer Reboiler	59,008/--	70,521/--	91,840/--
HBC631513	Debutanizer Reboiler	25,629/--	53,781/--	54,599/--

13.7.1.12 NGL Removal Reboilers Operating and Design Duties (minimum, normal, maximum), MMBtu/hr

The design duty for each reboiler is provided only in the data sheets, therefore only one case can be provided.

		Product Normal Operating/Design Duty (MMBtu/hr)
NAP695105	Scrub Column Reboiler	TBD
HBC631502	Deethanizer Reboiler	18.5
HBC631507	Depropanizer Reboiler	5.36
HBC631513	Debutanizer Reboiler	6.2

13.7.1.13 NGL Removal Reboilers Operating and Design Pressures (minimum, normal, maximum), psig

		Product Minimum Operating/Design Pressure (psig)	Product Normal Operating/Design Pressure (psig)	Product Maximum Operating/Design Pressure (psig)
NAP695105	Scrub Column Reboiler	--/--	928/--	--/1120
HBC631502	Deethanizer Reboiler	--/--	401/--	580/--
HBC631507	Depropanizer Reboiler	--/--	144/--	--/230
HBC631513	Debutanizer Reboiler	--/FV	32.7/--	--/180

13.7.1.14 NGL Removal Reboilers Operating and Design Inlet Temperatures (minimum, normal, maximum), °F

		Inlet Minimum Operating/Design Temperature (°F)	Inlet Normal Operating/Design Temperature (°F)	Inlet Maximum Operating/Design Temperature (°F)

NAP695105	Scrub Column Reboiler	--/-120	94/--	--/220
HBC631502	Deethanizer Reboiler	--/-50	210/--	--/290
HBC631507	Depropanizer Reboiler	--/-50	202/--	--/290
HBC631513	Debutanizer Reboiler	--/-30	175/--	--/260

13.7.1.15 NGL Removal Reboilers Operating and Design Outlet Temperatures (minimum, normal, maximum), °F

		Outlet Minimum Operating/Design Temperature (°F)	Outlet Normal Operating/Design Temperature (°F)	Outlet Maximum Operating/Design Temperature (°F)
NAP695105	Scrub Column Reboiler	--/-120	94/--	--/220
HBC631502	Deethanizer Reboiler	--/-50	234/--	--/290
HBC631507	Depropanizer Reboiler	--/-50	216/--	--/290
HBC631513	Debutanizer Reboiler	--/-30	189/--	--/260

13.7.1.16 NGL Removal Reflux Pumps Operating and Design Flow Rate Capacities (minimum, normal, maximum), gpm

		Product Minimum Operating/Design Flow Rate Capacity (gpm)	Product Normal Operating/Design Flow Rate Capacity (gpm)	Product Maximum Operating/Design Flow Rate Capacity (gpm)
PBA695106A/B	Scrub Column Reflux Pumps	--/--	1,909/1,909	--/2,291
PBA631505A/B	Deethanizer Reflux Pumps	--/--	383/383	--/460
PBA631510A/B	Depropanizer Reflux Pumps	--/--	146/146	--/175
PBA631511A/B	Propane Reinjection Pumps	--/--	74/74	--/81
PBA631516A/B	Debutanizer Reflux Pumps	--/--	107/107	--/128
PBA631517A/B	Butane Reinjection Pumps	--/--	65/65	--/72

13.7.1.17 NGL Removal Reflux Pumps Operating and Design Duties (minimum, normal, maximum), MMBtu/hr

Heating duties are not applicable to the NGL removal reflux pumps.

13.7.1.18 NGL Removal Reflux Pumps Operating and Design Suction Pressures (minimum, normal, maximum), psig

Based on information included in the equipment data sheets, the rated and maximum suction pressures are provided in the following table.

		Rated Suction Pressure (psig)	Maximum Suction Pressure (psig)
PBA695106A/B	Scrub Column Reflux Pumps	792	1,092
PBA631505A/B	Deethanizer Reflux Pumps	393	554

		Rated Suction Pressure (psig)	Maximum Suction Pressure (psig)
PBA631510A/B	Depropanizer Reflux Pumps	137	206
PBA631511A/B	Propane Reinjection Pumps	137	206
PBA631516A/B	Debutanizer Reflux Pumps	28	157
PBA631517A/B	Butane Reinjection Pumps	28	157

13.7.1.19 NGL Removal Reflux Pumps Operating and Design Inlet Temperatures (minimum, normal, maximum), °F

		Inlet Minimum Operating/Design Temperature (°F)	Inlet Normal Operating/Design Temperature (°F)	Inlet Maximum Operating/Design Temperature (°F)
PBA695106A/B	Scrub Column Reflux Pumps	--/-285	-69.8/--	--/150
PBA631505A/B	Deethanizer Reflux Pumps	-8/-14	-14/--	--/--
PBA631510A/B	Depropanizer Reflux Pumps	82/81	82/--	--/--
PBA631511A/B	Propane Reinjection Pumps	82/81	82/--	--/--
PBA631516A/B	Debutanizer Reflux Pumps	86/74	85/--	--/--
PBA631517A/B	Butane Reinjection Pumps	86/74	85/--	--/--

13.7.1.20 NGL Removal Reflux Pumps Operating and Design Discharge Pressures (minimum, normal, maximum), psig

		Discharge Minimum Operating/Design Pressure (psig)	Discharge Normal Operating/Design Pressure (psig)	Discharge Maximum Operating/Design Pressure (psig)
PBA695106A/B	Scrub Column Reflux Pumps	--/--	897/--	--/1,225
PBA631505A/B	Deethanizer Reflux Pumps	--/--	421/--	--/600
PBA631510A/B	Depropanizer Reflux Pumps	--/--	178/--	--/280
PBA631511A/B	Propane Reinjection Pumps	--/--	410/--	--/620
PBA631516A/B	Debutanizer Reflux Pumps	--/--	64/--	--/205
PBA631517A/B	Butane Reinjection Pumps	--/--	413/--	--/640

13.7.1.21 NGL Removal Reflux Pumps Operating and Design Outlet Temperatures (minimum, normal, maximum), °F

		Outlet Minimum Operating/Design Temperature (°F)	Outlet Normal Operating/Design Temperature (°F)	Outlet Maximum Operating/Design Temperature (°F)
PBA695106A/B	Scrub Column Reflux Pumps	--/-220	-69.8/--	--/150
PBA631505A/B	Deethanizer Reflux Pumps	--/-150	-14/--	--/290
PBA631510A/B	Depropanizer Reflux Pumps	--/-50	82/--	--/-290
PBA631511A/B	Propane Reinjection Pumps	--/-50	82/--	--/290
PBA631516A/B	Debutanizer Reflux Pumps	--/-30	85/--	--/260

		Outlet Minimum Operating/Design Temperature (°F)	Outlet Normal Operating/Design Temperature (°F)	Outlet Maximum Operating/Design Temperature (°F)
PBA631517A/B	Butane Reinjection Pumps	--/-30	85/--	--/260

13.7.1.22 NGL Removal Columns Startup and Operation

Three steps are required in the fractionation system – deethane, depropane and debutane. The three phases are needed for complete removal of heavies from the feed gas. The objective of the Deethanizer System is to separate ethane from the Scrub Column bottom liquid. The liquid from the bottom of the Scrub Column (MAF695104) is air cooled in the Scrub Column Cooler (HFF695110) to 59 °F before mixing with the streams from the other two liquefaction trains. The combined stream is then fed into the Fractionation Feed Separator (MBD631522) at 400 psig. Overhead vapor and bottom liquid from the Fractionation Feed Separator are fed separately to the Deethanizer Column (MAF631501).

The Deethanizer Column overhead pressure is controlled at 390 psig measured at the reflux drum. The overhead vapor is partially condensed to -14 °F in the Deethanizer Condenser (HBG631503) by boiling LP propane from the three liquefaction trains. The two-phase stream leaving the Deethanizer Condenser (HBG631503) is sent to the Deethanizer Reflux Drum (MBD631504). The vapor from the Deethanizer Reflux Drum (MBD631504) is routed to the LPG Reinjection Cooler (HBG631519) while the liquid provides reflux to the Deethanizer and/or make-up for the Ethane Refrigerant Storage Bullets (MBJ698701/2). An online analyzer is provided on the reflux line to check the composition of the ethane to meet Air Products specification. The level in the Deethanizer Reflux Drum (MBD631504) is controlled by the reflux flow rate to the Deethanizer Column (LC-FC cascade control).

Ethane make-up to the mixed refrigerant cycle is provided from the Deethanizer Column (MAF631501) overhead, upstream of the Deethanizer condenser (HBG631503).

The liquids from the bottom of the column are heated in the Deethanizer Reboiler (HBC631502) and partially vaporized using LP steam. The LP steam flow rate is controlled by the column temperature with a thru controller (TC) to limit the ethane content in the column bottoms. The non-vaporized propane and heavier liquids from the bottom of the column are reduced in pressure and fed to the Depropanizer Column (MAF631506).

The objective of the Depropanizer System is to separate propane from the C3+ feed from the Deethanizer Column (MAF631501). The Depropanizer Column (MAF631506) will receive feed from the bottom of the Deethanizer Column (MAF631501).

The Depropanizer Column overhead pressure is controlled at 132 psig measured at the reflux drum. The overhead vapor from the Depropanizer Column (MAF631506) is totally condensed in the air-cooled Depropanizer Condenser (HFF631508) and collected in the Depropanizer Reflux Drum (MBD631509).

The pressure control valve at the inlet of the Depropanizer Condenser (HFF631508) will control the Depropanizer Column (MAF631506) pressure while the pressure control valve on the condenser bypass line will control the condenser outlet pressure. The liquid from the condenser is sent to the Depropanizer

Reflux Drum (MBD631509). The level in the reflux drum is controlled by regulating the distillate flow rate to the LPG Reinjection Cooler (HBG631519).

The majority of the condensed liquid is used as a reflux and will be pumped back to the Depropanizer Column (MAF631506) by the Depropanizer Reflux Pumps (PBA631510A/B). The remaining portion is sent to the LPG Reinjection Cooler (HBG631519) by the Propane Reinjection Pumps (PBA631511A/B).

Liquid propane make-up is sent to the Propane Refrigerant Storage Drums (MBJ698721/2/3/4), which supply liquid make-up to the propane refrigerant cycle when required. Vapor propane make-up to the propane refrigerant and mixed refrigerant cycle is be provided from the Depropanizer Column (MAF631506) overhead, upstream of the Depropanizer Condenser (HFF631508).

The liquids from the bottom of the column is heated in the Depropanizer Reboiler (HBC631507) and partially vaporized using LP steam. The LP steam flow rate is controlled by the column temperature with a TC-FC cascade controller to limit the propane content in the column bottoms. The non-vaporized butane and heavier liquids that flow from the bottom of the column and are reduced in pressure and fed to the Debutanizer Column (MAF631512).

The objective of the Debutanizer System is to fully stabilize the Plant Condensate product stream so that it meets the Condensate specification. The Debutanizer Column (MAF631512) will receive the feed from the bottom of the Depropanizer Column (MAF631506).

The Debutanizer Column overhead pressure is controlled at 22 psig measured at the reflux drum. The overhead vapor from the Debutanizer Column is totally condensed in the air-cooled Debutanizer Condenser (HFF631514). The pressure control valve at the inlet of the Debutanizer Condenser (HFF631514) controls the Debutanizer Column (MAF631512) pressure while the pressure control valve on the condenser bypass line controls the condenser outlet pressure. The liquid from the condenser is sent to the Debutanizer Reflux Drum (MBD631515). The level in the reflux drum is controlled by the distillate flow rate to the LPG Reinjection Cooler (HBG631519).

The majority of the condensed liquid is used as a reflux and pumped back to the Debutanizer Column (MAF631512) by the Debutanizer Reflux Pumps (PBA631516A/B). The remaining portion is sent to the LPG Reinjection Cooler (HBG631519) by the Butane Reinjection Pumps (PBA631517A/B).

The liquids from the bottom of the column are heated in the Debutanizer Reboiler (HBC631513) and partially vaporized using LP steam. The LP steam flow rate is controlled by the column temperature with a TC-FC cascade controller to maintain the column bottoms specification. The C5+ (pentane and heavier) bottom products are air-cooled in the Debutanizer Condensate Product Cooler (HFF631518) and sent to the Condensate Storage Tank (ABJ634801).

13.7.1.23 NGL Removal Columns Piping, Vessel, and Equipment Design And Specifications

The NGL system columns, piping, vessels and other equipment are designed in accordance with the Project's Design Basis and Specification documents found in Appendix 13.B

13.7.1.24 NGL Removal Columns Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.7.1.25 NGL Removal Column Basic Process Control Systems

The NGL system process control system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.7.1.26 NGL Removal Columns Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the vapor handling operation as described in Appendix 13.E.5 and 13.N.1.

13.7.1.27 NGL Removal Columns Relief Valves And Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogens can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.7.1.28 NGL Columns Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.7.2 NGL Storage Design

Not Applicable

13.7.2.1 NGL Storage Tank Type

Not Applicable

13.7.2.2 Number of NGL Storage Tanks

Not Applicable

13.7.2.3 NGL Storage Tank Foundation Type

Not Applicable

13.7.2.4 NGL Storage Tank Operating and Design Capacities (minimum, normal, maximum), gal

Not Applicable

13.7.2.5 NGL Storage Tank Operating and Design Levels (minimum, normal, maximum), ft

Not Applicable

13.7.2.6 NGL Storage Tank Operating and Design Vacuums and Pressures (minimum, normal, maximum), in H_2O (vacuum) and psig

Not Applicable

13.7.2.7 NGL Storage Tank Operating and Design Temperatures (minimum, normal, maximum), °F

Not Applicable

13.7.2.8 NGL Storage Tank Operating and Design Densities (minimum, normal, maximum), specific gravity

Not Applicable

13.7.2.9 NGL Storage Startup and Operation

Not Applicable

13.7.2.10 NGL Storage Fill Shutdown

Not Applicable

13.7.2.11 NGL Storage Piping, Vessel, and Equipment Design and Specifications

Not Applicable

13.7.2.12 NGL Storage Isolation Valves, Drains, and Vents

Not Applicable

13.7.2.13 NGL Storage Basic Process Control Systems

Not Applicable

13.7.2.14 NGL Storage Safety Instrumented Systems

Not Applicable

13.7.2.15 NGL Storage Relief Valves, Discharge, and Redundancy

Not Applicable

13.7.2.16 NGL Storage Tank Impoundment

Not Applicable

13.7.2.17 NGL Storage Other Safety Features

Not Applicable

13.7.3 GL Disposition Design

Not Applicable. No NGLs products are produced.

13.7.3.1 NGL Final Disposition (truck stations, sendout pipelines, reinjection, fuel gas, etc.)

Not Applicable

13.7.3.2 Number of NGL Truck Stations or Sendout Pipelines

Not Applicable

13.7.3.3 NGL Truck Scales or Sendout Metering

Not Applicable

13.7.3.4 Number of NGL trucks, No. per year, truck capacity, gal

Not Applicable

13.7.3.5 NGL Pumps Type

Not Applicable

13.7.3.6 Number of NGL Pumps, Operating and Spare

Not Applicable

13.7.3.7 NGL Truck Fill/Sendout/Fuel Gas Operating and Design Flow Rate Capacities (minimum, normal, maximum), gpm or Standard Cubic Feet Per Minute (scfm)

Not Applicable

13.7.3.8 NGL Trucking/Sendout/Fuel Gas Pumps Operating and Design Suction Pressures (minimum/net positive suction head [NPSH], normal/rated, maximum), psig

Not Applicable

13.7.3.9 NGL Pumps Operating and Design Suction Temperatures (minimum, normal, maximum), °F

Not Applicable

13.7.3.10 NGL Pumps Operating and Design Discharge Pressures (minimum, normal/rated, maximum/shutoff), psig

Not Applicable

13.7.3.11 NGL Pumps Operating and Design Discharge Temperatures (minimum, normal/rated, maximum/shutoff), °F

Not Applicable

13.7.3.12 NGL Pumps Operating and Design Densities (minimum, normal, maximum), specific gravity

Not Applicable

13.7.3.13 NGL Truck/Sendout Startup and Operation

Not Applicable

13.7.3.14 NGL Truck/Sendout Isolation Valves, Drains, and Vents

Not Applicable

13.7.3.15 NGL Truck/Sendout Basic Process Control Systems

Not Applicable

13.7.3.16 NGL Truck/Sendout Safety Instrumented Systems

Not Applicable

13.7.3.17 NGL Truck/Sendout Relief Valves and Discharge

Not Applicable

13.7.3.18 NGL Truck/Sendout Other Safety Features

Not Applicable

13.8 HEAVIES/CONDENSATES REMOVAL, STORAGE, AND DISPOSITION

The objective of the Debutanizer System (as described in 13.7) is to fully stabilize the condensate product stream so that it meets the condensate specification. The Debutanizer Column (MAF631512) receives incoming gas from the bottom of the Depropanizer Column (MAF631506).

The Fractionation Design Basis (USAL-CB-PBDES-50-000002-000), provided in Appendix 13.B, establishes a design for the Fractionation System. Table 13.8 presents the condensate product specifications.

TABLE 13.8

Condensate Product Specification

Parameter	Value
Reid Vapor Pressure (RVP) at 100 °F per ASTM D-323	12 psia[a]
Basic Sediment and Water (BS&W)	0.5 vol% maximum (0.2 vol% water max)
Sulfur	0.5 wt%
H_2S	10 ppm by weight

[a] Conversion between TVP and RVP is: TVP {psia} = 1.0025 x RVP {psia} + 0.0305

The following Process Flow Diagram associated with the Condensate Storage and Loading area is included in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPFD-70-000634-001	Condensate Storage and Loading

The following P&IDs associated with the Condensate Storage and Loading area are included in Appendix 13.E

Drawing Number	Description
USAL-CB-PDPID-70-000634-701	Condensate Storage and Loading System Condensate Storage Tank
USAL-CB-PDPID-70-000634-702	Condensate Storage and Loading System Condensate Loading Pumps
USAL-CB-PDPID-70-000634-703	Condensate Storage and Loading System Condensate Truck Loading
USAL-CB-PDPID-70-000634-704	Condensate Storage and Loading System Offspec Condensate Storage Tank
USAL-CB-PDPID-70-000634-705	Condensate Storage and Loading System Offspec Condensate Pumps
USAL-CB-PDPID-70-000634-706	Condensate Storage and Loading System Vent KO Drum and Process Blowers
USAL-CB-PDPID-70-000634-707	Condensate Storage and Loading System Thermal Oxidizer

13.8.1 Heavies/Condensates Removal Design

All heavies/condensates are removed in the LPG removal system. Condensate and off-spec condensate is produced in the Debutanizer Column (HFF631514) and sent to storage, see Section 13.8.2.

13.8.1.1 Heavies/Condensates Removal Type

See Section 13.7

13.8.1.2 Heavies/Condensates Removal Operating and Design Inlet Flow Rate Capacities (minimum, normal, maximum), lb/hr

Not Applicable

13.8.1.3 Heavies/Condensates Removal Operating and Design Inlet Compositions (lean, normal, rich), %-vol

Not Applicable

13.8.1.4 Heavies/Condensates Removal Operating and Design Inlet Pressures (minimum, normal, maximum), psig

Not Applicable

13.8.1.5 Heavies/Condensates Removal Operating and Design Inlet Temperatures (minimum, normal, maximum), °F

Not Applicable

13.8.1.6 Heavies/Condensates Removal Operating and Design Outlet Product Flow Rates (minimum, normal, maximum), lb/hr

Not Applicable

13.8.1.7 Heavies/Condensates Removal Operating and Design Outlet Product Compositions (lean, normal, rich), %-vol

Not Applicable

13.8.1.8 Heavies/Condensates Removal Outlet Operating and Design Outlet Pressures (minimum, normal, maximum), psig

Not Applicable

13.8.1.9 Heavies/Condensates Removal Outlet Operating and Design Column Temperatures (minimum, normal, maximum), °F

Not Applicable

13.8.1.10 Heavies/Condensates Removal Startup and Operation

Not Applicable

13.8.1.11 Heavies/Condensates Removal Isolation Valves, Drains, and Vents

Not Applicable

13.8.1.12 Heavies/Condensates Removal Basic Process Control Systems

Not Applicable

13.8.1.13 Heavies/Condensates Removal Safety Instrumented Systems

Not Applicable

13.8.1.14 Heavies/Condensates Removal Relief Valves and Discharge

Not Applicable

13.8.1.15 Heavies/Condensates Removal Other Safety Features

Not Applicable

13.8.2 Heavies/Condensates Storage Design

13.8.2.1 Heavies/Condensates Storage Tanks Type

Atmospheric storage tanks are provided for Condensate (ABJ34801) and Offspec Condensate (ABJ634804) storage.

13.8.2.2 Number of Heavies/Condensates Storage Tanks

Two tanks are provided, one for each material.

13.8.2.3 Heavies/Condensates Storage Tanks Foundation Type

The tanks are provided with concrete slab foundations.

13.8.2.4 Heavies/Condensates Storage Operating and Design Capacities (minimum, normal, maximum), gal

		Storage Minimum Operating/Design Capacity (gal)	Storage Normal Operating/Design Capacity (gal)	Storage Maximum Operating/Design Capacity (gal)
ABJ634701	Condensate Storage Tank	--/--	357,234/--	--/475,890
ABJ634704	Offspec Condensate Storage Tank	--/--	100,466/--	--/126,904

13.8.2.5 Heavies/Condensates Storage Operating and Design Liquid Levels (minimum, normal, maximum), ft

		Storage Minimum Operating/Design Liquid Level (ft)	Storage Normal Operating/Design Liquid Level (ft)	Storage Maximum Operating/Design Liquid Level (ft)
ABJ634701	Condensate Storage Tank	--/--	40/--	--/--
ABJ634704	Offspec Condensate Storage Tank	--/--	24/--	--/--

13.8.2.6 Heavies/Condensates Storage Operating and Design Vacuums And Pressures (minimum, normal, maximum), inH_2O (vacuum) and psig

		Storage Minimum Operating/Design Vacuum (inH_20)	Storage Normal Operating/Design Vacuum (inH_20)	Storage Maximum Operating/Design Vacuum (inH_20)
ABJ634701	Condensate Storage Tank	--/--	8.0/--	--/--
ABJ634704	Offspec Condensate Storage Tank	--/--	8.0/--	--/--

		Storage Minimum Operating/Design Pressure (psig)	Storage Normal Operating/Design Pressure (psig)	Storage Maximum Operating/Design Pressure (psig)
ABJ634701	Condensate Storage Tank	--/--	2.0/--	--/--
ABJ634704	Offspec Condensate Storage Tank	--/--	2.0/--	--/--

13.8.2.7 Heavies/Condensates Storage Operating and Design Temperatures (minimum, normal, maximum), °F

		Storage Minimum Operating/Design Temperature (°F)	Storage Normal Operating/Design Temperature (°F)	Storage Maximum Operating/Design Temperature (°F)
ABJ634701	Condensate Storage Tank	-30/--	--/--	84/--
ABJ634704	Offspec Condensate Storage Tank	-30/--	--/--	84/--

13.8.2.8 Heavies/Condensates Storage Operating and Design Densities (minimum, normal, maximum), specific gravity

		Storage Minimum Operating/Design Specific Gravity	Storage Normal Operating/Design Specific Gravity	Storage Maximum Operating/Design Specific Gravity
ABJ634701	Condensate Storage Tank	--/--	0.68/--	--/--
ABJ634704	Offspec Condensate Storage Tank	--/--	0.63/--	--/--

13.8.2.9 Heavies/Condensates Storage Startup and Operation

Startup and operation of the condensate storage will follow fractionation as described in Section 13.7.1.

13.8.2.10 Heavies/Condensates Storage Isolation Valves, Drains, vnd Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5

13.8.2.11 Heavies/Condensates Storage Basic Process Control Systems

The vapor handling system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.8.2.12 Heavies/Condensates Storage Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the vapor handling operation as described in Appendix 13.E.5 and 13.N.1.

13.8.2.13 Heavies/Condensates Storage Relief Valves, Discharge, and Redundancy.

Vents from Condensate Storage and Loading area will be sent to the LP Flare when the Thermal Oxidizer will be out of service.

Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogens can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.8.2.14 Heavies/Condensates Storage Impoundment

A dike is provided around the Condensate Storage Tank and the Off-spec Condensate Storage Tank.

An additional impoundment sump is located to the western boundary of the Condensate Storage Tank and Truck Loading Area and sized to handle the maximum design spill volume of C5+ condensate during truck loading/unloading operations with a 10 percent margin, as the associated piping and appurtenances will not result in a larger volume.

A summary of all impoundment areas is provided in Section 13.34.

13.8.2.15 Heavies/Condensates Storage Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.8.3 Heavies/Condensates Disposition Design

13.8.3.1 Heavies/Condensates Final Disposition (truck stations, sendout pipelines, reinjection, fuel gas, etc.)

The condensate is loaded into truck trailers for purchase. The off-spec condensate is sent back into the process.

13.8.3.2 Number of Heavies/Condensates Truck Stations or Sendout Pipelines

One connection is provided for the condensate truck loading. The Off-spec condensate is sent back to the process and not exported from the facility via truck.

13.8.3.3 Heavies/Condensates Truck Scales or Sendout Metering

The method of custody transfer for condensate truck loading will be determined during detailed design.

13.8.3.4 Number of Heavies/Condensates Trucks, No. per year, truck capacity, gal

Based on the estimated 1,000 barrels per day capacity, approximately 3-4 trucks per day at will be loaded at a 12,000 gallons size truck and approximately 5-6 trucks per day will be loaded at a 8,000 gallons size truck.

13.8.3.5 Heavies/Condensates Pumps Type

		Pump Type
PBA634702A/B	Condensate Loading Pumps	Centrifugal Pump
PBA634705A/B	Offspec Condensate Pumps	Centrifugal Pump

13.8.3.6 Number of Heavies/Condensates Pumps, Operating and Spare

Two pumps for both the condensate and off-spec condensate. One is operating and one acts as spare.

13.8.3.7 Heavies/Condensates Truck Fill/Sendout/Re-Injection/Fuel Gas Operating and Design Flow Rate Capacities (minimum, normal, maximum), gpm

		Operating/Design Minimum Flow Rate Capacity (gpm)	Operating/Design Normal Flow Rate Capacity (gpm)	Operating/Design Maximum Flow Rate Capacity (gpm)
PBA634702A/B	Condensate Loading Pumps	--/--	133/133	--/147
PBA634705A/B	Offspec Condensate Pumps	--/--	12/12	--/13

13.8.3.8 Heavies/Condensates Trucking/Sendout/Fuel Gas Pumps Operating and Design Suction Pressures (minimum/ NPSH, normal/rated, maximum), psig

Based on information included in the equipment data sheets, the rated and maximum suction pressures are provided in the following table.

		Rated Suction Pressure (psig)	Maximum Suction Pressure (psig)
PBA634702A/B	Condensate Loading Pumps	1.3	46.7
PBA634705A/B	Offspec Condensate Pumps	1.5	68

13.8.3.9 Heavies/Condensates Pumps Operating and Design Suction Temperatures (minimum, normal, maximum), °F

		Operating/Design Minimum Suction Temperature (°F)	Operating/Design Normal Suction Temperature (°F)	Operating/Design Maximum Suction Temperature (°F)
PBA634702A/B	Condensate Loading Pumps	--/30	84/--	--/150
PBA634705A/B	Offspec Condensate Pumps	--/-30	59/--	--/150

13.8.3.10 Heavies/Condensates Pumps Operating and Design Discharge Pressures (minimum, normal/rated, maximum/shutoff), psig

		Operating/Design Minimum Discharge Pressure (psig)	Operating/Design Normal Discharge Pressure (psig)	Operating/Design Maximum Discharge Pressure (psig)
PBA634702A/B	Condensate Loading Pumps	--/--	46.7/--	--/61
PBA634705A/B	Offspec Condensate Pumps	--/--	68/--	--/88

13.8.3.11 Heavies/Condensates Pumps Operating and Design Discharge Temperatures (minimum, normal/rated, maximum/shutoff), °F

		Operating/Design Minimum Discharge Temperature (°F)	Operating/Design Normal Discharge Temperature (°F)	Operating/Design Maximum Discharge Temperature (°F)
PBA634702A/B	Condensate Loading Pumps	--/-30	84/--	--/150
PBA634705A/B	Offspec Condensate Pumps	--/-30	59/--	--/250

13.8.3.12 Heavies/Condensates Pumps Operating and Design Densities (minimum, normal, maximum), specific gravity

		Operating/Design Minimum Density (specific gravity)	Operating/Design Normal Density (specific gravity)	Operating/Design Maximum Density (specific gravity)
PBA634702A/B	Condensate Loading Pumps	--/--	0.68/--	--/--

PBA634705A/B	Offspec Condensate Pumps	--/--	0.603/--	--/--

13.8.3.13 Heavies/Condensates Truck/Sendout Startup and Operation

The Condensate Custody Metering System will be installed near the outlet of the Condensate Storage Tank and condensate will be loaded on truck via condensate loading pumps. This system will be of volume measurement type which will be finalized in Detailed Design Phase.

13.8.3.14 Heavies/Condensates Truck/Sendout Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.8.3.15 Heavies/Condensates Truck/Sendout Basic Process Control Systems

The condensate storage system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.8.3.16 Heavies/Condensates Truck/Sendout Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the condensate handling operation as described in Appendix 13.E.5 and 13.N.1.

13.8.3.17 Heavies/Condensates Truck/Sendout Relief Valves and Discharge

Vapors from the truck trailers will be sent back to the Condensate Storage Tank.

13.8.3.18 Heavies/Condensates Truck/Sendout Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.9 LIQUEFACTION SYSTEM

13.9.1 Refrigerant Trucking/Production Design

The refrigeration system for each of the liquefaction units requires make-up of the four refrigerant components.

Ethane, with a small amount of methane, will be supplied by the Deethanizer Column (MAF631501) in both vapor and liquid phases. The vapor phase will be intermittently routed to the LP/MR Compressor Suction Drums, while the liquid will be sent to Ethane Refrigerant Storage Bullets (MBJ698701/2) via the Deethanizer Reflux Pumps (PBA631505A/B). From storage, ethane will be vaporized in the Ethane Vaporizers (NAP698711/12) before being sent to the LP MR Compressor Suction Drum in the liquefaction trains. All ethane required for the process will be produced on site (the initial cool-down of Train 1 will occur without an ethane component in mixed refrigerant).

Propane refrigerant will be imported, via ISO containers, for the first filling of the Propane Refrigerant Storage Bullets (MBJ698721/2/3/4), prior to the start-up of the first liquefaction train. ISO containers unloading into the storage bullets will be done by the Propane Unloading Pump (PBA698713). The propane for first filling the remaining trains will be self-produced and not imported.

Propane make-up will be supplied intermittently by the Propane Refrigerant Storage Bullets and the Depropanizer Column (MAF631506) overhead. The Depropanizer Column also provides make-up for propane storage via the Propane Reinjection Pump (PBA631511A/B).

Methane make-up will be supplied intermittently by the Scrub Column Reflux Drum (MBD695107) as required.

Refrigeration grade liquid nitrogen will be supplied by the High Purity Liquid Nitrogen Storage and Vaporizer Package (V961640). Liquid nitrogen will be produced on-site in the Cryogenic High Purity Nitrogen Generation Package (V961602). Nitrogen make-up will be sent directly to the LP MR Compressor Suction Drum.

Additional details on the Refrigerant System is presented in the Refrigerant, Condensate and Diesel Storage Design Basis (USAL-CB-PBDES-00-000007-000), provided in Appendix 13.B.

Refer to the Refrigerant Process Flow Diagrams listed below and found in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPFD-70-000698-001	Process Flow Diagram Ethane Refrigerant Storage
USAL-CB-PDPFD-70-000698-002	Process Flow Diagram Propane Refrigerant Storage

Listed as follows are the Piping and Instrumentation Diagrams included in Appendix 13.E of this Resource Report which illustrate the Liquefaction Design.

Drawing Number	Description
USAL-CB-PDPID-70-000698-701	Piping & Instrumentation Diagram Refrigerant Storage System Ethane Refrigerant Storage Bullets
USAL-CB-PDPID-70-000698-702	Piping & Instrumentation Diagram Refrigerant Storage System Ethane Vaporizer
USAL-CB-PDPID-70-000698-703	Piping & Instrumentation Diagram Refrigerant Storage System Propane Refrigerant Storage Bullets 1, 2
USAL-CB-PDPID-70-000698-705	Piping & Instrumentation Diagram Refrigerant Storage System Propane Storage Pump
USAL-CB-PDPID-70-000698-706	Piping & Instrumentation Diagram Refrigerant Storage System Propane Unloading Pump

13.9.1.1 Source

The mixed refrigerant will also be a closed-loop system. The components in the mixed refrigerant will be nitrogen (N_2), methane (C_1), ethane (C_2), and propane (C_3).

13.9.1.2 Number of Refrigerant Trucks During Startup, Truck Capacity, gal

The number of refrigerant ISO containers required for initially charging and starting up the first train will be determined in detailed design. Liquid propane and nitrogen are readily available from local suppliers.

13.9.1.3 Number of Refrigerant Trucks, No. Per Year, Truck Capacity, gal

Following startup, the propane and ethane for normal operation will be self-produced and not imported.

13.9.1.4 Refrigerant Trucking/Production Operating and Design Compositions (minimum, normal, maximum), %-vol

The specifications for refrigerant propane and nitrogen are detailed in Table 13.9.1.4. Methane and ethane will be produced on-site and have the same composition as the Deethanizer Column overhead product. The depropanizer equipment in the fractionation system will produce propane with a concentration between 95.5 and 99.7 %-vol. The deethanizer equipment in the fractionation system will produce ethane with a concentration between 82 and 85 %-vol.

TABLE 13.9.1.4

Refrigerant Specifications

Refrigerant	Specification	
Propane	Ethane	0.2 percent maximum (mole basis)
	Propane	99.6 percent minimum (mole basis)
	C_{4+}	0.2 percent % maximum (mole basis)
	Water	Pass ASTM D2713 Dryness Test
Ethane	Ethane	80 percent minimum (mole basis)
Nitrogen	Purity	99.99 percent
	Oxygen	< 5 ppm
	Oil and hydrocarbons	< 1 ppm
	Water	< 1 ppm

13.9.1.5 Refrigerant Trucking/Production Operating and Design Flow Rate Capacities (minimum, normal, maximum), gpm

Ethane and propane production from the fractionation unit is discussed in Section 13.7.1, NGL Removal Design.

13.9.1.6 Refrigerant Trucking/Production Pumps Operating and Design Suction Pressures (minimum/NPSH, normal/rated, maximum), psig

The Propane Unloading Pump (PBA698713), has a rated suction pressure of 7psig and maximum suction pressure of 162 psig.

There is no unloading pump for the ethane system.

13.9.1.7 Refrigerant Trucking/Production Pumps Operating and Design Suction Temperatures (minimum, normal, maximum), °F

The Propane Unloading Pump (PBA698713), has a maximum pumping temperature of 84 °F and a minimum of -30 °F.

13.9.1.8 Refrigerant Trucking/Production Pumps Operating and Design Discharge Pressures (minimum, normal/rated, maximum/shutoff), psig

The Propane Unloading Pump (PBA698713), has an operating discharge pressure of 33 psig. The pump has a maximum discharge design pressure of 200 psig.

13.9.1.9 Refrigerant Trucking/Production Pumps Operating and Design Discharge Temperatures (minimum, normal/rated, maximum/shutoff), °F

The Propane Unloading Pump (PBA698713), has a design maximum discharge temperature of 140 °F and a design minimum of -40 °F.

13.9.1.10 Refrigerant Trucking/Production Pumps Operating and Design Densities (minimum, normal, maximum), specific gravity

The Propane Unloading Pump (PBA698713), has an operating specific gravity of 0.573, based on a temperature of -30 °F.

13.9.1.11 Number of Refrigerant Truck Stations

Imported propane will be brought to site in ISO containers and unloaded into a single transfer system to storage.

13.9.1.12 Refrigerant Truck Scales

Not Applicable.

13.9.1.13 Refrigerant Trucking/Production Startup and Operation

During start-up of the first LNG train, refrigerant quality liquid propane will be imported via International Standard for Organization (ISO) containers. From the ISO containers, the propane will be transferred to Propane Refrigerant Storage Bullets (MBJ698721/2/3/4).

Any propane required after start-up of the first LNG train will be produced on-site. During normal operations, propane will be produced from the Depropanizer Reflux Drum (MBD631509) using Propane Reinjection Pumps (PBA631511A/B).

From the Propane Refrigerant Storage Bullets, liquid propane will be supplied to the liquefaction processing trains as required using the Propane Storage pumps (PBA698718A/B).

All of the required ethane for the Liquefaction Facility (for initial fill during start-up and make-up as required) will be produced on-site.

Methane make-up will be supplied intermittently by the Scrub Column Reflux Drum (MBD695107) as required.

Refrigeration grade liquid nitrogen will be supplied by the High Purity Liquid Nitrogen Storage & Vaporizer Package (V961640). During normal operations, all nitrogen is produced on site, in the Cryogenic High Purity Nitrogen Generation Package (V961602). Nitrogen make-up will be sent directly to the LP Mixed Refrigerant Compressor Suction Drum.

13.9.1.13.1 Truck Unloading System

Not Applicable.

13.9.1.13.2 Refrigerant Pretreatment System

Not Applicable.

13.9.1.13.3 Vapor Handling

Not Applicable.

13.9.1.13.4 Pumps

During normal operations, propane will be produced from the Depropanizer Reflux Drum (MBD631509) using Propane Reinjection Pumps (PBA631511A/B).

13.9.1.13.5 Refrigerant Transfer/Makeup System

Refrigerant make-up to the trains is discussed in Section 13.9.3.

13.9.1.14 Refrigerant Trucking/Production Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.9.1.15 Refrigerant Trucking/Production Basic Process Control Systems

The system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC

13.9.1.16 Refrigerant Trucking/Production Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the operation as described in Appendix 13.E.5 and 13.N.1.

13.9.1.17 Refrigerant Trucking/Production Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogens can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.9.1.18 Refrigerant Trucking/Production Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.9.2 Refrigerant Storage Design

During start-up of the first LNG train, refrigerant quality liquid propane will be imported via International Standard for Organization (ISO) containers. From the ISO containers, the propane will be transferred to Propane Refrigerant Storage Bullets (MBJ698721/2/3/4). The Propane Unloading Pump (PBA698713) will be used to unload the liquid propane from the ISO container.

Any propane required after start-up of the first LNG train will be produced on-site. During normal operations, propane will be produced from the Depropanizer Reflux Drum (MBD631509) using Propane Reinjection Pumps (PBA631511A/B).

From the Propane Refrigerant Storage Bullets, liquid propane will be supplied to the liquefaction processing trains as required using the Propane Storage pumps (PBA698718A/B).

All of the required ethane for the Liquefaction Facility (for initial fill during start-up and make-up as required) will be produced on-site.

Liquid ethane will be transferred from the Deethanizer Reflux Drum (MBD631504) using Deethanizer Reflux Pumps (PBA631505A/B). This liquid ethane will be stored in the Ethane Refrigerant Storage Bullets (MBJ698701/2).

From the Ethane Refrigerant Storage Bullets, the ethane will be supplied to the liquefaction processing trains as required. Ethane will be supplied as a vapor stream. Ethane Vaporizers (NAP698711/2) will be used to evaporate the liquid ethane before sending it to the liquefaction processing trains.

13.9.2.1 Refrigerant Storage Tank Type

Propane and ethane are stored in pressure vessels.

13.9.2.2 Number of Refrigerant Storage Tanks, Operating and Spare

The design includes four propane storage bullets, operating in a 4 x 25% configuration, and two ethane bullets, operating in a 2 x 50% configuration.

13.9.2.3 Refrigerant Storage Tanks Foundations Type

The refrigerant storage bullets are horizontal pressure vessels that will be supported by concrete saddles.

13.9.2.4 Refrigerant Storage Operating and Design Capacities (minimum, normal, maximum), gal

Each propane storage bullet has a working volume of 54,050 gallons (7,225 ft^3). Combined storage capacity corresponds to the volume required for the initial fill of the propane and the mixed refrigerant circuits of one train.

