EVALUATION OF DECOMMISSIONED LNG STORAGE TANKS AT CHULA VISTA, CALIFORNIA

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San Diego Gas & Electric, SDG&E, built two of the first liquefied natural gas, LNG, peak shaving plants in the U.S. These plants were located on a common facility near SDG&E's South Bay power plant in Chula Vista, California, U.S.A., about 10 miles south of San Diego. The first plant went into service in 1965. A second liquefaction plant and storage tank were completed in 1970. These two plants were decommissioned in 1985 as a result of seismic evaluation based on the current perception of appropriate seismic design criteria for the site and on recent advances in dynamic structural analysis methods. The decision was made to dismantle the plants. The dismantling covered the period of April to September, 1990.

Gas Research Institute's LNG Plant Life Extension Program

The objective of Gas Research Institute, GRI, facility life extension research is to conduct investigations of older LNG storage facility equipment and structures to provide information to assess their continued fitness-for-service and to provide a basis for continued operation of U.S. LNG peak shaving and terminal facilities. The GRI program directly addresses the fitness of older facilities and seeks to identify mechanisms of facility aging, evaluate the impact of aging on facility safety, identify potential facility evaluation methods, and suggest potential remedial measures where necessary.

Few new LNG storage facilities have been constructed in the U.S. since the 1970s. As a result, the infrastructure of the LNG industry is made up of increasingly older facilities. Large LNG storage tanks in the U.S. now have accumulated approximately 2,400 tank-years of uneventful service with an average service period of 18 years. Questions have been periodically raised by organizations outside the industry (i.e., state and local regulatory agencies) regarding the fitness of these older facilities for continued safe operation. While these questions often fail to identify reasonable aging mechanisms, the industry is confronted with a unique problem: LNG operators are encouraged to offer "proof" that older facilities are safe.

Given the burdens of siting requirements under existing federal regulations (49 CFR Part 193), which apply to significant modifications of facilities as well as to construction of new facilities, the continued availability of older LNG facilities is extremely important to ensuring natural gas deliverability, especially during peak demand periods.

LNG storage tanks present the most pressing need for life extension given their costs, difficulties in assessing their in-service condition, and their importance relative to overall facility safety. As a result, GRI initiated life extension research in 1990 focusing on LNG storage tanks. In 1991, GRI plans to extend the emphasis of research to cover other types of facility equipment and structures.

Specific Concerns

Five specific concerns were identified prior to the field inspections. They are as follows:

1. *Long Term 9% Nickel Properties* -- Although there were no experiential[6] or theoretical reasons to expect long term changes in the properties of the 9% nickel, there was little general data and no data from LNG tanks actually in service conditions.
2. *In-service Crack Propagation* -- Pre-existing discontinuities, primarily in the welding, may lead to slow crack growth during the service period.

3. *Rotation at the Lower Corner of the Inner Shell* -- Field investigations and theoretical analysis by Neville and White[1] of the British Gas aluminum tank taken out of service suggest that thermal and stress cycles could cause yielding and fatigue in the aluminum at the junction of the inner shell and footer plate. The possibility exists that 9% nickel tanks could be subject to distress from similar causes.
4. *Insulation Compaction* -- Thermal and pressure cycles may compact the perlite insulation in the annular space causing unwanted pressure against the inner tank.
5. *Corrosion* -- No corrosion was expected inside the inner tank or in the annular space; the condition of the outer bottom was of particular interest.

San Diego Gas & Electric Opportunity

The decommissioning and dismantling of the facilities, and particularly the 9% nickel storage tanks, provided an excellent opportunity to evaluate the condition of the facility components relative to life limiting factors and means of extending the life of LNG facilities.

Facility Description

The SDG&E LNG facility consisted of two LNG peak shaving liquefaction plants with their respective LNG storage tanks.

Both plants were on the same site and were operated in a partially integrated manner. The first plant was put into service in 1965 and the second plant was put into service in 1970. The Plant #1 2MMscf/D liquefaction process utilized a turbo-expander cycle taking advantage of the pressure drop of the fuel gas to the South Bay Power Plant. The Plant #1 tank (T-1) had a volume of 175,000 bbls. The Plant #2 7MMscf/D liquefaction process utilized a closed loop nitrogen cycle. The Plant #2 tank (T-80) had a volume of 345,000 bbls. These tanks were some of the first large cryogenic tanks constructed for the storage of LNG. Both have inner tanks fabricated of 9% nickel steel, which at the time of design and construction, was a relatively new alloy for low temperature applications. Since then, over 100 similar large LNG tanks have been constructed.

Each of the LNG storage tanks had a complete inner tank (including roof) allowing a nitrogen purge in the annular space. Generalized cross sections of T-1 and T-80 are provided in *Figures 1* and *2*. Tank T-1 utilized a load-bearing insulation under the inner tank consisting of hollow, perlite-filled, concrete cylinders as shown in *Figure 3*. The inner tank of T-80 was supported conventionally on Foamglas blocks as shown in *Figure 4*. The inner tank of T-1 was secured with tie-down bolts (*Figure 3*) while the inner tank of T-80 was secured with tie-down straps (*Figure 4*).

