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EVALUATION OF LNG FACILITIES FOR AGING

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EVALUATION OF LNG FACILITIES FOR AGING

THE OBJECTIVE: **to assess the aging of the plant so it remains safe and reliable.**

1.0 INTRODUCTION

1.1 Background

Aging is the deterioration associated with the passage of time. Aging is not obsolescence.

Obsolescence is a condition that occurs when equipment becomes inefficient to operate, is no longer supported by the manufacturer, no longer meets code requirements, or is no longer wanted, although it is still in good working order. This can be outside the control of the owner or operator of the facility.

Some causes of obsolescence are:

1. The inability to obtain replacement parts, or the increased cost of parts and repairs which makes replacement more economical.

2. Changes in code requirements which affect the safety of the facility. Analyses would be needed to demonstrate applicability to grand-fathered facilities.

3. Development of a new product or technology which supercedes the technology of the existing equipment making is more efficient to operate.

The purpose of this paper is to review the LNG facility and comment, from the perspective of a consultant and an operator, on the ways in which the aging of the facility takes place.

The issue associated with aging is **how to maintain the safe operation of the LNG facility while it ages**. This concept entails the utilization of the resources of the facility to perform preventive maintenance on those components which impact the continued service of the plant.

This paper is based on the following assumptions:

1. The LNG facility was properly constructed in compliance with all applicable design and construction codes and quality standards, and therefore was acceptable to all governing jurisdictions at the time of its fabrication.

2. All inspections were performed and there are no questions or lingering doubts regarding the quality of vendor supplied components.

3. All maintenance is considered preventive and not cosmetic.

The focus is to review the factors needed to establish if the LNG facility and its components have, at a minimum, remained in their as-designed capabilities and are meeting performance requirements, despite years of aging through operational and stand-by periods.

This is not a comprehensive review of LNG facilities for compliance with their applicable governing code, but rather a presentation of possible mechanisms of aging that could, if not addressed, decrease the life of an operating LNG facility, be it peak shaving, base load, or import terminal.

Coping with aging requires maintaining existing equipment in operational condition while aging. It requires looking for techniques to extend equipment life with a focus on safety and reliability.

The responsibility for protecting the LNG facilities from detrimental effects of aging lies with the:

- Plant operators / Plant maintenance personnel.
- Managers with plant oversight responsibilities.
- Engineers involved with plant design, operations, maintenance, personnel safety, process safety systems, and stand-alone safety systems such as emergency shutdown, gas and flame detection systems.

1.2 Maintenance

A well-balanced maintenance program is the most important activity which can ensure continued safe and reliable operation of LNG facilities of any age. There are 3 styles of maintenance which are typically performed: corrective, preventive, and predictive. A well-balanced maintenance program achieves ratios of approximately 30% corrective to 70% preventive maintenance hours.

1. Corrective Maintenance is a reactive, unplanned, unscheduled maintenance activity typically associated with plant downtime when operating equipment fails to operate as required.

    a. While corrective maintenance cannot be eliminated, it should be minimized. A well-balanced maintenance program minimizes the corrective maintenance work hours to approximately 30% less than the preventive, predictive portion of the maintenance program.

   b. It is typically ineffective as the maintenance organization's schedule is often very disrupted especially when required maintenance / repair parts are not available.

   c. Corrective maintenance on average requires 3 times that of preventive or predictive maintenance due to a lack of effective planning.

2. Preventive Maintenance (PM) is a proactive, planned maintenance at a previously established recurring frequency.

   a. Preventive Maintenance (PM) frequency may be based on code-required activities, manufacturer's recommendations, industry best practices, benchmarking information, and/or operating hours governed by historical equipment observations during maintenance indicating the equipment is at a maximum wear/condition level.

   b. PM allows for improved efficiency of maintenance personnel due to pre-planning.

   c. PM allows required repair parts to be available to maintenance personnel without delay.

   d. PM typically requires 1/3 the hours of the same activity if unplanned.

   e. If the prioritized preventive activities are performed, they should result in reduced equipment downtime.

   f. See the AGA publication titled "LNG Preventive Maintenance Guide" for a list of suggested maintenance activities and frequencies.

3. Predictive Maintenance is a proactive, planned maintenance based on condition monitoring of process and equipment operating parameters.

   a. Condition monitoring can be based on lube oil analysis, vibration analysis, engine/compressor analysis, thermography, pressure, and/or temperature indications, etc.

   b. Predictive maintenance cannot be used to satisfy code-required frequency preventive maintenance.

   c. Predictive maintenance takes the best advantage of resources (personnel, parts, plant availability) as it tracks process and equipment condition to a point just prior to failure without premature replacement of parts as in the case of preventive maintenance.

d. Predictive maintenance must be balanced with the cost of additional analysis tools, training of personnel to utilize the tools, and the time for them to periodically conduct the condition monitoring.

The analysis tool which defines the balance between the various maintenance styles is risk assessment. Risk based inspection focused on locations of highest risk and use inspections appropriate to the age of the component and material of construction to maximize the potential of identifying any degradation. This enables management to identify areas of the facility to be inspected and outlines what to look for, allowing the plant to target its resources to maintain the facility at peak efficiency.

Current practice points to inspection and maintenance planning that is based on tradition and prescriptive rules rather than an integrated set of optimized processes where risk measures and safety are analyzed. A very efficient tool engaging new technology has emerged using risk based decisions in inspection and maintenance integrated with the day to day operations of a plant.

Risk assessment requires the understanding of the operational history of LNG facilities, its components, its operating practices, and its failure histories. By understanding the past, an assessment can be undertaken, within a certain amount of accuracy, to predict the future. This is a manifestation of the statement: “If we ignore the past, we are doomed to repeat it”.

