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Onshore Gas Gathering Systems – Concept Selection, Basic Design & Operation

Conventional vs Unconventional Gas Field Development

Shale gas is typically considered an "unconventional" resource, along with tight gas and coalbed methane. Of these three, coalbed methane (CBM) has several characteristics that make it quite different than shale gas and tight gas, including: shallow depth, low pressure and temperature, and the need for a significant early life "de-watering" stage. As a result, CBM developments have some considerably different aspects to them and will not be discussed further in this article.

There are a number of characteristics that differentiate Conventional and Unconventional gas field developments. A summary of these characteristics is presented in **Table 1**.

Table 1 Conventional and unconventional field characteristics

Characteristic	Conventional	Shale Gas	Tight Gas
Reservoir "rock" type	Sandstone and limestone/dolomite	Shale	Mostly sandstone
Areal extent	Generally smaller (with exceptions)	Large – very large	Moderate
Depth, ft	3,000 – 15,000	Similar to conventional	Similar to conventional
Porosity, %	5 – 20	2 – 10	4 – 10
Permeability, mD	5 – 500	<< 0.001	< 0.01
Pressure, psig	1,400 – 7,000	Similar to conventional	Often over-pressured
Temperature, F	100 – 300	Similar to conventional	Similar to conventional
Typical initial well flowrate, MMSCFD	1 – 100 (can be much higher)	3 – 30 (initial)	1 – 5
Production decline rate, %/yr	5 – 10	~ 70 → 6-8	60-80 → 10-15
Recovery factor, %	70 – 90	10 – 30	30 – 70
Well type	Mostly vertical	Horizontal	Mostly vertical/directional (for stacked sands)
Stimulation type	Often none	Multi-stage frac	Multi-stage frac
Bottomhole well spacing, acres/well	160 – 640	~ 80	5 - 40
Pad drilled wells ?	No	Yes	Mostly
Typical wells/pad	-	4 – 32	2 – 32
H_2S, %	0 – 30	0 – 0.1	0

CO_2, %	0 – 20	0 – 10	0.1 – 0.8
Hydrocarbon liquids, BBL/MMSCF	0 – 100	0 – 200	0 – 30

Associated and Non-Associated Gas

While the discussion in this article is focused on gas field development (non-associated gas), oil operations must also collect and transport solution gas (associated gas) to a gas plant for processing. Many of the issues discussed here will be relevant to these systems as well.

Conventional Gas Fields

The defining characteristic of "conventional" gas fields is higher reservoir permeability, which in turn results in the following features:

1. Relatively high flowrates.
2. Relatively low decline rates.
3. High flowing tubing pressures in the early years.
4. Large well spacing.
5. Mostly vertical wells and single-well surface sites.

By and large, the geology of conventional reservoirs also tends to make them smaller in areal extent than shale/tight gas reservoirs. Most conventional reservoirs have an areal extent of less than a few hundred square miles while shale gas plays can cover tens of thousands of square miles.

These characteristics have a significant impact on surface facilities design and operation, including the gas gathering system (GGS).

Unconventional Gas Fields

Perhaps not surprisingly, the main characteristic of unconventional gas fields is very low reservoir permeability. In order to achieve economic gas flowrates and recoverable reserves, these reservoirs typically require massive fracture stimulation treatments and, for the shales at least, long horizontal wellbore sections, in order to vastly increase access to formation surface flow area to offset the very low native permeability of the rock. The following features are typical of shale/tight sand developments:

1. Small bottomhole well spacing.
2. Pad drilled wells.
3. Relatively high initial production rates.
4. Rapid production decline.

5. Fairly early onset of well liquid loading problems due to lower production rates after the first few years, which usually requires i) some form of artificial lift and/or ii) significantly reduced back pressure to allow the wells to keep flowing.

An additional characteristic of many shale/tight sand reservoirs is their generally large areal extent. When combined with often fragmented acreage ownership, surface facilities design and operation can become complicated.

Certainly, it is generally true that many, if not most, of the conventional onshore gas fields around the world have been discovered and mostly developed, ie. the majority of the "easy" gas reserves have already been exploited. In the future, new field developments will mainly be focused on unconventional gas resources.

Well Site/Pad Facilities

The well site/pad facilities and gas gathering system are interconnected and generally not independent. Selection and design decisions in one area effect the other. While sometimes complicated, ideally these two pieces should be considered as an interactive and integrated system. Unfortunately, this often doesn't happen, for various reasons to be discussed.