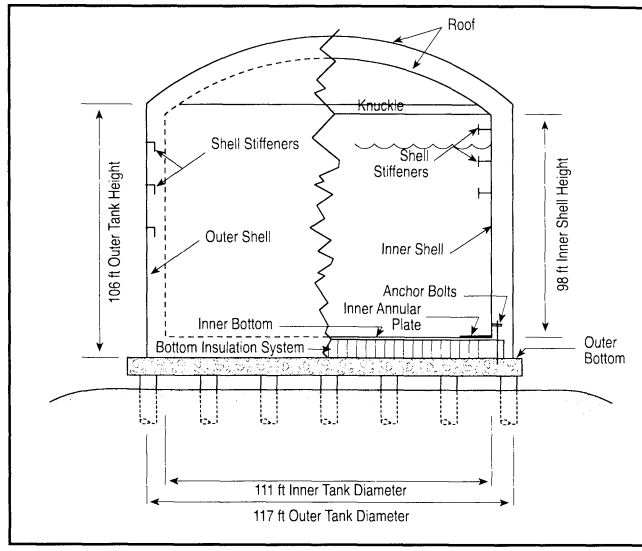

Figure 1 Tank T-1, San Diego Gas & Electric Co., Chula Vista, CA
Tank capacity = 175,000 bbls

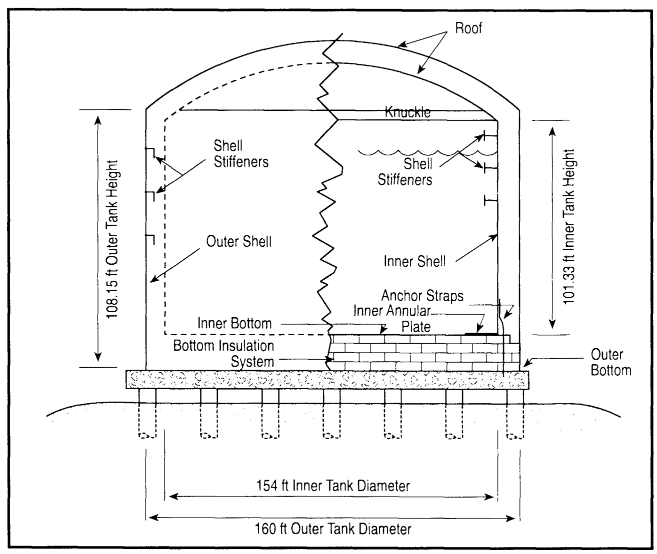

Figure 2 Tank T-80, San Diego Gas & Electric Co., Chula Vista, CA
Tank capacity = 348,000 bbls

General Approach

The general approach for the effort was to learn as much as possible from the dismantling experience as it relates to the objectives of the GRI Life Extension Program. However, the primary emphasis was on the LNG storage tanks. This emphasis was due to the combined facts that there has been no reported evaluations of 9% nickel LNG tanks taken out of service and that the LNG storage tanks are generally considered as the most significant hazard of an LNG facility.

There are many parts of an LNG plant which are readily accessible during normal operation and maintenance and are evaluated by operators on a routine basis. These

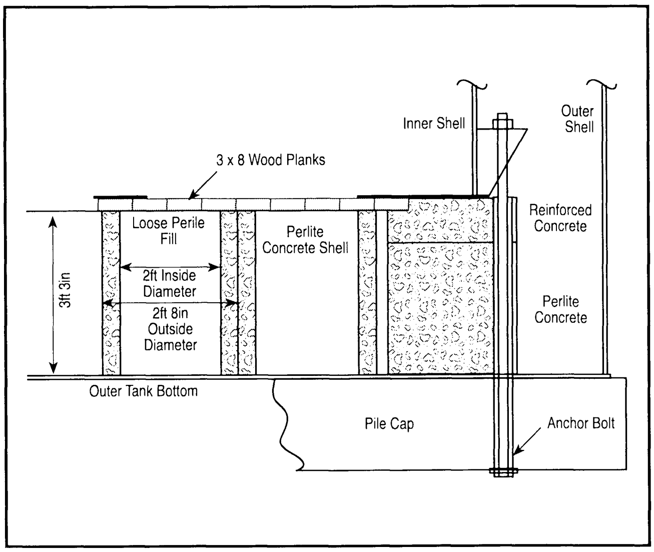

Figure 3 Tank T-1, Bottom Insulation System

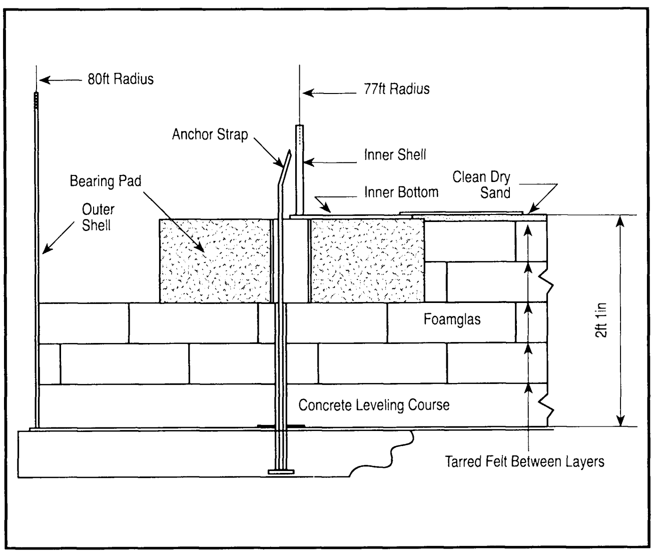

Figure 4 Tank T-80, Insulation Support

items are generally rather easily replaced and, hence, are not considered as life-limiting factors. The Inspection Plan was used to establish the basis and emphasis for the field investigation.

Project Technical Liaison Associates Materials Research Laboratories Program

PTL and MRL set specific goals for the evaluations to implement the GRI program objectives. The goals of the program were the following:

- Identify the factors and mechanisms that may limit the safe, economic life of LNG facilities.
- Identify the potential need for monitoring the life limiting factors during operation.
- Provide insight for in-service monitoring of life limiting factors.
- Provide insight for preventative measures and operational changes to extend facility life.
- Provide new service information that could improve designs in new facilities for extended life.

The work was organized by means of an Inspection Plan. MRL concentrated on the metallurgical aspects and PTL concentrated on the structural, insulation and operational aspects. Since most of the inspection was done during dismantling, the inspection timing, procedures and interpretation of findings were influenced by the dismantling process.

