The Use of Liquefied Natural Gas For Peaking Service

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THE USE OF LIQUEFIED NATURAL GAS FOR PEAKING SERVICE

I. EXECUTIVE SUMMARY

Liquefied natural gas (LNG) is becoming a significant factor in providing gas service during peak times in a number of regions of the U.S. and Canada. Based on a survey of LNG facilities conducted for this study, there are currently 85 LNG plants in North America, 56 with liquefaction capability and 29 satellite facilities containing holding tanks and vaporizers but without liquefaction. LNG facilities are located in 24 states and two provinces and are owned by 47 different companies, 43 local distribution companies (LDCs) and 4 pipelines. The combined vaporization or sendout capacity of LNG plants total 9.2 billion cubic feet per day (Bcfd), representing over 10 percent of peak capacity in the U.S.

While a number of LNG facilities built in the sixties and seventies were meant to receive imported natural gas, the vast majority of LNG plant in use today process domestic gas and are used primarily for peakshaving, i.e., for reducing the amount of gas service required from a pipeline during peak periods. The resurgence in the use of LNG plants for peakshaving currently taking place can be attributed to two main factors.

First, the Federal Energy Regulatory Commission (FERC) in its Order No. 636 required pipelines to employ the straight fixed-variable (SFV) rate design where all the pipeline's fixed costs are allocated to demand charges to be paid monthly regardless of actual utilization. For pipeline customers facing low load factors, the SFV rate design resulted in an increased costs of pipeline capacity held for peak service. In many cases, the right to retain pipeline capacity became one of the largest cost items for LDCs serving temperature-sensitive loads. This study estimates the total costs for an LNG plant with 100 MMcfd peak capacity and 2.0 billion of annual sendout capacity at $9.36/Mcf.

Second, LNG is an option that can provide peak period gas service without affecting gas properties, compared to the injection of propane-air mixtures, and at locations that are not restricted by geology, as underground storage would be.

In addition, LDCs are beginning to face increased competition in their retail markets with the advent of retail unbundling and the expected lower electricity prices due to restructuring of the electric industry. LDCs, particularly those in New England, Middle Atlantic and North Central states, have been exploring ways to reduce their costs in order to retain market share.

In many cases where cost savings are needed, LNG was the most suitable alternative. For example, for peak service that is more than a few days in a year, LNG facilities can offer better economics than propane-air mixtures and for services less than about a month in duration per year, LNG can be more competitive compared to incremental underground storage or pipeline capacity.

In a similar way, pipeline companies desiring to expand service at locations near the end of their service areas are considering LNG as an alternative to building pipeline capacity. In the case of the Cove Point LNG plant, the economics were favorable for converting an import plant into one for peakshaving using domestic gas.

LNG is also expected to benefit from an increased use of natural gas as a vehicular fuel because of its consistent chemical composition and from a faster rate of growth in peak demand compared to total demand. A number of new LNG peaking facilities are under development or evaluation including Rhode Island, North Carolina, Georgia and Tennessee. However, similar to pipelines, environmental concerns and public acceptance can represent hurdles to the construction of new LNG plants.

II. PEAKSHAVING AS COMPETITION TO PIPELINE CAPACITY

The natural gas industry continues to undergo rapid change due to regulatory reform at both the state and federal level and increasing competition. As a result, gas companies are under pressure to reduce costs while maintaining reliable service. One manifestation of this attention to cost control is an emphasis on using existing facilities more efficiently, rather than constructing traditional new capacity. In the past, profit growth may have been primarily the result of increasing rate base investment. Today, companies can lose if that increase in rate base causes unit costs to increase in a competitive market.

For many distribution companies and some pipelines, this may mean the use of additional peaking facilities in order to reduce or "shave" the amount of year-round capacity needed to meet service requirements. All of these factors are occurring during a period when large amounts of long term contracts between Local Distribution Company (LDCs) and pipelines are expiring and being renegotiated under different terms and sometimes lower levels of capacity obligation.

At the same time, significant new gas demand is being projected through the rest of the decade and beyond in the colder regions of North America. Some forecasts indicate peak day service requirements will grow at nearly twice the rate of the average daily winter requirement through the year 2005. This is in part due to the continuing increase in the use of gas to replace alternate space heating fuels, such as heating oil and electric resistance heating in the Northeastern United States.

Pipeline capacity utilization will also continue to be affected by Federal Energy Regulatory Commission (FERC) Order 636, which mandates that pipeline transportation rates be structured under the Straight Fixed-Variable (SFV) methodology. This form of rate structure places all fixed costs and return on investment in the demand charge, to be paid regardless of actual capacity usage. SFV rate design results in higher demand costs for LDCs and consequently increases their cost of holding peak capacity. Low load factor users of pipeline capacity are now paying higher fees under the SFV method compared to other rate designs.

In addition, pipeline utilization load factor may worsen because of the unbundling of LDC gas sales and transportation, which is being implemented in a few states and being considered by many more. Among other effects, this will decrease the average LDC load factor[1] and increase its seasonal use ratio[2]. As the peakedness of their load curve increases, LDCs have to be concerned about the efficiency with which their contracted pipeline transportation capacity is utilized. The increase in seasonal swing will degrade the LDCs pipeline transportation utilization efficiency and force them to implement other means of performance improvement.

LDCs are additionally being challenged by increasing electric price competition and the threat of market loss and erosion of profits. FERC's electric industry restructuring order will force gas LDCs to aggressively manage their supply portfolio to reduce cost in a new competitive environment. LDCs are realizing quickly that pipeline capacity underutilization can significantly impact their cost of service and thus their ability to compete with electricity.

Most LDCs in the New England, Middle Atlantic and East North Central states experience gas sales closely tied to regional Heating Degree Days (HDDs), days below 65 °F, when customers require natural gas for space heating. Indeed, more than 80 percent[3] of a typical utility's profit in this region is correlated to the residential customer and attendant heating requirements (i.e. HDDs). Residential customers purchase about 50 to 60 percent[4] of the annual gas sendout for most of these LDCs; however, they pay a significant premium over industrial and other large customers because they use gas at low load factor and on a firm basis. The LDCs utilization of pipeline transportation service, and, thus cost to customer, is affected by this usage pattern. LDCs, therefore, need to optimize system utilization in order to keep their costs down and retain load.

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[1] Defined as the ratio of the average daily throughput to the contracted capacity.
[2] Ratio of five highest to five lowest demand days
[3] AGA Gas Facts, the American Gas Association; 1993; pp. 8, 9
[4] Ibid, pp. 8, 9

In response to these economic pressures, LDCs are looking at cost control through load management and peakshaving.

Load management programs deal with demand-side issues and aspire to reduce the peaking needs by instituting curtailment and interruption incentives. Measures such as these are very difficult to carry out, particularly with weather sensitive, residential space heating which most often has limited fuel switching capability. A certain amount of curtailment can be effective for some market segments; however, this has the potential to label natural gas as an unreliable energy source. The effectiveness of load management is at best, limited, particularly in the growing residential markets.

With market share at risk, LDCs must be concerned with satisfying current customers fully and having low cost, reliable service to attract new ones. Where competitive with other options, peakshaving measures can contribute to cost reduction through enhanced system utilization, while providing high system reliability.

LDCs with large heat-sensitive load, no corresponding interruptible market, and a relatively low load factor, have an opportunity to optimize their transportation utilization with some type of peakshaving and a reduction in pipeline capacity contract costs. With open access becoming increasingly more available to small customers such as residential and small commercial, and the requirement in many states to be the supplier of last resort, LDCs are finding it imperative to have some sort of peakshaving service available to keep the system operating on the coldest days of the year.

Peakshaving is well established as a means of providing an incremental source of supply to meet energy needs on extremely cold days. In addition to providing large volumes of gas in the winter season, a peaking facility can serve as a backup to gas supply in the event of a disruption in normal pipeline deliveries and provide balancing services to transportation customers. The flexibility inherent to some peaking plants can provide significant operational support and possibly avoid some of the cost of pipeline demand charges.

Common peaking facility options in use today are line pack, propane-air plants, underground storage facilities, and LNG plants. Factors driving the selection of peaking alternatives have been location, comparative cost and operational flexibility.

Line Pack

Line pack in long transmission lines is oftentimes effective in serving hourly peaking requirements when the swings in hourly demand are predictable and limited in quantity and duration. The deliberate oversizing of distribution pipe to accommodate peaking storage needs is almost always prohibitively expensive, in the range of thousands of dollars per Mcf of storage for typical distribution pressures.

Propane-Air

Propane-air has been an effective and widely used source of peaking supply. Its attractiveness lies in its simplicity, reliability and low capital cost of roughly 35 to 40 percent of new pipeline construction. Propane-air plants are usually located on the distribution grid in the market area and must have access to pipeline, rail, or truck transportation to facilitate the delivery of propane. While widely used in the past, propane-air is losing its appeal due primarily to its limitations in compatibility with natural gas. An adequate supply of natural gas (at least 50% of mixture) must be added to the propane-air mixture to ensure acceptable Btu content levels and flame characteristics at the customer's burners. Additionally, those utilities offering compressed natural gas (CNG) for vehicles cannot allow propane into their system. The use of gas containing propane in CNG vehicles causes efficiency degradation and maintenance problems.

Underground Storage

Another widely used source of peaking supply is underground storage, either in a leached salt cavern or a formation of porous rock. The storage of natural gas in salt caverns is very effective for peaking purposes; however, it can only be considered in those areas with bedded salt formations or salt domes. Salt dome formations are typically found in the Gulf Coast area of the U.S. Bedded salts, found elsewhere, also have regional limitation.

While also limited to regional availability, though not nearly to the extent of salt formations, underground storage of natural gas in porous rock plays a vital role in the seasonal peaking operations and has been successfully utilized in the US for over 70 years. Storage of this type is most commonly developed in depleted oil or gas reservoirs, and, to a lesser degree, in porous subterranean aquifers. There are numerous advantages to underground reservoir storage. Market area storage characteristically has a low unit-investment cost of about 50 percent of new pipeline capacity. These projects are known for their large capacity, long-term deliverability, continuity of service, and safety. They are used for services of all magnitudes of hourly, daily and seasonal peak and are well suited for pipeline/LDC balancing operations. Generally, underground reservoir storage is most economically sized for service extending from 80 to 120 days per year. They have traditionally been used for seasonal peaking requirements and can be quite effective in improving the efficiency of system utilization when located advantageously.

Underground natural gas storage, with the exception of on-grid salt cavern storage, is generally not economical for needle peaking.[5] Oftentimes gas from underground storage must still be accessed via main transmission lines, thereby not fully avoiding costly pipeline demand charges. Another cost issue which can be significant, is the level of base, or cushion gas, which is necessary to provide the deliverability potential of the storage wells. In addition, a critical limit to the use of underground storage is the availability of favorable geology, which might not always be found in the market area.

[5] The highest gas demand in a year and usually occurs for a day or two on an LDC's system.

LNG Peakshaving

The advantages of LNG peaking plants are many. These facilities can almost always be sited somewhere on the distribution grid, thereby fully avoiding peak day related pipeline transportation costs and transmission disruption risks. LNG facilities can be sized to meet most supply requirements and also have the potential for relatively easy expansion. There are no compatibility issues, as found with propane-air, and the siting of an LNG plant is not significantly restricted by geology, as with underground storage. Most issues regarding LNG tend to be site specific; and these are typically resolved before the facility is constructed or placed in service. A greater control of gas supply and increased operations flexibility is attained with the ownership of LNG facilities. For LDCs, LNG provides more options in contract restructuring and enables the displacement/relinquishment of other more costly peaking supplies. For pipelines, LNG offers a means for providing additional peaking services to a number of LDCs in case pipeline capacity expansion is too costly. In comparison with alternative peaking sources, LNG is very competitive, particularly in the range of up to about 20 days of supply. Finally, it utilizes proven technology and has a commendable safety record.

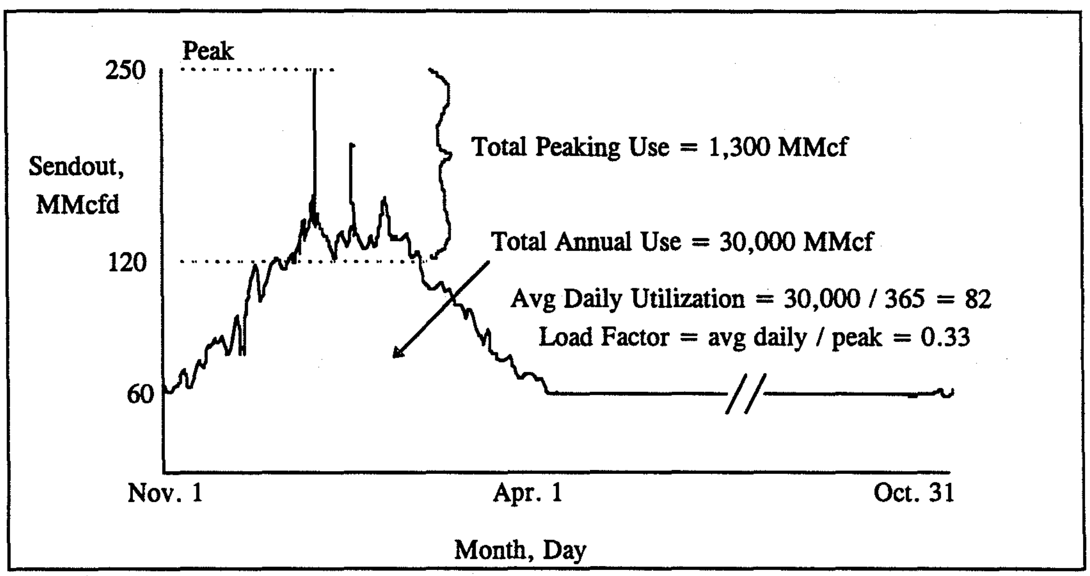
III. ECONOMICS OF PEAKSHAVING

A. Peakshaving Facilities versus Pipeline Transportation

The short durations of coldest weather affecting service areas in northern parts of the US, result in winter peak day loads often 2 to 3 times as large as normal winter loads. To ensure adequate supply on peak day, LDCs without market area supply must contract with pipeline company(ies) for transport capacity. This is, however, a very inefficient means of securing peaking service as this additional capacity is paid for on a 365 day basis, while actually being utilized for only a few days or, in some years, only a few hours.

