5.1 Introduction

As will be discussed in Chapter 9, natural gas has come to the forefront of the international energy debate due to increasing demands in many countries, headed by the United States, China, and India. This has been prompted by a changing worldwide preference in power generation because of environmental concerns. As a result, transport of natural gas over long distances has become very important. Two well-established technologies are predominantly used to transport natural gas from sources to consumption markets: pipelines, accounting for 70 percent of transported gas, and liquefied natural gas (LNG), accounting for the remaining 30 percent. Pipelines over land are the cost-effective technology of choice. Underwater pipelines are also feasible, but are quite expensive, as much as ten times the cost of on-land pipelines of same length, and are limited by the underwater terrain they have to traverse. The de facto choice for natural gas transport, when a pipeline cannot be used, is currently LNG. It is a technologically proven and safe method of transport. Also, a number of LNG terminals and ships are available worldwide. However, the investment cost is quite high for LNG facilities, both for the regasification process at the receiving terminal, and particularly, for the liquefaction process at the shipping terminal. Additionally, the energy consumed for LNG liquefaction and transport is high, amounting to as much as the equivalent of one quarter of the gas.

While LNG dominates the market for sea transport of natural gas, a number of recent studies have shown that compressed natural gas (CNG) is economically more attractive than LNG for sea transport of relatively smaller volumes of gas over shorter distances (Wang and
Marongiu-Porcu, 2008; Marongiu-Porcu et al., 2008; Nikolaou et al., 2009). CNG requires minimal investment in facilities at the shipping and receiving sites and wastes far less energy. The main capital cost for CNG is incurred in building the transportation vessels. Although the cost for transportation vessels is higher for CNG than for LNG (stemming from corresponding gas compression ratios of usually 200:1 versus 600:1, respectively), overall economics favor CNG for short distances and small loads, as outlined in Figure 5–1.

Figure 5–1 clearly suggests that CNG offers an economically attractive way to deliver commercial quantities of natural gas by ships to customers within 2,000 km (about 1,200 miles), assuming that underwater pipelines are not feasible. For smaller volumes, such as 1 to 2 Bcm/yr (about 100 MMscf/d to 200 MMscf/d), CNG is the indicated solution to bring natural gas to many markets. It should be emphasized that Figure 5–1 is premised on zero installed base, namely, facilities for each candidate technology would be built from scratch at nominal prices. Clearly, additional factors have to be taken into account when prices are distorted as a result of existing installed base (e.g., LNG terminals or ships), or supply and demand vary drastically as a result of economic growth or downturn.

In this chapter, we focus on natural gas transport via pipeline and CNG, as these two technologies rely on compression only and do not employ conversion of natural gas to a liquid. LNG, relying on conversion of natural gas to its liquid form via deep refrigeration, will be discussed in Chapter 6. Other gas transportation forms, such as gas-to-liquids (GTL), which relies on the conversion of natural gas to liquid products via chemical reactions, will be elaborated upon in Chapter 7.

### 5.2 Pipelines

A pipeline is a very efficient way to transport natural gas, especially on land. According to the EIA (2008), there were about 210 natural gas pipeline systems in the United States, spanning more than 300,000 miles of interstate and intrastate transmission pipelines. Interstate pipelines, often called “trunklines,” are long-distance and wide-diameter (20–42 in.), and traverse more than one state. There are more than 1,400 compressor stations to maintain pressure on this pipeline network. Intrastate pipelines operate inside a single state.

The basic concepts involved in pipeline capacity design are shown in Figure 5–2 (EIA, 2008). The supply sources of natural gas imported into a pipeline could be from another pipeline, LNG, gas processing plants, and gas gathering systems. Gas then goes through a
5.2 Pipelines

Long-distance trunkline and eventually reaches the consuming markets. During the nonheating season (spring–summer), excess gas goes to LNG peaking facilities and underground natural gas storage (which will be discussed in Chapter 8). During the heating season (winter) or peak period, additional gas is supplied into the pipeline transmission system to meet the demand from the customers. This pattern, which has lasted for decades, will be altered in the future because of two new issues: much larger LNG imports and the increasing use of natural gas for electricity generation (air conditioning has its own peaks in the summer).

**Figure 5–1**  *Economically preferred options for monetizing stranded natural gas*  (Wood et al., 2008)

**Figure 5–2**  *Basic pipeline capacity design concept*  (EIA, 2008)
5.2.1 Pipeline Size

Pipeline design means appropriate size, appropriate distance between compression stations, and adequate compressor sizes that would allow optimum operation and ability to expand in the future. Pipeline throughput depends on pipeline diameter and the operating pressure; taking into account the length of the pipeline and the terrain. Typical onshore pipeline operating pressure is about 700 to 1,100 psi (with some as high 4,000 psi); for offshore pipelines, the operating pressure is typically between 1,400 to 2,100 psi, depending on the material and the age of the pipeline (Speight, 2007).

As discussed in the previous chapter, after the natural gas processing, the gas in the transporting pipelines is purely methane, a single-phase compressible fluid. So the pressure drop in the horizontal pipeline can be calculated by using Eq. (3.68). In that equation, the average values of $Z$, $T$, and $\mu$ for the entire length of pipe are used. The kinetic energy pressure drop was neglected with the assumption that the flow rate is not very high. In a high rate, low pressure line, however, the change in kinetic energy may be significant and should not be neglected (Economides et al., 1994). In this case, for a horizontal pipeline, the mechanical energy balance is

$$\frac{dp}{\rho} + \frac{u \, du}{g_c} + \frac{2f_c u^2 dL}{g_c D} = 0. \tag{5.1}$$

For a real gas, $\rho$ and $u$ are given by Eqs. (1.10 and 3.59), respectively. The differential form of the kinetic energy term is

$$u \, du = -\left(\frac{4qZT}{\pi D^2} \frac{p_{sc}}{T_{sc}} \right)^2 \frac{dp}{p^3}. \tag{5.2}$$

Substituting for $\rho$ and $u \, du$ in Eq. (5.1), assuming average values of $Z$ and $T$ over the length of the pipeline, and integrating, we obtain

$$p_1^2 - p_2^2 = \frac{32 \times 28.97 \gamma_s \bar{Z} \bar{T}}{\pi^2 R_g D^4} \left(\frac{p_{sc} q}{T_{sc}}\right)^2 \left(\frac{2f_c L}{D} + \ln \frac{p_1}{p_2}\right), \tag{5.3}$$

which for field units is

$$p_1^2 - p_2^2 = (4.195 \times 10^{-6}) \frac{\gamma_s \bar{Z} \bar{T} q^2}{D^4} \left(\frac{24f_c L}{D} + \ln \frac{p_1}{p_2}\right), \tag{5.4}$$
where $p_1$ and $p_2$ are in psi, $T$ is in R, $q$ is in Mscf/d, $D$ is in inches, and $L$ is in ft. The friction factor is obtained from Eq. (3.57) as a function of the Reynolds number and pipe roughness. The Reynolds number for field units is given by Eq. (3.69).