The initial concept for field inspection of the tanks was to undertake the metallurgical inspections with the materials in their original place. This turned out to be neither feasible nor desirable. The dismantling contract was not for the purpose of scientific investigation. Therefore, schedule time and scaffolding for extensive in-place inspection was not feasible. The safe working conditions during dismantling were always a concern, especially when the structural integrity of the tanks had been reduced due to partial dismantling. In practice, it would have been very difficult to perform the same level of inspection with materials in their original positions as was done with the tank materials on the ground. As discussed later, this turned out to be quite advantageous for metallurgical reasons.

Dismantling Activities

For both tanks, the first steps were to displace the nitrogen purge on the inner tank and annulus followed by removal of the perlite. The outer tank was removed from around the inner tank. The inner tank roof was torch cut along a diameter and vertically down the wall of the tank to just above the tie-down connections. Circumferential cuts above the tie-down connections, about 6 ft. (1.8 m) above the floor level, were then made around the bottom, leaving a "hinge". The two halves of the inner tank were then leaning against each other for support. A cable was attached to the tank half with the bottom cut with the intent of pulling it over using the hinge as a pivot. However, the loss of support from the other tank half caused it to collapse rather than to pivot on the hinge. The roof fell into the tank floor and the lower sections of the wall spread in an outward direction, away from the foundation. The roof of the remaining half of the inner tank sagged from buckling under the knuckle. The other half of the inner tank was pulled down in a similar manner. The inner tank walls and roof were then cut into smaller pieces either by torch cutting, tearing or shearing.

Metallurgical Investigations

The metallurgical investigations and evaluations were undertaken by the staff of MRL and consisted of:

- Field examination of the tanks for corrosion and crack-like discontinuities, CLD's.
- Examination of discontinuities for evidence of crack extension during service.
- Measurement of chemical composition and mechanical properties of base plates and welds.
- Stress analysis.
- Fracture mechanics analysis.

This program was a field-experience oriented continuation of previous GRI efforts where GRI has taken a leadership position in sponsoring 9% nickel research[7,8,9] on material properties and fracture mechanics.

Field Examination

The stress and tearing necessary to pull the tanks down and apart caused a considerable pull to be applied to the welded sections thus tending to open the CLD's. Tearing of the tank wall materials and welds required that a considerable pull be applied to the wall sections. Essentially, this was testing to failure, which tended to open any CLD's in these sections. Many of these sections were additionally stressed by being dropped to the ground. The resulting bending and tensile stresses further tended to open the CLD's. Inspection of the tank wall plates on the ground in the sunlight made the discontinuities much easier to find than if the inspections had been conducted on the standing tanks.

The locations to be inspected for discontinuities were cleaned with a wire brush and examined with the naked eye or with a low-powered magnifying glass. When discontinuities, particularly CLD's, were found, the pieces containing the discontinuities were marked, cut out, and shipped to MRL for further examination. Large enough sample pieces were taken to provide both for fabrication laboratory test specimens and examination of discontinuities. Drawings of the tank walls showing the location of inspections and samples are shown in *Figures* 5 and 6.

Examination of Discontinuities

Fractures would start at discontinuities, which are defined as any interruptions in the tank material that cause stresses to concentrate. Discontinuities may be volumetric or planar. Volumetric discontinuities are essentially holes. Planar discontinuities are crack-like and hence, referred to as crack-like-discontinuities -- CLD's. Examples of volumetric type discontinuities are corrosion pits, slag inclusions, gas pockets and shrinkage in welds. Planar discontinuities generally consist of cracks, lack of fusion, or hot tears in welds. Shrinkage cavities might also have planar shapes. Planar discontinuities are much more effective in concentrating stress than are volumetric ones. Catastrophic fracturing that occurs in structures is almost always the result of crack growth from pre-existing CLD's or cracks. By determining the size and shape of discontinuities in the tank materials and examining the discontinuity surfaces, it was possible to ascertain whether or not there had been any in-service crack growth. The tank plates were carefully examined to find discontinuities that could be examined for crack growth, particularly for CLD's.

As expected, numerous small volumetric discontinuities were found in welds which were assumed to be shrinkage voids, gas pockets or slag inclusions. A sampling of pieces containing volumetric discontinuities were sent to the MRL laboratory. When surface cracks were found in welds, however, the complete weld became suspect, and most of the weld and some adjacent base plate was cut out and sent to the MRL laboratory. As cracks are more common in weld repairs, the weld repairs were given special scrutiny. Although no CLD's were found in repair welds in the field, a few pieces in which repairs were made were also sent to the MRL laboratory for more complete examination.

During dismantling, all the T-1 inner tank stiffeners broke away from the inner tank plates. These stiffeners had been joined to the inner tank shell by intermittent short stitch welding. These broken weld surfaces were

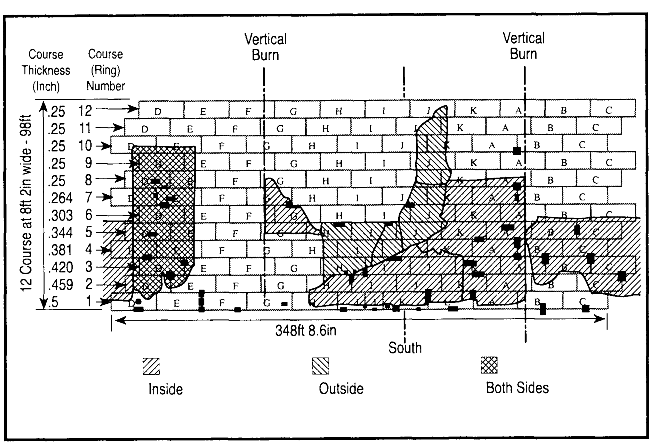

Figure 5 Tank T-1, Wall showing the individual plates from the floor to the knuckle. Cross-hatched sections show pieces removed from wall which were inspected by MRL.