A measure of the extent to which pipeline capacity is being used is the pipeline utilization efficiency, calculated as the ratio of the yearly average daily usage to the contracted capacity. Figure III-1, below, illustrates a typical seasonal sendout profile for a local distribution company.

Figure III-1
Typical LDC Natural Gas Sendout Profile



For this particular LDC, without some sort of peakshaving capability, a pipeline capacity of 250 MMcfd would have to be reserved to transport supplies to serve the peak day. This arrangement results in a load factor of 0.33, and corresponding unit cost of pipeline service, calculated as

$$U = [\ (12^*D) / (365^*L_f)\ ] + C$$

where U = unit cost of pipeline transportation

D = monthly transportation demand charge (assume \$8.00/Mcfd/month)

L_f = load factor

C = commodity charge (assume \$0.06/Mcf),

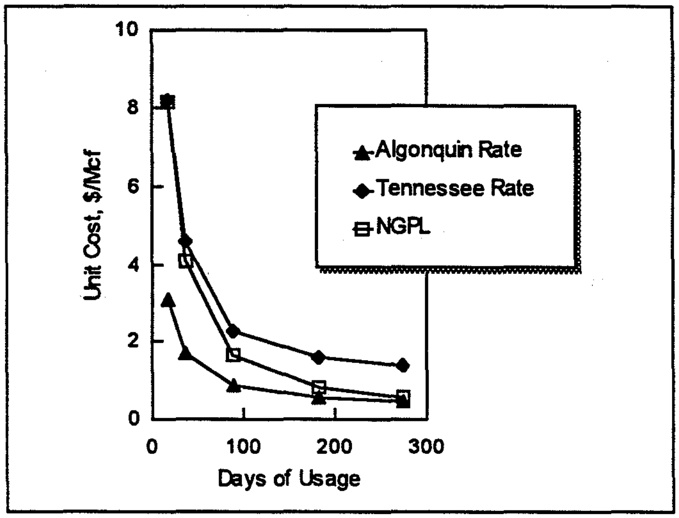
in the amount of $U = [\ (12^*8.00)/(365^*0.33)\ ] + 0.06 = \$0.85$/Mcf.

Supposing 130 MMcfd of peak day supply (1,300 MMcf seasonal peaking supply) could be "shaved" from the required pipeline transportation service through the acquisition of some type of peakshaving facility for ten days. This would result in a contracted pipeline capacity of 120 MMcfd, a load factor of 0.66 and a unit cost of pipeline service of $0.46/Mcf. This alternate source of peaking service would also have fixed costs, or demand charges, associated with it, and must be included in the cost saving calculations. Such demand charges are determined by plant capacity and include, among others, such costs as return on investment, standby labor, property taxes, and maintenance, and are treated the same as a pipeline demand charge.

A detailed analysis of LNG plant and operating costs is presented in Appendix A. That analysis indicates that for a typical plant with 100 MMcfd peak capacity and 2.0 billion of annual sendout capacity, the equivalent demand change would be $7.38/Mcf/month. Variable operating costs would be $0.37/Mcf. Adjusting for load factor, the total costs per unit of gas delivered would be $9.36/Mcf.

We can see from the above example that pipeline service can be more efficiently utilized at higher load factor. The extent of this differs among the different pipelines. Figure III-2 illustrates the effect of the number of days per year that contracted pipeline capacity is fully utilized on the unit cost of transportation for the pipelines depicted.

Figure III-2
Pipeline Unit Cost vs. Days of Usage



Source: Zinder Associates Rate Report, October, 1995.

The use of peakshaving supply to improve an LDC's load factor on its pipeline suppliers makes sense only when the facility used to replace pipeline capacity has a lower unit cost of service for the intended range of service.

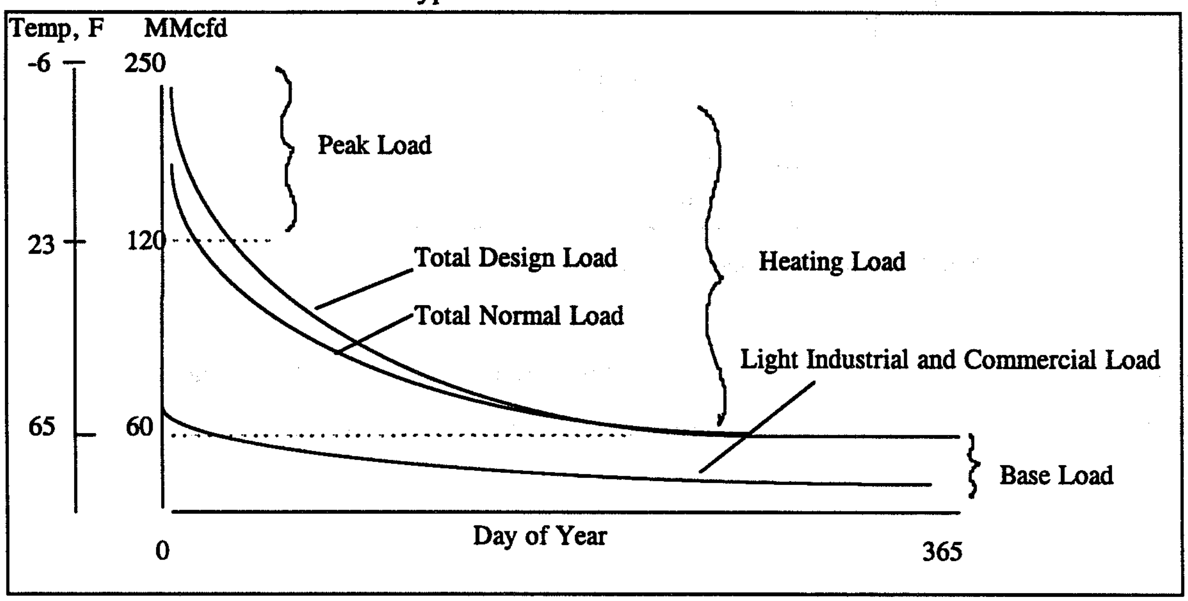
B. Choice of Peakshaving Options

For comparison purposes, the unit cost equation can be applied in the same basic manner for alternate sources of additional supply as for pipeline transportation. In general, gas supply related services with high demand charges, such as pipeline transportation, are most economical for blocks of service with high annual load factors. Peak blocks of supply with low annual load factors are most economically provided from peaking services with relatively low demand charges, such as gas storage, LNG and propane-air[6].

[6] IGT; Gas Distribution; May 10, 1995 "Peak Shaving By Gas Storage"; G.M. Mitchell, Stone & Webster

The load duration curve is a convenient way to represent the load requirements of a gas distribution company. This curve is constructed from long-term (commonly over 20 to 30 years) experience of weather-load relationships. The design year curve represents the coldest day and highest frequency of cold days that the LDC anticipates, whereas the normal year curve represents the sendout that will occur during a winter of average frequency. As seen in Figure III-3, for a typical LDC load duration curve, peaking occurs over a very short time, usually a few days. It represents a significant fraction of the daily load, however, it is a much smaller contributor to the seasonal heating load.

Figure III-3
Typical LDC Load Duration Curve



As mentioned earlier, there are certain choices available to the LDC to serve these highly seasonal gas demands. The primary task facing the LDC is selecting a peaking alternative which is least costly by comparison and serves the operational requirements of the company. Other related issues, such as siting a peaking plant, in particular an LNG facility, are discussed elsewhere in this report.

To assess the economic feasibility of a peakshaving alternative, or the combination of two or more different types of peaking alternatives, each must be configured on the basis of the range of service for which it, or they, will be operational. An optimized peaking gas supply portfolio will result when each peaking alternative is designed and utilized such that the overall annual cost to supply gas is at its lowest. A method in achieving this optimum is as follows:

1. Identify peaking options considered to be best suited for the requirements of the LDC and associated service area. In an area where underground storage is not possible because of available local geology, for instance, underground storage would not be an option. The restrictions governing the mixing of propane-air with system gas is another example of suitability to be considered.

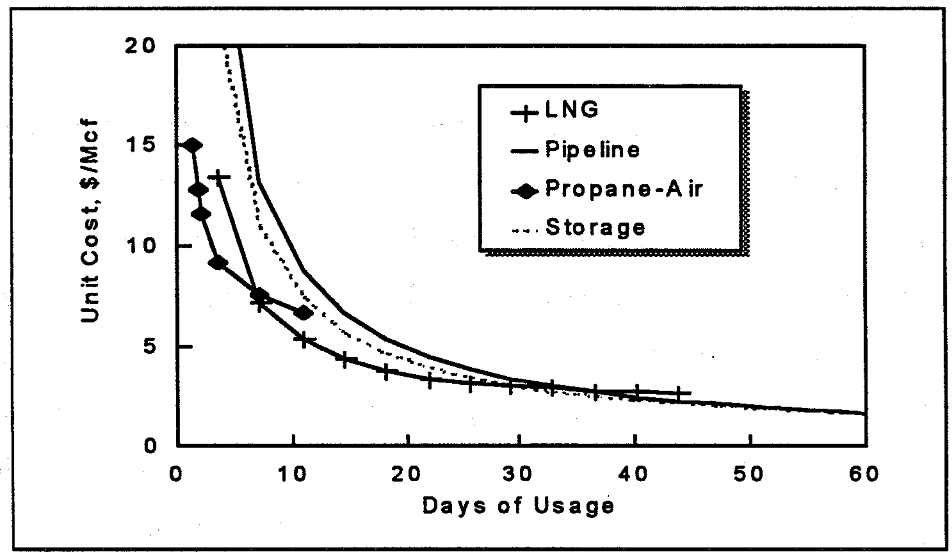
2. For each identified peaking option, the total annual cost of gas supply for a normal year weather occurrence is calculated for each incremental size of peaking range based on increasing threshold temperatures, i.e. the temperature below which a the peaking supply is used. The facility is configured to meet a design year weather occurrence similar to contracting for pipeline capacity to cover the LDC's greatest transportation need expected in any given year. The investment required to construct the facility in the size necessary to meet peak day demands will constitute the majority of the fixed costs of having the peaking facility available when needed.

3. The least cost mix of peaking supply is determined through implementation of an optimization methodology which substitutes conventional supply service with incrementally greater peak load durations of alternate peaking supply.

C. Example of the Configuration of Peakshaving Alternatives

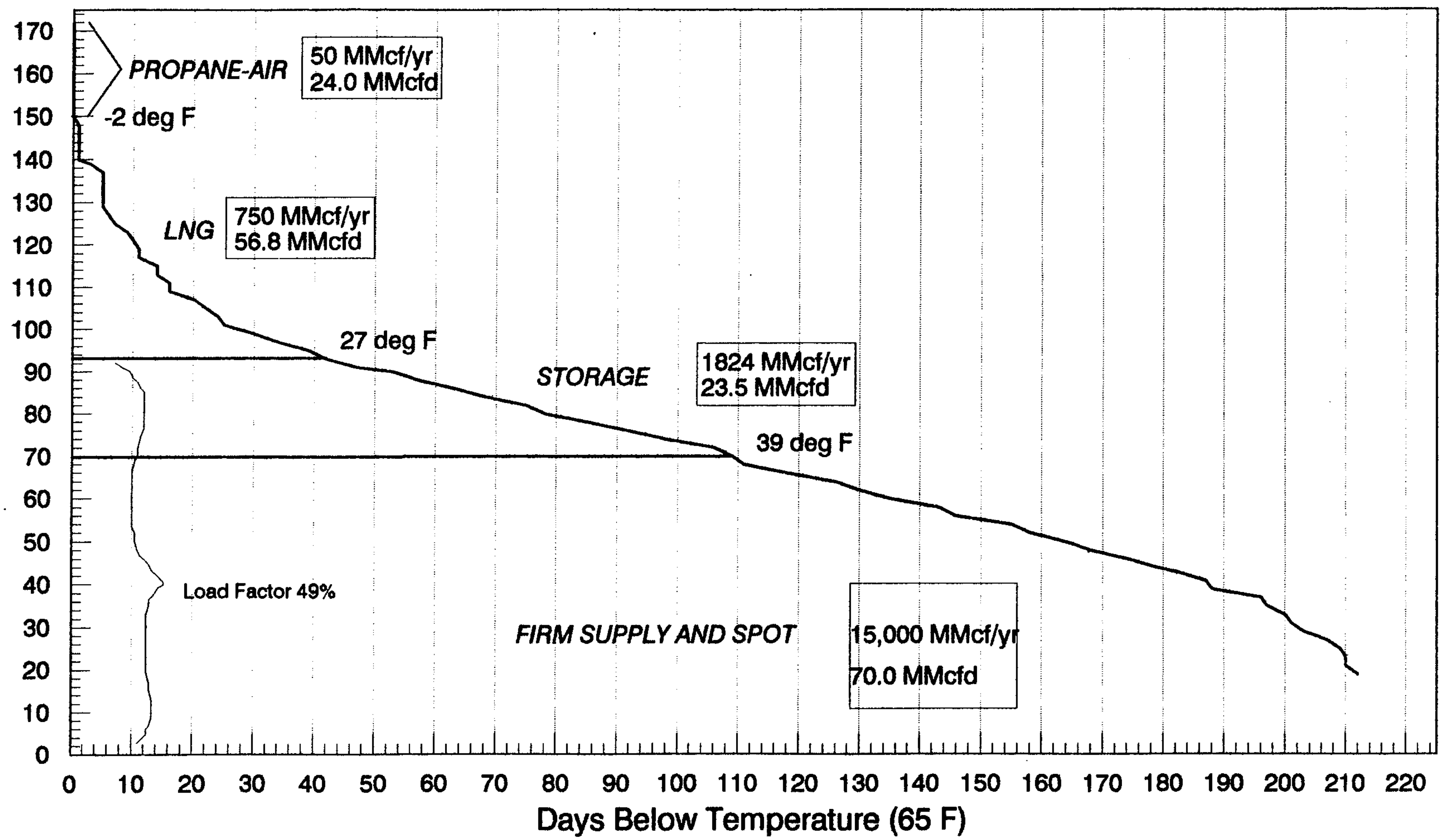
An illustration of the effect on the unit cost of gas at various levels of facility usage is presented in Figure III-4. The curves in this figure are representative of the cost of additional gas supply from several alternative peaking sources for a particular usage pattern influenced by US Rocky Mountain weather and typical characteristics of heat sensitive load. In this example, a propane-air facility would be used for the 8 coldest days of the year and an LNG plant would be cost effective for about 22 days of peak. Figure III-4 indicates LNG less costly than storage to about 30 days of usage. In this instance LNG would be designed for 22 days as propane-air would serve the coldest 8 days of demand. Storage would also fit economically into this supply portfolio as an alternative to pipeline capacity for a significant portion of the seasonal supply need.