Facilities Ownership

A factor that often affects surface facilities design and operation in certain areas, especially many unconventional gas developments, is the change in ownership at the edge of the pad, ie. between the wells and pad facilities owned and operated by the production company, and the gas gathering system (including compression and gas plant(s)) typically owned by a midstream gas gathering/processing company. This ownership "discontinuity" at the pad edge can often lead to inefficiencies and a non-optimal system overall. The gathering system entry pressure is typically the key variable.
In some parts of the world, the same company drills, produces and operates the wells, and also designs, builds and operates the gas gathering system and gas plant. In many ways, this allows for – at least in theory – a more optimally integrated overall operation. This "integrated" system ownership, ie. upstream + midstream, is less common now than in the past, as many of the large energy companies have sold their midstream assets to dedicated midstream companies.

Interacting Components

For both conventional and unconventional gas field developments, there are several interconnected - but interacting - pieces involved:

1. the reservoir.
2. the wells.
3. the wellsite/pad facilities.
4. the gas gathering system.

5. the gas plant.

In addition to the interactions between these pieces at any particular point in time, there is also a longer-term effect associated with reservoir pressure decline and a corresponding decline in well flowrates. For some gas fields, composition will also change over time, eg. leaning out of the gas due to retrograde condensation of heavier ends in the reservoir, increased formation water production, etc.

It is often difficult to evaluate these components in isolation of each other. It is the integrated aspect of GGS design and operation, and in particular, the subsurface-surface integration considerations – that has historically made this a complex area. The relatively sharp demarcation of knowledge that occurs – more or less – at the wellhead, between subsurface and surface technical people does not help matters. *Integrated Asset Models (IAMs)* have proven to be quite useful for modeling gathering system design and operation – including the subsurface-surface interaction aspects – especially over time. They take some effort and a multi-disciplinary approach is needed. The difference in ownership between the wells/pad facilities and the GGS/gas plants has in some cases limited the ability of IAMs to achieve their potential.

Main Surface Facilities Issues

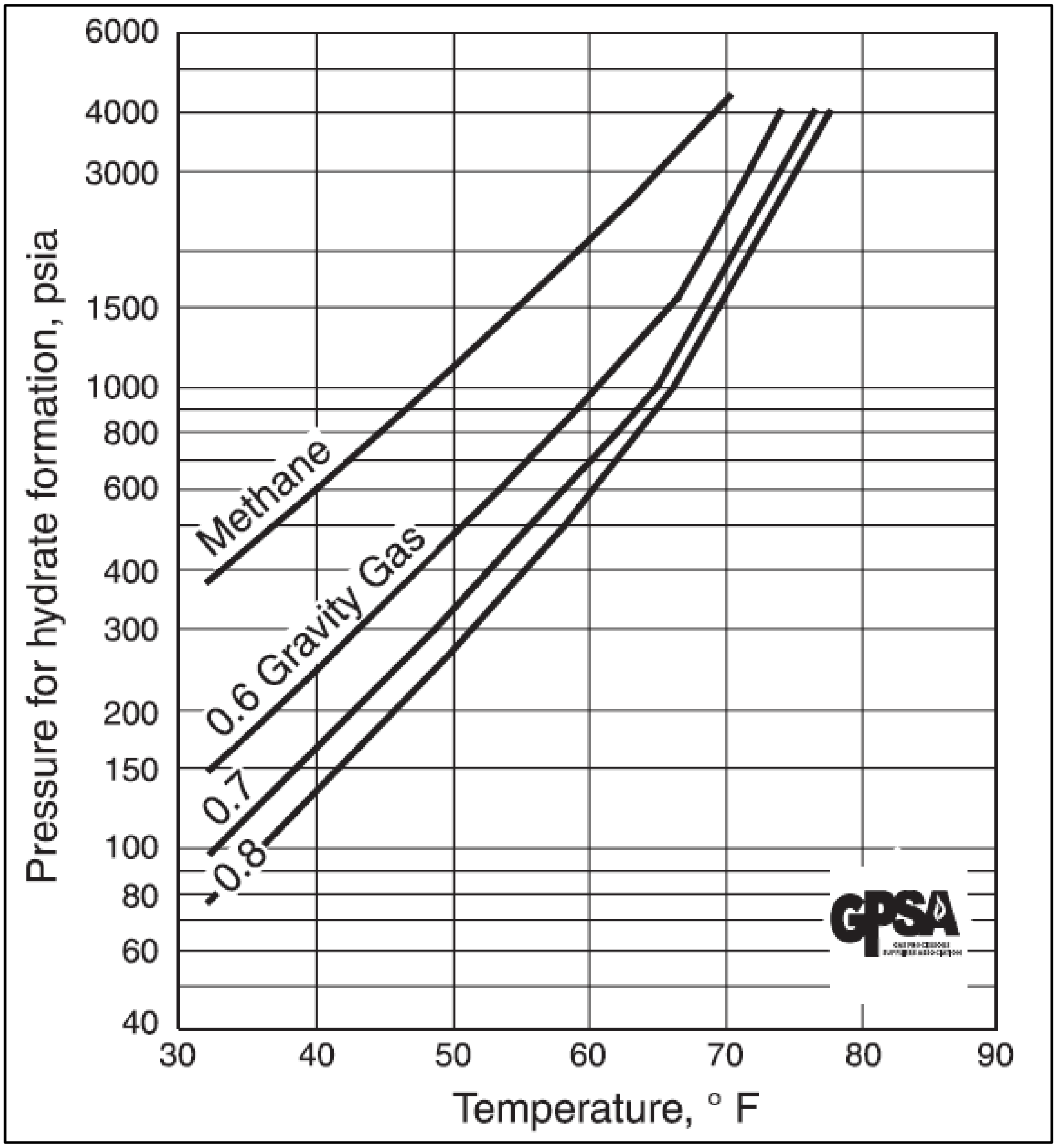
From the surface facilities point of view, the following – in no particular order – are the key areas to be considered:

