Federal Energy Regulatory Commission

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UGI LNG, Inc. **Docket No. CP17-14-000**

Temple Truck Rack Expansion Project

Environmental Assessment

Cooperating Agency:
U.S. Department of Transportation

Washington, DC 20426

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TECHNICAL ACRONYMS AND ABBREVIATIONS

ACHP	Advisory Council on Historic Preservation
APE	area of potential effect
CFR	Code of Federal Regulations
Commission	Federal Energy Regulatory Commission
CO	carbon monoxide
CO2	carbon dioxide
dBA	decibels on the A-weighted scale
Dth/day	Dekatherms per day
DOT	U.S. Department of Transportation
DHS	Department of Homeland Security
EA	environmental assessment
EPA	Environmental Protection Agency
FEED	front-end-engineering-design
FERC	Federal Energy Regulatory Commission
FWS	U.S. Fish and Wildlife Service
HAZOP	hazard and operability review
Leq	equivalent sound level
Ldn	day-night sound level
LNG	liquefied natural gas
LOD	Letter of Determination
MMcf	Million cubic feet
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act of 1969
NFPA	National Fire Protection Association
NGA	Natural Gas Act
NOx	nitrogen oxides
NOI	Notice of Intent to Prepare an Environmental Assessment for the Proposed Temple Truck Rack Expansion Project, and Request for Comments on Environmental Issues
NRC	Nuclear Regulatory Commission
NRHP	National Register of Historic Places
NSA	Noise-sensitive area
O3	ozone
OEP	Office of Energy Projects
OSHA	Occupational Safety and Health Administration
OTR	Ozone Transport Regions
PADCNR	Pennsylvania Department of Conservation of Natural Resources
PGA	Peak Ground Acceleration
PHMSA	Pipeline and Hazardous Material Safety Administration
Plan	FERC's Upland Erosion Control, Revegetation, and Maintenance Plan
PM_{10} / $PM_{2.5}$	particles with aerodynamic diameters of 10 microns or less / 2.5 microns or less

Procedures	FERC's Wetland and Waterbody Construction and Mitigation Procedures
Project	Temple Truck Rack Expansion Project
PSM	Process Safety Management of Highly Hazardous Chemicals; Explosives and Blasting Agents
PSD	Prevention of Significant Deterioration
RMP	Risk Management Plan
RQD	Rock quality designation
SHPO	State Historic Preservation Office
STV	STV Energy Services
Temple Facility	UGI's LNG Peak Shaver Facility in Berks County, Pennsylvania
UGI LNG	UGI LNG, Inc.
USGS	U.S. Geological Survey
UGI Utilities	UGI LNG Utilities, Inc.
VOC	volatile organic compounds

SECTION A - PROPOSED ACTION

1.0 INTRODUCTION

The staff of the Federal Energy Regulatory Commission (Commission or FERC) prepared this environmental assessment (EA) to analyze the effects of expanding UGI LNG, Inc's (UGI LNG) Peak Shaver Facility in Berks County, Pennsylvania (Temple Facility). UGI filed its application for the proposed facilities in Docket No. CP17-14-000, known as the Temple Truck Rack Expansion Project (Project). We[1] prepared this environmental assessment (EA) in compliance with the requirements of the National Environmental Policy Act of 1969 (NEPA) as implemented in the Council on Environmental Quality's regulations at Title 40 of the Code of Federal Regulations (CFR), Parts 1500-1508 (40 CFR 1500-1508), and the Commission's regulations at 18 CFR 380.

UGI LNG filed an application with the FERC on November 14, 2016, under section 7(c) of the Natural Gas Act (NGA) and Part 157 of the Commission's regulations. The EA is an integral part of the Commission's decision-making process whether to issue UGI LNG Certificate of Public Convenience and Necessity (Certificate) to construct and operate the proposed facilities.

Our principal purposes in preparing this EA are to:

- identify and assess potential impacts on the natural and human environment that could result from implementation of the proposed Project;
- describe and evaluate reasonable alternatives and specific mitigation measures, as necessary, to avoid or minimize project-related environmental impacts while still meeting the Project objectives; and
- facilitate public and agency involvement in the environmental review process.

The U.S. Department of Transportation (DOT) is a cooperating agency in the preparation of the EA. A cooperating federal agency has jurisdiction by law or special expertise with respect to environmental impacts associated with the proposal and is involved in the NEPA analysis.

2.0 BACKGROUND

The existing Temple Facility was constructed in 1971 by the United Gas Improvement Co., a predecessor to UGI LNG Utilities, Inc. (UGI Utilities). UGI LNG assumed ownership and control of the facility in 2007.[2] The Temple Facility operates as a peaking facility, providing

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[1] "We," "us," and "our" refers to environmental staff of the FERC's Office of Energy Projects (OEP).

[2] On April 19, 2007, the Commission issued an order in Docket Nos. CP06-442 000, CP06-443-000 and CP06-444-000 authorizing UGI LNG: (1) to acquire the Temple Facility from UGI Energy Services, Inc. and to acquire a 5,000-foot-long, 8-inch-diameter pipeline, interconnecting with Texas Eastern Transmission L.P. from UGI Utilities, Inc.; and (2) to construct and operate a new boil-off gas compressor, water pressure monitors, underground piping and pumps, and electrical equipment to upgrade the fire protection system associated with the facilities to be acquired.

firm and interruptible natural gas liquefaction, storage, and vaporization services. Liquefied natural gas (LNG) peak-shaving facilities store surplus natural gas that is used to meet the requirements of peak consumption during the winter or summer. The Temple Facility has historically been used to meet the daily and seasonal peaking needs of UGI Utilities. On occasion, the facility has also liquefied modest volumes of LNG for truck delivery to other facilities.

On June 22, 2009, in Docket No. CP08-458-000, the Commission authorized UGI LNG to construct and operate an additional LNG storage tank at the Temple Facility with 1,000 million cubic feet (MMcf) of working gas capacity and a 150 MMcf per day vaporization and send-out system, along with associated boil-off gas handling equipment. UGI LNG placed the new facilities into service on August 1, 2012.

On June 17, 2013, in Docket No. CP13-504-000, the Commission authorized UGI LNG to construct and operate a nitrogen-driven LNG subcooler system to add refrigeration capacity at the Temple Facility. The LNG subcooler system increased the liquefaction capability at the Temple Facility from 4 MMcf to 10 MMcf per day. UGI LNG placed the subcooler system into service on November 6, 2015.

Currently, UGI LNG provides firm and interruptible storage services at its Temple Facility, receiving gas supplies for liquefaction and storage from Texas Eastern Transmission L.P. and delivering vaporized LNG to customers of Texas Eastern and into the distribution system of UGI Utilities. The Temple Facility consists of two storage tanks with a total of 1.25 MMcf of storage capacity, a liquefaction system designed to deliver approximately 10 MMcf per day of LNG, and a vaporization system with a maximum daily vaporization capability and delivery rate of 205.2 MMcf per day. The Temple Facility contains one truck loading rack and scale that also enables UGI LNG to deliver LNG into trucks.

3.0 PURPOSE

According to UGI LNG, the purpose of the Project is to enable UGI LNG to provide more reliable service to its customers by allowing increased flexibility, coordination, and throughput. Additionally, increasing the number of truck racks would provide access to greater quantities of LNG from the Temple Facility, both in the normal course of business and in emergency situations. The Project would also allow UGI LNG to more reliably serve the growing demand for truck deliveries by UGI Energy Services. In addition to vaporizing LNG for pipeline redelivery as UGI LNG has traditionally provided, the Temple Facility has increasingly been used over the last several years for tank withdrawals by truck, enabling UGI Energy Services to serve end-use applications, including drill sites, remote industrials, and long-haul trucking firms in the Mid-Atlantic and Northeast United States.

Under Section 7(c) of the NGA, the Commission determines whether interstate natural gas transportation facilities are in the public convenience and necessity and, if so, grants a Certificate to construct and operate them. The Commission bases its decisions on technical competence, financing, rates, market demand, gas supply, environmental impact, long-term feasibility, and other issues concerning a proposed project.

4.0 SCOPE OF THIS ENVIRONMENTAL ASSESSMENT

The topics addressed in this EA include geology, soils, groundwater, surface waters, wildlife, vegetation, special status species, land use, recreation, visual impacts, cultural resources, air quality, noise, reliability and safety, cumulative impacts, and alternatives. No Project impacts would occur on wetlands or fisheries; therefore, these resources will not be discussed further. This EA describes the affected environment as it currently exists and the environmental consequences of the Project, and compares the Project's potential impact with that of various alternatives. This EA also presents our recommended mitigation measures.

As the lead federal agency for the Project, FERC is required to comply with Section 7 of the Endangered Species Act, as amended, and Section 106 of the National Historic Preservation Act (NHPA). These statutes have been considered in the preparation of this EA. In addition to FERC, other federal, state, and local agencies may use this EA in approving or issuing permits for all or part of the proposed Project. Permits, approvals, and consultations for the Project are discussed in section A.10 of this EA.

5.0 PROPOSED FACILITIES

UGI LNG proposes to expand its existing trailer loading/unloading facility by constructing two additional trailer loading/unloading racks. The addition would consist of two racks with scales, trailer loading skid, pump skid, transfer piping, and associated equipment. The Project would also include a new driveway connecting the expansion to Willow Creek Road. The Project is projected to increase UGI LNG's truck volumes to an average of three to six trucks per day, up from its 2008-2015 average of one to three trucks per day. Figure 1 shows the Project location.

6.0 PUBLIC REVIEW AND COMMENT

On January 23, 2017, the Commission issued a *Notice of Intent to Prepare an Environmental Assessment for the Proposed Temple Truck Rack Expansion Project, and Request for Comments on Environmental Issues* (NOI). The NOI was mailed to federal, state, and local government agencies; elected officials; environmental and public interest groups; other interested parties; and local libraries and newspapers. The Commission received one general comment from Megan Bermudez in response to the NOI concerning the impact on the land and increased truck traffic on Leesport Avenue. These impacts are discussed in section B below. No additional comments have been received.

7.0 LAND REQUIREMENTS

All construction activities associated with the Project, including equipment storage, construction laydown, and worker parking, would occur entirely within previously disturbed and currently maintained portions of the existing Temple Facility.

The property owned by UGI LNG covers 78 acres, with the fenced Temple LNG facility occupying approximately 30 acres. This fenced area includes the tertiary dikes, berms, and stormwater management system. The existing access road occupies approximately 0.7 acre outside the plant fence. The remaining 48 acres beyond the plant fence includes solar panels, maintained grassland, and limited agricultural production.

An approximately 60-foot by 150-foot area north of the proposed LNG trailer scale location would be used for equipment laydown. The existing Temple Facility driveway would be used for construction access and delivery of construction equipment. Project construction would require the use of 9.4 acres at the Temple Facility, all of which is within the existing fence line. During operation, the proposed facilities would require the permanent use of 5.6 acres of land.

8.0 CONSTRUCTION AND OPERATIONAL PROCEDURES

Construction would last approximately 12-14 weeks. UGI LNG would construct, operate, and maintain the Project in accordance with the DOT Federal Safety Standards for Liquefied Natural Gas Facilities, 49 CFR 193. The Project would also meet the National Fire Protection Association (NFPA) Standards for the Production, Storage, and Handling of LNG.

UGI LNG would comply with FERC's *Upland Erosion Control, Revegetation, and Maintenance Plan* (Plan) and *Wetland and Waterbody Construction and Mitigation Procedures* (Procedures). Typical equipment used during construction of the Project would include pickup trucks, dump trucks, fork lifts, cherry pickers, weld rigs, bobcat, front end loaders, and a crane.

UGI LNG would ensure that all contractors on-site receive environmental training prior to conducting on-site work and that the work is done in accordance with the FERC authorization and all applicable permits.

9.0 NON-JURISDICTIONAL FACILITIES

No non-jurisdictional facilities would be required for Project construction, operation, or maintenance.

10.0 PERMITS, APPROVALS, AND REGULATORY REVIEWS

Table 1 lists the federal and state regulatory agencies that have permit or approval authority or consultation requirements and the status of that review for portions of the Project. UGI LNG would be responsible for obtaining all necessary permits, licenses, and approvals required for its Project regardless of their listing in the table.

Table 1. Permits, Approvals, and Consultations for the Project		
Agency	**Permit/Approval/Consultation**	**Status**
Federal		
FERC	NGA, Section 7(c), Certificate	Pending
U.S. Fish and Wildlife Service	Endangered Species Act, Section 7 Consultation	Concurrence received July 2016
State		
Pennsylvania Fish and Boat Commission	Endangered Species Review	Concurrence received July 2016
Pennsylvania Game Commission	Endangered Species Review	Concurrence received July 2016
Pennsylvania Department of Conservation and Natural Resources	Endangered Species Review	Concurrence received July 2016
Pennsylvania Historic Museum Commission	NHPA, Section 106	Concurrence received June 2016
Pennsylvania Department of Environmental Protection Waterways Engineering and Wetlands	Post Construction Stormwater Management Plan Review, Individual National Pollutant Discharge Elimination System (NPDES) Stormwater Discharge Permit	Pending
County		
Berks County Conservation District	Erosion and Sedimentation Control Plan Review, Individual NPDES Stormwater Discharge Permit	Pending
Township		
Ontelaunee Township	Land Development Planning Approval	Pending. Application submitted September 2016.

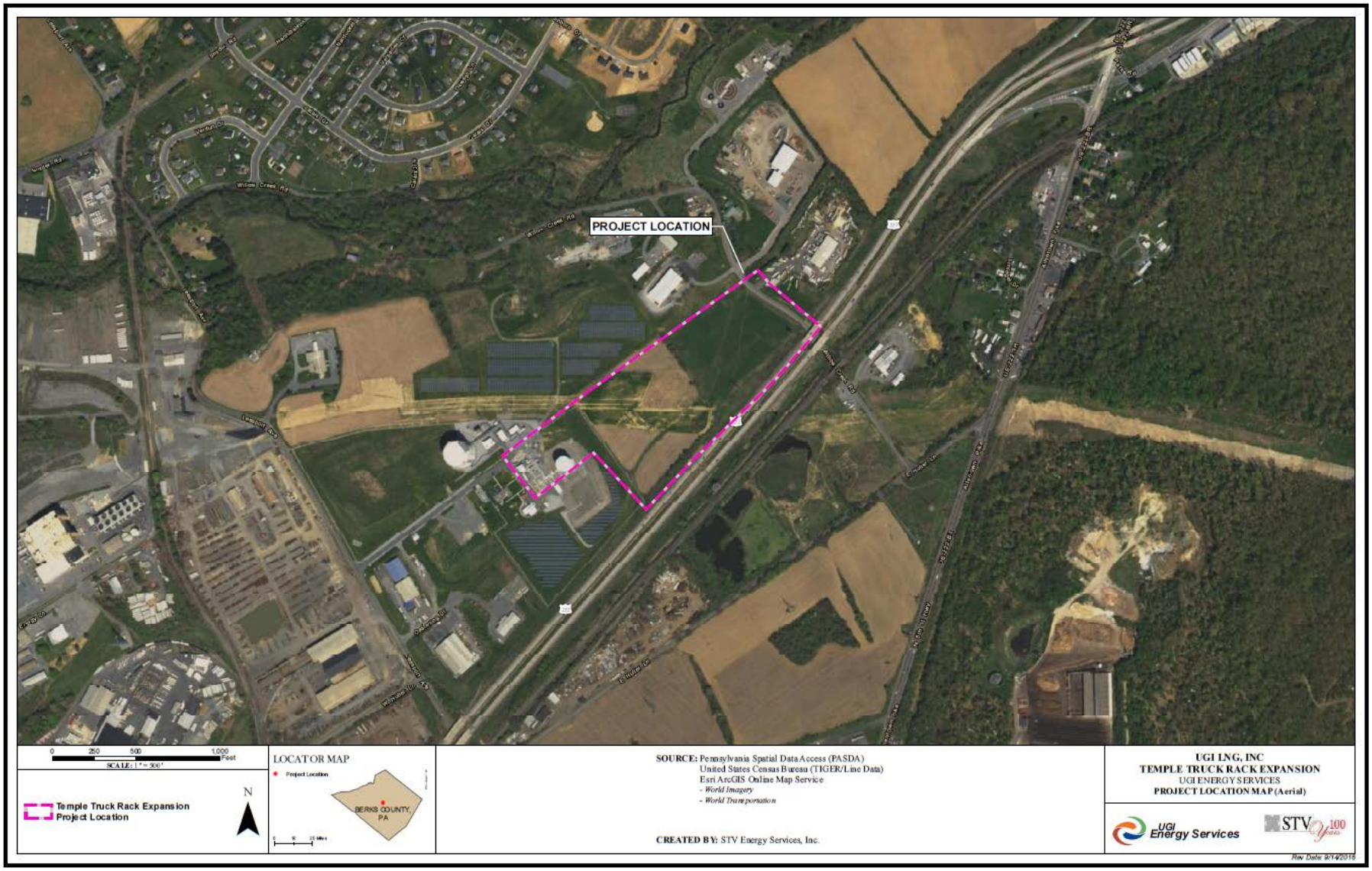

Figure 1. Project Location

SECTION B - ENVIRONMENTAL ANALYSIS

1.0 Geologic Conditions, Resources, Geologic and other Natural Hazards

1.1 Geologic Setting and Mineral Resources

The Project area is proposed within the Great Valley Section of Ridge and Valley Province of Pennsylvania, characterized by thrust sheets of intensely folded sedimentary rocks and dominated by shale and sandstone. The topography of the Project site is characterized by gently rolling hills, generally sloping down from north to south. Elevations range from approximately 300 to 355 feet above mean sea level.

Geotechnical borings conducted at the Project site identified surficial topsoil, silt, gravel with varying amounts of silt (saprolite[3]) and gravel composed of weathered limestone or dolomite fragments to a maximum depth of 34 feet underlain by weathered carbonate bedrock.

Bedrock consists of the Cambrian-Period Allentown formation and the Leithsville formation (Earth Engineering Incorporated (EEI) 2016; American Geotech, Inc. (AGI) 2013; Berg et al 1980). The Allentown formation consists of medium-gray dolomite and impure limestone. The Leithsville formation consists of dark to medium-gray crystalline dolomite. Based on the Pennsylvania Department of Conservation and Natural Resources (PADCNR) Web Mapping Application, the majority of the site is underlain by dolomite of the Leithsville formation with the northwestern majority of the site underlain by limestone and dolomite of the Allentown formation. Where bedrock was encountered in the borings, the top of bedrock ranged between 2 and 29 feet indicating a pinnacled bedrock surface characteristic of dissolution of carbonate bedrock leaving blocks or pinnacles. Rock quality designation (RQD) [4] obtained from bedrock cores showed overall poor to very poor RQDs between 0 and 48-percent (EEI 2016).

UGI LNG's Temple Facility is proposed inland from the Atlantic Ocean by more than 70 miles, and as such, is not susceptible to the direct effects of hurricane winds, storm surge, or flooding. UGI LNG indicated the project would be designed to withstand sustained winds of 150 miles per hour.

No oil or gas wells or aggregate mines were identified in the site vicinity. Coal mining is common in the area; however, the closest mines are approximately 29 miles north of the Project. The Project area has been previously impacted by farming and by LNG facility construction activities, and as such impacts on paleontological resources are not anticipated. However, in the event such resources are encountered, UGI LNG would consult with a professional

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[3] saprolite.—Soft, friable, weathered bedrock that retains the fabric and structure of the parent rock and exhibiting extensive intercrystal and intracrystal weathering (USDA Part 629 – Glossary of Landform and Geologic Terms; accessed at: https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=41992.wba).

[4] The RQD denotes the percentage of intact rock retrieved from a borehole. All pieces of intact rock core equal to or greater than 4 inches long are summed and divided by the total length of the core run. AMERICAN SOCIETY FOR TESTING AND MATERIALS, Standard Test Method for Determining Rock Quality Designation (RQD) of Rock Core (D 6032 – 96). Available at: https://fenix.ciencias.ulisboa.pt/downloadFile/844562369085596/D6032%2520Rock%2520Quality%2520Designation.pdf.

paleontologist to evaluate the find and to determine whether any appropriate mitigation or avoidance measures are warranted.

1.2 Geologic and Other Natural Hazards

Geologic hazards are naturally occurring physical conditions that are capable of producing property damage and loss of life. Typically, within the project area, these potential hazards could include seismic related issues such as ground rupture due to faulting, strong ground shaking, soil liquefaction, ground subsidence, and karst terrain. These site conditions are discussed in section 8.7 below, and with the exception of karst, we conclude that these hazards are either not in the Project area or are expected to have no impact on the Project. Given the potential for karst in the subsurface and the potential for karst development over the life span of the Project, we have included detailed information regarding karst in section 8.7, this section serves as background information.

Karst/Sinkhole Formation

Subsidence hazards involve either the sudden collapse of the ground to form a depression or the slow subsidence or consolidation of the sediments near the Earth's surface. Geotechnical investigations conducted on behalf of the UGI LNG liquefaction facility expansion (American Geotech, Inc. June 2013), and the Project (EEI, November 2016) indicate that limestone bedrock underlies the site. Limestone is a soluble, carbonate bedrock and is commonly known to produce karst topography and sinkholes. Previous geotechnical borings at the Temple Facility found several small voids in the underlying geology that were remediated with grout. After 40 years of operation, the remediated areas show no evidence of settling, fissures, or sinkhole development.

The geotechnical investigation (electromagnetic conductivity survey and geotechnical borings) conducted in 2013 at the Project site were performed to investigate the extent of a possible sinkhole and to obtain additional information for adequate foundation recommendations. As stated in the EEI report, the geophysical survey and two of the AGI geotechnical borings were conducted within the footprint of the planned truck loading facility (B-4 and B-4a). The geotechnical borings encountered bedrock at depths of 8 and 10 feet, respectively. The AGI geotechnical borings within the Project footprint, as well as the EEI geotechnical borings, found residual saprolite soils overlying carbonate bedrock. The borings showed varying depths to competent bedrock, and EEI noted that the bedrock exhibited a pinnacled base of carbonate rocks, which could present potential risks to sinkhole formation. Although no surficial sinkholes or other karst features were found within the footprint of the planned truck loading facility, the subsurface is characteristic of a karst bedrock environment given the poor bedrock core recovery and RQD values, and the loss of drilling (coring) fluids noted in the EEI boring logs.

The Project would not involve extensive excavations (i.e., aboveground and/or underground storage facilities, or pipeline construction) that could be impacted by the presence of karst. The earth grading activities necessary to construct the driveway would involve a net import of material. However, risk to the Project from karst features could come from construction and using the stormwater management facilities proposed on-site. Due to the increased impervious land cover from the proposed driveway and truck rack facility, the site would experience an overall increase in stormwater runoff rate and volume. In order to mitigate these increases, UGI LNG would use our Plan and Procedures and include a stormwater management basin to temporarily store runoff and release it slowly. The storage of water could

increase the risk of sinkholes, and therefore, UGI LNG would incorporate certain design features into the stormwater management design to mitigate these risks. These design features include using the stormwater management basin as a detention basin instead of an infiltration basin (which is normally required). Additionally, stormwater detention facilities have been designed with an oversized length to width ratio in order to avoid concentrating stormwater runoff, thereby reducing the potential for creating sinkholes.