The ethane bullets will be vacuum insulated and have a working capacity of 35,160 gallons (4,700 cubic feet). Combined storage capacity corresponds to the volume required for one train of the mixed refrigerant circuit.

13.9.2.5 Refrigerant Storage Operating and Design Levels (minimum, normal, maximum), ft

Not Applicable

13.9.2.6 Refrigerant Storage Operating and Design Pressures/Vacuums (minimum, normal, maximum), in H_2O (vacuum) and psig

Vacuum pressures will be provided in detailed design.

		Storage Minimum Operating/Design Pressure (psig)	Storage Normal Operating/Design Pressure (psig)	Storage Maximum Operating/Design Pressure (psig)
MBJ698721/2/3/4	Propane Refrigerant Storage Bullets	5.7/--	61/61	137.7/200
MBJ698701/2	Ethane Refrigerant Storage Bullets	--/--	390/--	--/480

13.9.2.7 Refrigerant Storage Operating and Design Temperatures (minimum, normal, maximum), °F

		Storage Minimum Operating/Design Temperature (°F)	Storage Normal Operating/Design Temperature (°F)	Storage Maximum Operating/Design Temperature (°F)
MBJ698721/2/3/4	Propane Refrigerant Storage Bullets	-30/-50	38/--	84/140
MBJ698701/2	Ethane Refrigerant Storage Bullets	-150/--	-16/--	--/--

13.9.2.8 Refrigerant Storage Operating and Design Densities (minimum, normal, maximum), specific gravity

		Storage Design Specific Gravity
MBJ698721/2/3/4	Propane Refrigerant Storage Bullets	0.53
MBJ698701/2	Ethane Refrigerant Storage Bullets	0.42

13.9.2.9 Refrigerant Storage Startup and Operation

Refrigerant storage bullets will be prepared for operation in accordance with vendor guidelines.

13.9.2.10 Refrigerant Storage Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.9.2.11 Refrigerant Storage Basic Process Control Systems

The system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC

13.9.2.12 Refrigerant Storage Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the operation as described in Appendix 13.E.5 and 13.N.1.

13.9.2.13 Refrigerant Storage Relief Valves, Discharge, and Redundancy

Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogens can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.9.2.14 Refrigerant Storage Tanks Impoundment

Discussion on the containment for the refrigerant storage bullets is provided in Section 13.34.

13.9.2.15 Refrigerant Storage Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.9.3 Refrigerant Charge/Loading Pumps Design

The refrigeration system for each of the liquefaction units will require make-up of the four refrigerant components. Ethane, with a small amount of methane, will be supplied by the Deethanizer Column (MAF631501) in both vapor and liquid phases. The vapor phase will be intermittently routed to the LP/Mixed Refrigerant Compressor Suction Drums, while the liquid will be sent to Ethane Refrigerant Storage Bullets (MBJ698701/2) via the Deethanizer Reflux Pumps (PBA631505A/B). From storage, ethane will be vaporized in the Ethane Vaporizers (NAP698711/12) before being sent to the LP Mixed Refrigerant Compressor Suction Drum in the liquefaction trains. All ethane required for the process will be produced on site (the initial cool-down of Train 1 will occur without an ethane component in the mixed refrigerant).

Propane make-up will be supplied intermittently by the Propane Refrigerant Storage Bullets and the Depropanizer Column (MAF631506) overhead. The Depropanizer Column will also provide make-up for propane storage via the Propane Reinjection Pump (PBA631511A/B).

13.9.3.1 Refrigerant Pumps Type

Pump service is intermittent and type will be determined during detailed design.

13.9.3.2 Number of Refrigerant Pumps, Operating and Spare

One Propane Storage Pump.

13.9.3.3 Refrigerant Pumps Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), gpm

The Propane Storage Pump (PBA698718) has a rated operating flow rate of 150 gpm.

13.9.3.4 Refrigerant Pumps Operating and Design Suction Pressures (minimum/NPSH, normal/rated, maximum), psig

The Propane Storage Pump (PBA698718) has a rated suction pressure of 141 psig and a maximum suction pressure of 143 psig.

13.9.3.5 Refrigerant Pumps Operating and Design Suction Temperatures (minimum, normal, maximum), °F

The Propane Storage Pump (PBA698718) has a pumping temperature that varies with ambient temperatures. The pump is designed for a minimum ambient temperature of -30 °F and a maximum of 84 °F.

13.9.3.6 Refrigerant Pumps Operating and Design Discharge Pressures (minimum, normal/rated, maximum/shutoff), psig

The Propane Storage Pump (PBA698718) has a discharge pressure of 296 psig.

13.9.3.7 Refrigerant Pumps Operating and Design Discharge Temperatures (minimum, normal, maximum), °F

See Section 13.9.3.5 for estimated discharge temperatures.

13.9.3.8 Refrigerant Pumps Operating and Design Densities (minimum, normal, maximum), specific gravity.

The Propane Storage Pump (PBA698718) has an operating specific gravity of 0.487 at 84 °F.

13.9.3.9 Refrigerant Pumps Startup and Operation

The Propane Storage Pump will be brought into operation for initial fill. During normal operation all additional propane will be supplied from the fractionation system.

13.9.3.10 Refrigerant Pumps Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.9.3.11 Refrigerant Pumps Basic Process Control Systems

The system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.9.3.12 Refrigerant Pumps Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the operation as described in Appendix 13.E.5 and 13.N.1.

13.9.3.13 Refrigerant Pumps Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogens can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.9.3.14 Refrigerant Pumps Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.9.4 Liquefaction Design

The AP-C3MR™ LNG Process designed and licensed by Air Products and Chemicals, Inc., (Air Products) has been selected for the Project.

Refer to Equipment List, Document No. USAL-CB-MLMEL-00-000001-000, included in Appendix 13.M, which includes operating conditions of the liquefaction unit equipment.

Additional details on the Liquefaction System are presented in the Liquefaction and Refrigeration System Design Basis (USAL-CB-PBDES-00-000006-000), provided in Appendix 13.B.

Refer to the Liquefaction Process Flow Diagrams listed below and found in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPFD-10-000666-001	Process Flow Diagram Process Refrigeration Systems MR/Propane Compressors
USAL-CB-PDPFD-10-000666-002	Process Flow Diagram Process Refrigeration Systems MR/Propane Compressors
USAL-CB-PDPFD-10-000666-003	Process Flow Diagram Process Refrigeration System MR/Propane Coolers

Drawing Number	Description
USAL-CB-PDPFD-10-000695-001	Process Flow Diagram Gas Liquefaction Systems Feed Gas Coolers and Defrost Gas Heater
USAL-CB-PDPFD-10-000695-002	Process Flow Diagram Gas Liquefaction System Scrub Column and Main Cryogenic Heat Exchanger

Listed as follows are the Piping and Instrumentation Diagrams included in Appendix 13.E of this Resource Report which illustrate the Liquefaction Design.

Drawing Number	Description
USAL-CB-PDPID-10-000666-101	Piping and Instrumentation Diagram Process Refrigeration Systems MR Return Line From Cryogenic Heat Exchanger
USAL-CB-PDPID-10-000666-111	Piping & Instrumentation Diagram Process Refrigeration Systems LP MR Comp. Suc. Drum And LP MR Comp. - String 1
USAL-CB-PDPID-10-000666-112	Piping & Instrumentation Diagram Process Refrigeration Systems LP MR Comp. Intercooler And MP MR Comp. Suc. Drum - String 1
USAL-CB-PDPID-10-000666-113	Piping & Instrumentation Diagram Process Refrigeration Systems MP MR Compressor And Intercooler - String 1
USAL-CB-PDPID-10-000666-114	Piping & Instrumentation Diagram Process Refrigeration Systems HP MR Comp. Suc. Drum And HP MR Comp. - String 1
USAL-CB-PDPID-10-000666-115	Piping & Instrumentation Diagram Process Refrigeration Systems HP MR Comp. Desuperheater And After-Cooler - String 1
USAL-CB-PDPID-10-000666-131	Piping & Instrumentation Diagram Process Refrigeration Systems MR HP/MP Propane Cooler
USAL-CB-PDPID-10-000666-132	Piping & Instrumentation Diagram Process Refrigeration Systems MR/LP Propane Cooler
USAL-CB-PDPID-10-000666-133	Piping & Instrumentation Diagram Process Refrigeration Systems HP MR Separator
USAL-CB-PDPID-10-000666-134	Piping & Instrumentation Diagram Process Refrigeration Systems MR Hydraulic Turbine
USAL-CB-PDPID-10-000666-141	Piping & Instrumentation Diagram Process Refrigeration Systems LP/MP Propane Suction Drum - String 1
USAL-CB-PDPID-10-000666-142	Piping & Instrumentation Diagram Process Refrigeration Systems HP Propane Suction Drum - String 1
USAL-CB-PDPID-10-000666-143	Piping & Instrumentation Diagram Process Refrigeration Systems Propane Refrigerant Compressor - String 1
USAL-CB-PDPID-10-000666-144	Piping & Instrumentation Diagram Process Refrigeration Systems Propane Desuperheater - String 1
USAL-CB-PDPID-10-000666-161	Piping & Instrumentation Diagram Process Refrigeration Systems Propane Condenser And Propane Accumulator
USAL-CB-PDPID-10-000666-162	Piping & Instrumentation Diagram Process Refrigeration Systems Propane Subcooler, Propane Transfer Drum And Pump
USAL-CB-PDPID-10-000666-163	Piping & Instrumentation Diagram Process Refrigeration Systems Propane Drain Connections
USAL-CB-PDPID-10-000666-171	Piping & Instrumentation Diagram Process Refrigeration Systems MR/PR Compressor Gas Turbine Driver - String 1
USAL-CB-PDPID-10-000695-101	Piping & Instrumentation Diagram Gas Liquefaction System Feed Gas Propane Coolers
USAL-CB-PDPID-10-000695-102	Piping & Instrumentation Diagram Gas Liquefaction System Scrub Column
USAL-CB-PDPID-10-000695-103	Piping & Instrumentation Diagram Gas Liquefaction System Main Cryogenic Heat Exchanger (LNG)
USAL-CB-PDPID-10-000695-104	Piping & Instrumentation Diagram Gas Liquefaction System Scrub Column Reflux Drum And Pumps
USAL-CB-PDPID-10-000695-105	Piping & Instrumentation Diagram Gas Liquefaction System LNG Hydraulic Turbine

Drawing Number	Description
USAL-CB-PDPID-10-000695-106	Piping & Instrumentation Diagram Gas Liquefaction System Scrub Column Cooler
USAL-CB-PDPID-10-000695-107	Piping & Instrumentation Diagram Gas Liquefaction System Main Cryogenic Heat Exchanger (MR)

13.9.4.1 Feed Gas Precooling System

This process will be based on the principle of precooling the feed gas with a closed propane refrigerant circuit and then condensing and subcooling the feed gas within a closed mixed refrigerant circuit. Each train will consist of a propane-precooled refrigeration system for feed gas cooling, and propane and mixed refrigerant systems for cooling and liquefying the natural gas in the Main Cryogenic Heat Exchanger (MCHE).

13.9.4.2 Number of Liquefaction Trains

The Liquefaction Facility will contain three identical 6.7 MMTPA liquefaction trains.

13.9.4.3 Liquefaction Process Type (Mixed Refrigerant, Cascade, Nitrogen, etc.)

Propane refrigeration will be provided by a closed-loop system that produces HP propane refrigerant. The refrigerant will be depressurized to successively chill the natural gas feed. The Scrub Column (MAF695104) will remove heavy components from the feed gas. Propane, at the three pressure levels, will be used to chill the mixed refrigerant before it will be used to chill, condense, and subcool the natural gas into LNG in the MCHE. LP propane will also be used to condense the deethanizer overhead vapor for refluxing the column.

The mixed refrigerant provides cooling for the MCHE (HBA695108). At high pressure, mixed refrigerant from the HP Mixed Refrigerant Compressor After-Cooler (HFF666132) will be cooled and partially condensed as it passes through the mixed refrigerant/HP Propane Cooler (HBG666105), Mixed Refrigerant/MP Propane Cooler (HBG666104), and Mixed Refrigerant/LP Propane Cooler (HBG666103).

13.9.4.4 Main refrigerant heat exchangers, cold box(es), etc.

Propane refrigerant at two pressure levels will be used to cool the treated feed gas coming from the Dehydration Unit in two coolers: Feed Gas/MP Propane Cooler (HBG695101) and Feed Gas/LP Propane Cooler (HBG695102). Propane refrigerant will be successively let down to medium (MP) and low pressure (LP) levels to provide the refrigeration at both chilling stages.

Propane refrigerant at three pressure levels will be used to cool the mixed refrigerant (MR) circuit in three coolers: MR/HP Propane Cooler (HBG666105), MR/MP Propane Cooler (HBG666104) and MR/LP Propane Cooler (HBG666103). Propane refrigerant will be successively let down to high, medium and low pressure levels to provide the refrigeration at the three chilling stages.

The mixed refrigerant (MR) provides cooling for the Main Cryogenic Heat Exchanger (HBA695108). At high pressure, mixed refrigerant from the HP MR Compressor After-Cooler (HFF666132) will be cooled and partially condensed as it passes through the MR/HP Propane Cooler (HBG666105), MR/MP Propane Cooler (HBG666104), and MR/LP Propane Cooler (HBG666103).

13.9.4.5 Refrigerant Compressors and Drivers

The MR compression system consists of two sets of parallel compressors, air coolers and propane coolers per train. The MR System has two parallel strings. Each string of the MR compressors will be coupled with a 50 percent propane compressor, which will be driven by the high efficiency industrial gas turbine driver (MR/PR Compressor Gas Turbine Driver CGT666111/151).

The low pressure MR vapor from the warm end of the MCHE will be split between the two parallel 50 percent parallel MR compression strings and then sent to the LP MR Compressor (CAE666113/153) via the LP MR Compressor Suction Drum (MBD666106/107). Discharge of the LP MR Compressor will be cooled in the LP MR Compressor Intercooler (HFF666121/161). The MR then enters the MP MR Compressor Suction Drum (MBD666124/164) before being compressed in the MP/HP MR Compressor (CAE666114/154) medium pressure stage. The discharge of the MP/HP MR Compressor MP stage will be cooled in the MP MR Compressor Intercooler (HFF666122/162). The vapor then enters the HP MR Compressor Suction Drum (MBD666123/163) before it will be compressed in the MP/HP MR Compressor high pressure stage. The compressor discharge will be cooled by the HP MR Compressor Desuperheater (HFF666131/171) and the HP MR Compressor After-Cooler (HFF666132/172). The MR/HP Propane Cooler (HBG666105), MR/MP Propane Cooler (HBG666104), and MR/LP Propane Cooler (HBG666103), further cool the HP MR before it is sent to the HP MR Separator (MBD666101).

The HP MR Separator separates the high pressure mixed refrigerant into gas and liquid streams, which flow through the MCHE. Vaporized mixed refrigerant that exits the MCHE flows back to the LP MR Suction Drum, completing the closed-loop refrigerant circuit.

Periodic make-up to the MR system will be sourced from the Propane Refrigerant Storage System, Ethane Refrigerant Storage System, Nitrogen System, Fractionation Unit, Scrub Column Reflux Drum overhead and flows to the LP MR Compressor Suction Drum.

The propane refrigeration system utilizes propane evaporating at two pressure levels to supply refrigeration to the feed circuit and propane evaporating at three pressure levels to supply refrigeration to the MR circuit. The Propane Refrigerant System consists of two parallel compressor strings per train, on the same shaft as the MR compressors. Each Propane Refrigerant Compressor (CAE666112/152) will be coupled with a gas turbine driver (MR/PR Compressor Gas Turbine Driver CGT666111/151).

Vapor from the LP Propane Suction Drum (MBD666141/181) feeds the first stage of the Propane Refrigerant Compressor (CAE666112/152). Vapor from the MP Propane Suction Drum (MBD666142/182) and the first stage discharge will be mixed and fed to the second stage of the Propane Refrigerant Compressor suction. Vapor from the HP Propane Suction Drum (MBD666143/183) and the second stage discharge will be mixed and fed to the third stage suction.

Propane from the discharge of the Propane Refrigerant Compressor will be desuperheated in the Propane Desuperheater (HFF666144/184). Downstream of the desuperheaters, the propane streams from both propane compression strings will be combined for further being condensed in the Propane Condenser

(HFF666191). The condensed propane will be collected in the Propane Accumulator (MBA666192). From the Propane Accumulator bottom, it passes through the Propane Subcooler (HFF666193) before being supplied to the propane coolers for feed gas and mixed refrigerant.

The Propane Accumulator will be fitted with the Propane Reclaimer (MBA666196) and the Propane Reclaimer Condenser (HBG666197), which allows a purging of non-condensables from the accumulator. These non-condensables will be vented to the MR system. Condensate formed in the tube side drops to the Propane Reclaimer as reflux to minimize propane losses during the purge operation.

Each train also supplies HP propane liquid to the LPG Reinjection Cooler (HBG631519) and the Deethanizer Condenser (HBG631503) in the Fractionation Area. The flow rate of each line will be controlled by the liquid level on each of the exchangers. Return vapor from the Fractionation System will be distributed equally between the LP Propane Suction Drums in each train.

Periodic make-up to the propane system will be sourced from the Propane Refrigerant Storage System and from the Fractionation Unit, and flows to the first stage suction of the Propane Compressor.

13.9.4.6 Liquefaction Operating and Design Flow Rate Capacities (Minimum, Normal, Maximum), MMscfd

The maximum flow rate to each liquefaction train will be approximately 930 MMSCFD per train.

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Normal Flow Rate, MMscfd	926	895	885	895	894	916

13.9.4.7 Liquefaction Operating and Design Inlet Compositions (Minimum/Lean/Light, Normal/Design/Average, Maximum/Rich/ Heavy), %-Vol

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Total Phase Mole Fraction						
CO2	0.0050	0.0050	0.0050	0.0050	0.0052	0.0049
H2S	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
N2	0.7650	0.7650	0.7650	0.6928	1.0108	0.8931
Methane	91.0917	91.0918	91.0917	90.9189	92.14253	91.0982
Ethane	5.7637	5.7637	5.7637	6.2487	4.17036	5.6694
Propane	1.9739	1.9739	1.9739	1.9098	1.73723	1.9404
i-Butane	0.1340	0.1340	0.1340	0.0683	0.29652	0.1317
n-Butane	0.1750	0.1750	0.1750	0.1024	0.38045	0.1720

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
i-Pentane	0.0370	0.0370	0.0370	0.0114	0.11717	0.0364
n-Pentane	0.0350	0.0350	0.0350	0.0114	0.10692	0.0344
Neopentane	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
C6+	0.0140	0.0140	0.0140	0.0255[b]	0.0241[c]	0.0138
Aromatics	0.0034	0.0034	0.0034	0.0034	0.0064	0.0033
Water	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Oxygen	0.0010	0.0010	0.0010	0.0010	0.0010	0.0011
Organic Sulfides[a]	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005

Notes:

[a] Organic Sulfides include methyl and ethyl mercaptans, dimethyl sulfide, carbon disulfide, and carbonyl sulfide.

[b] C6+ plus C6+ Pseudo components. C6+ Pseudo Components include C6 Pseudo, C7 Pseudo, C8 Pseudo, C9 Pseudo and C10 Pseudo Components.

[c] C6+ plus C6+ Pseudo components. C6+ Pseudo Components include PTU C6*, PTU C7*, PTU C8*, PTU C9* Components.

[d] For pseudo components characterization, refer to Design Basis - Liquefaction and Refrigeration System, document number USAL-CB-PBDES-00-000006-000 included in Appendix C.

[e] Flow rate of one train of total three trains

13.9.4.8 Liquefaction Operating and Design Inlet Pressures (Minimum, Normal, Maximum), psig

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Normal Pressure, psig	870	870	870	870	870	870

13.9.4.9 Liquefaction Operating and Design Inlet Temperatures (Minimum, Normal, Maximum), °F

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Normal Temp, °F	13	16	33	16	16	17

13.9.4.10 Liquefaction Final Exchanger Operating and Design Outlet Pressures (Minimum, Normal, Maximum), psig

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Normal Pressure, psig	638	635	656	628	638	631

13.9.4.11 Liquefaction Final Exchanger Operating and Design Outlet Temperatures (Minimum, Normal, Maximum), °F

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Normal Temp, °F	-246	-245	-244	-245	-248	-244

13.9.4.12 Liquefaction Condenser Operating and Design Inlet Temperatures (Minimum, Normal, Maximum), °F

Not Applicable

13.9.4.13 Liquefaction Condenser Operating and Design Outlet Temperatures (Minimum, Normal, Maximum), °F

Not Applicable

13.9.4.14 Liquefaction Cooling Fluid Operating and Design Inlet Temperatures (Minimum, Normal, Maximum), °F

Mixed refrigerant enters the MCHE in four stages: (1) vapor from the MR Separator, (2) liquid from the MR separator, (3) after the MR expander, and (4) after the JT valve. The JT Valve information is proprietary to the Liquefaction Vendor and not included in the Project's heat and material balances. Operating temperatures are presented below.

HMB Stream		Minimum Operating Temperature (°F)	Normal Operating Temperature (°F)	Maximum Operating Temperature (°F)
666122	Vapor from MR Separator	-30	-29	-21
666123	Liquid from MR Separator	-30	-29	-21
666160	Liquid from MR Expander	-208	-204	-198

13.9.4.15 Liquefaction Cooling Fluid Operating and Design Outlet Temperatures (Minimum, Normal, Maximum), °F

The MR vapor exiting the MCHE is between -40 °F and -28 °F.

13.9.4.16 Liquefaction Operating and Design Air Temperatures (Minimum, Normal, Maximum), °F

The absolute minimum ambient design temperature will be -30 °F. The maximum ambient design temperature will be 84 °F. The average ambient air temperature is 37.4 °F.

13.9.4.17 Refrigerant Compressor Operating and Design Flow Rate Capacities (Minimum, Normal, Maximum), MMscfd

Flows for the Mixed Refrigerant Compressor are presented in the following table.

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Flow Rate, MMscfd	638	599	592	612	601	630

Flows for the Propane Compressor are presented in the following table.

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Flow Rate, MMscfd	98	91	107	90	101	95

13.9.4.18 Refrigerant Compressor Operating and Design Suction Pressures (Minimum, Normal, Maximum), psig

Suction Pressures for the Mixed Refrigerant Compressor are presented in the following table.

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Pressure, psig	31	26	27	28	27	28

Suction pressures for the Propane Compressor are presented in the following table.

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Pressure, psig	2	2	6	2	2	2

13.9.4.19 Refrigerant Operating and Design Discharge Pressures (Minimum, Normal, Maximum/Shutoff), psig

Discharge Pressures for the Mixed Refrigerant Compressor are presented in the following table.

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Pressure, psig	861	827	780	867	814	814

Discharge pressures for the Propane Compressor are presented in the following table.

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Pressure, psig	134	134	132	134	134	104

13.9.4.20 Liquefaction System Startup and Operation

Commissioning will need to be completed to achieve a Ready for Start-Up (RFSU) status in the Liquefaction Facility prior to the initial plant start-up and cool-down with hydrocarbons from the Mainline or local gas tie-in.

Pre-commissioning of the Liquefaction Facility will consist of the following key activities:

- Function testing of all Integrated Control and Safety System (ICSS) and instrumentation devices;
- Function testing, energization and leave in service all primary and secondary utilities;
- Function testing of process equipment as far as practical;

- Nitrogen purging of all hydrocarbon piping and equipment;
- High pressure leak testing;
- Preliminary dry-out of the Main Cryogenic Heat Exchanger, Propane and Mixed Refrigerant systems; and
- LNG Storage Tank purging and dryout.

Initial plant start-up will begin when all piping circuits have been dried out and purged with nitrogen to remove all air from the systems. Defrost gas will be used to purge the propane refrigerant system and lower the dew point to -80 °F, with the defrost gas used for purging flowing to the flare. After reaching the -80 °F dew point, the propane refrigerant system will be purged with propane vapor and followed with the initial inventory charge of propane refrigerant.

Pretreated feed gas will be available to pressurize the feed circuit to the normal operating pressure up to the MCHE feed gas inlet block valve. The Propane Refrigeration Compressor will be placed online, followed by the MR compressor to begin the initial cool-down of the feed gas. The LNG train will be subsequently cooled down to normal operating temperatures and LNG production will be ramped up to design production rates.

The LNG Storage Tanks will be dried and purged prior to commissioning. Drying will be performed by removing all standing water. The tank will then be purged with dry gaseous nitrogen, vented and monitored until an interior dew point of -26 °F was reached. After the tank has been purged with nitrogen, it will be purged to a combustible gas concentration of no less than 90 percent in preparation for tank cool-down. The tank system has an independent cool-down fill line with spray nozzles designed specifically for cool-down of the LNG storage tank. During the initial introduction of liquid product, it will be important to have uniform cool-down. The primary container temperature gradient between any two adjacent cool-down resistance temperature detectors (RTDs) will not exceed 50 °F and the gradient between any two RTDs will not exceed 100 °F. The cool-down rate for the primary liquid container will be controlled to a maximum average of 9 °F per hour and will not exceed 15 °F per hour during any one-hour period. The cool-down cycle will be deemed complete when 6 inches of product liquid will be measured in the tank.

Following, commission and startup, four modes of operation are considered for Liquefaction.

13.9.4.20.1 Liquefaction without Ship Loading (Holding Mode)

In this operating mode (Holding Mode), LNG will be produced to the storage tanks in periods between LNGC loadings. When LNGCs are not being loaded, LNG production could be routed to either or both LNG Storage Tanks. LNG could also be transferred between tanks whenever an LNGC is not being loaded.

In this operating mode, BOG will be generated in the LNG storage tanks as a result of vapor displacement by the LNG product entering the storage tanks, from heat leaks into the system piping, from heat leaks through the insulated tank walls, and from heat added by the operating pump(s). BOG generated from these sources will be compressed by the HP BOG Compressors (CAE691842/52/62) and sent to the HP Fuel Gas System.

13.9.4.20.2 Liquefaction with Loading a Single LNG Carrier (Loading Mode)

In this operating mode (Loading Mode), LNG will be produced to the storage tanks while an LNGC will also be loaded. The Liquefaction Facility will be capable of loading LNGCs at a maximum rate of 12,500 cubic meters per hour. This rate could be delivered to either dock. In addition, this loading will not be interrupted by, nor will it interrupt, the production of LNG being sent to the storage tanks.

During ship loading, LNG will be going to and coming from all LNG Storage Tanks. The LNG Loading Arms will be used to transfer the LNG to the LNGC. A parallel vapor return will accommodate the vapor flow from the loading berth to the onshore BOG Header.

A portion of the vapor returned from the LNGC will flow to the storage tanks to make-up the liquid volume withdrawn during LNGC loading. The balance of the vapor will be returned to the HP Fuel Gas system via the HP BOG Compressors that will boost the pressure of the gas to about 470 psig.

13.9.4.20.3 No Liquefaction with Ship Loading

If LNG production were halted for any reason, an LNGC could still be loaded at one berth. The BOG will be compressed by the BOG Compressor and sent to the fuel gas system.

13.9.4.20.4 No Liquefaction and No Ship Loading (Idle Mode)

If LNG production were halted for any reason and no LNGC were being loaded, LNG will still be in the LNG Storage Tanks. For this situation, vapors produced in the storage tank will be compressed by the BOG compression system and a minor amount will be sent to the fuel gas system, as required.

13.9.4.21 Liquefaction System Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.9.4.22 Liquefaction System Basic Process Control Systems

The system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.9.4.23 Liquefaction System Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the operation as described in Appendix 13.E.5 and 13.N.1.

13.9.4.24 Liquefaction System Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogens can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.9.4.25 Liquefaction System Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.9.5 Cooling System Design

Process cooling for the liquefaction trains, other than those associated with the refrigeration process, will be accomplished using induced-draft fin-fan air coolers.

In the MR circuit, air coolers will be used to provide cooling for the compressor intercoolers, after-cooler, and desuperheater, and consist of the following:

- LP MR Compressor Intercooler (HFF666121/161);
- MP MR Compressor Intercooler (HFF666122/162);
- HP MR Compressor Desuperheater (HFF666131/171); and
- HP MR Compressor After-Cooler (HFF666132/172).

In the propane refrigerant circuit, air coolers will be used to provide cooling for desuperheating, condensing, and subcooling propane, and consist of the following:

- Propane Desuperheater (HFF666144/184);
- Propane Condenser (HFF666191); and
- Propane Subcooler (HFF666193).

Other than the air coolers, the MR circuit and the propane refrigerant circuit share the three kettle type heat exchangers used for cooling and partially condensing vapor MR prior to sending it to the MCHE. These heat exchangers are:

- MR/HP Propane Cooler (HBG666105);
- MR/MP Propane Cooler (HBG666104); and
- MR/LP Propane Cooler (HBG666103).

13.9.5.1 Cooling System Source and Type

The cooling system type is air-coolers.

13.9.5.2 Cooling System Operating and Design Storage Capacities (Minimum, Normal, Maximum), gal

Not Applicable.

13.9.5.3 Cooling System Operating and Design Flow Rate Capacities (Minimum, Normal, Maximum), gpm

Not Applicable.

13.9.5.4 Cooling System Operating and Design Delivery Pressures (Minimum, Normal, Maximum), psig

Not Applicable.

13.9.5.5 Cooling System Operating and Design Delivery Temperatures (Minimum, Normal, Maximum), °F

Not Applicable.

13.9.5.6 Cooling System Operating and Design Return Pressures (Minimum, Normal, Maximum), psig

Not Applicable.

13.9.5.7 Cooling System Operating and Design Return Temperatures (Minimum, Normal, Maximum), °F

Not Applicable.

13.9.5.8 Cooling System Startup and Operation

Not Applicable.

13.9.5.9 Cooling System Isolation Valves, Drains, and Vents

Not Applicable.

13.9.5.10 Cooling System Basic Process Control Systems

Not Applicable.

13.9.5.11 Cooling System Safety Instrumented Systems

Not Applicable.

13.9.5.12 Cooling System Relief Valves and Discharge

Not Applicable.

13.9.5.13 Cooling System Other Safety Features

Not Applicable.

13.10 LNG PRODUCT TRANSFER TO STORAGE

13.10.1 LNG Transfer to Storage Design

LNG exiting the MCHE is let down in pressure across the LNG Hydraulic Turbine (TGT695109) and/or its bypass JT valve. This stream is then be sent to the LNG Storage Tanks (ABJ691810/20).

Liquid hydraulic turbines are used to recover energy from flashing liquids thus reducing fuel gas consumption. Full-capacity bypass with pressure reducing valves (J-T valves) will be provided to ensure continuous operation in case the turbine trips and has to be taken out of service.

LNG properties at the outlet of the LNG Hydraulic Turbine are shown in Table 13.10.1.

TABLE 13.10.1

LNG Properties at the LNG Hydraulic Turbine

Feed Gas Case	Case 1 Average Gas, Winter Ambient	Case 2 Average Gas, Average Ambient	Case 3 Average Gas, High Ambient	Case 4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Ship Loading Average Gas Average Ambient
Mol wt	17.65	17.65	17.65	17.62	17.49	17.64
HHV British thermal units per standard cubic foot	1,087	1,087	1,087	1,086	1,074	1,084
Total Phase Mole Fraction						
Nitrogen	0.7653	0.7653	0.7653	0.6931	1.0145	0.8935
CO2	0.0050	0.0050	0.0050	0.0050	0.0052	0.0049
H2S	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Methane	91.1332	91.1334	91.1345	90.9599	92.4781	91.1398
Ethane	5.7663	5.7663	5.7664	6.2515	4.1853	5.6720
Propane	1.9748	1.9748	1.9749	1.9107	1.7418	1.9413
Isobutane	0.1341	0.1341	0.1341	0.0683	0.2356	0.1318
Butane	0.1751	0.1751	0.1751	0.1024	0.2573	0.1721
Isopentane	0.0267	0.0302	0.0276	0.0047	0.0610	0.0295
Pentane	0.0171	0.0134	0.0148	0.0020	0.0192	0.0126
Neopentane	0.0005	0.0005	0.0005	0.0005	0.0003	0.0005
C6+	0.0001	0.0002	0.0000	0.0001[b]	0.0000[c]	0.0002
Aromatics	0.0001	0.0001	0.0001	0.0001	0.0000	0.0001
Water	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	0.0010	0.0010	0.0010	0.0010	0.0010	0.0011
Organic Sulfides[a]	0.0004	0.0004	0.0004	0.0003	0.0005	0.0004

Notes:

[a] Organic Sulfides include methyl and ethyl mercaptans, dimethyl sulfide, carbon disulfide, and carbonyl sulfide.

[b] C6+ plus C6+ Pseudo components. C6+ Pseudo Components include C6 Pseudo, C7 Pseudo, C8 Pseudo, C9 Pseudo and C10 Pseudo Components.

[c] C6+ plus C6+ Pseudo components. C6+ Pseudo Components include PTU C6*, PTU C7*, PTU C8*, PTU C9* Components.

[d] For pseudo components characterization, refer to Design Basis - Liquefaction and Refrigeration System, document number USAL-CB-PBDES-00-000006-000 included in Appendix C.

13.10.1.1 LNG Product Transfer Pumps Type

There are no LNG Product Transfer Pumps. LNG exiting the Hydraulic Turbine is set directly to the LNG Storage Tanks.

13.10.1.2 Number of LNG Product Transfer Pumps, Operating and Spare

Not Applicable. There is one Hydraulic Turbine in each train.

13.10.1.3 LNG Product Transfer Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), gpm

Feed Gas Case	Case 1 Average Gas, Winter Ambient	Case 2 Average Gas, Average Ambient	Case 3 Average Gas, High Ambient	Case 4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Ship Loading Average Gas Average Ambient
Flow rate, gallon per minute	7,985	7,761	7,306	7,757	7,637	7,945

13.10.1.4 LNG Product Transfer Operating and Design Suction Pressures (minimum/NPSH, normal/rated, maximum), psig

The LNG Product Suction Pressure into the Hydraulic Turbine is the same as the Main Heat Exchanger Outlet Pressure (presented in Section 13.9.4.10)

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Normal Pressure, psig	638	635	656	628	638	631

13.10.1.5 LNG Product Transfer Operating and Design Suction Temperatures (minimum, normal, maximum), °F

The LNG Product Suction Temperature into the Hydraulic Turbine is the same as the Main Heat Exchanger Outlet Temperature (presented in Section 13.9.4.11)

	Case 1 Average Gas Winter Ambient	Case 2 Average Gas Average Ambient	Case 3 Average Gas High Ambient	Case-4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Average Gas Average Ambient Loading Mode
Normal Temp, °F	-246	-245	-244	-245	-248	-244

13.10.1.6 LNG Product Transfer Operating and Design Discharge Pressures (minimum, normal/rated, maximum/shutoff), psig

Feed Gas Case	Case 1 Average Gas, Winter Ambient	Case 2 Average Gas, Average Ambient	Case 3 Average Gas, High Ambient	Case 4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Ship Loading Average Gas Average Ambient
Temp, °F	-247	-246	-245	-246	-249	-245
Press, pounds per square inch gauge	120	120	120	120	120	120

13.10.1.7 LNG Product Transfer Operating and Design Discharge Temperatures (minimum, normal, maximum), °F

Feed Gas Case	Case 1 Average Gas, Winter Ambient	Case 2 Average Gas, Average Ambient	Case 3 Average Gas, High Ambient	Case 4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Ship Loading Average Gas Average Ambient
Temp, °F	-247	-246	-245	-246	-249	-245

13.10.1.8 LNG Product Transfer Operating and Design Densities (minimum, normal/rated, maximum), specific gravity

The design specific gravity for the LNG Hydraulic Turbine is 0.45.

13.10.1.9 LNG Flash Vessel Operating and Design Inlet Pressures (minimum, normal, maximum), psig

Not Applicable.

13.10.1.10 LNG Flash Vessel Operating and Design Inlet Temperatures (minimum, normal, maximum), °F

Not Applicable.

13.10.1.11 LNG Flash Vessel Operating and Design Outlet Pressures (minimum, normal, maximum), psig

Not Applicable.

13.10.1.12 LNG Flash Vessel Operating and Design Outlet Temperatures (minimum, normal, maximum), °F

Not Applicable.

13.10.1.13 Flash Gas Compressor Operating and Design Flow Rate Capacities (minimum, normal, maximum), MMscfd

Not Applicable.

13.10.1.14 Gas Compressor Operating and Design Suction Pressures (minimum, normal, maximum), psig

Not Applicable.

13.10.1.15 Flash Gas Compressor Operating and Design Suction Temperatures (minimum, normal, maximum), °F

Not Applicable.

13.10.1.16 Flash Gas Compressor Operating and Design Discharge Pressures (minimum, normal, maximum/shutoff), psig

Not Applicable.

13.10.1.17 Flash Gas Compressor Operating and Design Outlet Temperatures (minimum, normal, maximum), °F

Not Applicable.

13.10.1.18 LNG Product Transfer Startup and Operation

Description of the rundown line cooldown and startup operations is discussed in Section 13.9.4.20.

13.10.1.19 LNG Product Transfer Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.10.1.20 LNG Product Transfer Basic Process Control Systems

The transfer system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.10.1.21 LNG Product Transfer Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the vapor handling operation as described in Appendix 13.E.5 and 13.N.1.

13.10.1.22 LNG Product Transfer Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogens can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.10.1.23 LNG Product Transfer Other Safety Features

The Liquefaction Facility will use PiP technology, composed of an inner pipe of Invar (36 percent Ni), wrapped in insulating blankets and insulating spacers, and an outer pipe of 304 Stainless Steel for the LNG rundown lines which run from the liquefaction processing trains to each of the two LNG Storage Tanks. The annular space between the inner and outer pipe will be maintained at a sub-atmospheric or near-vacuum pressure which will inhibit the ability for LNG to remain in liquid form should a crack in the inner pipe occur. The outer 304 Stainless Steel pipe will be designed to the same pressure as the inner pipe and a leak detection system will be installed to advise in the event that the inner pipe lost containment. Further features may be added during detailed design.

13.10.2 LNG Rundown Properties to the LNG Storage Tanks

The net LNG flowrate and properties in the LNG Storage Tanks are shown in Table 13.10.2. The flowrates indicated will be 50 percent of the maximum flowrate from all three trains (e.g., the assumption is that 50 percent of the flow goes to the tank).

TABLE 13.10.2

LNG Net in Tank Properties

Feed Gas Case	**Case 1 Average Gas, Winter Ambient**	**Case 2 Average Gas, Average Ambient**	**Case 3 Average Gas, High Ambient**	**Case 4 100% PBU Average Ambient**	**Case 5 100% PTU Average Ambient (single train)**	**Case 6 Ship Loading Average Gas Average Ambient**
Temp, °F	-258	-258	-258	-258	-259	-258
Press, pounds per square inch gauge	0.7	0.7	0.7	0.7	0.7	0.7
Flow rate, gallon per minute	11,244	10,856	10,189	10,838	3,609	11,037
Mol wt	17.68	17.68	17.65	17.62	17.49	17.64
HHV British thermal units per standard cubic foot	1,095	1,096	1,100	1,095	1,083	1,095
Total Phase Mole Fraction						

TABLE 13.10.2

LNG Net in Tank Properties

Feed Gas Case	Case 1 Average Gas, Winter Ambient	Case 2 Average Gas, Average Ambient	Case 3 Average Gas, High Ambient	Case 4 100% PBU Average Ambient	Case 5 100% PTU Average Ambient (single train)	Case 6 Ship Loading Average Gas Average Ambient
Nitrogen	0.3298	0.3261	0.3052	0.2898	0.4763	0.3660
CO2	0.0053	0.0053	0.0053	0.0053	0.0055	0.0052
H2S	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Methane	91.1484	91.1434	91.1138	90.9092	92.7136	91.1564
Ethane	6.0655	6.0715	6.1087	6.5917	4.3799	6.0306
Propane	2.0775	2.0795	2.0923	2.0148	1.8229	2.0705
Isobutane	0.1410	0.1412	0.1420	0.0720	0.2466	0.1406
Butane	0.1842	0.1843	0.1855	0.1080	0.2692	0.1836
Isopentane	0.0281	0.0283	0.0292	0.0049	0.0639	0.0315
Pentane	0.0179	0.0180	0.0157	0.0021	0.0201	0.0134
Neopentane	0.0005	0.0005	0.0005	0.0005	0.0003	0.0005
C6+	0.0001	0.0002	0.0000	0.0002[b]	0.0000[c]	0.0002
Aromatics	0.0000	0.0001	0.0000	0.0000	0.0000	0.0001
Water	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	0.0008	0.0008	0.0008	0.0008	0.0008	0.0007
Organic Sulfides[a]	0.0004	0.0004	0.0005	0.0003	0.0004	0.0005

Notes:

[a] Organic Sulfides include methyl and ethyl mercaptans, dimethyl sulfide, carbon disulfide, and carbonyl sulfide.