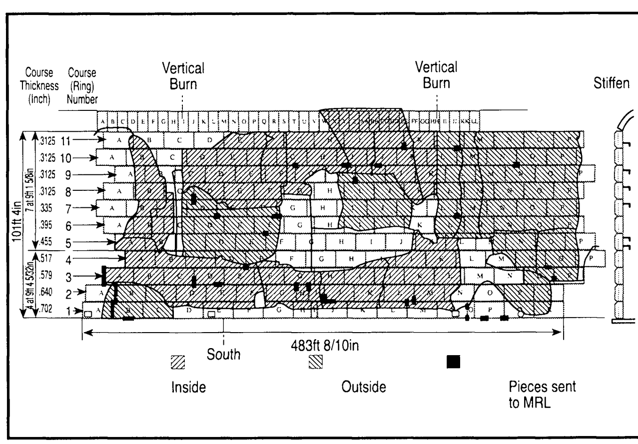

Figure 6 Tank T-80, Wall showing the individual plates from the floor to the knuckle. Cross-hatched sections show pieces removed from wall which were inspected by MRL.

also examined for CLD's, but none were found. The T-80 tank differed from T-1 in that the stiffeners were attached with a continuous fillet weld, many of which were cracked as a result of the dismantling. The inspection of the T-80 stiffener welds was more complete than was the case of T-1, and a number of plate sections containing stiffener fillet welds were also sent to MRL.

The vertical welds in the lower part of the inner tanks were ground, during construction, so that they could be radiographed. The girth welds were also ground for a few inches on either side of the vertical weld at "T" joints. As these portions of the plates and welds were the most highly stressed, they were selected for the most intense inspection and laboratory examination. For T-1, the inspection included about 40 percent of all the vertical welds, and 65 percent of the vertical welds in the first six courses. For T-80, almost all of the vertical welds in the shell and some in the knuckle were visually inspected.

Approximately 2.5 tons of plate from T-1 and 4 tons of plate from T-80 were sent to the MRL laboratory for further inspection and mechanical testing.

Fewer CLD's were found in T-80 than in T-1, possibly because the joint was made by automatic gas metal-arc welding rather than manual shielded metal-arc welding. In breaking up of the inner tanks, some tearing occurred within girth welds and within one knuckle weld. One short weld tear also occurred in a vertical weld. Pieces containing these tears were also sent to the MRL laboratory to determine whether or not weld cracking was the result of CLD's in the weld metal.

None of the CLD's which were opened and examined in the MRL laboratory showed any evidence of in-service crack extension. There is no certainty that the largest of the CLD's in the tanks was found. The fracture mechanics analysis described below was used to determine the CLD size necessary for a CLD to propagate while the tank was in service.

Chemical Composition and Mechanical Properties

The results of chemical analysis made on inner tank plates and the 1967 and 1987 American Society for Testing and Materials, ASTM, specification composition limits for A553, Type 1 steel are shown in *Table I.* The composition of all plates were well within the requirements of ASTM 553, Type 1 steel for both time periods. Weld metals, Inconel Filler Metal 92 and INCO-Weld A Electrode, were used in the tank construction. Chemical analyses were also made on the weld metal from a number of locations in the two tanks, but it is not possible to obtain undiluted compositions from the welds.

Tensile properties and Charpy V-Notch toughness tests were conducted on samples sent to the MRL laboratories. The results of the tensile properties tests are shown on *Table II* (base plates) and *Table III* (welds). The results of the Charpy toughness tests are shown on *Table IV* (base plates) and *Table V* (welds and heat-affected zones). Both the tensile and Charpy test results exceeded code requirements. The original mechanical property and Charpy toughness test data was not traceable to specific tank plates, nor were the tank plates traceable to specific mill heats. Therefore, no direct comparison of aging effects was possible. The fact that all toughness test values far exceeded the minimum code requirement does not guarantee that there was no loss of the original toughness. Nevertheless, the high Charpy toughness after 15 to 20 years of service indicate that the toughness would not have decreased to the code minimums of 25 ft/lbs after even a much longer service life, if ever. (Other aging tests of non-stressed 9% nickel samples have been reported by Consolidated Edison of New York and Brooklyn Union Gas Company.)

Stress Analysis

Determination of the stress environment of the samples required a stress analysis of the tanks. MRL developed a computer program which calculated the tangential and bending stresses in the plates.

Fracture Analysis

Since the SDG&E tanks were built, the new disci-

Table I Chemical analysis of base plates (Tanks T1 and T80).

Element	ASTM A553, Type 1 1967 & 1987	Identification of plate that was analysed						
		1K	1L	2C	3I	4A	5C	-
Tank T1								
Carbon(A)	0.13	0.10	0.09	0.12	0.06	0.09	0.09	-
Manganese(AB)	0.98	0.36	0.37	0.39	0.39	0.43	0.43	-
Phosphorus(A)	0.035	0.009	0.009	0.009	0.009	0.006	0.006	-
Sulfur(A)	0.040	0.008	0.009	0.008	0.007	0.010	0.010	-
Silicon(C)	0.13-0.45	0.18	0.18	0.19	0.22	0.23	0.23	-
Nickel	8.40-9.60	9.22	9.38	9.25	9.26	9.09	9.22	-
Tank T80								
Carbon(A)	0.13	0.07	0.07	0.08	0.08	0.08	0.07	0.07
Manganese(AB)	0.98	0.50	0.52	0.65	0.68	0.73	0.66	0.72
Phosphorus(A)	0.035	0.007	0.002	0.007	0.007	0.006	0.005	0.007
Sulfur(A)	0.040	0.012	0.011	0.008	0.008	0.004	0.004	0.010
Silicon(C)	0.13-0.45	0.21	0.21	0.18	0.19	0.22	0.26	0.24
Nickel	8.40-9.60	8.94	9.00	8.68	8.70	9.30	9.34	8.75

(A) Maximum (B) 1967, Mn = 0.90 (C) 1967, Si = 0.13-0.32

Table II Room temperature tensile properties of base plates (Test according to ASTM E 8)