Eq. (5.4) is identical to Eq. (3.68) except for the additional $\ln\left(\frac{p_1}{p_2}\right)$ term, which accounts for the kinetic energy pressure drop. Eq. (5.4) is an implicit equation in $p$ and must be solved iteratively. With a computer program, this should be very easy to do.

**Example 5–1 Calculation of pipeline pressures and dimensions**

Gas is gathered at point A from gas processing plants B and C (see Figure 5–3), and transported to customers at D. The gas rates from plants B and C are 80 and 50 MMscf/d, respectively.

The distances between BA, CA, and AD are 1,000 ft, 800 ft, and 10 miles, respectively. The diameters of pipelines CA and AD are 5 and 10 in., respectively. The pressure at destination D has to be 500 psi. Assume the temperature is $77^\circ$F in the whole process. The pipeline relative roughness is 0.001. All gas is methane.

1. What is the inlet pressure in the AD pipeline?

2. If gas from pipeline BA is injected into the main pipeline AD at the same pressure (BA outlet pressure = AD inlet pressure) and the inlet pressure at B has to be 1,240 psi, what should the diameter of pipeline BA be?

3. If the diameter of pipeline CA is 5 in., pressure at C is 1,000 psi. What is the outlet pressure at CA? To get CA gas stream injected to main stream AD at the same pressure as the inlet pressure of AD, how much pressure has to be boosted by a compressor?

**Solution**

1. For the total rate of 130 MMscf/d for pipeline AD, assume the Reynolds number is $1.0 \times 10^7$, with pipe relative roughness equal to 0.001. Using Eq. (3.57), the Fanning friction factor $f_f = 0.0049$ (will need to check Reynolds number once we get the pressure).

To calculate the inlet pressure of pipeline AD, the Z-factor is needed, and trial and error is indicated, because the Z-factor
depends on the pressure. Also, in checking for the Reynolds number, the viscosity must be adjusted by the calculated pressure.

Assume the inlet pressure is 1,000 psi. Since all the gas is methane, then \( \gamma = 0.56 \), \( p_{pc} = 673.6 \text{ psi} \), and \( T_{pc} = 346.1 \text{ R} \). For \( p = (1,000 + 500)/2 = 750 \text{ psi} \) and \( T = 77{°}F \), \( Z = 0.9 \) (from \( Z \) chart).

The left hand side (LHS) of Eq. (5.4) does not equal the right hand side (RHS). Adjust the inlet pressure and calculate the new \( Z \)-factor until the LHS of Eq. (5.4) equals the RHS. That gives an inlet pressure of pipeline AD 1,200 psi with \( Z = 0.89 \).

Check the Reynolds number: at \( (1,200 + 500)/2 = 850 \text{ psi} \) and \( 77{°}F \), viscosity is 0.0126 cp. The calculated Reynolds number (by using Eq. (3.69)) is \( 1.16 \times 10^7 \). That gives the \( f_l = 0.0049 \) (Eq. (3.57)). Therefore the previous assumption of \( 1.0 \times 10^7 \) is close enough.

Another option to tackle this problem is to assume that at a short distance from destination D (such as 3,000 ft or less), the pressure drop is small (less than 70 psi in this case). So one can assume in this segment of pipeline, \( Z \) is constant and can be calculated under the outlet condition (that is 500 psi). Use Eq. (5.4) to calculate the pressure at 3,000 ft away from destination D. Continue to do so until point A is reached which is 52,800 ft (10 miles) away from D.

2. Use Eq. (5.4), with \( p_1 = 1,240 \), \( p_2 = 1,200 \text{ psi} \), \( q = 80 \text{ MMscf/d} \), and \( L = 1,000 \text{ ft} \). The pipeline BA diameter is calculated as 6 in. with \( Z = 0.85 \), \( \mu = 0.0134 \text{ cp} \), \( N_{Re} = 1.1 \times 10^7 \), and \( f_l = 0.0049 \).
3. Use Eq. (5.4), with \( q = 50 \) MMscf/d, \( L = 800 \) ft, the calculated pipe CA outlet pressure is 960 psi with \( Z = 0.88 \), \( \mu = 0.0128 \) cp, \( N_{Re} = 8.8 \times 10^6 \), and \( f_f = 0.0049 \). A compressor to pressurize this gas stream to 1,200 psi, i.e., about 240 psi, is needed.

It is worth noting that the Fanning friction factor equals 0.0049 for all three cases, regardless of the differences in the Reynolds number. This is because at high turbulent flow, \( N_{Re} \) is a large number and \( 1/N_{Re} \) in Eq. (3.57) can be assumed to be zero. Therefore, the Fanning friction factor is only a function of the pipe relative roughness. This can be seen clearly from the Moody Diagram (1944), shown in Figure 5–4.

It is also worth noting that there are two “Moody diagrams” in the published literature and they all have the same vertical axis as “friction factor.” But the friction factor value is different. The best way to distinguish them is to check the friction factor under laminar flow. If the friction factor equals \( 16/N_{Re} \), then this Moody diagram (Figure 5–4) gives the Fanning friction factor \( (f) \), and it is the same as that calculated from Eq. (3.57). If the friction factor equals \( 64/N_{Re} \), then this Moody diagram gives the Darcy-Weisbach friction factor, and it has to be divided by 4 before using Eqs. (3.68 or 5.4) for calculations.

**Example 5–2 Determining the number of compressor stations needed along a major pipeline**

A 4,000-kilometer gas pipeline in Asia is 1,046 mm in diameter (X70 steel grade, wall thickness ranges from 14.6 to 26.2 mm) with designed pressure of 10 MPa. It can deliver 12 to 17 Bcm/yr of natural gas. If the pressure cannot be lower than 1,000 psi, and the compressor discharge pressure is 2,000 psi, how many gas compressor stations will be needed? Assume the pipeline relative roughness is 0.0006 and the temperature is 100°F.

**Solution**

With the pipeline wall thickness equal to 20 mm, the pipeline diameter, \( D = (1,046 - 20)/25.4 = 40 \) in. Assume the inlet pressure of the pipeline equals the discharge pressure of the compressor, and the outlet pressure of the pipeline equals the suction pressure of the compressor at each station, as shown in Figure 5–5. Thus, \( p_f = 2,000 \) psi,
Figure 5-4  *Moody diagram* (Moody, 1944)
5.2 Pipelines

\[ p_2 = 1,000 \text{ psi}, \] from which \( Z = 0.86, \mu = 0.0143 \text{ cp}, N_R = 3.14 \times 10^7 \) (Eq. (3.69)), and \( f_f = 0.00435 \) (Eq. (3.57)).