[b] C6+ plus C6+ Pseudo components. C6+ Pseudo Components include C6 Pseudo, C7 Pseudo, C8 Pseudo, C9 Pseudo and C10 Pseudo Components.

[c] C6+ plus C6+ Pseudo components. C6+ Pseudo Components include PTU C6*, PTU C7*, PTU C8*, PTU C9* Components.

[d] For pseudo components characterization, refer to Design Basis - Liquefaction and Refrigeration System, document number USAL-CB-PBDES-00-000006-000 included in Appendix C.

13.11 LNG STORAGE TANKS

13.11.1 LNG Storage Tank Design

The LNG Storage Tanks will be of a full containment design, composed of prestressed concrete primary and secondary wall panels, 9 percent nickel steel primary and secondary tank floors, an aluminum suspended deck, a foundation slab, a floor slab on seismic isolation, and a reinforced concrete outer tank dome roof. The primary and secondary concrete wall panels will have a carbon steel backing that acts as a non-load bearing vapor barrier. Insulation materials will be installed between the inner and outer tanks to minimize heat gain from the atmosphere to the inner tank contents. The tank structure will be designed to withstand a sustained wind of 150 miles per hour or 183 miles per hour basic 3-second gust wind speed.

The tank dimensions are be depicted in the drawings included in Appendix 13.L.2. The LNG Tank Specification (AKLNG-4030-MMM-SPC-DOC-00002) is included in Appendix 13.L.1.

Inner Tank

- 350-foot average inside diameter
- 100-foot inner wall panel height

Outer Tank

- 361 foot inside diameter, 366 foot outside diameter
- 104 foot outer wall panel height
- 168 foot from top of foundation slab to top of dome roof

The inner tank contains the hydrostatic pressure exerted by the LNG. The outer tank contains the vapor pressure and protects the tank insulation materials from the environment. The concrete outer tank will also be the secondary impoundment to confine the LNG in the unlikely event of a leak from the inner tank.

All process piping connections (for filling, emptying and BOG, etc.) for the tanks will be through the roof. There will be no penetrations through either the wall or bottom of either the primary (inner) or secondary (outer) prestressed concrete tanks.

13.11.1.1 LNG Storage Tank Type (Above Ground, Below Ground, Single, Double, Full, Membrane, Etc.)

Full Containment Prestressed Concrete Inner Tank, Prestressed Concrete Outer (with Reinforced Concrete Roof).

13.11.1.2 Number of LNG Storage Tanks

Two storage tanks.

13.11.1.3 LNG Storage Tank Foundation Type

The storage tank foundation will consist of a seismically isolated double concrete slab supported on structural fill. The two reinforced concrete slabs will be separated by plinths that rest on friction pendulum isolators. (Seismic isolation will be required due to nearby faults and high accelerations for OBE and SSE cases.) The double slab foundation provides an air gap that will eliminate the need for foundation heating.

13.11.1.4 LNG Storage Tank Insulation Systems

The primary container consists of 34-inch foam glass load bearing blocks. The high loads at the inner tank shell resulting from the shell weight will be carried by a reinforced precast concrete bearing ring supported by the insulation. Higher grade load bearing blocks will be used under the bearing ring.

A leveling course will be provided between the primary container's insulation and the secondary container's tank floor plate. The secondary container's floor plate will be supported by the upper base concrete slab.

Expanded perlite fills the 3-feet 8-inches wide annular space between the inner tank and the outer tank wall. Due to the performance of the concrete wall system, the expanded perlite does not require the addition of a resilient fiberglass blanket.

An important consideration for the installation of the perlite in the annular space will be that the perlite be mechanically vibrated after installation. Vibration will settle the perlite to reduce potential voids or pockets and maximize the insulating value of the system. A reservoir of perlite will be provided at the top of the annular space to compensate for future long-term perlite settlement. Perlite refill nozzles on the tank roof allow for replenishing the perlite, if necessary. Each nozzle will be equipped with a special coupling which allows for refilling during tank operation without vapor leakage.

Insulation on the suspended deck will be composed of 24-inch of fiberglass blanket.

Thermal corner protection will be unnecessary for the sliding-base precast concrete storage tanks.

13.11.1.5 LNG Storage Tanks Operating and Design Capacities (Minimum, Normal, Maximum), gal or m^3

Working capacity of 240,000 cubic meters. Gross Capacity of 259,000 cubic meters, to be confirmed.

13.11.1.6 Storage Tanks Operating and Design Liquid Levels (minimum, normal, maximum), ft

13.11.1.7 LNG Storage Tanks Operating and Design Pressures/Vacuums (minimum, normal, maximum), inH_2O (vacuum) and psig

Design pressure of 3.6 psig and vacuum pressure of -0.15 psig.

13.11.1.8 LNG Storage Tanks Operating and Design Temperatures (minimum, normal, maximum), °F

The LNG Storage Tank has a minimum design temperature of -270 °F, a maximum design temperature of 71 °F. The normal operating temperature is -260 °F.

13.11.1.9 LNG Storage Tanks Operating and Design Densities (minimum, normal, maximum), specific gravity

Specific gravity of 0.45.

13.11.1.10 LNG Storage Tanks Operating and Design Boil-off Rate (minimum, normal, maximum), %-vol per day

No greater than 0.05 weight percent of the maximum liquid capacity per day based on pure methane

13.11.1.11 LNG Storage Tanks Operating and Design Residence Times, days/hours

TBD

13.11.1.12 Hydrotest Water Source

The source of the hydrostatic test-water will either be marine waters withdrawn from Cook Inlet or freshwater supplied by the onsite groundwater wells.

13.11.1.13 Hydrotest Water Specifications and Concentrations, %-vol or ppm- v

If salt water is used, the intake within Cook Inlet will be equipped with a screen and the intake rate reduced as required by permits and to the extent practicable to minimize the potential for entrainment and impingement of marine life. Screened intake will be sized according to permit requirements and agency approval. Similarly, the withdrawal rate of freshwater from the onsite construction wells will be reduced as required by permits and to the extent practicable to reduce the potential for local groundwater drawdown. In advance of filling each tank, the hydrostatic testing water source will be tested to ensure that the water will meet all applicable permit requirements.

13.11.1.14 Hydrotest Water Available Flow Rate, gpm

Hydrostatic testing of each of the two LNG tanks will require approximately 42,000,000 gallons of Cook Inlet seawater over a 14–21-day period. It is estimated that the testing will be sequenced so that test water from the first tank could also be used as test water for the second tank. Freshwater from onsite wells will be used to rinse the tanks after the hydrotest. In advance of filling each tank, the hydrostatic test water source will be tested to ensure that the water will meet applicable permit requirements The LNG storage tanks will be hydrostatically tested in accordance with the requirements of American Petroleum Institute (API) Standard 620. Hydrostatic testing of Liquefaction Facility tanks and non-cryogenic piping will be carried out in accordance with applicable state and federal code and permit requirements. Hydrostatic testing of the LNG tanks will likely occur during the summer of the sixth year of construction.

13.11.1.15 Hydrotest Water Pressure, psig

To be determined in detailed design.

13.11.1.16 Hydrotest Water Discharge/Treatment

At hydrostatic test completion, the water will be tested and discharged in accordance with applicable permits via one of three outfalls into Cook Inlet. No biocides will be added to the test water and hydrostatic testing will likely occur in the warmer months.

13.11.1.17 LNG Storage Tank Startup and Operation

The LNG Storage Tanks will be dried and purged prior to commissioning. Drying will be performed by removing all standing water. The tank will then be purged with dry gaseous nitrogen, vented and monitored until an interior dew point of -26 °F was reached. After the tank has been purged with nitrogen, it will be purged to a combustible gas concentration of no less than 90 percent in preparation for tank cool-down. The tank system has an independent cool-down fill line with spray nozzles designed specifically for cool-down of the LNG storage tank. During the initial introduction of liquid product, it will be important to have uniform cool-down. The primary container temperature gradient between any two adjacent cool-down resistance temperature detectors (RTDs) will not exceed 50 °F and the gradient between any two RTDs will not exceed 100 °F. The cool-down rate for the primary liquid container will be controlled to a maximum average of 9 °F per hour and will not exceed 15 °F per hour during any one-hour period. The cool-down cycle will be deemed complete when 6 inches of product liquid will be measured in the tank

13.11.1.18 LNG Storage Tank Isolation Valves, Drains, and Vents

Height of LNG Storage Tank vent stacks shall be designed to limit incident heat flux from a relief valve fire to a maximum of 10000 Btu/(hr-ft^2) (32 kW/m2) on the concrete roof. The discharge stacks will be designed to prevent water, birds, and insects from affecting the discharge capability.

13.11.1.19 LNG Storage Tank Piping Support System

Tank piping will be routed from the tank roof to grade. The piping system design will account for the effects of two phase flow as determined during process detailed engineering. The support of the piping will use the tank top platform, steel guides attached to steel embedments in the tank shell, and a grade rack/spring support structure. On field-insulated lines, the weight of the vertical pipe may be carried by the top platform or by a sharing of the grade rack/spring support structure and the top platform. The shell supports will be mainly guides for the process lines.

In supporting these lines, cold shoes, insulated shields/bumpers, springs, U-bolts, and a multitude of details will be utilized, as appropriate, in the design as determined by the calculated loads and movements.

13.11.1.20 LNG Storage Tank Basic Process Control Systems

13.11.1.20.1 LNG Storage Tank Cooldown Sensors

The following cool-down sensors will be provided:

- Four Resistance Temperature Detectors (RTDs) on the inner tank bottom, within 3-feet of the tank steel plate floor. These will be located approximately 90 degrees apart and used for the purpose of indicating when the bottom has approached cool-down;
- Multi spot RTD bundle with individual RTDs located along the inner tank height;
- One RTD in the gas return line near where the cold gas leaves the inner vessel; and
- Two RTDs mounted in the dome space 180 degrees apart.

The LNG Storage Tanks will be designed for initial cool-down using LNG.

13.11.1.20.2 LNG Storage Tank Level Control

Tank level gauging and overfill protection will consist of two servo-type level gauges equipped with stilling wells and one high-level detection probe with cut-off switch. In addition, the tank will be supplied with one level, temperature, and density gauge to monitor stratification of the tank contents.

13.11.1.20.3 LNG Storage Tank Pressure Control

Two-gauge pressure transmitters and one absolute pressure transmitter will be provided. Separate pressure taps will also be provided into each of the servo gauges to use pressure transmitters as safety-related instrumentation.

13.11.1.20.4 LNG Storage Tank Density/Rollover Control

Level, temperature, and density gauges will be provided to monitor LNG density within the tank. They will send the level, temperature, and density data to the Tank Management System. The Tank Management System software will compute the density variations along the product height inside the tank. An alarm, indicating any potential density stratification inside the tank, will prompt the operator to mitigate the density stratification by mixing the tank contents from the bottom to the top of the tank. Preventive measures will be adopted in the tank design and operation to prevent the occurrence of rollover. These will include:

- A gas chromatograph to monitor the density of LNG being produced;
- Level, temperature, and density instruments to monitor LNG density within the tank;
- Selective filling of the tank by means of either the top or bottom fill lines based on relative densities of the LNG being produced and that will be present in the tank. (Note that, unlike a receiving terminal's tank, the contents of these tanks will be less subject to rapid density changes.); and
- Mixing of the tank contents from the bottom to the top by means of the in-tank pumps and the top fill line, as required.

13.11.1.21 LNG Storage Tank Safety Instrumented Systems

13.11.1.21.1 LNG Storage Tank Overfill Protection

Tank level gauging and overfill protection will consist of two servo-type level gauges equipped with stilling wells and one high-level detection probe with cut-off switch. In addition, the tank will be supplied with one level, temperature, and density gauge to monitor stratification of the tank contents.

13.11.1.21.2 LNG Storage Tank Overpressure Protection

Safety measures to protect the LNG storage tanks against vacuum and overpressure scenarios are included in the tank design.

13.11.1.22 LNG Storage Tank Relief Valves and Discharge

13.11.1.22.1 Calculations for Sizing Pressure and Vacuum Relief Valves

The pressure relief valves internal piping will penetrate through the tank roof and suspended deck. The pressure relief valves will be pilot operated using a pilot line penetrating the dome roof. The discharge of each pressure relief valve will be directed to an atmospheric vent stack with an angled discharge to limit rain and snow ingress yet allow full discharge flow. .

Pressure relief valve calculation will be in accordance with API 625 and NFPA 59A. The pressure relief valve sizing is often governed by the requirements of NFPA 59A Section 4.7.3.2 for 3 percent of the full tank contents in 24 hours.

The vacuum relief valve sizing will be based on a combination of maximum liquefied natural gas withdrawal by the in-tank pumps, maximum vapor withdrawal by the BOG compressors, and barometric pressure rise.

Isolation valves will be provided beneath each relief valve to facilitate maintenance.

13.11.1.23 LNG Storage Tank Impoundment System

13.11.1.23.1 LNG Storage Tank Containment

Prestressed Concrete Outer Tank

13.11.1.23.2 LNG Storage Tank Roof Spill Containment and Protection

For concrete roofs, contact with cryogenic liquid from a leak (generally of limited duration) will not be considered to have any impact on structural integrity. Local spalling could occur, but this will be repairable. With regard to the steel platforms, some risk of structural damage can be tolerated provided the structure will not collapse from the loss of any single, primary load bearing member. Liquid spilled on the roof will be directed, with the use of concrete curbing on the roof, to a stainless steel down-comer pipe running from the top to the bottom of the tank. The stainless steel downcomer pipe will then direct the liquid to the spill containment trench at the base of the tank for direction to the spill impoundment.

13.11.1.24 LNG Storage Tank Other Safety Features

13.11.1.24.1 LNG Storage Tank Leak Detection Instrumentation

Four RTDs at 90-degree intervals in the bottom of the annular space (secondary bottom) will be supplied for leak detection. Two additional RTDs will be installed notionally within the first 30 feet of the secondary wall facing the annular space. Low temperature alarms will alert operators of an inner tank breach.

13.11.1.24.2 Foundation Frost Heave Mitigation (Heaters Temperature Detection)

The double slab foundation provides an air gap which eliminates the need for foundation heating.

13.11.1.24.3 Design for Seismic Loads

The three seismic levels NFPA 59A (2006) required for the tank design are the OBE, SSE, and ALE. The OBE spectrum is defined as ground motions that have a 475-year return period, or 10 percent probability of exceedance in a 50-year period. The SSE is equivalent to the MCE described in ASCE 7 (2005). The

MCE is based on ground motions with a 2 percent probability of exceedance in 50 years (2,500-year return period). The ALE ground motion is one-half of the SSE (MCER) ground motions.

A pre-FEED site-specific geotechnical and seismic investigation provided preliminary horizontal and vertical seismic response spectra. From these spectra, it has been determined that the tank must be seismically isolated. The assumed system damping and periods, along with the design horizontal and vertical accelerations, have been listed in Table 13.11.1.24. The horizontal spectra have been reduced to account for the increase in the effective damping for the impulsive forces. For the preliminary design, the damping adjustment factors were calculated using ASCE 41-13 Equation 2-11. Per NFPA 59A (2013), the final response spectra will be provided for expected damping ratios of the isolated structure.

The site specific OBE response spectrum defines the geometric mean ground motions.

The vertical acceleration for each event has been taken as the maximum of one-half times the horizontal spectra with 5 percent damping and the acceleration from the vertical spectra with 5 percent damping while using the breathing period of the tank.

The tank and isolation system will be designed using a dynamic response-history analysis approach as required by API 620 Annex L for seismically isolated structures. The model will incorporate the entire inner and outer tank structures, as well as the liquid contents. The inner and outer tanks seismic design will be conducted in accordance with ACI 376, which includes the effects of restrained (impulsive) and sloshing (convective) liquid.

Load factors and material strength reduction factors for the concrete inner and outer tanks are in accordance with ACI 376 Code guidelines.

TABLE 13.11.1.24

Preliminary Liquefaction Facility Storage Tank Seismic Design Values

Description	Operating Basis Earthquake	Safe Shutdown Earthquake	Aftershock Level Earthquake
Isolated Base Damping Value			
Inner Tank and Impulsive Liquid	[a]	[a]	
Outer Tank – Empty	[a]	[a]	
Outer Tank – Spill			[a]
Convective Liquid	0.5 %	0.5 %	0.5 percent
Isolated Base Period			
Inner Tank Period	3.0 sec	3.5 sec	-
Outer Tank – Empty	3.0 sec	3.5 sec	-
Outer Tank – Spill	-	-	3.5 sec
Sloshing Wave	12.6 sec	12.6 sec	-
Horizontal Acceleration			
Inner Tank and Impulsive Liquid	0.084 g	0.127 g	-
Outer Tank – Empty	0.084 g	0.127 g	-
Outer Tank and Impulsive Liquid	-	-	0.064 g
Convective Liquid	0.018 g	0.032 g	0.016 g

TABLE 13.11.1.24

Preliminary Liquefaction Facility Storage Tank Seismic Design Values

Description	Operating Basis Earthquake	Safe Shutdown Earthquake	Aftershock Level Earthquake
Vertical Acceleration			
Inner Tank and Liquid	0.73 g	0.63 g	-
Outer Tank	0.73 g	0.63 g	-

[a] The damping values for impulsive seismic component are to be determined from isolator testing.

13.12 VAPOR HANDLING

13.12.1 Vapor Handling Design

BOG generated during LNGC loading will be collected into the BOG Header, which also accepts BOG from the LNG Storage Tanks before going into the BOG Compressor Drums (MBD691815/25/35). Any liquids in the BOG Header will be separated and the overheads will be compressed to 470 psig by the three LP and HP BOG Compressors (CAE691841/51/61 and CAE691842/52/62), and then cooled in the BOG Compressor After-Coolers (HFF691843/53/63).

The following Process Flow Diagrams associated with the vapor handling system are included in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPFD-80-000691-002	Process Flow Diagram LNG Storage and Loading System BOG Compressors

The following Piping and Instrumentation Drawings associated with the vapor handling System are included in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPID-80-000691-830	Piping & Instrumentation Diagram LNG Storage and Loading System BOG Compressor Pipework
USAL-CB-PDPID-80-000691-831	Piping & Instrumentation Diagram LNG Storage and Loading System BOG Compressor Suction Drum 1/3
USAL-CB-PDPID-80-000691-832	Piping & Instrumentation Diagram LNG Storage and Loading System BOG Compressor and Aftercooler 1/3
USAL-CB-PDPID-80-000691-861	Piping & Instrumentation Diagram LNG Storage and Loading System BOG Compressor Suction Drum Blowcase

13.12.1.1 Vapor Return Blowers Type

Not applicable.

13.12.1.2 Number of Vapor Return Blowers, Operating and Spare

Not applicable.

13.12.1.3 Vapor Return Blowers Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), lb/hr

Not applicable.

13.12.1.4 Vapor Return Blowers Operating and Design Suction Pressures (minimum, normal/rated, maximum), psig

Not applicable.

13.12.1.5 Vapor Return Blowers Operating and Design Suction Temperatures (minimum, normal, maximum), °F

Not applicable.

13.12.1.6 Vapor Return Blowers Operating and Design Discharge Pressures (minimum, normal/rated, maximum/shutoff), psig

Not applicable.

13.12.1.7 Vapor Return Blowers Operating and Design Discharge Temperatures (minimum, normal, maximum), °F

Not applicable.

13.12.1.8 Boil-off Gas (BOG) Low Pressure Compressors Type

Low pressure compressor is in series with high pressure compressor. Refer to the BOG High Pressure Compressor for relevant information.

13.12.1.9 Number of BOG Low Pressure Compressors, Operating and Spare

Low pressure compressor is in series with high pressure compressor. Refer to the BOG High Pressure Compressor for relevant information.

13.12.1.10 BOG Low Pressure Compressors Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), lb/hr

Low pressure compressor is in series with high pressure compressor. Refer to the BOG High Pressure Compressor for relevant information.

13.12.1.11 BOG Low Pressure Compressors Operating and Design Suction pressures (minimum, normal/rated, maximum), psig

Low pressure compressor is in series with high pressure compressor. Refer to the BOG High Pressure Compressor for relevant information.

13.12.1.12 BOG Low Pressure Compressors Operating and Design Suction temperatures (minimum, normal, maximum), °F

Low pressure compressor is in series with high pressure compressor. Refer to the BOG High Pressure Compressor for relevant information.

13.12.1.13 BOG Low Pressure Compressors Operating and Design Discharge Pressures (minimum, normal/rated, maximum/shutoff), psig

Low pressure compressor is in series with high pressure compressor. Refer to the BOG High Pressure Compressor for relevant information.

13.12.1.14 BOG Low Pressure Compressors Operating and Design Discharge temperatures (minimum, normal, maximum), °F

Low pressure compressor is in series with high pressure compressor. Refer to the BOG High Pressure Compressor for relevant information.

13.12.1.15 BOG High Pressure Compressors Type

The vapor handling system is common to the entire facility. The vapor return handling system consists of a LP centrifugal compressor and HP centrifugal compressor in series on a common variable frequency driver.

13.12.1.16 Number of BOG High Pressure Compressors, Operating and Spare

There are three LP/HP compressor units sized such that two units are sufficient to handle holding mode vapor loads. All three machines will be operating during loading at full design rate.

13.12.1.17 BOG High Pressure Compressors Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), lb/hr

		Minimum Operating/Design Flow Rate Capacity (lb/hr)	Operating/Design Flow Rate Capacity (lb/hr)	Maximum Operating/Design Flow Rate Capacity (lb/hr)
CAE691841/2	LP/HP BOG Compressor 1	24,131/--	144,224/--	148,918/--
CAE691851/2	LP/HP BOG Compressor 2	24,131/--	144,224/--	148,918/--
CAE691861/2	LP/HP BOG Compressor 3	24,131/--	144,224/--	148,918/--

13.12.1.18 BOG High Pressure Compressors Operating and Design Suction Pressures (minimum, normal/rated, maximum), psig

		Minimum Operating/Design Suction Pressure (psig)	Operating/Design Suction Pressure (psig)	Maximum Operating/Design Suction Pressure (psig)
CAE691841/2	LP/HP BOG Compressor 1	--/--	0.7/--	--/3.6
CAE691851/2	LP/HP BOG Compressor 2	--/--	0.7/--	--/3.6
CAE691861/2	LP/HP BOG Compressor 3	--/--	0.7/--	--/3.6

13.12.1.19 BOG High Pressure Compressors Operating and Design Suction Temperatures (minimum, normal, maximum), °F

		Minimum Operating/Design Suction Temperature (°F)	Operating/Design Suction Temperature (°F)	Maximum Operating/Design Suction Temperature (°F)
CAE691841/2	LP/HP BOG Compressor 1	--/-274	-258/--	-238/--
CAE691851/2	LP/HP BOG Compressor 2	--/-274	-258/--	-238/--
CAE691861/2	LP/HP BOG Compressor 3	--/-274	-258/--	-238/--

13.12.1.20 BOG High Pressure Compressors Operating and Design Discharge Pressures (minimum, normal/rated, maximum/shutoff), psig

		Minimum Operating/Design Discharge Pressure (psig)	Operating/Design Discharge Pressure (psig)	Maximum Operating/Design Discharge Pressure (psig)
CAE691841/2	LP/HP BOG Compressor 1	0/--	487/--	--/595
CAE691851/2	LP/HP BOG Compressor 2	0/--	487/--	--/595
CAE691861/2	LP/HP BOG Compressor 3	0/--	487/--	--/595

13.12.1.21 BOG High Pressure Compressors Operating and Design Discharge Temperatures (minimum, normal, maximum), °F

		Minimum Operating/Design Discharge Temperature (°F)	Operating/Design Discharge Temperature (°F)	Maximum Operating/Design Discharge Temperature (°F)
CAE691841/2	LP/HP BOG Compressor 1	136/--	169/--	214/482
CAE691851/2	LP/HP BOG Compressor 2	136/--	169/--	214/482
CAE691861/2	LP/HP BOG Compressor 3	136/--	169/--	214/482

13.12.1.22 Vapor Handling Startup and Operation

13.12.1.22.1 Vapor Return Blowers To or From the LNG Vessel

Not applicable.

13.12.1.22.2 BOG Low Pressure Compression

Low pressure compressor is in series with high pressure compressor. Refer to the BOG High Pressure Compressor for relevant information.

13.12.1.22.3 BOG High Pressure Compression, Including BOG Holding Mode Compression to Pipeline

The BOG Low and High Compressors pressurize natural gas generated from heat leak in the storage tanks, LNG rundown and loading lines, pump energy during the LNG pump operation and vapor return from the LNG ship during ship loading mode. After passing through the BOG Compressor Suction Drum, All sources pass head to the BOG compressor. The gas is compressed and cooled prior to going to the HP Fuel Gas system for consumption in the Turbine Drivers or the Regeneration Gas Heater. This system cannot reinject gas back into the supply pipeline.

13.12.1.22.4 BOG Utilization

The BOG system has two primary modes of operation. During holding mode (no ship loading), two BOG Compressor units are sufficient to handle the normal vapor loads from the LNG storage tanks and flash from the LNG rundown. During ship loading, all three units are required to manage the vapor load on the system.

13.12.1.23 Vapor Handling Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.12.1.24 Vapor Handling Basic Process Control Systems

The vapor handling system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.12.1.25 Vapor Handling Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the vapor handling operation as described in Appendix 13.E.5 and 13.N.1.

13.12.1.26 Vapor Handling Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogens can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.12.1.27 Vapor Handling Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.12.2 Boil-off Gas (BOG) Re-Condensation Design

13.12.2.1 BOG Recondenser Type

Not applicable.

13.12.2.2 Number of BOG Recondensers, Operating and Spare

Not applicable.

13.12.2.3 BOG Recondensers Operating and Design Inlet Flow Rate Capacities (minimum, normal/rated, maximum), lb/hr

Not applicable.

13.12.2.4 BOG Recondensers Operating and Design Inlet Pressures (minimum, normal/rated, maximum), psig

Not applicable.

13.12.2.5 BOG Recondensers Operating and Design Inlet Temperatures (minimum, normal, maximum), °F

Not applicable.

13.12.2.6 BOG Recondensers Operating and Design Outlet Flow Rate Capacities (minimum, normal/rated, maximum), lb/hr

Not applicable.

13.12.2.7 BOG Recondensers Operating and Design Outlet Pressures (minimum, normal/rated, maximum), psig

Not applicable.

13.12.2.8 BOG Recondensers Operating and Design Outlet Temperatures (minimum, normal, maximum), °F

Not applicable.

13.12.2.9 BOG Recondenser Startup and Operation

13.12.2.9.1 Minimum Sendout Rate for Recondensation

Not applicable.

13.12.2.9.2 BOG Recondensation

Not applicable.

13.12.2.10 BOG Recondenser Isolation Valves, Drains, and Vents

Not applicable.

13.12.2.11 BOG Recondenser Basic Process Control Systems

Not applicable.

13.12.2.12 BOG Recondenser Safety Instrumented Systems

Not applicable.

13.12.2.13 BOG Recondenser Relief Valves and Discharge

Not applicable.

13.12.2.14 BOG Recondenser Other Safety Features

Not applicable.

13.13 LNG PUMPS

13.13.1 LNG Tank/Low Pressure (LP) Pump Design

The storage and loading system is capable of loading a single LNG ship at a rate of 12,500 m^3/hr. This rate can be delivered to either loading berth but not simultaneously to both. In addition, this loading is not interrupted by, nor does it interrupt, the production of LNG being sent to the storage tanks. Seven of the LNG Loading & Circulating Pumps (PBA691811/12/13/14/21/22/23/24) transfer LNG from the LNG storage tanks to the LNG ship at a loading rate of 12,500 m^3/hr at a ship manifold delivery pressure of 44 psia. There will be two loading berths at the Facility, each equipped with two 16” LNG liquid loading arms (FAY691871/72/81/82), one 16” hybrid loading arm (FAY691874/84) and one 16” vapor return arm (FAY691873/83).

The following Process Flow Diagrams associated with the LNG LP pumps are included in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPFD-80-000691-001	Process Flow Diagram LNG Storage and Loading System Storage Tanks

The following Piping and Instrumentation Drawings associated with the LNG LP pumps are included in Appendix 13.E.

Drawing Number	Description

USAL-CB-PDPID-80-000691-801	Piping & Instrumentation Diagram LNG Storage and Loading System LNG Storage Pipework ABJ691810
USAL-CB-PDPID-80-000691-802	Piping & Instrumentation Diagram LNG Storage and Loading System LNG Storage - 1/3 ABJ691810
USAL-CB-PDPID-80-000691-803	Piping & Instrumentation Diagram LNG Storage and Loading System LNG Storage - 2/3 ABJ691810
USAL-CB-PDPID-80-000691-804	Piping & Instrumentation Diagram LNG Storage and Loading System LNG Storage - 4/3 ABJ691810
USAL-CB-PDPID-80-000691-820	Piping & Instrumentation Diagram LNG Storage and Loading System LNG Storage Tanks Common Pipework
USAL-CB-PDPID-80-000691-821	Piping & Instrumentation Diagram LNG Storage and Loading System Loading Pipework - Shore
USAL-CB-PDPID-80-000691-822	Piping & Instrumentation Diagram LNG Storage and Loading System Loading Pipework - Trestle

13.13.1.1 LNG tank/LP Pumps Type

The LNG loading pumps are submerged motor-type centrifugal pumps and located in pump wells within the LNG storage tanks. Each LNG Storage Tank is provided with a spare pump well.

13.13.1.2 Number of LNG tank/LP pumps, operating and spare

Each tank has four pumps in-tank within individual pumps wells. Seven of the LNG pumps are needed to reach the maximum load rate and therefore, one pump is an installed spare. Additionally, each tank has a spare pump well.

13.13.1.3 LNG tank/LP pumps operating and design flow rate capacities (minimum, normal/rated, maximum), gpm

		Minimum Operating/Design Flow Rate (gpm)	Operating/Design Flow Rate (gpm)	Maximum Operating/Design Flow Rate (gpm)
PBA691811	LNG Loading & Circulating Pump	--/--	7,925/--	--/--
PBA691812	LNG Loading & Circulating Pump	--/--	7,925/--	--/--
PBA691813	LNG Loading & Circulating Pump	--/--	7,925/--	--/--
PBA691814	LNG Loading & Circulating Pump	--/--	7,925/--	--/--
PBA691821	LNG Loading & Circulating Pump	--/--	7,925/--	--/--
PBA691822	LNG Loading & Circulating Pump	--/--	7,925/--	--/--
PBA691823	LNG Loading & Circulating Pump	--/--	7,925/--	--/--
PBA691824	LNG Loading & Circulating Pump	--/--	7,925/--	--/--

13.13.1.4 LNG tank/LP pumps operating and design suction pressures (minimum/NPSH, normal/rated, maximum), psig

		Minimum Operating/Design	Operating/Design Suction Pressure (psig)	Maximum Operating/Design

		Suction Pressure (psig)		Suction Pressure (psig)
PBA691811	LNG Loading & Circulating Pump	--/--	0.7/--	--/3.6
PBA691812	LNG Loading & Circulating Pump	--/--	0.7/--	--/3.6
PBA691813	LNG Loading & Circulating Pump	--/--	0.7/--	--/3.6
PBA691814	LNG Loading & Circulating Pump	--/--	0.7/--	--/3.6
PBA691821	LNG Loading & Circulating Pump	--/--	0.7/--	--/3.6
PBA691822	LNG Loading & Circulating Pump	--/--	0.7/--	--/3.6
PBA691823	LNG Loading & Circulating Pump	--/--	0.7/--	--/3.6
PBA691824	LNG Loading & Circulating Pump	--/--	0.7/--	--/3.6

13.13.1.5 LNG tank/LP pumps operating and design suction temperatures (minimum, normal, maximum), °F

		Minimum Operating/Design Suction Temperature (°F)	Operating/Design Suction Temperature (°F)	Maximum Operating/Design Suction Temperature (°F)
PBA691811	LNG Loading & Circulating Pump	--/--	-258/--	--/--
PBA691812	LNG Loading & Circulating Pump	--/--	-258/--	--/--
PBA691813	LNG Loading & Circulating Pump	--/--	-258/--	--/--
PBA691814	LNG Loading & Circulating Pump	--/--	-258/--	--/--
PBA691821	LNG Loading & Circulating Pump	--/--	-258/--	--/--
PBA691822	LNG Loading & Circulating Pump	--/--	-258/--	--/--
PBA691823	LNG Loading & Circulating Pump	--/--	-258/--	--/--
PBA691824	LNG Loading & Circulating Pump	--/--	-258/--	--/--

13.13.1.6 LNG tank/LP pumps operating and design discharge pressures (minimum, normal/rated, maximum/shutoff), psig

		Minimum Operating/Design Discharge Pressure (psig)	Operating/Design Discharge Pressure (psig)	Maximum Operating/Design Discharge Pressure (psig)
PBA691811	LNG Loading & Circulating Pump	--/--	94.6 /300	--/--
PBA691812	LNG Loading & Circulating Pump	--/--	94.6 /300	--/--
PBA691813	LNG Loading & Circulating Pump	--/--	94.6 /300	--/--
PBA691814	LNG Loading & Circulating Pump	--/--	94.6 /300	--/--
PBA691821	LNG Loading & Circulating Pump	--/--	94.6 /300	--/--
PBA691822	LNG Loading & Circulating Pump	--/--	94.6 /300	--/--
PBA691823	LNG Loading & Circulating Pump	--/--	94.6 /300	--/--
PBA691824	LNG Loading & Circulating Pump	--/--	94.6 /300	--/--

13.13.1.7 LNG tank/LP pumps operating and design discharge temperatures (minimum, normal, maximum), °F

		Minimum Operating/Design Discharge Temperature (°F)	Operating/Design Discharge Temperature (°F)	Maximum Operating/Design Discharge Temperature (°F)
PBA691811	LNG Loading & Circulating Pump	-259/-274	-257/--	--/150
PBA691812	LNG Loading & Circulating Pump	-259/-274	-257/--	--/150
PBA691813	LNG Loading & Circulating Pump	-259/-274	-257/--	--/150
PBA691814	LNG Loading & Circulating Pump	-259/-274	-257/--	--/150
PBA691821	LNG Loading & Circulating Pump	-259/-274	-257/--	--/150
PBA691822	LNG Loading & Circulating Pump	-259/-274	-257/--	--/150
PBA691823	LNG Loading & Circulating Pump	-259/-274	-257/--	--/150
PBA691824	LNG Loading & Circulating Pump	-259/-274	-257/--	--/150

13.13.1.8 LNG Tank/LP Pumps operating and design densities (minimum, normal/rated, maximum), specific gravity

		Minimum Operating/Design Density (sp. gr.)	Operating/Design Density (sp. gr.)	Maximum Operating/Design Density (sp. gr.)
PBA691811	LNG Loading & Circulating Pump	0.45/--	0.46/--	--/--
PBA691812	LNG Loading & Circulating Pump	0.45/--	0.46/--	--/--
PBA691813	LNG Loading & Circulating Pump	0.45/--	0.46/--	--/--
PBA691814	LNG Loading & Circulating Pump	0.45/--	0.46/--	--/--
PBA691821	LNG Loading & Circulating Pump	0.45/--	0.46/--	--/--
PBA691822	LNG Loading & Circulating Pump	0.45/--	0.46/--	--/--
PBA691823	LNG Loading & Circulating Pump	0.45/--	0.46/--	--/--
PBA691824	LNG Loading & Circulating Pump	0.45/--	0.46/--	--/--

13.13.1.9 LNG tank/LP pumps startup and operation

13.13.1.9.1 LNG pump to marine transfer (LNG carrier, LNG barge, etc.)

The LP pumps are used to transfer LNG from the LNG Storage Tanks to one or both of the LNG berths via two loading arms and a hybrid arm. The operation is monitored from the Central Control Room, Marine Terminal Building and onboard the vessel.

13.13.1.9.2 LNG pump to sendout for vaporization

Not applicable.

13.13.1.9.3 LNG pump minimum flow recycle

The LNG pumps in each tank are protected by a minimum flow recycle header that returns to the LNG Storage Tank.

13.13.1.9.4 LNG pump recirculation to marine transfer

The pump recycle piping enables the loading pumps to return liquid into the tank to maintain minimum flow or to allow circulation around the loading lines to maintain pipework at cryogenic temperatures.

13.13.1.9.5 LNG pump recirculation to sendout for vaporization

Not applicable.

13.13.1.9.6 LNG pump inter tank transfer

The LNG circulation header is used to transfer LNG between the two LNG storage tanks.

13.13.1.10 LNG tank/LP pumps isolation valves, drains, and vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Once in-service, the LNG tank cannot be fully isolated due to natural heat leak into the tank contents. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.13.1.11 LNG tank/LP pumps basic process control systems

The LP pumps shall be remotely operated through the plant DCS or through the Ship to Shore Communications Link System. Plant alarms shall alert operations both onshore and offshore to out of bound conditions set by the equipment manufacturer or EPC. Further information is found in Appendix 13.E.5 and 13.N.1.

13.13.1.11.1 LNG pump flow control

Pump flow control is achieved through the use of the minimum flow recycle and LNG circulation line.

13.13.1.12 LNG tank/LP pumps safety instrumented systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the loading operation as described in Appendix 13.E.5 and 13.N.1.

13.13.1.13 LNG tank/LP pumps relief valves and discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogens can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.13.1.14 LNG tank/LP pumps other safety features

No other safety features have been identified. Further features may be added during detailed design.

13.13.2 LNG Sendout/High Pressure (HP) System Design

Not applicable.

13.13.2.1 LNG HP pumps type

Not applicable.

13.13.2.2 Number of LNG HP pumps, operating and spare

Not applicable.

13.13.2.3 LNG HP Pumps Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), gpm

Not applicable.

13.13.2.4 LNG HP Pumps Operating and Design Suction Pressures (minimum/NPSH, normal/rated, maximum), psig

Not applicable.

13.13.2.5 LNG HP Pumps Operating and Design Suction Temperatures (minimum, normal, maximum), °F

Not applicable.

13.13.2.6 LNG HP Pumps Operating and Design Discharge Pressures (minimum, normal/rated, maximum/shutoff), psig

Not applicable.

13.13.2.7 LNG HP Pumps Operating and Design Discharge Temperatures (minimum, normal, maximum), °F

Not applicable.

13.13.2.8 LNG HP Pumps Operating and Design Densities (minimum, normal, maximum), specific gravity

Not applicable.

13.13.2.9 LNG HP Pumps Startup and Operation

Not applicable.

13.13.2.9.1 LNG Pump to Vaporization

Not applicable.

13.13.2.9.2 LNG Pump Minimum Flow Recycle

Not applicable.

13.13.2.10 LNG HP Pumps Isolation Valves, Drains, and Vents

Not applicable.

13.13.2.11 LNG HP Pumps Basic Process Control Systems

Not applicable.

13.13.2.11.1 LNG HP Pump Flow Control

Not applicable.

13.13.2.12 LNG HP Pumps Safety Instrumented Systems

Not applicable.

13.13.2.13 LNG HP Pumps Relief Valves and Discharge

Not applicable.

13.13.2.14 LNG HP Pumps Other Safety Features

Not applicable.

13.14 LNG TRUCKING

13.14.1 LNG Trucking Design

Not Applicable.

13.14.1.1 Number of LNG trucks unloaded, No. per year

Not Applicable.

13.14.1.2 LNG truck unloaded capacities, gal

Not Applicable.