The EEI report recommended that the foundation for the truck scales be below frost depth to prevent potential heave of the scale. In addition, EEI recommended that all soft/loose soils encountered during site development activities be carefully evaluated for possible sinkhole conditions, and that if encountered, sinkholes should be remediated under the observations of the on-site geotechnical engineer. EEI further recommended that the pit beneath the scale be lined because the facility is underlain by carbonate bedrock and susceptible to sinkhole formation. These design recommendations were incorporated into the design of the truck rack. UGI LNG states that the final design would address local and site-specific karst conditions. If necessary, UGI LNG would use the same approved methods previously implemented to mitigate any potential concerns and, per the recommendations of EEI, would perform mitigation measures under the direction of a geotechnical engineer. Sinkholes or voids that are encountered during excavation may be grouted with concrete (and may include rip rap or boulders to fill the voids). Additional recommendations are included in Section 8.7.

1.3 Conclusion

Based on the low risk of seismicity and soil liquefaction, landslides, and surface faulting, we conclude that the Project would not be impacted by these geologic hazards. Further, with the absence of geologic resources, such as mines and gas wells, the Project would not have an impact on geologic resources. We conclude that with implementation of the karst recommendations provided in section 8.7, the Project would not have a significant geological impact from the potential presence of karst in the subsurface.

2.0 Soils

The Project would cross herbaceous and agricultural vegetation types, as well as industrial lands. The soils have a low to moderate susceptibility of water and wind erosion. Additionally, about 88 percent (or 8 acres) are classified as prime farmland or farmland of statewide importance. Further, revegetation potential for Project area soils is high.

To aid in revegetation, thereby minimizing any potential erosion effects, UGI LNG has committed to implementing seeding the temporarily disturbed areas in accordance with the Pennsylvania Department of Environmental Protections recommendations. In addition, UGI LNG would implement our Plan, which would limit potential erosion and ensure revegetation of the temporary workspaces. However, about 5 acres of soils would be converted by paving or graveling the permanent right-of-way. Because this represents a negligible amount of overall soils within the Project area, we conclude that the Project would have minimal impacts on soils.

3.0 Water Resources

3.1 Groundwater

The Project area contains carbonate bedrock aquifers consisting of fractured, and solution-prone limestone and dolomite. The average depth to groundwater is between 11 and 33 feet. Groundwater yield in carbonate bedrock, such as the Allentown formation and the Leithsville formation, can vary, and depends largely on the degree of bedrock weathering, jointing, fracturing. Groundwater yields of 5 to 500 gallons per minute, and occasionally exceeding 3,000 gallons per minute are not uncommon. Groundwater in Pennsylvania is primarily used for drinking water (>50%), and other uses such as industry, mining, and agriculture. Based on UGI LNG's search of the U.S. Environmental Protection Agency's (EPA) Envirofacts website, there is no known soil or groundwater contamination in the Project area. Sole-source aquifers are aquifers that supply at least 50 percent of the drinking water consumed in the area where no alternative drinking water source is available that could physically, legally, or economically supply the area. Based on a search of the EPA database, there are no sole-source aquifers in the Project area. Additionally, there are no active water supply wells within 150 feet of the Project.

Construction of the Temple Truck Rack Expansion would not involve the use of groundwater. UGI LNG proposes to conduct pneumatic testing of the piping; therefore, no hydrostatic testing would be required. The only water requirements are for dust suppression. UGI LNG proposes to use water from a nearby municipal source for this purpose.

Potential impacts on groundwater from construction, in addition to karst described above and in section 8.7, include contamination from spills of hazardous materials and minor effects on groundwater recharge due to the disturbance and minor increase in impervious surface. UGI LNG would maintain spill response procedures for hazardous substances and response materials onsite. When construction is complete, UGI LNG would revegetate temporary workspaces as soon as possible. Therefore, we conclude that the Project would not have a significant impact on groundwater.

3.2 Surface Water

The Project would not directly impact any perennial waterbodies. One dry swale would be crossed by construction of a permanent access road. A culvert would be placed in this water feature to allow for the flow of water when needed. The Project is near Willow Creek and the construction area drains into this waterbody. Potential impacts on surface waters in the vicinity of construction include sedimentation due to erosion and contamination from spills of hazardous materials. UGI LNG's proposed use of erosion control devices such as silt fence and hay bales would prevent the migration of sediments into nearby waterbodies.

Stormwater management facilities would be constructed to manage the increase in impervious surfaces from the Project. If dewatering is required during construction, UGI LNG would discharge the water into filter bags and hay bale structures to minimize the potential impacts from dewatering such as erosion and sedimentation. Refueling would not be allowed within 100 feet of any waterbodies, including the dry swale. UGI LNG would implement its spill procedures to minimize the potential for contamination of waterbodies from accidental spills of fuels and other hazardous materials.

Based on the discussion above, including UGI LNG's use of the FERC's Plan and Procedures, we conclude that the Project would not have a significant impact on surface waters.

4.0 VEGETATION AND WILDLIFE

4.1 Vegetation

The Project area consists of herbaceous vegetation, including dandelions, poison ivy, and various species of upland grasses (4.9 acres). In addition, some agricultural land (3.3 acres) consisting of rotational crops is present. The remainder of the land that would be disturbed is commercial/industrial land (1.2 acres) which lacks vegetation. No sensitive or protected vegetation types would be impacted by the Project.

UGI LNG's implementation of our Plan would ensure that areas temporarily disturbed by construction are revegetated. In addition, the Plan would minimize any potential off-site impacts from erosion during construction by the use of temporary erosion control devices. We conclude that the Project would have a minor, temporary impact on vegetation.

4.2 Wildlife

Vegetation removal for construction of the Project would decrease the amount of wildlife habitat available in the Project area. However, there are sufficient areas adjacent to the proposed Project workspaces that provide similar habitats for wildlife displaced during construction and operation of the Project. Mobile species, such as most birds and larger mammals, would be expected to move out of the Project area once construction activities commence. Smaller species and less mobile individuals could be unintentionally killed by construction equipment.

Given the nature of the Project activities and the availability of similar habitat in the general area, we conclude that the Project would not have a significant impact on the region's wildlife.

Migratory Birds

Migratory birds are species that nest in the United States and Canada during the summer, and make short- or long-distance migrations for the non-breeding season. Neotropical birds migrate to and from the tropical regions of Mexico, Central and South America, and the Caribbean.

Migratory birds are protected under the Migratory Bird Treaty Act (16 U.S. Code 703-711), and Bald and Golden Eagles are additionally protected under the Bald and Golden Eagle Act (16 U.S. Code 668-668d). The Migratory Bird Treaty Act, as amended, prohibits the taking, killing, possession, transportation, and importation of migratory birds, their eggs, parts, or nests. Executive Order 13186 directs federal agencies to identify where unintentional take is likely to have a measurable negative effect on migratory bird populations and avoid or minimize adverse impacts on migratory birds through enhanced collaboration with the U.S. Fish and Wildlife Service (FWS), and emphasizes species of concern, priority habitats, and key risk factors and that particular focus should be given to population-level impacts.

Construction of the proposed facilities could overlap with the nesting season for migratory birds (generally April 1st- August 31st). However, there are no forested areas that would be impacted by the Project. Further, due to the highly disturbed nature of the Project area

from agricultural use and/or mowing, it does not provide high quality nesting habitat. Therefore, we conclude that the Project would not have a significant impact on migratory birds.

4.3 Special Status Species

Special status species are those species for which state or federal agencies provide an additional level of protection by law, regulation, or policy. Included in this category are federally listed and federally proposed species that are protected under the Endangered Species Act, or are considered as candidates for such listing by the FWS, and those species that are state-listed as threatened or endangered. No ESA listed species under the National Marine Fisheries Service would be impacted by the Project.

Based on a search of the Pennsylvania Natural Diversity Inventory, there are no state-listed species in the Project area. This search did not identify any species. We conclude that the Project would not affect state-listed species.

Federally Listed Species

UGI LNG conducted a search of the FWS's Information for Planning and Consultation system to identify federally listed species in the Project area. This search identified the Indiana bat, northern long-eared bat, and bog turtle as potentially occurring in the Project area.

Indiana bats and northern long-eared bats hibernate in caves and mines during the winter months. In the spring and summer, they forage in upland forests. Because there are none of these features present in the Project area, there is no suitable habitat. Therefore, we conclude that the Project would have *no effect* on the Indiana bat or northern long-eared bat.

Bog turtles prefer calcareous wetlands, meadows, bogs, spring seeps, and marshes. The Project area does not provide any suitable habitat for the bog turtle. Therefore, we conclude that the Project would have *no effect* on the bog turtle.

5.0 CULTURAL RESOURCES

Section 106 of the NHPA requires that all federal agencies, including FERC, take into account the effects of their undertakings on historic properties and afford the Advisory Council on Historic Preservation (ACHP) an opportunity to comment. Historic properties are archaeological sites, historic districts, buildings, structures, objects, or properties of traditional, religious, or cultural importance that are listed on or eligible for the National Register of Historic Places (NRHP). UGI LNG is assisting us by providing information, analyses, and recommendations, as allowed by the regulations for implementing Section 106 at Part 800.2(a)(3), and FERC's regulations at 18 CFR 380.12(f). FERC remains responsible for all findings and determinations under the NHPA. This section summarizes the current status of compliance with the NHPA for this Project.

We sent copies of our NOI to a range of stakeholders, including other federal agencies, such as the ACHP, EPA, U.S. Army Corps of Engineers, and the U.S. Department of the Interior's National Park Service, Bureau of Indian Affairs, and Bureau of Land Management; and state agencies, including the Pennsylvania Historical and Museum Commission. The NOI contained a paragraph about Section 106 of the NHPA, and stated that we use the notice to

initiate consultations with the State Historic Preservation Office (SHPO),[5] and to solicit their views, and those of other government agencies, interested Indian tribes, and the public on the Project's potential effects on historic properties. No agencies responded to our NOI.

UGI LNG indicated that the area of potential effect (APE) for this Project covers about 20 acres. The Project area consists of an agricultural field and lawn and is surrounded by land used for industrial purposes. We find the APE as defined by UGI LNG acceptable.

Consultations with Indian Tribes

Our NOI for this Project was sent to the Delaware Nation, Delaware Tribe, and Stockbridge-Munsee Band of Mohican Indians in Wisconsin. None of these Tribes responded indicating an interest in the Project.

In addition to FERC's consultations, UGI LNG communicated separately with potentially interested Indian tribes. UGI LNG's contractor, STV Energy Services (STV), sent letters dated July 25, 2016 to the same Indian Tribes listed above. The Delaware Tribe responded to UGI LNG's contact program, and indicated that no religious or cultural sites significant to the Tribe are in the Project area. In an email to STV, dated October 11, 2016, the Stockbridge-Munsee Tribe indicated that the Project area is outside their cultural area of interest. No response was received by the Delaware Nation.

Consultations with the SHPO

UGI LNG, and its contractors, communicated with the Pennsylvania SHPO, as documented in Table 2 below.

Table 2 Communications Between UGI and the Pennsylvania SHPO

Date	Actions
March 14, 2007	SHPO letter to UGI LNG stating there is a high potential for significant cultural resources in the Project area, so an archaeological survey should be conducted.
November 6, 2007	Letter from SHPO to UGI LNG reviewing the Milner Phase I and Phase II cultural resources survey and testing report, and agreeing with the report's recommendation that site 36BK556 is not eligible for the NRHP.
Undated	STV submitted a Project Review Form to the SHPO for the UGI Temple Truck Rack Expansion Project recommending that the Project does not involve any historic properties.
June 14, 2016	Letter from STV, representing UGI LNG, to SHPO recommending that the Project would not affect historic structures or archaeological sites because it was previously plowed and is surrounded by industrial land.
June 16, 2016	SHPO letter to STV stated that the Project has no potential to affect historic properties.
May 4, 2018	STV (on behalf of UGI LNG) submitted the Unanticipated Discovery Plan to the SHPO.

In a June 16, 2016 letter to STV, the Pennsylvania SHPO stated: "…it is our opinion that this project has no potential to affect historic properties. Therefore, your responsibility for consultation with the Pennsylvania State Historic Preservation Office…for this project is

[5] In the Commonwealth of Pennsylvania, the SHPO is housed within the Pennsylvania Historical and Museum Commission.

complete." Based on this letter, UGI LNG did not conduct a cultural resources survey covering the Project. FERC staff agrees with the SHPO.

UGI included an Unanticipated Discovery Plan (UDP) in Section 4.1.6 of Resource Report 4 of its application to the FERC. UGI LNG also submitted a copy of the UDP to the Pennsylvania SHPO via a letter from STV dated May 4, 2018. While the Pennsylvania SHPO has not commented on the UDP, we find the UDP acceptable.

No traditional cultural properties, sacred sites, aboriginal burials, or objects of cultural patrimony were identified in the APE by the National Park Service, Bureau of Indian Affairs, SHPO, STV, or any Indian tribes. After consultations with the SHPO and Indian tribes, FERC staff concludes that the Project would have no effect on sites of traditional, cultural, or religious importance to Indian tribes; and therefore, we have completed compliance with Section 101(d)(6) of the NHPA.

We and the SHPO agree that construction and operation of the Project should have no effects on historic properties. No additional investigations are necessary at the proposed facilities. We have completed the process of complying with Section 106 of the NHPA in accordance with 36 CFR 800. Because no historic properties would be affected, consultation with the ACHP for this Project is not necessary.

6.0 LAND USE, RECREATION, AND VISUAL RESOURCES

The Project would be constructed entirely within the fence line of the existing UGI LNG property area that was previously disturbed. Because the Project would not disturb any land outside of the existing property boundary, the Project would not impact any existing or planned residences or residential development. All construction parking would be within the existing UGI LNG property.

The Project would not affect any federally-designated or recognized natural, recreational or scenic areas, wildlife refuges, national parks, Indian reservations, wild and scenic rivers, trails, wilderness areas, or natural landmarks.

Visual impacts associated with construction would be temporary and short-term and most of the equipment would be relatively unobtrusive in comparison to other equipment at the Temple Facility. New facilities associated with the Project include two additional truck trailer loading/unloading racks and an access road. The proposed truck trailer racks and access road are consistent with the existing industrial land use at the existing facility. Therefore, no significant adverse visual impacts are expected during construction or operation.

The Commission received a comment in response to the NOI concerning increased truck traffic on Leesport Avenue. We note that the truck traffic from the proposed facility would increase from a maximum of three trucks per day to an average of six trucks per day. According to the State of Pennsylvania's Traffic Information Repository,[6] there were 5,935 vehicles per day traversing a counter 550 feet south of the UGI LNG "No admittance" sign on June 21, 2016. Although no truck volume information is given in this report, we note that in a 2011 survey 5.1 percent of vehicles were trucks. Assuming the same rate of trucks in 2016 as in 2011, this would

[6] https://www.dot7.state.pa.us/tire/tms-sites/14869/report

represent approximately 300 trucks traversing the counter per day. The three additional trucks per day proposed by UGI LNG would therefore result in an overall increase of truck traffic of about 1 percent. The overall traffic volume would also increase by a negligible amount. UGI LNG stated in its application that truck traffic could increase to a peak of 15 to 20 trucks per day on the 5 to 10 coldest days of the year due to peak demand. This would represent a 6 percent increase in truck traffic and a less than 1 percent increase in overall traffic. Because of the relatively small increase in traffic that would result from operation of the Project for most of the year, as well as the relatively few days when truck traffic could potentially increase at the facility, we conclude that the Project would not result in any significant impacts on traffic on Leesport Avenue.

7.0 AIR QUALITY AND NOISE

7.1 Existing Air Quality

Construction and operation of the Project could have an effect on local and regional air quality. Federal and state air quality standards have been designed to protect people and the environment from airborne pollutants. The EPA has established National Ambient Air Quality Standards (NAAQS) for nitrogen oxides (NO_x), carbon monoxide (CO), ozone (O_3), sulfur dioxide, lead, and inhalable particulate matter (PM_{10} and $PM_{2.5}$). PM_{10} and $PM_{2.5}$ include particles with aerodynamic diameters of 10 microns or less and 2.5 microns or less, respectively. States are allowed to adopt stricter standards than the NAAQS. The Pennsylvania Ambient Air Quality Standards add standards for total settled particulate, beryllium, total soluble fluorides (as hydrofluoric acid), and hydrogen sulfide; however, the Project would not result in any significant emissions of these pollutants.

Greenhouse gases are most commonly composed of carbon dioxide (CO_2), methane, nitrous oxide, O_3, water vapor, hydrofluorocarbons, and perfluorocarbons and result from human activities, such as burning fossil fuels, as well as occurring naturally. Combustion of fossil fuels emits CO_2, methane, and nitrous oxide, which are reported in terms of CO_2 equivalents calculated based on the global warming potential of each gas. While the Project would increase the amount of LNG delivered by truck, UGI LNG is not requesting to increase its overall sendout capacity. Therefore, there would be no increase in downstream greenhouse gas emissions associated with combustion products.

7.2 Existing Ambient Air Quality and Attainment Status

Measured ambient air pollutant concentration levels are used to determine the status of air quality for a given area. Areas that are at or below the NAAQS are designated as “attainment areas,” whereas those areas that are above the NAAQS are designated “nonattainment areas.” Those areas lacking data to determine attainment status are referred to as “unclassified areas.” Attainment areas that were once in nonattainment of the NAAQS for a given pollutant are referred to as “maintenance areas” for that pollutant.

Air Quality Control Regions have been established by the EPA in accordance with Section 107 of the Clean Air Act of 1970. The Air Quality Control Regions are defined as contiguous areas considered to have relatively uniform ambient air quality, and are treated as single geographical units. Berks County, Pennsylvania is a part of the marginal Reading nonattainment area for the 2008 O_3 standard and the moderate maintenance area for the 1997

$PM_{2.5}$ standard. Berks County is classified as in attainment/unclassifiable with respect to the NAAQS for CO, NO_x, sulfur dioxide, and PM_{10}.

The New Source Performance Standards Review federal regulatory program includes the Prevention of Significant Deterioration (PSD) regulations, which are intended to protect national public health and welfare while preserving the existing air quality in areas of special national or regional scenic, natural, recreational, or historic value where regulated pollutant levels are in compliance with the NAAQS (i.e., attainment areas). For existing major PSD sources, modifications that exceed the PSD significant emissions increase rates are subject to the PSD regulations. The Project would not exceed any PSD emission thresholds.

Under the PSD regulations, special consideration is given to Class I Areas or areas of special national or regional value from a natural, scenic, recreational, or historical perspective. If a new source or major modification of an existing source is subject to the PSD program and within 62 miles (100 kilometers [km]) of a Class I Area, the facility is required to notify the appropriate federal officials and assess the impacts of the proposed project on the Class I Area. The proposed modifications would not constitute either a major new source or a major modification and are therefore not subject to PSD program requirements. Furthermore, there are no Class I areas within 62 miles of the Project.

The New Source Performance Standards are set forth by the EPA at 40 CFR 60, Subparts A through OOOO and each applies to specific sources of air pollution. There are no applicable New Source Performance Standards or National Emission Standards for Hazardous Air Pollutants for this Project.

Federal actions are subject to the thresholds provided in Subpart B of 40 CFR for determining conformity of these actions to state or federal Implementation Plans. These conformity levels apply to nonattainment areas and maintenance areas. As noted above, the Project is proposed in nonattainment areas for ozone and $PM_{2.5}$. The Clean Air Act of 1970 further establishes Ozone Transport Regions (OTR) to control O_3 precursors and the Project site is within the OTR constituted by the northeast portion of the United States, from Northern Virginia to New England. The General Conformity Rule establishes more restrictive *de minimis* emission levels for certain nonattainment and maintenance areas in OTRs. *De minimis* emission rates for an O_3 nonattainment area inside an OTR is 50 tons per year of volatile organic compounds (VOC) and 100 tons per year of NO_x. The *de minimis* emission rates for all $PM_{2.5}$ nonattainment and maintenance areas is 100 tons per year.

Construction emissions from the Project for VOC and NO_x would be less than 1 ton per year, well below the *de minimis* emission rates.

7.3 Air Quality Impacts

A temporary impact on ambient air quality from construction emissions and fugitive dust may result from the Project. Emissions and fugitive dust would result from use of fossil-fueled construction equipment. In general, these emissions would be temporary, localized, and insignificant. Emissions of PM_{10} and $PM_{2.5}$ would represent the majority of air emissions during construction, primarily in the form of fugitive dust. Fugitive dust would be generated from land clearing, grading, excavation, concrete work, and vehicle traffic on paved and unpaved roads. Emissions would be variable, but would be greater during dry periods and in areas of fine-textured soils subject to surface activity.

During Project operation, there may be fugitive emissions of natural gas from piping components and loading activities. There are no new stationary point sources associated with the loading activities and electric pumps. The emissions increase from fugitive emissions is minimal and estimated to be 0.8 tons per year of VOC and 2,011 tons per year of CO_2 equivalents.

Potential impacts on air quality associated with construction and operation of the Project would be minimized by adherence to all applicable federal and state regulations. Based on the analysis presented above, we believe that the Project would have no significant impact on local or regional air quality.

7.4 Noise

Federal regulatory agencies typically assess noise impacts using two sound metrics: the equivalent sound level (L_{eq}) and the day-night sound level (L_{dn}). The energy of noise is measured in decibels. The units presented for all sound levels in this section are decibels on the A-weighted scale (dBA), which filters noise frequencies to characterize the human ear's response to sound. Human hearing can detect a 3 dBA change with a 5 dBA change being readily noticeable. Humans perceive a 10 dBA change in noise level as a doubling or halving of noise. The L_{eq} is the energy averaged sound level for a given period of time, for example hourly or a 24-hour period. An L_{dn} is also time averaged, but sound levels occurring during nighttime hours (that is, 10:00 pm to 7:00 am) incur a penalization of an additional 10 dBA to account for greater sensitivity, such as sleep disturbance, during these times.

In 1974, the EPA published *Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety* (EPA, 1974). This publication evaluates the effects of environmental noise with respect to health and safety. The document provides information for state and local governments to use in developing their own ambient noise standards. The EPA has determined that in order to protect the public from activity interference and annoyance outdoors in residential areas, noise levels should not exceed an L_{dn} of 55 dBA. We have adopted this criterion for the operational modifications proposed for the Project, unless existing noise is already above this criterion. General construction is not evaluated against the 55 dBA L_{dn} criterion. An L_{dn} of 55 dBA is equivalent to a continuous L_{eq} noise level of 48.6 dBA.

Construction of the Project would result in temporary, localized elevated noise levels from the use of heavy construction equipment. Construction would last approximately 12 to 14 weeks. Temporary increases in noise levels due to construction would be perceptible at nearby noise-sensitive areas (NSA) (e.g., residences), but would be partially mitigated by conducting construction during daytime hours. Additionally, UGI LNG would keep construction equipment in good working order and functioning in accordance with manufacturers' specifications.