The designed pipeline gas capacity, \( q = 16.5 \times (1,000,000/365) \times 35.31 = 1.6 \times 10^6 \text{ Mscf/d}, \) and by using Eq. (5.4), the pipeline segment between two compressor stations is calculated as \( L_1 = 1.0 \times 10^6 \text{ ft} = 310 \text{ km}. \) The total length of the pipeline is \( L = 4,000 \text{ km}, \) therefore, the number of compressor stations needed is \( 4,000/310 – 1 = 12. \)

### 5.2.2 Compression

Examples 5–1 and 5–2 clearly show that the pressure of natural gas flowing through a pipeline decreases along the distance because of friction pressure drop. Therefore, compressors are needed to ensure that the natural gas gets to the destination with sufficient pressure along the path and outlet.

According to the EIA (2007), along the interstate pipeline network, compressor stations are usually placed between 50 and 100 miles apart. Most compressor stations are unmanned, and are monitored by an electronic system that manages and coordinates the operations of several compressor stations. In a large-scale trunkline or a mainline, the average horsepower per compression station is about 14,000, and this can move about 700 MMcf/d of natural gas. Some of the largest stations can handle as much as 4.6 Bcf/day.

Two types of compressors are used: reciprocating and turbine engines. Most of them have natural gas-fired and high speed reciprocating engines. Both types of compressors are periodically retrofitted to cope with new emerging technologies, but most of the time, to increase efficiency and safety (EIA, 2007).

Besides compressors, there are other components in a compressor station. These include scrubbers and filters. Although gas is treated
before entering the transportation pipelines, liquid may still condense and accumulate in the pipelines during the transportation process, and particulates may form with the coating materials inside of the pipelines. Thus, liquids and solids have to be removed before entering compressors. Between the parallel or multistage compressors, interstage coolers are needed to cool down the heated gas due to pressurization, further reducing the needed horsepower (hp) of the compressor. The theoretical hp of the compressor required to compress a given amount of natural gas can be obtained from either the analytical solution or an enthalpy-entropy diagram. The enthalpy-entropy diagram approach can be found in Brown (1945). The analytical solution will be elaborated next.

**Theoretical Horsepower**

Horsepower (hp or HP) is the work done over a period of time. One hp equals 33,000 ft-lb/min, or 746 watts, or 75kg-m/s. It is commonly used in measuring the output of piston engines, turbines, electric motors, and other machinery. The theoretical hp of the compressor required to compress a given amount of natural gas can be calculated by assuming the system to be either isothermal ($\Delta T = 0$) or adiabatic/isentropic ($\Delta H = 0$). Of course, in reality, compression of a gas naturally increases its temperature, and there will always be some heat leaking out of the system.

When the system is assumed to be adiabatic, the calculated theoretical hp gives the maximum required hp while under the assumption of isothermal condition; the calculated theoretical value gives the minimum required hp. Therefore, the actual required hp to compress a given gas, shown in Figure 5–6, is between these upper and lower boundaries.

Assuming the change in kinetic energy, potential energy of position, and that the energy losses are negligible (Katz et al., 1959), the theoretical work required to compress natural gas becomes

$$W = \int_{p_1}^{p_2} Vdp,$$  \hspace{1cm} (5.5)

where $p_1$ and $p_2$ are the suction and discharge absolute pressures of the gas, respectively. Often a negative sign in front of the work ($W$) is to distinguish between compression and expansion.

For an ideal gas, if the compression process is isothermal, then

$$pV = nRT = \text{constant}.$$  \hspace{1cm} (5.6)
Substituting Eq. (5.6) into Eq. (5.5) and integrating, gives the theoretical hp to compress 1 mole of ideal gas as

\[ W = RT \ln\left(\frac{p_2}{p_1}\right). \]  

(5.7)

Similarly, if the compression process is under isentropic condition, then

\[ pV^k = \text{constant}, \] 

(5.8)

where \( k \) is evaluated under suction conditions and equals \( C_p/C_v \), the ratio of the ideal-gas specific heats with \( C_p \) and \( C_v \) at constant pressure and volume, respectively. Thus, using Eq. (5.6) and Eq. (5.8) in Eq. (5.5), the theoretical hp to compress 1 mole ideal gas is (Joffe, 1951)

\[ W = \frac{kRT}{k-1} \left[ \left(\frac{p_2}{p_1}\right)^{\frac{k-1}{k}} - 1 \right], \]  

(5.9)

where \( T_r \) is the gas suction temperature in R.

Several efforts have been made to empirically modify the ideal gas behavior to reflect the real gas behavior, and further, to calculate the theoretical hp for real gas (Katz et al., 1959; Edmister and McGarry, 1949; Joffe, 1951). The theoretical work (\( W \) in hp) required to
compress \( q_s \) MMscf/d real gas at standard conditions \( (T_{sc} = 60^\circ F, p_{sc} = 14.65 \text{ psia}) \) is given as:

\[
W = 0.08531 q_s T \left( \int_{0.2}^{p_2} \frac{Z dp_r}{p_r} - \int_{0.2}^{p_1} \frac{Z dp_r}{p_r} \right), \quad (5.10)
\]

under isothermal conditions (Katz et al., 1959), and under isentropic conditions (Katz et al., 1959)

\[
W = 0.08531 \frac{k}{k-1} q_s Z T_1 \left[ \left( \frac{p_2}{p_1} \right)^{(k-1)/k} - 1 \right]. \quad (5.11)
\]

The constant 0.08531 is a unit conversion factor.

Joffe’s (1951) study indicated that the actual or polytropic compression process of a real gas should be assumed as

\[
pV^n = \text{constant}, \quad (5.12)
\]

where \( n \) is a constant to be determined from the actual behavior of the gas in the compressor. That gives another empirically modified equation as

\[
W = 0.08531 \frac{n}{n-1} q_s Z T_1 \left[ \left( \frac{p_2}{p_1} \right)^{(n-1)/n} - 1 \right]. \quad (5.13)
\]

Replacing \( n/(n-1) \) by \( k/Z_1(k-1) \), Eq. (5.13) becomes

\[
W = 0.08531 \frac{k}{k-1} q_s T_1 \left[ \left( \frac{p_2}{p_1} \right)^{Z_1(k-1)/k} - 1 \right]. \quad (5.14)
\]

Some others (Economides et al., 1994) suggested a simplified empirical expression as

\[
W = 2.23 \times 10^2 q_s \left[ \left( \frac{p_2}{p_1} \right)^{0.2} - 1 \right]. \quad (5.15)
\]

The differences among these empirical solutions will be discussed further in Example 5–3.
Once the theoretical hp is obtained, the Brake horsepower (BHP), the actual or useful hp, which is added into the compressor, is then calculated as (Katz et al., 1959)

\[ BHP = \frac{\text{Theoretical HP}}{\text{Efficiency (E)}}. \] (5.16)

The efficiency, \( E \), is the combination of the compression and mechanical efficiencies. It is a function of suction pressure, compression ratio, speed, the physical design of the compressor, and the mechanical condition of the compressor. It can be determined from published data or from vendors directly. In most modern compressors, the compression efficiency is between 83 and 93\% while the mechanical efficiency is between 88 and 95\%. These give the overall efficiency of 75 to 85\% (Guo and Ghalambor, 2005).