13.14.1.3 Number of LNG trucks loaded, No. per year

Not Applicable.

13.14.1.4 LNG truck loaded capacities, gal

Not Applicable.

13.14.1.5 Number of LNG truck stations

Not Applicable.

13.14.1.6 LNG truck scales

Not Applicable.

13.14.1.7 LNG truck unloading operating and design flow rate capacities (minimum, normal, maximum), gpm

Not Applicable.

13.14.1.8 LNG truck loading operating and design flow rate capacities (minimum, normal, maximum), gpm

Not Applicable.

13.14.1.9 LNG truck unloading operating and design pressures (minimum, normal, maximum), psig

Not Applicable.

13.14.1.10 LNG truck loading operating and design pressures (minimum, normal, maximum), psig

Not Applicable.

13.14.1.11 LNG truck unloading operating and design temperatures (minimum, normal, maximum), °F

Not Applicable.

13.14.1.12 LNG truck loading operating and design temperatures (minimum, normal, maximum), °F

Not Applicable.

13.14.1.13 LNG truck pumps type

Not Applicable.

13.14.1.14 Number of LNG truck pumps, operating and spare

Not Applicable.

13.14.1.15 LNG Truck Pumps Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), gpm

Not Applicable.

13.14.1.16 LNG Truck Pumps Operating and Design Suction Pressures (minimum/NPSH, normal/rated, maximum), psig

Not Applicable.

13.14.1.17 LNG Truck Pumps Operating and Design Discharge Pressures (minimum, normal/rated, maximum/shutoff), psig

Not Applicable.

13.14.1.18 LNG Truck Pumps Operating and Design Densities (minimum, normal, maximum), specific gravity

Not Applicable.

13.14.1.19 LNG Trucking Startup and Operation

Not Applicable.

13.14.1.19.1 LNG Loading

Not Applicable.

13.14.1.19.2 LNG Unloading

Not Applicable.

13.14.1.19.3 Vapor Handling

Not Applicable.

13.14.1.20 LNG Trucking Piping, Vessel, and Equipment Design and Specifications

Not Applicable.

13.14.1.21 LNG Trucking Isolation Valves, Drains, and Vents

Not Applicable.

13.14.1.22 LNG Trucking Basic Process Control Systems

Not Applicable.

13.14.1.23 LNG Trucking Safety Instrumented Systems

Not Applicable.

13.14.1.24 LNG Trucking Relief Valves and Discharge

Not Applicable.

13.14.1.25 LNG Trucking Other Safety Features

Not Applicable.

13.15 LNG VAPORIZATION

13.15.1 LNG Vaporizers Design

Not Applicable.

13.15.1.1 Emission Design Criteria

Not Applicable.

13.15.1.2 LNG Vaporizers Type

Not Applicable.

13.15.1.3 Number of LNG Vaporizers, Operating and Spare

Not Applicable.

13.15.1.4 LNG Vaporizers Operating and Design Flow Rate Capacities (minimum, normal, maximum), MMscfd

Not Applicable.

13.15.1.5 LNG Vaporizers Operating and Design Heat Duties Each (minimum, rated, maximum), MMBtu/hr

Not Applicable.

13.15.1.6 LNG Vaporizers Operating and Design Pressures (minimum, normal, maximum), psig

Not Applicable.

13.15.1.7 LNG Vaporizers Operating and Design Inlet Temperatures (minimum, normal, maximum), °F

Not Applicable.

13.15.1.8 LNG Vaporizers Operating and Design Outlet Temperatures (minimum, normal, maximum), °F

Not Applicable.

13.15.1.9 LNG Vaporizers Startup and Operation

Not Applicable.

13.15.1.9.1 LNG Vaporizer Heating System

Not Applicable.

13.15.1.9.2 LNG Vaporization

Not Applicable.

13.15.1.10 LNG Vaporizers Isolation Valves, Drains, and Vents

Not Applicable.

13.15.1.10.1 Generated Water Handling/Disposal System

Not Applicable.

13.15.1.11 LNG Vaporizers Basic Process Control Systems

Not Applicable.

13.15.1.12 LNG Vaporizers Safety Instrumented Systems

Not Applicable.

13.15.1.13 LNG Vaporizers Relief Valves and Discharge

Not Applicable.

13.15.1.14 LNG Vaporizers Other Safety Features

Not Applicable.

13.16 HEAT TRANSFER FLUID (HTF) SYSTEM(S)

13.16.1 HTF Storage Design

Not Applicable

13.16.1.1 Number of HTF Trucks, No. per Year

Not Applicable

13.16.1.2 HTF Truck Capacities, gal

Not Applicable

13.16.1.3 Number of HTF Storage Tanks, Operating and Spare

Not Applicable

13.16.1.4 HTF Operating and Design Storage capacities, gal

Not Applicable

13.16.1.5 HTF Operating and Design Storage Pressures (minimum, normal, maximum), psig

Not Applicable

13.16.1.6 HTF Operating and Design Storage Temperatures (minimum, normal, maximum), °F

Not Applicable

13.16.1.7 HTF Operating and Design Residence Times, minutes

Not Applicable

13.16.1.8 HTF System Startup and Operation

Not Applicable

13.16.1.9 HTF System Isolation Valves, Drains, and Vents

Not Applicable

13.16.1.10 HTF System Basic Process Control Systems

Not Applicable

13.16.1.11 HTF System Safety Instrumented Systems

Not Applicable

13.16.1.12 HTF System Relief Valves and Discharge

Not Applicable

13.16.1.13 HTF System Other Safety Features

Not Applicable

13.16.2 HTF Heating System Design

Not Applicable

13.16.2.1 HTF Distribution List and Usage Requirement by Equipment, gpm

Not Applicable

13.16.2.2 Heating Source

Not Applicable

13.16.2.3 HTF Heaters Type

Not Applicable

13.16.2.4 Number of HTF Heaters, Operating and Spare

Not Applicable

13.16.2.5 HTF Heaters Operating and Design Heat Duty/Rate each (minimum, rated, maximum), MMBtu/hr

Not Applicable

13.16.2.6 HTF heaters operating and design pressures (minimum, normal, maximum), psig

Not Applicable

13.16.2.7 HTF Heaters Operating and Design Inlet Temperatures (minimum, normal, maximum), °F

Not Applicable

13.16.2.8 HTF Heaters Operating and Design Outet Temperatures (minimum, normal, maximum), °F

Not Applicable

13.16.2.9 HTF Pumps Type

Not Applicable

13.16.2.10 Number of HTF Pumps, Operating and Spare

Not Applicable

13.16.2.11 HTF Pumps Operating and Design Suction pressures (minimum/NPSH, normal/rated, maximum), psig

Not Applicable

13.16.2.12 HTF Pumps Operating and Design Discharge pressures (minimum, normal/rated, maximum/shutoff), psig

Not Applicable

13.16.2.13 HTF Pumps Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), gpm

Not Applicable

13.16.2.14 HTF Pumps Operating and Design Densities (minimum, normal, maximum), specific gravity

Not Applicable

13.16.2.15 HTF System Startup and Operation

Not Applicable

13.16.2.16 HTF System Isolation Valves, Drains, and Vents

Not Applicable

13.16.2.17 HTF System Basic Process Control Systems

Not Applicable

13.16.2.18 HTF System Safety Instrumented Systems

Not Applicable

13.16.2.19 HTF System Relief Valves and Discharge

Not Applicable

13.16.2.20 HTF System Other Safety Features

Not Applicable

13.17 BTU ADJUSTMENT

13.17.1 Btu Adjustment System Design

The BTU adjustment is performed via the LPG Reinjection System to balance refrigerant demand and condensate stabilization byproducts, while maximizing LNG HHV.

Four streams will be mixed and fed into the LPG Reinjection Cooler (HBG631519). They are:

- Vapor stream from the Deethanizer Reflux Drum (MBD631504);
- Liquid stream from the Deethanizer Reflux Drum (MBD631504), pumped by the Deethanizer Reflux Pump (PBA631516A/B);
- Liquid stream from the Depropanizer Reflux Drum (MBD631509), pumped by the Propane Reinjection Pump (PBA631511A/B); and
- Liquid stream from the Debutanizer Reflux Drum (MBD631515), pumped by the Butane Reinjection Pump (PBA631517A/B).

13.17.1.1 Btu Adjustment System Type

Btu Adjustment is achieved by the LPG Reinjection System.

13.17.1.2 Btu Adjustment System Mixing Location

Mixing location is within the liquefaction train, with reinjection occurring at the MCHE.

13.17.1.3 Btu Adjustment System Composition Specifications (minimum, normal, maximum), percent volume, Wobbe

Since the BTU adjustment does not significantly change the LNG HHV, this specification will be developed when marketing agreements are finalized.

13.17.1.4 Btu Adjustment System Operating and Design Flow Rate Capacities (minimum, normal, maximum), MMscfd or lb/hr

LPG from the LPG Reinjection Pumps (PBA631521A/B), have a design flow rate of 181 gpm which provides flow to all three liquefaction trains. Flow rates to each train are estimated to be between 42,851 lb/hr and 14,639 lb/hr, for the 100% PTU and Average Gas cases, respectively.

13.17.1.5 Btu Adjustment System Operating and Design Pressures (minimum, normal, maximum), psig

The LPG Reinjection Pumps (PBA631521A/B) have a discharge pressure of 890 psig.

13.17.1.6 Btu Adjustment System Operating and Design Temperatures (minimum, normal, maximum), °F

The LPG Reinjection Pumps (PBA631521A/B) have a pumping temperature of -23 °F.

13.17.1.7 Btu Adjustment System Startup and Operation

The vapor from the Deethanizer Reflux Drum (MBD631504), and the liquids from the Propane Reinjection Pump (PBA631511A/B), and the Butane Reinjection Pump (PBA631517A/B) fed to the LPG Reinjection Cooler (HBG631519). The mixed LPG is condensed in the LPG Reinjection Cooler (HBG631519) by LP propane to -23 °F. Propane for this cooler is supplied from the three process trains. The cooled LPG stream is then phase-separated in the LPG Reinjection KO Drum (MBD631520). Normally the liquid from the LPG Reinjection Cooler (HBG631519) will be subcooled and no vapor generated in the LPG Reinjection KO Drum (MBD631520). However, if excess vapor is present in the LPG Reinjection KO Drum (MBD631520), it will be sent to the Dry Gas Flare. The subcooled LPG is reinjected into the MCHE warm bundle.

13.17.1.8 Btu Adjustment System Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.17.1.9 Btu Adjustment System Basic Process Control Systems

The system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.17.1.10 Btu Adjustment System Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the operation as described in Appendix 13.E.5 and 13.N.1.

13.17.1.11 Btu Adjustment System Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogens can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.17.1.12 Btu Adjustment System Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.18 SENDOUT METERING SYSTEM

13.18.1 Sendout Metering Design

Not Applicable.

13.18.1.1 Sendout Operating and Design Flow Rate Capacities (minimum, normal, maximum), MMscfd

Not Applicable.

13.18.1.2 Sendout Operating and Design Pressures (minimum, normal, maximum), psig

Not Applicable.

13.18.1.3 Sendout Operating and Design Temperatures (minimum, normal, maximum), °F

Not Applicable.

13.18.1.4 Pipeline Operating and Design Flow Rate Capacities (minimum, normal, maximum), MMscfd

Not Applicable.

13.18.1.5 Pipeline Operating and Design Pressures (minimum, normal, maximum), psig

Not Applicable.

13.18.1.6 Pipeline Operating and Design Temperatures (minimum, normal, maximum), °F

Not Applicable.

13.18.1.7 Sendout Metering System Startup and Operation

Not Applicable.

13.18.1.8 Sendout Metering System Isolation Valves, Drains, and Vents

Not Applicable.

13.18.1.9 Sendout Metering System Basic Process Control Systems

Not Applicable.

13.18.1.10 Sendout Metering System Safety Instrumented Systems

Not Applicable.

13.18.1.11 Sendout Metering System Relief Valves and Discharge

Not Applicable.

13.18.1.12 Sendout Metering System Other Safety Features

Not Applicable.

13.19 FUEL GAS

13.19.1 Fuel Gas Design

Details on the Fuel Gas Systems can be found in the Fuel Gas Design Basis (USAL-CB-PBDES-50-000003-000) included in Appendix 13.B.

Fuel gas system is a common system supplying fuel gas at high and low pressure to the entire Facility including all continuous users and intermittent fuel gas users. The following Process Flow Diagrams associated with the fuel gas system are included in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDUFD-50-000965-001	Utility Flow Diagram LP Fuel Gas System
USAL-CB-PDUFD-50-000966-001	Utility Flow Diagram HP Fuel Gas System
USAL-CB-PDUFD-50-000966-002	Utility Flow Diagram HP Fuel Gas System HP Fuel Gas For Gas Turbine Drivers

The following Piping and Instrumentation Drawings associated with the fuel gas system are included in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPID-00-000000-051	Piping & Instrumentation Diagram Process Piping Interconnecting Diagram Inlet, Fuel, Flare, Water System & Power Generation Area
USAL-CB-PDPID-10-000966-101	Piping & Instrumentation Diagram HP Fuel Gas System HP Fuel Gas Header - Train 1
USAL-CB-PDPID-10-000966-101	HP Fuel Gas System HP Fuel Gas Header Train-1
USAL-CB-PDPID-50-000965-501	LP Fuel Gas System LP Fuel Gas Drum
USAL-CB-PDPID-50-000966-501	HP Fuel Gas System Start-Up Fuel Gas Filter and Heater
USAL-CB-PDPID-50-000966-502	HP Fuel Gas System HP Fuel Gas Mixing Drum and Heater
USAL-CB-PDPID-50-000966-503	HP Fuel Gas System Excess LPG Vaporizer
USAL-CB-PDPID-50-000966-505	HP Fuel Gas System HP Fuel Gas Heater and Condensate Pot
USAL-CB-PDPID-50-000966-551	HP Fuel Gas System HP Fuel Gas Header Inlet Gas Treating Area
USAL-CB-PDPID-50-000966-552	HP Fuel Gas System HP Fuel Gas Header Fractionation Area
USAL-CB-PDPID-60-000966-601	HP Fuel Gas System HP Fuel Gas Header Flare & Water System Area
USAL-CB-PDPID-60-000966-602	Piping & Instrumentation Diagram HP Fuel Gas System HP Fuel Gas Header/Power Generation
USAL-CB-PDPID-70-000966-701	Piping & Instrumentation Diagram HP Fuel Gas System HP Fuel Gas Header/Refrigerant Storage
USAL-CB-PDPID-70-000966-702	Piping & Instrumentation Diagram HP Fuel Gas System HP Fuel Gas Header/Flare
USAL-CB-PDPID-80-000966-801	HP Fuel Gas System HP Fuel Gas Header LNG Storage Tank Area

13.19.1.1 Fuel Gas Sources

Fuel gas is supplied from the Metering Station (for start-up), boil-off gas from the LNG Storage Tanks, make-up gas from downstream of the Mercury Adsorber After Filter, and LPG vapors from Excess LPG Vaporizer.

13.19.1.2 Fuel Gas Specifications

The fuel gas system has the following specifications.

Component Compsition (mol%)	Rich	Normal (Holding Mode)	Normal (Loading Mode)	Lean
N_2	0.7	8.3	10.3	15
C1	91.1	91	89	85
C2	5.8	0.5	0.5	--
C3	1.9	0.2	0.2	--
iC4	0.1	--	--	--
nC4	0.2	--	--	--
iC5	0.05	--	--	--
nC5	0.04	--	--	--
C6+	0.11	--	--	--
LHV (Btu/scf)	981	844	826	776

13.19.1.3 Fuel Gas Distribution List and Requirement by Equipment, MMscfd

The fuel gas usage list is presented by system.

Fuel Gas System	Equipment	Equipment Number	Usage Requirement (MMscfd)
HP	MR/PR Compressor Gas Turbine Driver 1/2	CGT666111 CGT666151	174
	Gas Turbine Generator 1/2/3/4	TGT833611 TGT833621 TGT833631 TGT833641	
LP	Thermal Oxidizer	EAL634706	0.09
LP	Purge Gas for West/Dry Flares and LP Flare	FLRH612703A/B/C FLRL613800	
LP	Wet/Dry Flare Pilots, LP Flare assist and pilots	FLRH612703A/B/C FLRL613800	
LP	Supplemental firing for HRSGs	EAC948611 EAC948621 EAC948631 EAC948641	

13.19.1.4 Fuel Gas Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), lb/hr

		Minimum Operating/Design Flow Rate (lb/hr)	Operating/Design Flow Rate (lb/hr)	Maximum Operating/Design Flow Rate (lb/hr)
--	Low Pressure Fuel Gas System	--/--	160/--	187/29,545

		Minimum Operating/Design Flow Rate (lb/hr)	Operating/Design Flow Rate (lb/hr)	Maximum Operating/Design Flow Rate (lb/hr)
--	High Pressure Fuel Gas System	128,798/--	328,504/340,173	--/385,147

13.19.1.5 Fuel Gas Operating and Design Pressures (minimum, normal/rated, maximum), psig

		Minimum Operating/Design Pressure (psig)	Operating/Design Pressure (psig)	Maximum Operating/Design Pressure (psig)
--	Low Pressure Fuel Gas System	--/--	46/50	--/150
--	High Pressure Fuel Gas System	--/--	420/410	--/600

13.19.1.6 Fuel Gas Operating and Design Temperatures (minimum, normal, maximum), °F

		Minimum Operating/Design Temperature (°F)	Operating/Design Temperature (°F)	Maximum Operating/Design Temperature (°F)
--	Low Pressure Fuel Gas System	--/-150	62/--	--/485
--	High Pressure Fuel Gas System	--/--	38/--	--/400

13.19.1.7 Fuel Gas Operating and Design Densities (minimum, normal, maximum), specific gravity

Fuel gas density is presented in lb/cf to match units in heat and material balances.

		Minimum Operating/Design Density (lb/cf)	Operating/Design Density (lb/cf)	Maximum Operating/Design Density (lb/cf)
--	Low Pressure Fuel Gas System	--/--	0.21/0.20	--/--
--	High Pressure Fuel Gas System	--/--	1.39/1.40	--/1.73

13.19.1.8 Fuel Gas Startup and Operation

The boil off gas from BOG Compressor Aftercoolers (HFF691843/53/63) will be normally sent to the HP Fuel Gas Mixing Drum (MFG966503). This will be the primary source of fuel gas.

BOG will be also used as regeneration gas for regenerating the Dehydration Beds. A part of the BOG will be routed to the regeneration gas system when a dehydration bed is to be regenerated. After regeneration, the gas will be routed to the HP Fuel Gas Mixing Drum from the overhead of the Regeneration Gas KO Drum (MBD661512).

Any additional fuel gas required to meet the fuel requirements (i.e. make up fuel gas during holding mode or when the BOG is not available) will be supplied from the upstream of the Mercury Adsorber After Filters (MAJ669504A/B/C). During normal holding mode operation, 10% of the fuel gas required will be supplied from the make up fuel gas. Make up fuel gas will be sent to the Start Up Fuel Gas Heater (NAP966502). Downstream of the heater, the gas pressure will be reduced and then the gas will be sent to the HP Fuel Gas Mixing Drum.

During start-up, the fuel gas required will be supplied from the upstream of the Inlet Gas Filters (MAJ623503A/B/C). Start up fuel gas will be sent to the Start Up Fuel Gas Filter (MAJ966501). Start-up fuel gas pressure will be reduced using a pressure control valve located downstream of the Start up Fuel Gas Filter and then sent to the Start up Fuel Gas Heater. Downstream of the heater, the gas pressure will be further reduced and then the gas will be sent to the HP Fuel Gas Mixing Drum.

For supplying the fuel gas for the flare purge and pilots, and assist gas for the LP Flare (FLRL613800), a separate stream from the downstream of the BOG Compressor Aftercoolers will be provided. A stream from the make up/start up fuel gas supply line will be connected to this stream as a secondary fuel gas source.

From the HP Fuel Gas Mixing Drum, the gas will be sent to the HP Fuel Gas Heater (HBG966515). LP steam will be supplied to heat the gas to the specified outlet temperature. LP condensate from the heater will be collected in HP Fuel Gas Heater Condensate Pot (MBD966510). From the condensate pot, the LP condensate will be then routed to the LP condensate header.

Gas from the HP Fuel Gas Heater will be sent to the HP fuel gas users. Any liquid accumulated at the bottom of the HP Fuel Gas Mixing Drum will be routed to the wet flare header.

A part of the HP fuel gas will be routed to the LP Fuel Gas Drum (MFG965501). From the LP Fuel Gas Drum, the gas will be sent to the LP fuel gas users. Any liquid condensed in the LP Fuel Gas Drum will be routed to the Slop Oil Tank (MBJ964750).

When the amount of BOG produced is higher than the overall fuel gas requirements (e.g. during loading mode), the excess BOG is routed to the BOG Recycle Compressor (CAR966505). The BOG recycle compressor will send the excess BOG to the upstream of the Dehydration Unit via the BOG Recycle Compressor Aftercooler (HFF966506).

During 100% PTU case, LPG from Debutanizer overhead will be routed to the HP Fuel Gas Mixing Drum. This arrangement is necessary to maintain LNG and condensate specifications during 100% PTU case. This LPG will be vaporized by Excess LPG Vaporizer (NAP966516) before routing it to the HP Fuel Gas Mixing Drum.

13.19.1.9 Fuel Gas Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.19.1.10 Fuel Gas Basic Process Control Systems

The fuel gas system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC. Further information is found in Appendix 13.E.5 and 13.N.1.

13.19.1.11 Fuel Gas Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the operation as described in Appendix 13.E.5 and 13.N.1.

13.19.1.12 Fuel Gas Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogens can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.19.1.13 Fuel Gas Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.19.1.14 Fuel Gas Odorant System

Since the fuel gas on-site is entirely consumed by the process and power generation equipment, there is no odorant added to this gas. Gas detectors throughout the facility monitor for incipient leaks to alert operations.

13.20 NITROGEN AND INERT GAS

13.20.1 Nitrogen Design

Nitrogen system is a common system supplying high purity and purge quality gas throughout the entire Facility.

Additional details on the Nitrogen System are included in the Nitrogen System Design Basis (USAL-CB-PBDES-60-000003-000) included in Appendix 13.B.

The following Process Flow Diagrams associated with the nitrogen system are included in Appendix 13.E.

Drawing Number	Description
USAL-CD-PDUFD-60-000961-001	Utility Flow Diagram – Utility Support Systems – Purge Nitrogen System

The following Piping and Instrumentation Drawings associated with the fuel gas system are included in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPID-10-000961-101	Nitrogen System Nitrogen Header Train-1
USAL-CB-PDPID-50-000961-501	Nitrogen System Nitrogen Header Inlet Gas Treating Area
USAL-CB-PDPID-50-000961-502	Nitrogen System Nitrogen Header Fractionation Area
USAL-CB-PDPID-60-000961-601	Nitrogen System High Purity Cryogenic Nitrogen Generation Package
USAL-CB-PDPID-60-000961-602	Nitrogen System High Purity Liquid Nitrogen Storage & Vaporizer Package
USAL-CB-PDPID-60-000961-603	Nitrogen System Piping Work
USAL-CB-PDPID-60-000961-604	Nitrogen System Purge Nitrogen Generation Packages
USAL-CB-PDPID-60-000961-605	Nitrogen System Nitrogen Receiver
USAL-CB-PDPID-60-000961-651	Nitrogen System Nitrogen Header Utility Area
USAL-CB-PDPID-60-000961-652	Nitrogen System Nitrogen Header Flare & Water System Area
USAL-CB-PDPID-70-000961-701	Nitrogen System Nitrogen Header Refrigerant Storage Area
USAL-CB-PDPID-80-000961-801	Nitrogen System Nitrogen Header Condensate & Diesel Storage and Sanitary Treatment Area
USAL-CB-PDPID-80-000961-802	Nitrogen System Nitrogen Header BOG Compressor Area
USAL-CB-PDPID-80-000961-803	Nitrogen System Nitrogen Header LP Flare Area
USAL-CB-PDPID-80-000961-804	Nitrogen System Nitrogen Header LNG Storage Tank Area
USAL-CB-PDPID-90-000961-901	Nitrogen System Nitrogen Header Offshore Trestle Area

13.20.1.1 Nitrogen Source

Two (2) types of Nitrogen Systems, Purge Nitrogen and a High Purity Nitrogen, will be provided for the Alaska LNG Project facility.

The Purge Nitrogen will be produced onsite with a purity of 98.5%. This nitrogen system consists of a Purge Nitrogen Generation Package (V961601A/B), and Nitrogen Receiver (MBE961630).

The High Purity Nitrogen will be produced onsite with a purity of 99.9%. This nitrogen system consists of a High Purity Cryogenic Nitrogen Generation Package (V961602), and High Purity Liquid Nitrogen Storage and Vaporizer Package (V961640).

13.20.1.1.1 Number of Liquid Nitrogen Trucks and Truck Capacity, gal

Not Applicable.

13.20.1.1.2 Nitrogen Production System and Production Rate, gpm

The Purge Nitrogen Generation produces 1,476 scfm for purge requirements for the facility.

The High Purity Cryogenic Nitrogen Generation Package produces 1,284 scfm of gaseous nitrogen. The liquefaction rate shall be determined in detailed engineering.

13.20.1.2 Nitrogen Distribution List of Continuous and Intermittent Users or Usage Factors, Including Leakage, and Usage Requirement by Equipment, scfm

Supply System	User	Usage Type	Usage Requirement (scfm)
Purge	Compressor Seals	Continuous	--
Purge	LNG Loading Pumps	Continuous	--
Purge	LNG Loading Arms	Intermittent	--
Purge	Train Maintenance Purge	Intermittent	--
Purge	Condensate Storage Tank	Intermittent	--
Purge	Off Spec Condensate Storage Tank	Intermittent	--
Purge	Slop Oil Storage	Intermittent	--
Purge	Demin Water Storage Tanks	Intermittent	--
Purge	Equalization Tank	Intermittent	--
Purge	DGF Tank	Intermittent	--
Purge	Post Purge for Wet and Dry Ground Flares	Intermittent	--
Purge	Back-up Purge Nitrogen to LP Flare	Intermittent	--
Purge	Utility Stations, Analyzers, Sample Points	Intermittent	--
Purge	Wet Dry and LP Flare KO Drum Spargers	Intermittent	--
Purge	Dry Flare Blowcase	Intermittent	--
Purge	BOG Compressor Suction Drum Blowcase	Intermittent	--
Purge	Loading arm drain/surge drum Blowcase	Intermittent	--
High Purity	Make up nitrogen to LP MR Suction Drum. (for MR Makeup)	Intermittent	--
High Purity	Nitrogen supply to nitrogen receiver	Intermittent	--

13.20.1.3 Number of Liquid Nitrogen Storage Tanks, Operating and Spare

The Liquid Nitrogen Storage Tank Package is to be defined further in detailed design engineering phase.

13.20.1.4 Liquid Nitrogen Storage Capacity, gal

The required liquid nitrogen storage is 160,000 gal (21,371 ft^3) based on a minimum holding time of 7 days for normal plant nitrogen consumption.

13.20.1.5 Number of Nitrogen Vaporizers, Operating and Spare

The number of nitrogen vaporizers is to be defined further in detailed engineering.

13.20.1.6 Liquid Nitrogen Vaporizer Type

The type of nitrogen vaporizer is to be defined further in detailed engineering.

13.20.1.7 Number of Nitrogen Receivers, Operating and Spare

There is one installed nitrogen receiver without sparing.

13.20.1.8 Liquid Nitrogen Vaporizer Operating and Design Flow Rate Capacities, scfm

		Minimum Operating/Design Flow Rate (scfm)	Operating/Design Flow Rate (scfm)	Maximum Operating/Design Flow Rate (scfm)
V961640	Liquid Nitrogen Vaporizer	0/0	--/--	--/3,586

13.20.1.9 Nitrogen Receivers Operating and Design Storage Capacities, scf

Based on the equipment data sheet, the design volume is based on a 5 minute retention time of the design nitrogen flow rate of 1,476 scfm.

		Minimum Operating/Design Capacity (scf)	Operating/Design Capacity (scf)	Maximum Operating/Design Capacity (scf)
MBE961630	Nitrogen Receiver	--/--	--/7,380	--/--

13.20.1.10 Nitrogen Receivers Operating and Design Storage Pressures (minimum, normal, maximum), psig

		Minimum Operating/Design Pressure (psig)	Operating/Design Pressure (psig)	Maximum Operating/Design Pressure (psig)
MBE961630	Purge Nitrogen Receiver	70/--	120/--	--/200

13.20.1.11 Nitrogen Receivers Residence Times, Minutes

The Purge Nitrogen Receiver have 5 minutes of residence time at the design nitrogen flow rate.

13.20.1.12 Nitrogen System Startup and Operation

The Purge Nitrogen System will be common for the three (3) Liquefaction Trains and supporting facilities. The Purge Nitrogen Generation Packages (V961601A/B) will use membrane air separation to produce gaseous nitrogen (GAN). Instrument air will be supplied to the package as an air source (feed). The gaseous nitrogen will be sent to the Nitrogen Receiver (MBE961630) and then to the purge nitrogen users via the purge nitrogen header.

The High Purity Nitrogen System is common for the three (3) Liquefaction Trains and supporting facilities. The High Purity Cryogenic Nitrogen Generation Package (V961602) will be a cryogenic air separation unit which will use instrument air (feed) to produce high purity gaseous nitrogen (GAN) and liquid nitrogen (LIN).

GAN will be supplied directly to high purity nitrogen users. LIN will be sent to the High Purity Liquid Nitrogen Storage and Vaporizer Package (V961640) and will be available for use upon demand.

LIN will be stored in nitrogen dewars and will be vaporized as required using the nitrogen vaporizer to supply nitrogen to the high purity intermittent N_2 users in gaseous state. High purity nitrogen header will be connected to the purge nitrogen header using a pressure control valve. This valve will open to supply high purity nitrogen to the purge nitrogen header if the purge nitrogen header pressure is low due to an upset in the Purge Nitrogen Generation Package and/or to supply a temporary high demand in N_2 supply.

13.20.1.13 Nitrogen System Shutdown

The Purge Nitrogen system is an essential service for liquefaction and loading operations. This system is spared 100% to maintain reliability.

The High Purity Cryogenic Nitrogen Generation Package can be isolated from the instrument air supply line to shutdown the system. This system is used to replenish the refrigerant mixture and provide supplemental nitrogen to the purge header.

13.20.1.14 Liquid Nitrogen Truck Loading

Liquid nitrogen deliveries are made directly into the liquid nitrogen storage vessels that are part of the High Purity Liquid Nitrogen Storage and Vaporizer Package.

13.20.1.15 Nitrogen System Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.20.1.16 Nitrogen System Basic Process Control Systems

The nitrogen system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC. Further information is found in Appendix 13.E.5 and 13.N.1.

13.20.1.17 Nitrogen System Safety Instrumented Systems

The safety instrumented system for the nitrogen systems are to be defined further in detailed engineering.

13.20.1.18 Nitrogen System Relief Valves and Discharge

T Relief valves are sized according to the governing scenario for each piece of equipment. Thermal reliefs are included on piping where cryogenic fluids can be blocked in. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.20.1.19 Nitrogen System Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.20.2 Inert Gas Design

Not Applicable.

13.20.2.1 Inert Gas Distribution List of Continuous and Intermittent Users or Usage Factors, Including Leakage, and Usage Requirement by Equipment, scfm

Not Applicable.

13.20.2.2 Inert Gas Compressors Type

Not Applicable.

13.20.2.3 Number Of Inert Gas Compressors, Operating and Spare

Not Applicable.

13.20.2.4 Number Of Inert Gas Receivers, Operating and Spare

Not Applicable.

13.20.2.5 Inert Gas Source

Not Applicable.

13.20.2.6 Inert Gas Specifications

Not Applicable.

13.20.2.7 Inert Gas Compressor Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), scfm

Not Applicable.

13.20.2.8 Inert Gas Compressor Operating and Design Discharge Pressures (minimum, normal/rated, maximum), psig

Not Applicable.

13.20.2.9 Inert Gas Receivers Operating and Design Storage Capacities, scf

Not Applicable.

13.20.2.10 Inert Gas Receivers Operating and Design Storage Pressures (minimum, normal, maximum), psig

Not Applicable.

13.20.2.11 Inert Gas Receivers Residence Times, minutes

Not Applicable.

13.20.2.12 Inert Gas Startup and Operation

Not Applicable.

13.20.2.13 Inert Gas Isolation Valves, Drains, and Vents

Not Applicable.

13.20.2.14 Inert Gas Basic Process Control Systems

Not Applicable.

13.20.2.15 Inert Gas Safety Instrumented Systems

Not Applicable.

13.20.2.16 Inert Gas Relief Valves and Discharge

Not Applicable.

13.20.2.17 Inert Gas Other Safety Features

Not Applicable.

13.21 INSTRUMENT AND PLANT/UTILITY AIR

13.21.1 Instrument Air Design

The Plant and Instrument Air System will be common for all three liquefaction trains and supporting facilities.

Compressed air will be required for plant and instrument air. The air system will meet the air demands for all three LNG trains and the common facilities. Air filters, dryers, and a receiver will be required to ensure dry air will be supplied to all plant instruments and valve actuators. The system will contain the Air Compressor Package (V955601), which consists of two 50 percent motor-driven main air compressors and one 50 percent low-sulfur diesel-fueled back-up compressor, a Compressed Air Receiver (MAM956602), an Instrument Air Dryer Package (V956603) that will contain two 100 percent Dryers, and an Instrument Air Receiver (MIA956610).

The Air Compressor Package will compress air to 150 psig, which will flow to the Compressed Air Receiver before being sent to the Instrument Air Dryer Package for removal of any condensed water. From the Instrument Air Dryer Package, dry air will then flow to the Instrument Air Receiver to be distributed to users. An Instrument Air Receiver will be provided at the outlet of the dryer package. This vessel will provide sufficient volume to slow the drop of instrument air pressure after a compressor malfunction/trip allowing users of instrument air to be curtailed in a controlled manner.

Typically the Plant and Instrument Air System for an LNG facility supplies compressed air for the following purposes:

- Dry air (i.e. Instrument Air) for instruments and purging.
- Compressed air (i.e. Plant Air) for pneumatic tools and other utility needs.

However, for Alaska LNG, as part of the effort to winterize the plant, a single dry air system be used for both type of services and no wet compressed air will be permitted/allowed in any part of the air system/headers. Therefore, a portion of instrument air will be used for plant air functions. There will be no separate plant air.

Additional details on the Instrument Air Systems can be found in the Plant and Instrument Air Design Basis (USAL-CB-PBDES-60-000002-000) included in Appendix 13.M.

The following Utility Flow Diagram is associated with the Plant and Instrument Air System and is included in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDUFD-60-000956-001	Air Systems – Air Dryers, Filters and Receivers

The following P&IDs are associated with the Plant and Instrument Air System and are included in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPID-10-000951-101	Utility/Service Air Distribution System Train-1
USAL-CB-PDPID-50-000951-501	Utility/Service Air Distribution System Inlet Gas Treating Area
USAL-CB-PDPID-50-000951-502	Utility/Service Air Distribution System Fractionation Area
USAL-CB-PDPID-60-000951-601	Utility/Service Air Distribution System Utility Area
USAL-CB-PDPID-60-000951-602	Utility/Service Air Distribution System Flare & Water System Area
USAL-CB-PDPID-70-000951-701	Utility/Service Air Distribution System Refrigerant Storage Area
USAL-CB-PDPID-80-000951-801	Utility/Service Air Distribution Condensate & Diesel Storage and Sanitary Treatment Area
USAL-CB-PDPID-80-000951-802	Utility/Service Air Distribution System BOG Compressor Area
USAL-CB-PDPID-80-000951-803	Utility/Service Air Distribution System LP Flare Area
USAL-CB-PDPID-80-000951-804	Utility/Service Air Distribution System LNG Storage Tank Area
USAL-CB-PDPID-90-000951-901	Utility/Service Air Distribution System Offshore Trestle Area
USAL-CB-PDPID-10-000952-101	Instrument Air Distribution System Train-1
USAL-CB-PDPID-50-000952-501	Instrument Air Distribution System Inlet Gas Treating Area
USAL-CB-PDPID-50-000952-502	Instrument Air Distribution System Fractionation Area
USAL-CB-PDPID-60-000952-601	Instrument Air Distribution System Utility Area
USAL-CB-PDPID-60-000952-602	Instrument Air Distribution System Flare & Water System Area
USAL-CB-PDPID-70-000952-701	Instrument Air Distribution System Refrigerant Storage Area
USAL-CB-PDPID-80-000952-801	Instrument Air Distribution System Diesel Condensate Storage

Drawing Number	Description
USAL-CB-PDPID-80-000952-802	Instrument Air Distribution System BOG Compressor Area
USAL-CB-PDPID-80-000952-803	Instrument Air Distribution System LP Flare Area
USAL-CB-PDPID-80-000952-804	Instrument Air Distribution System LNG Storage Tank Area
USAL-CB-PDPID-90-000952-901	Instrument Air Distribution System Offshore Trestle Area
USAL-CB-PDPID-60-000955-601	Air Compressors Air Compressor Package
USAL-CB-PDPID-60-000956-601	Air Dryers, Filters and Receivers Compressed Air Receiver
USAL-CB-PDPID-60-000956-602	Air Dryers, Filters and Receivers Instrument Air Dryer Package
USAL-CB-PDPID-60-000956-603	Air Dryers, Filters and Receivers Instrument Air Receiver

13.21.1.1 Instrument Air Distribution List of Continuous and Intermittent Users or Usage Factors, Including Leakage, and Usage Requirement by Equipment, scfm

The Air and Plant Air equipment is designed with a 20% design margin.

13.21.1.2 Instrument Air Specifications, Dew Point, Particulates

Contaminant allowance will be in accordance with ISA S7.01 (Quality Standard for Instrument Air)

13.21.1.3 Number of Filters, Operating and Spare

The number of filters will be determined by vendor in Detailed Design Phase.

13.21.1.4 Instrument Air Compressors Type

The type of Air Compressors will be determined by vendor in Detailed Design Phase.

13.21.1.5 Number Of Instrument Air Compressors, Operating and Spare

The package will include three (3) 50% air compressors, two (2) electric drives(CAE955603/04) and one (1) diesel spare (as a backup for electric drive) (CAE955601), and the required auxiliary equipment and instrumentation.

13.21.1.6 Instrument Air Compressor Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), scfm

Each compressor will provide oil-free air at a design rate of 6,059 standard cubic feet per minute.

13.21.1.7 Instrument Air Compressor Operating and Design Discharge Pressures (minimum, normal/rated, maximum), psig

Operating Pressure	135 pounds per square inch gauge
Operating Pressure (Min)	85 pounds per square inch gauge
Design Pressure	170 pounds per square inch gauge

13.21.1.8 Instrument Air Drying System Type

Dryers will be of the heat-less type and will be provided with inlet filters to coalesce and remove water droplets from the incoming wet compressed air and the outlet filters will remove desiccant fines from the outlet air discharge

13.21.1.9 Number Of Instrument Air Dryers, Operating and Spare

Two (2) 100% dryers will be provided in the Instrument Air Dryer Package.

13.21.1.10 Instrument Air Dryers Operating and Design Dew Point Temperatures, °F

Dew Point	-40 °F maximum at 135 pounds per square inch gauge

13.21.1.11 Number Of Air Receivers, Operating and Spare

One instrument air receiver is included in the design. No spares are included.

13.21.1.12 Air Receiver Operating and Design Storage Capacities, scf

The Air Receiver is designed to handle output from the compressor plus a 20% design margin.

13.21.1.13 Instrument Air Receiver Operating and Design Storage Pressures (minimum, normal, maximum), psig

The dryer package will be sized to continuously deliver air at 135 psig at maximum continuous air flow rate with 20% design margin.

13.21.1.14 Air Receiver Residence Times, sec

The Instrument Air Receiver will be sized for a minimum of 10 minutes of surge capacity between the normal and minimum operating pressures at maximum continuous air flow rate.

13.21.1.15 Instrument Air Startup and Operation

The instrument air system will be commissioned with guidance from the vendor selected during the detailed design phase.