	Tensile Strength MPa	(ksi)	Yield Strength MPa	(ksi)	Elongation (%)	Tensile Strength MPa	(ksi)	Yield Strength MPa	(ksi)	Elongation (%)
Specified minimum properties from API 620, Appendix Q 1966 and 1985[(A)]	689.5	(100.0)	568.1	(85.0)	20.0	–	–	–	–	–
	Girth Direction (Longitudinal Direction of Plate)					Axial Direction (Transverse Direction of Plate)				
Tank T1										
1st course - average (plate thickness: 0.5in)[(B)]	793.2	(115.0)	713.9	(103.5)	25.8	790.0	(114.7)	717.6	(104.1)	25.8
2nd course - average (plate thickness: 0.459in)	801.4	(116.2)	701.9	(101.5)	25.8	796.9	(115.6)	726.3	(105.3)	25.0
3rd course - average (plate thickness: 0.420in)	801.2	(116.2)	681.8	(98.9)	26.3	810.3	(117.5)	665.7	(96.5)	25.0
Tank T80										
1st course - average (plate thickness: 0.702in)	760.2	(110.3)	709.6	(102.9)	26.8	758.1	(110.0)	708.5	(102.8)	25.5
2nd course - average (plate thickness: 0.640in)	801.4	(116.2)	701.9	(101.5)	25.8	796.9	(115.6)	726.3	(105.3)	25.0
3rd course - average (plate thickness: 0.570in)	764.0	(110.8)	703.7	(102.1)	27.7	765.0	(111.0)	701.2	(101.7)	26.0
7th course - average (plate thickness: 0.335in)	790.9	(114.7)	745.0	(108.1)	25.5	788.8	(114.4)	781.9	(113.4)	24.0

(A) ASTM specified A20 states that: "The longitudal axis of the tension-test specimen shall be transverse to the final rolling direction of the plate."
(B) Nominal dimensions from construction drawings.

Table III Room temperature tensile properties of welds (Test according to ASTM E 8)

	Tensile Strength MPa	(ksi)	Yield Strength MPa	(ksi)	Elongation (%)
Specified minimum properties from API 620, Appendix Q 1966 and 1985[(A)]	655.0	(95.0)	362.0	(52.5)	–
			Vertical weld (All weld metal specimens)		
Tank T1					
2nd course - average (plate thickness: 0.459in)[(B)]	698.8	(101.1)	437.5	(63.5)	26.5
Tank T80					
1st course - average (plate thickness: 0.702in)	706.5	(102.5)	435.3	(63.1)	34.7
2nd course - average (plate thickness: 0.640in)	753.6	(109.3)	474.7	(68.9)	28.0
3rd course - average (plate thickness: 0.570in)	724.2	(105.0)	443.3	(64.3)	38.7
7th course - average (plate thickness: 0.335in)	701.9	(101.8)	406.1	(58.9)	37.5

(A) ASTM specified A20 states that: "The longitudal axis of the tension-test specimen shall be transverse to the final rolling direction of the plate."
(B) Nominal dimensions from construction drawings.

pline of fracture mechanics has been developed. The techniques of fracture mechanics allow the description of the conditions that will cause fracturing to be more accurate than was possible at the time the tanks were built.

As no crack extension was found in the laboratory samples of CLD's, no life-limiting prediction can be made. If crack extension had been found, the tanks could be considered as having limited life. The absence of crack growth does not indicate infinite life, but for the

Table IV Charpy V-notch impact toughness of base plates (10mm x 10mm specimens)

	Test Temperature Deg C	(Deg F)	Absorbed Energy Joules	(ft/lbs)	Shear Percent	Lateral Expansion mm	(mils)	Absorbed Energy Joules	(ft/lbs)	Shear Percent	Lateral Expansion mm	(mils)
Specified minimum properties from API 620, Appendix Q 1966 and 1985[(A)]	-196	(-321)	33.9	(25.0)[B]	–	0.38	(15.0)[A]	–	–	–	–	–
			Girth Direction (Longitudinal Direction of Plate)					Axial Direction (Transverse Direction of Plate)				
Tank T1												
1st course - average	-196	(-321)	62.4	(46.0)	59.8	0.76	(30.0)	43.2	(31.9)	51.0	0.53	(20.9)
(plate thickness: 0.5in)[(B)]	-162	(-260)	82.2	(60.6)	80.3	1.03	(40.7)	53.6	(40.3)	70.7	0.72	(28.3)
2nd course - average	-196	(-321)	58.2	(42.9)	58.2	0.68	(26.8)	48.0	(35.4)	55.2	0.57	(22.4)
(plate thickness: 0.459in)	-162	(-260)	103.1	(76.0)	100.0	1.19	(46.8)	83.7	(61.7)	88.0	1.07	(42.1)
3rd course - average	-196	(-321)	82.8	(61.1)	75.5	0.95	(37.5)	67.1	(49.5)	73.0	0.83	(32.7)
(plate thickness: 0.420in)	-162	(-260)	103.1	(76.0)	100.0	1.19	(46.8)	83.7	(61.7)	88.0	1.07	(42.1)
Tank T80												
1st course - average	-196	(-321)	77.0	(56.8)	68.2	0.93	(36.7)	46.9	(34.6)	61.7	0.62	(24.2)
(plate thickness: 0.702in)	-162	(-260)	99.9	(73.7)	90.7	1.19	(46.8)	61.9	(45.7)	73.2	0.86	(33.7)
2nd course - average	-196	(-321)	57.0	(42.0)	79.0	0.70	(27.3)	–	–	–	–	–
(plate thickness: 0.640in)	-162	(-260)	88.1	(65.0)	100.0	1.14	(45.0)	–	–	–	–	–
3rd course - average	-196	(-321)	75.7	(55.8)	57.7	1.03	(40.6)	54.0	(39.8)	46.0	0.72	(28.3)
(plate thickness: 0.570in)	-162	(-260)	96.3	(71.0)	69.7	1.25	(49.3)	66.9	(49.3)	65.3	0.90	(35.3)
Not Full-Thickness Tests:												
7th course - average	-196	(-321)	51.5	(38.0)	57.0	0.65	(25.7)	–	–	–	–	–
(plate thickness: 0.335in)	-162	(-260)	68.5	(50.5)	72.7	0.93	(36.7)	–	–	–	–	–