The ratio of \( p_2/p_1 \) is called compression ratio \( (R_c) \). Since compression generates heat, this ratio is usually kept under six. In field practice, this ratio seldom exceeds four (Guo and Ghalambor, 2005) to ensure that the compressor performs at high efficiency. That is why, very often, the natural gas is compressed in stages. In that case, the overall compression ratio is

\[ R_o = \left( \frac{p_f}{p_1} \right)^{1/n}, \] (5.17)

where \( p_f \) is the final discharge pressure in psia and \( n \) is the number of stages.

**Heat Removed by Interstage Cooler**

According to the work done by Joffe (1951), the discharge temperature can be determined as

\[ T_2 = \frac{Z_1}{Z_2} T_1 R_c^{(k-1)/k}, \] (5.18)

with \( T_1 \) and \( T_2 \) in °F or R. This equation is not recommended when the discharge temperature of the gas is considerably above its critical temperature.
Once the discharge temperature $T_2$ is known, the heat removed by the interstage cooler can be calculated as

$$\Delta H = n_g \overline{C_p} \Delta T,$$

where $n_g$ is the number of lb-moles of natural gas. $\overline{C_p}$ is the specific heat under constant operating pressure and average temperature of the interstage cooler.

**Example 5–3** Calculate the required horsepower needed at each compressor station in Example 5–2. Use $k = 1.28$.

**Solution**

Given in Example 5–2, the suction and discharge pressures of gas are $p_1 = 1,000$ psi and $p_2 = 2,000$ psi. (Note: the pipeline inlet pressure = compressor discharge pressure and the pipeline outlet pressure = compressor suction pressure. See Figure 5–5.) Also $T_1 = 100^\circ$F and $q = 1.6 \times 10^3$ MMscf/d. So, at suction conditions, $Z_1$ can be calculated as 0.89.

For the theoretical work needed to compress $1.6 \times 10^3$ MMscf/d natural gas from 1,000 to 2,000 psi, use Eq. (5.11),

$$W = 0.08531 \times \frac{1.28}{1.28 - 1} \times 1.6 \times 10^3 \times 0.89 \times (100 + 460) \times \left[\left(\frac{2,000}{1,000}\right)^{1.28-1} - 1\right]$$

$$= 51,189 \text{ hp}.$$

Use Eq. (5.14),

$$W = 0.08531 \times \frac{1.28}{1.28 - 1} \times 1.6 \times 10^3 \times 0.89 \times (100 + 460) \times \left[\left(\frac{2,000}{1,000}\right)^{0.89 \times (1.28-1) / 1.28} - 1\right]$$

$$= 50,773 \text{ hp}.$$
Use Eq. (5.15),

\[ W = 2.23 \times 10^2 \times 1.6 \times 10^6 \times \left[ \left( \frac{2,000}{1,000} \right)^{0.2} - 1 \right] = 53,056 \text{ hp}. \]

Results show the empirical solution proposed by Economides et al. (1994) is higher and on the more conservative side.

### 5.3 Marine CNG Transportation

CNG is natural gas compressed at pressures of 2,000 to 3,000 psi (130 to 200 atm) and sometimes chilled (but not liquefied) to temperatures down to \(-40^\circ\text{F} (\sim -40^\circ\text{C})\) for even higher reduction of its volume. It is a technology proven in many applications, including transport by ship, truck, and barge. It has been used to fuel taxis, private vehicles, and buses worldwide.

CNG transportation over sea requires specifically designed CNG ships, which are, in effect “floating pipelines”. While at the time of this writing, there were at least six commercial concepts of marine transport of CNG, none had yet materialized, although there were several signs that the technology was to be deployed soon.

The required onshore facilities for loading and offloading from CNG transport, shown in Figure 5–7, consist of simple jetties or buoys which are minimal compared to LNG. The key differences between these two technologies are summarized in Table 5–1.

The first attempt towards commercial CNG transport by ship was made in the 1960s (Broeker, 1969). Columbia Gas’ SIGALPHA (originally named Liberty Ship) completed cycles of loading, transport, offloading, and regasification of both CNG and MLG (medium condition liquefied gas) in cargo bottles. The capacity of the SIGALPHA was 820 Mscf of MLG and 1,300 Mscf of CNG. The American Bureau of Shipping (ABS) classified the SIGALPHA for service and the U.S. Coast Guard awarded SIGALPHA a certificate of compliance. The project was eventually aborted, because at that time, it was not economical to proceed as the price of natural gas was extremely low.

There have been three factors which have prevented CNG marine transport. First, most investment have been on LNG, for understandable reasons (see Figure 5–1). Second, the use of CNG was envisioned

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1. Section contributed by Michael Nikolaou, based on concepts introduced by Nikolaou et al. (2009) and Nikolaou (2008).
to take market share away from LNG, which, as was explained above, is not necessarily a good approach, because CNG and LNG are suitable for different transportation scenarios (see Figure 5–1). Third, innovative low-cost and high-efficiency designs for CNG vessels have become available in the 2000s.

There are several areas (Figure 5–8) where population centers are separated from natural gas sources by 2,000 km (or 1,200 miles) or less across water. For each of these areas, there exist multiple scenarios for CNG distribution, in terms of number of vessels, vessel capacities, and itineraries. Identification of promising scenarios is necessary to determine project economics, and possibly guide future technological developments, particularly as new CNG vessel technologies become available (Stenning and Cran, 2000; Dunlop and White, 2003).