A decision based on risk has to be made with every component. The potential impact a failure of a specific component has on the down time of the facility has to be determined. This information is used as a guide in deciding to repair or replace.

The recent significant expansion of LNG use throughout the world has changed the dynamics of the LNG industry in the US and throughout the world. The peak shaving facilities that were the initial basis of the industry from the 1960s to the 1990s, are being supplemented by the rapid buildup of base load import terminals. To date, there are 4 active import terminals in the continental US which regularly accept LNG shipments: Distrigas’s Everett MA; Southern LNG’s Elba Island, Savannah, GA; Dominion’s Cove Point, MD; and Trunkline’s Lake Charles, LA facilities.

The bulk shipping of LNG has significantly expanded and the base load facilities experience significant usage. LNG transfers take place on a several-times/week basis, which is the direct opposite of the peak shaving facilities, which were designed to fill the LNG tanks over a defined, long time period. With the present weather patterns in some areas of the country, the peak shaving plant could stand idle the entire winter, resulting in completely different aging concerns.

This difference in utilization results in significantly accelerated cycles for base load facilities compared to peak shaving facilities. These operational differences directly affect the remaining life of the facility and have to be taken into account throughout the design phase.

If the basis for the plant changes, i.e., a peak shaving plant becomes upgraded to a base load or a higher through-put facility, the equipment experiences a significant change in demand and most probably has to be replaced.

1.3 Risk

Risk management is the prioritization / allocation of resources needed to maintain the LNG facility's production at its design capacities while maintaining a safe, code compliant operation. A risk assessment can be performed to measure the probability and the consequences of all the potential events that comprise a system failure.

As part of the assessment, risk models can be developed by factoring all the above components as risk indicators. Various factors must be considered. Risk is not constant, conditions are changing with time. When performing a risk evaluation, we are actually taking a snapshot of the risk picture at a moment in time. Changes in variables such as population density, type of product, and stress levels will change the failure probability and the possible consequences.

Risk management (the reaction to perceived risks) can then be applied by assessing the risk levels identified for the facility by the risk assessment and preparing and executing an action plan to address current and future risks .

Risk cannot be made to disappear; risks can be minimized to the extent that no unacceptable risk remains.

1.4 LNG Industry Status

The LNG industry has performed its role in the energy field of the world with an exemplary safety record. This achievement has been reached because of the design codes and industry dedication to safety. The initial design code, NFPA 59A - 1967, followed by, in the US, 49CFR193, in 1980, and the EN 1473 / EN 14620 codes in Europe, and similar standards in other countries have successfully guided the industry.

Although there are fundamental differences in these code documents, the industry, through its design and construction practices and inspection procedures have supported this industry for over 50 years of safe practices throughout the world.

With this global expansion and the introduction of new materials and construction practices, together with the ongoing re-evaluations of acceptable design criteria, the potential LNG facility design and siting changes resulting from this work will have a direct effect on the industry.

The focus of this paper is: how to assess the aging of these plants so the industry remains safe, and therefore, reliable.

1.5 How Do We Review the Past?

An independent review and analysis of the facility to identify the component(s) which could shut down the facility for the longest period time is the first step in prioritizing the aging / remaining life assessment of the facility. This becomes an iterative process, with the results of each component or process review determining which subsequent component has the greatest chance of shutting the facility down in the event of its sudden failure.

This analysis considers a shutdown resulting from a catastrophic failure / fire / component destruction or a shutdown from a high risk component because that component could not be replaced in a timely fashion and failure occurred.

In an evaluation of equipment failure, it is essential to know WHY the failure occurred.

The industry learns from facility experiences through meetings and the sharing of knowledge, experience, and the results of forensics.

A failure could be an isolated occurrence or the beginning of a series of failures. The cause of a failure could be as simple as old age, poor initial construction practices which were not detected at the time of construction, unknown misuse or improper maintenance, inappropriate operation or procedures, or ineffective operator training. The plant conditions have to be understood if the facility is to be *fit-for-service* for future operation.

1.6 Factors Which Affect LNG Facilities in the Energy Industry

LNG plants have been built in a variety of locations: in the desert, on river banks, at the seaside, near metropolitan areas and major interstate highways, and as water-based / off-shore facilities. The corrosive conditions in these environments that are to be considered include air borne salts, humidity, and vehicle emissions (soot). The environmental corrosion protection barrier system used to protect a carbon steel substrate must be maintained and regularly assessed.

The presence of steel, assumed to be a non-stainless grade, regardless of its usage in the facility, i.e., rebar in concrete structures, anchor straps, outer shell of LNG tanks or any other carbon steel component in the LNG facility, mandates that rigorous corrosion protection steps be taken to protect the carbon steel. Since its corrosion product always occupies a greater volume than the metal it consumes, this in-situ expansion of corrosion products is destructive to the steel components / concrete coatings or equipment in an LNG facility, regardless of their location.

Visual inspection is the most effective technique in this case, with rusting the most obvious visual clue that corrosion is taking place. No inspection of conditions can change the outcome, once the corrosion process has started, but the inspection will be proactive to protecting steel components, by allowing the identification of the failure process.

Another issue which follows from the protection of the substrate is the present status of the coating system that is in place; this coating could be paint, concrete, insulation or a thermal radiation protection system. This value can be determined through a comprehensive program of coating thickness measurements and the assessment of the efficacy of the coating as it presently exists. If rust spotting is taking place, the coating system has failed. Blistering of the coating is a precursor to its failure.

The presence of cryogenic spill/splash protection structures can make visual inspection of the surfaces behind these protection structures difficult and inspection procedures must allow for this. Inspection of these substrate surfaces is required and difficult.

2.0 INSPECTION OVERVIEW

2.1 Inspection Goals

The discussions above have presented an overview of risk-based aging assessment. This overview is summarized here:

1. Identify how components age / deteriorate in LNG facilities.

2. Locate these components and assign a risk value to the impact of their unexpected failure, incorporating shut down times, cost of replacement, etc.