1. Avoidance of hydrates.
2. Sweet vs sour (H2S) gas.
3. Liquids handling and disposition, including multiphase flow problems (hydrocarbon liquids and water).
4. Corrosion/materials selection.
5. Line sizing considerations.
6. System architecture.
7. Provisions for future drawdown of flowing/reservoir pressure to maintain deliverability and maximize reserves recovery – mainly compression.

1. Avoidance of Hydrates

In some parts of the world, hydrate formation is not a major concern. These are normally warm regions, nearer the equator. Moving farther north and south, ambient temperatures begin to drop, including shallow ground temperatures at typical pipeline burial depths. In these regions, hydrates may be a problem in the winter but not at other times of the year. Eventually, ie. > ~ 40^{o} latitude north and south, ambient/pipeline burial temperatures are low enough to make hydrates a problem year-round. **Figure 1** shows typical hydrate formation conditions as a function of gas gravity.

Figure 1 Hydrate formation conditions.



Minimum winter temperatures at typical pipeline burial depths range from ~ 35 F in northern Alberta to ~ 55 F in the southern United States. From **Figure 1**, for a typical 0.65 SG gas, a flowing temperature of 35 F corresponds to a hydrate pressure of ~ 135 psig, while a temperature of 55 F corresponds to a hydrate pressure of ~ 535 psig. In many parts of the world, sales gas transmission pipelines operate at a nominal pressure of 1,000 psig. Depending on the type of gas plant used for processing, plant inlet pressures (excluding inlet compression) often range from 1,050 – 1,400 psig, with the highest end of this range being typical for a Joule-Thomson (JT) type of plant. While there are certainly a reasonable number of JT plants in operation world-wide, they are much less common than refrigeration and turbo-expander plants, resulting in a typical operating pressure range of 1,100 – 1,300 psig for most high-pressure gas gathering systems *(a strong case can be made that both JT and refrigeration plants would* *benefit from low-temperature separator operating pressures in the 500-600 psig range which would help plant operation and reduce back-pressures on the upstream wells/GGS. The drawback is, that to do this would normally involve the installation of sales gas compression initially, with the associated high cost)*. These pressures are well into hydrate formation territory for typical buried pipeline flowing gas temperatures.

A potentially feasible hydrate prevention strategy might be to design and operate the gathering system at pressures below the hydrate forming pressure at the minimum expected flowing temperature. This would definitely be an option for shallow, low pressure gas fields but would not normally be desirable for higher pressure developments for a few reasons:

1. To achieve the necessary low pressures would require the early installation of compression which incurs a large upfront cost.
2. The wells may need to be choked to control flowrates which would negate any potential deliverability benefits associated with lower GGS back-pressure.
3. Low pressure operation in early field life when gas flows are typically largest will require larger pipe diameters due to the low gas density, though higher line pressure drops may be tolerable in early well life. This again, incurs a large upfront cost.