13.21.1.16 Instrument Air Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5

13.21.1.17 Instrument Air Basic Process Control Systems

Typically, pressure controller downstream of the compressor package will control the instrument air header pressure and send signal to a load shedding module provided as part of the Air Compressor Package. This module will control the three (3) air compressors as needed to maintain the instrument air header pressure.

A dew point analyzer at the dryer outlet will monitor the instrument air, so that -40 °F dew point air at 135 psig will be continuously delivered to the users. Instrument air will be supplied to the Nitrogen Package as a dry air source.

The system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.21.1.18 Instrument Air Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the operation as described in Appendix 13.E.5 and 13.N.1.

13.21.1.19 Instrument Air Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.21.1.20 Instrument Air Other Safety Features

No other safety features have been identified. Further features may be added during detailed design

13.21.2 Plant/Utility Air Design

Therefore, a portion of instrument air will be used for plant air functions. There will be no separate plant air.

13.21.2.1 Plant/Utility Air Compressors Type

Not Applicable.

13.21.2.2 Number Of Plant/Utility Air Compressors, Operating and Spare

Not Applicable.

13.21.2.3 Plant/Utility Air Distribution List of Continuous and Intermittent Users or Usage Factors, Including Leakage, and Usage Requirement by Equipment, scfm

Not Applicable.

13.21.2.4 Plant/Utility Air Specifications

Not Applicable.

13.21.2.5 Plant/Utility Air Compressors Operating and Design Flow Rate Capacities (Minimum, Normal/Rated, Maximum), scfm

Not Applicable.

13.21.2.6 Plant/ Utility Air Compressors Operating and Design Discharge Pressures (minimum, normal/rated, maximum), psig

Not Applicable.

13.21.2.7 Number Of Plant/Utility Air Receivers, Operating and Spare

Not Applicable.

13.21.2.8 Plant/Utility Air Receivers Operating and Design Storage Capacities, scf

Not Applicable.

13.21.2.9 Plant/Utility Air Receivers Operating and Design Storage Pressures (minimum, normal, maximum), psig

Not Applicable.

13.21.2.10 Plant/Utility Air Receivers Operating and Design Residence Times, Minutes

Not Applicable.

13.21.2.11 Plant/Utility Air Startup and Operation

Not Applicable.

13.21.2.12 Plant/Utility Air Isolation Valves, Drains, and Vents

Not Applicable.

13.21.2.13 Plant/Utility Air Basic Process Control Systems

Not Applicable.

13.21.2.14 Plant/Utility Air Safety Instrumented Systems

Not Applicable.

13.21.2.15 Plant/Utility Air Relief Valves and Discharge

Not Applicable.

13.21.2.16 Plant/Utility Air Other Safety Features

Not Applicable.

13.22 UTILITY WATER AND OTHER UTILITIES

13.22.1 Utility Water Design

Fresh groundwater will be pumped by the Well Pumps (PBA976601/02/41/42) to the Freshwater Tanks (BBJ976605/6). The Freshwater Tank Pumps (PBA976607A/B/C/D) will pump the freshwater from the tanks to the Freshwater Pre-Heater (HBG976609). The heated freshwater will be mixed in the Clarifier Feed Mixer (MX976630) with an oxidizer and coagulant before going to the Clarifier (ABM976613A/B). The water will then go to the Clarified Water Clear Well (BBJ9756614) and will be pumped by the Clarifier Water Forwarding Pumps (PBM976617A/B) to the UF Cartridge Filters (MAJ976629A/B). The water will then be filtered again in the Ultrafiltration Filter Units (MAJ976622A/B) and go to the Filtered Water Storage Tank (BBJ976626). The Filtered Water Forwarding Pumps (PBA976628A/B) will then pump utility water to the users.

Some of the filtered water from the Filtered Water Forwarding Pumps will go to the 1st Pass RO Mixer (MX976643) and will be mixed with an anti-scalant and sodium bisulfite. The water will then be filtered in the CIP Cartridge Filter (MAJ976646) and the 1st Pass RO Filter (MAK976634) and then goes to the RO Permeate Tank (BBJ977601). The Potable Water Feed Pumps (PBA977603A/B) will pump the water to the Activated Carbon Cartridge Filters (MAJ977632A/B) and the water will then go to the Potable Water Storage Tank (BBJ977621) where it will be mixed with sodium hypochlorite. The Potable Water Forwarding Pumps (PBA977630A/B) will pump the potable water from the tank to the users.

Additional details on the Utility and Potable Water Systems can be found in the Fresh Water Design Basis (USAL-CB-PBDES-60-000004-000) included in Appendix 13.B.

The Potable Water System is illustrated on the following Utility Flow Diagrams, which are included in Appendix 13.E.

Document Number:	Description:
USAL-CB-PDUFD-60-000976-001	Utility Flow Diagram Fresh Water and Sanitary Systems Fresh Water Intaking
USAL-CB-PDUFD-60-000976-002	Utility Flow Diagram Fresh Water and Sanitary Systems Fresh Water Pretreatment
USAL-CB-PDUFD-60-000976-003	Utility Flow Diagram Fresh Water and Sanitary Systems Reverse Osmosis
USAL-CB-PDUFD-60-000977-001	Utility Flow Diagram Fresh Water and Sanitary Systems Potable Water Systems
USAL-CB-PDUFD-60-000979-001	Utility Flow Diagram Fresh Water and Sanitary Systems Demineralized Water

The following P&IDs are associated with the Fresh, Utility, Potable and Demineralized Water System and are included in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPID-10-000976-101	Freshwater and Sanitary System Utility Water Header Train-1
USAL-CB-PDPID-50-000976-501	Freshwater and Sanitary System Utility Water Header Inlet Gas Treating Area
USAL-CB-PDPID-50-000976-502	Freshwater and Sanitary System Utility Water Header Fractionation Area
USAL-CB-PDPID-60-000976-601	Freshwater and Sanitary System Well Pumps PBA976601/41
USAL-CB-PDPID-60-000976-602	Freshwater and Sanitary System Well Pumps PBA976602/42
USAL-CB-PDPID-60-000976-603	Freshwater and Sanitary System Freshwater Tank BBJ976605
USAL-CB-PDPID-60-000976-604	Freshwater and Sanitary System Freshwater Tank BBJ976606
USAL-CB-PDPID-60-000976-605	Freshwater and Sanitary System Freshwater Tank Pumps
USAL-CB-PDPID-60-000976-606	Freshwater and Sanitary System Freshwater Pre-Heater and Condensate Pot
USAL-CB-PDPID-60-000976-607	Freshwater and Sanitary System Firewater Make Up Pumps
USAL-CB-PDPID-60-000976-608	Freshwater and Sanitary System Clarification and Filter Press Package
USAL-CB-PDPID-60-000976-609	Freshwater and Sanitary System Clarified Water Clearwell Tank
USAL-CB-PDPID-60-000976-610	Freshwater and Sanitary System Clarified Water Forwarding Pumps
USAL-CB-PDPID-60-000976-611	Freshwater and Sanitary System Water Purification UF Package
USAL-CB-PDPID-60-000976-612	Freshwater and Sanitary System Filtered Water Storage Tank
USAL-CB-PDPID-60-000976-613	Freshwater and Sanitary System Filtered Water Forwarding Pumps
USAL-CB-PDPID-60-000976-614	Freshwater and Sanitary System Reclaimed Water Sump and Pumps
USAL-CB-PDPID-60-000976-615	Freshwater and Sanitary System Reverse Osmosis Package
USAL-CB-PDPID-60-000976-616	Freshwater and Sanitary System CIP System
USAL-CB-PDPID-60-000976-651	Freshwater and Sanitary System Utility Water Header Utility Area
USAL-CB-PDPID-60-000976-652	Freshwater and Sanitary System Utility Water Header Flare & Water System area
USAL-CB-PDPID-70-000976-701	Freshwater and Sanitary System Utility Water Header Refrigerant Storage Area
USAL-CB-PDPID-80-000976-801	Freshwater and Sanitary System Utility Water Header Condensate & Diesel Storage and Sanitary Treatment Area
USAL-CB-PDPID-80-000976-802	Freshwater and Sanitary System Utility Water Header BOG Compressor Area
USAL-CB-PDPID-80-000976-803	Freshwater and Sanitary System Utility Water Header LP Flare Area
USAL-CB-PDPID-80-000976-804	Freshwater and Sanitary System Utility Water Header LNG Storage Tank Area
USAL-CB-PDPID-90-000976-901	Freshwater and Sanitary System Utility Water Header Offshore Trestle Area
USAL-CB-PDPID-10-000977-101	Potable Water System Potable Water Header Train-1
USAL-CB-PDPID-50-000977-501	Potable Water System Potable Water Header Inlet Gas Treating Area
USAL-CB-PDPID-50-000977-502	Potable Water System Potable Water Header Fractionation Area
USAL-CB-PDPID-60-000977-601	Potable Water System RO Permeate Tank
USAL-CB-PDPID-60-000977-602	Potable Water System RO Permeate Forwarding Pumps
USAL-CB-PDPID-60-000977-603	Potable Water System Activated Carbon Cartridge Filters
USAL-CB-PDPID-60-000977-604	Potable Water System Potable Water Package
USAL-CB-PDPID-60-000977-605	Potable Water System Potable Water Storage Tank
USAL-CB-PDPID-60-000977-606	Potable Water System Potable Water Forwarding Pumps
USAL-CB-PDPID-60-000977-607	Potable Water System Sodium Hypochlorite Generator Package and Distribution Pumps
USAL-CB-PDPID-60-000977-651	Potable Water System Potable Water Header Utility Area

Drawing Number	Description
USAL-CB-PDPID-60-000977-652	Potable Water System Potable Water Header Flare & Water System Area
USAL-CB-PDPID-70-000977-701	Potable Water System Potable Water Header Refrigerant Storage Area
USAL-CB-PDPID-80-000977-801	Potable Water System Potable Water Header Condensate & Diesel Storage and Sanitary Treatment Area
USAL-CB-PDPID-80-000977-802	Potable Water System Potable Water Header BOG Compressor Area
USAL-CB-PDPID-80-000977-803	Potable Water System Potable Water Header LP Flare Area
USAL-CB-PDPID-80-000977-804	Potable Water System Potable Water Header LNG Storage Tank Area
USAL-CB-PDPID-90-000977-901	Potable Water System Potable Water Header Offshore Trestle Area
USAL-CB-PDPID-10-000979-101	Demineralized Water System Demineralized Water Header Train-1
USAL-CB-PDPID-60-000979-601	Demineralized Water System Demineralization Package
USAL-CB-PDPID-60-000979-602	Demineralized Water System Demineralized Water Storage Tank
USAL-CB-PDPID-60-000979-603	Demineralized Water System Demineralized Water Forwarding Pumps
USAL-CB-PDPID-60-000979-604	Demineralized Water System Neutralization Package
USAL-CB-PDPID-60-000979-605	Demineralized Water System Chemical Sump and Lift Pumps

13.22.1.1 Utility Water Type (Service Water, Potable Water, Demineralized Water, Steam, Chemical Treatment. Scavengers)

Ground water will be treated through the following steps to generate the water requirement for liquefaction facility:

- Fresh Water Supply
- Pretreatment
- Potable water treatment
- Water Demineralization
- Treated Water Distribution (Potable, Utility, Demineralized Water)
- Reject Water Treatment

13.22.1.2 Utility Water Sources

Ground water will supply the utility, potable and demineralized water demands.

13.22.1.3 Utility Water Distribution List and Usage Requirement by Equipment, gpm

Potable Water	
Item	**Demand, gpm**
Personnel Consumption	50 gallon/day/person (400 personnel)
Safety Showers	30
Utility Water	
Pump seals/bearings	1.5
Utility stations	15

Demineralized water system is designed to supply water to the water wash on refrigeration and power plant gas turbines and the makeup water for the steam system. Normal consumption is 90 gpm with three power plant units running.

13.22.1.4 Utility Water Operating and Design Storage Capacities (Minimum, Normal, Maximum), gal

2 x 50% Fresh Water tanks will be installed to equalize and buffer ground water from different wells. Support at least the pump-out rate of 840 gpm for fire protection requirement in 24 hrs without any incoming well water. Normal effective holding is 612,000 gallon each (preliminarily).

1 x 100% Filtered Water Storage Tank provides backwash water, utility water, and water for RO package. It will be designed for 3 days of continuous operation, pumps seals and two utility water stations. Normal effective holding is 151,200 gallon (preliminarily).

1 x 100% RO Permeate Tank provides potable water, RO cleaning, and demineralized water requirement. It is designed for 4 hours flow buffer. Normal effective holding capacity is 75,000 gallons.

The Demineralized Water Storage Tank is nitrogen blanketed, and designed to hold demineralized water from the Demineralization Package (V979601). The tank provides 3 days of operation for steam generation system, and GT's wash water requirement. Normal effective holding is 390,000 gallon (preliminarily).

Potable Water Storage Tank is equipped with eductor for effective chlorination. It holds potable water ready for 3 days of normal facility operation, with a normal holding of 66,000 gallons. The tank will be designed to supply 3 days of potable water requirement for three LNG Trains and the common facilities.

13.22.1.5 Utility Water Operating and Design Flow Rate Capacities (Minimum, Normal, Maximum), gpm

Potable Water Design conditions:

- •Operating Temperature: normal 80°F (min 60 F, max 90 F).
- Design Flowrate: 2 x average consumption of 400 personnel + 2 x standard safety show flow = 90 gpm, Selected 100 gpm.
- Normal Flowrate: 15 gpm.

Utility Water Design conditions:

- Operating Temperature: normal 80°F (min 60 F, max 90 F).
- Design Flowrate: 1.5 x average seal consumption + 5 x utility water station flow, rounded up to 90 gpm.
- Normal Flowrate: Preliminarily 5 gpm.

13.22.1.6 Utility Water Operating and Design Pressures (Minimum, Normal, Maximum), psig

Potable Water Design conditions:

- Operating Pressure: 30 - 80 psig.
- Normal Pressure: 55 psig.

Utility Water Design conditions:

- Operating Pressure: 30 - 90 psig, normal 75 psig.

13.22.1.7 Utility Water Startup and Operation

Startup and Operation sequence for the freshwater system will be developed in detailed design phase.

13.22.1.8 Utility Water Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.22.1.9 Utility Water Basic Process Control Systems

The system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.22.1.10 Utility Water Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the operation as described in Appendix 13.E.5 and 13.N.1.

13.22.1.11 Utility Water Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.22.1.12 Utility Water Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.22.2 Other Utilities Design

The Diesel Storage and Distribution System will be provided to store and supply diesel to the following users:

- Diesel Day Tank (ABJ411606) of the Firewater Pump (diesel driven);
- Air Compressor Diesel Day Tank (ABJ955602); and
- Diesel for in plant vehicle use.

Diesel fuel will be imported via trucks and will be stored in the Diesel Storage Tank (BBJ911701). Diesel Truck Unloading Filter (MAJ911705) will be used to remove any impurities from the diesel before being sent to the storage tank.

From the Diesel Storage Tank, diesel will be transferred to the Diesel Day Tanks as required, using the Diesel Transfer Pumps (PBA911702A/B). A Diesel Fuel Filter (MAJ911704) will be provided downstream of the pumps to remove any impurities before transferring it to the users.

Additional details on the Diesel System is presented in the Refrigerant, Condensate and Diesel Storage Design Basis (USAL-CB-PBDES-00-000007-000), provided in Appendix 13.B.

The following Utility Flow Diagram is associated with the Diesel System and is included in Appendix 13.E:

Drawing Number	Description
USAL-CB-PDUFD-70-000911-001	Liquid Fuel Systems – Diesel Storage and Distribution System

The following P&IDs are associated with the Wastewater and Diesel System and are included in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPID-70-000911-701	Diesel Oil Storage and Distribution System Diesel Storage Tank
USAL-CB-PDPID-70-000911-702	Diesel Oil Storage and Distribution System Diesel Transfer Pumps

13.22.2.1 Other Utilities Type (Amine Solutions, Water Glycol Solutions, Aqueous Ammonia, Etc.)

Ultra-Low Sulfur Diesel will be utilized.

13.22.2.2 Other Utility Distribution List and Usage Requirement by Equipment, gpm

User	Diesel Consumption (gal/hr)
Air Compressor Package	21
Fire Water Pump Package	14

13.22.2.3 Other Utility Sources

Not Applicable

13.22.2.4 Number of Other Utility Truck Stations

One truck station for diesel unloading.

13.22.2.5 Other Utility Operating and Design Storage Capacities (Minimum, Normal, Maximum), gal

1X100% Diesel Storage Tank will be designed to store diesel for three (3) days of combined supply to all users (i.e. Diesel can be supplied for three (3) days of continuous operation of diesel driven Air Compressor and diesel driven Fire Water Pump when operating at the same time without any incoming diesel to the storage tank.)

An additional 1,000 gallon of storage capacity is provided to store diesel for in plant vehicle use.

13.22.2.6 Other Utility Operating and Design Flow Rate Capacities (Minimum, Normal, Maximum), gpm

The Diesel Transfer Pumps (PBS911702) have a rated flow rate of 55 gpm.

13.22.2.7 Other Utility Operating and Design Pressures (Minimum, Normal, Maximum), psig

The Diesel Transfer Pumps (PBS911702) have a rated suction pressure of 1 psig and a discharge pressure of 35 psig.

13.22.2.8 Utility Truck Scales

Not Applicable

13.22.2.9 Utilities Startup and Operation

Startup and Operation sequence for the diesel system will be developed in detailed design phase

13.22.2.10 Utilities Isolation Valves, Drains, and Vents

This system shall be isolatable through a series of manual valves and depressurization lines for maintenance activities. Further information on isolation, vents and drains can be found on drawings in Appendix 13.E.5.

13.22.2.11 Utilities Basic Process Control Systems

The system shall be remotely operated through the plant DCS. Plant alarms shall alert operations to out of bound conditions set by the equipment manufacturer or EPC.

13.22.2.12 Utilities Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system shall initiate shutdown valves to isolate the operation as described in Appendix 13.E.5 and 13.N.1.

13.22.2.13 Utilities Relief Valves and Discharge

Relief valves are sized according to the governing scenario for each piece of equipment. Further information is provided in Appendix 13.R.1 and 13.R.2.

13.22.2.14 Utilities Other Safety Features

No other safety features have been identified. Further features may be added during detailed design.

13.23 PIPING AND VALVES

13.23.1 Piping and Valve Design

Piping systems for the Liquefaction Facility are described below. The use of flanges in cryogenic piping will be minimized, except where entry or disassembly for inspection or maintenance after start-up will be anticipated or required, such as for heat exchangers or relief valves.

Strategic efforts will be made to minimize the number and size of penetrations. Wherever possible, penetrations for sensing lines for level, pressure, and differential pressure will be combined for both local and remote instrumentation.

LNG headers and dead-headed piping will be provided with a means for maintenance cooling. Piping that serves in intermittent operation will also be provided with a means for maintenance cooling.

The majority of the equipment and piping systems will be located in shop-fabricated modules. The equipment and piping systems will be arranged to achieve the most efficient process flow. Arrangements will provide maintenance and operation access along with any required platforms. Each module will have either a small pipe spool or single weld ("golden" weld) to make the final connection between modules. This "golden" weld will be radiographed to ensure the integrity of the weld. Final connection of trains will either be flanged or a welded. Details of these connections will be completed during a later phase of the Project.

Process-related piping systems are designed in accordance with following Piping Specifications included in Appendix 13.F.2.

TABLE 13.23.1

Piping Specifications

Drawing Number	Description
USAI-PT-LSPDS-00-000001-000	Piping Material Classifications Line Class 150
USAI-PT-LSPDS-00-000002-000	Piping Material Classifications Line Class 300
USAI-PT-LSPDS-00-000003-000	Piping Material Classifications Line Class 600
USAI-PT-LSPDS-00-000004-000	Piping Material Classifications Line Class 900
USAI-PT-LSPDS-00-000005-000	Piping Material Classifications Line Class 1500
USAI-PT-LSPDS-00-000006-000	Piping Material Classifications Line Class 2500

13.23.1.1 Piping and Valve List(s)

Piping and valves are shown on the P&IDs included in Appendix 13.E.5. A final piping and valve list will be provided in detailed design.

13.23.1.2 Tie-In List(s)

Tie-ins are shown on the P&IDs included in Appendix 13.E.5. A final tie-in list will be provided in detailed design

13.23.1.3 Isolation, Vent and Drain Philosophies

Preliminary isolation, vent and drain configurations are shown on the P&IDs in Appendix 13.E.5. Final configuration to be determined in detailed design.

13.23.1.4 Car Seal and Lock Philosophy

Preliminary car seals and lock-out tag-out configurations are shown on the P&IDs in Appendix 13.E.5. Final configuration to be determined in detailed design.

13.23.1.5 Piping Layout

The locations of major pipe racks at the LNG Facility are shown in the general plot plans included in Appendix 13.A.1. See Section 13.23.1.6 for additional detail on the general piperack layouts.

13.23.1.6 Pipe Supports and Pipe Racks

Utility and process pipes as well as cable trays will be supported on structural steel pipe racks and/or miscellaneous pipe supports which will be serving and connecting the different process units in each of the liquefaction processing trains and the supporting utilities. These structures will be supported on reinforced concrete foundations with piles where required. Typical pipe rack drawings are detailed below and included in Appendix 13.E.

Drawing Number	Description
USAL-CB-NDCPT-00-000274-001	Structural Steel Overall Piperacks Key Plan Layout
USAL-CB-NDCPT-00-000274-002	Structural Steel Main Unit Piperack Transverse Elevation Section A
USAL-CB-NDCPT-00-000274-003	Structural Steel Main Unit Piperack Longitudinal Elevation Section B
USAL-CB-NDCPT-00-000274-004	Structural Steel Piperack Typical Bents Section C through J
USAL-CB-NDCPT-00-000274-005	Structural Steel Piperack Longitudinal Elevation Section K and L
USAL-CB-NDCPT-00-000274-006	Structural Steel Piperack Longitudinal Elevation Section M through P

13.23.1.7 Piping, Valve, Flange and Insulation Design and Specifications

The Piping Specifications included in Appendix 13.F of this Resource Report defines the acceptable piping components and minimum requirements for piping materials for all piping classes.

Piping will be insulated where necessary to conserve energy, maintain process stability, reduce noise (acoustic insulation), protect personnel and/or to prevent moisture condensation and freezing. Insulation thickness will be based upon design parameters relevant to site conditions, including cold or hot service, ambient temperature, relative humidity, wind velocity and maximum heat gain/loss.

Piping insulation specifications are identified in Document No. USAL-CB-RSPDS-00-290220-000, USAL-CB-RSPDS-00-290221-000 and USAL-CB-RSPDS-00-015665-000 (included in Appendix 13.F).

13.23.1.7.1 Conditions and Loads (E.G. Pressures, Temperatures, Vibration, Internal And External Corrosion, Etc.)

The Piping Specifications included in Appendix 13.F of this Resource Report defines the acceptable loads for piping.

13.23.1.7.2 Material of Construction Temperature Limits

The Piping Specifications included in Appendix 13.F of this Resource Report defines the acceptable piping temperature limits.

13.23.1.7.3 Material of Construction Allowable Stress Limits

The Piping Specifications included in Appendix 13.F of this Resource Report defines the acceptable piping stress limits.

13.23.1.7.4 Material of Construction Corrosivity Potential And Corrosion Allowance

The Piping Specifications included in Appendix 13.F of this Resource Report defines the acceptable corrosion allowances.

13.23.1.7.5 Cathodic Protection

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the facility.

13.23.1.8 Positive Material Identification Requirements*

An asterisk (*) indicates guidance is optional and will be provided in detailed design

13.23.1.9 Post Weld Heat Treatment*

An asterisk (*) indicates guidance is optional and will be provided in detailed design

13.23.1.10 Non-Destructive Examination (NDE)*

An asterisk (*) indicates guidance is optional and will be provided in detailed design

13.23.1.10.1 Weld Radiographic/Ultrasonic Testing

The Piping Specifications included in Appendix 13.F of this Resource Report defines the necessary testing requirements.

13.23.1.10.2 Magnetic Particle or Liquid Penetrant Examination

The Piping Specifications included in Appendix 13.F of this Resource Report defines the necessary testing requirements.

13.23.1.10.3 Pneumatic/Hydrostatic Leak Testing Medium and Pressure

The Piping Specifications included in Appendix 13.F of this Resource Report defines the necessary testing requirements.

13.23.1.10.4 Other

Not Applicable

13.23.1.11 Piping and Valve Preventive Maintenance*

An asterisk (*) indicates guidance is optional and will be provided in detailed design.

13.23.1.11.1 Internal and External Examination

An asterisk (*) indicates guidance is optional and will be provided in detailed design.

13.23.1.11.2 Corrosion Under Insulation

An asterisk (*) indicates guidance is optional and will be provided in detailed design.

13.23.1.11.3 Metal thickness tests

An asterisk (*) indicates guidance is optional and will be provided in detailed design.

13.24 PROCESS VESSELS

13.24.1 Process Vessel Design

The Project Master Equipment List, Document No. USAL-CB-MLMEL-00-000001-000, which summarizes the major process equipment and applicable design conditions for the facility, is included in Appendix M. The listed process equipment is reflective of the required equipment to meet the design of Train 1, and the majority of this equipment will be replicated in Trains 2 and 3. The definition of the area designators (i.e., the fourth set of characters in the document number) is as follows: bullet 10 – Train 1, bullet 50 – Common Process and so on. A “50” for the area designator indicates the equipment will be in the Common Process area (Inlet Facility, Fractionation). A “60” for the area designator indicates the equipment will be in the Utilities area (Power Generation, Diesel Oil Unit, Water System, Air and Nitrogen). A “70” for the area designator indicates the equipment will be in the Offsite Facilities/Infrastructure area (Wet & Dry Flare KO Drums, Flare, Effluent Treatment, Refrigerant Storage, Impounds, Non-Process Buildings etc.). An “80” for the area designator indicates the equipment will be in the Storage and Loading area (BOG compression, LP Flare, Condensate Storage, LNG Storage, Tanks, Topsides)

13.24.1.1 Process Vessel List

Tag Number	Equipment Title
USAL-CB-PTTDS-10-HBG666197	Propane Reclaimer Condenser HBG666197
USAL-CB-PTTDS-10-HBG695101	Feed Gas/MP Propane Cooler HBG695101
USAL-CB-PTTDS-10-HBG695102	Feed Gas/LP Propane Cooler HBG695102
USAL-CB-PTTDS-10-HFF666121	LP MR Compressor Intercooler HFF666121/61
USAL-CB-PTTDS-10-HFF666122	MP MR Compressor Intercooler HFF666122/62
USAL-CB-PTTDS-10-HFF666131	HP MR Compressor Desuperheater HFF666131/71
USAL-CB-PTTDS-10-HFF666132	HP MR Compressor After-Cooler HFF666132/72
USAL-CB-PTTDS-10-HFF666144	Propane Desuperheater HFF666144/84
USAL-CB-PTTDS-10-HFF666191	Propane Condenser HFF666191
USAL-CB-PTTDS-10-HFF666193	Propane Subcooler HFF666193
USAL-CB-PTTDS-10-HFF695110	Scrub Column Cooler HFF695110
USAL-CB-PTTDS-10-MAF695104	Scrub Column MAF695104
USAL-CB-PTTDS-10-MBA666192	Propane Accumulator MBA666192
USAL-CB-PTTDS-10-MBA666194	Propane Transfer Drum MBA666194
USAL-CB-PTTDS-10-MBA666196	Propane Reclaimer MBA666196
USAL-CB-PTTDS-10-MBD666101	HP MR Separator MBD666101
USAL-CB-PTTDS-10-MBD666106	LP MR Compressor Suction Drum MBD666106/107
USAL-CB-PTTDS-10-MBD666123	HP MR Compressor Suction Drum MBD666123/163
USAL-CB-PTTDS-10-MBD666124	MP MR Compressor Suction Drum MBD666124/164
USAL-CB-PTTDS-10-MBD666141	LP Propane Suction Drum MBD666141/181
USAL-CB-PTTDS-10-MBD666142	MP Propane Suction Drum MBD666142/182
USAL-CB-PTTDS-10-MBD666143	HP Propane Suction Drum MBD666143/183
USAL-CB-PTTDS-10-MBD695107	Scrub Column Reflux Drum MBD695107
USAL-CB-PTTDS-50-HBG631503	Deethanizer Condenser HBG631503
USAL-CB-PTTDS-50-HBG631519	LPG Reinjection Cooler HBG631519
USAL-CB-PTTDS-50-HFF631508	Depropanizer Condenser HFF631508
USAL-CB-PTTDS-50-HFF631514	Debutanizer Condenser HFF631514
USAL-CB-PTTDS-50-HFF631518	Debutanizer Condensate Product Cooler HFF631518
USAL-CB-PTTDS-50-HFF661509	Regeneration Gas Cooler HFF661509
USAL-CB-PTTDS-50-HFF966506	BOG Recycle Compressor After-Cooler HFF966506
USAL-CB-PTTDS-50-MAF631501	Deethanizer Column MAF631501
USAL-CB-PTTDS-50-MAF631506	Depropanizer Column MAF631506
USAL-CB-PTTDS-50-MAF631512	Debutanizer Column MAF631512
USAL-CB-PTTDS-50-MAJ623503	Inlet Gas Filters MAJ623503A/B/C
USAL-CB-PTTDS-50-MAJ661510	Molecular Sieve Dryer After-Filters MAJ661510A/B/C

Tag Number	Equipment Title
USAL-CB-PTTDS-50-MAJ669504	Mercury Adsorber After-Filters MAJ669504A/B/C
USAL-CB-PTTDS-50-MAJ966501	Start Up Fuel Gas Filter MAJ966501
USAL-CB-PTTDS-50-MBA661502	Molecular Sieve Dryer MBA661502/3/4/5/6/7
USAL-CB-PTTDS-50-MBA669501	Mercury Adsorber MBA669501/2/3
USAL-CB-PTTDS-50-MBD623504	Inlet Gas Heater Condensate Pot MBD623504
USAL-CB-PTTDS-50-MBD631504	Deethanizer Reflux Drum MBD631504
USAL-CB-PTTDS-50-MBD631509	Depropanizer Reflux Drum MBD631509
USAL-CB-PTTDS-50-MBD631515	Debutanizer Reflux Drum MBD631515
USAL-CB-PTTDS-50-MBD631520	LPG Reinjection KO Drum MBD631520
USAL-CB-PTTDS-50-MBD631522	Fractionation FEED Separator MBD631522
USAL-CB-PTTDS-50-MBD631545	Deethanizer Reboiler Condensate Pot MBD631545
USAL-CB-PTTDS-50-MBD631546	Depropanizer Reboiler Condensate Pot MBD631546
USAL-CB-PTTDS-50-MBD631547	Debutanizer Reboiler Condensate Pot MBD631547
USAL-CB-PTTDS-50-MBD661512	Regeneration Gas KO Drum MBD661512
USAL-CB-PTTDS-50-MBD966510	HP Fuel Gas Heater Condensate Pot MBD966510
USAL-CB-PTTDS-50-MFG965501	LP Fuel Gas Drum MFG965501
USAL-CB-PTTDS-50-MFG966503	HP Fuel Gas Mixing Drum MFG966503
USAL-CB-PTTDS-50-NAP966516	Excess LPG Vaporizer NAP966516
USAL-CB-PTTDS-60-ABJ987663	Steam Condensate Tank ABJ987663
USAL-CB-PTTDS-60-HBG987666	Contaminated Condensate Cooler HBG987666
USAL-CB-PTTDS-60-HFF948616	Blowdown Cooler 1 HFF948616
USAL-CB-PTTDS-60-HFF987618	LP Steam Dump Condenser 1 HFF987618
USAL-CB-PTTDS-60-HFF987661	Steam Condensate Cooler HFF987661
USAL-CB-PTTDS-60-HFF987668	LP Steam Condenser HFF987668
USAL-CB-PTTDS-60-HPL987662	Demin/Condensate Exchanger HPL987662
USAL-CB-PTTDS-60-MAJ977632	Activated Carbon Cartridge Filters MAJ977632A/B
USAL-CB-PTTDS-60-MAJ987665	Condensate Activated Carbon Filter MAJ987665A/B/C
USAL-CB-PTTDS-60-MAM956602	Compressed Air Receiver MAM956602
USAL-CB-PTTDS-60-MBD976640	Freshwater Pre-Heater Condensate Pot MBD976640
USAL-CB-PTTDS-60-MBD987667	LP Condensate Separator MBD987667
USAL-CB-PTTDS-60-MBE961630	Nitrogen Receiver MBE961630
USAL-CB-PTTDS-60-MIA956610	Instrument Air Receiver MIA956610
USAL-CB-PTTDS-60-V961640	High Purity Liquid Nitrogen Storage & Vaporizer Package V961640
USAL-CB-PTTDS-60-V976610	Clarification and Filter Press Package V976610
USAL-CB-PTTDS-70-BBJ997720	Equalization Tank BBJ997720
USAL-CB-PTTDS-70-MAJ911704	Diesel Fuel Filter MAJ911704

Tag Number	Equipment Title
USAL-CB-PTTDS-70-MAJ911705	Diesel Truck Unloading Filter MAJ911705
USAL-CB-PTTDS-70-MBD612701	Dry Flare KO Drum MBD612701
USAL-CB-PTTDS-70-MBD612705	Wet Flare KO Drum MBD612705
USAL-CB-PTTDS-70-MBD612708	Dry Flare Blowcase MBD612708
USAL-CB-PTTDS-70-MBJ698701	Ethane Refrigerant Storage Bullets MBJ698701/2
USAL-CB-PTTDS-70-MBJ698721	Propane Refrigerant Storage Bullets MBJ698721/2/3/4
USAL-CB-PTTDS-70-MBJ964750	Slop Oil Tank MBJ964750
USAL-CB-PTTDS-70-NAP612709	Scrub Column Bottoms Vaporizer NAP612709
USAL-CB-PTTDS-70-NAP698711	Ethane Vaporizers NAP698711/12
USAL-CB-PTTDS-70-NBJ911701	Diesel Storage Tank NBJ911701
USAL-CB-PTTDS-70-PBD997721	Equalization Tank Skimmer PBD997721
USAL-CB-PTTDS-70-V997731	CPI Separator Package V997731
USAL-CB-PTTDS-70-V997740	DGF Package V997740
USAL-CB-PTTDS-80-HFF691843	BOG Compressor After-Coolers HFF691843/53/63
USAL-CB-PTTDS-80-JAR691816	BOG Compressor Suction Drum Desuperheaters JAR691816/26/36
USAL-CB-PTTDS-80-MAB691840	BOG Compressor Suction Drum Blowcase MAB691840
USAL-CB-PTTDS-80-MAB691877	Loading Arm Drain/Surge Drum Blowcase Berth 1/2 MAB691877/87
USAL-CB-PTTDS-80-MBD613801	LP Flare KO Drum MBD613801
USAL-CB-PTTDS-80-MBD691815	BOG Compressor Suction Drums MBD691815/25/35

13.24.1.2 Process Vessel Layout

In accordance with requirements in Section 2.2 and also Section 3.4 of the NFPA 59A – 2001, equipment and buildings have been located to provide adequate access for normal operation and maintenance activities.

In accordance with requirements of Section 3.1 and 3.2 of NFPA 59A – 2001, process equipment will be located outdoors where feasible for ease of operation and to facilitate manual firefighting and dispersal of accidentally released liquids and gases. Enclosed structures or buildings where process equipment will be located will have enough ventilation or cover in accordance with the requirements of Sections 2.3.2 and 2.3.3 of NFPA 59A - 2001.

13.24.1.3 Process Vessel Support

To be determined in detailed design. Support structures will be properly designed to support the necessary loads.

13.24.1.4 Process Vessel and Insulation Design and Specifications

A list of specifications to be developed in detailed design as well as the preliminary specifications prepared are included in Appendix 13.F.

13.24.1.4.1 Conditions and Loads (e.g. Pressures, Temperatures, Vibration, Internal and External Corrosion, Etc.)

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility.

13.24.1.4.2 Material of Construction Allowable Stress Limits

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.24.1.4.3 Material of Construction Temperature Limits

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.24.1.4.4 Material of Construction Corrosivity Potential and Corrosion Allowance

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.24.1.4.5 Cathodic Protection

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.24.1.5 NDE

Process vessel testing requirements will be performed in accordance with all applicable codes. The EPC contractor will provide testing requirements for all process vessels.

13.24.1.5.1 Magnetic Particle or Liquid Penetrant Examination

To be determined in detailed design.

13.24.1.5.2 Full or Spot Radiographic or Ultrasonic Testing

To be determined in detailed design.

13.24.1.5.3 Pneumatic or Hydrostatic Leak Testing Pressure

To be determined in detailed design.

13.24.1.6 Process Vessel Preventive Maintenance

Preventative maintenance will be performed in accordance with FERC requirements. Maintenance will include inspections (visual and/or internal, where applicable) for corrosion, deterioration, or abnormal visual indications.

13.24.1.6.1 Internal and External Examination

To be determined in detailed design.

13.24.1.6.2 Corrosion Under Insulation

To be determined in detailed design.

13.24.1.6.3 Metal Thickness Tests

To be determined in detailed design.