3. Utilize the proper NDE tools and instruments to determine the present operational status of the equipment.

4. Take the NDE / Instrumentation data and compare with original design / fabrication / operating conditions.

5. Analyze these results accordingly to accurately determine the remaining life / fitness for service of the equipment, component or system being analyzed.

2.2 Review Plant Data

____Review plant records in order to identify any indications of aging:

1. Determine if the efficiency of the plant has changed.

   Determine if there has been a change in the amount of energy required to liquefy or vaporize an equivalent amount of LNG.

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   Determine what has caused this change – internally or externally fouled heat exchangers, inaccurate instrumentation, pumps/compressors which are not operating at design values, or changes in gas composition which are beyond process design limits.
2. Determine if there have been Increases in plant down time: periods when processes or equipment are unable to operate/function as required.

   Determine the reasons for this down time – lack of preventive maintenance, inappropriate preventive maintenance, inappropriate maintenance frequency, ineffective procedures or operation. Further analysis may also isolate the reason for increased down time to old components, components from one manufacturer, new components, process water side components.

   Determine if there has been an increase in frequency of component failures and identify the components that have failed based on age, location, and manufacturer of the failed component(s).

3. Identify any physical changes in the components in an LNG facility such that their usability is compromised. Examples: instruments becoming obsolete through technology changes, interior components no longer usable because they have suffered aging failures – rubbers, non-metallics, creep failures, etc.

4. Confirm that operating capabilities are being maintained by the control / monitoring / protection and security systems. Has the sensitivity of the systems changed? Have the set points drifted? Have the sensors deteriorated?

5. Determine the necessity of installing new systems because the systems that are in place are no longer replaceable and/or can no longer be serviced. Some equipment or parts have become obsolete.

6. Confirm that the facility is in compliance with current (updated or revised) applicable governing standards.

7. In the case of a grand-fathered facility,

a. Confirm that the existing components are operating safely and efficiently.
b. Make safety-related changes without losing the grand-fathered status.

2.3 Inspection Guidelines

Identify the component(s) which could shut down the facility for the longest time.

Prioritize the inspection/evaluation.

Identify the cause of any failures which have occurred.

3.0 AREAS IN AN LNG FACILITY THAT SHOULD BE MONITORED FOR AGING

Inspect, monitor and maintain the following areas of an LNG plant to ensure the continued operational capabilities of the plant:

1. Equipment for product manufacture, storage, handling and transfers.

   a. The stationary LNG storage container – the tank.
   b. LNG pumps, associated piping and their control systems.
   c. Liquefaction systems – the cold box, expanders/compressors, refrigerant compressors, pre-treatment systems (water/CO_2 removal).

2. Supporting Mechanical Equipment

   a. Piping penetrations.
   b. LNG and refrigerant transfer piping - loading and unloading systems.
   c. Send out systems - vaporizers.

3. Plant control, safety, security and maintenance.

4. Fire protection systems, security systems, and emergency shutdown procedures.

5. Electrical, motor control stations, power systems and,

6. Instrumentation and controls.

7. Manpower and training.

8. Maintenance.

4.0 PIPING

Piping in an LNG plant is primarily stainless steel or carbon steel. There is some aluminum, 9% nickel piping and specialty high alloy materials piping. The concerns are related to expansion, contraction, bending, and fatigue loading. LNG piping systems are subjected to frequent thermal cycles and the associated expansion and contraction cycles.

The corrosion issues are mostly related to the stainless steel piping since this is the cryogenic piping which may or may not be insulated, depending upon its function in the LNG plant.

The corrosion issues associated with stainless steels are pitting corrosion and stress corrosion cracking. Stainless steel is prone to chloride stress corrosion cracking, sensitization-caused corrosion around welds, and pitting corrosion from localized corrosion conditions. **The subtle danger with stainless steels is that the corrosion may not be recognized until the component is leaking.**

Stainless steels, while inherently extremely corrosion resistant, do have failure mechanisms that are not obvious. Pitting corrosion and stress corrosion cracking mechanisms are common deterioration mechanisms associated with the 18-8 austenitic stainless steels. Higher grade alloys have been developed to insure corrosion immunity in specific environments, but the prediction of the service environment at the time of the design is a difficult aspect of plant design.

Carbon steel, on the other hand, corrodes in an obvious fashion. Corrosion under insulation is a prevalent corrosion failure mechanism in any plant where insulated piping is present. The rust that is generated by the carbon steel may be visible and its progress can be readily measured.

The most damaging feature of carbon steel rusting is that the rust occupies significantly more volume than the metal consumed. Therefore, component movement / lifting by the corrosion product or failure of the concrete "cover" on a significant scale is a condition that must be prevented.

Vacuum jacketed piping is an excellent cryogenic piping system which has a rigid external insulation jacket. The failure mode associated with the outer jacket is a direct function of the service environment to which the material is exposed. If the piping is exposed to atmospheric conditions, then the corrosion environment is generally known. If the outer jacket is exposed to a more corrosive environment, it has to be appropriately protected and monitored.

The most common failure mechanism is pitting corrosion, since the stainless steel or other metal outer jacket is exposed to external contamination. Corrosion protection mechanisms for carbon steel surfaces most often are not appropriate or effective on stainless or high alloy materials.

5.0 TANKAGE

5.1 Outer Bottom of Metal Tanks

Inspect the bottom grouting between the outer bottom footer plate and the ring wall for any evidence of leakage or corrosion.

Inspect the tank for the presence of water seepage from under the tank.

Inspect the area around the footer plate / ring wall interface (chine) for bubbling when water is present. Bubbling detected around the footer plate / ring wall interface when water is present is a direct sign that leakage of the outer containment vessel is occurring, if the outer vessel is the pressure containment system.