Figure III-4
Unit Cost of Peaking Alternatives vs. Days of Usage



The results of the application of the previously mentioned optimization methodology are likely to indicate an apportionment of peaking sources as displayed in Figure III-5. When this was done, firm pipeline transportation capacity was reduced by about 46%, increasing the load factor from 28% to 49%, through the use of two sources of peaking supply (Propane-Air and LNG; storage still required firm pipeline transportation, however it allowed the purchase of less expensive summer spot gas). The utilization level of the LNG facilities is only 3.6%, demonstrating its cost effectiveness at low load factor. An overall reduction in annual average cost of gas amounting to 16% could be realized for this LDC with the inclusion of these peakshaving services.

Figure III-5
Load Curve with Peakshaving
Normal Heating Season, Rocky Mountain LDC



Load Variation: 1,959 Mcf/DDD
Winter Base Load: 19,008 Mcfd

Peak Deliverability Requirement: 171,814 Mcfd
Annual Deliverability Requirement: 17,642 MMcf
Load Factor 28%

IV. SURVEY OF INSTALLED LNG CAPACITY

Methodology

Stone & Webster has compiled a database of installed LNG peaking facilities in North America. The information sources used to develop this database were both those in the public domain and those derived from our consulting experience in the natural gas industry. Survey forms were sent to all operators of known LNG facilities to verify their associated statistics and to request information on any proposed LNG sites. The survey form is provided in Appendix B. The survey response rate was 77% for peakshaving facilities and 50% for satellite facilities, a rate considered to be excellent for this type of voluntary survey.

The survey was limited to LNG facilities in North America. LNG facilities are commonly classified either as those which have the capability of liquefying natural gas or those which do not liquefy, but rather receive natural gas in liquid form for storage and sendout. The latter type facilities are known as LNG satellite facilities, while the former are generally referred to as LNG peaking facilities. A separate analysis was conducted for each category.

Survey Results

LNG is produced and stored at 56 facilities on the North American continent. The breakdown of the 56 peaking facilities on a state and province basis is shown in Table IV-1. The peaking facilities are owned by 47 separate companies: 43 LDCs and 4 transmission companies listed in Table IV-2. There are additionally 29 satellite facilities. A breakdown of the satellite facilities by state or province is shown in Table IV-3. The satellite facilities are owned by 26 separate companies; 25 LDCs and 1 transportation company. The companies owning satellite facilities are listed in Table IV-4. Total LNG liquefaction capacity is 321.9 MMcf per day. Identification of production by state and province is shown in Table IV-5, while ownership is shown in Table IV-6. Several owners did not provide associated statistics for their facilities. Where no other data sources were available production and regasification capacities were recorded as zero. The effect of this can be seen in Table IV-5 and IV-6. Total liquefaction and regasification is therefore slightly understated, but the effect is not significant. The total regasification capacity is 9,158 MMcf per day of which 8,295 MMcf per day is associated with peaking facilities and 863 MMcf per day with satellite facilities. Peaking facility regasification by state or province is illustrated in Table IV-7 while satellite facility regasification by state and province is shown in Table IV-8.

Table IV-1
Peaking Facilities by State and Province

State/Province	Number of Facilities
1. AL	3
2. AR	1
3. CT	1
4. DE	1
5. GA	4
6. IA	4
7. ID	1
8. IL	1
9. IN	4
10. MA	6
11. MD	1
12. MN	2
13. NC	3
14. NE	1
15. NJ	1
16. NV	1
17. NY	3
18. OR	2
19. PA	3
20. SC	2
21. TN	4
22. VA	2
23. WA	1
24. WI	2
25. Ontario	1
26. Quebec	1
Grand Total	**56**

Table IV-2
Peaking Facility Ownership

Company Name		Number of Peaking Facilities
1.	Alabama Gas Corporation	2
2.	Associated Natural Gas/Southwestern Energy	1
3.	Atlanta Gas Light Co.	3
4.	Baltimore Gas & Electric Co.	1
5.	Bay State Gas Co.	1
6.	BC Gas Inc.	1
7.	Boston Gas Co.	2
8.	Brooklyn Union Gas Co.	1
9.	Centra Gas Ontario Inc.	1
10.	Chattanooga Gas Co.	1
11.	Citizens Gas & Coke Utility	2
12.	City of Trussville Utilities Board	1
13.	Colonial Gas Co.	1
14.	Columbia Gas Transmission Corp.	1
15.	Connecticut Natural Gas Corp.	1
16.	Consolidated Edison Of New York Inc.	1
17.	Delmarva Power & Light Co.	1
18.	East Tennessee Natural Gas Co.	1
19.	Fall River Gas Co.	1
20.	Gaz Metropolitan	1
21.	Intermountain Gas Co.	1
22.	Kokomo Gas & Fuel Co.	1
23.	Long Island Lighting Co.	1
24.	Memphis Light, Gas & Water Div.	1
25.	Metropolitan Utilities District of Omaha	1
26.	MidAmerican Energy Co.	3
27.	Minnegasco Inc.	1
28.	Nashville Gas Co.	1
29.	NIPSCO	1
30.	North Carolina Natural Gas Corp.	1
31.	Northern Natural Gas Co.	2
32.	Northern States Power Co. - Minnesota	1
33.	Northern States Power Co. - Wisconsin	1
34.	Northwest Natural Gas Co.	2
35.	Northwest Pipeline Corp.	1
36.	Paiute Pipeline	1
37.	Peoples Gas Light & Coke Co.	1
38.	Philadelphia Electric Co.	1
39.	Philadelphia Gas Works	1
40.	Piedmont Natural Gas Co.	1
41.	Public Service Company of N.C. Inc.	1
42.	Roanoke Gas	1
43.	South Carolina Pipeline Corp.	1
44.	Transcontinental Gas Pipe Line Co.	1
45.	UGI Utilities Inc.	1
46.	United Cities Gas Co.	1
47.	Wisconsin Electric	1
Grand Total		**56**

Table IV-3

Satellite Facilities by State and Province

State	Number of Facilities
1. CT	2
2. GA	2
3. MA	7
4. NH	3
5. NJ	5
6. PA	1
7. RI	3
8. SC	2
9. TN	1
10. VA	1
11. WI	2
Grand Total	**29**

Table IV-4

Satellite Facility Ownership

Company Name	Number of Satellite Facilities
1. Algonquin LNG	1
2. Austell Natural Gas System	1
3. Bay State Gas Co.	1
4. Boston Gas Co.	1
5. City of Holyoke Gas & Electric Dept.	1
6. City of Norwich Dept. of Public Utilities	1
7. Colonial Gas Co.	1
8. Energy North Natural Gas Inc.	3
9. Essex County Gas Co.	1
10. Fitchburg Gas & Electric Light Co.	1
11. Fort Hill Natural Gas Authority	1
12. Lynchburg Gas/Commonwealth Gas Services Inc.	1
13. New Jersey Natural Gas Co.	2
14. Northern States Power Co. - Wisconsin	1
15. NUI Corporation	1
16. Philadelphia Gas Works	1
17. Providence Gas Co.	1
18. Public Service Electric & Gas Co.	1
19. South Carolina Pipeline Corp.	1
20. South Jersey Gas Co.	1
21. Southern Connecticut Gas Co.	1
22. United Cities Gas Co.	2
23. Valley Resources Inc.	1
24. Westfield Gas & Electric Light Dept.	1
25. Wisconsin Gas Co.	1
Grand Total	**29**

Table IV-5

LNG Liquefaction Capacity by State and Province

State	Total Liquefaction Capacity in MMcfd
1. AL	11.2
2. AR	.6
3. CT	6.0
4. DE	1.6
5. GA	30.8
6. IA	17.5
7. ID	3.7
8. IL	10.0
9. IN	35.6
10. MA	34.3
11. MD	5.0
12. MN	15.9
13. NC	8.7
14. NE	6.2
15. NJ	9.0
16. NV	5.6
17. NY	13.6
18. OR	7.5
19. PA	35.0
20. SC	11.4
21. TN	25.0
22. VA	6.2
23. WA	19.7
24. WI	2.5
25. Ontario	0
26. Quebec	0
Grand Total	**321.9**

Table IV-6

LNG Liquefaction Capacity by Owner

Company	Liquefaction Capacity in MMcfd
1. Alabama Gas Corporation	6.2
2. Associated Natural Gas/Southwestern Energy	0.6
3. Atlanta Gas Light Co.	30.0
4. Baltimore Gas & Electric Co.	5.0
5. Bay State Gas Co.	10.0
6. BC Gas Inc.	4.4
7. Boston Gas Co.	14.1
8. Brooklyn Union Gas Co.	5.1
9. Centra Gas Ontario Inc.	0.0
10. Chattanooga Gas Co.	10.0
11. Citizens Gas & Coke Utility	12.9
12. City of Trussville Utilities Board	5.0
13. Colonial Gas Co.	0.0
14. Columbia Gas Transmission Corp.	5.2
15. Connecticut Natural Gas Corp.	6.0
16. Consolidated Edison Of New York Inc.	5.5
17. Delmarva Power & Light Co.	1.6
18. East Tennessee Natural Gas Co.	5.0
19. Fall River Gas Co.	0.0
20. Gaz Metropolitan	0.0
21. Intermountain Gas Co.	3.7
22. Kokomo Gas & Fuel Co.	2.5
23. Long Island Lighting Co.	3.0
24. Memphis Light, Gas & Water Div.	5.0
25. Metropolitan Utilities District of Omaha	6.2
26. MidAmerican Energy Co.	6.7
27. Minnegasco Inc.	5.0
28. Nashville Gas Co.	5.0
29. NIPSCO	20.2
30. North Carolina Natural Gas Corp.	3.5
31. Northern Natural Gas Co.	21.7
32. Northern States Power Co. - Minnesota	10.1
33. Northern States Power Co. - Wisconsin	1.7
34. Northwest Natural Gas Co.	7.5
35. Northwest Pipeline Corp.	19.7
36. Paiute Pipeline	5..6
37. Peoples Gas Light & Coke Co.	10.0
38. Philadelphia Electric Co.	6.0
39. Philadelphia Gas Works	26.2
40. Piedmont Natural Gas Co.	5.2
41. Public Service Company of N.C. Inc.	0.0
42. Roanoke Gas	1.0
43. South Carolina Pipeline Corp.	7.0
44. Transcontinental Gas Pipe Line Co.	9.0
45. UGI Utilities Inc.	2.7
46. United Cities Gas Co.	0.0
47. Wisconsin Electric	0.8
Grand Total	**321.9**

Table IV-7

LNG Peaking Regasification Capacity by State and Province

State	Regasification Capacity in MMcfd
1. AL	360
2. AR	30
3. CT	57
4. DE	25
5. GA	690
6. IA	423
7. ID	76
8. IL	300
9. IN	597
10. MA	728
11. MD	252
12. MN	372
13. NC	379
14. NE	60
15. NJ	402
16. NV	105
17. NY	720
18. OR	216
19. PA	220
20. SC	684
21. TN	241
22. VA	211
23. WA	585
24. WI	135
25. Ontario	300
26. Quebec	129
Grand Total	**8295**

Table IV-8

LNG Satellite Regasification Capacity by State or Province

State	Regasification capacity in MMcfd
1. CT	87
2. GA	50
3. MA	146
4. NH	6
5. NJ	195
6. PA	90
7. RI	143
8. SC	104
9. TN	5
10. VA	5
11. WI	19
Grand Total	**863**

Peaking facilities reported four primary types of refrigeration cycle. Mixed Refrigerant Cycle was the most common and represented 41% of the facilities. Expander or Expander/Cascade accounted for 26.8% of peaking facilities followed by Cascade or Modified Cascade with 19.7% and MRL with 16.1%. The remaining 5.4% of facilities use a variety of cycles including dual Joule Thomson and IRC.

There are four large LNG import receiving terminals in the U.S. (listed below by location and owner). Only two of these are presently operating (Everett and Lake Charles), but another has been converted to LNG peaking service (Cove Point).