13.25 ROTATING EQUIPMENT

13.25.1 Rotating Equipment Design*

The Project Master Equipment List, Document No. USAL-CB-MLMEL-00-000001-000, which summarizes the major process equipment and applicable design conditions for the facility, is included in Appendix M. The listed process equipment is reflective of the required equipment to meet the design of Train 1, and the majority of this equipment will be replicated in Trains 2 and 3. The definition of the area designators (i.e., the fourth set of characters in the document number) is as follows: bullet 10 – Train 1, bullet 50 – Common Process and so on. A “50” for the area designator indicates the equipment will be in the Common Process area (Inlet Facility, Fractionation). A “60” for the area designator indicates the equipment will be in the Utilities area (Power Generation, Diesel Oil Unit, Water System, Air and Nitrogen). A “70” for the area designator indicates the equipment will be in the Offsite Facilities/Infrastructure area (Wet & Dry Flare KO Drums, Flare, Effluent Treatment, Refrigerant Storage, Impounds, Non-Process Buildings etc.). An “80” for the area designator indicates the equipment will be in the Storage and Loading area (BOG compression, LP Flare, Condensate Storage, LNG Storage, Tanks, Topsides)

13.25.1.1 Rotating Equipment and Drivers List

Tag Number	Equipment Title
USAL-CB-feet TDS-60-PFW411601	Firewater Pump (Electric) PFW411601
USAL-CB-feet TDS-60-PFW411602	Firewater Pump (Diesel) PFW411602
USAL-CB-feet TDS-60-PFW411603	Firewater Jockey Pump PFW411603A/B
USAL-CB-PTTDS-00-BBH973001	Sanitary Lift Stations and Pumps BBH973001/2/3/4/5/6/7/8/9/10 PBH973011/2/3/4/5/6/7/8/9/20A/B
USAL-CB-PTTDS-10-CAE666112	Propane Refrigerant Compressor CAE666112/52

Tag Number	Equipment Title
USAL-CB-PTTDS-10-CAE666113	LP MR Compressor CAE666113/53
USAL-CB-PTTDS-10-CAE666114	MP/HP MR Compressor CAE666114/54
USAL-CB-PTTDS-10-HBG666103	MR/LP Propane Cooler HBG666103
USAL-CB-PTTDS-10-HBG666104	MR/MP Propane Cooler HBG666104
USAL-CB-PTTDS-10-HBG666105	MR/HP Propane Cooler HBG666105
USAL-CB-PTTDS-10-PBA666195	Propane Transfer Pump PBA666195
USAL-CB-PTTDS-10-PBA695106	Scrub Column Reflux Pumps PBA695106A/B
USAL-CB-PTTDS-10-TGT666102	MR Hydraulic Turbine TGT666102
USAL-CB-PTTDS-10-TGT695109	LNG Hydraulic Turbine TGT695109
USAL-CB-PTTDS-50-CAR966505	BOG Recycle Compressor CAR966505
USAL-CB-PTTDS-50-PBA631505	Deethanizer Reflux Pumps PBA631505A/B
USAL-CB-PTTDS-50-PBA631510	Depropanizer Reflux Pumps PBA631510A/B
USAL-CB-PTTDS-50-PBA631511	Propane Reinjection Pumps PBA631511A/B
USAL-CB-PTTDS-50-PBA631516	Debutanizer Reflux Pumps PBA631516A/B
USAL-CB-PTTDS-50-PBA631517	Butane Reinjection Pumps PBA631517A/B
USAL-CB-PTTDS-50-PBA631521	LPG Reinjection Pumps PBA631521A/B
USAL-CB-PTTDS-60-PBA976601	Well Pumps PBA976601/602/641/642
USAL-CB-PTTDS-60-PBA976607	Freshwater Tank Pumps PBA976607A/B
USAL-CB-PTTDS-60-PBA976608	Firewater Make Up Pumps PBA976608/648
USAL-CB-PTTDS-60-PBA976628	Filtered Water Forwarding Pumps PBA976628A/B
USAL-CB-PTTDS-60-PBA977602	RO Permeate Forwarding Pumps PBA977602A/B
USAL-CB-PTTDS-60-PBA977630	Potable Water Forwarding Pumps PBA977630A/B
USAL-CB-PTTDS-60-PBA979632	Demineralized Water Forwarding Pumps PBA979632A/B
USAL-CB-PTTDS-60-PBE987664	Steam Condensate Tank Pumps PBE987664A/B/C
USAL-CB-PTTDS-60-PBE987669	LP Condensate Pumps PBE987669A/B
USAL-CB-PTTDS-60-PBH976616	Reclaimed Water Sump Pumps PBH976616A/B
USAL-CB-PTTDS-60-PBH979634	Chemical Sump Lift Pumps PBH979634A/B
USAL-CB-PTTDS-60-PBM976617	Clarified Water Forwarding Pumps PBM976617A/B
USAL-CB-PTTDS-60-PBM977612	Sodium Hypochlorite Distribution Pumps PBM977612A/B
USAL-CB-PTTDS-60-V955601	Air Compressor Package V955601
USAL-CB-PTTDS-70-PBA634702	Condensate Loading Pumps PBA634702A/B
USAL-CB-PTTDS-70-PBA634705	Offspec Condensate Pump PBA634705A/B
USAL-CB-PTTDS-70-PBA698713	Propane Unloading Pump PBA698713
USAL-CB-PTTDS-70-PBA698718	Propane Storage Pump PBA698718
USAL-CB-PTTDS-70-PBA911702	Diesel Transfer Pumps PBA911702A/B
USAL-CB-PTTDS-70-PBA964734	CPI Slop Oil Pumps PBA964734A/B

Tag Number	Equipment Title
USAL-CB-PTTDS-70-PBA964736	CPI Sludge Pumps PBA964736A/B
USAL-CB-PTTDS-70-PBA997722	Equalization Tank Pumps PBA997722A/B
USAL-CB-PTTDS-70-PBA997769	Flotation Unit Sludge Pumps PBA997769A/B
USAL-CB-PTTDS-70-PBE612706	Wet Flare KO Drum Pump PBE612706A/B
USAL-CB-PTTDS-70-PBE964751	Slop Oil Transfer Pump PBE964751
USAL-CB-PTTDS-70-PBH991111	Oil Sump Pumps PBH991111/611/612 A/B
USAL-CB-PTTDS-70-PBH997121	PCSW Collection Sump 1 Pump PBH997111/121/112/122/511/521/611/621/612/622/613/623/614/624
USAL-CB-PTTDS-70-PBH997523	PCSW Collection Sump 3 Pump PBH997513/23
USAL-CB-PTTDS-70-PBH997647	PCSW Collection Sump 2 Pump PBH997627/28/47/48
USAL-CB-PTTDS-70-PBH997764	Observation Basin Pumps PBH997764/65
USAL-CB-PTTDS-70-PBH998112	Liquefaction Compressor Impoundment Sump Pumps PBH998112/22/13/23
USAL-CB-PTTDS-70-PBH998121	Liquefaction Train Impoundment Sump Pumps PBH998111/21
USAL-CB-PTTDS-70-PBH998512	Fractionation Area Impoundment Sump Pumps PBH998512/22
USAL-CB-PTTDS-70-PBH998521	Inlet Facilities Area Impoundment Sump Pumps PBH998511/21
USAL-CB-PTTDS-70-PBH998713	OSBL Piperack Area Impoundment Sump Pumps PBH998713/23
USAL-CB-PTTDS-70-PBH998721	Condensate Truck Loading Area Impoundment Sump Pumps PBH998721/711
USAL-CB-PTTDS-70-PBH998722	Refrigerant Storage Area Impoundment Sump Pumps PBH998712/22
USAL-CB-PTTDS-70-PBH998813	LNG Storage Tank Area Impoundment Sump Pumps PBH998813/23
USAL-CB-PTTDS-70-PBH998814	BOG Compressor Area Impoundment Sump Pumps PBH998814/24
USAL-CB-PTTDS-70-PBH998821	LNG Loading Berth 1/2 Impoundment Sump Pumps PBH998811/21/12/22
USAL-CB-PTTDS-80-CAE691841	LP/HP BOG Compressors CAE691841/42/51/52/61/62
USAL-CB-PTTDS-80-PBA691811	LNG Loading & Circulating Pumps PBA691811/12/13/14/21/22/23/24

13.25.1.2 Rotating Equipment Layout

Rotating equipment is shown on the plot plans included in Appendix 13.E.6. An equipment list is provided in Appendix 13.M.3. A final equipment list and plot plan will be provided in detailed design.

13.25.1.3 Rotating Equipment Support

To be determined in detailed design. Support structures will be properly designed to support the necessary loads.

13.25.1.4 Rotating Equipment Design And Specifications

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility.

13.25.1.4.1 Conditions and Loads (e.g. Pressures, Temperatures, Vibration, Internal And External Corrosion, Etc.)

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.25.1.4.2 Performance Curves

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.25.1.4.3 Material Of Construction Allowable Stress Limits

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.25.1.4.4 Material Of Construction Temperature Limits

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.25.1.4.5 Material Of Construction Corrosivity Potential And Corrosion Allowance

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.25.1.4.6 Cathodic Protection

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.25.1.5 Machinery Monitoring System

Monitoring systems will be designed in accordance with all applicable codes and based on vendor requirements. Details of the machinery monitoring systems will be available in detailed design.

13.25.1.6 Rotating equipment preventive maintenance

Preventative maintenance will be performed in accordance with all applicable codes and based on vendor requirements. Equipment monitoring systems will have performance monitoring which will allow operators and vendors to identify deviations in typical equipment parameters. Details of the preventative maintenance plans will be available in detailed design.

13.25.1.6.1 Performance monitoring and tests

Details of the performance monitoring plans will be available in detailed design.

13.26 FIRED EQUIPMENT

13.26.1 Fired Equipment Design*

The Project Master Equipment List, Document No. USAL-CB-MLMEL-00-000001-000, which summarizes the major process equipment and applicable design conditions for the facility, is included in Appendix M. The listed process equipment is reflective of the required equipment to meet the design of Train 1, and the majority of this equipment will be replicated in Trains 2 and 3. The definition of the area designators (i.e., the fourth set of characters in the document number) is as follows: bullet 10 – Train 1, bullet 50 – Common Process and so on. A “50” for the area designator indicates the equipment will be in the Common Process area (Inlet Facility, Fractionation). A “60” for the area designator indicates the equipment will be in the Utilities area (Power Generation, Diesel Oil Unit, Water System, Air and Nitrogen). A “70” for the area designator indicates the equipment will be in the Offsite Facilities/Infrastructure area (Wet & Dry Flare KO Drums, Flare, Effluent Treatment, Refrigerant Storage, Impounds, Non-Process Buildings etc.). An “80” for the area designator indicates the equipment will be in the Storage and Loading area (BOG compression, LP Flare, Condensate Storage, LNG Storage, Tanks, Topsides)

13.26.1.1 Fired equipment list

Tag Number	Equipment Title
USAL-CB-feet TDS-60-BAP412602	Firewater Tank Heater BAP412602A/B
USAL-CB-PTTDS-10-NAP661113	Defrost Gas Heater NAP661113
USAL-CB-PTTDS-50-HBG623501	Inlet Gas Heater HBG623501
USAL-CB-PTTDS-50-HBG966515	HP Fuel Gas Heater HBG966515
USAL-CB-PTTDS-50-NAP661513	Regeneration Gas Heater NAP661513/14
USAL-CB-PTTDS-50-NAP966502	Start Up Fuel Gas Heater NAP966502
USAL-CB-PTTDS-60-HBG976609	Freshwater Pre-Heater HBG976609
USAL-CB-PTTDS-70-EAL634706	Thermal Oxidizer EAL634706
USAL-CB-PTTDS-70-FLRH612703	Wet and Dry Ground Flare FLRH612703A/B/C
USAL-CB-PTTDS-80-FLRL613800	LP Flare FLRL613800

13.26.1.2 Fired equipment layout

Fired equipment is shown on the plot plans included in Appendix 13.E.6. An equipment list is provided in Appendix 13.M.3. A final equipment list and plot plan will be provided in detailed design.

13.26.1.3 Fired equipment support

To be determined in detailed design. Support structures will be properly designed to support the necessary loads.

13.26.1.4 Fired equipment design and specifications

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility.

13.26.1.4.1 Conditions and loads (e.g. pressures, temperatures, vibration, internal and external corrosion, etc.)

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.26.1.4.2 Duty

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.26.1.4.3 Material of construction allowable stress limits

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.26.1.4.4 Material of construction temperature limits

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.26.1.4.5 Material of construction corrosivity potential and corrosion allowance

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.26.1.4.6 Cathodic protection

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.26.1.5 Burner Management System

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.26.1.6 Fired equipment preventive maintenance

A list of specifications to be developed in detailed design is included in Appendix 13.F. Appendix 13.F includes preliminary specifications for the LNG Facility

13.26.1.6.1 Performance monitoring and tests

Details of the performance monitoring plans will be available in detailed design.

13.27 BUILDINGS AND STRUCTURES

13.27.1 Buildings and Structures Design

Construction will be in accordance with code requirements consistent with the function of each building and structure, though in general, buildings will be pile supported with a concrete slab, or pile cap floor.

Where required by code, buildings and structures that house liquefaction process equipment will be constructed of open frames and non-load bearing walls. For further details regarding the Buildings' Design Criteria, refer to the Structural Design Criteria, Document No. USAL-CB-NBDES-00-000004-000 located in Appendix 13.B.14.

13.27.1.1 Buildings list with dimensions and purpose

Table 13.27.1.1 provides a list of buildings and structures and their preliminary dimensions.

TABLE 13.27.1.1

Project List of Buildings and Structures with Dimensions and Purpose

Building or Structure	Purpose	Approximate Size (square feet)
South Guard House	Guard House	600
Warehouse Area	Storage	56,200
Maintenance Area	Maintenance	30,600
Central Control Room	Operations and Control	20,000
Marine Terminal Building	Loading Operations and Control	2,800
Power Generation GIS Substation	Substation	5,400
Essential Power Substation	Substation	5,400
Main Substation – Train 1	Substation	5,400
Main Substation – Train 2	Substation	5,400
Main Substation – Train 3	Substation	5,400
Auxiliary Substation	Substation	4, 200
Offsites Substation	Substation	5,400
Gas Treatment Substation	Substation	5,400
Utilities Substation	Substation	5,400
BOG Substation	Substation	5,400
Jetty Area Substation	Substation	2,700
Berth 1 Substation	Substation	2,700
Berth 2 Substation	Substation	2,700
MOF Substation	Substation	2,000
Refrigerant Compressor 1 – Train-1	Compressor Weather Protection	24,000
Refrigerant Compressor 2 – Train-1	Compressor Weather Protection	24,000
Refrigerant Compressor 1 – Train-2	Compressor Weather Protection	24,000
Refrigerant Compressor 2 – Train-2	Compressor Weather Protection	24,000

TABLE 13.27.1.1

Project List of Buildings and Structures with Dimensions and Purpose

Building or Structure	Purpose	Approximate Size (square feet)
Refrigerant Compressor 1 – Train-3	Compressor Weather Protection	24,000
Refrigerant Compressor 2 – Train-3	Compressor Weather Protection	24,000

13.27.1.2 Building and structure design and specifications

For further details regarding the Buildings' Design Criteria, refer to the Structural Design Criteria, Document No. USAL-CB-NBDES-00-000004-000 located in Appendix 13.B.14.

13.27.1.3 Building layout and siting

The Building Drawings, which provide preliminary plans and elevations of buildings, are referenced below and included in Appendix 13.M.8.

Drawing Number	Description
USAL-CB-CDAED-00-SEC066101-001	Architectural Main Guard House Preliminary Plan
USAL-CB-CDAED-00-SEC066101-002	Architectural Main Guard House Preliminary Elevation A & B
USAL-CB-CDAED-00-SEC066101-003	Architectural Main Guard House Preliminary Elevation C & D
USAL-CB-CDAED-00-WHSE064101-001	Architectural Warehouse Building Preliminary Plan
USAL-CB-NDCPT-00-000063-002	Structural Typical Compressor Shelter Preliminary Roof Plan [a]
USAL-CB-NDCPT-00-000063-003	Structural Typical Compressor Shelter Preliminary Plan at Crane Rail Beam [a]
USAL-CB-NDCPT-00-000063-004	Structural Typical Compressor Shelter Preliminary Plan at Operating Platform [a])
USAL-CB-NDCPT-00-000063-005	Structural Typical Compressor Shelter Preliminary Elevation at Col. Line A & B [a]
USAL-CB-NDCPT-00-000063-006	Structural Typical Compressor Shelter Preliminary Elevation at Col. Line 1 through 7 [a]

Notes:

[a] Applicable to the Refrigerant Compressor 1 - Train-1, Refrigerant Compressor 2 - Train-1, Refrigerant Compressor 1 - Train-2, Refrigerant Compressor 2 - Train-2, Refrigerant Compressor 1 - Train-3, Refrigerant Compressor 2 - Train-3

13.28 ELECTRICAL

13.28.1 Power Requirements

The Liquefaction Facility electrical system, equipment, and installation will be designed in accordance with the Applicable National Codes, Local Codes and Regulations and Federal Regulations. The system will be designed to maximize reliability and safety while considering costs, ease of maintenance.

Power for the Liquefaction Facility will be provided from in-plant generators that generate at 13.8 kilovolts, 3-phase, 60 hertz. Power will be fed from a combined cycle power plant with four Gas Turbines and two Steam Turbine Generators in an N+1 configuration, such that any N generators will be able to provide the full power requirement for the liquefaction and marine facilities without supplemental firing. Load

Shedding and Power Management Systems will be utilized to allow reliable and ease of operation across all operating ranges.

In addition, the local utility grid, operated by Homer Electric Association (HEA), will be connected to the main switchgear in the main power distribution substation for essential power. Essential power will be distributed from the main power distribution substation to the major substations at 13.8 kilovolts. Essential loads will be energized with essential power during total blackout. Essential power will also be used as black start power for GTG starting and for feeding typical loads such as safety egress lighting in the plant, HVAC, instrument air compressors, battery chargers for the Un-interruptible Power Supply (UPS) system, critical valves, and essential lube oil, seal oil systems during black start.

The Liquefaction Facility Electrical System Design for the Project will conform to the standards, design documents and specifications outlined in the Electrical Design Basis document USAL-CB-EBDES-00-000001-000, in Appendix 13.B.1 and as shown on the Electrical Overall One Line diagram USAL-CB-EDSLD-00-000001-000, in Appendix 13.N.3.

The total calculated maximum load demand for normal operation is 103.8 MW (without including future load growth and contingency). Refer to the Electrical Load List and Summary USAL-CB-ELLSC-00-000001-00, in Appendix 13.N.1 for a breakdown of load requirements.

13.28.1.1 Main Power Supply, Utility/Generated

The main power supply will be generated by, on-site, generators that generate at 13.8kV, 3-phase, 60Hz. Power will be derived from a combined cycle power plant with multiple Gas & Steam Turbine Generators. Essential Power will be supplied from HEA via the local grid.

13.28.1.2 Electrical Equipment Layout Drawings*

The substation equipment layouts for the Liquefaction Facility are captured on the General Equipment Arrangement Diagrams for the Electrical Substations. The layout drawings are detailed below and included in Appendix 13.N.7.

Drawing Number	Title
USAL-CB-EDLAY-80-LER822872-001	Electrical General Equipment Arrangement Berth #1 Substation Building – LER822872 Building and Room Layout
USAL-CB-EDLAY-80-LER822873-001	Electrical General Equipment Arrangement Berth #2 Substation Building – LER822873 Building and Room Layout
USAL-CB-EDLAY-80-LER823870-001	Electrical General Equipment Arrangement BOG Substation Building – LER823870 Building and Room Layout
USAL-CB-EDLAY-80-LER823871-001	Electrical General Equipment Arrangement Jetty Area Substation Building – LER823871 Building and Room Layout

13.28.1.3 Cable Routing Drawings*

To be developed in detailed design.

13.28.1.4 Main Power Generators, Type

The main power generators will be gas turbine generators and steam turbine generators which will be installed on site as part of a combined cycle power plant.

13.28.1.5 Number of Main Power Generators, Including Any Black Start Generators

Four identical gas turbine generators (GTG) and two identical steam turbine generators (STG) will be installed on site as part of a 4 unit - 2x1 combined cycle power plant. Two GTGs and one STG in operation in one power unit and one GTG and one STG in operation in another unit (N mode) will supply 143 megawatts under average ambient conditions. A black start power system will be part of the 13.8kV essential bus in the main distribution substation with the local utility Homer Electric Association (HEA). Power supplied from the 13.8 kV essential power systems will be used for black start of one of the main GTGs.

13.28.1.6 Main Power Supply Voltage, Kilovolt (kV)

The main power supply will be generated by, on-site, generators that generate at 13.8kV, 3-phase, 60Hz. Refer to the Electrical Load List and Summary USAL-CB-ELLSC-00-000001-00, in Appendix 13.N.1 for a breakdown of requirements.

13.28.1.7 Main Power Supply Capacity, Kilovolt Ampere (kVa)

The main power supply capacity for normal operation is 117,880 kVa. Refer to the Electrical Load List and Summary USAL-CB-ELLSC-00-000001-00, in Appendix 13.N.1 for a breakdown of requirements.

13.28.1.8 Emergency Power Supply, Utility/Generated

Emergency loads and essential loads are normally powered from the normal power system. Upon the failure of normal power system, essential incoming circuit breaker will close and essential/emergency loads are powered from Local utility grid (Homer Electric Association).

13.28.1.9 Emergency Power Generators, Type

Not applicable

13.28.1.10 Number of Emergency Power Generators, No.

Not applicable

13.28.1.11 Emergency Power Voltage, kV

Not applicable

13.28.1.12 Emergency Power Capacity, kVa

Not applicable

13.28.1.13 UPS Services, Voltage, Size And Capacity, V, kVa, Hr

UPS power will be furnished from 12 UPS units, varying in capacity from 15 kVA to 50 kVA each. All are three phase units with output 208/120 volts. The systems will be designed to deliver capacity for 150 minutes. For additional information, refer to the Electrical Load List and Summary, Document No. USAL-CB-ELLSC-00-000001-000, included in Appendix O, and in the following table.

Drawing Number	Description
USAL-CB-ELLSC-00-000001-000	Electrical Load List and Summary
USAL-CB-EDSLD-00-000001-000	Overall Electrical One Line Diagram
USAL-CB-EDSLD-00-000002-000	Electrical One Line Diagram Typical Uninterruptable Power Supply
USAL-CB-EDSLD-10-000001-001	Electrical One Line Diagram Train 1 Substation – LER823170
USAL-CB-EDSLD-20-000001-001	Electrical One Line Diagram Train 2 Substation – LER823270
USAL-CB-EDSLD-30-000001-001	Electrical One Line Diagram Train 3 Substation – LER823370
USAL-CB-EDSLD-50-000001-001	Electrical One Line Diagram Gas Treatment Substation – LER823570
USAL-CB-EDSLD-60-000001-001	Electrical One Line Diagram Power Generation Auxiliary Substation – LER823671
USAL-CB-EDSLD-60-000002-001	Electrical One Line Diagram Utilities Substation -LER823672
USAL-CB-EDSLD-60-000003-001	Electrical One Line Diagram Main Substation – LER824670
USAL-CB-EDSLD-60-000004-001	Electrical One Line Diagram Essential Power Substation – LER829673
USAL-CB-EDSLD-80-000001-001	Electrical One Line Diagram Berth #1 Substation – LER822872
USAL-CB-EDSLD-80-000002-001	Electrical One Line Diagram Berth #2 Substation – LER822873
USAL-CB-EDSLD-80-000003-001	Electrical One Line Diagram BOG Substation – LER823870
USAL-CB-EDSLD-80-000004-001	Overall Electrical One Line Diagram Jetty Substation – LER823871

13.28.1.14 Transformer Type, Dry/Oil

Power transformers will be of the liquid filled, outdoor type. Liquid shall be suitable for the absolute minimum ambient temperature indicated in the Electrical Design Basis document USAL-CB-EBDES-00-000001-000, in Appendix 13.B.1

13.28.1.15 Number of Transformers

A total of forty eight (48) transformer are current allocated for the project. The description of the transformer for the Project is outlined in the Electrical Equipment List USAL-CB-ELMEL-00-000001-000, in Appendix 13.N.1.

13.28.1.16 Electrical Distribution System

The Liquefaction Facility Electrical System Design for the Project will conform to the standards, design documents and specifications outlined in the Electrical Design Basis document USAL-CB-EBDES-00-000001-000, in Appendix 13.B.1 and as shown on the Electrical Overall One Line diagram USAL-CB-EDSLD-00-000001-000, in Appendix 13.N.3.

13.28.1.17 Distribution and Voltage Levels

Power will be generated at 13.8kV and supplied to double 13.8kV ANSI Metal-Clad switchgears coupled with Is-limiter in main power distribution substation. The main power distribution to the major unit substations in the facility as well as soft starters and/or captive transformers for the large motors will be at 13.8kV. Distribution at 13.8 kV, 4.16kV, 480V, 120/208VAC and 125VDC will also be utilized.
The essential power system will be distributed within the LNG Plant at 13.8 kilovolts and stepped down to 4.16 kilovolts, 480 volts and 208/120 volts.

The Liquefaction Facility Electrical Distribution Design for the Project will conform to the standards, design documents and specifications outlined in the Electrical Design Basis document USAL-CB-EBDES-00-000001-000, in Appendix 13.B.1 and as shown on the Electrical Overall One Line diagram USAL-CB-EDSLD-00-000001-000, in Appendix 13.N.3.

13.28.1.18 Uninterruptible Power Supply, Battery Backup System

The UPS shall be adequately sized to handle the specific duty involved, may be of the Pulse Width Modulated (PWM) or Ferro resonance type with 480 V three-phase primary and 208/120 V three phase four-wire or 120 V single-phase two-wire secondary. The batteries for the UPS system shall be of the Valve Regulated Lead Acid (VRLA) gel type, 6V cell and sized to power the system for 150 minutes after loss of normal power.

13.28.1.19 Electrical Cable Schedule/List*

An asterisk (*) indicates information that may become available during final design and is not expected to be finalized at the time of application. If requested by FERC, more information can be provided in detailed design.

13.28.1.20 Electrical Cable Design and Specification

The Liquefaction Facility Electrical Cable Design for the Project will conform to the standards, design documents and specifications outlined in the Electrical Design Basis document USAL-CB-EBDES-00-000001-000, in Appendix 13.B.1.

13.28.1.21 Cathodic Protection

Cathodic Protection system shall be designed and installed by a NACE certified firm.

13.28.1.22 Hazardous Area Classifications

The Hazardous Classification of plant areas are shown on Hazardous Area
Classification drawings for the purpose of aiding in selection of electrical components on process equipment, electrical equipment, and wiring methods. For additional information, refer to the Electrical Hazardous Area Classification, included in Appendix 13.N.5, and in the following table.

Drawing Number	Description
USAL-CB-EDHAC-00-000001-000	Electrical Hazardous Area Classification Key Plan
USAL-CB-EDHAC-00-000001-001	Electrical Hazardous Area Classification LNG Complex Area Plan
USAL-CB-EDHAC-10-000001-001	Electrical Hazardous Area Classification Liquefaction Train 1 Plan
USAL-CB-EDHAC-20-000001-001	Electrical Hazardous Area Classification Liquefaction Train 2 Plan
USAL-CB-EDHAC-30-000001-001	Electrical Hazardous Area Classification Liquefaction Train 3 Plan
USAL-CB-EDHAC-50-000003-001	Electrical Hazardous Area Classification Inlet Gas Treatment and HP & LP Fuel Area Plan
USAL-CB-EDHAC-60-000001-001	Electrical Hazardous Area Classification Power Generation Area Plan
USAL-CB-EDHAC-60-000002-001	Electrical Hazardous Area Classification Non-Hydrocarbon Utility Plan
USAL-CB-EDHAC-60-000004-001	Electrical Hazardous Area Classification Waste Water Treatment Area Plan 1
USAL-CB-EDHAC-70-000001-001	Electrical Hazardous Area Classification Open Ground Flare Area Plan
USAL-CB-EDHAC-70-000002-001	Electrical Hazardous Area Classification Waste Water Treatment Area Plan 2
USAL-CB-EDHAC-80-000001-001	Electrical Hazardous Area Classification Common Process & Utility Area Plan
USAL-CB-EDHAC-80-000002-001	Electrical Hazardous Area Classification LNG Storage Tank Area Plan 1
USAL-CB-EDHAC-80-000003-001	Electrical Hazardous Area Classification LNG Storage Tank Area Plan 2
USAL-CB-EDHAC-80-000006-001	Electrical Hazardous Area Classification Berth Area Plan 1
USAL-CB-EDHAC-80-000007-001	Electrical Hazardous Area Classification Berth Area Plan 2

13.28.1.23 Ignition Control Setbacks and Separation

Separation distances for ignition sources are in accordance with NFPA 59A – 2001 edition.

13.28.1.24 Electrical Pass-Through Seals and Vents to the Atmosphere

Connections on the pressure boundary of each LNG In-Tank Pump, each LNG Liquid Expander and each MR Liquid Expander to electrical leads and instrumentation cable conduits will be sealed to prevent the passage of LNG or Methane or other hydrocarbons through the associated seal into the conduit or cable core, as required by Section 7.6 of NFPA 59A – 2001 edition.

The connections will include a primary seal, a purged space and another seal between the flammable fluid and the electrical system. The specific seal arrangement may vary depending on the vendor selected for the equipment. The arrangement will include provision for purge gas flow and for detection of flammable gas leakage through the primary seal. To allow for this usage, the nitrogen supply system has been sized to allow for consumption of some nitrogen for this demand.

Similarly, the pass-through seal design for other pressure boundary instrumentation will also meet NFPA 59A Section 7.6 requirements.

The Electrical Seal Drawing (AKLNG-4030-EEE-DWG-DOC-00078) is contained in Appendix 13.N.6.

13.29 PLANS AND PROCEDURES

13.29.1 Operation and Maintenance Plans

13.29.1.1 Operation Procedure Development

Procedures for the operation and maintenance (O&M) of the Liquefaction Facility will be developed to comply with the applicable requirements of:

- 49 C.F.R. Part 193 Subpart F – Operations and NFPA 59A. This will include policies for operating procedures, monitoring of operations, emergency procedures, personnel safety, investigation of failures, communication systems, and operating records;
- 49 C.F.R. Part 193 Subpart G – Maintenance and NFPA 59A. This will include policies for maintenance procedures, fire protection, isolating and purging, repairs, control systems, corrosion control, and maintenance records;
- 49 C.F.R. Part 193 Subpart J – Security and NFPA 59A Annex C – Security. This will include policies for security procedures, protective enclosures, security communications, and security monitoring and warning signs; and
- 33 C.F.R. Parts 127 – Waterfront Facilities Handling Liquefied Natural Gas and Liquefied Hazardous Gas. This will include policies for development of operations and emergency manuals for the LNG marine transfer area

13.29.1.2 Safety Procedures (E.G., Hot Work And Other Work Permit Procedures, Etc.)

Training will include:

- Safe systems of work;
- Personal protective equipment and clothing;
- Emergency response; and
- Training required by the Occupational Safety and Health Administration (OSHA) and other applicable training specific for the Facility.

13.29.1.3 Maintenance Plan and Procedure Development

During detailed design, maintenance procedures will be developed for the operational phase of the facility and will be implemented once the facility goes into operation. These procedures will include all maintenance requirements to ensure safety and reliability of the facility and will comply with all applicable codes and standards.

13.29.1.4 Operations and Maintenance Structure

Current estimates are that O&M of the Liquefaction Facility will require approximately 310 personnel, 240 located at the Liquefaction Facility and 70 support staff personnel based in Anchorage. Current staffing plans assume that facility staff in Nikiski will reside off site.

Finalized details on the operating and maintenance staffing structure will be provided in detailed design.

13.29.1.5 Number of Operation and Maintenance Personnel*

An asterisk (*) indicates guidance is optional and will be provided in detailed design

13.29.1.6 Location of Operation and Maintenance Personnel*

An asterisk (*) indicates guidance is optional and will be provided in detailed design

13.29.1.7 Operation and Maintenance Personnel Training*

13.29.1.7.1 Environmental Training

Training will be provided in environmental management and mitigation to comply with the requirements of the various permits that will be issued for the Liquefaction Facility at the federal, state, and local levels.

13.29.1.7.2 Hands-On Training

Hands-on training will be provided at all stages of the Project that includes the following activities:

- Pre-commissioning;
- Commissioning;
- Maintenance; and
- Operations and Start-up.

13.29.1.7.3 Ongoing Training

Ongoing training of all personnel will continue throughout the life of the facility. Both new and current personnel will have a defined program for the job role they will perform. For new hires, in addition to the initial competency assessment, training will include the basic Health, Safety, Security, and Environmental curriculum and a general plant familiarization program, and for current personnel there will be a defined refresher program on these same topics that also ensure compliance with any time based training required. The job specific training will consist of on-the-job training as well as classroom training and will include a competency assessment program to validate knowledge. An Operator Training Simulator (OTS) system will be developed prior to plant start-up that will be used to validate the various plant startup procedures and will provide specific operating scenarios for both control room and field operator knowledge assessment prior to initial startup and during lifecycle operation Environmental Training

Training will be provided in environmental management and mitigation to comply with the requirements of the various permits that will be issued for the Liquefaction Facility at the federal, state, and local levels.

13.29.1.8 Training Plans and Procedures*

As described in Sections 13.29.1.7.1-13.29.1.7.3, training plans will be developed in detailed design.

13.29.1.9 Management Procedures (E.G., Alarm Management, Shift Procedures/Fatigue Management, Management of Change Procedures, Etc.)*

An asterisk (*) indicates guidance is optional and will be provided in detailed design

13.30 INSTRUMENTATION AND CONTROLS

13.30.1 Basic Process Control System Design (BPCS)

The Liquefaction Facility Integrated Control and Safety System (ICSS) will provide the capability for operations to be managed from the Control Room located in the Main Control Building The ICSS will monitor and control the liquefaction process during start-up, shutdown, normal operation, abnormal operation or process upsets, and emergency shutdown conditions.

The ICSS will facilitate:

- Sufficient online event monitoring and control capabilities to ensure continuous, safe, reliable and efficient operation;
- Alerting operators in a timely manner of any abnormal conditions requiring manual intervention;
- Bringing the plant or equipment to a safe state for any abnormal conditions; and
- Tools to support Maintenance and Engineering activities.

The LNG ICSS will be able to communicate with other facilities including the PBU, PTU Gas Expansion, Mainline, and GTP.

The ICSS for the Project will conform to the standards, design documents and specifications outlined in the Integrated Control and Safety System Design Basis (USAL-CB-IBICS-00-000005-000), in Appendix 13.B.1 and the Safety Instrumented System Specification (USAI-PT-ISPDS-00-150707-000), in Appendix 13.F.3.

13.30.1.1 Instrument List

Instruments are shown on the P&IDs included in Appendix 13.E.5. A final instrument list will be provided in detailed design.

13.30.1.2 Instrumentation Design and Specifications

The Liquefaction Facility Instrumentation Design and Specifications for the Project will conform to the standards and design documents outlined in Basis of Design, in Appendix 13.B.1 and the Specification, in Appendix 13.F.3.

Document Number	Description
USAL-CB-IBICS-00-000005-000	Integrated Control and Safety System Design Basis
USAI-PT-ISPDS-00-150707-000	Safety Instrumented System Specification
TBD*	Actuators for On/Off Valves
TBD*	Area Classification and Related Electrical Design for Flammable Liquids, Gases or Vapors
TBD*	Alarm System
TBD*	Control Systems and Equipment Management System Security Implementation
TBD*	Electric Motor Operators for Valves
TBD*	Environmental Protection for Instrumentation
TBD*	Fire and Gas Detection Systems
TBD*	Fireproofing
TBD*	Flow Instruments
TBD*	High Integrity Pressure Protection Systems
TBD*	Instrument and Essential Services Power Supplies
TBD*	Instrument Transmission Systems
TBD*	Instrument Wire and Cable
TBD*	Level Instruments
TBD*	Piping at Control and Protective System Valve Stations
TBD*	Piping Component Selection and System Design
TBD*	Piping for Instruments
TBD*	Power System Design
TBD*	Pressure Instruments
TBD*	Pressure Relief, Flare and Vapor Disposal Systems
TBD*	Pressure Relief Valves
TBD*	Programmable Logic Controllers
TBD*	Temperature Instruments
* to be developed in FEED	

13.30.1.3 BPCS Philosophy

The ICSS will be designed such that each train can operate independently without affecting the operation of other trains, yet integrated with other trains for information exchange. The ICSS will protect the controlled process from intermittent, transient, and permanent system faults.

The Control System will consist of field instrumentation and a number of microprocessor-based sub-systems located in Local Equipment Rooms (LERs) throughout the LNG Plant. The ICSS for the LNG Plant will utilize commercially available and proven hardware and software that has passed technical evaluation by Primary operator interfaces and controls will be located in the Control Room located in the Main Control Building. LERs will have operator work stations for interfacing with the field for instrument calibration, trouble-shooting, and monitoring. The Process Control System (PCS) provides the LNG Plant personnel with user-friendly information displays for monitoring, processing, and automatic and manual control of the processes. The LNG Plant will have analyzer buildings and Continuous Emission Monitoring (CEMS) buildings that will interface with PCS.

The Liquefaction Facility Integrated Control and Safety System (ICSS) for the Project will conform to the standards, design documents and specifications outlined in the Integrated Control and Safety System Design Basis (USAL-CB-IBICS-00-000005-000), in Appendix 13.B.1 and the Safety Instrumented System Specification (USAI-PT-ISPDS-00-150707-000), in Appendix 13.F.3.

13.30.1.4 BPCS Architecture

The Liquefaction Facility Integrated Control and Safety System (ICSS) architecture for the Project will conform to the standards, design documents and specifications outlined in the Integrated Control and Safety System Design Basis (USAL-CB-IBICS-00-000005-000), in Appendix 13.B.1.

ICSS Architecture diagrams are detailed below and included in Appendix 13.P.2

Document No.	Reference Title
USAL-CB-IDBLK-00-000001-001 through 003	Integrated Control and Safety System (ICSS) Architecture Preliminary Block Diagrams

13.30.1.5 BPCS Design and Specifications

The Liquefaction Facility Integrated Control and Safety System (ICSS) Design and Specification for the Project will conform to the standards and design documents outlined in the Integrated Control and Safety System Design Basis (USAL-CB-IBICS-00-000005-000), in Appendix 13.B.1 and the Safety Instrumented System Specification (USAI-PT-ISPDS-00-150707-000), in Appendix 13.F.3.

The Liquefaction Facility BPCS Design and Specifications for the Project will conform to the standards and design documents outlined in Basis of Design, in Appendix 13.B.1 and the Specification, in Appendix 13.F.3.

Drawing Number	Description
USAL-CB-IBICS-00-000005-000	Integrated Control and Safety System Design Basis
USAI-PT-ISPDS-00-150707-000	Safety Instrumented System Specification
TBD*	Alarm System
TBD*	Control Systems and Equipment Management System Security Implementation
TBD*	Power System Design
TBD*	Programmable Logic Controllers
* to be developed	

13.30.1.6 Number of Servers, Operating and Backup

The current Liquefaction Facility design has an estimated seven (7) operating, two (2) backup servers and ten (10) Virtualized servers. During detailed engineering the final numbers of servers will be confirmed.

13.30.1.7 Number of Historians, Operating and Backup

During detailed engineering the final numbers of historians will be confirmed.

13.30.1.8 Distributed Control Systems (DCS) Block Diagrams

The Distributed Control System (DCS) Block Diagrams are included in Appendix 13.P.2

Document No.	Reference Title
USAL-CB-IDBLK-00-000001-001 through 003	Integrated Control and Safety System (ICSS) Architecture Preliminary Block Diagrams

13.30.1.9 PLC And DCS Software

The PLC and DCS Software for the Liquefaction Facility will be a Plant Control System (PCS) platform and shall be capable of operating under the supervision of an advanced process control system (APC). This computational software shall be capable of safely and reliably operating the LNG facility under the watchful eye of the panel operator. The PCS manufacturer will be determined during FEED. The PLC and DCS software for the Project will conform to the standards and design documents outlined in the Integrated Control and Safety System Design Basis (USAL-CB-IBICS-00-000005-000), in Appendix 13.B.1 and the Safety Instrumented System Specification (USAI-PT-ISPDS-00-150707-000), in Appendix 13.F.3

13.30.1.10 Control Communication Types

Acceptable network protocols include Highway Addressable Remote Transducer (HART), Modbus, Allen Bradley Control Net, TCP/IP, and OLE for Process Control (OPC). A standard computing platform will be used for HMI Operator Workstations. The Control Communication Types for the Project will conform to the standards and design documents outlined in the Integrated Control and Safety System Design Basis (USAL-CB-IBICS-00-000005-000), in Appendix 13.B.1 and the Safety Instrumented System Specification (USAI-PT-ISPDS-00-150707-000), in Appendix 13.F.3.

13.30.1.11 Number of Lines of Communication to Control Room, Operating and Backup

Communication between the equipment in the LERs, the CCR Rack Room and the Operator Consoles in the CCR shall be determined during detailed design.

13.30.1.12 Control Power Sources, Operating and Backup

ICSS cabinets shall be fed from two sources of power, one of which should be UPS. Main essential and UPS power shall be supplied to the F&G Detection System to meet local and regulatory requirements.

The control power sources for the Project will conform to the standards and design documents outlined in the Integrated Control and Safety System Design Basis (USAL-CB-IBICS-00-000005-000), in Appendix 13.B.1 and the Safety Instrumented System Specification (USAI-PT-ISPDS-00-150707-000), in Appendix 13.F.3.

13.30.1.13 Human Machine Interface (HMI) Local and Control Room Displays, Type

Liquefaction Facility will have supervisory level HMI's. Human Machine Interfaces (HMIs) will be located in the CCR, Maintenance Building, Marine Terminal Building, OTS room and LERs. The system shall be capable of dividing human interface functions into operating areas. The HMI Display Types for the Project will conform to the standards, design documents and specification outlined in the Integrated Control and Safety System Design Basis (USAL-CB-IBICS-00-000005-000), in Appendix 13.B.1.

13.30.1.14 Number of HMI Control Room Displays

The Liquefaction Facility will have fifty (50) HMI and six (6) large displays in the Control room. Other HMI are also located within other buildings/rooms which is based on the Integrated Control and Safety System (ICSS) Architecture Preliminary Block Diagrams included in Appendix 13.P.2

Document No.	Reference Title
USAL-CB-IDBLK-00-000001-001 through 003	Integrated Control and Safety System (ICSS) Architecture Preliminary Block Diagrams

13.31 SAFETY INSTRUMENTED SYSTEMS

13.31.1 Safety Instrumented System (SIS) Design

The SIS will be independent and segregated from the PCS but interfaced to it through redundant data links that allow the operator to monitor SIS data from the CCR using the same HMI. The SIS will serve to protect personnel, environment, and equipment from abnormal and hazardous conditions without operator intervention, by activating defined SIFs when the PCS is not capable of maintaining the plant within its defined normal and safe operating envelope.