Monitor for leakage using portable gas equipment. Implement HC sniffing to determine the leak tightness and to determine the extent and possibly the source of the leakage.

Inspect the anchor straps for corrosion at the concrete ring wall / platform interface, typically on an annual basis.

Monitor the amperage and voltage demands of the under-tank heaters. Frequent replacement is a viable monitoring tool. The presence of corrosion inside the conduit should be a point of concern. Consider pressure testing this conduit for leakage

With respect to the tank itself, inspect for frost spots on the outer surfaces, as these would indicate a loss of insulation performance in the annular space. Infrared imaging of the tank would detect this condition.

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5.2 Concrete Tanks and Structures

There are many issues to address in assessing the aging of concrete in an LNG facility: the concrete ring wall can deteriorate, footer plate corrosion issues, the foundation or pile cap may shift through motion or cracking.

The issues with concrete are related to the durability of the concrete, the presence of surface cracking, and the possible improper placement of the reinforcing bars in the concrete; insufficient cover is usually the primary problem, resulting in the inability to protect the steel from water and chloride contact, which will cause the steel rebar to corrode.

On-site testing must be performed during the pouring of the concrete to insure that the correct properties are obtained from the finished concrete structure. No amount of post-construction inspection can remedy out-of-specification concrete.

Inspect the outer surfaces of concrete structures for visual evidence of rusting on the exterior surfaces of the concrete or surface cracking / deterioration.

Inspect for frost spots on the outer surfaces, as these would indicate a loss of insulation performance in the annular space. Infrared imaging of the tank would detect this condition.

Inspect for the loss of environmental protection (as evidenced by rusting) covering the very-high-strength steel music wire exterior wrapping on externally circumferentially prestressed concrete tanks. This shall be immediately corrected, since the wrapping is critical to maintaining the outer shell in a compressive state.

Inspect pre-stressing tendons on internally prestressed concrete tanks for loss of seals which would significantly compromise the tank. These circumferential and vertical pre-stressing tendons are located in fully grouted metallic conduit whose function is to protect these highly stressed components from corrosion.

5.3 Structural Concerns

Survey the tank foundation regularly (typically, annually) to look for settlement of the foundations, ring walls, and structures compared to initial construction data.

Address any evidence of cracking, sag or foundation settlement.

5.4 Pumps

The LNG pumps are located either in the tank (for the over-the-top fill-and-pump-out tanks) or in the dike area within close proximity to the tank and within separate pump housings (for tanks which have a bottom withdrawal line).
There are less problems with the in-the-tank / over-the-top pumping system than there are with the external pumps. The in-tank pumps are cooled once and stay cold unless they are removed for maintenance; the external pumps are subjected to significant thermal cycling, since they are warm until needed, cooled down, operated, and then allowed to warm up after use. The area of concern is increased thermal cycling and a higher possibility of failure from improper cool down practices, which would be in violation of existing cool down procedures.

The electrical connection to the pump is critical since gas leakage could occur into the electrical supply side of the system and result in an incident. Specific changes in the design of these installations have been taken to prevent this occurrence.

The same holds for the truck loading or unloading pumps.

Monitor the electrical requirements over time to determine if change is taking place.

Monitor vibration to determine if an out-of-balance condition is occurring. (This can be done non-invasively.)

6.0 LIQUEFACTION

6.1 Liquefaction Systems – the Cold Box, Pretreatment Systems, and Expanders/Compressors

The liquefaction system contains the equipment that takes the natural gas from the pipeline and pre-treats it (removes water vapor, CO_2, and heavy hydrocarbons and other unwanted constituents present in the feed gas stream). These contaminants have the potential of liquefying / solidifying at temperatures above the liquefaction temperature of the natural gas, methane, which is -260°F.

In order for the liquefaction system to work, the gas feed stock must be clean and be within plant process design values. If the contaminants are not removed, the system will become plugged. The re-generation skid (dryer and absorbers) are part of the gas quality system.

If the molecular sieves which are used for water and CO_2 removal are damaged from out-of-specification inlet gas, improper operation, or the age and condition of the sieve reduces its performance, the gas will not be properly cleaned up. If the gas is not clean, it cannot be properly liquefied. Watch for trace contaminants, lube oils, and mishandling during regeneration.

6.2 Cold Box

Liquefaction of the natural gas takes place in the cold box. It could be an environmentally controlled structure which keeps all water vapor away from the refrigeration heat exchangers or it could be a design in which the heat exchangers are individually insulated and are not in a confined structure.

The presence of water in these extreme cold areas causes ice buildup which can physically destroy the heat exchangers by expansion. Because the heat exchangers are subjected to high thermal cycling, thermal fatigue can take place. Wear failures can also take place.

Plugging from heavies (petroleum products that solidify at the low temperatures in these heat exchangers, typically referred to as riming) can occur in the cold box. Those petroleum products should be removed or limited in volume by the pretreatment system.

Ice formation can structurally destroy heat exchangers. Breakages occur from ice originating from moisture carry-overs or inadvertently introduced by leakage, or during disassembly or faulty start-up. In addition, excessive external ice is a sure indication of reduced liquefaction capacity caused by the heat leak from the failed insulation. The heat exchangers associated with liquefaction processes are usually complex, multiple pass brazed aluminum heat exchangers. The possibility of poor brazing between pass boundaries and the possibility of poor fabrication at internal and external connection points must be considered.

If the performance of the liquefaction system is decreasing over time, it is possible to perform a cleaning effort to remove any surface films deposited in the inner passageways of the heat exchangers; these films can significantly reduce heat transfer. Such a cleaning was successfully done this past summer and the throughput in this peak shaving facility now exceeds the production numbers when the facility initially went on line.