Because construction noise is temporary, localized, and would cease once the Project is constructed, we conclude that no significant impacts would result from construction noise associated with the Project.

The only significant noise source for this Project would be from additional truck traffic. The truck traffic would only be active intermittently during daytime hours. Historically, the Temple Facility received about one to three trucks per day with a peak of five to six trucks per day. After the Project is completed, truck traffic would increase to about three to six trucks per

day, with a peak of 15 to 20 trucks per day. However, peak truck traffic typically would only occur on the coldest five to ten days of winter.

An acoustic model was used to analyze potential operational noise impacts at NSAs, both of them residential areas, in the vicinity of the Project. Table 3 shows the projected noise levels at each NSA.

Table 3. Noise Analysis for the Project

NSA	Distance / Direction	Measured Existing (L_{dn})	Proposed Truck Noise (L_{dn})	Truck Noise + Existing (L_{dn})	Increase (L_{dn})
1	1,700	45	43.6	47.37	+2.37
2	1,200	51	46.6	52.35	+1.35

Based on the noise analysis above, noise levels attributable to operation of the Project would not cause an exceedance of our threshold of 55 dBA L_{dn} at the NSAs and we conclude that operation of the Project would not have a significant impact on the noise environment in the vicinity of the Project.

8.0 RELIABILITY AND SAFETY

8.1 LNG Facility Regulatory Oversight

LNG facilities handle flammable and sometimes toxic materials that can pose a risk to the public if not properly managed. These risks are managed by the companies owning the facilities, through the site location, design, construction, and operation of the LNG facilities. In order to ensure that companies are managing these risks appropriately, they are regulated by multiple federal agencies that share regulatory authority over the siting, design, construction, and operation of LNG facilities. The safety, security, and reliability of UGI LNG's Project are regulated by the DOT, the Department of Homeland Security (DHS), and the FERC.

The DOT establishes and has the authority to enforce the federal safety standards for the siting, construction, operation, and maintenance of onshore LNG facilities, as well as for the siting of marine cargo transfer systems at waterfront LNG facilities, under the Natural Gas Pipeline Safety Act (49 U.S. Code [USC] 1671 *et seq.*). The DOT's LNG safety regulations are codified in 49 CFR 193, which prescribes safety standards for LNG facilities used in the transportation of gas by pipeline that are subject to federal pipeline safety laws (49 USC 60101 *et seq.*), and 49 CFR 192. As a cooperating agency, the DOT evaluates whether an applicant's proposed project siting meets the DOT requirements. If the project is constructed and becomes operational, the facilities would be subject to the DOT's inspection program to ensure compliance with the requirements of 49 CFR 193.

The DHS was provided with the authority to regulate the security of certain chemical plants in the United States, under Section 550 of the Homeland Security Appropriations Act of 2007. Accordingly, on April 9, 2007, DHS created the "Chemical Facility Anti-Terrorism Standards" under 6 CFR 27 to establish risk-based performance standards related to plant security. On November 20, 2007, DHS issued the list of threshold quantities of chemicals of interest which trigger Part 27 review. The existing LNG facility would store methane, primarily in the form of LNG, above threshold quantities and is therefore required to comply with the security regulations under 6 CFR 27. The Project would not significantly change the total

amount of methane onsite or include any additional chemicals of interest that would be on site above concentrations and threshold quantities in Appendix A of 6 CFR 27. If the Project is constructed and becomes operational, the facilities would be subject to the DHS's Chemical Facility Anti-Terrorism Standards regulatory program. DHS staff would make the final determination of whether the facilities are in compliance with the requirements of 6 CFR 27.

The FERC authorizes the siting and construction of LNG facilities under the NGA and delegated authority from the U.S. Department of Energy. The FERC requires the LNG project applicants to file standard information to perform safety and reliability engineering reviews. FERC's filing regulations are codified in 18 CFR 380.12 (m) and (o), and requires each applicant to identify how its proposed design would comply with the DOT's siting requirements of 49 CFR 193, Subpart B. The level of detail necessary for this submittal requires the project sponsor to perform substantial front-end engineering of the complete project.[7] The design information is required to be site-specific and developed to the extent that further detailed design would not result in significant changes to the siting considerations, basis of design, operating conditions, major equipment selections, equipment design conditions, or safety system designs. As part of the review required for a FERC order, we use this information from the applicant to assess whether the proposed facilities would have a public safety impact and to issue recommendations for the Commission to consider for incorporation as conditions in the order. If the facilities are approved and the recommendations are incorporated into the order as conditions, FERC staff would review material filed to satisfy the conditions of the order and conduct periodic inspections throughout construction. FERC staff generally recommend that, if the facilities are constructed and become operational, the companies be subject to reporting requirements and project facilities be subject to inspections to ensure compliance with the order throughout the life of the facilities.

Federal regulations issued by the Occupational Safety and Health Administration (OSHA) under 29 CFR 1910.119 (Process Safety Management of Highly Hazardous Chemicals; Explosives and Blasting Agents [PSM]), and the EPA under 40 CFR 68 (Chemical Accident Prevention Provisions) cover hazardous substances, such as methane, propane, and ethylene at many industrial plants in the United States. However, on October 30, 1992, shortly after the promulgation of the OSHA Process Safety Management regulations, OSHA issued a letter of interpretation that precluded the enforcement of PSM regulations over gas transmission and distribution facilities. In a subsequent letter on December 9, 1998, OSHA further clarified that this letter of interpretation applies to LNG distribution and transmission facilities.

In addition, EPA's preamble to its final rule in the Federal Register, Volume 63, Number 3, 639-645, clarified that exemption from the requirements in 40 CFR 68 for regulated substances in transportation, including storage incident to transportation, is not limited to pipelines. The preamble further clarified that the transportation exemption applies to LNG facilities subject to oversight or regulation under 49 CFR 193, including facilities used to liquefy natural gas or used to transfer, store, or vaporize LNG in conjunction with pipeline transportation. In subsequent correspondence with OSHA and EPA staff, it was clarified that OSHA's PSM and EPA's Risk Management Plan (RMP) regulations would only apply to LNG

[7] Additional guidance on information to be submitted regarding the safety, reliability, and engineering design can be found in our Guidance Manual for Environmental Report Preparation for Applications Filed Under the Natural Gas Act, Volume II, Liquefied Natural Gas Project Resource Reports 11 & 13 Supplemental Guidance, February 2017, FERC Docket No. AD16-3-000.

facilities if they were not subject to DOT LNG regulations or if they contained toxic materials listed under OSHA PSM or EPA RMP regulations above the threshold quantities and concentrations. Given that the UGI LNG Project would not meet either of these criteria, the above OSHA and EPA regulations are not applicable.

8.2 DOT Siting Requirements and Part 193 Subpart B Determination

The Commission's regulations under 18 CFR 380.12(o)(14) require UGI LNG to identify how the proposed design complies with the siting requirements of 49 CFR 193, Subpart B. The scope of DOT's siting authority under 49 CFR 193 applies to LNG facilities used in the transportation of gas by pipeline subject to the federal pipeline safety laws and 49 CFR 192.

Siting the LNG facilities with regard to ensuring that the proposed site selection and location would not pose an unacceptable level or risk to public safety is required by DOT's regulations in 49 CFR 193, Subpart B. DOT reviews the information and criteria submitted by UGI LNG to demonstrate compliance with the safety standards prescribed in Part 193 Title 49, Subpart B and issues a Letter of Determination (LOD) to the Commission on whether the proposed facilities would meet the DOT siting standards. The LOD will evaluate the hazard modeling results and endpoints used to establish exclusion zones, as well as UGI LNG's evaluation on potential incidents and safety measures incorporated in the design or operation of the facility specific to the site that have a bearing on the safety of plant personnel and the surrounding public. The LOD will serve as one of the considerations for the Commission to deliberate in its decision to authorize, with or without conditions, or deny an application.

The requirements in 49 CFR 193, Subpart B state that an operator or government agency must exercise legal control over the activities as long the facility is in operation that can occur within an "exclusion zone," defined as the area around an LNG facility that could be exposed to specified levels of thermal radiation or flammable vapor in the event of a release of LNG or ignition of LNG vapor. Approved mathematical models must be used to calculate the dimensions of these exclusion zones. The siting requirements of the 2001 edition of NFPA 59A, an industry consensus standard for LNG facilities, are incorporated into 49 CFR 193, Subpart B by reference, with regulatory preemption in the event of conflict. The following sections of Part 193 specifically address siting requirements:

- Section 193.2051, Scope, states that each LNG facility designed, replaced, relocated or significantly altered after March 31, 2000, must be provided with siting requirements in accordance with Subpart B and NFPA 59A (2001). In the event of a conflict with NFPA 59A (2001), the regulatory requirements in Part 193 prevail.
- Section 193.2057, Thermal Radiation Protection, requires that each LNG container and LNG transfer system have thermal exclusion zones in accordance with Section 2.2.3.2 of NFPA 59A (2001).
- Section 193.2059, Flammable Vapor-Gas Dispersion Protection, requires that each LNG container and LNG transfer system have a dispersion exclusion zone in accordance with Sections 2.2.3.3 and 2.2.3.4 of NFPA 59A (2001).
- Section 193.2067, Wind Forces, requires that shop fabricated containers of LNG or other hazardous fluids less than 70,000 gallons must be designed to withstand wind forces based on the applicable wind load data in American Society of Civil Engineers (ASCE) 7 *Minimum Design Loads and Associated Criteria for*

Buildings and Other Structures (2005). All other LNG facilities must be designed for a sustained wind velocity of not less than 150 miles per hour (mph) unless the DOT Administrator finds a lessor wind speed is justified or the most critical combination of wind velocity and duration for a 10,000-year mean return interval.

As stated in Section 193.2051, LNG facilities must be provided with the siting requirements of NFPA 59A (2001). The siting requirements within an LNG facility are contained in NFPA 59A, Chapter 2, and include but may not be limited to:

- NFPA 59A (2001) section 2.1.1(c) requires consideration of protection against forces of nature. Section 2.1.1(d) also requires that other factors applicable to the specific site that have a bearing on the safety of plant personnel and surrounding public be considered, including an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility.
- NFPA 59A (2001) section 2.2.3.2 requires provisions to minimize the damaging effects of fire from reaching beyond a property line, and requires provisions to prevent a radiant heat flux level of 1,600 British thermal units per square foot per hour (Btu/ft^2-hr) from reaching beyond a property line that can be built upon. The distance to this flux level is to be calculated with LNGFIRE3 or with models that have been validated by experimental test data appropriate for the hazard to be evaluated and that have been approved by DOT.
- NFPA 59A (2001) 2.2.3.4 requires provisions to minimize the possibility of any flammable mixture of vapors from a design spill from reaching a property line that can be built upon and that would result in a distinct hazard. Determination of the distance that the flammable vapors extend is to be determined with DEGADIS or approved alternative models that take into account physical factors influencing LNG vapor dispersion.[8]

Taken together, Part 193 and NFPA 59A (2001) require that flammable LNG vapors either from an LNG tank withdrawal impoundment or from a design spill do not extend beyond areas in which the operator or a government agency legally controls all activities. Furthermore, consideration of other hazards which may affect the public or plant personnel must be evaluated as prescribed in NFPA 59A (2001) Section 2.1.1(d).

Together, Part 193 and NFPA 59A (2001) also specify three radiant heat flux levels for LNG storage tank spills, which must be considered for as long as the facility is in operation:

- 1,600 Btu/ft^2-hr - This level can extend beyond the plant property line that can be built upon, but cannot include areas that are used for outdoor assembly by groups of 50 or more persons;[9]

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[8] DOT has approved two additional models for the determination of vapor dispersion exclusion zones in accordance with 49 CFR 193.2059: FLACS 9.1 Release 2 (Oct. 7, 2011) and PHAST-UDM Version 6.6 and 6.7 (Oct. 7, 2011).

[9] The 1,600 Btu/ft^2-hr flux level is associated with producing pain in less than 15 seconds, first degree burns in 20 seconds, second degree burns in approximately 30-40 seconds, 1% mortality in approximately 120 seconds, and 100% mortality in approximately 400 seconds, assuming no shielding from the heat, and is typically the maximum allowable intensity for emergency operations with appropriate clothing based on average 10 minute exposure.

- 3,000 Btu/ft^2-hr - This level can extend beyond the plant property line that can be built upon, but cannot include areas that contain assembly, educational, health care, detention or residential buildings or structures;[10] and
- 10,000 Btu/ft^2-hr - This level cannot extend beyond the plant property line that can be built upon.[11]

The requirements for design spills from process or transfer areas are more stringent. For LNG spills, the 1,600 Btu/ft^2-hr flux level cannot extend beyond the plant property line onto a property that can be built upon.

In addition, NFPA 59A Section 2.1.1 requires that factors applicable to the specific site with a bearing on the safety of plant personnel and surrounding public must be considered, including an evaluation of potential incidents and safety measures incorporated into the design or operation of the facility. DOT has indicated that potential incidents, such as vapor cloud explosions and toxic releases should be considered to comply with Part 193 Subpart B.[12]

Design spills are used in the determination of the siting and hazard calculations required by 49 CFR 193. Prior to the incorporation of NFPA 59A in 2000, the design spill in Part 193 assumed the full rupture of "a single transfer pipe which has the greatest overall flow capacity" for not less than 10 minutes (old Section 193.2059[d]). With the adoption of NFPA 59A (2001), section 2.2.3.5 specifies design spills for LNG containers, but the basis for the design spills for impounding areas serving only vaporization, process, or LNG transfer areas became the flow from any single accidental leakage source. Neither Part 193 nor NFPA 59A (2001) define "single accidental leakage source."

UGI LNG provided the DOT with information related to the requirements in 49 CFR 193. On April 4, 2018, the DOT provided a letter to FERC staff regarding the information DOT reviewed for the analysis of the Project to determine it had no objection to the design spill methodologies being used for the selection of single accidental leakage sources as part of the requirements under 49 CFR 193 Subpart B.[13]

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[10] The 3,000 Btu/ft^2-hr flux level is associated with producing pain in less than 5 seconds, first degree burns in 5 seconds, second degree burns in approximately 10-15 seconds, 1% mortality in approximately 50 seconds, and 100% mortality in approximately 180 seconds, assuming no shielding from the heat, and is typically the critical heat flux for piloted ignition of common building materials (e.g., wood, PVC, fiberglass, etc.) with prolonged exposures.

[11] The 10,000 Btu/ft^2-hr flux level is associated with producing pain in less than 1 seconds, first degree burns in 1 seconds, second degree burns in approximately 3 seconds, 1% mortality in approximately 10 seconds, and 100% mortality in approximately 35 seconds, assuming no shielding from the heat, and is typically the critical heat flux for unpiloted ignition of common building materials (e.g., wood, PVC, fiberglass) and degradation of unprotected process equipment after approximate 10 minute exposure and to reinforced concrete after prolonged exposure.

[12] The U.S. DOT Pipeline and Hazardous Material Safety Administration's "LNG Plant Requirements: Frequently Asked Questions" item H1, https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-plant-requirements-frequently-asked-questions, accessed Aug 2018.

[13] April 4, 2018 letter "Re: UGI LNG Temple Truck Rack Expansion Project, FERC Docket CP17-14" from Kenneth Lee to Rich McGuire. Filed in Docket Number CP17-14-000 on April 6, 2018. Accession Number 20180406-3047.

On August 31, 2018, FERC and DOT signed an MOU to streamline LNG project reviews and eliminate duplicative efforts.[14] DOT will issue an LOD to FERC on the 49 CFR 193 Subpart B regulatory requirements, which would be filed with the Commission as part of the consolidated record for the Project and would be one of the considerations for the Commission to deliberate in its decision to authorize, with or without modification or conditions, or deny an application. The LOD will provide DOT's Pipeline and Hazardous Material Safety Administration's (PHMSA) analysis and conclusions regarding 49 CFR 193 Subpart B regulatory requirements.

The DOT's conclusion on the siting and hazard analysis required by Part 193 would be based on preliminary design information which may be revised as the engineering design progresses to final design. DOT regulations also contain requirements for the design, construction, installation, inspection, testing, operation and maintenance, and contingency plans for LNG facilities, which would be completed during later stages of the Project. If the facilities are approved and constructed, final compliance with the requirements of 49 CFR 193 will be subject to DOT's inspection and enforcement programs.

8.3 LNG Facility Historical Record

The operating history of the U.S. LNG industry has been free of safety-related incidents resulting in adverse effects on the public or the environment with the exception of the October 20, 1944, failure at an LNG plant in Cleveland, Ohio. The 1944 incident in Cleveland led to a fire that killed 128 people and injured 200 to 400 more people.[15] The failure of the LNG storage tank was due to the use of materials not suited for cryogenic temperatures. LNG migrated through streets and into underground sewers due to inadequate spill impoundments at the site. Current regulatory requirements ensure that proper materials suited for cryogenic temperatures are used in the design and that spill impoundments are designed and constructed properly to contain a spill at the site. To ensure that this potential hazard would be addressed for proposed LNG facilities, we evaluate the preliminary and final specifications for suitable materials of construction and for the design of spill containment systems that would properly contain a spill at the site.

Another operational accident occurred in 1979 at the Cove Point LNG plant in Lusby, Maryland. A pump electrical seal on an LNG pump with submerged electrical motor caused flammable gas vapors to enter an electrical conduit and settle in a confined space. When a worker switched off a circuit breaker, the flammable gas ignited, causing heavy damage to the building and a worker fatality. With the participation of the FERC, lessons learned from the 1979 Cove Point accident resulted in changing the national fire codes to better ensure that the situation would not occur again. To ensure that this potential hazard would be addressed for proposed facilities that have electrical seal interfaces, we evaluate preliminary designs and generally recommend that companies provide the final design details of the electrical seal design at the interface between flammable fluids and the electrical conduit or wiring system, electrical

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[14] August 31, 2018 Memorandum of Understanding between the Department of Transportation and the Federal Energy Regulatory Commission Regarding Liquefied Natural Gas Transportation Facilities, https://www.ferc.gov/legal/mou/2018/FERC-PHMSA-MOU.pdf

[15] For a description of the incident and the findings of the investigation, see "U.S. Bureau of Mines, Report on the Investigation of the Fire at the Liquefaction, Storage, and Regasification Plant of the East Ohio Gas Co., Cleveland, Ohio, October 20, 1944," dated February 1946.

seal leak detection system, and the details of a downstream physical break (i.e. air gap) in the electrical conduit to prevent the migration of flammable vapors.

On January 19, 2004, a blast occurred at Sonatrach's Skikda, Algeria, LNG liquefaction plant that killed 27 and injured 56 workers. No members of the public were injured. Findings of the accident investigation suggested that a cold hydrocarbon leak occurred at Liquefaction Train 40 and was introduced into a high-pressure steam boiler by the combustion air fan. An explosion developed inside the boiler firebox, which subsequently triggered a larger explosion of the hydrocarbon vapors in the immediate vicinity. The resulting fire damaged the adjacent liquefaction process and liquid petroleum gas separation equipment of Train 40, and spread to Trains 20 and 30. Although Trains 10, 20, and 30 had been modernized in 1998 and 1999, Train 40 had been operating with its original equipment since start-up in 1981. To ensure that this potential hazard would be addressed for proposed facilities, we evaluate the preliminary design for mitigation of flammable vapor dispersion and ignition in buildings and combustion equipment to ensure they are adequately covered by hazard detection equipment that could isolate and deactivate any combustion equipment whose continued operation could add to or sustain an emergency. We also generally recommend that companies provide the final design details for our approval.

On March 31, 2014, a detonation occurred within a gas heater at Northwest Pipeline Corporation's LNG peak-shaving plant in Plymouth, Washington.[16] This internal detonation subsequently caused the failure of pressurized equipment, resulting in high velocity projectiles. The plant was immediately shut down, and emergency procedures were activated, which included notifying local authorities and evacuating all plant personnel. No members of the public were injured, but one worker was sent to the hospital for injuries. As a result of the incident, the liquefaction trains and a compressor station onsite were rendered inoperable. Projectiles from the incident also damaged the control building that was located near pre-treatment facilities and penetrated the outer shell of one of the LNG storage tanks. All damaged facilities were ultimately taken out of service for repair. The accident investigation showed that an inadequate purge after maintenance activities resulted in a fuel-air mixture remaining in the system. The fuel-air mixture auto-ignited during startup after it passed through the gas heater at full operating pressure and temperature. To ensure that this potential hazard would be addressed for proposed facilities, we would generally recommend that companies provide a plan for purging that addresses the requirements of the American Gas Association Purging Principles and Practice and to provide justification if not using an inert or non-flammable gas for purging. In evaluating such plans, we assess whether the purging could be done safely based on review of other plans and lessons learned from this and other past incidents. If an applicant proposes use of flammable mediums for cleaning, dry-out or other activities, we evaluate the plans against other recommended and generally accepted good engineering practices, such as NFPA 56, Standard for Fire and Explosion Prevention during Cleaning and Purging of Flammable Gas Piping Systems.

We also generally recommend that companies provide operating and maintenance plans, including safety procedures, prior to commissioning. In evaluating such plans, we assess whether the plans cover all standard operations, including purging activities associated with

[16] For a description of the incident and the findings of the investigation, see Root Cause Failure Analysis, Plymouth LNG Plant Incident Investigation under CP14-515.

startup and shutdown. Also, in order to prevent other sources of projectiles from affecting occupied buildings and storage tanks, we generally recommend that companies incorporate mitigation into their final design with supportive information that demonstrates it would mitigate the risk of a pressure vessel burst or BLEVE from occurring.

8.4 FERC Engineering and Technical Review of the Preliminary Engineering Designs

In addition to DOT regulatory requirements and Subpart B LOD and U.S. Coast Guard regulatory requirements and Letter of Recommendation, FERC requires an applicant to provide safety, reliability, and engineering design information as part of its application, including hazard identification studies and front-end-engineering-design (FEED) information for its proposed project. FERC staff evaluates this information to assess the safety and reliability of the project. The objectives of our FEED review focuses on evaluating the potential hazards from within and nearby the site, including external events, which may have the potential to cause damage or failure to the project facilities, and the engineering design and safety and reliability concepts of the various protection layers to mitigate the risks of potential hazards.

The primary concerns are those events that could lead to a hazardous release of sufficient magnitude to create an offsite hazard or interruption of service. Further, the potential hazards are dictated by the site location and the engineering details. For NEPA purposes, the site location is assessed relative to external impacts, while a more comprehensive review of the preliminary and final engineering details would continue to be carried out with recommendations provided to the Commission for consideration to include in the order and throughout the final design of the project.

8.5 External Impact Review

To assess the potential impact from external events, FERC staff conducted a series of reviews to evaluate transportation routes, land use, and activities within the facility and surrounding the Project site and the safeguards in place to mitigate the risk from events, where warranted. FERC staff coordinated the results of the reviews with other federal agencies to assess potential impacts from vehicles and rail; aircraft impacts on and from nearby airports and heliports; pipeline impacts from nearby pipelines; and impacts on and from adjacent facilities that handle hazardous materials under EPA's RMP regulations and nuclear facilities under Nuclear Regulatory Commission's (NRC's) regulations. Specific mitigation of impacts from use of external roadways, rail, helipads, airstrips, or pipelines are also considered as part of the engineering review done in conjunction with the NEPA review.