(A) 1985 only (B) Nominal dimension from construction drawings

Table V Charpy V-notch impact toughness of welds and heat-affected zones (10mm x 10mm specimens)

	Test Temperature Deg C	(Deg F)	Absorbed Energy Joules	(ft/lbs)	Shear Percent	Lateral Expansion mm	(mils)	Absorbed Energy Joules	(ft/lbs)	Shear Percent	Lateral Expansion mm	(mils)
Specified minimum properties from API 620, Appendix Q 1966 and 1985 (transverse direction of plate)	-196	(-321)	33.9	(25.0)	–	0.38	(15.0)[A]	–	–	–	–	–
			Vertical Welds					Heat-Affected Zones				
Tank T1												
1st course - average	-196	(-321)	76.4	(56.3)	100	1.68	(66.0)	87.2	(64.3)	100	1.12	(44.0)
(plate thickness: 0.5in)[(B)]	-162	(-260)	74.1	(54.7)	100	1.72	(67.7)	101.0	(74.5)	100	1.44	(56.7)
2nd course - average	-196	(-321)	74.8	(55.2)	–	1.37	(54.0)	92.0	(67.8)	–	1.02	(40.3)
(plate thickness: 0.459in)	-162	(-260)	73.2	(54.0)	–	1.59	(62.7)	93.6	(69.5)	–	1.01	(39.7)
Tank T80												
1st course - average	-196	(-321)	148.3	(109.3)	100	2.11	(83.0)	115.6	(85.3)	100	1.25	(49.3)
(plate thickness: 0.702in)	-162	(-260)	155.1	(114.3)	100	2.29	(90.3)	120.2	(88.7)	100	1.48	(58.2)
2nd course - average	-196	(-321)	104.2	(76.8)	100	1.58	(62.3)	111.7	(82.3)	100	1.02	(40.3)
(plate thickness: 0.640in)	-162	(-260)	105.8	(78.0)	100	1.70	(67.0)	114.8	(84.7)	100	0.97	(38.3)
3rd course - average	-196	(-321)	149.2	(110.0)	100	2.35	(92.7)	123.6	(91.2)	100	1.38	(54.3)
(plate thickness: 0.570in)	-162	(-260)	154.2	(113.7)	100	2.46	(97.0)	129.0	(95.2)	100	1.43	(56.3)
Not Full-Thickness Tests:												
7th course - average	-196	(-321)	92.9	(68.5)	100	2.04	(80.3)	66.9	(49.3)	100	1.35	(53.3)
(plate thickness: 0.335in)	-162	(-260)	95.1	(70.2)	100	2.07	(81.7)	68.0	(50.2)	100	1.22	(48.0)

(A) 1985 only (B) Nominal dimension from construction drawings size of the CLD's found, the tank life would be very long compared to the 15 and 20 years of service of the SDG&E tanks.

Fracture mechanics analysis methods[2,3] were used to calculate the critical size of CLD necessary for crack extension. It was also used to determine the crack length for which the crack arrest toughness would arrest a crack propagation. The critical crack length for the bottom course of shell plates is shown on *Table VI.* Critical crack lengths for crack arrest are shown in *Table VII.*

Table VI Full-crack or crack-like-discontinuity length needed to initiate a fast-running crack in course No. 1 of LNG tanks, (filled to the top of cylindrical height of tanks).
Fill height: Tank T1 - 29.9m (1,176in)
Tank T80 - 30.9m (1,216in.)

	Max. Stress MPa	(ksi)	K_c MPa-m$^{1/2}$	(ksi-in$^{1/2}$)	$2a_c$ mm	(in)
Tank 1	26.4	(182)	216	(197)	560	(22)
Tank T80	27.0	(186)	245	(223)	660	(26)

These values are tentative until the stress analysis is complete.

Table VII "Total damage zone" over which a fast crack will run and arrest in course No. 1 of LNG tanks when encountering "normal" material, (filled to the top of cylindrical height of tanks).
Fill height: Tank T1 - 29.9m (1,176in)
Tank T80 - 30.9m (1.216in.)

	Max. Stress MPa	(ksi)	K_c MPa-m$^{1/2}$	(ksi-in$^{1/2}$)	$2a_c$ mm	(in)
Tank 1	26.4	(182)	304	(277)	820	(32)
Tank T80	27.0	(186)	363	(331)	1000	(39)

These "damage zone" lengths are still tentative until the stress analysis is completed.

Corrosion

Field examination for evidence of corrosion was undertaken by both PTL and MRL as well as by George Moller[11], a recognized expert in corrosion and nickel alloys. The interest was in evidence that might indicate that there had been damage to the tank or that there had been some unexpected corrosion mechanism at work.

The inside surfaces of the inner tank of both T-1 and T-80 was fairly uniformly covered with rust to the height of the water level of hydrostatic test. Above that level, there was very little rust. The SDG&E welding inspector for the tank construction was located and stated that the rust intensity and distribution was visually "just like the day after the hydro test." Most of the rust was not due to hydrotest water attacking the tank steel, but was a layer of deposited rust particles. These rust particles were the result of grinding residue on the inner tank floor that floated on top of the water during hydrotesting and was deposited on the tank wall as the water was drained.