The insulation can settle within the cold box, destroying its effectiveness and decreasing the efficiency of the cold gas processes. Infrared imaging studies can be performed on these cold boxes to determine any loss of insulation.

Perlite, which is the primary insulating system in the tanks and cold boxes, is an abrasive product that can easily penetrate through aluminum if a small gas leak takes place. Rock wool or fiberglass “wool” is also used for the insulation.

6.3 Penetrations into Cold Box

The cold box must be inspected for leakage. The entrance of water will be undetected for long time periods and the heat exchangers will experience significant corrosion, to the point that they could be structurally or operationally compromised. Corrosion of the exterior of the actual heat exchangers and connecting piping is a significant concern because this condition, if not corrected, could destroy critical components within the cold box or the cold box itself,

Typically, one method to reduce water from leaking into cold boxes is to apply a slight pressure on the box from a dry gas source. Regular confirmation that the pressure is being maintained is necessary.

Extensive faying surface corrosion alters the thermal design conditions of the components in the cold box by reducing the heat transfer away from the heat exchanger, which could alter the performance of the unit.

6.4 Pretreatment Systems

The vessels that are typically used to strip out the water vapor, the CO_2, and the heavies from the gas stream contain molecular sieve. The regeneration of the sieves typically requires that the vessels and their contents be heated to nearly 450°F to drive off the contaminates in the sieve material. These vessels should be examined for thermal cycling damage by NDE of vessel welds.
It is also recommended that where sieve materials are used, sieve samples be taken on a scheduled basis (every 2-3 years). These samples should be analyzed for breakdown, for cracking, clogging, coking, etc. The analysis can often be provided by the sieve manufacturer.

6.5 Drivers for Liquefaction

The mechanical driver for the liquefaction process could be a compressor, a turbine let-down expander running on pipeline pressure, or it could be a gas-fueled turbine driving a refrigeration machine to compress the refrigerant or natural gas feed stock and allow the expansion processes to cool the gas to the point of liquefaction.

Compressors and expanders: High speed rotating compressors and expanders are the heart of some liquefaction systems and rotate at – 10,000 to 20,000 rpm. At those operating speeds they would destroy themselves within minutes if not maintained.

The main process power generators - compressors, turbines or reciprocating units should be examined visually and with a borescope for frame cracking, foreign object damage or evidence of corrosion. The turbine should be inspected for hot section damage.

The equipment / drivers must be made to be as reliable as possible and should be inspected at regular intervals and closely monitored during operation as components such as the wheels could fail and cause even more damage to the unit than just the loss of the wheel.

Prediction of failure can only be postulated through changes in the vibrational spectrum exhibited by these units. Therefore, permanent vibration monitoring should be considered if supported by the equipment manufacturer. At these very high speeds, destruction is quick and total. The difficulty is that these wheels and housing are long-lead items and a destructive wheel failure can throw metal debris through the liquefaction system.

Review vibration monitoring records which report any changes in the vibrational spectrum exhibited by these units.

6.6 Refrigerant

The refrigerant used in some liquefaction systems can deteriorate and become corrosive, usually because of mostly external contamination from leaking seals. The corrosive refrigerant can attack screens, housings and ultimately cause a significant liquefaction system failure.
Monitor the chemical characteristics of the refrigerant on a prescribed sampling basis.

The introduction of corrosion control samples into the refrigerant stream is beneficial, represents good maintenance and engineering practice, and is required by most codes.

7.0 PROCESS CORROSION / WATER CORROSION ISSUES

4 I pr e esve i e

Carbon steel rusting is a continuous mechanism that will stop only when oxygen or water is removed. The techniques to achieve this goal constitute a major industry: rust prevention and mitigation of the consequences. If a metal tank wall or roof is not protected, it will ultimately fail through corrosion.

1. Inspect all surfaces where water can collect on or adjacent to the steel outer tank or components.

2. Inspect the intersection of the outer bottom plates, anchor straps, and the concrete ring wall where water can collect, corroding the carbon steel footer plates and the anchor straps.

3. Inspect the tank roof above where the knuckle ring and the roof membrane intersect, since it is a place where water can collect.

4. Inspect the circular stiffeners, roofing penetrations, equipment on the roof, the pumping skid and metal surfaces unTDer0.60000 557.1600 TD0.1200 T Tw(af TD(.)Tj3.48070

has insulation on it for cryogenic spill/splash or fire protection purposes) at regular frequencies to ensure that the metal surfaces remain free of corrosion.

7. Inspect all equipment on saddles, on the ground or in a pit; the risk of moisture collecting on the faying surfaces or on covered surfaces must be addressed.

8. Process heat exchanger internal conditions and any areas where moisture can collect (or water can freeze and thaw) must be examined.

8.0 OPERATIONS

8.1 Operating and Maintenance Procedures

Review the operating and maintenance procedures to confirm that current and effective. Do they need to be reviewed for applicability? For operating personnel to operate the process safely and efficiently and maintenance personnel make the appropriate decisions for the facility, all plans (drawings, etc.) and procedures must be accurate.

Code 49 CFR 193.2017 requires all plans and procedures be updated whenever a component has changed significantly, a new component is installed, and at intervals not exceeding 27 months, but at least once every two calendar years.

Verify that leak surveys are being performed and results are analyzed.

Verify that the firewater supply and delivery system is performing from a capability and corrosion viewpoint. The pump performance and the water delivery system can easily be mechanically verified, but the corrosion status of the components requires a little more effort and direction.

8.2 Performance Concerns

Identify any unexplained/unacceptable increases in the boil-off rate. Boil off is a parameter that can easily be measured and is a design acceptance parameter.

8.3 Thermal Performance / Frost or Hot Spots - Tankage and Piping

Examine the outer tank for the presence of frost spots. Determine the reasons for this condition and take appropriate action.