FERC staff uses a risk based approach to assess the potential impact of the external events and the adequacy of the mitigation measures. The risk based approach uses data based on the frequency of events that could lead to an impact and the potential severity of consequences posed to the Project site and the resulting consequences to the public beyond the initiating events. The frequency data is based on past incidents and the consequences are based on past incidents and/or hazard modeling of potential failures.

<u>Road</u>

FERC staff generally reviews whether any truck operations would be associated with a proposed project and whether any existing roads would be near the site. FERC staff uses this information to evaluate whether a project and any associated truck operations could increase the

risk along the roadways and subsequently to the public, and whether any pre-existing unassociated vehicular traffic could adversely increase the risk to the proposed project site and, subsequently increase the risk to the public. In addition, all facilities, once constructed, must comply with the requirements of 49 CFR 193 and would be subject to DOT's inspection and enforcement programs. DOT regulations under 49 CFR 193.2155(a)(5)(ii) require that structural members of an impoundment system be designed and constructed to prevent impairment of the system's performance reliability and structural integrity as a result of a collision by or explosion of a tank truck that could reasonably be expected to cause the most severe loading if the LNG facility adjoins the right-of-way of any highway. Similarly, NFPA 59A (2001), Section 8.5.4, requires transfer piping, pumps, and compressors to be located or protected by barriers so they are safe from damage by rail or vehicle movements. However, the DOT regulations and NFPA 59A requirements do not indicate what collision(s) or explosion(s) could reasonably be expected to cause the most severe loading. FERC staff evaluated frequency and consequence data from these events to evaluate these potential impacts.

FERC staff evaluated the risk of the truck operations based on the frequency of trucks, consequences from a release, using incident data from DOT Federal Highway Administration, National Highway Traffic Safety Administration, and Pipeline and Hazardous Material Safety Administration (PHMSA), and proposed mitigation to prevent or reduce the impacts of a vehicular incident. Incident data indicates hazardous material incidents are very infrequent (0.004 incidents per lane-mile per year) and nearly 75-80% of hazardous material vehicular incidents occur during unloading and loading operations while the other 20-25% occur while in transit or in transit storage. In addition, approximately 99% of releases are 1,000 gallons or less and catastrophic events that would spill 10,000 gallons or more make up less than 0.1% of releases and less than 1% result in injuries and less than 0.1% result in fatalities. Based on the frequencies of the historical releases and potential consequences, LNG truck operation hazardous material incidents would not present a significant risk or increase in risk of impacting the existing LNG facilities and there should not be a significant risk or increase in risk to the public above existing levels.

UGI LNG would also install a driveway arrangement that allows the LNG trucks to enter the eastern side of the plant and drive to an area where the trucks would turn down hill and then reverse uphill and turn while backing up to reach the unloading skid. When asked whether alternative arrangements were considered, UGI LNG indicated that site limitations prevented the use of a roundabout or drive-through driveway within the plant. While we recognize a roundabout may be difficult to install given the location of the pipelines and other factors, the details of the limitations that would preclude extending existing road infrastructure was not clearly presented or understood. UGI LNG responded that the presence of existing equipment and facilities were within the path of a pull-through driveway; however, plot plans, aerials, and onsite inspections do not indicate such obstacles and show the proposed driveway coming within 50 feet of an existing plant road on Osterling Drive. In addition, UGI LNG indicated it performed a site access analysis to determine the proposed driveway route, which evaluated safety to truck traffic and impacts on the facilities and existing site conditions. However, this analysis was not provided and it was not clear as to whether the proposed entrance and exit locations would minimize the risks compared to other arrangements or whether the proposed entrance and exit location and added trucking activities would minimize the risk of hazardous material incidents on external roadways impacting the public. As part of the same data request responses, UGI LNG indicated it would install a guardrail along portions of the proposed

driveway to prevent a truck from accidentally heading down hill and backing up into the area where the nearby dike causes a drop off.

There were no major highways or roads within close proximity to piping or equipment containing hazardous materials at the site that would raise concerns of direct impacts from a vehicle on an external road impacting the Project facilities.

As a result of no high speed roads adjacent to piping and equipment containing hazardous materials and a negligible increase in risk of hazardous-material incidents impacting the facilities and nearby population, FERC staff concludes that the proposed Project would not pose a significant risk or significant increase in risk to the public due to vehicle external impacts.

Rail

FERC staff generally reviews whether any rail operations would be associated with a proposed project and whether any existing rail lines would be near the site. FERC staff uses this information to evaluate whether a project and any associated rail operations could increase the risk along the rail line and subsequently to the public and whether any pre-existing unassociated rail operations could adversely increase the risk to a project site and subsequently increase the risk to the public. In addition, all facilities, once constructed, must comply with the requirements of 49 CFR 193 and would be subject to DOT's inspection and enforcement programs. DOT regulations under 49 CFR 193.2155(a)(5)(ii) states if the LNG facility adjoins the right-of-way of any railroad, the structural members of an impoundment system must be designed and constructed to prevent impairment of the system's performance reliability and structural integrity as a result of a collision by, or explosion of, a train or tank car that could reasonably be expected to cause the most severe loading. Section 8.5.4 of NFPA 59A (2001), incorporated by reference in 49 CFR 193, requires transfer piping, pumps, and compressors to be located or protected by barriers so that they are safe from damage by rail or vehicle movements. However, the DOT regulations and NFPA 59A requirements do not indicate what collision(s) or explosion(s) could reasonably be expected to cause the most severe loading. FERC staff evaluated frequency and consequence data from these events to evaluate these potential impacts.

Incident data indicates hazardous material incidents are very infrequent (0.006 incidents per rail-mile per year). In addition, approximately 95% of releases are 1,000 gallons or less and catastrophic events that would spill 30,000 gallons or more make up less than 1% of releases and less than 1% result in injuries and less than 0.1% result in fatalities.

There would be no rail transportation associated with the Project. The closest rail line is a rail spur approximately 700 to 2,000 feet away from piping, equipment, and containers with hazardous materials to the south, east, and west of the existing LNG plant. Given that the Project would not include any rail transportation and given the incident rates, distance, and position of the closest rail lines relative to the populated areas near the LNG terminal and the relative consequences from failure of the Project facilities compared to existing equipment, FERC staff concludes that the proposed Project would not pose a significant increase in risk to the public as a result of the proximity of the Project to the rail lines.

Air

FERC staff generally reviews whether any aircraft operations would be associated with a proposed project and whether any existing aircraft operations would be near the site. FERC staff uses this information to evaluate whether a project and any associated aircraft operations could

increase the risk to the public and whether any pre-existing unassociated aircraft operations could adversely increase the risk to a project site and subsequently increase the risk to the public. In addition, all facilities, once constructed, must comply with the requirements of 49 CFR 193 and would be subject to DOT's inspection and enforcement programs. DOT regulations under 49 CFR 193.2155(b) require an LNG storage tank to not be within a horizontal distance of 1 mile from the ends, or 1/4 mile from the nearest point of a runway, whichever is longer and that the height of LNG structures in the vicinity of an airport must comply with DOT Federal Aviation Administration (FAA) requirements.

The DOT FAA regulations in 14 CFR 77 require companies to provide notice to the FAA of its proposed construction. This notification should identify all equipment that are more than 200 feet above ground level or lesser heights if the facilities are within 20,000 feet of an airport (at 100:1 ratio or 50:1 ratio depending on length of runway) or within 5,000 feet of a helipad (at 100:1 ratio). In addition, mobile objects that would be above the height of the highest mobile object that would normally traverse it would require notification to DOT FAA.

There would be no aircraft associated with the Project. The closest airport to the Project facilities and existing site is the Reading Regional Airport, which is approximately 3.3 miles away. Other airports within a 20 mile radius, include the Kutztown, Don's Place Airpark, Blue Mountain Academy, Old Commonwealth Aerodrome, Boyer, Arnold, Morgantown, Cuantros Vientos, Zettlemoyer, Bally Spring Farm, ButterValley, Crosswinds Airfield, Dimascio Field, Pottstown Municipal, Burt's, Bentley, Grimes, and New Hanover Airports.

Lastly, the Project facilities would be much less in height compared to the two existing LNG storage tanks, and given the small height and footprint of the proposed facilities that are sited between the storage tanks, FERC staff concludes that the proposed Project would not pose a significant risk to the public or significantly increase the risk to the public as a result of the proximity of the Project to the existing airports.

Pipelines

FERC staff generally reviews whether any pipeline operations would be associated with a proposed project and whether any existing pipelines would be near the site. FERC staff uses this information to evaluate whether a project and any associated pipeline operations could increase the risk to the pipeline facilities and subsequently to the public, and whether any pre-existing unassociated pipeline operations could adversely increase the risk to a project site and subsequently increase the risk to the public. Pipelines associated with this Project must meet DOT regulations under 49 CFR 192. In addition, all facilities, once constructed, must comply with the requirements of 49 CFR Parts 192 and 193 and would be subject to DOT's inspection and enforcement programs.

The proposed Project facilities would include an LNG truck driveway that would cross four Texas Eastern pipelines as well as a Sunoco liquid petroleum line. In addition, the Project facilities would have grading within and a proposed crossing of UGI Utilities, natural gas pipeline and Buckeye Partners, L.P. (Buckeye) refined liquid petroleum products pipeline easement. UGI LNG worked with each utility company to identify the exact location of each of the facilities so that the information could be included in the UGI LNG's design plans. UGI LNG also performed soft dig test holes at the locations of the Texas Eastern and Sunoco pipeline crossings and at several locations within the UGI Utilities easement to determine the exact depth of cover for each pipeline. UGI LNG revised its plans based on comments and requirements

from each utility company owner, and provided any requested information to assist the utility company owners with their review of the Project. Each utility company performed a review of the Project encroachments and the potential impact on their pipeline facilities, and UGI LNG has incorporated all of the pipeline utility owner's recommendations into its plans, as discussed below.

UGI Utilities performed pipe stress calculations using specifications from the existing pipeline (internal pressure, wall thickness, grade of steel, pipe diameter, etc.) and analyzed both dead loading from increase in cover and live load conditions. The live loading conditions included H-20 (16,000 pound) loading and anticipated loads from construction equipment, although the UGI Utilities pipeline would not be crossed by the Project driveway. The calculations showed the pipeline would be within allowable stress limits, which UGI Utilities approved. UGI Utilities also requested that UGI LNG hold a preconstruction meeting and that a full-time UGI Utilities inspector be on-site when UGI LNG is working within 25 feet of UGI Utilities' pipeline.

Texas Eastern's internal engineers reviewed the Project, performing pipe stress calculations to ensure that the pipelines would be protected during and after construction. Texas Eastern would require UGI LNG to construct a concrete bridging slab across its easement, to further protect its pipelines from live loading during the operation of the Project. UGI LNG will include this requirement into its final design and also proposes using temporary timber matting within the Texas Eastern easement to protect its pipelines from construction impacts.

Sunoco's internal engineers reviewed the Project, performing pipe stress calculations to determine that the pipeline would be protected during and after construction. Sunoco requested a minor revision to one of the Project storm drains that is adjacent to its easement to prevent discharge of stormwater directly over the pipeline. UGI LNG has included the applicable Sunoco construction guidelines into the construction documents to ensure all of Sunoco's requirements are met. UGI LNG also proposes using temporary timber matting to protect Sunoco's pipeline from construction traffic.

Due to the limited encroachment on the Buckeye easement and the fact that the Project will not cross its pipelines, Buckeye reviewed the Project improvements and approved the encroachment without any additional requirements. However, UGI LNG proposes using temporary timber matting in the Buckeye easement during construction.

In addition, FERC staff evaluated the potential risk from an incident from the pipelines and their potential impacts for frequencies that exceeded an initial screening threshold of 3e-5 per year. Based on incorporation of the utility company recommendations and based on an evaluation of the potential likelihood of pipeline incidents and potential consequences from a pipeline incident, FERC staff concludes that the proposed Project would not significantly increase the risk to the public beyond existing risk levels that are present from the pipelines. Nonetheless, UGI LNG's existing emergency procedures manual also addresses procedures for incidents along each pipeline to mitigate the impacts in the unlikely event of an incident. In conclusion, FERC staff concludes that the proposed Project would not pose a significant increase in risk to the public as a result of the proximity of the Project to the pipelines.

Hazardous Material Facilities and Power Plants

FERC staff reviews whether any EPA RMP regulated facilities handling hazardous materials and power plants were near a proposed site to evaluate whether the facilities could adversely increase the risk to a project site, and whether a project site could increase the risk to the EPA RMP facilities and power plants and subsequently increase the risk to the public.

The existing UGI LNG plant is in an industrial area adjacent to several chemical and packaging facilities subject to EPA RMP regulations. The closest facility handling hazardous materials is the Brenntag Northeast, Inc. facility approximately 0.5 mile to the southeast that is involved in wholesale chemical distribution. It's facilities handle toxic and flammable materials regulated by EPA RMP, including cyclohexylamine, ehtylenediamine, hydrofluoric acid, and isopropylamine. There are another two facilities (Ontelaunee Energy Center and Maiden Creek Filtration Plant) within 1 mile handling anhydrous ammonia and chlorine; four in a 3-mile-radius (Americold Leesport Plant, Giorgio Fresh Company, Coyne Chemical, and Cryovac Packaging); and several others are within a 10-mile-radius. The Ontelaunee Energy Center also has gas power generation. Aside from the solar panels onsite and the Onelaunee Energy Center, there are no power plants within close proximity and the closest nuclear power plant is more than 20 miles away.

The EPA RMP regulations require certain hazard distances to be calculated and a risk management plan to be developed commensurate with those consequences. We evaluated the consequences from these nearby facilities based on EPA RMP worst case scenario hazard distances. While many of the scenarios modeled under worst case weather conditions could reach the Project facilities and the existing UGI LNG facilities, the Project facilities would not significantly increase the risk to the public beyond those that currently exist. In addition, the Project facilities would be within UGI LNG's existing site, and based on hazard analyses of the Project facilities, the Project facilities would not significantly increase the risk to the EPA RMP regulated facilities beyond those that currently exist. Finally, the expanded UGI LNG plant would be able to shutdown to a safe state in the unlikely event of an incident, and existing emergency response plans address the need to coordinate with the local emergency response office in charge on the decision to evacuate areas around and outside of the plant in the case of an incident; EPA RMP regulations would also require EPA RMP regulated facilities to have similar emergency response plans.

8.6 Engineering Review

In addition to potential external impacts based on the site location, we require the applicant to study the engineering design to assess the safeguards built into the engineering design to reduce the risk of an incident occurring and impacting the public. In general, we consider an acceptable design to include various layers of protection or safeguards to reduce the risk of a potentially hazardous scenario from developing into an event that could impact the offsite public. These layers of protection are generally independent of one another so that any one layer would perform its function regardless of the initiating event or failure of any other protection layer. Such design features and safeguards typically include:

- a facility design that prevents hazardous events, including the use of inherently safer designs; suitable materials of construction; adequate design margins from operating limits for process piping, process vessels, and storage tanks; adequate design for wind, flood, seismic, and other outside hazards;

- control systems, including monitoring systems and process alarms, remotely-operated control and isolation valves, and operating procedures to ensure that the facility stays within the established operating and design limits;
- safety instrumented prevention systems, such as safety control valves and emergency shutdown systems, to prevent a release if operating and design limits are exceeded;
- physical protection systems, such as appropriate electrical area classification, proper equipment and building spacing, pressure relief valves, spill containment, and cryogenic, overpressure, and fire structural protection, to prevent escalation to a more severe event;
- site security measures for controlling access to the plant, including security inspections and patrols, response procedures to any breach of security, and liaison with local law enforcement officials; and
- onsite and offsite emergency response, including hazard detection and control equipment, firewater systems, and coordination with local first responders, to mitigate the consequences of a release and prevent it from escalating to an event that could impact the public.

We believe the inclusion of such protection systems or safeguards in a plant design can minimize the potential for an initiating event to develop into an incident that could impact the safety of the offsite public. The review of the engineering design for these layers of protection is initiated in the application process and carried through to the next phase of a proposed project in the final design if authorization is granted by the Commission.

The reliability of these layers of protection is informed by occurrence and likelihood of root causes and the potential severity of consequences based on past incidents and validated hazard modeling. As a result of the continuing engineering review, we provide recommendations to the Commission for consideration to include as conditions in the order. If a facility is authorized and recommendations are adopted as conditions to the order, FERC staff would continue its engineering review through final design, construction, commissioning, and operation.

In developing the FEED, UGI LNG conducted a “What If” checklist based hazard analysis on the proposed LNG truck loading system. The “What If” analysis looked at individual component failure modes, assigned a severity level for each failure mode, and assigned the likelihood for each failure mode. The analysis identified potential hazards for the safety systems, process area and truck scale, process utilities, and the adjacent LNG storage tank and considered the consequences of these hazards. The study also identified the safeguards that would be in place to prevent or mitigate the hazard and proposed recommendations as needed to eliminate, prevent, control, or mitigate the hazards. We generally recommend that companies conduct and provide a more detailed and thorough hazard and operability review (HAZOP) analysis prior to construction of the final design. The HAZOP would be performed by UGI LNG during the final design phase to identify the major hazards that may be encountered during the operation of facilities. The HAZOP study would be intended to address hazards of the process, engineering and administrative controls, and would provide a qualitative evaluation of a range of possible safety, health, and environmental effects that may result from the design or operation of the

facilities. Recommendations to prevent or minimize these hazards would be generated from the results of the HAZOP review. We generally recommend that companies should file the HAZOP study on the completed final design. We evaluate the HAZOP to ensure all systems and process deviations are covered with appropriate and consistent severity, likelihood, and risk values with commensurate layers of protection in accordance with recommended and generally accepted good engineering practices, such as American Institute of Chemical Engineers, *Guidelines for Hazard Evaluation Procedures*. We also generally recommend the resolutions of the HAZOP review recommendations be provided for FERC staff review and approval. Once the design has been subjected to a HAZOP review, the design development team tracks changes in the facility design, operations, documentation, and personnel. UGI LNG would evaluate these changes to ensure that the safety, health, and environmental risks arising from these changes are addressed and controlled based on its change management procedures. If adopted into the order, resolutions of the HAZOP review recommendations would be monitored by the FERC staff. Once the design has been subjected to a HAZOP review, the design development team would track changes in the facility design, operations, documentation, and personnel. UGI LNG would evaluate these changes to ensure that the safety, health, and environmental risks arising from these changes would be addressed and controlled based on their change management procedures. We generally recommend that companies file all changes to their FEED for review and approval by FERC staff. However, major modifications could require an amendment or new proceeding.

8.7 Geotechnical and Structural Design Review

UGI LNG filed geotechnical and structural design information for its facilities to demonstrate the site preparation and foundation designs would be appropriate for the underlying soil characteristics and to ensure the structural design of the Project facilities would be in accordance with federal regulations, standards, and recommended and generally accepted good engineering practices. The application focuses on the resilience of the Project facilities against natural hazards, including extreme geological, meteorological, and hydrological events, such as earthquakes, tsunamis, seiche, hurricanes, tornadoes, floods, rain, ice, snow, regional subsidence, sea level rise, landslides, wildfires, volcanic activity, and geomagnetism.

8.7.1 Geotechnical Evaluation

FERC regulations under 18 CFR 380.12(h)(3) require geotechnical investigations to be provided. In addition, FERC regulations under 18 CFR 380.12(o)(14) require an applicant demonstrate compliance with regulations under 49 CFR 193 and NFPA 59A. All facilities, once constructed, must comply with the requirements of 49 CFR 193 and would be subject to DOT's inspection and enforcement programs. DOT regulations incorporate by reference NFPA 59A (2001), which requires in section 2.1.4 soil and general investigations of the site to determine the design basis for the facility. However, no additional requirements are set out in 49 CFR 193 or NFPA 59A on minimum requirements for evaluating existing soil site conditions or evaluating the adequacy of the foundations; therefore, FERC staff evaluated the existing site conditions, geotechnical report, and proposed foundations to ensure they are adequate for the LNG facilities as described more fully below.

UGI LNG contracted EEI to conduct geotechnical investigations and provide a report that evaluated existing soil site conditions and proposed foundation design for the Project. The existing site has an elevation that ranges between 300 to 355 feet (North American Vertical Datum 1988 [NAVD 88]). The top 1 to 5 inches of the Project site consists of topsoil with

groundwater observed between 11 to 33 feet below existing ground surface. The design of the Project facility and roadway indicates that the site elevation would remain consistent with the existing grade, but would have a net fill to maintain the elevation. The structural fill material would be placed in lifts specified in the Geotechnical Engineering Report and compacted to 93 to 98 percent of maximum dry density for standard proctor tests in accordance with ASTM D698, or to 90 to 95 percent of maximum dry density for modified proctor tests in accordance with ASTM D1557 depending on the location (nonstructural, basins and berms, foundations, paved areas, and slabs).

EEI performed a total of 13 test borings of the Project, ranging from 1.8 feet to 34 feet below existing ground surface and spaced approximately every 150 feet along most the driveway, with some larger distances near the base of the driveway where the grade was not as steep. EEI performed classification tests (water content, Atterberg limit tests, and sieve tests), California Bearing Ratio test, and compression tests. No triaxial tests were conducted, but these are more critical for steeper grades or berms where slope stability is of concern. In addition, corrosion potential tests (pH, electrical resistivity, chloride content, sulfate content) that are commonly carried out were not conducted. These tests can be informative in determining whether degradation of foundation supports (e.g., concrete or steel piles) or underground piping are of concern. While the use of shallow foundations and no underground piping are proposed for this Project that would negate much of the value for most of these tests, the pH tests might be useful in determining whether there is a higher potential for acidic groundwater to be present, which would exacerbate dissolution of limestone and formation of sinkholes. Other corrosion tests might have some value in determining buried electrical conduit design and protective coatings. Therefore, we recommend in Section 8.9 Conclusions on Facility Reliability and Safety that UGI LNG evaluate the corrosivity of soils to determine whether additional measures may be necessary to minimize dissolution of underlying carbonate rocks and minimize corrosion of underground piping and utilities prior to initial site preparation.

Based on the test borings conducted, the site is composed of topsoil extending to depths of approximately 1 inch to 5 inches and underlain stratum 1, consisting of sandy clay and silt with varying amounts of sand and silty sand extending to a depth between approximately 1 foot to 33.5 feet below existing grade. Stratum 1 is underlain by stratum 2, which consists of a sandy gravel with varying amounts of silt and weathered limestone and dolomite rock to depths between 1.8 feet and 34 feet below existing grade. Due to the varying depths to bedrock beneath Stratum 2, EEI noted that the bedrock exhibits a pinnacle base of limestone and dolomite formations, carbonate rocks, which presents a potential risk to sinkhole formations (discussed in more detail in a later section).