Many conventional gas reservoirs are relatively deep, eg. > 7,000 feet, and therefore at fairly high pressures, at least initially, eg. 3000+ psig. Gas wells producing from these reservoirs will generally have the capability of flowing at reasonable rates and high tubing pressures for a number of years. The wells will often be choked for flowrate control, at least in their early life. Over time, reservoir pressure will decline due to depletion, flowrates will fall, chokes will be opened, and eventually the wells will have difficulty flowing against high gathering system backpressures. At this time, it is typically necessary to either 1) drill more wells, and/or 2) install compression to reduce backpressure on the wells in order to maintain deliverability and also to maximize gas reserves recovery which is inversely proportional to reservoir abandonment pressure for “volumetric” reservoirs. While drilling more wells to maintain field deliverability may be feasible during the early years, the addition of compression will normally be required eventually.

Certainly as reservoir pressures decline over time, and compression is added, a point may be reached when the operating pressure drops below the hydrate formation pressure at the minimum prevailing GGS temperature condition. Depending on the system design, it may be possible to discontinue hydrate prevention measures in order to save operating costs and salvage equipment. This will normally mean changing from a dry to a wet system, and the implications of this would have to be considered.

Assuming the GGS will initially operate at high line pressures, the following options are available for hydrate prevention:

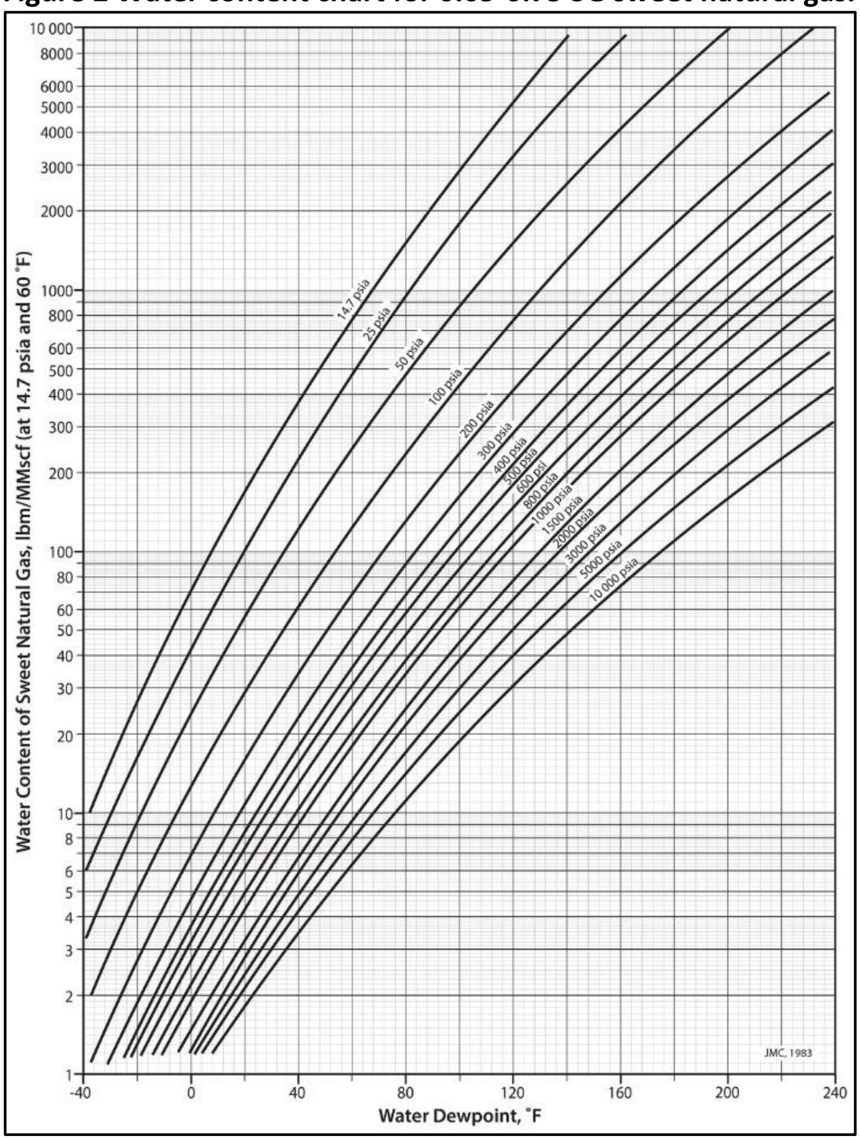
i) Remove the water by dehydrating the gas.
ii) Keep the gas/wellstream above the hydrate formation temperature at the prevailing pressure.
iii) Utilize a chemical to inhibit hydrate formation.