It was found that the layer of rust was superficial and could be easily removed by rubbing, which is consistent with the conclusion that it was not rust corrosion of the shell plate but a rust particle layer deposited by the receding hydrotest water. There were three notable instances of non-uniformity of the rust. A few shell plates below the hydrotest level had a very thin rust layer believed to be a result of the hydrotest water not wetting the plate surface. This was probably an artifact of residual oil from the rolling. There was heavier rust where the mill-scale had been removed by scraping or grinding. However, this occurred prior to the tank being put into service. Where the high nickel weld metal had been ground, the weld did not rust, although many looked slightly rusty due to the film deposit mentioned above.

Extra efforts were made to find volumetric discontinuities in the tanks near the welds in both the base plate and the heat-affected zone, since this is where corrosion pitting would most likely occur, but none was found.

The bottom side of the inner tank bottoms showed no signs of in-service corrosion. This surface on T-80 was of particular interest because T-80 had experienced a leak during the first attempt at hydrotesting. No evidence of detrimental effects from this leak were found. As the annular space was purged with nitrogen, no in-service corrosion of these surfaces was expected.

The outer surfaces of the outer tank were also examined for corrosion. The three most vulnerable locations are -- the weld joint between the ring girder -- the weld between the bottom shell plate and the floor of the outer -- the areas near ice covered piping. No significant corrosion was found in any of these locations. There was some rust on the bottom side of the outer tank bottom, but there appeared to be little, if any, pitting and no significant metal loss. The good condition around the bottom can be at least partly attributed to SDG&E's practice of keeping the gap between the outer bottom and the pile cap well sealed.

Structural Inspections

At all stages of dismantling, the tanks were inspected for evidence of structural distress or deformations. Of particular interest were evidence of rotation at the junction between the bottom shell plate and the footer plate of the inner tank. This was the area identified by Neville and White[1] as a potential source of yielding and fatigue, at least in aluminum tanks. The angle between the shell plate and footer plate was checked with a carpenter's square and the flatness of both were also checked. No evidence of rotation or yielding was apparent, suggesting that any such rotation was within the elastic limits of the material. In this regard, the concrete bearing pad under the edge of the inner tank bottom was carefully inspected for any imprint from contact with the bottom. None was found. Our tentative conclusion is that the suggested caution by Neville and White regarding maintaining a minimum LNG liquid level in normal operations is probably not applicable to 9% nickel tanks. It should be noted, however, that the SDG&E tanks did not undergo complete draining except when they were decommissioned.

The concentricity of the inner and outer shell was checked to the extent possible. Any off-center movement of the inner tank would have been apparent from the relative location of the tank bottom and the tie-down straps or bolts. Off-center movement of the outer tank would have been apparent from a change in location relative to the pile cap. No evidence of non-concentric movement was found.

The tie-down bolts on T-1 were all found to be at least hand tight and there was no evidence of distress or deformation from excess tension. Some of the tie-down straps on the inner tank of T-80 were found to be loose due to a loss of thickness in the load bearing insulation supporting the bearing pad. However, there was no evidence of distress or deformation from excess tension.

Prior to dismantling, all external lines in the facility as well as those directly associated with the tanks were visually checked for distress and proper provisions for expansion and contraction. No problems were found. To the extent possible, the annular piping was checked for signs of distress or unexpected movement. None was found. All of the expansion joints were in good shape. Particular attention was paid to the bottom withdrawal lines and the area surrounding their connection to the inner tank bottom. In T-1, the bottom withdrawal line was 10 in. (25.4 cm) while for T-80 it was an 8 in. (20.32 cm) line. No signs of distress were found.

The circumference of the inner tank rests on a bearing pad made of lightly reinforced concrete. At approximately one half of the locations where the 180 tie-down straps passed through the bearing pad, there were cracks through the bearing pad. See *Figure 4* for additional construction details. These cracks were generally in the vertical plane of the tank radius. In addition, all the cracks were completely through the section of the bearing pad and of constant opening. This latter feature seemed to argue against bending as a cause of cracking. Also, there was no discernable pattern of preferential cracking around the circumference of the tank. Discussions with Dr. Simpson lead us to the conclusion that these were shrinkage cracks which would not be unexpected in this application over long periods of time. It should be noted that the bearing pad is not a structural member beyond its role as a support under the edge of the inner tank.

SDG&E personnel reported that the facility had experienced five "locally significant" earthquakes. No evidence of any effects of these earthquakes was found. Data on the severity of the earthquakes was not investigated, but they were not significant relative to the seismic design of the tanks.

The top surface of the pile cap was not accessible for inspection during the inspection period. The periphery of the pile cap was examined closely and no signs of cracking or distress were found. Only the outside ring of piles could be visually inspected and no signs of distress were found.

SDG&E surveyed the tank foundations for settlement on an annual basis. These records were reviewed and it was concluded that there was no significant settlement of the pile-supported foundations.

Perlite Insulation

Both T-1 and T-80 had an anti-compaction blanket against the inner tank to compensate for changes in annular space dimensions of the tanks due to changes in pressure, temperature or liquid level. In T-1, the fibreglass blanket was glued on to the inner tank in sections of approximately 24 x 48 in. (61 x 122 cm). When the perlite was removed, many of these blanket sections came loose. There was no evidence that they had become detached before the perlite removal. It is our opinion that the drag down force of the perlite removal was the cause of the detachment.

In T-80, long curtains of fibreglass blanket were hung from the knuckle of the inner tank. These blankets, about 36 in. (91 cm) wide, remained in place while the perlite was removed.

The handling and disposal of the perlite was initially a significant problem for the demolition contractor, but satisfactory techniques were ultimately developed.