1. Lake Charles, Louisiana -- Trunkline Gas Co. (Pan Energy)
2. Elba Island, Georgia -- Southern Natural Gas
3. Cove Point, Maryland -- Columbia Gas Transmission
4. Everett, Massachusetts -- Distrigas (Cabot LNG)

Tables IV-9 through IV-11 below show the historical in-service time periods for LNG peak shaving capacities and respective number of plants. The bulk of the peak shaving capacity was installed between 1965 and 1975. This is demonstrated in the bar graph of Figure IV-1. The construction activity of that time was the result of rapidly expanding natural gas demand and capacity limitations on major US pipelines. The same construction activity is evident in LNG satellite capacity, as seen in Tables IV-12 and IV-13, and Figure IV-2. The significant reduction in construction activity that occurred after 1975 was the result of gas supply curtailments, the development of more economically attractive peaking supply options (underground storage), and federally mandated restrictions in 1978 on the use of natural gas as boiler fuel.

Table IV-9

Time Period	LNG peak shaving liquefaction capacity in MMcfd	No. of facilities	Average Capacity per facility, MMcfd
1965-1970	64.3	14	4.6
1971-1975	196.0	31	6.1
1976-1980	34.8	7	5.0
1981-1985	5.6	1	5.6
1986-1990	13.5	2	6.8
1991-1995	7.8	1	7.8

Table IV-10

Time Period	LNG peak shaving vaporization capacity in MMcfd	No. of facilities	Average vaporization capacity per facility, MMcfd
1965-1970	2874	14	205
1971-1975	4241	31	136
1976-1980	446	7	64
1981-1985	105	1	105
1986-1990	450	2	225
1991-1995	180	1	180

Table IV-11

Time Period	LNG peak shaving storage capacity in MMcf of liquid	No. of facilities	Average Storage Capacity per facility
1965-1970	16462	14	1176
1971-1975	36267	31	1170
1976-1980	6800	7	971
1981-1985	1011	1	1011
1986-1990	3000	2	1500
1991-1995	1011	1	1011

Figure IV-1

Peaking Construction Patterns

in Number of Facilities per Time Period

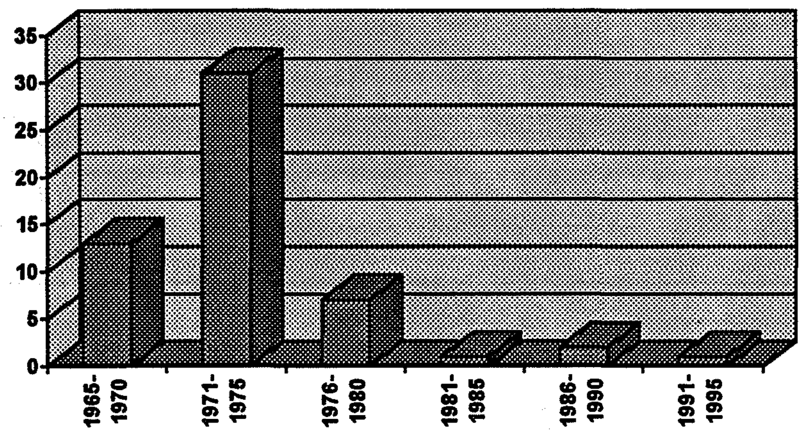


Table IV-12

Time Period	LNG Satellite vaporization capacity in MMcfd	No. of plants	Average Vaporization Capacity per facility
1965-1970	31.4	3	10.3
1971-1975	743.3	25	29.8
1976-1980	0	0	0
1981-1985	0	0	0
1986-1990	0	0	0
1991-1995	89.8	1	89.8

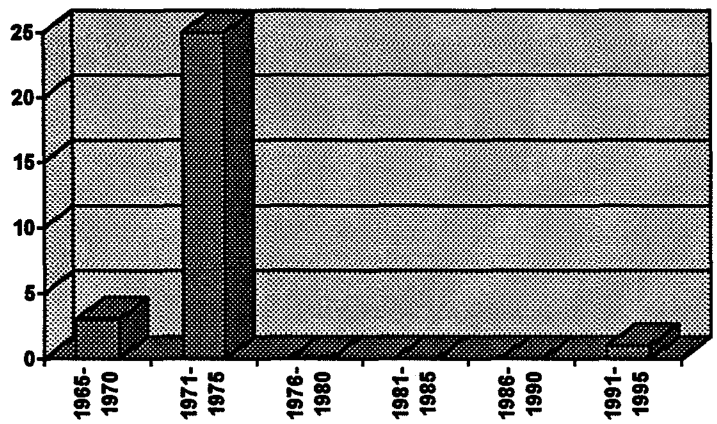
Table IV-13

Time Period	LNG satellite storage capacity in MMcf of liquid	No. of plants	Average Storage Capacity per facility, MMcfd
1965-1970	170	3	57
1971-1975	8862	25	354
1976-1980	0	0	N/A
1981-1985	0	0	N/A
1986-1990	0	0	N/A
1991-1995	928	1	928

Figure IV-2

Satellite Construction Patterns

in Number of Facilities per Time Period



There is renewed interest in peak shaving with LNG as a result of regulatory change affecting pipeline services, competition for market share, improved project economics (vis-à-vis conventional pipeline capacity) and growth in peak-day demand. Testimony to this renewed interest is witnessed, in part, by recent projects such as:

> Cove Point, Maryland which has 3.6 Bcf total storage capacity, 15 MMcfd liquefaction capacity and 400 MMcfd vaporization capacity. This facility offers 10, 5 and 3-day service primarily to Mid-Atlantic and Southeastern Markets. Cove Point was formerly a base load import terminal that has now been converted to a peakshaving facility.

Several other new projects are under development including:

1. Pine Needle LNG
    - Guilford County, N.C.
    - 4 Bcf storage; 20 MMcfd liquefaction; 400 MMcfd vaporization
    - in-service May 1999; estimated cost $107 MM

- interconnection with Transco

2. Algonquin Gas Transmission
    - Providence, R.I.
    - Upgrade to existing LNG facilities -- convert storage to peaking facility
    - Total Capacities: 2 Bcf storage; 40 MMcfd liquefaction; 375 MMcfd vaporization
    - estimated cost $75.7 MM; in-service date 1998
    - interconnection with Algonquin
3. Granite State
    - Wells, Maine
    - 2 Bcf storage; no liquefaction; 64 MMcfd vaporization
    - estimated cost $44 MM; in-service 1999
4. Memphis Light, Gas & Water
    - 1 Bcf storage; 5.5 MMcfd liquefaction; 100 MMcfd vaporization
    - estimated cost $35 MM
5. Various others being considered in Georgia and Massachusetts.

The capacity additions listed above represent a significant increase in the construction of LNG facilities. While not at the level of 1971 - 1975 the construction projected for 1996 - 2000 reflects the improved economic viability of LNG.

V. Major Components of a Typical LNG Peaking Plant

The following is a general overview of the major facilities comprising LNG peaking plants. This overview is intended to provide the reader unfamiliar with the major components of a typical LNG plant a greater understanding of the design, engineering, construction and operating characteristics. It is noted that this is only an overview, limited by what is considered informative for the overall purpose of this report, without delving into detailed technical issues.

Background

The commercial practice of liquefying natural gas commenced during World War I by the British for the recovery of helium. In 1941 the world's first commercial LNG storage plant was built in Cleveland by the East Ohio Gas Company. This plant was designed for peakshaving purposes and had an initial storage capacity of about 170 MMcf utilizing three spherical tanks. After two and one-half years of successful operation, a 100 MMcf tank of cylindrical design was added. It was established, after the disastrous failure of this tank, that the inner shell of 3.5 percent nickel steel, was inadequate at the service temperature of LNG. This event signaled the need for critical evaluation of the hazards involved in the storage of LNG. The Bureau of Mines report RI 6099, indicated at that time, that, regardless of the Cleveland incident, the application of the system for liquefying and storing large quantities of natural gas could safely be undertaken in suitably designed above ground tanks.

It wasn't, however, until 1964, when the next LNG peaking plant with above ground storage was built in the US. The need for LNG peaking facilities was greatest in the Northeast and Middle Atlantic areas where rapid increases in peak demand were experienced and where geologic conditions precluded the use of storage in underground reservoirs. The improvements in technology have since promoted the use of LNG for peakshaving purposes in regard to both safety and cost effectiveness.

The primary function of an LNG peaking plant, to provide pipeline quality natural gas on days of peak demand, involves three major operations; liquefaction, storage and regasification (vaporization) of natural gas. To accomplish this, natural gas is first transformed into its liquid form, requiring refrigeration and condensation, to a temperature of about -260 F. As a liquid, natural gas is stored at atmospheric pressure in refrigerated tanks, where the liquid requires only 1/600 of its equivalent gaseous volume. Finally, when needed for sendout on peak days, the liquid is revaporized by the addition of heat, through the vaporization unit.

Identifying the design requirements of the peakshaving plant is a critical aspect of facility planning, as this will establish the daily liquefaction, daily sendout and storage requirements. These specifications will also narrow the options on plant type and site selection. Exclusion and dispersion zone requirements are significantly more rigorous for the LNG plants with capacities exceeding about 2,000 dekatherms per day sendout and storage of 70,000 gallons (5,800 Mcf). The greater acreage required to comply with these restrictions may require the site to be located on the outer reaches of the distribution system, in turn causing additional expense in distribution to enable service system wide. Alternatively, access to the distribution system may have to be gained through pipeline transportation tariffs, the costs which one is attempting to avoid.

The design of a typical LNG facility provides for about 5 to 15 days of storage at the design maximum sendout rate. Liquefaction, which can be implemented during the off-season, is usually sized to fill the installed storage capacity in about 200 days. Some facilities rely on third party suppliers to more cost efficiently replenish their LNG storage. This is most commonly done with 10,000 gallon tanker trucks, and makes for prudent design to have trucking loading and unloading facilities included at most sites.

Site

The processes involved in the operation of an LNG peaking facility require that careful consideration be given to the proposed location of the plant. As with other types of process plants, successful operation depends greatly on the integration of the plant design with the characteristics of the immediate environment. Key items of consideration are certain specifics of meteorological interest such as the ranges of temperature, humidity, and atmospheric pressure, prevailing wind and rainfall patterns. Additionally, soil stability must be identified as well as the potential for earthquake, flood, and tornado. The site specific regulatory mandates, as imposed by federal, state, and local authorities must also be considered. Among others, regulatory mandates have an impact on the required property size in terms of required exclusion zones to protect off-property targets from thermal radiation and flammable vapor gas dispersion resulting from leaks or spills of LNG and other fluids. In this regard, the site must have sufficient acreage for the required spill zone and must be adequate for vapor dispersion. The local permitting climate, or public opinion can also impact the siting of an LNG plant. This can be problematic, as LNG is not well understood by the public, thus having the potential for siting difficulties. Additionally, the proposed plant location must have adequate access to necessary pipeline connections and electric transmission, water and roads. Finally, the site should be located in the market area or have backhaul capacity into the market.

In addition to the above key requirements, satellite peaking plants, where liquefaction is not carried out, must have adequate accessibility, for trucks and/or railcars, to supply the plant with LNG. Satellite plants usually have smaller storage tanks, as these are commonly refilled during the heating season. Satellite LNG peaking facilities should be located near a depot of LNG supply to minimize transportation costs.

Gas Treatment, Feed and Product

The process of liquefying natural gas requires tight controls over the feed gas quality. Components such as water, carbon dioxide and heavy hydrocarbons, which would solidify at temperatures encountered in LNG operations, must be removed. All other trace impurities which could present problems should be identified and removed or dealt with in the design of the facilities. To meet product specifications, the removal of certain compounds such as sulfur and nitrogen, while generally not problematic in LNG processes, may also need to be considered. All other considerations normally given to a conventional gas treatment plant, such as the variations in feed hydrocarbon composition, flow rate, pressure, and temperature will, likewise, need to be considered in the design of an LNG gas treatment facility. The equipment utilized in the gas purification process are generally filter-separators and adsorbers (e.g. molecular sieve and amine).

As water and carbon dioxide content in the feed stream can fluctuate significantly, it is important that the plant operator be able to monitor these and make appropriate adjustments if needed. Likewise, the purified natural gas stream to be liquefied, should be monitored continuously for water and carbon dioxide content. Carbon dioxide is typically monitored by an infra-red type analyzer, while there are a number of analyzers in general use for monitoring water content.

Experience has shown that a water content of no more than 0.1 part per million by volume is satisfactory for LNG plants under specified operating conditions.[7] Water removal is generally achieved through a molecular sieve utilizing synthetic zeolite adsorbent or other dry desiccants such as activated alumna, activated bauxite, and silica gel.[8]

Safe LNG operating practice requires a carbon dioxide content of below 50 parts per million by volume in the treated feed gas stream. The most commonly employed methods

[7] The American Gas Association, "Gas Engineering and Operating Practices", Volume I, Supply; 1987
[8] Ibid., pp. 33-42

of removing carbon dioxide from the feed gas stream are through amine and molecular sieve processes, although other processes have been used.

Desiccant dust, compressor oil and heavy hydrocarbons found in the feed gas stream are usually removed with conventional inlet filter separators, mist extractors, or carbon filters. The amount of pentanes plus should not exceed 0.1 mole percent. In areas where mercury might be present in the gas stream, a mercury absorber bed utilizing sulfur impregnated activated carbon, or other proved catalysts, should be provided. Mercury in the feed gas corrodes aluminum, which is used in the cryogenic liquefaction exchangers, and should be limited to less than 0.01 micrograms per cubic meter of feed gas to the cryogenic section[9].