Perform an infra-red survey of the outer tank and roof area, piping runs, and cold box to determine if cold spots exist in the tank, if the insulation is performing effectively, or if hot spots exist in electrical components.

8.4 Interior / Exterior Rotational Movement

Review records of the instrumentation which records this motion to report the position of the inner tank relative to the outer tank. If unexpected rotational or lateral motion beyond design values occurs, action must be taken.

8.5 Roll Over of the LNG Product

____Roll over induces movement of the product and stresses the inner containment structures and generates significant pressures in the tank and much boil off which is a loss of product. Proper product handling (tank filling based on density and temperature, liquefier performance related to gas quality) and monitoring of storage tanks allows the operator to control this condition. Monitoring can be performed utilizing a variety of instruments to indicate product density at various tank product levels and/or observation of temperatures at varying levels within the inner tank.

____Inspect for proper product handling and monitoring to ensure that roll-over of LNG product is controlled.

8.6 Cool Down / Thermal Cycling

Review and evaluate the written procedures which govern the cool-down of each system of components to cryogenic temperatures; cool-down must be limited to a predetermined rate and a distribution pattern that maintains the thermal stresses within the design limits of the system during the cool-down period.

Inspect the pipe runs for any signs of distress or distortion.

Inspect components for evidence of physical distortion through nondestructive means, such as penetrant testing, looking for the presence of cracking or surface pitting corrosion.

Monitor pipe penetrations subject to thermal cycling for evidence of fatigue cracking.

Inspect expansion joints for pitting corrosion, overload, squirm, over-extension, surface corrosion, and distortion. Insulation or excessive icing should not hinder movement.
Inspect cryogenic swivels to ensure that they are operative, properly sealed and lubricated.

Inspect surface conditions on cryogenic piping.

Monitor cryogenic piping over time for physical distortion from structural overload conditions or fabrication conditions.

8.7 Exposed Surfaces of Product Containing Components

Inspect surfaces of all exposed product-containing components for:

1. localized distortion,
2. corrosion, stress corrosion, pitting corrosion,
3. visual evidence of overstress from lack of flexibility,
4. visual evidence of fatigue cracking at changes in pipe sections or intersections,
5. the status of insulation systems (vacuum jacketed, foam glass insulation, polyurethane foam).

8.8 Send out Systems - LNG Vaporizers

Every LNG facility has vaporizers which convert the LNG to natural gas for introduction back into the pipeline.

The fundamental principle that makes LNG economically feasible is that in liquefaction, the product volume is reduced 620 times at a storage temperature of -260°F and a storage pressure as low as 1 psig +/-. In that condition, however, it is liquid natural gas which requires vaporization or gasification (conversion back to the gaseous state and the associated 620-fold volume expansion) to make it usable. Therefore, vaporizers are a required part of this technology. Odorization of the natural gas takes place after vaporization.

The approach to achieve effective vaporization is to introduce sufficient heat to the LNG vaporizer system without damaging the metallurgy of the heat exchanger. Some of the older methods used to vaporize LNG utilize direct flame temperature to the metal tubes, which has been known to cause cracking of the methane, causing destructive failure of the tubes and fire.

There are five types of vaporizers presently in use:

8.8.1 Submerged Combustion Type

Drain, dry, and internally inspect submerged combustion type vaporizers on an annual basis; examine the general structure, the headers, spargers and tube bundles and support system.

Inspect the tube bundle for wear which could release LNG or NG into the water bath, i.e., the heat transfer medium. Localized evidence of rust on the tubes or weld areas must be further investigated.

Inspect the downcomers internally for evidence of damage from thermal cycling, overheating and wear.

Monitor the bath chemistry to ensure that the water doesn't become corrosive to stainless steels.

Install witness tubes into the water baths to allow a non-destructive inspection of the LNG tube bundle through representative tube samples which are exposed to the water bath conditions.

Install corrosion coupons into the water bath to allow interval monitoring of the corrosivity of the water bath.

8.8.2 Direct-fired

Inspect direct-fired units to establish the metallurgical state of the coils and ensure that carburization has not occurred. This form of damage is detected by measuring the magnetic response in weld areas of the heat exchanger piping using an instrument called a Magnetoscop.

Internally inspect the fire boxes for evidence of cracking or burn damage.

8.8.3 Shell-and-tube

Inspect shell-and-tube units on the shell (water or heat transfer) side for possible corrosion.

8.8.4 Falling-Film-Type

Inspect falling-film-type units for surface corrosion resulting from deposits which can form on the stainless steel surfaces.

Penetrant inspect areas around inlet nozzles and spot welds for cracking.

8.8.5 Ambient Heat

Inspect ambient heat exchangers for pitting corrosion and stress corrosion failures.

8.9 Water Bath / Glycol Water Bath Systems

Monitor the chemistry of water / glycol water baths to ensure that they are operating in a non-corrosive chemical range to minimize any water-side corrosion as follows:

1. Inspect the burner refractories in any heating system.

2. Inspect blowers

3. Inspect circulation pumps for loss of cooling water which is critical to vaporizer operation. If the burner area is not cooled, the metallurgy around the burners will be destroyed.

4. Install low-temperature monitoring / interlock devices where non-cryogenic piping is located at the discharge end of the vaporizers, so that no out-of-temperature condition takes place (i.e., cold vapor is transmitted to the lines which causes the non-cryogenic piping to crack).

5. Inspect for evidence of cracking or abrasion wear.

9.0 EQUIPMENT

9.1 Piping Systems

9.1.1 Valves - Piping / Control Valves / Fittings

Inspect all pressure / relief and vacuum control valves on an annual basis as prescribed in 49 CFR 193 to ensure that they are operating as designed.

Operate internal valves / ESD valving on a periodic basis.