Due to the shallow depth to bedrock and anticipated loading on foundations to be low, EEI recommended the use of shallow foundations consisting of strip footings, spread footings, or turned down slab for the truck loading scales. In addition, EEI recommended that the area beneath the truck scale be removed of soft/loose soils and provided with structural fill and compacted. It is anticipated that rock will be encountered during excavation, in which case rock excavating techniques such as hydraulic hammering is expected to be required. EEI recommends that the base of foundations for the truck scales be embedded a minimum of 3 feet below the final grade to protect against frost heave. Total settlement is anticipated to be less than 1 inch and differential settlement to be less than 0.5 inch, provided proper construction and the use of compacted structural fill material beneath foundations. EEI provided recommendations

for both flexible (e.g., asphalt) and rigid (e.g., concrete) pavement design in accordance with American Association of State Highway and Transportation Officials' *Guide for Design of Pavement Structures*, 1993. EEI indicated that the pavement should be placed over structural fill, and in the event of encountering rock within pavement subgrade, rock should be removed to a minimum of 6 inches below the base coarse to provide adequate flexibility to maintain the pavement. Foundation recommendations were also provided in UGI LNG's application for high mast lighting foundations, but were not provided for the piping and equipment associated with the truck loading skids. However, UGI LNG's subsequent filings provided foundation drawings for piping and equipment associated with the truck loading indicating consistent shallow foundation designs to that recommended in the geotechnical report. In addition, we recognize as the design progresses from FEED to final design that changes may occur and, therefore, we generally recommend that companies provide all site preparation drawings and specifications, foundation design drawings, specifications, and calculations with them being stamped and sealed by the professional engineer of record prior to construction of final design.

8.7.2 Structural Evaluation and Natural Hazard Evaluation

FERC regulations under 18 CFR 380.12(m) requires applicants address the potential hazard to the public from failure of facility components resulting from accidents or natural catastrophes, how these events would affect reliability, and what design features and procedures have been used to reduce potential hazards. Also, FERC regulations under 18 CFR 380.12(o)(14) requires an applicant to demonstrate how they would comply with 49 CFR 193 and NFPA 59A. In addition, all facilities, once constructed, must comply with the requirements of 49 CFR 193 and would be subject to DOT's inspection and enforcement programs. DOT regulations under 49 CFR 193 have some specific requirements on designs to withstand certain loads (e.g., wind) from natural hazards and also incorporates by reference NFPA 59A (2001 and 2006) and ASCE 7-05 and ASCE 7-93 via NFPA 59A (2001). Furthermore, the facilities would be constructed to the requirements in the 2009 International Building Code (IBC) and ASCE 7-05. These regulations and standards require various structural loads to be applied to the design of the facilities, including live (i.e., dynamic) loads, dead (i.e., static) loads, and environmental loads from extreme events, such as earthquakes, tsunamis, seiche, hurricanes, tornadoes, floods, rain, ice, snow, regional subsidence, landslides, wildfires, volcanic activity, and geomagnetism. FERC staff evaluated the design basis for the environmental loads as described more fully for the various natural hazards below. In addition, FERC staff generally recommend companies provide final design information (e.g., drawings, specifications, and calculations) and associated quality assurance and control procedures with the documents stamped and sealed by the professional engineer of record. If a project is authorized and constructed, the company would install equipment in accordance with its final design.

<u>Earthquakes, Tsunamis, and Seiche</u>

Earthquakes and tsunamis have the potential to cause damage from the shaking ground motion and fault ruptures. Earthquakes and tsunamis often result from sudden slips along fractures in the earth's crust (i.e., faults) and the resultant ground motions caused by those movements, but can also be a result of volcanic activity or other causes of vibration in the earth's crust. Seismic and other geological events have the potential to cause damage or failure of facilities as a result of ground motions. The severity of these events are often determined on the probability that they occur and are sometimes referred to as the average number years that the event is expected to re-occur, or in terms of its mean return/recurrence interval. In addition, the

severity of the ground motions are affected by the type/direction and severity of the fault activity and the distance and type of soils the seismic waves must travel from the hypocenter (or point below the epicenter where seismic activity occurs). To assess the potential impact from earthquakes, UGI LNG evaluated historic earthquakes along fault locations and their resultant ground motions.

The U.S. Geological Survey (USGS) maintains a database and map containing information on surface and subsurface faults and folds in the United States that are believed to be sources of earthquakes of greater than 6.0 magnitude occurring during the past 1.6 million years (Quaternary Period).[17] There are no Quaternary-aged faults identified in the database or map in near proximity to the Project (USGS, 2006b). While there are no faults identified near the site that would potentially be the epicenter of large ground motions, this does not mean that there is no risk of earthquakes causing ground motions that can impact the site as ground motions can be felt large distances away from an earthquake depending on number of factors. In fact, on January 16, 1994, there was a 4.6 magnitude earthquake with an epicenter within 10 miles of the UGI LNG site while the existing plant was operating. No significant damage occurred.

DOT regulations under 49 CFR 193 incorporate by reference NFPA 59A (2001) and NFPA 59A (2006) for LNG storage tanks (which are not proposed in this project). NFPA 59A (2001) requires piping and equipment piping and equipment with cold contents (−20 °F or lower) to be designed dynamically for the operating basis earthquake (OBE) or statically 0.60 S_{DS} (maximum spectral acceleration of the design earthquake which equals 2/3 of the Maximum Considered Earthquake [MCE]) as specified in the National Earthquake Hazards Reduction Program (NEHRP) Recommended Provisions. The OBE is defined as a seismic event with ground motion that has a 10 percent probability of exceedance within a 50-year period (a 475-year return period event) or as two-thirds of the maximum considered earthquake, MCE. The MCE ground motions are defined as having a 2 percent probability of exceedance within a 50-year period, or a 2,475 year mean return period. NFPA 59A (2001), Appendix B.5.2, refers seismic design for the remainder of the LNG facilities to NEHRP Recommended Provisions, but these are in a non-mandatory Appendix B. We also recognize the current FERC regulations under 18 CFR 380.12(h)(5) continues to incorporate National Bureau of Standards Information Report (NBSIR) 84-2833. NBSIR 84-2833 provides guidance on classifying stationary storage containers and related safety equipment as Category I and classifying the remainder of the LNG project structures, systems, and components as either Category II or Category III, but does not provide specific guidance for the seismic design requirements for them. Absent any other regulatory requirements, FERC Guidance recommends that other LNG project structures classified as Seismic Category II or Category III be seismically designed to satisfy the Design Earthquake (DE) and seismic requirements of the ASCE 7-05 in order to demonstrate there is not a significant impact on the safety of the public. ASCE 7-05 is recommended as it is a complete American National Standards Institute consensus design standard, its seismic requirements are based directly on the NEHRP Recommended Provisions, and it is referenced directly by the IBC. Having a link directly to the IBC and ASCE 7 is important to accommodate seals by the engineer of record because the IBC is directly linked to state professional licensing laws while the NEHRP Recommended Provisions are not. We also generally recommend LNG storage

[17] USGS, Quaternary Fault and Fold Database of the United States, https://earthquake.usgs.gov/hazards/qfaults/, August 2018.

containers be designed to withstand aftershock level earthquakes, which is assumed as ½ SSE in accordance with NFPA 59A (2013 and 2016).

Ground motions are dependent not only on the magnitude of the seismic event at the hypocenter, but also dependent on the subsurface conditions between the hypocenter and location of interest at the ground surface. Depending on the underlying conditions, ground motions can amplify by a factor of two or more. As a result, ASCE 7 requires the site classification of the underlying soils (the upper 100 feet) according to shear wave velocities, standard penetration resistance, and undrained shear strength.[18] The geotechnical investigations of the proposed Project location performed by EEI indicated the site classification is Site Class C. However, it is unclear what criteria this was based upon as the only relevant information provided in the report was average blow count per foot in stratum I (2 to 28 below count per foot) and II (5 to >50) with most observed on the upper ends. However, the average values were not calculated or provided in accordance with ASCE 7-05 or equivalent. Previous geotechnical investigations indicate different Site Classes, including Site Class B, C, and E, but also provided standard penetration resistance blow counts of 3 to 64 with a median of 30, which are indicative of Site Class D in accordance with ASCE 7-05 or equivalent. Other USGS tools assume the Site Class as B/C boundary (based on an assumed shear velocity of 2,500 ft/s for the location).[19] Based upon this incomplete and conflicting information, FERC staff issued a data request. In response, UGI LNG indicated that it identifies the Project as a Site Class D, but did not provide any additional support in accordance with ASCE 7-05 or equivalent. Therefore, we recommend in Section 8.9 Conclusions on Facility Reliability and Safety that UGI LNG provide supportive information for the Site Class determination in accordance with ASCE 7-05 prior to construction of final design.

The USGS and Applied Technology Council both provide websites that determine the location specific ground accelerations in accordance with various structural codes, including ASCE 7-05, ASCE 7-10, IBC-2006/2009, IBC 2012/2015, NEHRP 2003, NEHRP 2009, and others.[20] Based on the USGS and Applied Technology Council sources using Site Class D, the Project site ground motions would be S_S=0.255 g, S_1=0.06 g, S_{MS}=0.408 g (1.6*S_S), S_{M1}=0.144 g (2.4*S_1), S_{DS}=0.272 g (S_{DS}=2/3*S_{MS}), and S_{D1}=0.096 g (S_{D1}=2/3*S_{M1}). This would indicate an unadjusted (i.e., Site Class B) MCE peak ground acceleration (PGA) of 0.102 g (PGA=S_S/2.5), adjusted (i.e., Site Class D) MCE PGA of 0.163 g (PGA=S_{MS}/2.5), and adjusted DE PGA of 0.109 g. Other USGS tools that attempt to directly provide ground motion accelerations for PGA, 0.2 sec (short) spectral period, and 1.0 second spectral period, for OBE and SSE (SSE=MCE=S_M) equivalent return periods assuming a Site Class as B/C boundary indicate OBE and SSE PGA of 0.0274 g and 0.0896 g, OBE and SSE short spectral period of 0.0549 g and 0.160 g, and OBE and SSE 1.0 sec spectral period of 0.0164 g and 0.0382 g.[21] UGI LNG did not state in its application what they were using for their ground motions, but provided USGS

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[18] There are six different site classes in ASCE 7-05, A through F, that are representative of different soil conditions that impact the ground motions and potential hazard ranging from Hard Rock (Site Class A), Rock (Site Class B), Very dense soil and soft rock (Site Class C), Stiff Soil (Site Class D), Soft Clay Soil (Site Class E), to soils vulnerable to potential failure or collapse, such as liquefiable soils, quick and highly sensitive clays, and collapsible weakly cemented soils (Site Class F).

[19] USGS, Unified Hazard Tool, https://earthquake.usgs.gov/hazards/interactive/, August 2018.

[20] USGS, U.S. Seismic Design Maps, https://earthquake.usgs.gov/designmaps/us/application.php?, August 2018.

[21] USGS, Unified Hazard Tool, https://earthquake.usgs.gov/hazards/interactive/, August 2018.

published maps for OBE and SSE equivalent return periods PGAs for Site Class B. Based on these maps, the site would have OBE of 0.02-0.3 g and SSE of 0.06-0.1 g PGAs. Use of the USGS OBE and SSE equivalent return period Site Class B maps are inconsistent with previous indications of Site Class C in the EEI geotechnical report and the Site Class D indicated in a data request response by UGI LNG. It is also unclear on whether UGI LNG would use OBE and SSE equivalent return period ground motions or not. Use of OBE would be consistent with DOT regulatory requirements, and use of SSE would be more stringent than DOT regulatory requirements and would be more consistent with FERC Guidance for Seismic Category II facilities. While previous editions of NFPA 59A are silent on categorization, NFPA 59A (2016) would indicate the UGI LNG Project facilities are Risk Category III and would indicate use of DE values. However, the use of Site Class B values with OBE and SSE values would result in a net under-prediction of ground motions because the site coefficients for Site Class D based on unadjusted MCE ground motions outweigh the two thirds value of MCE used for determining the DE. Therefore, we recommend in Section 8.9 Conclusions on Facility Reliability and Safety that UGI LNG provide justification for the Site Class in accordance with ASCE 7-05 and adjust ground motions prior to construction of final design.

ASCE 7-05 also requires determination of the Seismic Design Category based on the Occupancy Category and severity of the earthquake design motion. The Occupancy Category is based on the importance of the facility and the risk it poses to the public.[22] In response to a data request, UGI LNG has identified the Project as a Seismic Design Category B. Seismic Design Category B would appear to be consistent with the 2009 IBC and ASCE 7-05 (and ASCE 7-10) based on the Site Class B ground motions for the site and an Occupancy Category (or Risk Category) of III. However, Seismic Design Category C would appear to be consistent with 2009 IBC and ASCE 7-05 for Site Class D and an Occupancy Category (or Risk Category) of IV. Therefore, we also recommend in Section 8.9 Conclusions on Facility Reliability and Safety that UGI LNG provide supportive information on the Seismic Design Category and Occupancy Category (or Risk Category) in accordance with ASCE 7-05 or equivalent prior to construction of final design.

Seismic events can also result in soil liquefaction in which saturated, non-cohesive soils temporarily lose their strength/cohesion and liquefy (i.e., behave like viscous liquid) when subjected to dynamic forces such as intense and prolonged ground shaking. Areas susceptible to liquefaction may include saturated soils that are generally sandy or silty. Typically, these soils are along rivers, streams, lakes, and shorelines or in areas with shallow groundwater. Based on the geotechnical report provided by EEI, UGI LNG has concluded that the soil at the site is not

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[22] ASCE 7-05 defines Occupancy Categories I, II, III, and IV. Occupancy Category I represents facilities with a low hazard to human life in even of failure, such as agricultural facilities; Occupancy Category III represents facilities with a substantial hazard to human life in the event of failure or with a substantial economic impact or disruption of day to day civilian life in the event of failure, such as buildings where more than 300 people aggregate, daycare facilities with facilities greater than 150, schools with capacities greater than 250 for elementary and secondary and greater than 500 for colleges, health care facilities with 50 or more patients, jails and detention facilities, power generating stations, water treatment facilities, telecommunication centers, hazardous facilities that could impact public; Occupancy Category IV represents essential facilities, such as hospitals, fire, rescue, and police stations, emergency shelters, power generating stations and utilities needed in an emergency, aviation control towers, water storage and pump structures for fire suppression, national defense facilities, and hazardous facilities that could substantially impact public; and Occupancy Category II represents all other facilities. ASCE 7-10 changed the term to Risk Categories I, II, III, and IV with some modification.

considered to be susceptible to liquefaction based on low seismic activity, near surface saturation, and soil conditions.

Seismic events in waterbodies can be the source of tsunamis or seiches by sudden displacement of the floors in the ocean or standing water. Due to the geographic location of the Project, low probability and historical record of seismic events in the Project area, and lack of conditions for landslides (discussed in more detail in a later section), tsunamis and seiches are not anticipated to have an effect on the Project.

Hurricanes, Tornadoes, and other Meteorological Events

Hurricanes, tornadoes, and other meteorological events have the potential to cause damage or failure of facilities due to high winds and floods, including failures from flying or floating debris. The severity of these events are often determined on the probability that they occur and are sometimes referred to as the average number of years that the event is expected to re-occur, or in terms of its mean return/recurrence interval. To assess the potential impact from hurricanes, tornadoes, and other meteorological events, UGI LNG evaluated such events.

The Project site has not been directly hit by hurricanes within the last 100 years, but has been subjected to four hurricanes with paths crossing within 25 miles of the Project location, reaching Category 2 or greater, including an unnamed hurricane in 1929, Hurricane Able in 1952, Hurricane Diane in 1955, and Hurricane Christ in 1988.

In accordance with DOT regulations under 49 CFR 193.2067, shop fabricated containers of LNG or other hazardous fluids less than or equal to 70,000 gallons must be designed in accordance with ASCE 7-05. For all other facilities, including but not limited to piping, rotating equipment, and vapor barriers, LNG facilities must be designed to withstand a sustained wind speed of 150 mph or winds that have 0.5 percent probability of being exceeded in 50 years (10,000-year mean return interval) unless the PHMSA Administrator finds lower velocity is justified by adequate supportive data. ASCE 7 and other structural standards generally use 3-second gust wind speeds in calculating wind loads.

On October 16, 2017, UGI LNG indicated that it would design the Project facilities to withstand the sustained wind speed of 150 mph, in response to FERC staff's August 8, 2017 engineering information request, to be consistent with the requirements of 49 CFR 193.2067. We evaluated this proposed wind speed against historical events and the 1 in 10,000 year event alternative requirement as well as against ASCE 7-05 (and ASCE 7-10 and ASCE 7-16) for Occupancy Category III (Risk Category III) requirements for shop fabricated containers less than 70,000 gallons using various wind gust conversion factors for use in structural codes that use a 3-second gust value. Specifically, we estimated a 150-mph sustained wind speed would correspond to a 183-mph 3-second gust using the Durst Curve as suggested in Appendix C of ASCE 7-05. In addition, ASCE 7-05 indicates the basic wind speed for the Project facilities location would be a 90 mph 3-second gust. However, as noted in the limitation of ASCE 7-05, tornadoes were not considered in developing basic wind speed distributions and Appendix C of ASCE 7-05 makes reference to American Nuclear Society (ANS) 2.3 (1983 edition), Standard for Estimating Tornado and Extreme Wind Characteristics at Nuclear Power Sites. This document has since been revised in 2011 and reaffirmed in 2016 and is consistent with NUREG/CR-4461, Tornado Climatology of the Contiguous U.S. Rev. 2 (NUREG, 2007). These documents provide maps of a 100,000 mean year return period for tornadoes using 2° latitude and longitude boxes in the region to estimate a tornado striking within 4,000 feet of an area.

Figures 5-8 and 8-1 from NUREG/CR-4461 indicate a 100,000 year maximum tornado wind speed of 127 mph 3-second gust for a 100,000 year tornado. Later editions of ASCE 7 (ASCE 7-10 and ASCE 7-16) make reference to International Code Council (ICC) 500, Standard for Design and Construction of Storm Shelters, for 10,000 year tornadoes. However, the ICC 500 maps were conservatively developed based on tornadoes striking regions and indicate a 160 mph 3-second gust for a 10,000 year event, which is higher than the 127 mph 3-second gust in ANS 2.3 and NUREG/CR-4461. As a result, FERC staff concludes that the use of a sustained wind speed of 150 mph, 183 mph 3-second gust, is adequate for the proposed facilities. As a cooperating agency and in accordance with the MOU, the DOT will provide a LOD as to whether an applicant's proposed Project meets the DOT siting requirements, including wind speed requirements. In addition, if the Project is constructed and becomes operational, the facilities would be subject to the DOT's inspection and enforcement programs. Final determination of whether the facilities are in compliance with the requirements of 49 CFR 193 would be made by the DOT staff.

In addition, FERC staff evaluated historical tropical storm, hurricane, and tornado tracks in the vicinity of the Project facilities using data from DHS Homeland Infrastructure Foundation Level Data and National Oceanic Atmospheric Administration's (NOAA) Historical Hurricane Tracker.[23,24] FERC staff identified at least three tornado tracks within a 10 mile radius with several more to the northeast of the proposed facilities and existing site. The closest of which occurred less than 2 miles away in November 4, 1954. Similarly, FERC staff identified several tropical storms and hurricanes that impacted the area, including Hurricane Hazel (Category 4) in 1954, Hurricane Connie (Category 4) in 1955, Hurricane Agnus (Category 1) in 1972, Hurricane Dennis (Category 2) in 1999, Hurricane Isabel (Category 5) in 2003, Hurricane Ivan (Category 5) in 2004, Hurricane Ike (Category 4) in 2008, Hurricane Irene (Category 3) in 2011, and Hurricane Sandy (Category 3) in 2012.[25]

Potential flood levels may also be informed from the Federal Emergency Management Agency (FEMA) Flood Insurance Rate Maps, which identifies Special Flood Hazard Areas (base flood) that have a 1 percent probability of exceedance in 1 year to flood (or a 100 year mean return interval) and moderate flood hazard areas that have a 0.2 percent probability of exceedance in 1 year to flood (or a 500 year mean return interval). According to the FEMA National Flood Hazard Layer, the Project is not within a Special Flood Hazard Area or at risk for floods up to and including the 0.2% annual chance of flood. In addition to the Project not residing within a Special Flood Hazard Area, the site's gently slopped topography reduces the risk of flooding due to storm events.

Landslides and other Natural Hazards

Landslides, karst terrain, volcanic activity, and geomagnetism, and other natural hazards have the potential to cause damage or failure of facilities. Like other natural hazards, the

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[23] DHS, Homeland Infrastructure Foundation Level Data, https://hifld-geoplatform.opendata.arcgis.com/, August 2018.

[24] NOAA, Historical Hurricane Tracker, https://coast.noaa.gov/hurricanes/, August 2018.

[25] Hurricane Saffir-Simpson Categories based on maximum attained and not necessarily at landfall or specific location. The following wind speeds are associated with Category 5 >156 mph sustained, >195 mph 3-second gust, Category 4 130-156 mph sustained, 166-195 mph 3-second gust, Category 3 111-129 mph sustained, 141-165 mph 3-second gust, Category 2 96-110 mph sustained, 117-140 mph 3-second gust, Category 1 74-95 mph sustained, 91-116 mph 3-second gust.

severity of these events are often determined on the probability that they occur and are sometimes referred to as the average number years that the event is expected to re-occur, or in terms of its mean return/recurrence interval.

Landslides involve the down slope movement of earth materials under a force of gravity due to natural or man-made causes and potential can be affected by rainfall, slope angle, soil type, seismic activity, and previous landslides. The Project is proposed in a gently sloping, developed area considered to have a low incidence of landslides, and USGS maps indicate the UGI LNG Project site is proposed just outside a landslide susceptible area based on elevation data and has not had any previously identified fast moving landslides.[26]

Karst terrain indicates areas where sinkholes can develop. Karst primarily occurs from dissolution of underlying soluble rocks by surface and ground water. The most common rocks associated with karst are carbonate rocks (limestone and dolomite) and rock salts and other evaporate rocks (e.g., gypsum). The proposed Project is in an identified karst region where dolomite and limestone are present and are susceptible to dissolution when exposed to water.[27] During site investigations, EEI identified voids within the borehole samples. EEI has recommended that UGI LNG closely observe construction activities for soft/loose or abnormally moist soil conditions. If encountered, EEI recommended that the poor soil materials be removed and the extent of unstable soils be further evaluated. EEI also recommended that any areas susceptible to sinkholes be stabilized and repaired, and that areas exhibiting "solution activity" be overseen by the geotechnical engineer of record. As a result of the potential sinkhole formation risk, FERC staff recommend in Section 8.9 Conclusions on Facility Reliability and Safety that UGI LNG take additional measures for the Project.

Volcanic activity is primarily a concern along plate boundaries on the west coast of Alaska and Hawaii. Based on FERC staff review of maps from USGS[28] and DHS[29] of the nearly 1,500 volcanoes with eruptions since the Holocene period (in the past 10,000 years) there are no known active or historic volcanic activity within approximately 1,500 miles.