Consideration in the design of facilities must be given to the disposal of the separated fluids, regenerated gas, and process-created contaminants. Fluids which are separated are collected and usually drained to a hold tank for periodic disposal by truck. The regeneration gas stream is often re-injected into the pipeline. Care must be given to assure adequate flow in the receiving pipeline to accept the regenerated gas with its increased components of impurities.

The typical composition and properties of LNG are presented in Table V-1. The ability of LNG plants to provide a consistent composition and a high methane content makes LNG an ideal source of fuel for natural gas vehicles.

Liquefaction

Subsequent to pretreatment, the gas stream is processed to convert it from its vapor state to liquid form. The liquefaction process basically involves the removal of energy in the form of sensible and latent heat, thereby reducing the gas stream volume by a ratio of 600 to 1, to its liquid form at about -260°F. It is not uncommon to find liquefaction capacities

[9] "Challenges Facing LNG", Oil & Gas Journal, July 3, 1995, p 44

Table V-1

Typical LNG Properties

LNG Component	Mole %
Nitrogen	0.0061
Methane	0.8964
Ethane	0.0772
Propane	0.0151
n-Butane	0.0021
i-Butane	0.0031
Pentane Plus	0.0001

LNG Properties

Gross Heating Value	1100	Btu/Scf
Molecular Weight	17.8	
Specifc Gravity to Air	0.616	
Density of Liquid at 16 psia	3.82	lbs/gal
Density to Water	0.457	
Temperature at 16 psia	-258.5	Fahrenheit
Btu per cubic foot of liquid	0.666	MMBtu
Btu per pound of liquid	23,336	
Scf Vapor per cubic foot Liquid	605.5	

as high as 10 MMcfd at peaking plants. Generally, liquefaction facilities are designed to fill the storage tank capacity in about 200 days, the extent of the non-heating season.

The removal of heat to facilitate liquefaction is accomplished by two general methods. Variations to these are practiced in the industry. The two general means of heat removal are:

1. The transfer of heat through refrigerants using
   a) several circuits of single component refrigerants in a cascading type cycle, or
   b) a single circuit of a blend of refrigerants in a mixed refrigerants cycle.

2. The application of expander cycles

Detailed description of the liquefaction processes can be found in the literature. Presented here are simplified basics of each process.

1. Cycles Using Refrigerants

The most widely applied liquefaction process in LNG operations is the type utilizing refrigerants. Commonly referred to as the evaporator cycle, it operates on the concept of transferring heat from the process stream to the refrigerant during phase change of the latter from liquid to vapor. The heat required by the refrigerant, to enable its vaporization, is provided by the process stream, which in turn is cooled sufficiently to promote condensing. A schematic of the basic evaporator cycle is provided in Figure V-1. In a closed loop the refrigerant is compressed in its vapor state and subsequently cooled in a heat exchanger with cooling water to facilitate condensing. The liquid refrigerant is then allowed to expand causing a reduction in temperature. At this state it is vaporized, extracting the required heat of vaporization from the process stream (thereby cooling it)

Figure V-1

Basic Evaporator Cycle

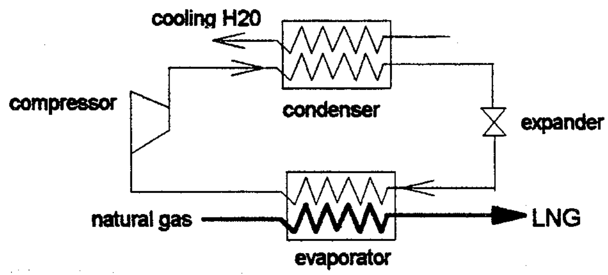
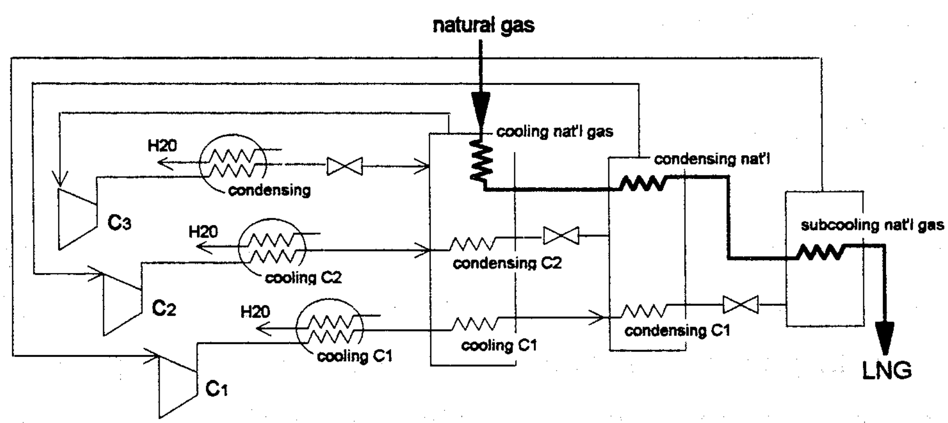


Figure V-2

Simple Cascade Cycle



through contact in a heat exchanger. The refrigerant, at this stage a vapor, is then charged through the compressor, completing the cycle in a continuous process.

a) Cascading Cycles

As each individual refrigerant can provide only a certain range of cooling, a system in which a series of refrigerants are used to obtain a lower and lower temperature is employed. This is the cascading principle. A simple cascade system for LNG is shown schematically in Figure V-2. Refrigerants commonly used are propane, ethylene and methane. By increasing the number of refrigerants employed in the liquefaction process, improvements in the cascade cycle efficiency can generally be realized[10]. In this sense it is very practical and can be adopted to meet virtually any cooling requirement.

b) Mixed Refrigerants Cycle

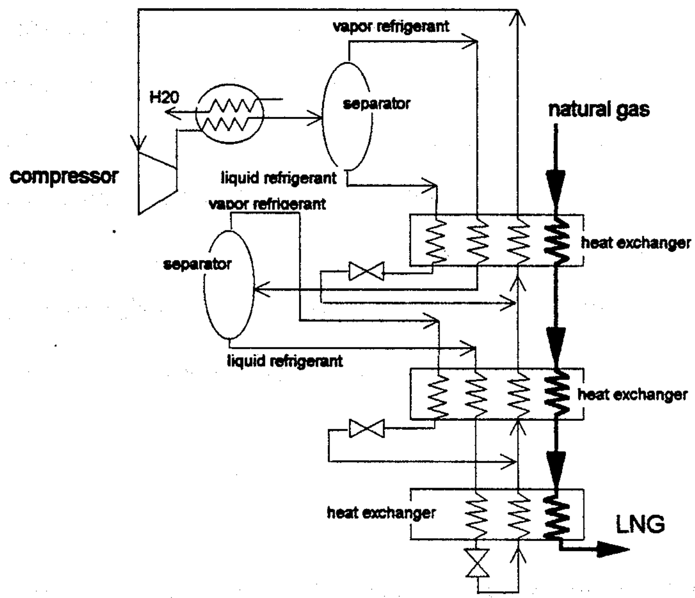
Under certain circumstances, investment costs may be reduced by utilizing a variation of the cascade cycle which involves the mixture of several refrigerants in a single stream. There are numerous variations of this cycle in use today, many of which are proprietary with the developers of the technology. Figure V-3 depicts a simplified schematic of a mixed refrigerant cycle. In general, a refrigerant mixture of components such as butane, propane, ethane, methane, and nitrogen is brought into contact with the natural gas feed stream at various stages of refrigerant vaporization. The refrigerant stream is compressed, cooled and separated into vapor and liquid streams. In a series of condensing, expanding and revaporization operations, heat is transferred to provide cooling and liquefaction of the natural gas stream, partial condensing of the refrigerant vapor stream and subcooling of the refrigerant liquid stream in a continuous process.

The major components required for the operation of the evaporator cycle are compressors, heat exchangers, water cooling units, and instrumentation. Additionally,

[10] AGA LNG Information Book, Operating Section Report, 1981, p 26

Figure V-3

Basic Mixed Refrigerant Cycle



equipment will be needed to reject the compressor lubricating oil from the refrigerant, refrigerant storage and handling, and heavy hydrocarbon recovery (from the natural gas stream).

2. Expander Cycle

The second type of liquefaction process, the expander cycle, utilizes the energy available in high pressure gas to perform external work by expansion through a turbine or engine while lowering the temperature of the working fluid. There are many variations of this process, the combinations of which depend on a number of factors to include the applicable economic variables and the limits imposed by the design criteria and conceptualization. A schematic of a basic expander cycle is shown in Figure V-4. The high pressure natural gas stream is split into two streams. The first stream is expanded through either a turbine or engine to produce a cooling effect, while being reduced in pressure. The second stream is cooled through contact in a heat exchanger with the expanded stream. Once cooled, the high pressure stream is then further cooled by expanding through a valve, thereby facilitating condensing. A separator provides for the separation of liquid and vapor streams. The separated liquid is sent to storage while the vapor is sent to the distribution system after serving as a heat sink for the high pressure gas stream.

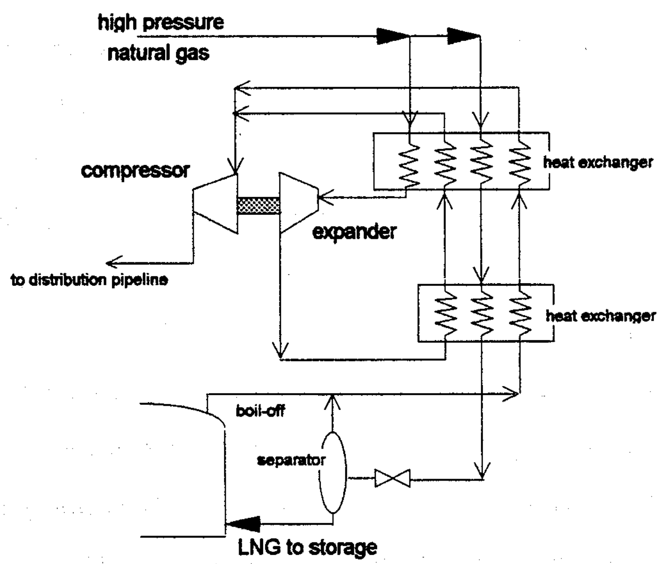
Construction costs for a given capacity of liquefaction is mostly influenced by the cycle employed, feed gas pressure and requirements for flash gas reliquefaction.

Storage

Following liquefaction, the natural gas is pumped to the storage vessel(s) where the liquid is held at atmospheric pressure until such time as it is needed for system demand. As the storage of LNG represents a large concentration of contained energy, as much as 2 Bcf for

Figure V-4

Basic Expander Cycle



some of the largest peaking plants, the primary consideration in the design and construction is safety.

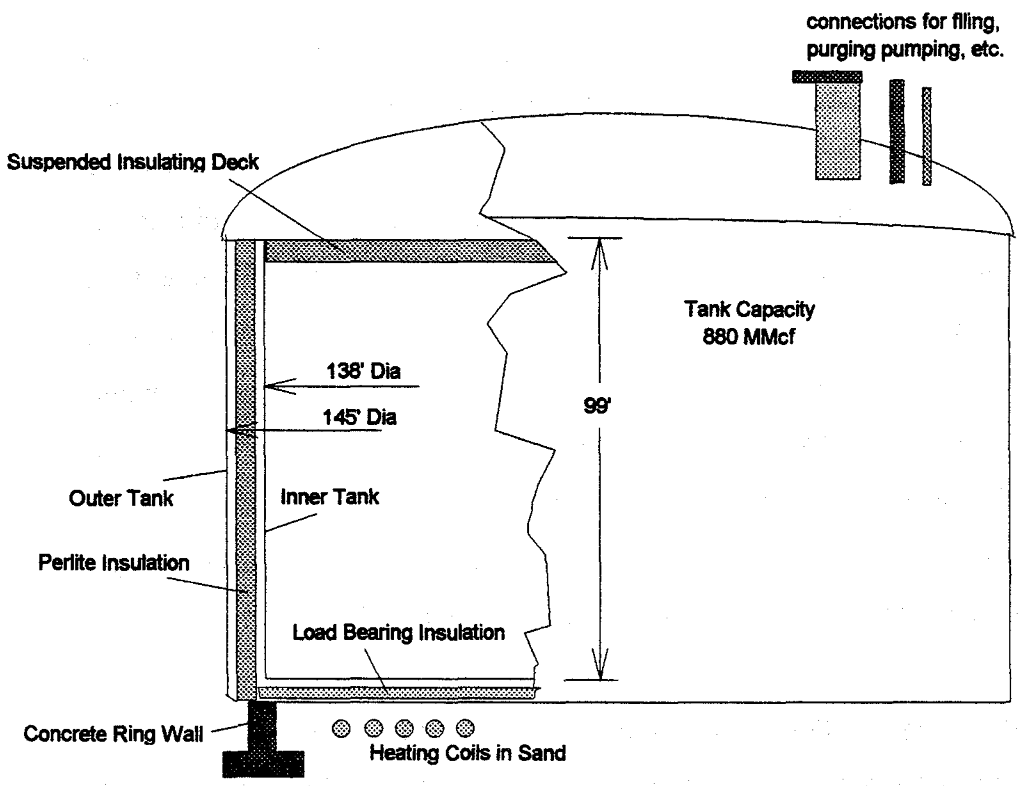
The most commonly used LNG storage vessel is the above ground, free standing, double-wall type. These are generally flat-bottomed tanks, cylindrical in shape and having a domed roof, successfully used for cryogenic service since the early fifties. The outer tank, consists of a shell made of carbon steel and basically acts as a vapor/moisture barrier and container of insulation. The inner tank is of either nickel steel or aluminum, suitable for cryogenic temperatures. An insulation deck is suspended from the dome of the outer tank over the top of the inner tank. The two tanks are separated by an insulation layer of expanded inorganic material, commonly called perlite. Additionally, a rigid insulating material, such as foamglass, separates the inner tank from the conventional, pile supported, concrete foundation. For safety purposes, the tank is surrounded with an earthen dike (burm) to provide a minimum containment volume of 1.5 times the storage tank volume. A typical double-wall LNG tank is depicted in Figure V-5.