5.3.1 CNG Carriers

CNG technology is quite simple and can be easily brought into practical applications, assuming the economics are attractive. Creative
Table 5–1  Process and Cargo Differences between CNG and LNG (Patel et al., 2008)

<table>
<thead>
<tr>
<th></th>
<th>CNG</th>
<th>LNG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid State</td>
<td>Gas</td>
<td>Liquid</td>
</tr>
<tr>
<td>Pressure</td>
<td>100–50 bar (1,450 – 3,600 psi)</td>
<td>1 bar (14.5 psi)</td>
</tr>
<tr>
<td>Temperature</td>
<td>30°C to –40°C (or 86 to –40°F)</td>
<td>–163°C (or –261°F)</td>
</tr>
<tr>
<td>Loading</td>
<td>Dehydrate, compress</td>
<td>Treat, liquefy, store</td>
</tr>
<tr>
<td>Terminals</td>
<td>Jetty or buoy</td>
<td>Jetty, or regas offshore</td>
</tr>
<tr>
<td>Ships</td>
<td>Simple, like bulk-carrier</td>
<td>Sophisticated, efficient</td>
</tr>
<tr>
<td>Receiving</td>
<td>Heat &amp; decompress—untilize energy released</td>
<td>Store, regasify</td>
</tr>
<tr>
<td>Loading/Offloading</td>
<td>Gas under pressure</td>
<td>As liquid</td>
</tr>
<tr>
<td>Compression Ratio</td>
<td>~200–250:1</td>
<td>~600:1</td>
</tr>
<tr>
<td>Containment D/t</td>
<td>~25–60</td>
<td>~1,000</td>
</tr>
<tr>
<td>Material</td>
<td>Fine grain normalized C-Mn steel, FRP</td>
<td>Aluminum, stainless, Ni steel</td>
</tr>
</tbody>
</table>

Figure 5–8  Regions actively investigating CNG projects  (Dunlop and White, 2003)
solutions have been proposed for the choice of materials (e.g., steel, composites), configuration of gas containers (e.g., vertical or horizontal cylinders, coiled pipe), and loading and offloading techniques. There is also flexibility in the choice of transport vessels, which can be ships or barges, depending on a number of factors, as shown in Table 5–2.

The new generation of CNG ships under consideration is optimized to transport large quantities of gas. Such ships can carry approximately one-third the amount of an LNG carrier of the same size. The economic attractiveness of CNG hinges on the far lower capital cost of required land facilities and the considerably lower operating costs compared to LNG. Several companies have developed CNG delivery systems. Some of them have already received approval by classification organizations and are ready for commercialization.

One CNG technology variant employs a high-pressure gas storage and transportation system based on a coil of relatively small diameter pipe (6 to 8 inches, about 15 to 20 cm) sitting in a steel-girder carousel (Figure 5–9). Considering natural gas compressed at 3,000 psi and at ambient temperature, a typical CNG carrier assembled with 108 carousels can offer up to 330 MMscf (about 10 MMscm) capacity.

Another CNG technology variant requires that the compressed gas is also cooled to temperatures generally below 0°F, to achieve a further reduction of the gas specific volume. This high-pressure gas storage and transportation system, is based on horizontal or vertical arrays of 36-meter (about 118 ft), long large diameter pipes (40 in, about 1 m), segregated, and manifolded into a common pressure and flow system in groups of 24, called modules. These modules are then arranged in holds, whose count determines the CNG carrier capacity. The largest model of such a vessel can offer up to 800 MMscf (about 22 MMscm) of capacity. One example of this type of containment is shown in Figure 5–10.

How does chilling help reduce the volume of CNG?

The relationship between volume, \( V \), pressure, \( p \), and temperature \( T \), is given by the real gas law shown in Eq. (1.2), or rearranged as

\[
V = \frac{ZnRT}{p}. \tag{5.20}
\]

The volume taken by an amount of gas \( n \), is proportional to \( ZT/p \). Consequently, if gas pressure needs to be raised to a certain value, for gas volume to be reduced to a certain amount at ambient temperature, lowering the temperature (chilling) can reduce the compression
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requirement for the gas to occupy the same volume. At typical CNG pressure levels (2,000–3,000 psi), the Z-factor (calculated as discussed in the note below), may differ significantly from 1 when the temperature varies, as shown in Figure 5–11. Therefore, the Z-factor must also be taken into account in related calculations.

Table 5–2 CNG Sea Transport Vessels *(John Dunlop, Personal Communication, 2008)*

<table>
<thead>
<tr>
<th></th>
<th>Articulated Tug Barge</th>
<th>Ship</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volume</td>
<td>0.7–2 MMcm (25–75 MMscf)</td>
<td>8–29 MMcm (300–1,000 MMscf)</td>
</tr>
<tr>
<td>Loading/unloading rates</td>
<td>0.3–2 MMcm/day (10–75 MMscf/day)</td>
<td>2–14 MMcm/day (75–500 MMscf/day)</td>
</tr>
<tr>
<td>Distance</td>
<td>100–1,000 km (50–500 nautical miles)</td>
<td>250–5,000 km (135–2,700 nautical miles)</td>
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<tr>
<td>Speed</td>
<td>&lt;25 km/hr (&lt;14 knots)</td>
<td>&lt;33 km/hr (&lt;18 knots)</td>
</tr>
<tr>
<td>Estimated cost</td>
<td>$15–35 million</td>
<td>$150–350 million</td>
</tr>
</tbody>
</table>

Figure 5–9 *Schematic of a CNG vessel* (Courtesy Sea NG Corp., 2008)
The value of $ZT/p$ is shown in Figure 5–12, suggesting that mild chilling may have a significant effect on CNG volume. For example, as shown in Figure 5–12, the same amount stored at about 3,000 psi and 100°F can be stored at about 2,000 psi and 0°F. To what degree...
chilling is used to relax compression is ultimately determined by economics.

For the analysis presented here, it is assumed that ships are suitable for the weather conditions prevailing over sea transportation routes. A typical itinerary for a CNG vessel involves a cycle consisting of the following steps: gas loading at the source, transportation to delivery site(s), offloading, and returning to the source. The number and capacity of these ships, as well as related itineraries, will be the focus of the following analysis. Some economic issues will be discussed as well.

### 5.3.2 Optimizing Vessel Capacity and Itineraries in CNG Transportation

Optimization of the number of transportation vessels, capacity, and transportation itinerary ultimately depends on economics. However, an all-encompassing economic optimization, comprised of both fixed and operating costs, would be overly complicated and sensitive to a number of factors, such as natural gas price, transportation cost, and others. Even though such optimization is certainly feasible for a
particular project, the generation of merely an optimal solution would provide little insight into the general principles that guide the design of CNG transportation fleets and schedules. Therefore, the objective of this section is to present a physical optimization, namely optimization of the number of vessels required, capacity of each vessel, and itineraries followed.

The rationale for choosing this type of optimization is that the main capital expenditure (more than 80%) for CNG projects is for transportation vessels (as opposed to less than 40% for LNG projects). In the following analysis, simplified assumptions are made. That is, the natural gas has to be delivered to each receiving site at a constant rate throughout the year, without taking seasonal variation into account. An annual average rate is used for each receiving site, although the same analysis could be easily repeated for peak rates as well.