Geomagnetic disturbances may occur due to solar flares or other natural events with varying frequencies that can cause geomagnetically induced currents, which can disrupt the operation of transformers and other electrical equipment. USGS provides a map of geomagnetic disturbance intensities with an estimated 100 year mean return interval.[30] The map indicates the UGI LNG site could experience geomagnetic disturbance intensities of -20 to -40 nano-Tesla with a 100-year mean return interval. However, UGI LNG would be designed such that if a loss of power were to occur, the valves would move into a fail-safe position. This could result in a

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[26] USGS, U.S. Geological Survey Miscellaneous Field Studies Map 2329, *Map Showing Inventory and Regional Susceptibility for Holocene Debris Flows, and Related Fast-Moving Landslides in the Conterminous United States*, https://pubs.usgs.gov/mf/1999/2329/mf2329_sheet2.pdf, accessed Sep 2018.

[27] USGS, Karst in the United States: A Digital Map Compilation and Database, https://pubs.usgs.gov/of/2014/1156/, accessed Sep 2018.

[28] United States Geological Survey, *U.S. Volcanoes and Current Activity Alerts*, https://volcanoes.usgs.gov/index.html, accessed Aug 2018.

[29] Department of Homeland Security, *Homeland Infrastructure, Foundation-Level data (HIFLD)*, Natural Hazards, hifld-geoplatform.opendata.arcgis.com, accessed Aug 2018

[30] United States Geological Survey, *Magnetic Anomaly Maps and Data for North America*, https://mrdata.usgs.gov/magnetic/map-us.html#home, accessed Aug 2018.

disruption in trucking activities, but we expect this to be a temporary impact and would not significantly impact natural gas supplies to U.S. customers.

8.8 Process Design Review

UGI LNG proposes to deliver LNG onto trucks from the existing single containment LNG storage tanks through a proposed truck loading skid. This transfer of fluids from the existing tanks would be through the use of two new LNG truck loading pumps running in parallel. Each pump would be capable of loading two trucks simultaneously.

The failure of this equipment could pose potential harm if not properly safeguarded through the use of appropriate controls and operation. UGI LNG would install process control valves and instrumentation to safely operate and monitor the facilities. Alarms would have visual and audible notification in the existing control room to warn operators that process conditions may be approaching design limits. Operators would have the capability to take action from the existing control room to mitigate an upset. UGI LNG would also update their existing control systems and existing human-to-machine interface to include the proposed Project facilities. UGI LNG would update facility operation procedures after completion of the final design to reflect the additional trucking facilities; this timing is fully consistent with accepted industry practice. We generally recommend that companies to provide more information on the operating and maintenance procedures prior to commissioning, including safety procedures, hot work procedures and permits, abnormal operating conditions procedures, and personnel training. We evaluate these procedures to ensure that an operator can operate and maintain all systems safely, based on benchmarking against other operating and maintenance plans and comparing against recommended and generally accepted good engineering practices, such as American Institute of Chemical Engineers, *Guidelines for Writing Effective Operating and Maintenance Procedures*. In addition, we generally recommend measures such as tagging and labeling instrumentation and valves, piping, and equipment and providing car-seals/locks to address human factor considerations and improve facility safety and prevent incidents. We also generally recommend that an alarm management program in accordance with International Society of Automation (ISA) Standard 18.2 be in place to ensure the effectiveness of the alarms.

In the event of a process deviation, emergency shutdown (ESD) valves and instrumentation would be installed to monitor, alarm, shut down, and isolate equipment and piping during process upsets or emergency conditions. The Project would have a shutdown valve that would be triggered by the existing Temple I emergency shutdown as well as having local shutdown capabilities specifically targeting the Project. FERC staff generally evaluate whether companies' safety instrumented systems with higher reliabilities would comply with ISA Standard 84.01 and other recommended and generally accepted good engineering practices. We generally recommend that companies provide information, for review and approval, on the final design, installation, and commissioning of instrumentation and emergency shutdown equipment to ensure appropriate cause-and-effect alarm or shutdown logic and enhanced representation of the emergency shutdown valves in the facility control system.

If the Project is authorized and constructed, UGI LNG would install equipment in accordance with its design. FERC staff generally recommend that project facilities be subject to periodic inspections during construction and that companies provide commissioning plans, procedures, and commissioning demonstration tests that would verify the performance of equipment. In addition, we generally recommend that companies provide semi-annual reports

that include abnormal operating conditions and process upsets. Furthermore, we generally recommend project facilities be subject to regular inspections throughout the life of the facilities to verify that equipment is being properly maintained and to verify basis of design conditions, such as feed gas and sendout conditions, do not exceed the original basis of design.

8.8.1 Mechanical Design Review

The proposed Project design specifies materials of construction and ratings suited to the pressure and temperature conditions of the process design. Piping, flanges, and valves would be designed, fabricated, assembled, erected, inspected, examined, and tested in accordance with the ASME Standards B31.3, B16.5, B16.10, B16.20, B16.25, and B16.34; American Petroleum Institute (API) Standards 594, 598, 600, 602, and 609; and other recommended and generally accepted good engineering practices. Pressure vessels would be designed, fabricated, and tested in accordance with the 2007 edition of the ASME Boiler and Pressure Vessel Code (BPVC) Section VIII and testing (i.e. use of pressure test factors). We generally recommend that companies provide the procedures for pressure/leak tests which address the requirements of ASME BPVC Section VIII, to assure pressure/leak tests are done safely and in accordance with ASME BPVC Section VIIII and recommended and generally accepted good engineering practices. The heat exchanger would be designed to ASME BPVC Section VIII standards. Rotating equipment would be designed API Standards 610 and other recommended and generally accepted good engineering practices.

Pressure safety relief valves and vents would be installed to protect process equipment and piping. The safety relief valves would be designed to handle process upsets and thermal expansion within piping, per NFPA 59A (2001 edition) and would be designed in accordance with ASME Section VIII; API Standards 520, 521, and 526; and other recommended and generally accepted good engineering practices. In addition, we generally recommend that companies provide final design information on pressure and vacuum relief devices to ensure that the final sizing, design, and installation of these components are adequate and in accordance with the standards reference and other recommended and generally accepted good engineering practices.[31]

If the Project is authorized and constructed, UGI LNG would install equipment in accordance with its proposed design. FERC staff would generally recommend project facilities be subject to periodic inspections during construction where we would verify equipment nameplates reflect the approved design. FERC staff also generally recommend that companies provide quality assurance and quality control plans to ensure equipment and construction work are being performed according to proposed project specifications, procedures, codes, and standards. In addition, we generally recommend that companies provide semi-annual reports that include equipment malfunctions and abnormal maintenance and project facilities be subject to regular inspections throughout the life of the facilities to verify in the field that equipment is being properly maintained.

8.8.2 Security Design Review

Security plans are another key component in mitigating the risk of an incident occurring from intentional acts. UGI LNG's existing facilities are subject to 6 CFR 27 Chemical Facility Anti-Terrorism Standards regulations. Depending on the potential consequences and subsequent

[31] UGI LNG does not have equipment (e.g., LNG storage tanks) that would have vacuum relief valves.

tier, facilities that are considered high risk must also complete a security vulnerability assessment and develop a site security plan addressing the vulnerabilities identified in the security vulnerability assessment. These must be submitted to DHS for review and approval and updated as changes to the facilities occur. Under 6 CFR 27.230 Risk-Based Performance Standards, the security vulnerability assessment should address the following:

- secure and monitor the perimeter of the facility,
- control access,
- deter, detect, and delay a breach,
- secure and monitor shipping, receipt, and storage of hazardous materials,
- deter theft or diversion of dangerous chemicals,
- deter inside sabotage,
- deter cyber sabotage,
- develop and exercise an emergency response plan,
- maintain communication and warning systems,
- provide security training, exercises, and drills of personnel,
- perform background checks,
- escalate protection during periods of elevated threat;
- identify, investigate, and report significant security incidents to DHS and local law enforcement,
- maintain appropriate records, and
- address any particular or additional security measures and performance standards DHS may specify.

UGI LNG's existing facilities and proposed facilities, once constructed, are required to comply with DOT regulations under 49 CFR 193 Subpart J, which also specifies security requirements, including:

- design and construction of protective enclosures,
- security lighting,
- security monitoring,
- positive identification of all persons entering the plan,
- warning signs,
- requirements for conducting security inspections and patrols,
- liaison with local law enforcement officials,
- security communications,
- alternative power sources, and
- warning signs.

UGI LNG would update its existing security fencing, gates, lighting, camera systems, and instruction detection to deter, monitor, and detect intruders into the facility. FERC staff evaluate these drawings to determine if the facilities would be fully enclosed by a protective barrier with controlled access. In order to minimize the risk of an intentional event, we generally recommend that companies provide protective barriers at entrances that would mitigate intentional vehicular impacts as well as provide documentation that an adequate number of lights and coverage of cameras and intrusion detection would be provided along the fence line and internal to the plant. We also evaluate one line drawings and uninterruptable power supply for security and safety equipment, and evaluate emergency response plans to ensure that they address potential security incidents.

FERC staff would continue to evaluate the preliminary design information along with DOT and DHS regarding security measures, including protective enclosures, access controls, lighting, security monitoring, (e.g., camera), intrusion detection systems, communication systems, and emergency power. We generally recommend that companies provide final security drawings that show both operating and security lighting and cameras, as well as final design details of vehicular access points and their associated barriers, chicane, and/or security personnel. In addition, we generally recommend that companies provide information on any changes to security plans and designs. Lastly, we generally recommend that companies provide semi-annual reports that include any security incidents and project facilities be subject to regular inspections throughout the life of the facilities to ensure updates are being made to the plans.

8.8.3 Hazard Mitigation Design Review

If operational control of the facilities were lost and operational controls and emergency shutdown systems failed to maintain the Project within the design limits of the piping and safety relief valves, a release could potentially occur. FERC regulations under 18 CFR 380.12(o)(1) through (4) require applicants to provide information on spill containment, spacing and plant layout, hazard detection, hazard control, and firewater systems. In addition, 18 CFR 380.12(o)(7) require applicants to provide engineering studies on the design approach and 18 CFR 380.12(o)(14) requires applicants to demonstrate how they comply with 49 CFR 193 and NFPA 59A. As required by 49 CFR 193 through NFPA 59A (2001) Section 9.1.2, fire protection must be provided for all DOT regulated LNG plant facilities based on an evaluation of sound fire protection engineering principles, analysis of local conditions, hazards within the facility, and exposure to or from other property. NFPA 59A (2001) also requires the evaluation determine type, quantity, and location of hazard detection and hazard control, passive fire protection, emergency shutdown and depressurizing systems, and emergency response equipment, training, and qualifications.

All facilities, once constructed, must comply with the requirements of 49 CFR 193 and would be subject to DOT's inspection and enforcement programs. However, NFPA 59A (2001) also indicates that the wide range in size, design, and location of LNG facilities precludes the inclusion of detailed fire protection provisions, such as those that would apply to all facilities comprehensively and that would include subjective performance-based criteria which designate where ESD systems and hazard controls are required. Furthermore, NFPA 59A (2001) does not provide any additional guidance on the placement or selection of hazard detection equipment and provides minimal requirements on firewater. Therefore, FERC staff evaluated the proposed spill containment and spacing, hazard detection, emergency shutdown and depressurization systems, hazard control, firewater coverage, structural protection, and onsite and offsite emergency

response to ensure they would provide adequate protection of the LNG facilities as described more fully below.

UGI LNG performed a preliminary fire protection evaluation to ensure that adequate mitigation would be in place, including spill containment and spacing, hazard detection, emergency shutdown and depressurization systems, hazard control, firewater coverage, structural protection, and onsite and offsite emergency response. We generally recommend that companies provide a final fire protection evaluation and provide more information on the final design, installation, and commissioning of spill containment, hazard detection, hazard control, firewater systems, structural fire protection, and onsite and offsite emergency response procedures.

Spill Containment

In the event of a LNG release, the sloped areas surrounding the Project facilities would direct a spill away from equipment and into an impoundment system. This arrangement would minimize the dispersion of flammable vapors into confined, occupied, or public areas and minimize the potential for heat from a fire to impact adjacent equipment, occupied buildings, or public areas if ignition were to occur.

Under NFPA 59A (2001) Section 2.2.2.2, the capacity of impounding areas for LNG transfer areas must equal the greatest volume that can be discharged from any single accidental leakage source during a 10-minute period or during a shorter time period based upon demonstrable surveillance and shutdown provisions acceptable to the DOT. All facilities, once constructed, must comply with the requirements of 49 CFR 193 and would be subject to DOT's inspection and enforcement programs. As part of our preliminary engineering review, we evaluate whether impoundment systems would be sized to contain the largest flow capacity from a single pipe for 10 minutes or the capacity of the largest vessel served, whichever is greater. In addition, we generally recommend that companies provide additional information on final design of these systems where details are yet to be determined and where the final design could change as a result of these details or other changes in the final design of the Project.

Automatically-operated sump pumps for impoundment areas must have redundant automatic shutdown controls and water removal requirements as specified in 49 CFR 193.2173. All facilities, once constructed, must comply with the requirements of 49 CFR 193 and be subject to DOT's inspection and enforcement programs. UGI LNG's proposed pumps would have the capacity to remove water at minimum of 25 percent of the rate from a storm of a 10-year frequency and one-hour duration, as required by 49 CFR 193.2173. The sump pump would be manually activated. A float level would be used to trigger an alarm, notifying operators that the sump needs to be drained. Operators must then manually activate the sump pump. However, the sump pump can be deactivated manually or automatically. UGI LNG plans on providing low temperature detectors in the sub-containment sump to prevent pumps from operating if LNG is present, but there would not be a redundant means of detection because the sump pumps would not be automatically activated.

If the Project is authorized and constructed, UGI LNG would install spill impoundments in accordance with its design. FERC staff generally recommend the project facilities be subject to periodic inspections during construction where we would verify the spill containment system, including dimensions, slopes of curbing and trenches, and capacity, matches final design information. In addition, FERC staff generally recommend project facilities be subject to regular

inspections throughout the life of the facilities to verify that impoundments are being properly maintained.

Spacing and Plant Layout

The spacing of vessels and equipment between each other, from ignition sources, and to the property line would need to meet the requirements of 49 CFR 193, which incorporates NFPA 59A (2001). NFPA 59A (2001) further references NFPA Standards 30, NFPA 58, and NFPA 59. All facilities, once constructed, must comply with the requirements of 49 CFR 193 and would be subject to DOT's inspection and enforcement programs. FERC staff evaluate the spacing to determine if there could be cascading damage and to inform what fire protection measures may be necessary to reduce the risk of cascading damage. If the Project is authorized, UGI LNG would finalize the plot plan, and FERC staff generally recommend that the final drawings be provided and that changes be provided for review and approval to ensure capacities and setbacks are maintained. If the facilities are constructed, UGI LNG would install equipment in accordance with the spacing indicated on the proposed plot plans, and FERC staff generally recommend that facilities are subject to periodic inspections during construction to verify equipment is installed in appropriate locations and the spacing is met in the field. In addition, FERC staff generally recommend that project facilities be subject to regular inspections throughout the life of the facilities to continue to verify that equipment setbacks from other equipment and ignition sources are being maintained.

Ignition Controls

Project areas would be designated with a hazardous electrical classification and provided with process seals in accordance with NFPA 59A, 70, and 497; and Institute of Electrical and Electronics Engineers standards C2, and C37.2. Depending on the risk level, these areas would either be classified as non-classified, Class 1 Division 1, or Class 1 Division 2. In addition, equipment in these areas would be designed such that in the event a flammable vapor is present, the equipment would have a minimal risk of igniting the vapor. FERC staff evaluate electrical area classification drawings to verify that companies would meet these electrical area classification requirements in NFPA 59A, 70, and other recommended and generally accepted good engineering practices, such as API RP 500 and NFPA 497.

If the Project is authorized, UGI LNG would finalize the electrical area classification drawings. FERC staff generally recommend the final design of the electrical area classification be filed to determine whether any changes would result in any safety and reliability impacts. If facilities are constructed, UGI LNG would install appropriately classed electrical equipment, and FERC staff generally recommend project facilities be subject to inspections to spot check electrical equipment in the field to verify equipment is installed as designed. In addition, FERC staff generally recommend project facilities be subject to regular inspections throughout the life of the facilities to ensure electrical equipment is maintained (e.g., bolts on explosion proof equipment properly installed, panels provided with purge, etc.) or appropriately de-energized and locked out and tagged out when being serviced.

Hazard Detection, Emergency Shutdown, and Depressurization Systems

UGI LNG would also install hazard detection systems to detect cryogenic spills, flammable vapors, and fires. The hazard detection systems would alarm and notify personnel in the area and control room to initiate an emergency shutdown, depressurization, or initiate other

appropriate procedures, and would meet ISA Standard 12.13 and other recommended and generally accepted good engineering practices. However, we note that UGI LNG did not make reference to NFPA 72, which is incorporated into DOT regulations and provides requirements for hazard detection, alarm, and notification. Additionally, UGI LNG did not include a specification for hazard detection in its application. Therefore, we recommend in Section 8.9 Conclusions on Facility Reliability and Safety that UGI LNG provide specifications, including hazard detection, prior to the construction of final design.

FERC staff evaluate the adequacy of the general hazard detection type, location, and layout to ensure adequate coverage to detect cryogenic spills, flammable vapors, and fires as well as the related cause and effect matrices that would initiate an alarm, shutdown, or other action based on the FEED. FERC staff generally recommend that companies provide additional information on the final design of all hazard detection systems where details are yet to be determined (e.g., manufacturer and model, elevations, etc.) and hazard detection layout drawings. If the Project is authorized and constructed, UGI LNG would install hazard detectors according to its specifications. FERC staff generally recommend that project facilities are subject to periodic inspections during construction to verify hazard detectors and ESD pushbuttons are appropriately installed in the field per approved design and are functional based on cause and effect matrices prior to introduction of hazardous fluids. In addition, FERC staff generally recommend project facilities be subject to regular inspections throughout the life of the facilities to verify hazard detector coverage and functionality is being maintained and hazard detectors are not being bypassed without appropriate precautions.

Hazard Control

If ignition of flammable vapors occurred, existing hazard control devices would be utilized to extinguish or control incipient releases and fires, and would meet NFPA 59A; NFPA 10, and 17; as well as other recommended and generally accepted good engineering practices.

FERC staff evaluate the adequacy of the number and availability of handheld, wheeled, and fixed fire extinguishing devices throughout the site based on the FEED. FERC staff also generally evaluate whether the spacing of the fire extinguishers meets NFPA 10. In addition, we generally recommend that companies provide additional information on final design of these systems where details are yet to be determined (e.g., manufacturer and model, elevations, flowrate, capacities, etc.) and where the final design could change as a result of these details or other changes in the final design of the Project.

If the Project is authorized and constructed, UGI LNG would utilize existing hazard control facilities, in addition to installing a proposed dry chemical system. FERC staff generally recommend that facilities be subject to periodic inspections during construction to verify hazard control equipment is installed in the field and functional prior to introduction of hazardous fluids. In addition, FERC staff generally recommend project facilities be subject to regular inspections throughout the life of the facilities to verify in the field hazard control coverage and that hazard control facilities are being properly maintained and inspected.

Passive Cryogenic and Fire Protection

If a fire could not be separated, controlled, or extinguished to limit cryogenic exposures and fire exposures to insignificant levels, passive cryogenic and/or fire protection (e.g. fireproofing structural steel) would be provided to prevent failure of structural supports of

equipment and pipe racks. The structural fire protection would comply with NFPA 59A (2001) and other recommended and generally accepted good engineering practices. FERC staff generally evaluate whether passive cryogenic and fire protection is applied to pressure vessels and structural supports to facilities that could be exposed to cryogenic liquids or to radiant heats of 4,000 Btu/ft^2-hr or greater from fires with durations that could result in failures[32] and that they are specified in accordance with recommended and generally accepted good engineering practices with a fire protection rating commensurate to the radiant heat and duration. In addition, we generally recommend that companies provide additional information on the final design of these systems where details are yet to be determined (e.g., calculation of structural fire protection materials, thicknesses, etc.) and where the final design could change as a result of these details or other changes in the final design of the Project.[33]

During our preliminary review, we noted the potential for high radiant heat from a fire in the proposed impoundment system reaching the adjacent LNG storage tank. However, a host of mitigative steps are available and we recommend in Section 8.9 Conclusions on Facility Reliability and Safety that UGI LNG take additional steps such that the facility's firewater system can adequately address radiant heat concerns.

If the Project is authorized and constructed, UGI LNG would install structural cryogenic and fire protection. FERC staff generally recommend project facilities be subject to periodic inspections during construction to verify structural cryogenic and fire protection is properly installed in the field as designed prior to introduction of hazardous fluids. In addition, we generally recommend project facilities be subject to regular inspections throughout the life of the facilities to continue to verify that passive protection is being properly maintained.

Firewater Systems

UGI LNG would utilize its existing firewater system during an emergency to cool the surface of nearby storage vessels, piping, and equipment exposed to heat from a fire, and would meet NFPA 59A and 17 requirements. As part of the preliminary engineering review, we evaluated the firewater system (e.g., hydrants, hose reels, and monitors) to cover the Project facilities and assess the appropriateness of the associated demands of those devices and worst case fire scenarios to evaluate the size the of the existing firewater pumps. In addition, we generally recommend that an updated fire protection evaluation be carried out on final design where details are yet to be determined and where the final design could change as a result of these details or other changes in the final design of a project. FERC staff generally recommend that project facilities be subject to periodic inspections and commissioning tests to verify the firewater and foam systems are installed and functional as designed prior to introduction of hazardous fluids. In addition, we generally recommend that project facilities be subject to regular inspections throughout the life of the facilities to ensure firewater systems are being properly maintained and tested.

[32] Pool fires from impoundments are generally mitigated through use of emergency shutdowns, depressurization systems, structural fire protection, and firewater, while jet fires are primarily mitigated through the use of emergency shutdowns, depressurization systems, and firewater without structural fire protection.

Onsite and Offsite Emergency Response Plans

As required by 49 CFR 193.2509, LNG plant operators need to prepare emergency procedures manuals that provide for: a) responding to controllable emergencies and recognizing an uncontrollable emergency; b) taking action to minimize harm to the public including the possible need to evacuate the public; and c) coordinating and cooperating with appropriate local officials. Specifically, Section 193.2509(b)(3) requires "Coordinating with appropriate local officials in preparation of an emergency evacuation plan…," which sets forth the steps required to protect the public in the event of an emergency.

The emergency procedures would provide protection of personnel and the public as well as the prevention of property damage that may occur as a result of incidents at the facility. FERC staff evaluates the initial draft of the emergency response procedures to assure that it covers the hazards associated with the Project. UGI LNG currently has an existing Facility Response Plan in place which covers procedures to respond to a plant emergency. The existing Facility Response Plan would need to be updated to include the proposed facilities and emergencies related to Project operations. We generally recommend additional information on development and final updated emergency response plans prior to introduction of hazardous fluids. In addition, FERC staff generally recommend that project facilities be subject to regular inspections and a requirement for updates be filed on the plans throughout the life of the facilities.

8.9 Conclusions on Facility Reliability and Safety

As part of the NEPA review and NGA determinations, Commission staff assesses the potential impact on the human environment in terms of safety and whether the proposed facilities would be in the public interest based on whether it would operate safely, reliably, and securely.