The SIS implements safety instrument functions (SIF) for PSD, Emergency Shutdown (ESD) System and FGDS. The SIS hardware will be selected, engineered, installed, and interconnected to achieve a high level of performance, availability, and reliability in accordance with the plant safety integrity level (SIL) evaluation. It will provide detection, logic sequencing, and actuation of devices to place the system or facility in a safe state. The SIS will be designed to allow changes or upgrades to the system without a process shutdown. Acceptable spurious trip rates for any SIF will satisfy the availability rate planned for the facility.

The process facility fire and gas (F&G) detectors will interface with the SIS system through direct integration for F&G monitoring and executive actions (such as process shutdown, emergency depressurization, HVAC shutdown/recirculation, and suppression system activation as appropriate). Non-process building F&G (i.e., Life Safety F&G) are designed in accordance with NFPA 72 with an Underwriters' Laboratories (UL)-approved controller and supervised circuits and integrated into the SIS via redundant data links. Manual Pull Stations located in both occupied areas and process modules will be connected to the Life Safety F&G system via supervised circuits. F&G Sensors (fire detectors, gas monitors) will be selected according to Project specs, regulatory requirements, fire hazard assessments, and gas dispersion studies. The Process Facility and Life Safety Fire and Gas Detection Systems will send separate hardwired signals to the PAGA System for confirmed fire or gas alarms. The PAGA system will be used to annunciate fire and gas emergency conditions, audibly and visibly where required. Additionally, the F&G systems will activate the beacons/horns in the process areas to notify personnel of the F&G alert. Hardwired pushbuttons at the Critical Actions Panel or at the PCS console in the CCR will be provided for manual fire and foam pump control.

The PCS and SIS will be integrated to provide an ICSS. The ICSS system will be supplied by a qualified Automation provider and will maintain the facility within the safe operating limits. The ICSS will deliver F&G Detection/Protection where such protection is required.

The SIS for the Project will conform to the standards, design documents and specifications outlined in the Integrated Control and Safety System Design Basis (USAL-CB-IBICS-00-000005-000), in Appendix 13.B.1 and the Safety Instrumented System Specification (USAI-PT-ISPDS-00-150707-000), in Appendix 13.F.3.

13.31.1.1 SIS, FGS, ESD and depressurization philosophies

The SIS will have completely independent hardware, wiring systems, and field instrumentation. The components of the SIS consist of sensors, logic solvers, and final control elements. It is anticipated that several other proprietary systems will be provided with mechanical equipment packages such as: gas turbine generators, centrifugal compressors, and fired heater equipment. Safety interlocks will be implemented in protective systems supplied by the manufacturer. Interfaces between the manufacturer’s packaged system and the SIS will provide protection for external upset conditions that require shutdown of the mechanical equipment.

The SIS will consist of the following components:

- PSD;
- ESD; and
- FGDS

Refer to the Integrated Control and Safety System Design Basis (USAL-CB-IBICS-00-000005-000), in Appendix 13.B.1 and the Safety Instrumented System Specification (USAI-PT-ISPDS-00-150707-000), in Appendix 13.F.3 for additional description of the SIS System philosophies.

13.31.1.1.1 PSD System

Process shutdowns will be activated through the PSD system. Specific shutdowns are outlined in the cause and effect diagrams. Examples of process shutdowns include:

- High-high pressure, liquid level, or temperature;
- Low-low pressure, liquid level, or temperature; and
- Gas detection.

Shutdown devices will use independent process equipment connections and transmitters from the normal operational transmitters used for control functions. Switches will not be used for protective systems. In all cases where a device will cause a shutdown, a pre-alarm will be provided to alert the operators to a problem before a shutdown occurs. The ultimate over-pressure protection will be a mechanical relief valve (PSV).

13.31.1.1.2 ESD System

The LNG Facility will be equipped with an ESD system that is designed to protect personnel, the environment, and the facility in the event of upset emergency conditions such as fire (local or plant-wide), combustible or toxic fluid leak, mechanical failure of equipment, etc. In these events, depending on the severity of the emergency, the whole or part of the plant will be isolated remotely by the closing of process and utility stream isolation valves to and from the plant/area, and may initiate shutdown of critical running equipment.

In general, the ESD system will have three ESD levels that will perform shutdown/isolation of the entire facility or a specific train or system within the LNG Facility. Activation of a specific ESD shutdown/isolation will be a separate and distinct action. If blowdown is subsequently required, the blowdown will be initiated as a separate and distinct action.

13.31.1.1.3 FGD System

The FGDS will be provided to monitor the facility for detection of fire and combustible/flammable and toxic gas, the initiation of alarms, and the discharge of fixed fire protection systems and equipment. The system will automatically and reliably alert personnel to the existence and location of such conditions, and initiate prescribed control actions.

Non-process buildings (outside of the process area) and LERs have Fire Alarm Control Panels (FACPs) that comply with the requirements of NFPA 70 and 72. FACPs send summary output signals to the SIS. Process area alarm beacons, alarm horns, and manual alarm call (MAC) points are integrated with the Local Equipment Room (LER) FACPs.

Process areas (hydrocarbon processing) and utility areas will be protected by the FGDS. The process area FGDS will be segregated from the PCS and integrated into the SIS. Any turbine enclosures will be protected by a standalone vendor-supplied FGDS, which will provide outputs to the SIS. The FACPs and SIS will also interface with the heating and ventilation system and the PAGA system.

13.31.1.2 SIS and FGS architecture

The Liquefaction Facility Integrated Control and Safety System (ICSS) SIS and FGS architecture for the Project have been incorporated into the Integrated Control and Safety System (ICSS) Architecture Preliminary Block Diagrams.

ICSS Architecture diagrams are detailed below and included in Appendix 13.P.2

Document No.	Reference Title
USAL-CB-IDBLK-00-000001-001 through 003	Integrated Control and Safety System (ICSS) Architecture Preliminary Block Diagrams

13.31.1.3 SIS, FGS, and ESD cause and effect matrices

The Liquefaction Facility Integrated Control and Safety System (ICSS) SIS, FGS and ESD cause and effects matrices for the Project have been incorporated into the ICSS Cause and Effect diagrams that are detailed below and included in Appendix 13.Q.1.

Document No.	Reference Title
USAL-CB-PDZZZ-10-000001-000	Cause & Effect Diagram (Gas Liquefaction System)
USAL-CB-PDZZZ-10-000002-000	Cause & Effect Diagram (Process Refrigeration System)
USAL-CB-PDZZZ-50-000001-000	Cause & Effect Diagram (Inlet Treating System/Mercury Removal System)
USAL-CB-PDZZZ-50-000002-000	Cause & Effect Diagram (Gas Dehydration and Regeneration Gas System)
USAL-CB-PDZZZ-50-000003-000	Cause & Effect Diagram (LPG Fractionation System)
USAL-CB-PDZZZ-50-000004-000	Cause & Effect Diagram (Fuel Gas System)
USAL-CB-PDZZZ-60-000001-000	Cause & Effect Diagram (Power Generation System)
USAL-CB-PDZZZ-60-000002-000	Cause & Effect Diagram (Air System/Nitrogen System)
USAL-CB-PDZZZ-60-000003-000	Cause & Effect Diagram (Water System)
USAL-CB-PDZZZ-70-000001-000	Cause & Effect Diagram (Condensate Storage And Loading System)
USAL-CB-PDZZZ-70-000002-000	Cause & Effect Diagram (Refrigerant Storage System)
USAL-CB-PDZZZ-70-000003-000	Cause & Effect Diagram (Flare And Vent System)
USAL-CB-PDZZZ-70-000004-000	Cause & Effect Diagram (Diesel/Slop Oil System)
USAL-CB-PDZZZ-80-000001-000	Cause & Effect Diagram (LNG Storage And Loading System)
USAL-CB-FDCEM-00-000001-000	Cause & Effect Diagrams (Fire & Gas)

13.31.1.4 SIS, FGS, and ESD design and specifications

Refer to the Integrated Control and Safety System Design Basis (USAL-CB-IBICS-00-000005-000), in Appendix 13.B.1 and the Safety Instrumented System Specification (USAI-PT-ISPDS-00-150707-000), in Appendix 13.F.3 for additional design and specifications for the SIS System.

13.31.1.5 Number of SIS and FGS servers, operating and backup*

An asterisk (*) indicates information that may become available during final design and is not expected to be finalized at the time of application. If requested by FERC, more information can be provided in detailed design.

13.31.1.6 Number of SIS and FGS historians, operating and backup*

An asterisk (*) indicates information that may become available during final design and is not expected to be finalized at the time of application. If requested by FERC, more information can be provided in detailed design.

13.31.1.7 SIS and FGS block diagrams

ICSS Block Diagram are detailed below and included in Appendix 13.P.2

Document No.	Reference Title
USAL-CB-IDBLK-00-000001-001 through 003	Integrated Control and Safety System (ICSS) Architecture Preliminary Block Diagrams

13.31.1.8 SIS and FGS software*

An asterisk (*) indicates information that may become available during final design and is not expected to be finalized at the time of application. If requested by FERC, more information can be provided in detailed design.

13.31.1.9 List of ESD valves

The List of ESD Valve are detailed below and included in Appendix 13.Q.3

Document No.	Reference Title
USAL-CB-ILZZZ-00-000002-000	Shutdown Valve List

13.31.1.10 ESD valve spacing*

An asterisk (*) indicates information that may become available during final design and is not expected to be finalized at the time of application. If requested by FERC, more information can be provided in detailed design.

13.31.1.11 ESD closure times*

An asterisk (*) indicates information that may become available during final design and is not expected to be finalized at the time of application. If requested by FERC, more information can be provided in detailed design.

13.31.1.12 SIS, FGS, and ESD Safety Integrity Levels (SIL)*

An asterisk (*) indicates information that may become available during final design and is not expected to be finalized at the time of application. If requested by FERC, more information can be provided in detailed design.

13.32 SECURITY PLANS

13.32.1 Physical Security Plans

The Site Security Plan (referred to herein as Site Security Plan) describes site security provisions and features and is Sensitive Security Information. The Site Security Plan will be designed based on the requirements of the Code of Federal Regulation 33 C.F.R. 105, and will be treated as Sensitive Security Information in accordance with United States Coast Guard (USCG) regulations. This information will be made available upon request in accordance with the USCG disclosure requirements for Sensitive Security Information.

13.32.1.1 Security Plan Developments

The Liquefaction Facility will employ a Site Security Plan developed to provide procedures that will enhance the safety and security of the LNG Plant and Marine Terminal Facility against unlawful acts. Security measures included in the Site Security Plan include:

- Perimeter security;
- Access points into the Liquefaction Facility;
- Restrictions and prohibitions applied at the access points;
- Identification systems; and
- Screening procedures.

A CCTV system will be installed to monitor the fence line, active access points to the Liquefaction Facility and the interior of the Liquefaction Facility.

Intrusion detection systems will be installed at the perimeter security fence.

Key features of the Site Security Plan include:

- Security Procedures
  - Description of the Liquefaction Facility security administration and organization;
  - Facility security officer qualifications.
  - Response to change in MARSEC level.
  - Procedures for interfacing with vessels.
  - Declaration of Security (DOS) requirements.
  - Security measures and procedures for handling cargo.
  - Procedures for delivery of vessels for bunkers and stores.
  - Security monitoring procedures;
  - Security incident procedures (such as evacuation, reporting incidents, briefing personnel, securing non-critical operations);
  - Security measures for access control, including perimeter security, access points into the Liquefaction Facility, restriction and prohibitions applied at the access points, identification system, acceptable forms of personnel identification, visitors' log and passes, screening procedures for personnel and vehicles, access control and screening procedures;

- Restricted areas and procedures; and
- Audits and security plan amendments.

- Security Systems and Equipment Maintenance
    - Security fencing system;
    - Buildings, equipment and other structures that will be enclosed;
    - Location of the means of access and egress through the protective enclosure;
    - Methods of maintaining security of gates that will be used for access and egress and procedures that will be used during emergency situations;
    - Security lighting systems; and
    - Security systems and equipment maintenance requirements.

13.32.1.2 Lighting

Security lighting system design will be included in the Facility Security Plan.

13.32.1.3 Physical Barriers (e.g. Fences, Vehicle Barriers, etc.)

The Site Security Fence drawings listed below and included in Appendix 13.E.12, provide preliminary plans for types and locations of fences.

Drawing Number	Description
USAL-CB-CDFEN-00-000087-001	Civil Site Security Fence Plan Layout
USAL-CB-CDFEN-00-000087-101	Civil Site Security Fence Sections and Details Layout

13.32.1.4 Site and Onsite Access Controls

Security measures will be implemented to control access and egress from the Liquefaction Facility at all MARSEC levels.

In the present design premise for the Liquefaction Facility, onshore access to the site will be controlled through defined gates with an ID badged-based proximity card reader system that will control and log personnel ingress and egress to and from the facilities. In addition, these limited access points will be managed by security personnel. The system will be monitored at a centralized location and other designated locations. This system will interface with each location, the central location and the security camera system to ensure complete integration and functionality.

A limited number of access points will be constructed and their design (i.e., vehicle barriers, sliding gates, etc.) will be based on the outcome of the security risk assessments.

For access to the process units or Marine Terminal, there will be additional access control points that will require access by card readers. Depending on the location, the card reader will be Transportation Worker Identification Credential (TWIC) capable. Additionally, some of these access points will be controlled by a physical security guard and/or monitored by cameras. This type of controlled access will be implemented within the facility at locations deemed as restricted areas (i.e., select buildings, rooms and areas). The access control system will be capable of monitoring at centralized and other designated locations and will interface with each area, including the camera system, to create a fully integrated and functional security system.

13.32.1.5 Intrusion Monitoring

A CCTV system will be installed to provide remote surveillance capability. Cameras will monitor all entry points on the site, designated sections of the plant, the marine area and the perimeter fence line. The cameras will utilize a combination of fixed and pan/title/zoom features to provide 100 percent coverage of the perimeter fence line and other designated areas (including the Marine Terminal). Controls and monitoring for the security camera system will be located in a centralized location but will also allow remote monitoring at various locations via the security network.

The camera system will integrate with the site access control and intrusion detection system to allow for visual inspection of potential threats.

The Camera Layout drawing, Drawing No. USAL-CB-IDLAY-00-000735-001 is included in Appendix 13.E.12 and provides preliminary plans for camera types and locations.

13.32.1.6 Intrusion Detection

Intrusion detection systems will be installed at the perimeter security fence. The fence line system will detect, alarm and accurately identify the locations of any attempts of intrusion through the security fence. The fence line perimeter will be partitioned into zones, and each zone will be alarmed and logged at the security system console.

The final design of this system will be determined after completion of the security risk assessment, but may consist of a single or combination of technologies such as motion sensing cameras, lighting, fiber optics, radar, etc. Monitoring for the systems will be performed from a centralized security control location and will be site mapped to allow threat locations to be identified easily.

13.32.1.7 Site Security Communication

The Facility Security Plan includes communication systems and procedures to provide effective and continuous communications between all personnel; LNGCs interfacing with the Marine Terminal; the Captain of the Port (COTP); and federal, state, and local authorities with security responsibilities.

13.32.1.8 Site Security Service and Number of Site Security Personnel

13.32.1.9 Site Security Use of Force

13.32.1.10 Site Security Training

The Facility Security Plan includes details of training that must be provided to all personnel who will be involved in providing security at the Marine Terminal. Training will be provided to comply with the requirements of 49 C.F.R. Part 193, Subpart H, NFPA 59A (2001) Annex D and 33 C.F.R. Part 127.503.

- Required personnel training and qualifications;
- Training documentation and review requirements; and
- Required drills and exercises

13.32.1.11 Setbacks, Blast Walls, Hardened Structures, and Blast Resistant Designs

A buffer zone is provided around the entire facility to provide a physical distance between facilities and the property line. The LNG Storage Tanks and Liquefaction trains are located centrally in the plot plan, at a maximum distance away from public roads. The Control Room is located more than 800 feet away from a public road.

13.32.2 Cybersecurity Plans

The facility will be designed to prevent cybersecurity breaches and will include appropriate controls and firewalls. Final details will be developed in detailed design.

13.32.2.1 Cybersecurity Plan Developments

Cybersecurity plans will be developed throughout detailed design.

13.32.2.2 Physical Access to Control Systems

Access points will be minimized to essential personnel only. Final details will be developed in detailed design.

13.32.2.3 Computer and Network Access Controls

Final details will be developed in detailed design.

13.32.2.4 Intrusion Monitoring

The cybersecurity system shall integrate protection systems with centralized monitoring capability. Anti-virus software shall be installed on all workstations and servers. Configuration of the Anti-virus software is the responsibility of the supplier, in order not to impair the behavior of the device (specifically the operator work stations). Final details will be developed in detailed design.

13.32.2.5 Intrusion Detection

The system will include intrusion detection. Final details will be developed in detailed design.

13.32.2.6 Cybersecurity Personnel and Response Teams

Final details will be developed in detailed design.

13.32.2.7 Cybersecurity Awareness and Training

Employees will be trained in awareness and appropriate measures to minimize potential cybersecurity attacks. Final details will be developed in detailed design.

13.32.2.8 Air Gaps, Waterfalls, and Firewalls

Final details will be developed in detailed design.

13.33 RELIEF VALVE AND FLARE/VENT SYSTEMS

13.33.1 Relief Valves and Flare/Vent Systems Design

LP Flare (FLRL613800) will be installed in the LNG tank area to relieve the emergency vapor releases from the LNG Storage and Loading System. When the Marine Terminal receives a warm LNGC direct from drydock, the LP flare will be used to dispose of the inert gas with the assistance of fuel gas enrichment. Compressor seal gases from liquefaction trains and analyzer vents from the entire facility will also be routed to the LP Flare.

When the Thermal Oxidizer will be out of service, the vents from C5+ Condensate Storage and Loading will be also routed to the LP Flare. Vapor releases will go to the LP Flare via LP Flare KO Drum (MBD613801) where any condensed liquids will be knocked out.

The Wet and Dry Ground Flares will consist of 3 x 50 percent enclosures. Each enclosure will have a 1 x 50 percent Wet Flare and a 1 x 50 percent Dry Flare. 2 x 50 percent enclosures will be in operation and 1 x 50 percent enclosure will be as spare.

Vent and relief streams that could potentially contain a significant concentration of water (e.g., vents/reliefs from the Dehydration Unit), or significant concentration of heavy hydrocarbons that could freeze at cryogenic temperatures (e.g., vents/reliefs from Debutanizer Column) will be routed to the wet flare header.

The blowdown streams from the dehydration beds will be routed to the dry flare header due to low blowdown temperature. However, the relief valves on the dehydration beds and relief/blowdown/vent streams from the regeneration section of the Dehydration Unit will be routed to the wet flare header.

The wet flare header will be routed to the Wet Flare (FLRH612703) via Wet Flare KO Drum (MBD612705). The drum will include the ability to vaporize any accumulated light hydrocarbons. Any remaining heavy hydrocarbon liquid in this drum will be pumped to the Slop Oil Tank (MBJ964750) using the Wet Flare KO Drum Pumps (PBE612706A/B). The Dry Flare System will be used for safe disposal of dry hydrocarbon streams.

The Dry Flare will serve the Inlet Facilities, liquefaction processing trains, Fractionation Unit, and Refrigerant Storage area. This system will consist of two dedicated header systems: one for vapor and one for liquid releases. All vapor and liquid headers will connect to the Dry Flare KO Drum (MBD612701). The drum will include the ability of vaporizing lighter material that may accumulate in the drum at a sufficient rate to avoid a high level in the KO drum. The remaining heavy liquid will be drained to the Dry Flare Blowcase (MAB612708) and will then be sent to the Wet Flare KO Drum.

Refer to Utility Flow Diagrams listed below and in Appendix 13.E.

Drawing Number	Description
USAL-CB-PDPFD-70-000612-001	Process Flow Diagram Dry Flare Collection
USAL-CB-PDPFD-70-000612-002	Process Flow Diagram Wet Flare Collection
USAL-CB-PDPFD-70-000612-003	Process Flow Diagram Wet and Dry Flare
USAL-CB-PDPFD-80-000613-001	Process Flow Diagram LP Flare

13.33.1.1 List of Relief Valves

Relief valves are shown on the P&IDs included in Appendix 13.E.6. A final relief valve list will be provided in detailed design.

13.33.1.2 Relief Valve Philosophy

The Flare System Design Basis is provided in Appendix 13.B.2

13.33.1.3 Relief Valve Studies

To be completed in detailed design.

13.33.1.4 Vent Stack Philosophy

Not Applicable

13.33.1.5 Vent Stack Type

Not Applicable

13.33.1.6 Number of Vent Stacks

Not Applicable

13.33.1.7 Vent Stack Height and Diameter

Not Applicable

13.33.1.8 Vent Stack Studies

See the Flare and Vents Study Report (USAL-CB-PRTEC-00-000004-000) included in Appendix 13.R.3.

13.33.1.9 Vent Sources

Not Applicable

13.33.1.10 Vent Stack Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), MMscfd

Not Applicable

13.33.1.11 Vent Stack Operating and Design Pressures (minimum, normal/rated, maximum), psig

Not Applicable

13.33.1.12 Vent Stack Operating and Design Temperatures (minimum, normal, maximum), °F

Not Applicable

13.33.1.13 Vent Stack Operating and Design Densities (minimum, normal, maximum), specific gravity

Not Applicable

13.33.1.14 Flare Philosophy

The Flare System Design Basis is provided in Appendix 13.B.2.

13.33.1.15 Flare Type

Refer to the LP Flare datasheet (USAL-CB-PTTDS-80-FLRL613800) and Wet and Dry Ground Flare datasheet (USAL-CB-PTTDS-70-FLRL612703), included in Appendix M.

13.33.1.16 Number of Flares

Two ground flares and one LP Flare

13.33.1.17 Flare Height and Diameter

Flare height will be determined during the detailed design phase.

13.33.1.18 Flare Studies

See the Flare and Vents Study Report (USAL-CB-PRTEC-00-000004-000) included in Appendix 13.R.3.

13.33.1.19 Flare Sources

A Wet and Dry Ground Flare (FLRH612703A/B/C) collects vapor and liquid reliefs from pretreatment and liquefaction process equipment.

An elevated/vertical LNG Storage LP Flare (FLRH613800) collects low pressure reliefs from the LNG storage and loading areas.

13.33.1.20 Flare Operating and Design Flow Rate Capacities (minimum, normal/rated, maximum), MMscfd

		Maximum Relieving Case at Stack /Flare Inlet (MMscfd)
FLRL613800	LP Flare	231
FLRL612703A/B/C	Wet Gas Flare	208
FLRL612703A/B/C	Dry Gas Flare	725

13.33.1.21 Flare Operating and Design Pressures (minimum, normal/rated, maximum), psig

		Maximum Pressure at Stack /Flare Inlet(psig)
FLRL613800	LP Flare	2
FLRL612703A/B/C	Wet Gas Flare	25
FLRL612703A/B/C	Dry Gas Flare	25

13.33.1.22 Flare Operating and Design Temperatures (minimum, normal, maximum), °F

		Temperature at Stack /Flare Inlet (°F)
FLRL613800	LP Flare	-237
FLRL612703A/B/C	Wet Gas Flare	-32
FLRL612703A/B/C	Dry Gas Flare	44

13.33.1.23 Flare Operating and Design Densities (minimum, normal, maximum), specific gravity

		Maximum Molecular Weight at Stack /Flare Inlet (--)
FLRL613800	LP Flare	17.1
FLRL612703A/B/C	Wet Gas Flare	17.68
FLRL612703A/B/C	Dry Gas Flare	33.26

13.33.1.24 Flare Operating and Design Radiant Heat (maximum), Btu/ft^2-hr

For the Wet and Dry Ground Flares, the radiation is not expected to be an issue, since the flare is hidden behind a radiation fence. To confirm this, flare vendors will be asked to provide estimates of thermal radiation outside of the ground flare's radiation fence during the detailed design phase.

13.33.1.25 Flare Operating and Design Decibel (maximum), Decibels on the A-weighted Scale

The noise from the flare shall be limited to 85 dBA at any operating location for discharges up to the maximum production flaring rate or the maximum periodic long duration rate, whichever is higher. The noise from the flare at any operating location shall be limited to 105 dBA for the emergency flaring cases. Local noise regulations shall be followed when more stringent.

13.34 SPILL CONTAINMENT

13.34.1 Spill Containment System Design

The Liquefaction Facility will comply with applicable provisions of 49 C.F.R. Parts 193 and NFPA 59A - 2001 for spill containment systems, which are summarized below. In accordance with NFPA 59A, the release scenarios associated with LNG spills from piping will be based on a 10-minute duration, and spill scenarios associated with hydrocarbon spills from containers will be based on 110 percent of maximum volume.

Spill containment systems for plant equipment and piping have been sized to contain the largest volume of spill from any of the identified spill scenarios.

Materials for the trenches will be pre-cast concrete trench, sumps will be designed detailed design phase.

For further information regarding the scenarios considered in the design of the spill containment system for the Liquefaction Facility, refer to the Hydrocarbon Spill Containment Sizing Report, Document No. USAL-CB-FRZZZ-00-000005-000 in Appendix 13.S.2.

Key drawings summarizing the design and layout of the Liquefaction Plant sumps are detailed below.

Drawing Number	Description

USAL-CB-CDDRN-00-000999-001	LNG Spill Containment Trench and Sump Key Plan Layout
USAL-CB-CDDRN-00-000999-002	LNG Spill Containment Trench and Sump Plan – Area 1 Layout
USAL-CB-CDDRN-00-000999-003	LNG Spill Containment Trench and Sump Plan – Area 2 Layout

13.34.1.1 Spill Containment Philosophy

The design spill volumes for each of the spill containment sumps within the LNG Plant will be based on the sizing parameters summarized in Table 13.34.1.1.

TABLE 13.31.1.1

Liquefaction Plant Sump Sizing Basis

Stormwater Risk Level	Basis of Sump Volume Sizing
Medium Risk Area: Run-off from process areas will be classified as medium risk (i.e., stormwater that may possibly contain oil from equipment maintenance or equipment failure) and will be directed to a containment area.	Sump to be sized based on the greater of the following: First Flush[2] 110 percent of largest single equipment volume Run-off from a 10-year frequency, 1-hour storm A 10-minute full pipe rupture, including pump run-out, as applicable
Chemical Risk Area: Run-off from areas with chemical-containing equipment or storage (i.e. stormwater from areas containing acid, or caustic service equipment or waste/chemical storage) will be directed to a containment area.	Sump to be sized based on the greater of the following: First Flush[1] The sum of 100 percent of the largest single tank, or equipment, volume and the run-off from a 25-year frequency, 24-hour duration rainfall The run-off from a 10-year frequency 1-hour storm
Liquefied Gas Risk Area: Run-off from areas containing LNG and liquefied refrigerants will be directed to impoundment areas.	Sump to be sized based on the greater of the following: A 10-minute full pipe rupture (including pump run-out, as applicable) The sum of 100 percent of the largest single tank, or equipment, volume and the run-off from a 25-year frequency, 24-hour duration rainfall 110 percent of the largest single containment tank, or equipment volume or 100% of the combined tank volumes, if serving multiple tanks.

13.34.1.2 Spill Locations and Flows

13.34.1.2.1 LNG Process Train and Storage

As indicated in the LNG Spill Containment Trench and Sump Plan – Area 1 Layout, Document No. USAL-CB-CDDRN-00-000999-002, an impoundment sump will be located in the southwest corner of each train and sized to handle the maximum design spill volume from the piping between the MR/LP Propane Cooler (HBG666103) and the HP MR Separator (MBD666101). The sump design for each LNG train is summarized in Table 13.34.1.2-1.

2 The first flush is defined as the initial surface run-off volume that is composed of the first inch over a given area.

TABLE 13.34.1.2-1

LNG Train Spill Spill Containment Area Information

Drawing Number	USAL-CB-CDDRN-00-000999-002
Design Spill Volume	17,915 cubic feet
Sump Internal Surface Area	50.0 feet X 50.0 feet
Sump Working Liquid Depth	8.0 feet
Sump Working Volume	20,000 cubic feet
Sump Total Liquid Depth	11.0 feet
Sump Design Capacity	27,500 cubic feet

In each train, there will also be two smaller impoundment sumps sized to handle the maximum design spill volume from the largest MR Compressor Suction Drum (MBD666106/107), as the associated piping and appurtenances will not result in a larger volume. Table 13.34.1.2-2 summarizes the design criteria for these smaller sumps within each train.

TABLE 13.34.1.2-2

MR Compressor Suction Drum Spill Containment Area Information

Drawing Number	USAL-CB-CDDRN-00-000999-002
Design Spill Volume	318 cubic feet
Sump Internal Surface Area	12.0 feet X 12.0 feet
Sump Working Liquid Depth	6.0 feet
Sump Working Volume	864 cubic feet
Sump Total Liquid Depth	9.0 feet
Sump Design Capacity	1,296 cubic feet

The Liquefaction Facility will use PiP technology, composed of an inner pipe of Invar (36 percent Ni), wrapped in insulating blankets and insulating spacers, and an outer pipe of 304 Stainless Steel for the LNG rundown lines which run from the liquefaction processing trains to each of the two LNG Storage Tanks. The annular space between the inner and outer pipe will be maintained at a sub-atmospheric or near-vacuum pressure which will inhibit the ability for LNG to remain in liquid form should a crack in the inner pipe occur. The outer 304 Stainless Steel pipe will be designed to the same pressure as the inner pipe and a leak detection system will be installed to advise in the event that the inner pipe lost containment.

As indicated in the LNG Spill Containment Trench and Sump Plan – Area 1 Layout, an impoundment sump will be located to the western boundary (plant coordinates) of the LNG Storage Tank Area and sized to handle the maximum design spill volume of LNG from the conventional piping sections of the LNG loading and LNG rundown lines within the LNG storage Tank area, including a 20 percent margin in consideration of pump run-out. Table 13.34.1.2-3 summarizes the sump design for the LNG Storage Tank Area.

TABLE 13.34.1.2-3

LNG Storage Tank Spill Containment Area Information

Drawing Number	USAL-CB-CDDRN-00-000999-002
Design Spill Volume	88,991 cubic feet

Sump Internal Surface Area	70.0 feet X 70.0 feet
Sump Working Liquid Depth	20.0 feet
Sump Working Volume	98,000 cubic feet
Sump Total Liquid Depth	23.0 feet
Sump Design Capacity	112,700 cubic feet

13.34.1.2.2 Fractionation Product Storage and Truck Loading

As indicated in the LNG Spill Containment Trench and Sump Plan – Area 2 Layout, Document No. USAL-CB-CDDRN-00-000999-003, an impoundment sump will be located to the western boundary of the Condensate Storage Tank and Truck Loading Area and sized to handle the maximum design spill volume of C5+ condensate or diesel during truck loading/unloading operations with a 10 percent margin, as the associated piping and appurtenances will not result in a larger volume. The resulting sump design criteria are summarized in Table 13.34.1.2-4

TABLE 13.34.1.2-4

Condensate Storage Tank and Truck Loading Spill Containment Area Information

Drawing Number	USAL-CB-CDDRN-00-000999-003
Design Spill Volume	1,176 cubic feet
Sump Internal Surface Area	20.0 feet X 20.0 feet
Sump Working Liquid Depth	10.0 feet
Sump Working Volume	4,000 cubic feet
Sump Total Liquid Depth	13.0 feet
Sump Design Capacity	5,200 cubic feet

13.34.1.2.3 Refrigerant Storage

As indicated in the LNG Spill Containment Trench and Sump Plan – Area 2 Layout, an impoundment sump will be located near the eastern boundary (plant coordinates) of the Refrigerant Storage Area and sized to handle the maximum design spill governed by one Propane Refrigerant Storage Bullet volume with a 10 percent margin, as the associated piping and appurtenances will not result in a larger volume. Table 13.34.1.2-5 summarizes the sump design for the Refrigerant Storage Area.

TABLE 13.34.1.2-5

Refrigerant Storage Spill Containment Area Information

Drawing Number	USAL-CB-CDDRN-00-000999-003
Design Spill Volume	9,137 cubic feet
Sump Internal Surface Area	35.0 feet X 30.0 feet
Sump Working Liquid Depth	10.0 feet
Sump Working Volume	10,500 cubic feet
Sump Total Liquid Depth	13.0 feet
Sump Design Capacity	13,650 cubic feet

13.34.1.2.4 Fractionation Area

As indicated in the LNG Spill Containment Trench and Sump Plan – Area 2 Layout, an impoundment sump will be located to the northern boundary (plant coordinates) of the Fractionation Area and sized to handle the maximum design spill volume of heavy hydrocarbons from the discharge line of the Deethanizer Reflux Pump (PBA631505A/B), including a 20 percent margin in consideration of pump run-out. Table 13.34.1.2-6 summarizes the sump design for the Fractionation Area.

TABLE 13.34.1.2-6

Franctionation Spill Containment Area Information

Drawing Number	USAL-CB-CDDRN-00-000999-003
Design Spill Volume	737 cubic feet
Sump Internal Surface Area	15.0 feet X 12.0 feet
Sump Working Liquid Depth	6.0 feet
Sump Working Volume	1,080 cubic feet
Sump Total Liquid Depth	9.0 feet
Sump Design Capacity	1,620 cubic feet

13.34.1.2.5 BOG Compressor Area

As indicated in the LNG Spill Containment Trench and Sump Plan – Area 2 Layout, an impoundment sump will be located to the southern boundary (plant coordinates) of the BOG Area and sized to handle the maximum design spill volume from the BOG Compressor Suction Drum-Blowcase (MAB691840) with a 10 percent margin, as the associated piping and appurtenances of these vessels will not result in a larger volume. The BOG Area sump design parameters are summarized in Table 13.34.1.2-7

TABLE 13.34.1.2-7

BOG Compressor Spill Containment Area Information

Drawing Number	USAL-CB-CDDRN-00-000999-003
Design Spill Volume	189 cubic feet
Sump Internal Surface Area	15.0 feet X 12.0 feet
Sump Working Liquid Depth	6.0 feet
Sump Working Volume	1,080 cubic feet
Sump Total Liquid Depth	9.0 feet
Sump Design Capacity	1,620 cubic feet

13.34.1.2.6 LNG Loading Lines

Similar to the rundown lines, PiP technology, composed of an inner pipe of Invar (36 percent Ni), wrapped in insulating blankets and insulating spacers, and an outer pipe of 304 Stainless Steel will be utilized for the LNG loading lines which run from the LNG Storage Tank Area to each of the two LNG loading berths.

The transition between the PiP technology and conventional 304 Stainless Steel lines with urethane foam insulation will occur within the LNG Storage Tanks Area and at the loading arms on each berth. At each of the berths, the portion of the loading platform located directly under the loading line ESDVs and the loading arms will be paved, curbed and directed to an impoundment sump. The basis for a design spill at the loading berths will be a rupture in the 16-inch LNG loading arm pipe downstream of the ESDV, which lasts for one minute based upon 30 seconds for the two-out-of-three voting by the hazard detection equipment to occur, and then 30 seconds closure time for the ESDV. The resulting sump design criteria are summarized in Table 13.31.1.2-8.

TABLE 13.31.1.2-8

Loading Berth Spill Containment Area Information

Drawing Number	USAL-CB-LDLAY-00-000001-001, 002, 003, & 004
Design Spill Volume	1,854 cubic feet
Sump Internal Surface Area	40.0 feet X 10.0 feet
Sump Working Liquid Depth	5.0 feet
Sump Working Volume	2,000 cubic feet
Sump Total Liquid Depth	8.0 feet
Sump Design Capacity	3,200 cubic feet

13.34.1.3 Impoundment Volumetric Capacities

Impoundment volumes and capacities are described in the previous section.

13.34.1.4 Trench and Trough Volumetric Flow Capacities

Trench and trough sizing will occur during detailed design to include trench dimensions and slope. The trench system will be sized to adequately convey the maximum liquid spill into each dedicated impounding basin.

13.34.1.5 Downcomer Volumetric Flow Capacities

The downcomber will be sized for the maximum credible event while considering vaporization. This calculation will be performed during the detailed design phase.

13.34.1.6 Impoundment System Water Removal

The water removal system (or pump) inside impoundment area will have adequate capacity to remove water at a rate equal to 25 percent of the maximum predictable collection rate from a 10-year storm, one hour in duration. Table 13.34.1.6 provides the run-off coefficients for various plant areas that in turn drive the design of the stormwater drainage system.

TABLE 13.34.1.6

Liquefaction Facility Run-off Coefficients

Descriptions	Coefficient 1, C
Concrete and asphalt paved areas	0.95
Compacted gravel areas	0.60
Unpaved areas (not categorized above)	0.50
Undeveloped areas	0.30

13.34.1.7 Storm Water Flow Design Basis

The site stormwater drainage system will be based on an overland flow concept. Gravity flow will proceed from areas through swales, culverts, and storm channels until it reaches a collection pond. After the solids settle, the effluent proceeds to the outfalls. The drainage with underground drainage system and catch basins will be used where specified, but the preference will be for open channels and culverts.

The design storm will be based on a 25-year frequency storm for different process or non-process areas, as well as the areas which will remain undeveloped or off-site in the vicinity of the plant. In addition, the stormwater run-off associated with a 100-year storm will be evaluated to quantitatively assess the sensitivity of the system design to the lower frequency event.

The design of the spill conveyance will increase the stormwater sumps by 12-inches to account for snow melt run-off following a maximum two-week accumulation during severe weather conditions.

The design storm for temporary facilities will be a five-year frequency storm.

Surface run-off from off-site entering to the plant site will be diverted to off-site by designing perimeter berm and ditches to minimize the stormwater draining by plant drainage system.

Each outfall will be detailed per its maximum design flow, required slope protection and erosion control.

13.34.1.8 Storm Water Drainage Calculations

Rainfall intensity and depths will be based on historical data from NOAA Atlas 14, Volume 7, Version 2. Refer to Rainfall Design Basis (Document No. USAL-CB-CBDES-00-000005-000) for the rainfall intensities and depth based on the precipitation frequency for site permanent monument No. 3 (Latitude 60.6611° Longitude -151.5308°, corresponding to Alaska State Plane coordinate N 2436025.11 E 1398109.13) at the Liquefaction Facility site. Precipitation frequency estimates will be based on frequency analysis of annual maxima series.

The minimum ditch gradient will be 0.1 percent.

Ditches or channels serving areas subject to firewater flows will be designed to carry the design storm run-off or firewater flows, whichever is greater.

Channels serving areas subject to LNG spill will be designed to carry the LNG spill flow, firewater flow or the design storm run-off, whichever is greater.

13.34.1.9 Impoundment System Snow and Ice Removal

Uncontaminated snow is to be removed from the pad with conventional equipment such as front end loaders, snow plows, etc

13.34.1.10 Snow and Ice Load Basis of Design and Removal

Refer to Metocean and Ice Design Basis, Document No. USAL-PM-JBDES-90-000002-000 in Appendix 13.B.23 for ice loads and the Rainfall Design Basis (USAL-CB-CBDES-00-000005-000) in Appendix 13.B.12 for snow return periods

13.35 PASSIVE PROTECTION SYSTEMS

13.35.1 Passive Protection Design

Passive fire protection has been provided on structural and equipment supports, pressurized equipment, and building components where flame impingement or excessive radiation is possible from a LNG jet or pool fire which if failure occurs could lead to further event escalation.

Details of the Passive Protection design are included in the Process Safety Design Basis (USAL-CB-PBDES-00-000001-000), included in Appendix 13.B

13.35.1.1 Passive Protection Philosophy

Type of fireproofing material(s) shall be selected in FEED. Non-proprietary fireproofing material may not be considered for use unless satisfactory evidence is given that it has passed an appropriate fire test. Also proprietary materials shall have passed the appropriate fire test specific to its application e.g. cellulosic or hydrocarbon pool and / or jet fire applications.

13.35.1.2 Cryogenic Structural Protection

Plant, equipment and structural steel shall be protected from cryogenic spills through selection of suitable materials of construction (e.g., concrete, stainless steel) or by application of insulating materials to prevent embrittlement failure.

13.35.1.3 Vapor Barriers

Not Applicable

13.35.1.4 Equipment Layout Setbacks and Separation

The unit plot layouts, maintenance and laydown areas take into consideration accessibility and safety.