All of these components must meet code requirements and must be inspected for functionality at prescribed frequencies. The control valves should be monitored for accuracy and repeatability on a periodic basis. Pneumatic valve actuators should be overhauled at a frequency to insure the soft goods remain pliable and leak free.

Test relief valves per requirements of governing codes (49 CFR 193 for frequency [annually] and follow ASME requirements for testing and repair).

9.1.2 Distance Pieces

Inspect all thermal protection distance pieces for abnormal ice formation which would be indicative of inadequate air circulation and could expose materials that are temperature- or toughness-dependent to temperatures below its design limit.

9.1.3 Outlet Piping

Inspect the LNG outlet piping to verify that the piping below the insulation remains in acceptable condition. If corrosion is observed, immediate action is required.

9.1.4 Insulation

If water is present at the pipe-to-insulation interface over a carbon steel pipe, the pipe will corrode significantly, depending on the frequency of wetting and drying and the chloride level of the solution on the pipe surface. If stainless steel pipe is exposed to under-insulation corrosion, i.e., the surfaces are wet and the pipe is hot, stress corrosion cracking could occur if chlorides are present.

The presence of ice under the insulation on stainless steel lines is not a corrosion problem when the line is cold, but rather a problem when the line is at room temperature. The presence of a chloride-containing insulation product could result in pitting corrosion of the pipe surfaces, but not when the pipe is cold.

Inspect the pipe surfaces beneath insulation for evidence of corrosion which would indicate that the effectiveness of the insulation is compromised.

Inspect for the presence of water / ice at the pipe-to-insulation interface. Consider performing an annual infrared survey of the piping for evidence of water, indicative of the failure of the environmental sealing associated with the insulation. The vapor barrier is an integral part of the insulation system and has to be maintained in a satisfactory condition.

9.1.5 Creep & Cracking of Inner Tank Floor Insulation

Using the under tank thermocouple survey capability, monitor the tank for thermal profile, which would be indicative of deterioration of the under tank insulation or the inner tank floor conditions.

9.1.6 Molecular Sieves

Examine molecular sieves for thermal cycling damage and under insulation corrosion (CUI). Welds must be inspected.

9.1.7 Foreign Matter

Inspect for the presence of foreign matter in the tank by examining the sumps of the LNG pumps and by inspecting the impeller(s) for damage during pump maintenance.

Determine the nature and origin of any contaminant on the LNG side, whenever such a condition is detected.

If the contaminant is identified as perlite (which can only come from the inside of the tank), this would suggest that the suspended deck or circumferential sealing has been breached. Additionally, perlite from the suspended deck can be introduced through the deck breather, if installed, and can be caused by quick variations between the internal container and the outer tank annular space.

9.1.8 Welds

Inspect all visible welds for visual evidence of motion or cracking, which is a precursor to complete failure. Rust staining on carbon steel welds is a sign of weld distress.

There are two primary reasons why welds would be cracking:

1. Poor Fabrication Quality

   Based on the quality control and auditing incorporated in the governing codes, the possibility of a fabrication-introduced condition which has the potential of component failure is extremely remote.

   Similarly, It is possible that a fabrication “notch” could exist adjacent to weld or braze areas and could propagate to a crack. This could occur anywhere in metallic and non-metallic systems.

   In our opinion, this represents a “real-world” condition and the present industry design codes compensate for this possible occurrence through the use of design safety margins.

2. Excessive Loading

   Based on the design criteria for the plant, the possibility of excessive loading on welds is not a design occurrence. However, because of workmanship and unexpected outside conditions, the possibility of excessive loads on a weld or a mechanical connection must be considered in any structural review and audit. The evidence of excessive loading can be determined by localized distortion, craze markings in a coating, or a component or assembly that exhibits significant “movement” when disassembled.

3. Metallurgical Considerations

   All welding procedures in an LNG plant in this country are in strict accordance with Section IX of the ASME Boiler and Pressure Vessel Code. The possibility of metallurgical considerations resulting in weld cracking is extremely remote, but can happen through manufacturing mistakes or an incorrect assessment of the environment the weld is to be placed into, with weld deterioration / cracking resulting from that exposure.

9.1.9 Outer Bottom - Metal Tanks

The welds associated with the outer bottom of a metal tank can only be inspected through extraordinary means. All efforts to seal the footer plate at the ring wall from external corrosion must be made.

The bottom grouting between the outer bottom footer plate and the ring wall is an essential area of defense against corrosion. No leakage or corrosion of this area can be accepted, since it is always exposed to water, be it rain water, condensation water or ground water.

9.1.10 Lubricating Fluids

Monitor lubricating fluids to maintain lubricity and prevent system corrosion. Watch for contamination of oil and the loss of the circulation pump.

Implement a lube oil analysis program which includes wear particle analysis. Filter elements may also be analyzed for particle analysis.

Send out the filters for periodic testing.

9.2 Corrosion Protection Systems

9.2.1 Cathodic Protection

Cathodic protection systems must be examined and verified that they are operating satisfactorily. Any underground piping or buried components must be reviewed. Consider examining some critical wire runs for durability of insulation.

If the facility has a cathodic protection system in place to protect the outer bottom of the tank from corrosion, that system should be monitored on a yearly basis or as specified by the governing code.

9.2.2 Exterior Corrosion Assessment

Examine all piping and all buried components for external pitting corrosion, since the exposed surface may be in contact with various corrodants.

9.2.3 Cooling Tower and Water Treatment

Verify that the corrosion treatment of the process water side of the LNG liquefaction system is being maintained within acceptable ranges.

Verify "corrosion" status of all heat exchanger surfaces which are in contact with water.

Perform regular external cleaning of fin-tube-style air-cooled heat exchangers to optimize heat transfer. Also, the fan, if provided, must be cleaned, inspected for damage and balance periodically. Clean fan blades move more air. Blades have failed and can not only shut down the facility, but can also cause harm to personnel if nearby in the event of a failure.