As a cooperating agency, the DOT assists the FERC by determining whether UGI LNG's proposed design would meet the DOT's 49 CFR 193 Subpart B siting requirements. The DOT reviewed design spill information submitted by UGI LNG and on April 6, 2018, the DOT provided a letter to FERC staff stating that the DOT had no objection to UGI LNG's methodology to comply with the Part 193 siting requirements for the proposed Project facilities. DOT will provide a LOD on the Project's compliance with 49 CFR 193 Subpart B. This determination will be provided to the Commission as further consideration to the Commission on its decision and final action on the Project application. If the facilities are authorized and constructed, the facility would be subject to the DOT's inspection and enforcement program and final determination of whether a facility is in compliance with the requirements of 49 CFR 193 would be made by the DOT staff.

In addition, FERC staff reviewed potential external impacts based on the site location and conducted a technical review of the engineering design in conjunction with NEPA that would continue throughout final design, and throughout the life of the facility. Based on our external impact analysis and preliminary evaluation of the engineering design, we conclude that the UGI LNG Project design would include acceptable layers of protection or safeguards that would reduce the risk of a potentially hazardous scenario from developing into an event that could impact the offsite public. Furthermore, the following recommendations would be provided to the Commission for consideration to incorporate as possible conditions to an order. These recommendations would be implemented prior to initial site preparation, prior to construction of final design, prior to commissioning, prior to introduction of hazardous fluids, prior to

commencement of service, and throughout the life of the facility to enhance the reliability and safety of the facility and to mitigate the risk of impact on the public.

- **UGI LNG should employ a special inspector (professional geologist and/or geotechnical engineer) during construction, and a copy of the special inspector's reports should be included in the monthly status reports filed with the Secretary (see condition 8 above). The special inspector should be responsible for:**

  a. observing the construction of the Project facilities to be certain it conforms to the design drawings and specifications;

  b. furnishing inspection reports to the engineer- or architect-of-record and other designated persons. All discrepancies should be brought to the immediate attention of the contractor for correction, and then if uncorrected, to the engineer- or architect-of-record; and

  c. submitting a final signed report stating whether the work requiring special inspection was, to the best of his/her knowledge, in conformance with the approved plans and specifications and the applicable workmanship provisions.

- **Prior to construction of final design, UGI LNG should file with the Secretary the following information, stamped and sealed by the professional engineer-of-record, registered in Pennsylvania:**

  a. evaluation of whether potential corrosivity of soil exists that could exacerbate solubility of underlying carbonate rocks or corrode underground piping and utilities using recognized test methods, such as ASTM G51, (2012), Standard Test Method for Measuring pH of Soil for Use in Corrosion Testing;

  b. evaluation of type of underlying rock, extent of jointing, and voids to determine potential of sinkhole formation based on location, inclination, thickness, and face length of jointing and location and size of voids underneath the project facilities using recognized methods, such as rock coring seismic reflection, and ground penetration radar, and include resultant data;

  c. evaluation of underlying soils to determine Site Class in accordance with ASCE 7-05, Minimum Design Loads for Buildings and Other Structures, that is used as basis of design for ground motions and associated Seismic Design Category;

  d. development of a monitoring, detection, response and mitigation plan for sinkhole formation during construction and operation within the footprint of all foundations and driveway using recognized methods, such as periodic photogrammetry and periodic ground penetration radar, and include criteria for response and mitigation;

  e. quality assurance and control procedures to be used for civil/structural design and construction;

  f. site preparation drawings and specifications;

  g. seismic specifications for procured equipment; and

h. liquefied natural gas (LNG) project structures and foundation design drawings and calculations (including prefabricated and field constructed structures).

Information pertaining to these specific recommendations should be filed with the Secretary, for review and written approval by the Director of the Office of Energy Projects (OEP), or the Director's designee, within the timeframe indicated by each recommendation. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 833 (Docket No. RM16-15-000), including security information, should be submitted as critical energy infrastructure information pursuant to 18 CFR 388.113. See *Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information*, Order No. 833, 81 Fed. Reg. 93,732 (December 21, 2016), FERC Stats. & Regs. 31,389 (2016), *reh'g pending*. Information pertaining to items such as offsite emergency response, procedures for public notification and evacuation, and construction and operating reporting requirements would be subject to public disclosure. All information should be filed <u>a minimum of 30 days</u> before approval to proceed is requested.

- **<u>Prior to initial site preparation</u>, UGI LNG should file an overall project schedule, which includes the proposed stages of the commissioning plan.**
- **<u>Prior to initial site preparation</u>, UGI LNG should file quality assurance and quality control procedures for construction activities.**
- **<u>Prior to initial site preparation</u>, UGI LNG should file procedures for controlling access during construction.**
- **<u>Prior to construction of final design</u>, UGI LNG should file change logs that list and explain any changes made from the front end engineering design provided in UGI LNG's application and filings. A list of all changes with an explanation for the design alteration should be provided and all changes should be clearly indicated on all diagrams and drawings.**
- **<u>Prior to construction of final design</u>, UGI LNG should file an up-to-date equipment list, process and mechanical data sheets, and specifications.**
- **<u>Prior to construction of final design</u>, UGI LNG should include up-to-date process flow diagrams (PFDs) and piping and instrument diagrams (P&IDs). The PFDs should include heat and material balances. The P&IDs should include the following information:**

  a. equipment tag number, name, size, duty, capacity, and design conditions;

  b. equipment insulation type and thickness;

  c. valve high pressure side and internal and external vent locations;

  d. piping with line number, piping class specification, size, and insulation type and thickness;

  e. piping specification breaks and insulation limits;

  f. all control and manual valves numbered;

  g. relief valves with size and set points; and

h. drawing revision number and date.

- **<u>Prior to construction of final design</u>, UGI LNG should file P&IDs, specifications, and procedures that clearly show and specify the tie-in details required to safely connect the Project to the existing LNG facility.**
- **<u>Prior to construction of final design</u>, UGI LNG should file a car seal philosophy and a list of all car-sealed and locked valves consistent with the P&IDs.**
- **<u>Prior to construction of final design</u>, UGI LNG should file a hazard and operability review of the completed design prior to issuing the P&IDs for construction. A copy of the review, a list of the recommendations, and actions taken on the recommendations should be filed.**
- **<u>Prior to construction of final design</u>, UGI LNG should file the safe operating limits (upper and lower), alarm and shutdown set points for all instrumentation (i.e., temperature, pressures, flows, and compositions).**
- **<u>Prior to construction of final design</u>, UGI LNG should file a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems.**
- **<u>Prior to construction of final design</u>, UGI LNG should file cause-and-effect matrices for the process instrumentation, fire and gas detection system, and emergency shutdown system The cause-and-effect matrices should include alarms and shutdown functions, details of the voting and shutdown logic, and set points.**
- **<u>Prior to construction of final design</u>, UGI LNG should file a SIL verification study validating the pump cavitation and high flow shutdowns as SIL 2 or higher rated systems.**
- **<u>Prior to construction of final design</u>, UGI LNG should specify that all emergency shutdown valves are to be equipped with open and closed position switches connected to the Distributed Control System /Safety Instrumented System.**
- **<u>Prior to construction of final design</u>, UGI LNG should demonstrate that, for hazardous fluids, piping and piping nipples 2 inches or less in diameter are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators.**
- **<u>Prior to construction of final design</u>, UGI LNG should specify that piping specifications for stainless steel piping capable of operating at cryogenic temperatures should require the inner and outer ring of spiral wound gaskets to be stainless steel.**
- **<u>Prior to construction of final design</u>, UGI LNG should specify all drains from high pressure hazardous fluid systems are to be equipped with double isolation and bleed valves.**

- **<u>Prior to construction of final design</u>, UGI LNG should file the sizing basis and capacity for the final design of the pressure relief valves for major process equipment and vessels.**
- **<u>Prior to construction of final design</u>, UGI LNG should file final electrical area classification drawings.**
- **<u>Prior to construction of final design</u>, UGI LNG should file drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A (2001).**
- **<u>Prior to construction of final design</u>, UGI LNG should file details of an air gap or vent installed downstream of process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap should vent to a safe location and be equipped with a leak detection device that should continuously monitor for the presence of a flammable fluid, alarm the hazardous condition, and shut down the appropriate systems.**
- **<u>Prior to construction of final design</u>, UGI LNG should file the final design details of the spill containment systems that would properly contain a spills at the site.**
- **<u>Prior to construction of final design</u>, UGI LNG should file drawings and specifications for vehicle barriers at each facility entrance for access control.**
- **<u>Prior to construction of final design</u>, UGI LNG should file complete plan drawings of the security fencing and facility access and egress.**
- **<u>Prior to construction of final design</u>, UGI LNG should file security camera drawings showing the location, areas covered, and features of the camera (fixed, tilt/pan/zoom, motion detection alerts, low light, mounting height, etc.) to verify camera coverage of the entire perimeter with redundancies and cameras interior to the facility that would enable rapid monitoring of the LNG plant.**
- **<u>Prior to construction of final design</u>, UGI LNG should file an updated fire protection evaluation of the proposed facilities. A copy of the evaluation, a list of recommendations and supporting justifications, actions taken on the recommendations should be filed.**
- **<u>Prior to construction of final design</u>, UGI LNG should file spill containment system drawings with dimensions and slopes of curbing, trenches, impoundments, and capacity calculations considering any foundations and equipment within impoundments.**
- **<u>Prior to construction of final design</u>, UGI LNG should provide protection measures to reduce the effective radiant heat load on the existing LNG storage tank to below 4,000 Btu/ft^2-hr due to a fire event in the proposed impoundment. A combination of passive and active protection should be**

provided and demonstrate the effectiveness and reliability. Passive mitigation should be supported by calculations for the thickness limiting temperature rise and active mitigation should be justified with calculations demonstrating flow rates and durations of any cooling water would mitigate the heat absorbed by the vessel.

- **<u>Prior to construction of final design</u>, UGI LNG should file a drawing showing the location of the emergency shutdown buttons. Emergency shutdown buttons should be easily accessible, conspicuously labeled, and located in an area which would be accessible during an emergency.**

- **<u>Prior to construction of final design</u>, UGI LNG should file complete drawings and a list of the hazard detection equipment. The drawings should clearly show the location and elevation of all detection equipment. The list should include the instrument tag number, type and location, manufacturer and model, alarm indication locations, and shutdown functions of the hazard detection equipment.**

- **<u>Prior to construction of final design</u>, UGI LNG should file a technical review of its proposed facility design that:**

  a. identifies all combustion/ventilation air intake for equipment and buildings and the distances to any possible hazardous fluid release (LNG, flammable refrigerants, flammable liquids and flammable gases); and

  b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices would isolate or shut down any combustion or ventilation equipment whose continued operation could add to or sustain an emergency.

- **<u>Prior to construction of final design</u>, UGI LNG should file complete plan drawings and a list of the fixed and portable dry-chemical, and other hazard control equipment. Plan drawings should clearly show the location by tag number of all fixed and portable extinguishers. The list should include the equipment tag number, type, capacity, manufacturer and model, equipment covered, discharge rate, and automatic and manual remote signals initiating discharge of the units.**

- **<u>Prior to construction of final design</u>, UGI LNG should file the final design details of the pipe shrouding and release impingements that demonstrates how their design accounts the mechanical forces from a release at maximum pressures and thermal stresses and shock from sudden cryogenic temperatures of a LNG release. In addition, the final design should consider the installation of the pipe shrouding and impingements to ensure that operation and maintenance of equipment and valves is not impacted.**

- **<u>Prior to construction of final design</u>, UGI LNG should file the final design details verifying that the 3-inch vapor/liquid return piping would be fitted with a means to prevent horizontal releases from extending outside of the pump skid spill containment.**

- **<u>Prior to construction of final design</u>, UGI LNG should file an evaluation of the voting logic and voting degradation for hazard detectors.**
- **<u>Prior to commissioning</u>, UGI LNG should file detailed plans and procedures for: testing the integrity of onsite mechanical installation; functional tests; introduction of hazardous fluids; operational tests; and placing the equipment into service.**
- **<u>Prior to commissioning</u>, UGI LNG should file the procedures for pressure/leak tests which address the requirements of American Society of Mechanical Engineers (ASME) VIII and ASME B31.3. The procedures should identify the pneumatic and hydrostatic test pressures for each line.**
- **<u>Prior to commissioning</u>, UGI LNG should file a plan for clean-out, dry-out, purging, and tightness testing. This plan should address the requirements of the American Gas Association's Purging Principles and Practice and should provide justification if not using an inert or non-flammable gas for clean-out, dry-out, purging, and tightness testing.**
- **<u>Prior to commissioning</u>, UGI LNG should tag all equipment, instrumentation, and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves.**
- **<u>Prior to commissioning</u>, UGI LNG should file updated operation and maintenance procedures and manuals, as well as safety procedures to include the Project facilities.**
- **<u>Prior to commissioning</u>, UGI LNG should file an updated emergency procedures to include the Project facilities as well as instructions to handle onsite emergencies related to the hazardous project fluids.**
- **<u>Prior to introduction of hazardous fluids</u>, UGI LNG should file snow removal procedures, file snow volume allowances in the impounding systems, or otherwise demonstrate snow would not inhibit or reduce flow and capacity of the impoundment systems.**
- **<u>Prior to introduction of hazardous fluids</u>, UGI LNG should complete and document all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the Distributed Control System and the Safety Instrumented System that demonstrates full functionality and operability of the system.**
- **<u>Prior to introduction of hazardous fluids</u>, UGI LNG should develop an alarm management program to reduce alarm complacency and maximize the effectiveness of operator response to alarms.**
- **<u>Prior to introduction of hazardous fluids</u>, UGI LNG should conduct and document firewater pump performance test of existing firewater pump and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant should be shown on facility plot plan(s) that would be used for new project facilities.**

- **<u>Prior to introduction of hazardous fluids</u>, UGI LNG should complete and document a pre-startup safety review to ensure that installed equipment meets the design and operating intent of the facility. The pre-startup safety review should include any changes since the last hazard review, operating procedures, and operator training. A copy of the review with a list of recommendations, and actions taken on each recommendation, should be filed.**
- **<u>Prior to commencement of service</u>, UGI LNG should label piping with fluid service and direction of flow in the field, in addition to the pipe labeling requirements of NFPA 59A (2001).**
- **<u>Prior to commencement of service</u>, UGI LNG should notify the FERC staff of any proposed revisions to the security plan and physical security of the plant.**

In addition, we recommend that the following measures should apply <u>throughout the life</u> of the Project facilities:

- **The facilities should be subject to regular FERC staff technical reviews and site inspections on at least a <u>biennial</u> basis or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, UGI LNG should respond to a specific data request, including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed P&IDs reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted semi-annual report, should be submitted.**
- **UGI LNG should report any design modifications and operating problems for the Project facilities in the <u>semi-annual</u> operational reports filed with the Secretary for the facility.**
- **<u>Semi-annual</u> operational reports should be filed with the Secretary to identify changes in facility design and operating conditions; abnormal operating experiences; activities (including truck arrivals, liquefied and vaporized quantities, boil off/flash gas); and plant modifications, including future plans and progress thereof. Abnormalities should include, but not be limited to: unloading/loading problems, potential hazardous conditions from offsite vessels, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank, and higher than predicted boil off rates. Adverse weather conditions and the effect on the facility also should be reported. Reports should be submitted <u>within 45 days after each period ending June 30</u>**

and December 31. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" should be included in the semi-annual operational reports. Such information would provide the FERC staff with early notice of anticipated future construction/maintenance projects at the LNG facilities.

- **The plant's incident reporting requirements should be updated to the following: significant non-scheduled events, including safety-related incidents (e.g., LNG, heavier hydrocarbons, refrigerant, or natural gas releases, fires, explosions, mechanical failures, unusual over pressurization, and major injuries) and security-related incidents (e.g., attempts to enter site, suspicious activities) should be reported to FERC staff. In the event an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification should be made immediately, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification should be made to FERC staff within 24 hours. This notification practice should be incorporated into the LNG facility's emergency plan. Examples of reportable hazardous fluids related incidents include:**

  a. fire;

  b. explosion;

  c. estimated property damage of $50,000 or more;

  d. death or personal injury necessitating in-patient hospitalization;

  e. release of hazardous fluids for five minutes or more;

  f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

  g. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

  h. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes hazardous fluids to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices;

  i. a leak in an LNG facility that contains or processes hazardous fluids that constitutes an emergency;

  j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility that contains or processes hazardous fluids;

l. safety-related incidents to hazardous fluids transportation occurring at or en route to and from the LNG facility; or

m. an event that is significant in the judgment of the operator and/or management even though it did not meet the above criteria or the guidelines set forth in an LNG facility's incident management plan.

- **In the event of an incident, the Director of OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property or the environment, including authority to direct the LNG facility to cease operations. Following the initial company notification, FERC staff would determine the need for a separate follow-up report or follow up in the upcoming semi-annual operational report. All company follow-up reports should include investigation results and recommendations to minimize a reoccurrence of the incident.**

9.0 CUMULATIVE IMPACTS

In accordance with NEPA and with FERC policy, we evaluated the potential for cumulative effects of the Project. Cumulative impacts represent the incremental effects of a proposed action when added to other past, present, or reasonably foreseeable future actions, regardless of the agency or party undertaking such other actions. Cumulative impacts can result from individually minor, but collectively significant actions, taking place over time.

This cumulative effects analysis generally follows a method set forth in relevant Council on Environmental Quality and EPA guidance and focuses on potential impacts from the proposed Project on resource areas or issues where the incremental contribution would be potentially significant when added to the potential impacts of other actions. To avoid unnecessary discussions of insignificant impacts and projects, and to adequately address and accomplish the purposes of this analysis, an action must first meet the following three criteria to be included in the cumulative analysis:

- affect a resource potentially affected by the Project;
- cause this impact within all, or part of, the Project area; and
- cause this impact within all, or part of, the time span for the potential impact from the Project.

Our cumulative impacts analysis considers actions that impact environmental resources affected by the proposed action, within all or part of the Project area affected by the proposed action (i.e., geographic scope), and within all or part of the time span of the impacts.

The EA analyzed the Project's impacts on geology and soils; groundwater; vegetation and wildlife; cultural resources; land use and visual resources; and air quality and noise. We determined there would be no impacts on cultural resources; therefore, this resource is not

discussed further in this cumulative impact analysis. Similarly, we determined that Project impacts on soils, geology, groundwater, vegetation and wildlife, general land use, air quality, and noise would not be sufficient to cause cumulative impacts. Therefore, the potential for the proposed Project to result in cumulative impacts is limited to traffic. In our cumulative impact analysis, we considered impacts on traffic using a geographic scope of Muhlenberg and Ontelaunee Townships, Pennsylvania.

An evaluation was performed to identify past, present, and reasonably foreseeable future projects within the resource-specific geographic scope. In this analysis, we consider the impacts of past projects as part of the affected environment (environmental baseline) which was described and evaluated in the preceding analysis. However, present effects of past actions that are relevant and useful are also considered. We identified one project within the geographic scope for the Project, a proposed warehouse/trucking development project approximately 0.3 mile southeast of the Project in Muhlenberg Township (Ontelaunee Township, 2018).[34]

Project-related impacts on traffic during construction would be minor and mostly short-term during construction activities (12-14 weeks). Cumulative impacts on traffic may occur as construction of the warehouse/trucking development project may take place at the same time as construction of the Project. The Project would contribute a negligible amount, approximately 140 trips per day by workers during peak construction and a minimal amount of construction vehicle traffic, to these overall short-term cumulative impacts.

Project-related impacts on traffic during operations would be negligible as only three more trips to the site per day (for most of the year) would be added, representing a 1 percent increase in traffic. Should the warehouse/trucking facility (0.3 mile southeast of the Project) be built, it would add approximately 1,140 additional trips daily during operations (ITE, 2010). Therefore, the Project would contribute negligibly to overall cumulative impacts on traffic during operations.

[34] No new facilities were identified within Ontelaunee Township.

SECTION C - ALTERNATIVES

In accordance with NEPA and Commission policy, we evaluated several alternatives to the Project to determine whether they would be reasonable and environmentally preferable to the proposed action. These alternatives included the no action alternative, system alternatives, and site alternatives. Our evaluation criteria for developing and reviewing alternatives were:

- ability to meet the Project's stated objective;
- technical and economic feasibility and practicality; and
- significant environmental advantage over the proposed action.

Through environmental comparison and application of our professional judgment, each alternative is considered to a point where it becomes clear if the alternative could or could not meet the three evaluation criteria. The alternatives were reviewed against the evaluation criteria in the sequence presented above. The first consideration for including an alternative in our analysis is whether it could satisfy the stated purpose of the Project. An alternative that cannot achieve the purpose of the Project cannot be considered as an acceptable replacement for the Project. The second evaluation criteria is feasibility and practicality. Many alternatives are technically and economically feasible. Technically practical alternatives, with exceptions, would generally require the use of common construction methods. An alternative that would require the use of a new, unique, or experimental construction method may not be technically practical because the required technology is not available or is unproven. Economically practical alternatives would result in an action that generally maintains the price competitive nature of the proposed action. Generally we do not consider the cost of an alternative as a critical factor unless the added cost to design, permit, and construct the alternative would render the project economically impractical.

Alternatives that would not meet the Project's objective or were not feasible were not brought forward to the next level of review (i.e., significant environmental advantage over the proposed Project). Determining if an alternative provides a significant environmental advantage requires a comparison of the impacts on each resource as well as an analysis of impacts on resources that are not common to the alternatives being considered. The determination must then balance the overall impacts with all other relevant considerations. In comparing the impact between resources, we also considered the degree of impact anticipated on each resource. Ultimately, an alternative that results in equal or minor advantages in terms of environmental impact would not compel us to shift the impacts to another location, potentially affecting a new set of landowners.

1.0 NO ACTION ALTERNATIVE

Under the No Action Alternative, UGI LNG would not construct and operate the Project; therefore, the potential environmental impacts associated with the Project would be avoided. In this situation, however, the Project objectives would not be met. UGI LNG would not be able to transport additional natural gas for its customers, nor would increasing demand in the region be satisfied. In that case, UGI LNG or another company may need to construct and operate a separate facility. That would be redundant for UGI LNG and it is likely that the cost of

constructing and operating another peak shaving facility would not be economically viable. In addition, regardless of who built the new facility, the environmental impacts would likely be greater than this proposed action. Based on the minimal impact of the Project, and the potential benefits to the region, we have dismissed this alternative as a reasonable alternative to meet the Project objectives.

2.0 SYSTEM ALTERNATIVES

System alternatives would use other existing, modified, or proposed facilities to meet the objectives of the proposed Project. A system alternative would make it unnecessary to construct all or part of the Project, although modifications or expansion of existing or proposed pipeline systems may be required. The purpose of identifying and evaluating system alternatives is to determine whether the environmental impacts associated with construction and operation of the Project could be avoided or reduced by using another pipeline system, while still meeting the objectives of the Project.