In accordance with requirements in Section 2.2 and also Section 3.4 of the NFPA 59A – 2001, equipment and buildings have been located to provide adequate access for normal operation and maintenance activities.

In accordance with requirements of Section 3.1 and 3.2 of NFPA 59A – 2001, process equipment will be located outdoors where feasible for ease of operation and to facilitate manual firefighting and dispersal of accidentally released liquids and gases. Enclosed structures or buildings where process equipment will be located will have enough ventilation or cover in accordance with the requirements of Sections 2.3.2 and 2.3.3 of NFPA 59A - 2001.

In accordance with the requirements of Section 3.2.2 of NFPA 59A – 2001, valves will be installed so that pumps and compressors can be isolated for maintenance.

In accordance with the requirements of Sections 3.3 and 2.2.1.2 of NFPA 59A – 2001, flammable refrigerant and flammable liquid storage areas will be sloped and provided with impoundments to minimize the possibility that accidental spills and leaks that could endanger important structures, equipment or adjoining property, or reach waterways.

13.35.1.5 Blast Walls, Hardened Structures, and Blast Resistant Design

Not Applicable

13.35.1.6 Fire-Proofing, Firewalls, And Radiant Heat Shields Design

Fireproofing is provided throughout the facility. Appendix 13.S.9 includes a Fireproofing Equipment List (USAL-CB-FLZZZ-00-0000009-000).

Drawings in Appendix 13.S.11 illustrate the Fire Proofing layouts

Drawing Number	Description
USAL-CB-FDZZZ-00-000001-001	Fire Exposed Area Layout LNG Trains, LNG Storage Tank, Common Process & Utility
USAL-CB-FDZZZ-00-000001-002	Fire Exposed Area Layout Offshore Trestle
USAL-CB-FDZZZ-00-000001-003	Fire Exposed Area Layout Admin, Condensate & Diesel Storage and Waste Water Treatment
USAL-CB-FDZZZ-00-000001-008	Fire Exposed Area Layout Process Train (OSBL)
USAL-CB-FDZZZ-00-000001-009	Fire Exposed Area Layout Power Generation, Non-Hydrocarbon, Utility, Open Ground Flare, Inlet Gas Treating and HP & LP Fuel

13.35.1.7 Other Passive Protection (E.G. Mounding, Elevated Heating, Ventilation, and Air Conditioning [HVAC] Intakes; Foam Glass Blocks; Etc.)

TBD

13.36 HAZARD DETECTION SYSTEMS

13.36.1 Hazard Detection System Design

Fire & Gas Detection System (FGS), part of the Safety Instrumented System (SIS) will be installed as part of the Liquefaction Facility to detect and mitigate the occurrence of physical situations that could result in injury to personnel and/or damage to property and the environment. The FGS will accomplish this by detecting and alerting facility operators to the presence of fire, LNG and refrigerant spills, flammable gas and cryogenic liquid leak hazards. Operators will take necessary actions to control and minimize the extent and severity of these hazards. Upon receipt of confirmed fire/gas detection alarms, activation of the protective systems will be automatic to shutdown the applicable process and utility equipment and to activate the fire suppression systems, as applicable.

The integrated FGS will be a high-integrity system, and will continuously supervise and alert operating personnel to LNG, refrigerant, and condensate spills, fires, or flammable gas leaks. The FGS will be based on a Supervising Fire Alarm System in accordance with NFPA 59A and NFPA 72.

The main FGS Human Machine Interfaces (HMIs) and operator interface will be located in the Central Control Room (CCR). The CCR will provide controls for the entire facility. Local PAGA speakers and strobes will provide local audible/visible notification and system release functions. The entire field-mounted fire and gas instrumentation will be hard-wired to the SIS and then networked to the other FGS components. The FGS will have a communication link to the PCS for the display of FGS status and alarm signals on the PCS.

The FGS will consist of the following components:

- Flame detectors, temperature detectors, flammable gas detectors, and other sensor types will be located in process and facility areas that may have flammable liquid or gas present. These instruments will be accessible for maintenance and readability;

- Visual and audio alarms (notification devices) that indicate hazards will be present. The audio alarms will be distinct for the type of hazard (e.g., fire, flammable gas release);

- Main fire alarm HMIs located in the Central Control Room. A high-integrity Nationally Recognized Testing Laboratory (NRTL) approved system for fire supervising service will be provided. Building fire alarm panels will be networked to the SIS and main fire alarm HMI.

- Hard-wired switches will be located in the Central Control Room; and

- Manual alarm activation switches throughout the facilities.

The FGS will execute logic for single detectors as well as for groups of detectors. For example, a voting scheme may be applied where three detectors will be installed in a particular area and alarms from two out of the three detectors will initiate a confirmed alarm and associated executive action.

Supervising capability will be provided via video display screens located in the Central Control Room. All FGS alarms will be alarmed in the SIS.

Operating personnel will be able to initiate appropriate firefighting and/or shutdown actions via hard-wired switches provided at the Central Control Room consoles in response to a fire and/or gas release event.

The FGS system will be designed such that no single failure point will affect system integrity. All circuits and devices will be monitored and shorts to ground will not prevent alarm or communication capability. Failure of any single active component supplied within the system will not cause a loss of multiple field devices, and during such a failure, the system will remain on-line and will continue to monitor for fire and gas releases. Additionally, the system will accommodate a means for alarming any fault in the system.

On-line and off-line diagnostics will be provided to assist in system maintenance and troubleshooting. Diagnostics will be provided for every major system component and peripheral.

The Liquefaction Facility hazard detection instrumentation will be provided as shown on the drawings included in Appendix 13.S. This hazard detection instrumentation will consist of flame detectors, gas detectors, low temperature detectors, heat detectors, and smoke detectors.

Selection will be based on which type is suitable for the conditions at each detector location.

13.36.1.1 Hazard Detection Philosophies (Selection, Layout, Alarm, Activation, and/Or Shutdown Setpoints, Voting Logic, Voting Degradation Logic)

The design Philosophy for the Hazard Detection System is provided in the Integrated Control and Safety System Design Basis (USAL-CB-IBICS-00-000005-000) included in Appendix 13.B.18.

13.36.1.2 Hazard Detection Design and Performance Criteria (E.G., Minimum Detector Spacing, Maximum Detection Time, Etc.)

The Hazard Control and Safety Equipment List, Document No. USAL-CB-FLZZZ-00-000007-000, included in Appendix 13.S, provides the location and type.

13.36.1.3 Low Temperature Detectors

Low temperature detection will be installed near LNG equipment in the LNG sumps.

13.36.1.4 Oxygen Deficiency Detectors

Not Applicable

13.36.1.5 Toxic Gas Detectors

Not Applicable

13.36.1.6 Flammable/Combustible Gas Detectors

The Gas Detection System will be composed of point source type gas detectors and line-of-sight type gas detectors connected to the appropriate element of the FGS.

13.36.1.7 Flame Detectors

Flame detectors will be provided in high leak potential equipment areas to monitor locations where release and subsequent ignition of hydrocarbons will be credible.

13.36.1.8 Heat Detectors

Heat detectors will fall into three categories: fixed-temperature devices, rate-of-rise, and rate-compensated devices.

Smoke detectors will be addressable with an alarm light-emitting diode (LED) for identification in the event of an alarm condition.

13.36.1.9 Smoke/Products of Combustion Detectors

Not Applicable

13.36.1.10 Manual Pull Stations

Manual alarm call points will be provided in accessible areas throughout the plant for personnel to report the occurrence of an emergency condition.

13.36.1.11 Audible and Visual Notification Systems for Field, Control Room, Plant Wide, And Offsite

Fire alarm strobes, gas alarm strobes, Public Address and General Alarm (PAGA) speakers and PAGA beacons will be provided in all plant areas. Strobes will have distinct coloration to facilitate type of hazard identified.

13.36.1.12 Other Hazard Detectors (e.g., Rate of Rise Temperature Detectors, Acoustic Leak Detectors, Closed-Circuit Television [CCTV] Detectors, Carbon Monoxide, Etc.)

TBD

13.37 HAZARD CONTROL SYSTEMS

13.37.1 Hazard Control System Design

Dry chemical systems are effective against hydrocarbon pools and three-dimensional fires, particularly those involving spills or leaks when risk of re-ignition will be low. Potassium bicarbonate dry chemical will be used in portable extinguishers, both handheld and wheeled. Extinguisher size will depend on the type, location and size of the hazard, existence of nearby ignition sources, and the ability to access the hazard.

Portable CO_2 extinguishers, complete with wall mounting brackets/cabinets, will be provided in the Central Control Room, electrical and power substations, switchgear rooms, and other rooms/buildings where electrical hazards will be present.

Water mist will be used to provide automatic fire extinguishing in enclosures with gas turbine drivers. A total flooding gaseous agent may be used to provide automatic fire extinguishing protection in selected LERs (local electrical rooms). Safety shower and eyewash stations will be located in areas within the facility where personnel may be exposed to materials that can cause injury to eye and body.

13.37.1.1 Hazard Control Philosophies (Selection, Layout, Activation)

For hazard control equipment coverage, see equipment layouts detailed in Section 13.37.1.3 and Hazard Control Safety Equipment List, Document No. USAL-CB-FLZZZ-00-000007-000 included in Appendix 13.S.

13.37.1.2 Performance Criteria (e.g., Minimum Flow and Capacity, Maximum Travel Distance/Spacing, Etc.)

For hazard control equipment coverage, see equipment layouts detailed in Section 13.37.1.3 and Hazard Control Safety Equipment List, Document No. USAL-CB-FLZZZ-00-000007-000, included in Appendix 13.S.

13.37.1.3 Portable Fire Extinguishers Design and Layout With Reference To Drawings in Appendix 13.S

The drawings referenced below provide the locations at which portable and wheeled dry chemical equipment will be located throughout the facility. These drawings are included in Appendix 13.S.

Drawing Number	Description
USAL-CB-FDLAY-00-000001-000	Escape Route and Safety Equipment Layout, Overall Layout
USAL-CB-FDLAY-00-000001-001	Escape Route and Safety Equipment Layout, Liquefaction processing trains, LNG Storage Tank, Common Process & Utility
USAL-CB-FDLAY-00-000001-002	Escape Route and Safety Equipment Layout, Offshore Trestle
USAL-CB-FDLAY-00-000001-003	Escape Route and Safety Equipment Layout, Admin, Condensate & Diesel Storage and Wastewater Treatment
USAL-CB-FDLAY-00-000001-005	Escape Route and Safety Equipment Layout, North Gate
USAL-CB-FDLAY-00-000001-008	Escape Route and Safety Equipment Layout, Process Train (ISBL)
USAL-CB-FDLAY-00-000001-009	Escape Route and Safety Equipment Layout, Power Generation, Non-Hydrocarbon Utility, Open Ground Flare, Inlet Gas Treating and HP & LP Fuel

13.37.1.4 Fixed Dry Chemical Systems Design and Layout With Reference To Drawings in Appendix 13.S

Not Applicable

13.37.1.5 Clean Agent Systems Design and Layout With Reference To Drawings in Appendix 13.S

TBD

13.37.1.6 Carbon Dioxide Systems Design and Layout With Reference To Drawings In Appendix 13.S

Carbon Dioxide systems are not include in the design, but Carbon Dioxide portable extinguishers are used in the Central Control Room, electrical and power substations, switchgear rooms, and other rooms/buildings where electrical hazards will be present.

The drawings referenced below provide the locations at which carbon dioxide equipment will be located throughout the facility. These drawings are included in Appendix 13.S.

Drawing Number	Description
USAL-CB-FDLAY-00-000001-000	Escape Route and Safety Equipment Layout, Overall Layout
USAL-CB-FDLAY-00-000001-001	Escape Route and Safety Equipment Layout, Liquefaction processing trains, LNG Storage Tank, Common Process & Utility
USAL-CB-FDLAY-00-000001-002	Escape Route and Safety Equipment Layout, Offshore Trestle
USAL-CB-FDLAY-00-000001-003	Escape Route and Safety Equipment Layout, Admin, Condensate & Diesel Storage and Wastewater Treatment
USAL-CB-FDLAY-00-000001-005	Escape Route and Safety Equipment Layout, North Gate
USAL-CB-FDLAY-00-000001-008	Escape Route and Safety Equipment Layout, Process Train (ISBL)
USAL-CB-FDLAY-00-000001-009	Escape Route and Safety Equipment Layout, Power Generation, Non-Hydrocarbon Utility, Open Ground Flare, Inlet Gas Treating and HP & LP Fuel

13.37.1.7 Other Hazard Control Systems (E.G., Nitrogen Snuffing, Dispersive Fans, Building Ventilation, Etc.) Design and Layout With Reference To Drawings in Appendix 13.S

TBD

13.38 FIRE WATER SYSTEM

13.38.1 Fire Water Design

The onshore portion of the Liquefaction Facility firewater system will be a looped, underground firewater main with a loop on the jetty trestle to deliver firewater to the onshore LNG Plant areas and Marine areas. The water source for this system will be provided by the freshwater system. This firewater main will be fed by the firewater pumps. The water source for the freshwater system will be from new water wells drilled on the site within the secured area.

Firewater for the LNG loading berths and jetty access trestle will be fed by a 16-inch main that will be continuously circulated by use of a 4-inch line and jockey pumps, which will maintain the firewater system pressure and circulation rate. Heat tracing will be required for firewater system stagnant points, such as drains, deluge plugs, branch lines, and pressure gauges, etc.

13.38.1.1 Fire Water Philosophy

The Fire Protection System Design Basis, Document No. USAL-CB-FBDES-00-000002-000, is included in Appendix 13.B.

13.38.1.2 Fire Water System Design Cases, Demands, Calculations, and Basis Of Sizing

The firewater demand for the Liquefaction Facility will be designed to be 4,900 gallons per minute. The firewater residual pressure while delivering the maximum required firewater rate will be at least 100 psig at any user point (hydrant, monitor, etc.). The firewater pressure will not exceed 165 psig at any user point. The design basis scenario will be the Propane Refrigerant Storage Area which considers one firewater monitor at 500 gallons per minute, 3,400 gallons per minute for deluge systems, and 1,000 gallon per minute for hose allowance per NFPA 59A (2001) Section 9.4.2. Selected buildings to be identified in FEED will have automatic sprinkler systems.

Water mist fire protection systems will be provided within enclosures for the turbine compressors and power generators complying with NFPA 750 and project requirements. Other potential fire scenarios considered in the calculation will be covered by the design basis demand. The calculation demonstrates that the existing firewater system will be capable of providing the required flow rate at the required fire main pressures through the firewater distribution system.

13.38.1.3 Main Fire Water Supply and Back Up Supply (E.G., Fire Water Tank, Pond, Ocean, Wells, City, Etc.)

The firewater supply will be provided from the firewater tank. The firewater tank sizing provides a back-up firewater supply. Refer to the Fire Protection System Design Basis, Document No. USAL-CB-FBDES-00-000002-000, included in Appendix 13.B for additional details.

13.38.1.4 Fire Water Supply Pressure, Psig

The water source for the freshwater system will be from new water wells drilled on the site within the secured area.

13.38.1.5 Fire Water Storage Type and Capacity, Gal

The water supply for the firewater system will be provided by the Firewater Tank, which will have a capacity sufficient to provide water to the largest Liquefaction Facility demand for at least two hours as required by NFPA 59A. An additional two hours of water storage will be added to the Firewater Tank to serve as a 100 percent reserve capacity. The 100 percent reserve capacity will provide an adequate and reliable water source in the event that the primary two-hour storage capacity will become depleted. The minimum volume of the firewater tank will be 1,200,000 gallons. Refer to the Fire Protection System Design Basis, for additional details.

13.38.1.6 Main Fire Water Pumps and Driver Type

The firewater system will consist of freshwater supplying Main Firewater Pumps PFW411601 and PFW411602; and Jockey Pumps PFW411603A and PFW411603B. The following pumps will be provided for the firewater system:

- One Electric motor driven pump (5,000 gallon per minute at 150 psig);
- One Diesel engine driven pump (5,000 gallons per minute at 150 psig); and

- Two Electric motor driven jockey pumps (100 gallons per minute at 150 psig).

The electric motor driven jockey pumps can be driven by power obtained from either the on-site power facility or the local power grid.

Firewater pump installation, including the fire pumps, drivers, controllers, piping, valves, fuel tanks, and interconnecting wiring, etc., will be in accordance with NFPA 20.

Refer to Firewater and Jockey Pump Data Sheets, Equipment Tag Nos. PFW411601, PFW411602, and PFW411603A/B included in Appendix M.

13.38.1.7 Number of Main Fire Water Pumps, Operating And Standby

Two 100% firewater pumps are provided for operation, no pumps are available for standby. One operating and one standby Jockey Pump is provided.

13.38.1.8 Main Fire Water Pumps Operating and Design Flow Rate Capacities (Minimum, Rated, Maximum), gpm

TBD

13.38.1.9 Main Fire Water Pumps Operating and Design Pressures (Minimum, Rated, Maximum)

TBD

13.38.1.10 Jockey/Make Up Water Source

Jockey Pumps take suction from the Firewater Tank.

13.38.1.11 Jockey/Make Up Water Operating and Design Flow Rate Capacities (Minimum, Rated, Maximum), gpm

TBD

13.38.1.12 Jockey/Make Up Water Operating and Design Pressures (Minimum, Rated, Maximum), psig

TBD

13.38.1.13 Fire Water Piping Design and Layout With Reference To Drawings in Appendix 13.S

The drawings referenced below provide the firefighting equipment layout and coverage throughout the facility. These drawings are included in Appendix 13.S.

Drawing Number	Description
USAL-CB-FDFGS-00-000001-001	Firefighting Equipment Layout (Coverage + Pipe Plans), Liquefaction processing trains, LNG Storage Tank, Common Process & Utility
USAL-CB-FDFGS-00-000001-002	Firefighting Equipment Layout (Coverage + Pipe Plans), Offshore Trestle

Drawing Number	Description
USAL-CB-FDFGS-00-000001-008	Firefighting Equipment Layout (Coverage + Pipe Plans), Admin, Condensate & Diesel Storage and Wastewater Treatment
USAL-CB-FDFGS-00-000001-009	Firefighting Equipment Layout (Coverage + Pipe Plans), Power Generation, Non-Hydrocarbon Utility, Open Ground Flare, Inlet Gas Treating and HP & LP Fuel

The Firewater P&ID drawings are detailed below and included in Appendix 13.S:

Drawing Number	Description
USAL-CB-FDPID-00-000411-001	Piping & Instrumentation Diagram Firewater Pumps
USAL-CB-FDPID-00-000411-002	Piping & Instrumentation Diagram Firewater Storage And Jockey Pumps
USAL-CB-FDPID-00-000412-001	Piping & Instrumentation Diagram Firewater Distribution System Common Process/Utilities/Ref. & Condensate Stg./Buildings
USAL-CB-FDPID-00-000412-002	Piping & Instrumentation Diagram Firewater Distribution System LNG Process Train 1/2/3
USAL-CB-FDPID-00-000412-003	Piping & Instrumentation Diagram Firewater Distribution System LNG Storage/REF. Storage/BOG/Fractionation/AIR & Nitrogen/Jetty
USAL-CB-PDPID-60-000976-607	Piping & Instrumentation Diagram Freshwater and Sanitary System Firewater Make Up Pump

13.38.1.13.1 Freeze Protection (Burial Depth Below Frost Depth, Aboveground Heat Tracing, Etc.)

Firewater for the LNG loading berths and jetty access trestle will be fed by a 16-inch main that will be continuously circulated by use of a 4-inch line and jockey pumps, which will maintain the firewater system pressure and circulation rate. Heat tracing will be required for firewater system stagnant points, such as drains, deluge plugs, branch lines, and pressure gauges, etc.

13.38.1.14 Fire Water Hydrants Design and Layout With Reference To Drawings In Appendix 13.S

The drawings referenced below provide the firefighting equipment layout and coverage throughout the facility. These drawings are included in Appendix 13.S.

Drawing Number	Description
USAL-CB-FDFGS-00-000001-001	Firefighting Equipment Layout (Coverage + Pipe Plans), Liquefaction processing trains, LNG Storage Tank, Common Process & Utility
USAL-CB-FDFGS-00-000001-002	Firefighting Equipment Layout (Coverage + Pipe Plans), Offshore Trestle
USAL-CB-FDFGS-00-000001-008	Firefighting Equipment Layout (Coverage + Pipe Plans), Admin, Condensate & Diesel Storage and Wastewater Treatment
USAL-CB-FDFGS-00-000001-009	Firefighting Equipment Layout (Coverage + Pipe Plans), Power Generation, Non-Hydrocarbon Utility, Open Ground Flare, Inlet Gas Treating and HP & LP Fuel

The Firewater P&ID drawings are detailed below and included in Appendix 13.S:

Drawing Number	Description
USAL-CB-FDPID-00-000411-001	Piping & Instrumentation Diagram Firewater Pumps
USAL-CB-FDPID-00-000411-002	Piping & Instrumentation Diagram Firewater Storage And Jockey Pumps

Drawing Number	Description
USAL-CB-FDPID-00-000412-001	Piping & Instrumentation Diagram Firewater Distribution System Common Process/Utilities/Ref. & Condensate Stg./Buildings
USAL-CB-FDPID-00-000412-002	Piping & Instrumentation Diagram Firewater Distribution System LNG Process Train 1/2/3
USAL-CB-FDPID-00-000412-003	Piping & Instrumentation Diagram Firewater Distribution System LNG Storage/REF. Storage/BOG/Fractionation/AIR & Nitrogen/Jetty
USAL-CB-PDPID-60-000976-607	Piping & Instrumentation Diagram Freshwater and Sanitary System Firewater Make Up Pump

13.38.1.15 Fire Water Monitors Design and Layout With Reference To Drawings In Appendix 13.S

The drawings referenced below provide the firefighting equipment layout and coverage throughout the facility. These drawings are included in Appendix 13.S.

Drawing Number	Description
USAL-CB-FDFGS-00-000001-001	Firefighting Equipment Layout (Coverage + Pipe Plans), Liquefaction processing trains, LNG Storage Tank, Common Process & Utility
USAL-CB-FDFGS-00-000001-002	Firefighting Equipment Layout (Coverage + Pipe Plans), Offshore Trestle
USAL-CB-FDFGS-00-000001-008	Firefighting Equipment Layout (Coverage + Pipe Plans), Admin, Condensate & Diesel Storage and Wastewater Treatment
USAL-CB-FDFGS-00-000001-009	Firefighting Equipment Layout (Coverage + Pipe Plans), Power Generation, Non-Hydrocarbon Utility, Open Ground Flare, Inlet Gas Treating and HP & LP Fuel

The Firewater P&ID drawings are detailed below and included in Appendix 13.S:

Drawing Number	Description
USAL-CB-FDPID-00-000411-001	Piping & Instrumentation Diagram Firewater Pumps
USAL-CB-FDPID-00-000411-002	Piping & Instrumentation Diagram Firewater Storage And Jockey Pumps
USAL-CB-FDPID-00-000412-001	Piping & Instrumentation Diagram Firewater Distribution System Common Process/Utilities/Ref. & Condensate Stg./Buildings
USAL-CB-FDPID-00-000412-002	Piping & Instrumentation Diagram Firewater Distribution System LNG Process Train 1/2/3
USAL-CB-FDPID-00-000412-003	Piping & Instrumentation Diagram Firewater Distribution System LNG Storage/REF. Storage/BOG/Fractionation/AIR & Nitrogen/Jetty
USAL-CB-PDPID-60-000976-607	Piping & Instrumentation Diagram Freshwater and Sanitary System Firewater Make Up Pump

13.38.1.16 Hose Reels Design and Layout with Reference to Drawings in Appendix 13.S

The drawings referenced below provide the firefighting equipment layout and coverage throughout the facility. These drawings are included in Appendix 13.S.

Drawing Number	Description
USAL-CB-FDFGS-00-000001-001	Firefighting Equipment Layout (Coverage + Pipe Plans), Liquefaction processing trains, LNG Storage Tank, Common Process & Utility
USAL-CB-FDFGS-00-000001-002	Firefighting Equipment Layout (Coverage + Pipe Plans), Offshore Trestle

Drawing Number	Description
USAL-CB-FDFGS-00-000001-008	Firefighting Equipment Layout (Coverage + Pipe Plans), Admin, Condensate & Diesel Storage and Wastewater Treatment
USAL-CB-FDFGS-00-000001-009	Firefighting Equipment Layout (Coverage + Pipe Plans), Power Generation, Non-Hydrocarbon Utility, Open Ground Flare, Inlet Gas Treating and HP & LP Fuel

The Firewater P&ID drawings are detailed below and included in Appendix 13.S:

Drawing Number	Description
USAL-CB-FDPID-00-000411-001	Piping & Instrumentation Diagram Firewater Pumps
USAL-CB-FDPID-00-000411-002	Piping & Instrumentation Diagram Firewater Storage And Jockey Pumps
USAL-CB-FDPID-00-000412-001	Piping & Instrumentation Diagram Firewater Distribution System Common Process/Utilities/Ref. & Condensate Stg./Buildings
USAL-CB-FDPID-00-000412-002	Piping & Instrumentation Diagram Firewater Distribution System LNG Process Train 1/2/3
USAL-CB-FDPID-00-000412-003	Piping & Instrumentation Diagram Firewater Distribution System LNG Storage/REF. Storage/BOG/Fractionation/AIR & Nitrogen/Jetty
USAL-CB-PDPID-60-000976-607	Piping & Instrumentation Diagram Freshwater and Sanitary System Firewater Make Up Pump

13.38.1.17 Water Screens and Deluge Systems Design And Layout With Reference To Drawings In Appendix 13.S

No water screens are included in the design. The drawings referenced below provide the deluge system equipment layout and coverage throughout the facility. These drawings are included in Appendix 13.S.

Drawing Number	Description
USAL-CB-FDFGS-00-000001-001	Firefighting Equipment Layout (Coverage + Pipe Plans), Liquefaction processing trains, LNG Storage Tank, Common Process & Utility
USAL-CB-FDFGS-00-000001-002	Firefighting Equipment Layout (Coverage + Pipe Plans), Offshore Trestle
USAL-CB-FDFGS-00-000001-008	Firefighting Equipment Layout (Coverage + Pipe Plans), Admin, Condensate & Diesel Storage and Wastewater Treatment
USAL-CB-FDFGS-00-000001-009	Firefighting Equipment Layout (Coverage + Pipe Plans), Power Generation, Non-Hydrocarbon Utility, Open Ground Flare, Inlet Gas Treating and HP & LP Fuel

The Firewater P&ID drawings are detailed below and included in Appendix 13.S:

Drawing Number	Description
USAL-CB-FDPID-00-000411-001	Piping & Instrumentation Diagram Firewater Pumps
USAL-CB-FDPID-00-000411-002	Piping & Instrumentation Diagram Firewater Storage And Jockey Pumps
USAL-CB-FDPID-00-000412-001	Piping & Instrumentation Diagram Firewater Distribution System Common Process/Utilities/Ref. & Condensate Stg./Buildings
USAL-CB-FDPID-00-000412-002	Piping & Instrumentation Diagram Firewater Distribution System LNG Process Train 1/2/3
USAL-CB-FDPID-00-000412-003	Piping & Instrumentation Diagram Firewater Distribution System LNG Storage/REF. Storage/BOG/Fractionation/AIR & Nitrogen/Jetty
USAL-CB-PDPID-60-000976-607	Piping & Instrumentation Diagram Freshwater and Sanitary System Firewater Make Up Pump

13.38.1.18 Expansion Foam Philosophy

A fixed low expansion foam system will be provided for Condensate Storage Tank ABJ634801 and Offspec Condensate Storage Tank ABJ634804, based on NFPA 30. The Truck Loading Station will also be provided with general area foam/water spray coverage beneath the roof canopy. Additional coverage will be provided below the truck tanker carriage. Protection of the loading station is provided on the basis that fire occurrence during transfer operations of this type has the potential to escalate very rapidly and will present a significant delay in time for effective manual response.

High expansion foam is not used at the Facility.

13.38.1.19 Expansion Foam System Design Cases, Demands, Calculations, and Basis Of Sizing

Foam protection is provided on the NFPA 30 basis that (1) tank working capacity with Class I liquid is greater than 50,000 gallons; and (2) tank is provided with fixed cone roof (i.e. no internal floating roof). Based on the largest tank diameter in this area, an additional portable foam hose stream allowance of 50 gpm will be provided for each tank to extinguish small spill fires.

Additional details on the Foam System design is presented in the Fire Protection System Design Basis (USAL-CB-FBDES-00-000002-000), included in Appendix 13. B

13.38.1.20 Expansion Foam Water Supply

Water is supplied to the Foam System from the Firewater loop.

13.38.1.21 Expansion Foam Supply

TBD

13.38.1.22 Expansion Foam Type (E.G. Low Expansion Aqueous Film-Forming Foam [Afff], High Expansion Foam, Etc.)

Low expansion foam will be utilized in the condensate areas.

13.38.1.23 Expansion Foam Concentration, Percent Volume

Low expansion foam has an expansion ration between 2 to 1 and 20 to 1.

13.38.1.24 Expansion Foam Storage Type and Capacity, Gal

TBD

13.38.1.25 Expansion Foam Pumps and Driver Type

TBD

13.38.1.26 Number Of Expansion Foam Pumps, Operating And Standby

TBD

13.38.1.27 Expansion Foam Pumps Operating and Design Flow Rate Capacities (Minimum, Rated, Maximum), Gpm

Minimum low expansion foam solution discharge density will be 0.16 gpm/ft2 in accordance with NFPA 16. A dedicated fixed foam concentrate and proportioning system with suitable winterization provisions will be provided

Minimum application rate will be 0.10 gpm/ft2 of liquid surface area, as specified in NFPA 11, Table of Minimum Discharge Times and Application Rates for Fixed Foam Discharge Outlets on Fixed- Roof Storage Tanks.

13.38.1.28 Expansion Foam Pumps Operating and Design Pressures (Minimum, Rated, Maximum)

TBD

13.38.1.29 Expansion Foam Piping Design and Layout With Reference To Drawings In Appendix 13.S

The drawing referenced below provides the foam layout and coverage throughout the facility. This drawing are included in Appendix 13.S.

Drawing Number	Description
USAL-CB-FDFGS-00-000001-008	Firefighting Equipment Layout (Coverage + Pipe Plans), Admin, Condensate & Diesel Storage and Wastewater Treatment

The P&ID that indicated firewater to the foam system is detailed below and included in Appendix 13.S:

Drawing Number	Description
USAL-CB-FDPID-00-000412-001	Piping & Instrumentation Diagram Firewater Distribution System Common Process/Utilities/Ref. & Condensate Stg./Buildings

13.38.1.29.1 Freeze Protection (Burial Depth Below Frost Depth, Aboveground Heat Tracing, Etc.)

Heat tracing will be required for firewater system stagnant points, such as drains, deluge plugs, branch lines, and pressure gauges, etc.

13.38.1.30 Expansion Foam Generators Design and Layout With Reference To Drawings In Appendix 13.S

TBD

13.38.1.31 Expansion Foam Hose Reels Design and Layout With Reference To Drawings In Appendix 13.S

Not Applicable.

13.38.1.32 External Impact Protection (Bollards)

Bollards will be provided around fire protection equipment to protect from vehicle traffic.

13.39 EMERGENCY RESPONSE PLAN

13.39.1 Emergency Response Plan

A combined Emergency Response Plan (ERP) will be developed to incorporate not just the Liquefaction Facility and GTP, but also the Mainline System that is part of this overall Project development. Within this combined plan will be individual ERPs that will meet all regulatory requirements and address the site-specific nature of the covered facilities.

The combined ERP will be developed using the nationally recognized Federal Emergency Management Agency (FEMA) guidelines and use the National Incident Management System (NIMS) as the methodology with the Incident Command System (ICS) organizational structure. The combined and individual plans will be prepared in consultation with stakeholders to ensure that all actions to emergencies are coordinated and understood by emergency responders, local community leaders, the government, and the general public.

Individual ERPs will be site-specific and identify the types of emergencies that will require notification to appropriate agencies. The individual ERPs will contain the response organization and resources (e.g., diagrams, maps, plans, and procedures) necessary to respond adequately. The ICS is the common emergency response tool used by industry and local emergency response agencies. The Project's ICS will link to plans maintained by other affected response agencies or third parties and thus help to ensure appropriate communications, understanding, and cooperation are in place.

In accordance with the FERC Draft Guidance for Terminal Operator's Emergency Response Plan (ERP), the ERP will be prepared in consultation with the state and local agencies, and the Project representatives will request FERC approval prior to the commencement of construction.

The GTP ERP will include details for:

- Description of response to fire and deployment of resources;
- Organizational chart for emergency response and fire fighting;
- Number of emergency response personnel;
- Number and type of emergency response apparatus;
- Response to emergencies and deployment of resources;
- Public and onsite notification and communication;

- Access and egress locations and roadways, internal and external to site;
- Proposed frequency and type of security and emergency response training and drills for onsite personnel and emergency responders;
- Contact and communications with the State Fire Marshal;
- Contacts and communications with all other appropriate agencies;
- Preliminary Cost Sharing Plans with any state and local agencies and responders to fund security, emergency management, and training costs; and
- Schedule for any future actions, studies, or meetings to develop the Emergency Response Plan and Cost Sharing Plan

13.39.1.1 Incident Command System Organizational Chart For Emergency Response

The ERP will include a description of the ICS organizational chart that will identify the primary job roles that exist in the operations phase and who will be expected to fill these roles in an event of an emergency. The ICS will also be used to coordinate with local emergency response agencies to provide appropriate communications, understanding, and cooperation is in place. This will help ensure that the ERPs will be appropriately linked to plans maintained by other affected response agencies or third parties.

The individual ERPs will be supported by various Emergency Operations Centers (EOCs). There will also be a backup EOC in the event that the primary EOC is not operational. The purpose of the EOCs will be to provide coordinated support for field personnel and other emergency services following a system emergency, and to mobilize operations resources to work with local first responders to secure the incident site and control/contain the emergency event.

13.39.1.2 Proximity of Emergency Response, Fire Brigades/Departments, Mutual Aid, and Local Law Enforcement

The Nikiski Fire Department is located approximately 5 minutes away and the Kenai Police Department is approximately 15 minutes away from the facility.

13.39.1.3 Number of Emergency Response Personnel

As the design develops in the later phases of the Project, hazard analyses will be performed to further define the type and scope of incidents that could occur during operations. Emergency response scenarios will then be developed for various incidents and will detail the type of response required and resources to be deployed. These emergency response scenarios will be developed in consultation with the relative fire prevention, law enforcement, and emergency response agencies in determining an appropriate plan of action. Each scenario will then describe how the facility will coordinate with these agencies to support the emergency response required.

13.39.1.4 Number and Type of Emergency Response Apparatus

These hazard analyses will also be used to design the various detection and response processes or systems to address these incidents. These processes or systems will provide notification back to the main control room when there is a hazard to be addressed. Based on the type of hazard detected, a notification process will be in place to provide that appropriate action is taken to inform affected personnel both onsite and offsite.

13.39.1.5 Response to Emergencies and Deployment Of Resources

The ERP will detail protocols for responding to emergencies and how resources will be deployed.

13.39.1.6 Public and Onsite Notification and Communication

The ERP will also identify the types of emergencies that will provide notification to appropriate agencies and will detail the response organization and resources (e.g., diagrams, maps, plans, and procedures) necessary to respond adequately. It will include designated contacts with state and local emergency response agencies and procedures for notification of local officials and emergency response agencies.

13.39.1.7 Multiple Access and Egress Locations and Roadways, Internal and External To Site

Provisions shall be made for emergency egress from ignited and unignited hydrocarbon spills.

The following table presents the minimum number of exits and minimum egress route clearances for the facility

	Number of Exits
Enclosed, staffed areas where fuel, chemicals, or other flammable materials are used	2
Any areas over 20 ft (6.1 m) long	2
Nearest means of escape from a platform less than 50 ft (15 m)	1
Nearest means of escape from a platform more than 50 ft (15 m)	2

All areas with two or more exits shall be arranged to enable exits to be located at opposite or diagonally opposite ends of the work area. The maximum travel distance to a means of escape shall not exceed 200 feet (61 m).

	Vertical	Horizontal
Primary egress route	90 in. (2,286 mm)	44 in. (1,120 mm)
Secondary egress route	90 in. (2,286 mm)	30 in. (760 mm)

Egress routes in pre-FEED have been detailed in the series of Escape Route and Safety Equipment Layouts. These drawings are included in Appendix 13.S.

Drawing Number	Description
USAL-CB-FDLAY-00-000001-000	Escape Route and Safety Equipment Layout, Overall Layout
USAL-CB-FDLAY-00-000001-001	Escape Route and Safety Equipment Layout, Liquefaction processing trains, LNG Storage Tank, Common Process & Utility
USAL-CB-FDLAY-00-000001-002	Escape Route and Safety Equipment Layout, Offshore Trestle
USAL-CB-FDLAY-00-000001-003	Escape Route and Safety Equipment Layout, Admin, Condensate & Diesel Storage and Wastewater Treatment
USAL-CB-FDLAY-00-000001-005	Escape Route and Safety Equipment Layout, North Gate
USAL-CB-FDLAY-00-000001-008	Escape Route and Safety Equipment Layout, Process Train (ISBL)
USAL-CB-FDLAY-00-000001-009	Escape Route and Safety Equipment Layout, Power Generation, Non-Hydrocarbon Utility, Open Ground Flare, Inlet Gas Treating and HP & LP Fuel

Details of the egress route design is included in the Process Safety Design Basis (USAL-CB-PBDES-00-000001-000), included in Appendix 13.B

13.39.1.8 Preliminary Evacuation Routes Within and Adjacent To Plant and LNG Vessel Route

The emergency response plan will include evacuation routes within and adjacent to the facility.

13.39.1.9 Proposed Frequency and Type f Security and Emergency Response Training and Drills For Onsite Personnel And Emergency Responders

The emergency scenarios identified will also be used to determine the training and emergency drills that will occur internally and with external agencies/stakeholders. The frequency and type of training and drills will be developed in consultation with emergency responders and then reflected in the ERP.

13.39.1.10 Contact and Communications With The Coast Guard, Including LOI And Submittal Of Preliminary Waterway Suitability Assessment (At Time Of Pre-Filing), And Submittal Of A Follow-On Waterway Suitability Assessment (At Time Of Application)

At this stage of the Project, consultation with the Coast Guard have not commenced as they relate to the ERPs. As this Project develops, further dialogue will occur with these groups to understand their capacity to support emergencies that may occur at the facility, how they will interact with the facility for emergency response, and how mutual aid support will occur with other industry in the area. Mutual Aid Agreements and processes for securing additional assistance from non-company resources will be established as needed.

13.39.1.11 Contact and Communications with the State Fire Marshal

At this stage of the Project, consultation with the Alaska State Fire Marshal have not commenced as they relate to the ERPs. As this Project develops, further dialogue will occur with these groups to understand their capacity to support emergencies that may occur at the facility, how they will interact with the facility for emergency response, and how mutual aid support will occur with other industry in the area. Mutual Aid Agreements and processes for securing additional assistance from non-company resources will be established as needed.

13.39.1.12 Contacts and Communications with All Other Appropriate Agencies

As this Project develops, further dialogue will occur with any additional agencies to understand their capacity to support emergencies that may occur at the facility, how they will interact with the facility for emergency response, and how mutual aid support will occur with other industry in the area. Mutual Aid Agreements and processes for securing additional assistance from non-company resources will be established as needed.

13.39.1.13 Preliminary Cost-Sharing Plans with Any State and Local Agencies and Responders To Fund Security, Emergency Management, And Training Costs

At this stage in the Project, any preliminary cost sharing plans have not been discussed or developed

13.39.1.14 Schedule for Any Future Actions, Studies or Meetings To Develop The Emergency Response Plan and Cost-Sharing Plan

During the FERC NEPA process, the Project will start coordination with appropriate entities to proceed development of the Emergency Response Plan and Cost Sharing Plans. Consultations will go throughout detailed design and a finalized Emergency Response Plan and Cost Sharing Plan will be complete prior to the Project going into service.