9.3 Plant Systems

9.3.1 Process Control Systems

These systems demand very high reliability and many are configured with redundancy schemes.

These systems can quickly become obsolete as hardware becomes mature and is no longer available from the manufacturer. Software changes regularly and older versions are typically required to be upgraded to stay current with the manufacturer's supported version.

Typically, upgrades to control systems require long term budgeting.

9.3.2 Control Systems and Instrumentation

Periodically calibrate / test all control system instrumentation to insure accurate operation at code-defined frequencies. This includes vibration meters, pressure gages, and relief valves.

Initiate a gage calibration program as part of the facility's operation and maintenance program.

9.3.3 Fire Protection, Safety & Security Systems

The requirements for and maintenance of these systems are with NFPA 59A and other NFPA standards.

1. Emergency Shut-down Systems

   Testing of these systems is code required to determine if the process has changed and if that should be considered in the ESD system.

   Verify that instrumentation for liquefaction, storage, and vaporization facilities has not been inadvertently changed or deteriorated so that in the event that power or instrument air failure occurs, the system will still proceed to a failsafe condition as designed and that it is maintained until the operations can take action either to reactivate or to secure the system.

Verify that if an ESD occurs, all systems perform as required and a hazardous environment is not developed locally, which could ignite in the emergency.

2. Automatic Activation of Shut-down Systems

   Is your ESD manually or automatically actuated? If not, should automatic activation be considered?

3. Gas Detection, Flame Detection, and Smoke Detection Systems

   Is the coverage adequate? Are replacement parts available?

4. Extinguishing Systems

   Are fixed systems performing as designed? Are replacement parts still available?

5. Fire Protection Water Systems

   Is the water supply and delivery system performing at design flows? If not, are internal corrosion/deposits the problem? If a fire pump is used, is the pump performing as designed?

6. Security Systems

   Determine that the security system is doing what it was designed to do. If not, it may require upgrading. It is the intent of this system to allow the facility security person to have complete knowledge of who is in the facility at any given time and where that person is. Regular testing of these systems is recommended to ensure not only that the system is functional, but also that security personnel respond.

9.3.4 Electrical Systems

Monitor cathodic protection systems (impressed or sacrificial) for effectiveness on a periodic basis. Investigate any change taking place in the readings. Thermal imaging and motor analysis equipment can be utilized to conduct continued monitoring of these components.
Perform vibration monitoring to determine if an out-of-balance condition is occurring in electric motor components. These types of analyses are particularly useful because they can be conducted non-invasively.

Review all underground piping or components to ensure effective cathodic protection.

Inspect electrical substations / motor control stations periodically for evidence of overheating – consider an infrared survey as a means of inspection.

Determine if power distribution systems are still current, or are now obsolete because of aging.

The electrical conduit has to be maintained, since it carries the wiring and instrumentation cabling throughout the facility. Its corrosion failure from weathering must be prevented. There is no easy solution to this corrosion.

9.3.5 Emergency Shutdown

Verify that instrumentation for liquefaction, storage, and vaporization facilities has not been inadvertently changed or deteriorated so that in the event that power or instrument air failure occurs, the system will still proceed to a failsafe condition that is maintained until the operators can take action either to reactivate or to secure the system.

Verify that if an ESD occurs, all systems perform as required and a hazardous environment is not developed locally, which could ignite in the emergency.

10.0 SUMMARY

This review has discussed some of the areas associated with aging issues in an LNG facility. These are the areas which should be monitored in order to keep the facility fit for service. **Properly maintained, the LNG plant can be expected to have an excellent operational life. Obsolescence, on the other hand, must be monitored and an effective plant maintenance and replacement program can only be beneficial to life extension studies.** .

The largest component, the LNG tank, provided it is maintained and monitored, will remain fit for service essentially forever.

All other components can be easily replaced with a minimal down time period, depending on how the risk assessment is performed in the life of the major pieces of equipment.

The safety record of the LNG industry has been exemplary because of the commitment of all interested groups which have worked together to make it a safe industry.

There have been only two loss-of-life incidents in this country that have been associated with LNG and an active operating facility. The first incident was in Cleveland, 1944, which was a failure of a storage tank caused by poor metallurgy and significantly held back the LNG industry in this country for several decades. This incident was the genesis of the practices incorporated in NFPA 59A to this day that has guided it successfully to today's LNG industry. the second incident was at the Cove Point LNG Terminal in 1978 when vapor leaked from an LNG pump into the conduit system leading back into the motor control center when a spark in the motor control center (building) ignited the gas causing an explosion.

Other failures which have occurred have been thoroughly and objectively investigated to establish what actually failed. Design changes have been incorporated as a direct result of these investigations.

The incident at Sonatrach in January 2004, to the best of our knowledge, was the result of operational practices and design; the combustion air intake for a steam generating boiler was adjacent to an area where an unexpected release of cold, dense, hydrocarbon vapors from an adjacent building took place.

It is believed that this hydrocarbon gas release entered the combustion air intake of this furnace, with the resulting explosion destroying two of the several liquefaction trains at this site. There were approximately 56 fatalities, but the cause was not an LNG incident.

The industry - the regulatory agencies (local, city, state and federal [DOT, PHMSA, FERC]), the consensus standards such as NFPA 59A, the user groups, the industry support groups (such as the American Gas Association), are keeping the LNG industry operating as safely and efficiently as possible as their primary objective. This commitment to safety will allow the LNG industry to go forward **fit for service**.

The aging / obsolescence issues will continue to demand attention and action, since the goal of every owner / operator is to obtain maximum life from every component without any increased risk of failure or operating expenses, recognizing that these facilities are getting older on a daily basis.