Load Bearing Insulations

The load bearing insulation used in T-1 was 32 in. (81 cm) diameter by 39 in. (99 cm) long, hollow concrete cylinders with the void spaces filled with loose perlite. This construction is shown in some detail in *Figure 3*. The cylinders were overlain with a floor of 3 x 8 in. (8 x 20 cm) Douglas fir planking. The inner 9% floor was placed directly on the wood floor with 12 in. (30 cm) wide asbestos strips located under the weld areas. From all appearances, this insulation system was exactly the same as when it was put into service 25 years before. The load bearing insulation used in T-80 was four layers of Foamglas, each layer being 5 in. (13 cm) thick. This construction is shown in additional detail in *Figure 4*. There were two unexpected observations relative to the Foamglas. When the inner bottom was removed, there was a very consistent 1.25-1.5 in. (3-4 cm) gap between the inner vertical surface of the bearing pad and the mass of Foamglas under the tank floor. This gap extended at constant width through the top two layers and then decreased or disappeared in the bottom two layers. The width of the gap corresponds to slightly more than the expected contraction of the bearing pad and slightly less than the expected contraction of the inner tank. It is our opinion that this gap is a result of the bearing pad contracting during cool-down causing the Foamglas blocks to be compacted. When the tank warmed up, the bearing pad expanded away from the Foamglas leaving the gap. This hypothesis ignores the thermal contraction and expansion of the Foamglas, but it should be noted that the Foamglas has a vertical temperature profile from -260°F (-162°C) to near ambient.

The other unexpected observation relative to the Foamglas was the loss of up to 1.5 in. (4 cm) of thickness under the bearing pad. This loss characteristically was a crushing of the Foamglas surface that was directly under the concrete bearing pad. The amount of this loss did not appear to have any particular pattern around the circumference of the tank. The loading on the Foamglas had a design safety factor of approximately five as the loading was about 20 psi and the minimum required material was 100 psi per the accepted ASTM test method. Discussions with Pittsburgh Corning Corporation, PCC, the manufacturer of the Foamglas, and subsequent tests at the PCC laboratory revealed that the ASTM test uses a hot tar dip between layers to transfer and distribute the loads from the cellular structure of one block to the other in such a way as to avoid point loading. Without this load transfer medium, the point loading can cause progressive cell structure failure at only 10 to 15% of the nominal material compressive strength.

In the SDG&E T-80 tank, the Foamglas layers were separated by a tar impregnated felt layer. This apparently was generally effective in providing the load transfer between Foamglas layers, as this loss was found almost exclusively under the bearing pad. The drawings did not indicate that there should be tar impregnated felt under the bearing pad, although it was found in some places. A picture from the construction records taken before the bearing pad was poured shows the felt extending to the tie-down tubes, or about half way under the bearing pad. It is suggested that the direct contact of the concrete and possibly the radial relative motion of the gearing pad over the foam glass caused a combination of point loading and abrasion which resulted in crushing of the top of this layer of Foamglas. The loss of thickness in the Foamglas caused a slackening of the tie-down straps as manifested by gaps up to 1.25 in. (3 cm) between the locking bar on the upper end of the tie-down straps and the tie-down strap keepers.

Operational Evaluations

The history of plant and tank operations was generally trouble free relative to any issues of a life limiting nature. Four matters warrant comment. The previously mentioned leak in T-80 during hydrotest appeared to have no residual effects after it was repaired, although the leak was not easily found.

T-1 had a very small leak in the inner tank which caused a methane build-up in the nitrogen purged annulus. The size and approximate location of this leak was determined in 1982 by PTL under contract to SDG&E. It was determined that this leak at its current size, posed no problem for the operation or integrity of the tank. The rate of methane build-up was monitored by SDG&E and found to be constant, indicating that the leak was not increasing in size.

Although SDG&E had periodically experienced higher than expected nitrogen losses from the annular purge system, these were attributable to aging of the diaphragm in the breather tank. There was no evidence found indicating any problems inherent in the concept or design of a complete inner tank.

SDG&E, at times, experienced difficulties in getting the bottom withdrawal pumps to prime. There was some concern that this problem was due to restrictions in the flow out of the bottom outlet due to debris, solids or viscosity. Inspection of the screens around the bottom outlets of both tanks revealed no indication of solids or debris. There was no pattern of particles surrounding the outlets indicating any particle entrainment in the flow. The pump net positive suction head, NPSH, problems were later mitigated by piping and operational changes.

Non-tank Observations

Inspections were made of equipment and structures in the facilities not related to the storage tanks. As expected, certain equipment showed deterioration with time that would require periodic replacement or major repairs. These included hot regeneration gas piping, regeneration gas heater, vaporizer tubes and vaporizer burners. None of these items were judged to be life limiting from an economic or safety standpoint.

As part of the inspections, the SDG&E archives of construction and operations records were searched. As a result of annual "record purge days" and record retention policies, some potentially interesting records had been discarded. Fortunately, SDG&E had kept engineering drawings current such that the physical plant was accurately reflected by the facility drawings. We also found that the tank contractor, CBI, had understandably discarded all but the most basic information from their files. We conclude that an important part of an owner's life extension efforts for a facility should include preservation of relevant construction and operational records.

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Summary

The dismantling of the San Diego Gas & Electric liquid natural gas, LNG, facilities offered an opportunity to evaluate two of the first 9% nickel steel LNG storage tanks in the U.S.

The metallurgical evaluation concluded that:

- There was no slow crack extension from pre-existing crack-like discontinuities.
- The chemical composition and the mechanical properties of base 9% nickel plate and weld metal were consistent with both the present requirements of American Petroleum Institute, API, 620 Appendix Q and the requirements current at the time the tanks were built.
- The tank materials had good resistance to crack initiation as well as the capability to arrest cracks that might be accidentally initiated.
- There was no significant amount of corrosion found.

The structural and operational performance evaluation concluded that:

- No evidence was found indicating unsatisfactory structural or operational performance.
- No evidence was found of distress at the joint between the shell plate and the footer plate of the inner tanks.
- The compaction control blankets performed as intended and there was no evidence of perlite compaction.
- There was some loss of Foamglas insulation under the concrete bearing pad in Tank T-80 attributable to lack of a load distributing material at Foamglas surfaces.

A computer program was developed which allowed the stress environment to be established for the fracture mechanics analyses. From this, crack initiation resistance and crack arrest capabilities were determined.

The retention of construction and operational records for extended life operations is important.

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