Other types of LNG storage, such as spherical metal tanks, buried concrete tanks, and in-ground frozen storage, have been used in LNG plants. Certain drawbacks associated with these types of designs, however, have been experienced in existing installations. It is the double-wall type that has been used as the basis for design variation in common use today. The double-wall principle is utilized for a wide variety of free standing, cylindrical storage vessels generally termed as double containment vessels.

The double containment design embodies the principle of duplicity, or back-up, with the primary objectives of containing the liquid in the event of a leak and protecting the liquid from outside forces such as wind born projectiles and vapor cloud explosion (the ignition of an accumulation of flammable vapor, such as natural gas). These vessels typically utilize prestressed concrete as either an outer shell or an integrated part of the vessel wall(s).

Figure V-5

Cutaway View of Typical Above Ground Double-Wall LNG Tank



The selection of the type of LNG tank to be installed should always include the consideration of:

- safety
- site specifics
- local regulatory requirements
- risk of impact on outer tank walls
- economics of number of tanks and tank size
- tank foundation heating requirements
- prior tank operating experience

Industry experience with the double-wall LNG tank design can be summarized with the following economic and technical advantages:[11]

- No geographic limitation for location of storage unit
- Controlled heat influx, allowing low heat influx by design.
- Long life and low maintenance; insulation system and liquid container have equal life.
- Proved by hydrostatic and pneumatic testing to overload conditions.
- Proven technology through years of operating experience.
- Complete accessibility for inspection or for removal from service for modification.
- No contamination of stored product.
- Rapid and inexpensive cooldown (or warmup). Ready for service within days after completion..
- Fixed costs with all costs known before selection and installation; predictable construction schedule.
- Minimum technical and economic risk due to well established material properties and quality assurance procedures.

As part of the LNG tank design, careful consideration must be given to the tank internal components. All possible operating conditions under which the tank and its components will be subjected, must necessarily be included in these considerations. Operating conditions such as tank cooldown, normal operation and decommissioning, and will identify the specific loads the tank and its components will experience. Internal components include the facilities to allow adequate liquid loading (top or bottom), purge

[11] "LNG Information Book 1981", American Gas Association, p. 46

system, and cooldown devices. Additionally, consideration must be given to the pros and cons of various pump designs and configurations. There are, for instance, certain advantages to having the pump located internally, submerged in the LNG as opposed to locating it out-of-tank. To avoid penetrating the tank below the liquid level, tanks are built with the necessary connections through the top of the tank, where possible.

Generalized tank cost estimates are complicated by required items generally associated with the installation of the tank. As much as 30 percent of the total storage installation cost can be comprised of non-tank specific items such as liquid and gas piping, fire control, site preparation and piling. The cost of the storage facility can also be significantly affected by such factors as tank layout , intertank distance, tank type, and soil/subsoil conditions.

Vaporization

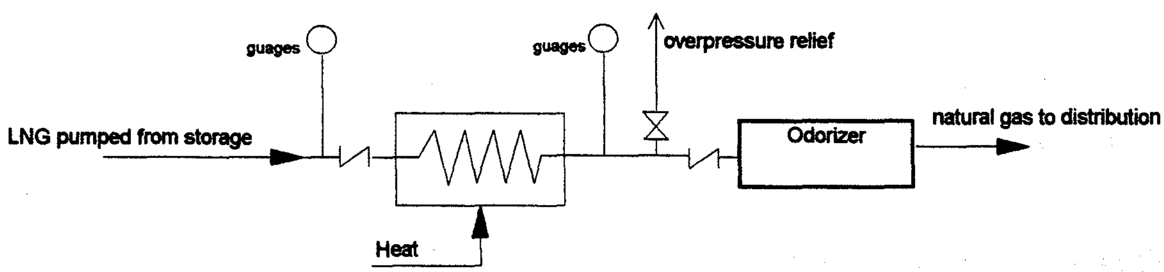
While liquefaction facilities are generally sized to fill the storage tank capacity in about 200 days, the vaporization facilities in a peakshaving plant are typically designed to revaporize the entire plant storage in 5 to 15 days. Plants with vaporization capacities up to 200 MMcfd are not uncommon.

The vaporization process involves pumping the liquid from the storage tank, to the required pressure level, through a heat exchanger, where vaporization takes place. The facility is a relatively simple system, consisting of liquid pumps, vaporizers, piping, and control, metering and odorization equipment. Figure V-6 is a diagram of a simplified typical LNG vaporizer system.

LNG vaporizers can be classified into two types; Direct Fired and Indirect Fired. A Direct Fired vaporizer can generally be thought of as a vaporizer in which the heat from the combustion gases directly contacts the tubes through which the LNG flows in the heat exchanger. In an Indirect Fired vaporizer, the LNG tubes in the heat exchanger are

Figure V-6

Simplified LNG Vaporizer System Schematic



contacted with an intermediate fluid, such as an Ethylene Glycol-water solution, which is pumped through the heat exchanger after being heated by combustion gases. The most commonly used vaporizer in the U.S. is the Direct Fired type. Both types of vaporizers utilize propane or other liquid that does not freeze at LNG temperatures.

Although the cost of the vaporization system represents only a small fraction of the entire plant cost, its importance cannot be underestimated. Vaporization is relied upon by the peaking plant operator to provide system supply at times of critical need.

Safety and Related Design Codes

Extensive research has been conducted on the technical issues related to LNG design and operation with the purpose of identifying the most reasonable means of achieving maximum safety to plant personnel and the public. Much of this research has centered on LNG spill evaporation rates, vapor dispersion, thermal radiation, fire control and vapor suppression. From this work, analytical vapor dispersion and heat radiation models have been developed to predict the consequences of LNG spills and fires. The combination of these efforts with LNG and cryogenic industries plant operating experience has contributed to the current standards for safety and design codes for the LNG industry.

Critical to the safe performance of the components in an LNG facility is the proper selection of materials, particularly for service in cryogenic application. Key metallic materials specification include minimum melting points and impact resistance at low temperature. Corrosion considerations are particularly important in LNG operations as the materials will have to withstand those stresses compounded by the long term exposure to cryogenic temperatures. It is, therefore, critical that only acceptable alloys and metal joining methods are employed in the design and construction of an LNG plant.

There are a number of guidelines that specify the metallic materials of use for LNG plants. Among others, these are listed in ANSI B31.3 for Chemical Plant and Petroleum Refinery

Piping: ASME VIII for The ASME Boiler and Pressure Vessel Code - Unfired Pressure Vessels; and API 620 Appendix Q, API Standard for Design and Construction of Large, Welded, Low-Pressure Storage Tanks.

The following is a list of some of the key agencies governing codes and specifications related to LNG facilities design, construction, safety and operation.

- Department of Transportation (DOT)
- Environmental Protection Agency (EPA)
- American Concrete Institute (ACI)
- American Gas Association (AGA)
- American Institute of Steel Construction (ANSI)
- American Petroleum Institute (API)
- American Society of Mechanical Engineers (ASME)
- American Society for Testing and Materials (ASTM)
- American Welding Society (AWS)
- National Association of Corrosion Engineers (NACE)
- National Electrical Manufacturers Association (NEMA)
- National Fire Protection Association (NFPA)
- other state and local agencies

Appendix A

LNG Peaking Facility Costs

Key in determining meaningful comparisons of peaking alternatives and the ultimate optimization of peaking supply, are the cost parameters generated for each peaking facility for each duration or level of usage. An attempt will be given here to identify the major components of cost for LNG peaking facilities.

Gas utilities intent on minimizing their cost of peaking service will commonly rely on consultants and/or engineering/contracting firms, to provide cost related information. Publicly available literature on the subject of peaking facilities cost in general, and LNG facilities cost, in particular, is quite meager. The last published costs were based on mid-1980s costs and design and construction standards. While the design and construction standards have not changed significantly (with the exception of more stringent diking requirements) since that time, the costs have escalated by a factor of roughly 130%.[1]

This section presents information related to the cost of LNG peaking facilities and its major components. Information herein is derived from a combination of actual costs, FERC filings, construction proposals, and historical published figures which have been escalated. To ensure reasonableness, manufacturers and engineering/contracting firms have been asked to confirm these figures. The purpose of presenting cost information here is to provide rough budget estimates for LNG peaking facilities for interested parties in the valuation of market opportunities.

It should be further noted that costs presented here are generalized averages. They would obviously need adjustment as required by site specific conditions/requirements. These would include such specifics as the need to construct larger liquefaction and storage facilities for filling of satellite storage-only facilities which have no liquefaction capability.

[1] Marshall Valuation Service; Marshall & Swift, L.P.; 1996

A) LNG Plant Investment Costs

LNG plant capital costs are typically made up from the major components of the plant as identified below for a large range of plant sizes in terms of increasing storage capacity:

LNG Plant Component	Typical Fraction of Overall Cost
Tanks and Dikes	35% to 56%
Liquefaction	22% to 29%
Plant Facilities	10% to 13%
Pumps and Vaporizers	6% to 14%
Fire Protection & Security	6% to 9%

Land and Engineering/Management costs typically are an additional 10% of total plant costs.

Generalized LNG plant costs for a wide range of plant sizes are more meaningfully presented in terms of cost curves for the major cost components of the plant. Figures A-1 through A-6 illustrate the cost/capacity relationships for a range of LNG plant sizes. Costs in these figures are for 1) Total Plant, 2) Plant Liquefaction and Pretreatment, 3) Storage, 4) Pumpout and Vaporization, 5) Plant Facilities, and 6) Fire and Safety[2]. Costs from this report were updated with actual current costs and indices, expanded to include a wider range of plant sizes, and confirmed by system manufacturers and engineering/contracting firms[3]. These costs are representative of plants with average specifications located in the Middle Atlantic states.

As seen from the series of cost curves in Figures A-1 through A-6, total plant direct construction costs for a 1 Bcf (300,000 Bbls) plant can range from $19 to $29 million. This wide variance is due to the nature of budget estimates, which have greater variances than costs based on actual quotations. Note that these costs also do not include the costs for land or engineering/management. Direct construction costs are commonly figured into the fixed cost component of the plant.

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[2] AGA Operating Section Proceedings, 1985; Arlington, VA, pp. 58-62.

[3] Courtesy of Chicago Bridge & Iron

B) LNG Plant Operating Costs

Operation and Maintenance (O&M) costs are comprised of utilities, maintenance/ materials, and labor. These are commonly categorized as fixed and variable costs, whereas the investment cost is considered to be entirely fixed.

Fixed Costs

The fixed O&M costs are the utilities (fuel and electric) to handle and replace the boil-off gas (BOG) and for overall continuous plant demand, the maintenance/materials, and labor.

BOG is the vapor that naturally collects in the storage vessel and must be removed to prevent pressure build-up. The vaporization of LNG in the storage vessel is an important process for the removal of heat from the vessel. BOG can be roughly estimated as six hundredths of a percent (0.0006) of the total storage capacity per day. For a 2 Bcf storage tank, the annual BOG is estimated to be 438 MMcf, or about 22 percent of the stored LNG. The BOG is commonly sent to the distribution system, usually requiring some boost in pressure. The estimated amount of fuel to accomplish this, assuming compression to 200 psi, can be roughly estimated as 19.8 MMBtu per MMcf of BOG. Fuel to makeup the BOG with LNG is estimated at 144 MMBtu per MMcf of BOG.

The annual cost of Maintenance and Materials can be reasonably estimated as a fraction of the plant costs, as follows:

Area	Matl's & Maint., % of Plant Costs
Liquefaction	1.8
Storage	0.5
Vaporization	1.8

Annual labor costs are typically estimated on the basis of 2 to 3 operators per shift at about $85,000 per year each, including overhead and benefits.

For a 2 Bcf LNG plant with liquefaction capacity of 10 MMcfd and vaporization capacity of 100 MMcfd, with a cost of $42 MM (26% Liquefaction; 45% Storage; 12% Vaporization; or a total of $47 MM including Land and Engineering/Management) for direct construction, the annual fixed costs are estimated as follows:

Fixed Cost Category[4]	$ MM
Plant Investment {@ 15% LDC Levelized Fixed Charge Rate}	7.05
Fuel, B G {438MMcf * (19.8 +144)MMBtu/MMcf*$2/MMBtu}	0.14
Electricity, Tank Heater {150,000Kwhr/yr/Bcf stored*2.Bcf*$0.0636/Kwhr}	0.02
Materials and Maintenance	
Liquefaction {$42 MM * 0.26 * 0.018}	0.20
Storage {$42 MM * 0.45 * 0.005}	0.10
Vaporization {$42 MM* 0.12 * 0.018}	0.10
Electricity, Continuous Plant Demand{550,000Kwhr/yr/MMcfd Liq Cap*10^{-5} MMcfd*$0.0636/Kwhr}	0.11
Labor {9 opertrs * $85,000 ea.}	0.77
Interest on Inventory[5] {@ 10 percent}	0.36
Total Fixed Costs	8.85

For fixed costs in the amount of $8.85 million, an equivalent demand charge, based on the plant deliverable capacity of 100 MMcfd, would be calculated as $7.38/Mcfd/mo.