As explained in the following sections, the preferred path for CNG transportation vessels may follow “hub-and-spoke” or “milk-run” patterns depending on consumption rates at receiving sites. For sites with consumption rates high enough to justify using transportation vessels above a minimum reasonable size for each site, a hub-and-spoke pattern is preferred. Each vessel would serve as storage facility while offloading gas to consumption. If consumption is low, then vessels with size above a reasonable minimum will visit multiple sites and offload natural gas to local storage at each site (milk-run pattern). Storage capacity should be high enough for gas to last until the next vessel following the milk-run pattern would visit that site.

A potential mix of hub-and-spoke and milk-run schemes for CNG transportation from the Trinidad area to island countries in the Caribbean are shown in Figure 5–14 and Figure 5–15, respectively (Nikolaou et al., 2009).

**Hub-and-Spoke CNG Distribution Pattern**

To explain the basis for the hub-and-spoke pattern, assume for now that no storage facilities are available at the site of gas delivery. Rather, each transportation vessel from which gas is offloaded also serves as a floating storage facility during the offloading period. The offloading rate can be adjusted according to market demand. To ensure continuous delivery of gas to a market, at least one vessel must be offloading gas to consumption at any given time. (If the offloading rate cannot meet the consumption rate, multiple vessels will be offloading concurrently.) As soon as gas offloading is completed, a second vessel (already connected to the delivery line) must take over. After being disconnected from the delivery line, the empty first vessel will have to travel back to the nat-
ural gas source, be loaded with gas, and return to the delivery point to resume as needed. This cycle can be repeated indefinitely to ensure uninterrupted gas delivery. Assuming that the offloading rate can meet the consumption rate and absence of any storage facility at the delivery site, a minimum of two vessels are required for uninterrupted delivery, as shown in Figure 5–16. After the first vessel offloads the entire amount of gas at the delivery site, it enters a travel-to-source/load/travel-to-sink cycle that involves the following steps:

1. Disconnect from the delivery line (black bar).
2. Travel to the source (white bar).
3. Connect to the loading line (black bar).
4. Load gas (gray bar).
5. Disconnect from the loading line (black bar).
6. Travel to the delivery site (white bar).
7. Connect to the delivery line (black bar) in anticipation of starting gas delivery.

While the first vessel is offloading, the second vessel completes the cycle (1) through (7) described above and is ready to start offloading. At the same time, the first vessel repeats the cycle (1) through (7).
It is clear that, for uninterrupted gas delivery, the diagram of Figure 5–16 can be extended to three or more vessels. For the case of three vessels, two vessels successively offload, while the third vessel completes the total cycle of the above steps (1) through (7) as shown in Figure 5–17. Extrapolation to \( n \) vessels is straightforward (Figure 5–18) under the assumption that the loading site can handle the itineraries of \( n – 1 \) vessels as they load. The key is to ensure that the next vessel in line is ready to start offloading after the previous one has completed offloading. To accomplish this, while one vessel is completing the cycle of the above steps (1) through (7), the remaining vessels successively offload their entire loads; and each one of them enters the cycle (1) through (7) after finishing offloading.

**Figure 5–14** Potential “Hub-and-Spoke” scheme for CNG distribution to island countries in the Caribbean Sea with large consumption of electricity (Nikolaou et al., 2009)
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Figure 5–15 Potential “Milk-Run” scheme for CNG distribution to island countries in the Caribbean Sea with small consumption of electricity (Nikolaou et al., 2009)

Figure 5–16 Scheduling of gas delivery from a single source to a single delivery site using two CNG vessels

Figure 5–17 Scheduling of gas delivery from a single source to a single delivery point using three CNG vessels
The schedules shown in Figure 5–17, Figure 5–18, and Figure 5–19, determine the capacity required for each vessel in order to complete each schedule. Matching the time taken by a vessel to complete the cycle travel/load/travel (above steps (1) through (7)) to the time taken by the remaining \( n - 1 \) vessels to successively offload at a rate dictated by market demand, implies that the natural gas capacity (volume) of each vessel must be (Nikolaou et al., 2009)

\[
G_n = \frac{4t_{\text{connect}} + \frac{2L}{v}}{(n - 1)(1 - f) - \frac{1}{q_{\text{offload}}}} - \frac{1}{q_{\text{load}}}.
\] (5.21)

Eq. (5.21) implies that the total capacity \( G_{\text{total}} \) for a fleet of \( n \) vessels per cycle is

\[
G_{\text{total}} = \frac{4t_{\text{connect}} + \frac{2L}{v}}{(n - 1)(1 - f) - \frac{1}{q_{\text{offload}}}} - \frac{1}{q_{\text{load}}}.
\] (5.22)

Eq. (5.21) and Eq. (5.22) imply that the (theoretically) minimum total capacity for given \( t_{\text{connect}}, L, v, q_c, \) and \( q_{\text{load}} \) is

\[
G_{\text{total, min}} = \frac{4t_{\text{connect}} + \frac{2L}{v}}{1 - f} q_{\text{offload}},
\] (5.23)
attained as \( n \to \infty \). The above value for \( G_{\text{total,min}} \) serves as an order of magnitude estimate only and would never be realized in practice. This is because it would correspond to an inordinately large number of vessels, each of tiny capacity (essentially an approximation of a “floating pipeline” by a series of discrete carriers). Nevertheless, it is interesting to visualize the trend of \( G_{\text{total,min}} \) as a function of offloading rate, \( q_{\text{offload}} \), and travel distance, \( L \) (Figure 5–19).

Since \( G_n \) must be positive, Eq. (5.21) implies a lower bound on the number of vessels, \( n \), required to implement a schedule as

\[
n \geq 1 + \frac{q_{\text{offload}}}{q_{\text{load}}(1 - f)}.
\]

Eq. (5.24) provides the minimum number of vessels required to implement a CNG delivery schedule and it is the smallest integer, \( n_{\text{min}} \), that is larger than or equal to

\[
1 + \frac{q_c}{q_{\text{load}}(1 - f)}
\]
as shown in Figure 5–19. Here it is assumed that 2 to 10% of loaded gas is spent as fuel during transportation. Obviously, a number of vessels larger than \( n_{\text{min}} \) could be used, but that would be uneconomical.

Given that the cost of a CNG transportation fleet of \( n \) vessels is an increasing function of the total capacity of the fleet, Eq. (5.22) gives a trend of the investment needed to service a market, given a consumption rate, \( q_c \), and distance from the source, \( L \). The following trends emerge from Eq. (5.22):

1. For distances between gas source and delivery point of a few hundred kilometers and for sailing speed of about 25 km/hr (Table 5–2), the total travel time \( 2(L/v) \) dominates \( 4t_{\text{connect}} \) in Eq. (5.22), which implies that total fleet capacity is roughly proportional to CNG transportation distance as

\[
G_{\text{total}} \approx \frac{2nL}{v} \left( \frac{1}{n-1} \right) \left( 1 - \frac{f}{q_{\text{load}}} \right) \frac{1}{q_{\text{offload}}}.
\] (5.25)

This observation agrees with Figure 5–1, which indicates that CNG is preferable for relatively short distances (<2,000 km), because most of the capital investment for CNG projects is for transportation vessels.