Although other existing natural gas pipeline systems are in the region, we are not aware of any system alternatives that would meet the objectives of the proposed Project. In order to meet the purpose and need of the Project, the other pipeline companies would need to build new pipeline facilities in addition to adding compression and/or looping to their existing systems to connect to the proposed receipt and delivery points and to deliver the additional capacity. Construction of these facilities would likely result in impacts similar to or greater than the proposed Project and would therefore not provide a significant environmental advantage. For these reasons, we have eliminated these pipeline system alternatives from further consideration. Additionally, these significant modifications would not meet the schedule of the proposed Project or UGI LNG's contractual commitments.

3.0 SITING ALTERNATIVES

The location of the Project was selected by UGI LNG because it would be within the Temple Facility. This facility has existing liquefaction and storage facilities. We did not identify another site that would be environmentally preferable to the location of the Project, or meet the Project objectives. Additionally, no specific concerns were raised during scoping and the Project site lacks sensitive resources. Therefore, because our alternatives analysis are resource and comment driven, we did not evaluate site alternatives further.

4.0 CONCLUSION ON ALTERNATIVES

In conclusion, our review identified no alternatives that satisfied our evaluation criteria. Further, we received no requested alternatives from stakeholders. Therefore, we conclude that the proposed action is the preferred alternative that can meet the Project objectives.

SECTION D - RECOMMENDATIONS

Based on the analysis in this EA, we conclude that if UGI LNG constructs and operates the proposed facilities in accordance with its application and supplements, and our recommended mitigation measures below, approval of the Project would not constitute a major federal action significantly affecting the quality of the human environment. We recommend that the Commission Order contain a finding of no significant impact and include the mitigation measures listed below as conditions of any Authorization the Commission may issue.

1. UGI LNG shall follow the construction procedures and mitigation measures described in its application and supplements, including responses to staff data requests, and as identified in the EA, unless modified by the Order. UGI LNG must:

    a. request any modification to these procedures, measures, or conditions in a filing with the Secretary of the Commission (Secretary);

    b. justify each modification relative to site-specific conditions;

    c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and

    d. receive approval in writing from the Director of the Office of Energy Projects (OEP) **before using that modification**.

2. The Director of OEP, or the Director's designee, has delegated authority to address any requests for approvals or authorizations necessary to carry out the conditions of the Order, and take whatever steps are necessary to ensure the protection of environmental resources during construction and operation of the Project. This authority shall allow:

    a. the modification of conditions of the Order;

    b. stop-work authority and authority to cease operation; and

    c. the imposition of any additional measures deemed necessary to ensure continued compliance with the intent of the conditions of the Order as well as the avoidance or mitigation of unforeseen adverse environmental impact resulting from Project construction and operation.

3. **Prior to any construction**, UGI LNG shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel, environmental inspectors (EIs), and contractor personnel will be informed of the EI's authority and have been or will be trained on the implementation of the environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

4. The authorized facility locations shall be as shown in the EA, as supplemented by filed Project figures. **As soon as they are available, and before the start of construction**, UGI LNG shall file with the Secretary any revised detailed survey maps/figures for the facility approved by the Order. All requests for modifications of environmental conditions of the Order or site-specific clearances must be written and must reference locations designated on these Project figures.

5. UGI LNG shall file with the Secretary detailed maps/figures and aerial photographs at a scale not smaller than 1:6,000 identifying all facility relocations, and staging areas, pipe storage yards, new access roads, and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the figures. Each area must be approved in writing by the Director of OEP **before construction in or near that area.**

   This requirement does not apply to extra workspace allowed by the Commission's Plan and/or minor field realignments per landowner needs and requirements which do not affect other landowners or sensitive environmental areas such as wetlands.

   Examples of alterations requiring approval include all facility location changes resulting from:

   a. implementation of cultural resources mitigation measures;

   b. implementation of endangered, threatened, or special concern species mitigation measures;

   c. recommendations by state regulatory authorities; and

   d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

6. **Within 60 days of the acceptance of the authorization and before construction** begins, UGI LNG shall file an Implementation Plan with the Secretary for review and written approval by the Director of OEP. UGI LNG must file revisions to the plan as schedules change. The plan shall identify:

   a. how UGI LNG will implement the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests), identified in the EA, and required by the Order;

   b. how UGI LNG will incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and construction drawings so that the mitigation required at each site is clear to onsite construction and inspection personnel;

   c. the number of EIs assigned, and how the company will ensure that sufficient personnel are available to implement the environmental mitigation;

   d. company personnel, including EIs and contractors, who will receive copies of the appropriate material;

   e. the location and dates of the environmental compliance training and instructions UGI LNG will give to all personnel involved with construction and restoration (initial and refresher training as the Project progresses and personnel change),

   f. the company personnel (if known) and specific portion of UGI LNG's

organization having responsibility for compliance;

g. the procedures (including use of contract penalties) UGI LNG will follow if noncompliance occurs; and

h. for each discrete facility, a Gantt or PERT chart (or similar Project scheduling diagram), and dates for:

(1) the completion of all required surveys and reports;

(2) the environmental compliance training of onsite personnel;

(3) the start of construction; and

(4) the start and completion of restoration.

7. UGI LNG shall employ at least one EI during construction of the Project. The EI shall be:

a. responsible for monitoring and ensuring compliance with all mitigation measures required by the Order and other grants, permits, certificates, or other authorizing documents;

b. responsible for evaluating the construction contractor's implementation of the environmental mitigation measures required in the contract and any other authorizing document;

c. empowered to order correction of acts that violate the environmental conditions of the Order, and any other authorizing document;

d. responsible for documenting compliance with the environmental conditions of the Order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and

e. responsible for maintaining status reports.

8. Beginning with the filing of its Implementation Plan, UGI LNG shall file updated status reports with the Secretary on a **monthly** basis until all construction and restoration activities are complete. Problems of a significant magnitude shall be reported to the FERC **within 24 hours**. On request, these status reports will also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

a. an update on UGI LNG's efforts to obtain the necessary federal authorizations;

b. Project schedule, including current construction status of the Project and work planned for the following reporting period;

c. a listing of all problems encountered, contractor nonconformance/deficiency logs, and each instance of noncompliance observed by the EI during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);

d. a description of the corrective and remedial actions implemented in response to all instances of noncompliance, nonconformance, or deficiency;

e. the effectiveness of all corrective and remedial actions implemented;

f. a description of any landowner/resident complaints which may relate to compliance with the requirements of the order, and the measures taken to satisfy their concerns; and

g. copies of any correspondence received by UGI LNG from other federal, state, or local permitting agencies concerning instances of noncompliance, and UGI LNG's response.

9. UGI LNG shall employ a special inspector (professional geologist and/or geotechnical engineer) during construction, and a copy of the special inspector's reports shall be included in the **monthly** status reports filed with the Secretary (see condition 8 above). The special inspector shall be responsible for:

   a. observing the construction of the Project facilities to be certain it conforms to the design drawings and specifications;

   b. furnishing inspection reports to the engineer- or architect-of-record and other designated persons. All discrepancies shall be brought to the immediate attention of the contractor for correction, and then if uncorrected, to the engineer- or architect-of-record; and

   c. submitting a final signed report stating whether the work requiring special inspection was, to the best of his/her knowledge, in conformance with the approved plans and specifications and the applicable workmanship provisions.

10. UGI LNG must receive written authorization from the Director of OEP **before commencing construction of any Project facilities**. To obtain such authorization, UGI LNG must file with the Secretary documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof).

11. UGI LNG must receive written authorization from the Director of OEP **prior to introducing hazardous fluids into the Project facilities**. Instrumentation and controls, hazard detection, hazard control, and security components/systems necessary for the safe introduction of such fluids shall be installed and functional.

12. UGI LNG must receive written authorization from the Director of OEP **before placing into service** the components of the Project. Such authorization will only be granted following a determination that the facilities have been constructed in accordance with FERC approval, can be expected to operate safely as designed, and the rehabilitation and restoration of the right-of-way and other areas affected by the Project are proceeding satisfactorily.

13. **Within 30 days of placing the authorized facilities in service**, UGI LNG shall file an affirmative statement with the Secretary, certified by a senior company official:

   a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; or

   b. identifying which of the conditions in the Order UGI LNG has complied with or will comply with. This statement shall also identify any areas affected by the Project where compliance measures were not properly implemented, if not

previously identified in filed status reports, and the reason for noncompliance.

14. **Prior to construction of final design**, UGI LNG shall file with the Secretary the following information, stamped and sealed by the professional engineer-of-record, registered in Pennsylvania:

    a. evaluation of whether potential corrosivity of soil exists that could exacerbate solubility of underlying carbonate rocks or corrode underground piping and utilities using recognized test methods, such as ASTM G51, (2012), *Standard Test Method for Measuring pH of Soil for Use in Corrosion Testing*;

    b. evaluation of type of underlying rock, extent of jointing, and voids to determine potential of sinkhole formation based on location, inclination, thickness, and face length of jointing and location and size of voids underneath the project facilities using recognized methods, such as rock coring, seismic reflection, and ground penetration radar, and include resultant data;

    c. evaluation of underlying soils to determine Site Class in accordance with ASCE 7-05, *Minimum Design Loads for Buildings and Other Structures*, that is used as basis of design for ground motions and associated Seismic Design Category;

    d. development of a monitoring, detection, response and mitigation plan for sinkhole formation during construction and operation within the footprint of all foundations and driveway using recognized methods, such as periodic photogrammetry and periodic ground penetration radar, and include criteria for response and mitigation;

    e. quality assurance and control procedures to be used for civil/structural design and construction;

    f. site preparation drawings and specifications;

    g. seismic specifications for procured equipment; and

    h. liquefied natural gas (LNG) project structures and foundation design drawings and calculations (including prefabricated and field constructed structures).

Information pertaining to these specific recommendations shall be filed with the Secretary, for review and written approval by the Director of OEP, or the Director's designee, within the timeframe indicated by each recommendation. UNG LNG shall submit specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 833 (Docket No. RM16-15-000), including security information, as critical energy infrastructure information pursuant to Title 18 of the Code of Federal Regulations, Part 388.113 (18 CFR 388.113). See *Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information*, Order No. 833, 81 Fed. Reg. 93,732 (December 21, 2016), FERC Stats. & Regs. 31,389 (2016), *reh'g pending*. Information pertaining to items such as offsite emergency response, procedures for public notification and evacuation, and construction and operating reporting requirements will be subject to public disclosure. All information shall be filed **a minimum of 30 days** before approval to proceed is requested.

15. **Prior to initial site preparation**, UGI LNG shall file an overall project schedule, which includes the proposed stages of the commissioning plan.

16. **Prior to initial site preparation**, UGI LNG shall provide quality assurance and quality control procedures for construction activities.

17. **Prior to initial site preparation**, UGI LNG shall file procedures for controlling access during construction.

18. **Prior to construction of final design**, UGI LNG shall file change logs that list and explain any changes made from the front end engineering design provided in UGI LNG's application and filings. A list of all changes with an explanation for the design alteration shall be provided and all changes shall be clearly indicated on all diagrams and drawings.

19. **Prior to construction of final design**, UGI LNG shall provide an up-to-date equipment list, process and mechanical data sheets, and specifications.

20. **Prior to construction of final design**, UGI LNG shall file up-to-date Piping and Flow Diagrams and Piping and Instrument Diagrams (P&IDs). The Piping and Flow Diagrams shall include heat and material balances. The P&IDs shall include the following information:

    a. equipment tag number, name, size, duty, capacity, and design conditions;

    b. equipment insulation type and thickness;

    c. valve high pressure side and internal and external vent locations;

    d. piping with line number, piping class specification, size, and insulation type and thickness;

    e. piping specification breaks and insulation limits;

    f. all control and manual valves numbered;

    g. relief valves with size and set points; and

    h. drawing revision number and date.

21. **Prior to construction of final design**, UGI LNG shall file P&IDs, specifications, and procedures that clearly show and specify the tie-in details required to safely connect the Project to the existing LNG facility.

22. **Prior to construction of final design**, UGI LNG shall file a car seal philosophy and a list of all car-sealed and locked valves consistent with the P&IDs.

23. **Prior to construction of final design**, UGI LNG shall file a hazard and operability review of the completed design prior to issuing the P&IDs for construction. UGI LNG's review shall include a list of the recommendations and actions taken on the recommendations.

24. **Prior to construction of final design**, UGI LNG shall file the safe operating limits (upper and lower), alarm and shutdown set points for all instrumentation (i.e., temperature, pressures, flows, and compositions).

25. **Prior to construction of final design**, UGI LNG shall file a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems.

26. **Prior to construction of final design**, UGI LNG shall file cause-and-effect matrices for the process instrumentation, fire and gas detection system, and emergency shutdown

system The cause-and-effect matrices shall include alarms and shutdown functions, details of the voting and shutdown logic, and set points.

27. **Prior to construction of final design**, UGI LNG shall file a Safety Integrity Level verification study validating the pump cavitation and high flow shutdowns as Safety Integrity Level 2 or higher rated systems.

28. **Prior to construction of final design**, UGI LNG shall specify that all emergency shutdown valves are to be equipped with open and closed position switches connected to the Distributed Control System /Safety Instrumented System.

29. **Prior to construction of final design**, UGI LNG shall demonstrate that, for hazardous fluids, piping and piping nipples 2 inches or less in diameter are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators.

30. **Prior to construction of final design**, UGI LNG shall specify that piping specifications for stainless steel piping capable of operating at cryogenic temperatures shall require the inner and outer ring of spiral wound gaskets to be stainless steel.

31. **Prior to construction of final design**, UGI LNG shall specify all drains from high pressure hazardous fluid systems are to be equipped with double isolation and bleed valves.

32. **Prior to construction of final design**, UGI LNG shall file the sizing basis and capacity for the final design of the pressure relief valves for major process equipment and vessels.

33. **Prior to construction of final design**, UGI LNG shall file final electrical area classification drawings.

34. **Prior to construction of final design**, UGI LNG shall file drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A (2001).

35. **Prior to construction of final design**, UGI LNG shall file details of an air gap or vent installed downstream of process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap shall vent to a safe location and be equipped with a leak detection device that shall continuously monitor for the presence of a flammable fluid, alarm the hazardous condition, and shut down the appropriate systems.

36. **Prior to construction of final design**, UGI LNG shall file drawings and specifications for vehicle barriers at each facility entrance for access control.

37. **Prior to construction of final design**, UGI LNG should file complete plan drawings of the security fencing and facility access and egress.

38. **Prior to construction of final design**, UGI LNG shall file security camera, intrusion detection, and lighting drawings. The camera drawings should show the location, areas covered, and features of the camera (fixed, tilt/pan/zoom, motion detection alerts, low light, mounting height, etc.) to verify camera coverage of the entire perimeter with redundancies and cameras interior to the facility that will enable rapid monitoring of the LNG plant. The intrusion detection drawings shall show or note the location of the

intrusion detection to verify it covers the entire perimeter of the LNG plant. The lighting drawings shall show the location, elevation, type of light fixture, and lux levels of the lighting system.

39. **Prior to construction of final design**, UGI LNG shall file an updated fire protection evaluation of the proposed facilities. UGI LNG's filing shall include a copy of the evaluation, a list of recommendations and supporting justifications, and actions taken on the recommendations.

40. **Prior to construction of final design**, UGI LNG shall file spill containment system drawings with dimensions and slopes of curbing, trenches, impoundments, and capacity.

41. **Prior to construction of final design**, UGI LNG shall provide protection measures to reduce the effective radiant heat load on the existing LNG storage tank to below 4,000 British thermal unit per square foot per hour due to a fire event in the proposed impoundment. Passive mitigation shall be supported by calculations for the thickness limiting temperature rise and active mitigation shall be justified with calculations demonstrating flow rates and durations of any cooling water will mitigate the heat absorbed by the vessel.

42. **Prior to construction of final design**, UGI LNG shall file a drawing showing the location of the emergency shutdown buttons. Emergency shutdown buttons shall be easily accessible, conspicuously labeled, and located in an area which will be accessible during an emergency.

43. **Prior to construction of final design**, UGI LNG shall file complete drawings and a list of the hazard detection equipment. The drawings shall clearly show the location and elevation of all detection equipment. The list shall include the instrument tag number, type and location, manufacturer and model, alarm indication locations, and shutdown functions of the hazard detection equipment.

44. **Prior to construction of final design**, UGI LNG shall file a technical review of its proposed facility design that:

    a. identifies all combustion/ventilation air intake for equipment and buildings and the distances to any possible hazardous fluid release (LNG, flammable refrigerants, flammable liquids and flammable gases); and

    b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices will isolate or shut down any combustion or ventilation equipment whose continued operation could add to or sustain an emergency.

45. **Prior to construction of final design**, UGI LNG shall file complete plan drawings and a list of the fixed and portable dry-chemical, and other hazard control equipment. Plan drawings shall clearly show the location by tag number of all fixed and portable extinguishers. The list shall include the equipment tag number, type, capacity, manufacturer and model, equipment covered, discharge rate, and automatic and manual remote signals initiating discharge of the units.

46. **Prior to construction of final design**, UGI LNG shall file the final design details of the pipe shrouding and release impingements that demonstrates how their design accounts

the mechanical forces from a release at maximum pressures and thermal stresses and shock from sudden cryogenic temperatures of a LNG release. In addition, the final design shall consider the installation of the pipe shrouding and impingements to ensure that operation and maintenance of equipment and valves is not impacted.

47. **Prior to construction of final design**, UGI LNG shall file the final design details verifying that the 3-inch vapor/liquid return piping will be fitted with a means to prevent horizontal releases from extending outside of the pump skid spill containment.

48. **Prior to construction of final design**, UGI LNG shall file an evaluation of the voting logic and voting degradation for hazard detectors.

49. **Prior to commissioning**, UGI LNG shall file detailed plans and procedures for: testing the integrity of onsite mechanical installation; functional tests; introduction of hazardous fluids; operational tests; and placing the equipment into service.

50. **Prior to commissioning**, UGI LNG shall file the procedures for pressure/leak tests which address the requirements of American Society of Mechanical Engineers (ASME) VIII and ASME B31.3. The procedures shall identify the pneumatic and hydrostatic test pressures for each line.

51. **Prior to commissioning**, UGI LNG shall file a plan for clean-out, dry-out, purging, and tightness testing. This plan shall address the requirements of the American Gas Association's Purging Principles and Practice and should provide justification if not using an inert or non-flammable gas for clean-out, dry-out, purging, and tightness testing.

52. **Prior to commissioning**, UGI LNG shall tag all equipment, instrumentation, and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves.

53. **Prior to commissioning**, UGI LNG shall file updated operation and maintenance procedures and manuals, as well as safety procedures to include the Project facilities.

54. **Prior to commissioning**, UGI LNG shall file an updated emergency procedures to include the Project facilities as well as instructions to handle onsite emergencies related to the hazardous project fluids.

55. **Prior to introduction of hazardous fluids**, UGI LNG shall file snow removal procedures, file snow volume allowances in the impounding systems, or otherwise demonstrate snow will not inhibit or reduce flow and capacity of the impoundment systems.

56. **Prior to introduction of hazardous fluids**, UGI LNG shall complete and document all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the Distributed Control System and the Safety Instrumented System that demonstrates full functionality and operability of the system.

57. **Prior to introduction of hazardous fluids**, UGI LNG shall develop an alarm management program to reduce alarm complacency and maximize the effectiveness of operator response to alarms.

58. **Prior to introduction of hazardous fluids**, UGI LNG shall conduct and document firewater pump performance test of existing firewater pump and firewater monitor and

hydrant coverage test. The actual coverage area from each monitor and hydrant shall be shown on facility plot plan(s) that will be used for new project facilities.

59. **Prior to introduction of hazardous fluids**, UGI LNG shall complete and document a pre-startup safety review to ensure that installed equipment meets the design and operating intent of the facility. The pre-startup safety review shall include any changes since the last hazard review, operating procedures, and operator training. A copy of the review with a list of recommendations, and actions taken on each recommendation, shall be filed.

60. **Prior to commencement of service**, UGI LNG shall label piping with fluid service and direction of flow in the field, in addition to the pipe labeling requirements of NFPA 59A (2001).

61. **Prior to commencement of service**, UGI LNG shall notify the FERC staff of any proposed revisions to the security plan and physical security of the plant.

62. **Prior to commencement of service**, UGI LNG shall file progress on construction of the Project in monthly reports. Details shall include a summary of activities, problems encountered, contractor non-conformance/ deficiency logs, remedial actions taken, and current project schedule. Problems of significant magnitude shall be reported to the FERC within 24 hours.

In addition, we recommend that the following measures shall apply **throughout the life of the Project** facilities:

63. The facilities shall be subject to regular FERC staff technical reviews and site inspections on at least a **biennial** basis or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, UGI LNG shall respond to a specific data request, including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed P&IDs reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted semi-annual report, shall be submitted.

64. UGI LNG shall report any design modifications and operating problems for the Project facilities in the **semi-annual** operational reports filed with the Secretary for the facility.

65. **Semi-annual** operational reports shall be filed with the Secretary to identify changes in facility design and operating conditions; abnormal operating experiences; activities (including truck arrivals, liquefied and vaporized quantities, boil off/flash gas); and plant modifications, including future plans and progress thereof. Abnormalities shall include, but not be limited to: unloading/loading problems, potential hazardous conditions from offsite vessels, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank, and higher than predicted boil off rates. Adverse weather conditions and the effect on the facility also shall be reported. Reports shall be submitted

within 45 days after each period ending June 30 and December 31. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" shall be included in the semi-annual operational reports. Such information will provide the FERC staff with early notice of anticipated future construction/maintenance projects at the LNG facilities.

66. The plant's incident reporting requirements shall be updated to the following: significant non-scheduled events, including safety-related incidents (e.g., LNG, heavier hydrocarbons, refrigerant, or natural gas releases, fires, explosions, mechanical failures, unusual over pressurization, and major injuries) and security-related incidents (e.g., attempts to enter site, suspicious activities) shall be reported to FERC staff. In the event an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification shall be made **immediately**, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification shall be made to FERC staff **within 24 hours**. This notification practice shall be incorporated into the LNG facility's emergency plan. Examples of reportable hazardous fluids related incidents include:

    a. fire;

    b. explosion;

    c. estimated property damage of $50,000 or more;

    d. death or personal injury necessitating in-patient hospitalization;

    e. release of hazardous fluids for five minutes or more;

    f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

    g. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

    h. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes hazardous fluids to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices;

    i. a leak in an LNG facility that contains or processes hazardous fluids that constitutes an emergency;

    j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

    k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility that contains or processes hazardous fluids;

l. safety-related incidents to hazardous fluids transportation occurring at or en route to and from the LNG facility; or

m. an event that is significant in the judgment of the operator and/or management even though it did not meet the above criteria or the guidelines set forth in an LNG facility's incident management plan.

67. In the event of an incident, the Director of OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property or the environment, including authority to direct the LNG facility to cease operations. Following the initial company notification, FERC staff will determine the need for a separate follow-up report or follow up in the upcoming semi-annual operational report. All company follow-up reports shall include investigation results and recommendations to minimize a reoccurrence of the incident.

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SECTION F - REFERENCES

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