Variable Costs

Variable costs include those that can be more directly tied to the amount of product being processed during an average year of operation. These are the costs related to liquefaction fuel (or transport to storage) and vaporization fuel. The commodity cost of the processed gas is also considered a variable cost and will necessarily have to be considered when making cost comparisons. For propane-air facilities, a commodity premium for propane would be considered. For LNG or other storage facilities, a commodity cost savings may be realized when purchasing less expensive summer spot gas. For purposes of illustration the cost of gas will be tallied separately in this assembly of costs.

[4] Note: natural gas and electric utilities estimated at $2.00/MMMBtu and $0.0636/Kwhr, respectively

[5] Includes average amount of yearly inventory, incremental cost of liquefaction, cost of gas, and interest rate.

The calculation of the variable costs are based on a Liquefaction design capacity of 10 MMcfd planned to be used for 100 days during an average year, and Vaporization of 100 MMcfd for 10 days.

Variable Cost Category[6]	$ MM
Fuel, Liquefaction {10MMcfd*100days*144 MMBtu/MMcf*$2/MMBtu}	0.29
Electricity, Tank Pump {65Kwhr/MMscf*1000MMscf*$0.0636/Kwhr}	neg.
Fuel, Vaporization {100MMcfd*10days*1050Btu/cf*$2/MMBtu*0.02}	0.04
Other, Vaporization {100% of Vaporization fuel}	0.04
Total Variable Costs	0.37
	or $ 0.37/Mcf

C) LNG Plant Total Annual Costs

The total annual cost of peakshaving is the sum of the fixed and variable costs, including investment cost, O&M cost, and the cost of gas, as follows:

	$ MM
Total Fixed and Variable Costs, excluding cost of gas	9.22
Cost of Gas {@$2.0/MMBtu*$10^3$MMcf*1050Btu/cf}	2.10
Total Annual Cost, including cost of gas	11.32
Average Annual Cost per Storage Capacity {@2.1*10^6MMBtu = 2,000 MMcf*1050Btu/cf}	$ 5.39/MMBtu or $ 5.66/Mcf

This specific plant has a load factor of 2.7 percent based on an annual average sendout of 1 Bcf and a peak deliverable capacity of 100 MMcfd. For this level of usage, the unit cost, as calculated in our earlier equation, is

LNG Plant Unit Cost = [(12*7.38)/(365*0.027)] + 0.37 = $9.36/Mcf.

This represents the unit cost for having the peaking facility in-place, on standby and ready for service. As mentioned above, another cost item for consideration is the cost of gas. Gas storage systems, such as LNG, commonly purchase spot gas for storage during the summer months, when natural gas is oftentimes less expensive than during the winter season. Cost savings can also be

6 Natural gas and electric utilities estimated at $2.00/MMBtu and $0.0636/Kwhr, respectively

realized by utilizing cheaper interruptible transportation service during the summer to transport gas to the LNG facility. These are generally variable costs, which would be added to the above calculated facilities unit cost of gas supply. In the above example, the cost of gas at $2.00 per MMBtu would result in an additional variable cost of $2.10 per Mcf (assuming 1050 Btu/cf). In comparison, firm gas supply to be available on peak, while currently not commonly marketed with a demand charge, will have an associated cost premium.