2. Given a fleet of several vessels (\( n >> 1 \)) and distance \( L \) between gas source and delivery point, the total fleet capacity becomes roughly proportional to CNG offloading rate, \( q_{\text{offload}} \), as

\[
G_{\text{total, min}} = \frac{4t_{\text{connect}} + 2L}{v} \frac{1}{1 - f} q_{\text{offload}}.
\] (5.26)

This is also in agreement with an upper limit on the range of distances for CNG shown in Figure 5–1.

**Example 5–4** Calculation of the fleet size for a given market by using Hub-and-spoke CNG transportation scheme

Natural gas must be delivered as CNG to a destination located 600 nautical miles away from a shipping point at a rate of 500 MMscf/d.
What CNG fleet should service this market? Assume that the maximum loading and offloading rate is 150 MMscf/d, the time needed to connect or disconnect to facilities is 1 hour, the sailing velocity is 14 knots, and that 4% of natural gas loaded is consumed as fuel.

**Solution**

Since the offloading rate cannot satisfy the consumption rate, multiple cycles of CNG vessels must be used. Given that $q_c = 500$ MMscf/d and $q_{\text{offload, max}} = 150$ MMscf/d, there is a need for at least

$$q_c / q_{\text{offload, max}} = 500 / 150 = 3.3,$$  \hspace{1cm} (5.27)

or 4 cycles. Each cycle should deliver $q_{\text{offload, max}} = 500/4 = 125$ MMscf/d.

From Eq. (5.24), the smallest number of vessels needed for each cycle must be greater than or equal to

$$n \geq 1 + \frac{125}{150 \times (1 - 0.04)} = 1.87,$$  \hspace{1cm} (5.28)

i.e., greater than or equal to 2. Consequently, from Eq. (5.22), the capacity of the total fleet for all 4 cycles would be

$$G_{\text{total, all cycles}} = 4n \frac{4 \times 1(\text{hr}) + 2 \times \frac{600(\text{nm})}{14(\text{nm/hr})} \times \frac{1(\text{d})}{125(\text{MMscf/d})}}{(n - 1)(1 - 0.04) - \frac{1}{150(\text{MMscf/d})}} \times \frac{24(\text{hr})}{1(\text{d})},$$ \hspace{1cm} (5.29)

and from Eq. (5.21), the capacity of each vessel would be

$$G_n = \frac{4 \times 1(\text{hr}) + 2 \times \frac{600(\text{nm})}{14(\text{nm/hr})} \times \frac{1(\text{d})}{125(\text{MMscf/d})}}{(n - 1)(1 - 0.04) - \frac{1}{150(\text{MMscf/d})}} \times \frac{24(\text{hr})}{1(\text{d})}.$$ \hspace{1cm} (5.30)

The above two equations can be used to visualize the dependence of the total fleet capacity and vessel capacity on the number of vessels, $n$, used per cycle, as shown in Figure 5–20.

From a scheduling viewpoint, it would be possible to service this market with 2 vessels per cycle (a total of 8 vessels for all 4 cycles); but that would require vessel sizes of about 3,689 MMscf each, which is clearly beyond constructability limits. However, using 3 vessels per cycle would reduce that requirement to vessel sizes of 430 MMscf each, which is clearly feasible (cf. Table 5–2). The total fleet size for 3 vessels per cycle would be $3 \times 4 \times 430 = 5,160$ MMscf.
Note that the total fleet capacity would be reduced significantly (by about 30%, from 5,160 to 3,653 MMscf) if 4 vessels per cycle were used, as can be visualized in Figure 5–20. Increasing the number of vessels even more would reduce the fleet size, but not significantly, and the theoretical lower limit, Eq. (5.26), would be quickly approached. Of course, operating costs would increase as the number of vessels increases, but given that the fixed cost for CNG (mainly ves-
sels) is quite high, there is an incentive to balance fixed and operating costs using medium size fleets and relatively small vessels.

This conclusion is arrived at by the quantitative analysis presented above, and is contrary to the wrong intuition that might opt for large vessels, hoping to realize economies of scale.

Example 5–5 Sensitivity evaluation of hub-and-spoke CNG transportation scheme

If the assumed consumption of 500 MMscf/d in Example 5–4 is an overestimate of the true consumption by 25%, what is the excess capacity built in a CNG fleet?

Solution

For a 25% overestimate of 500 MMscf/d, true consumption must be \( q_c = 400 \) MMscf/d. For this level of consumption and \( q_{\text{offload,max}} = 150 \) MMscf/d, there is a need for at least

\[
q_c / q_{\text{offload,max}} = 400 / 150 = 2.7 ,
\]

i.e. 3 cycles. Each cycle should deliver \( q_{\text{offload,max}} = 400/3 = 133 \) MMscf/d. Using Eq. (5.24), the smallest number of vessels needed for each cycle must be greater than or equal to

\[
n \geq 1 + \frac{133}{150 \times (1 - 0.04)} = 1.92 ,
\]

or greater than or equal to 2. Consequently, using Eq. (5.22), the capacity of the total fleet for all 3 cycles, would be

\[
G_{\text{total, all cycles}} = 3n \frac{4 \times 1(\text{hr}) + 2 \times \frac{600(\text{nm})}{14(\text{nm/hr})}}{n-1)(1-0.04)} \frac{1}{133(\text{MMscf/d})} \frac{1}{150(\text{MMscf/d})} \frac{1(\text{d})}{24(\text{hr})} ,
\]

and from Eq. (5.21), the capacity of each vessel, would be

\[
G_n = \frac{4 \times 1(\text{hr}) + 2 \times \frac{600(\text{nm})}{14(\text{nm/hr})}}{n-1)(1-0.04)} \frac{1}{133(\text{MMscf/d})} \frac{1}{150(\text{MMscf/d})} \frac{1(\text{d})}{24(\text{hr})} .
\]
The above two equations can be used to visualize the dependence of the total fleet capacity and vessel capacity on the number of vessels, \( n \), used per cycle, and are presented in Figure 5–21. Compared to the results in Example 5–4, shown in Figure 5–20, there is a clear reduction (by 25% of the reduced values) in the total fleet volume that would be required to service consumption at the actual (lower) capacity. However, the vessel sizes required are approximately the same.

These results suggest that servicing a consumption market with CNG using a hub-and-spoke scheme is flexible, in that a fleet may be built and subsequently augmented with similar vessels if demand increases, without excessive capital costs.