Figure A-1
LNG Peaking Plant Total Cost

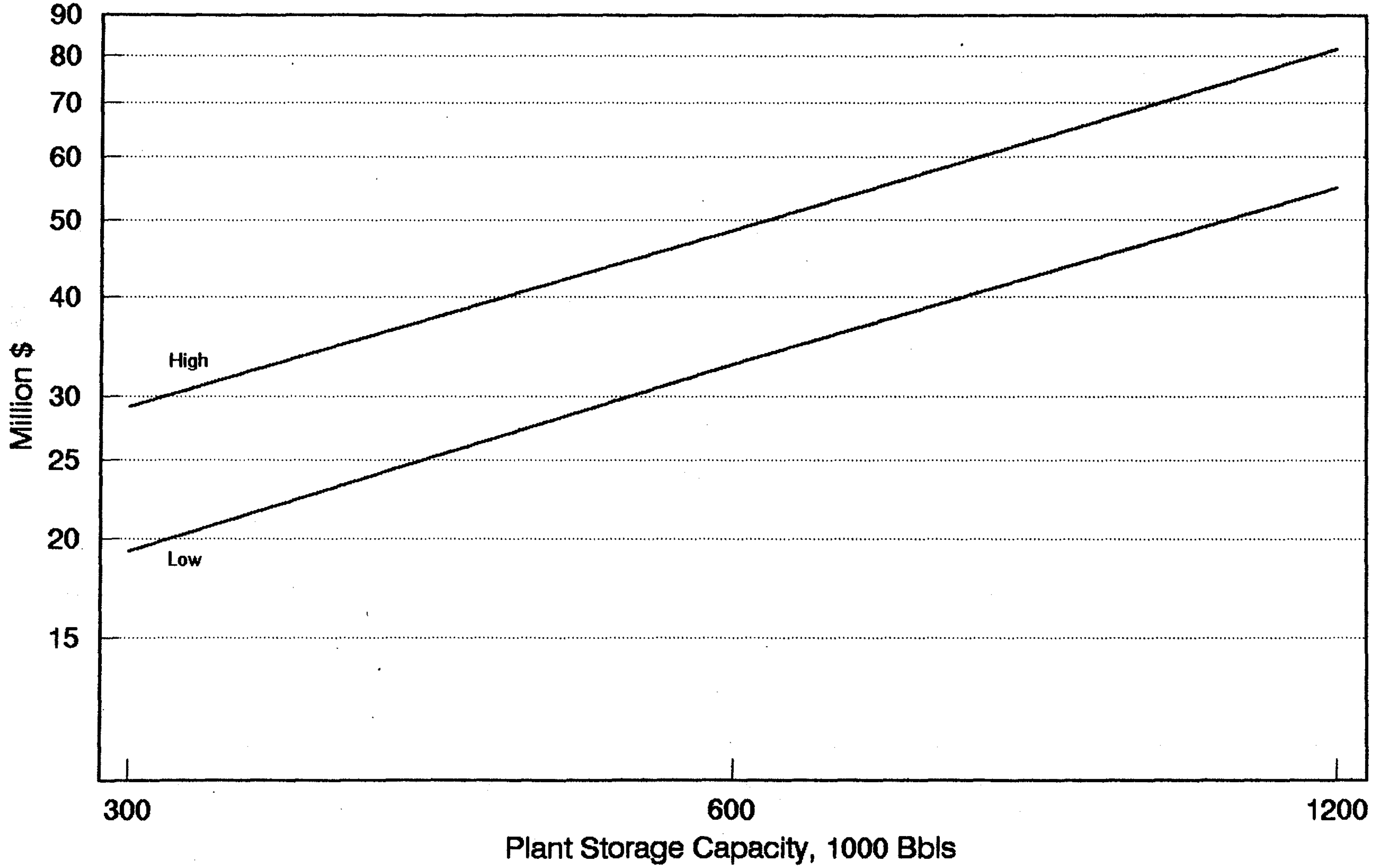


Figure A-2
LNG Plant Liquefaction and Pretreatment Cost

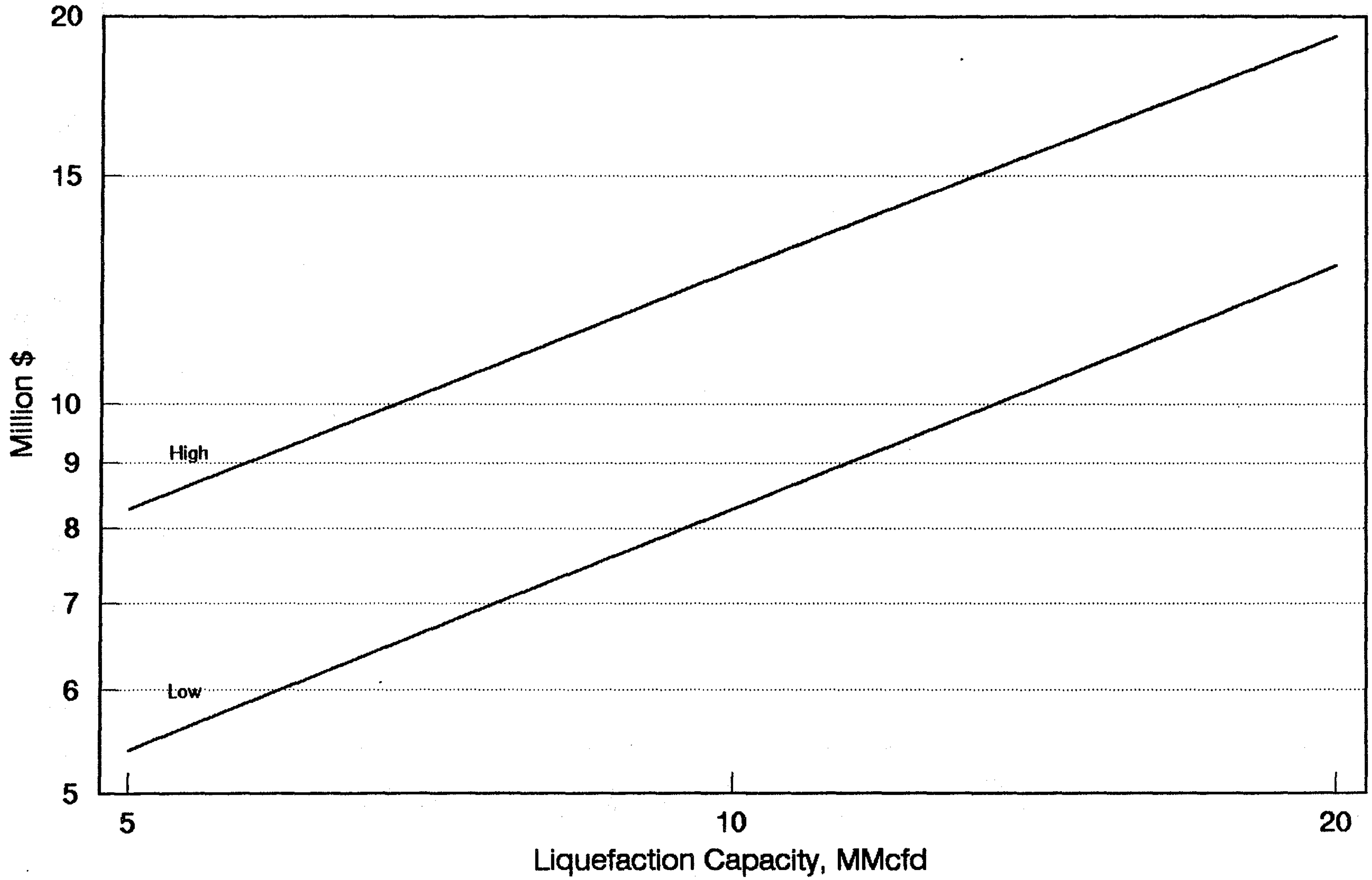


Figure A-3
LNG Storage Costs

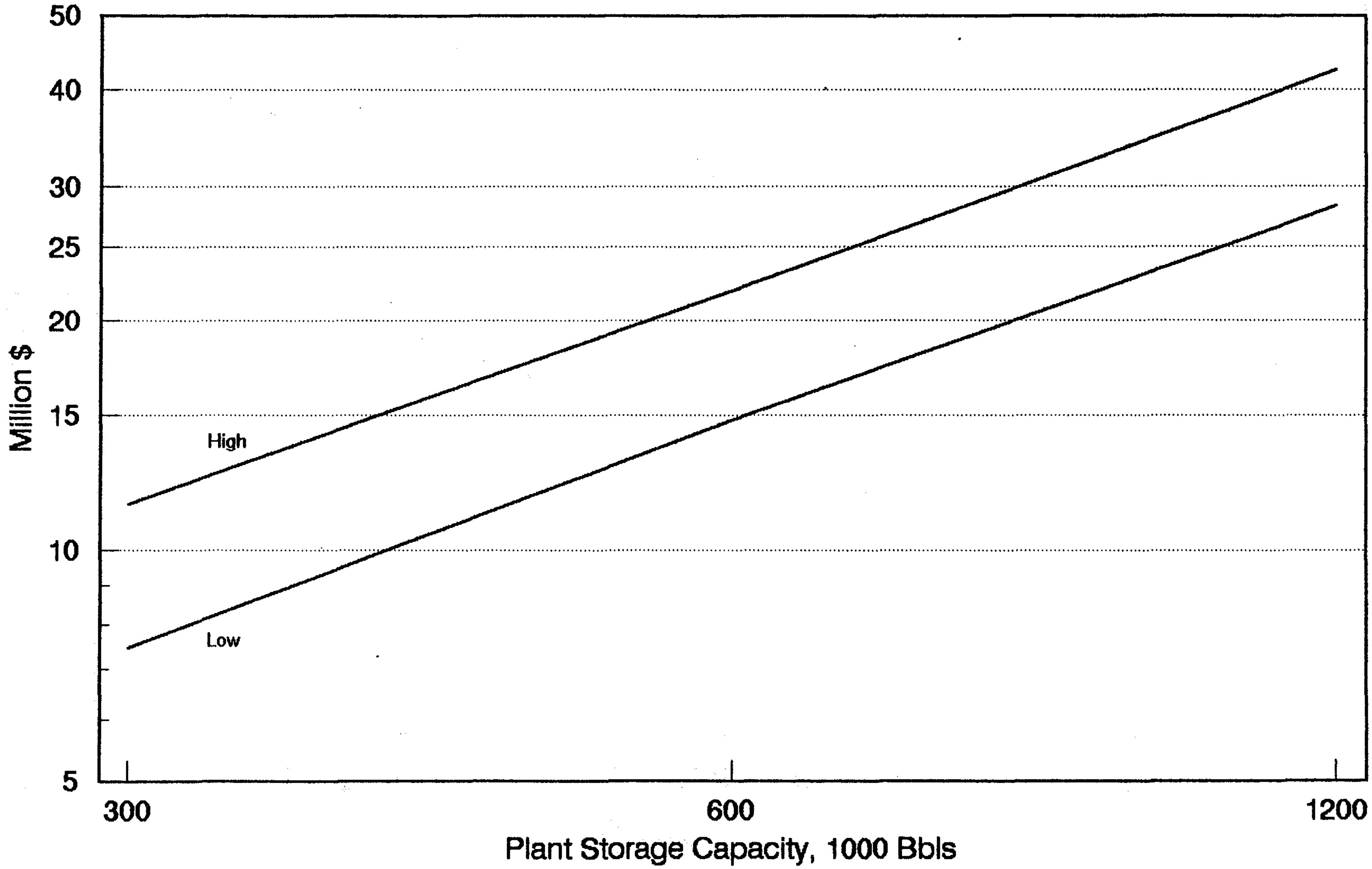


Figure A-4
LNG Plant Pumpout and Vaporization Cost

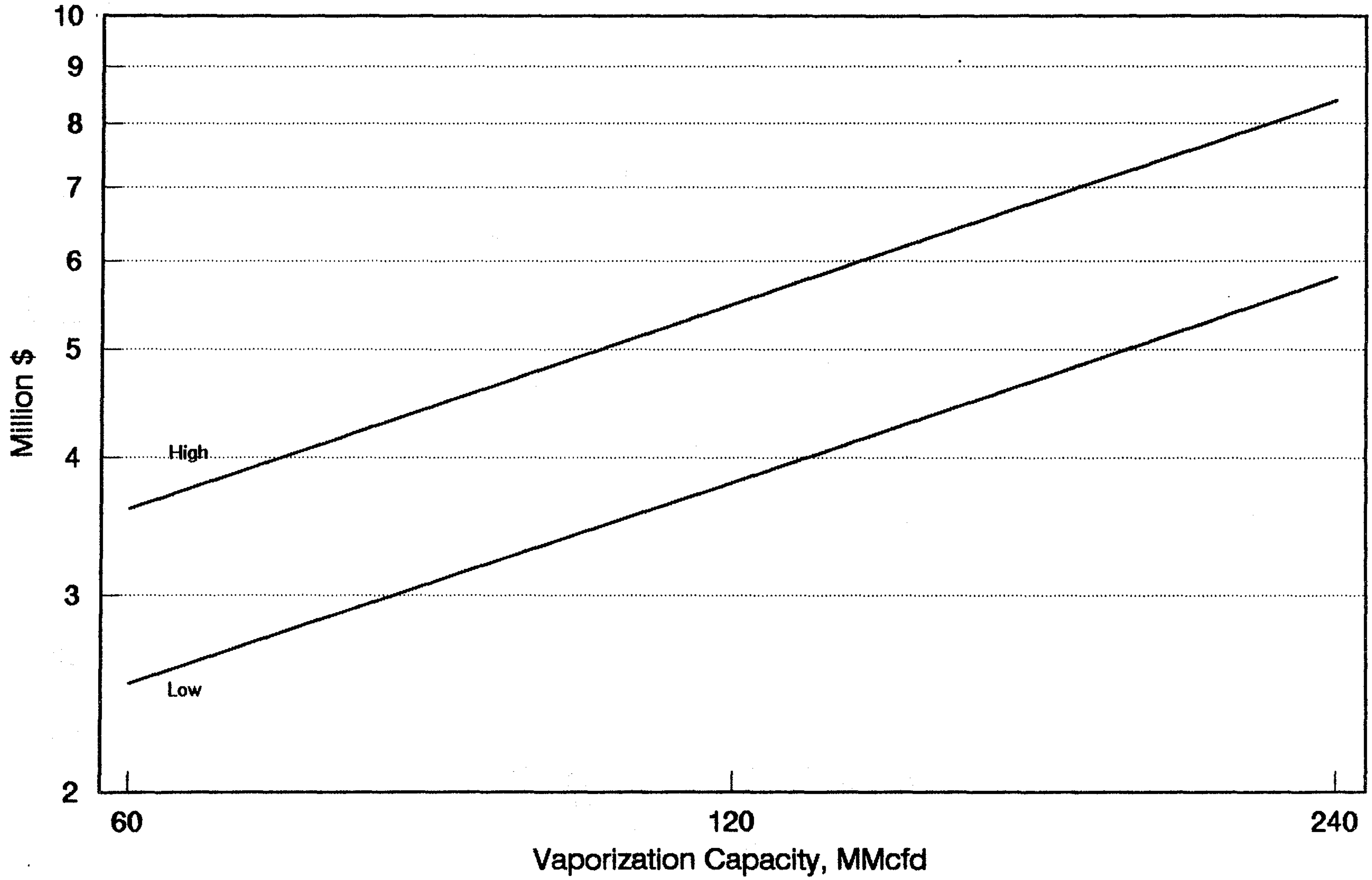


Figure A-5
LNG Plant Facilities Cost

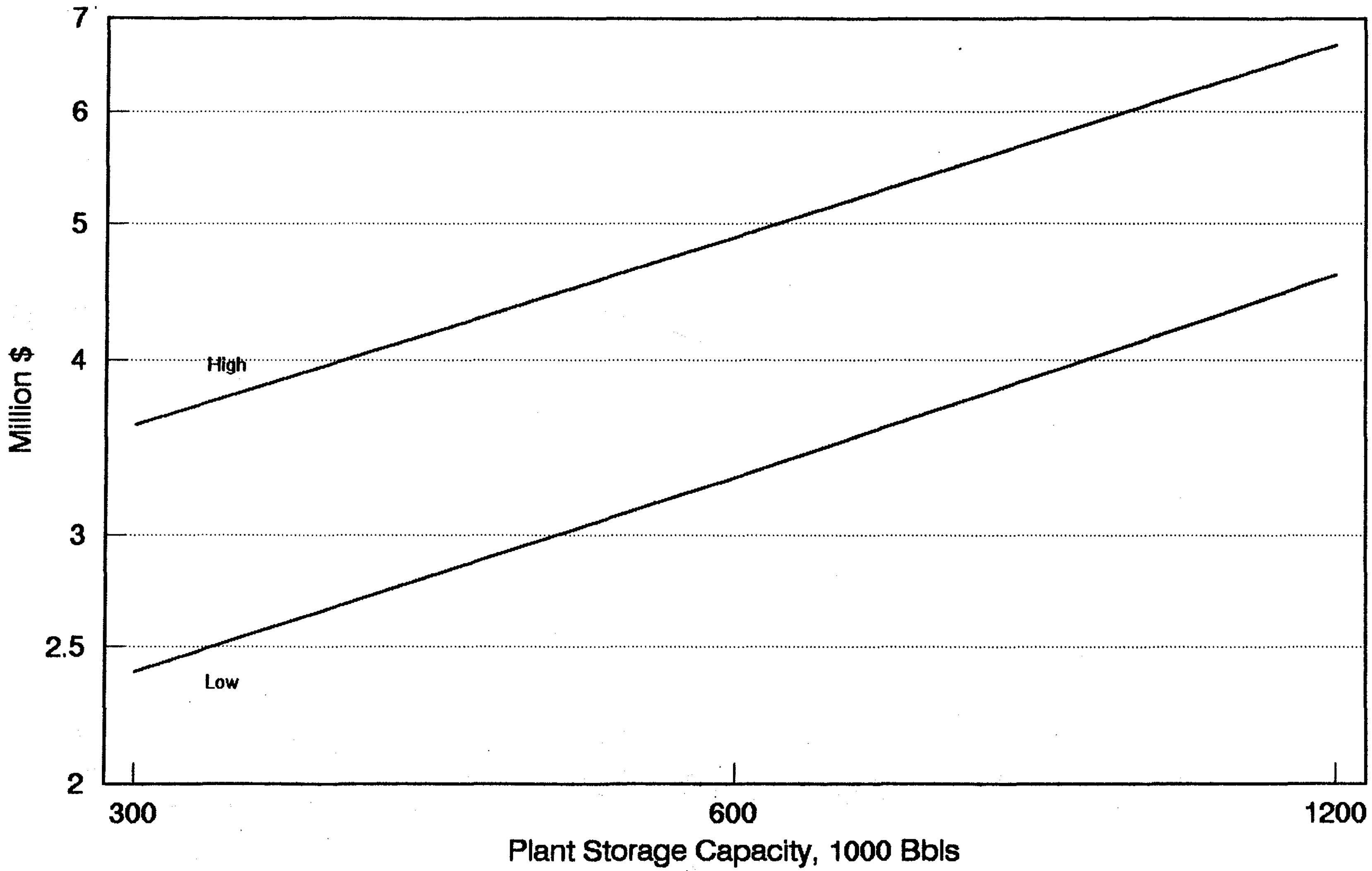
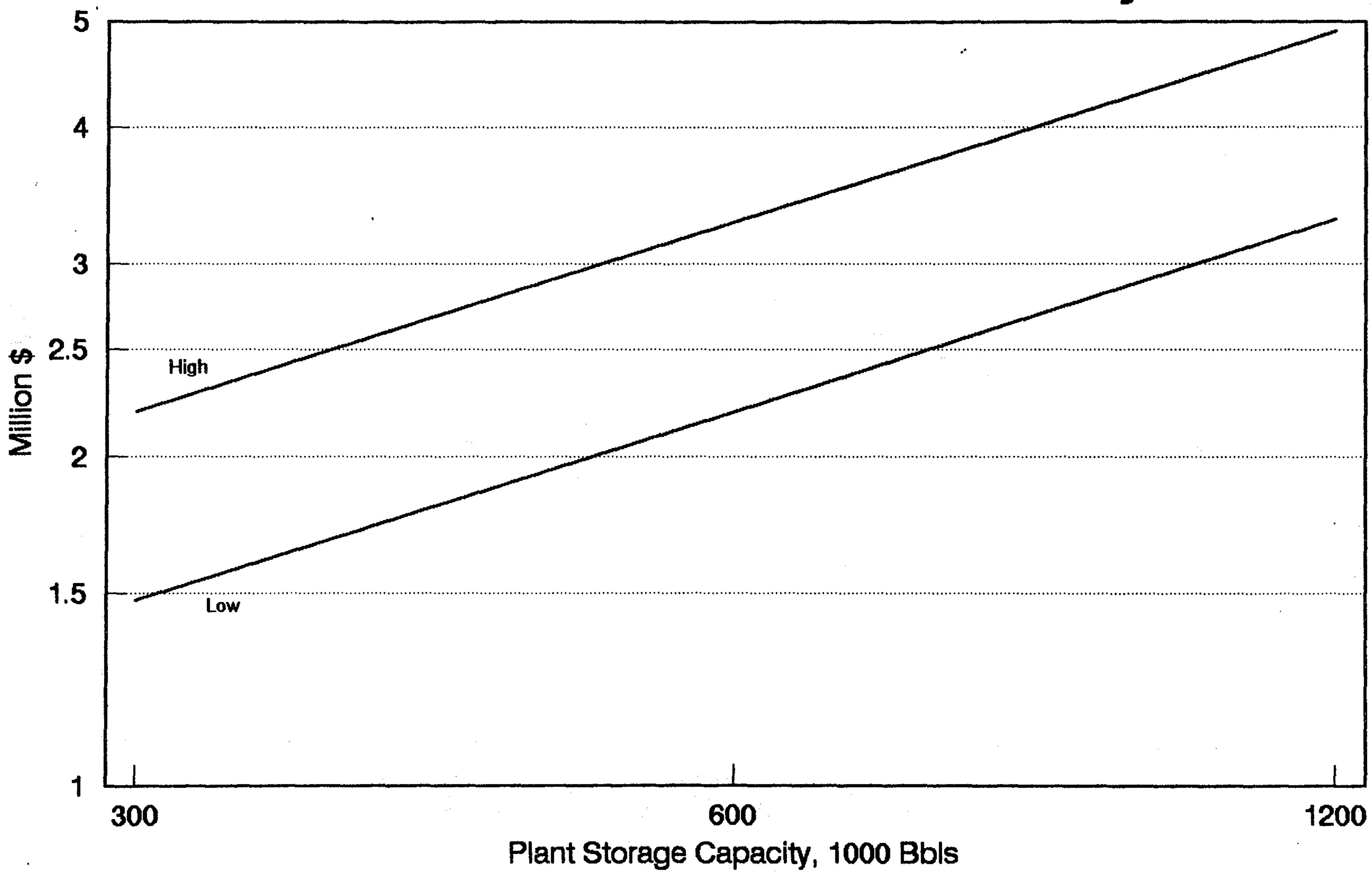


Figure A-6
LNG Plant Fire Protection and Security Cost



Appendix B

For Used for LNG Capacity Survey

Company Name:	Gas Company
Facility Location:	City, State
Daily Production Capacity (liquid m3/day):	
Number of Liquefaction Units:	
Liquefaction Cycle:	
Process Design:	
Number of Tanks:	
Individual Tank Capacity (liquid m3):	
Storage Tank Location:	
Storage Tank Container Type (inner shell):	
Storage Tank Container Type (outer shell):	
Storage Contractor:	
Regasification Flow (MM3/hr.):	
Number of Regasification Units:	
Type of Regasification Units:	
Initial Year of Operation:	
Expansions:	
Expansion Date:	

Are any expansions planned? - please describe briefly
Which pipeline(s) and/or liquefaction plant(s) feed this facility?
How many safety incidents have occurred at this facility?
Briefly describe the most serious.
What has been the reliability of this facility? e.g. how many hours of unplanned shut-down have been logged?
Are you aware of any proposed LNG projects in your area? - please provide as many details as possible (owners, size, etc.)