**Milk-Run CNG Distribution Pattern**

A Milk-run pattern is shown in Figure 5–13. Consider \( N \) natural gas receiving sites (terminals \( T_1, \ldots, T_N \)), each consuming gas at a rate \( q_{c,i}, i = 1, \ldots, N \). Gas is to be provided to each of these points successively by \( n \) CNG vessels, each of capacity (volume) \( V_n \). Each vessel will deliver a gas load \( G_{\text{load},i}, i = 1, \ldots, N \) to each receiving site per visit. Each receiving site has local gas storage capacity \( G_{\text{storage},i}, i = 1, \ldots, N \). All vessels can load and offload gas at a rate \( q_{\text{load}} >> q_{c,i} \) and travel at speed \( v \).

A gas delivery schedule for each vessel involves gas loading at the source, travel, offloading to each destination \( T_i, i = 1, \ldots, N \) successively, and return to the source, to repeat the cycle, as shown in Figure 5–22. The cyclical route, shown in Figure 5–13, is the minimum closed path from the source through the delivery points and back. While finding this minimum path through numerical optimization is a challenging problem for large values of \( N \), it is not difficult for small values of \( N \) (order of 10). Probabilistic methods, such as simulated annealing or genetic algorithms can be used.

The gas delivery schedule must be such that each gas receiving site \( T_1, \ldots, T_N \) is visited by a vessel on time, gets a corresponding gas load offloaded (while passing a fraction of that load to the market for consumption), and has enough gas left in storage to last until the next vessel arrives. Figure 5–22 indicates that \( n \) similar vessels visit each of the \( N \) receiving sites successively and deliver gas, a fraction of which is stored in order to last until the next vessels in the cycle starts delivery. Here the narrow black bars indicate the time needed to connect or disconnect a vessel to a station.

From the analysis done by Nikolaou (2008), the capacity of each vessel, \( G_{\mu} \), in a fleet of \( n \) similar vessels is
the total capacity of the fleet is

\[ G_{total,n} = nG_n = \frac{(N + 1)2t_{connect} + t_{travel}}{(1 - f)\left(\frac{1}{q_{c,1} + \ldots + q_{c,N}} - \frac{2}{nq_{load}}\right)}, \]  

(5.36)
Figure 5–22  Schedule development for CNG distribution by \( n \) similar vessels to \( N \) receiving sites serviced successively on a cyclical path as shown in Figure 5–13.
the cycle time for a vessel is

\[
t_{\text{cycle}} = \frac{(N + 1)2t_{\text{connect}} + t_{\text{travel}}}{1 - 2 \frac{q_{c,1} + \ldots + q_{c,N}}{nq_{\text{load}}}}, \tag{5.37}
\]

the amount of gas to be delivered to each receiving site per visit is

\[
G_{\text{load},k} = \frac{(N + 1)2t_{\text{connect}} + t_{\text{travel}}}{n - 2 \frac{q_{c,1} + \ldots + q_{c,N}}{q_{\text{load}}} q_{c,k}}, \tag{5.38}
\]

and the amount of gas to be stored at each receiving site is

\[
G_{\text{storage},k} = G_{\text{load},k} - q_{c,k} \frac{G_{\text{load},k}}{q_{\text{load}}} = \frac{(N + 1)2t_{\text{connect}} + t_{\text{travel}}}{n - 2 \frac{q_{c,1} + \ldots + q_{c,N}}{q_{\text{load}}} q_{c,k} (1 - \frac{q_{c,k}}{q_{\text{load}}})}. \tag{5.39}
\]

Eq. (5.35) and Eq. (5.36) suggest that the required capacity of a vessel or a fleet is influenced primarily by points in the delivery path, along with the distances from each other, contributing to the term \(L/v\). In fact, the effect of including or excluding a destination from the service plan depends more on the additional travel time, rather than the additional amount of gas this destination requires.

Eq. (5.36) implies that for very large fleets \((n \to \infty)\), i.e., approximation of a pipeline by a fleet, the total fleet capacity is

\[
G_{\text{total},n} = \lim_{n \to \infty} nG_n = \frac{((N + 1)2t_{\text{connect}} + t_{\text{travel}})(q_{c,1} + \ldots + q_{c,N})}{1 - f}, \tag{5.40}
\]

and the total cycle time is

\[
\lim_{n \to \infty} t_{\text{cycle}} = (N + 1)2t_{\text{connect}} + t_{\text{travel}}, \tag{5.41}
\]

as expected.

Since the capacity \(V_n\) of a vessel must be positive, Eq. (5.35) implies that for a given maximum loading/offloading rate \(q_{\text{load}}\) and
given total consumption rate $q_{c,1} + \ldots + q_{c,N}$, the number of vessels, $n$, is bounded as

$$n > \frac{2(q_{c,1} + \ldots + q_{c,N})}{q_{load}}. \quad (5.42)$$

**Example 5–6** Optimization of milk-run CNG transportation scheme for a given market

Natural gas must be delivered as CNG to three destinations with corresponding consumption rates $q_{c,1} = 18$, $q_{c,2} = 13$, and $q_{c,3} = 5$ MMscf/d. The minimum milk-run path to these destinations is shown in Figure 5–23. Assume a maximum loading rate $q_{load} = 150$ MMscf/d, sailing speed $v = 14$ knots (nm/hr), and 4% of CNG is spent as fuel.

Application of Eq. (5.29) for the first destination yields

$$G_2 = \frac{4 \times 1 \text{ (hr)} + 2 \times \frac{120 \text{ (nm)}}{14 \text{ (nm/hr)}}}{18 \text{ (MMscf/d)}} \frac{1 \text{ (d)}}{24 \text{ (hr)}}, \quad (5.43)$$

which yields a vessel capacity $G_2 = 18.7$ MMscf, if two vessels are used in a single cycle. Vessel capacity would be even smaller if more vessels were used ($n > 2$). Calculations for vessel capacities for the other two destinations give $G_1 = 24.6$ and $G_3 = 14.4$ MMscf. Such capacities would be below the smallest practical capacity of a CNG ship or even a barge (see Table 5–2). Therefore, a milk-run scheme must be considered.

Application of Eqs. (5.35 to 5.42) yields the results seen in Table 5–3.

The three consumption markets can be serviced by a single vessel ($n = 1$) completing the milk-run cycle in 5.2 days. Significant local storage has to be provided in this case. Increasing the number of vessels decreases the fleet size, $G_{total,n}$, as well as the required storage $G_{storage,1}$, $G_{storage,2}$, and $G_{storage,3}$. However, using five vessels or more would require vessels (barges) that would be far too small to be practical. Therefore, a balance between fixed and operating costs would be found using from one to four vessels (barges).
Table 5–3  Results from Example 5–6

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<th>$G_{load,2}$ (MMscf)</th>
<th>$G_{load,3}$ (MMscf)</th>
<th>$G_{storage,1}$ (MMscf)</th>
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5.4 References