There are pro's and con's to each of these options, and all three are used.

i) <u>Remove the water, ie. dehydrate the gas.</u>

The water content of saturated typical natural gas stream is shown in **Figure 2** The water removal requirements for field dehydration applications are not necessarily the same as "sales gas" specifications but are typically similar, with the main requirement being to prevent condensation of free water out of the gas during transportation. Values of 3-7 lb/MMSCF are typical, dependent mainly on minimum ambient/flowing temperatures.

Figure 2 Water content chart for 0.65-0.75 SG sweet natural gas.



There are two dehydration methods that are normally considered:

1. Glycol (normally triethylene glycol) dehydration (probably 90+% of field gas dehydration applications).
2. Mole sieve dehydration.

A 3'rd potential gas dehydration option is calcium chloride ($CaCl_2$), but this is typically more of a niche application – low gas flowrates, low-moderate gas temperatures – and will not be considered further in this article.

Gas dehydration also has significant benefits with respect to GGS corrosion control and materials selection.

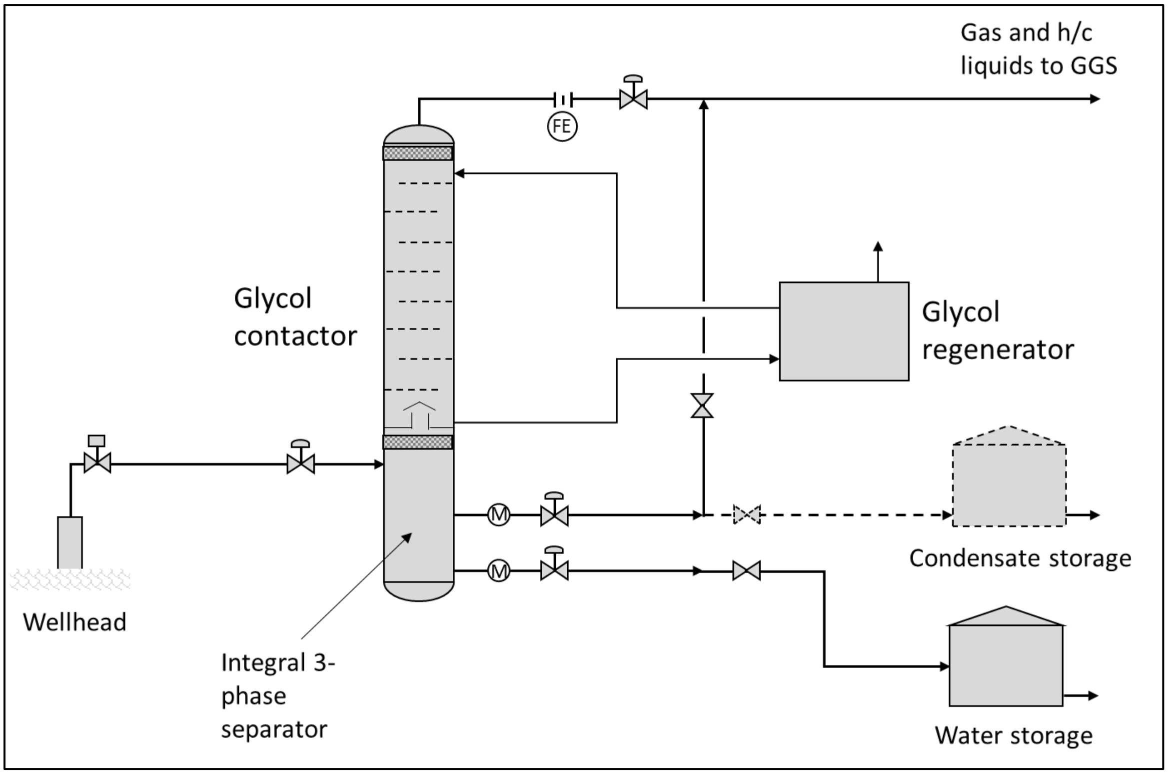
The required dried gas outlet spec will typically be dictated by the dewpoint corresponding to the minimum flowing gas temperature (winter) in the gathering system at the worst case (highest) operating pressure condition likely to be experienced. In general, the minimum flowing temperature is mainly a function of geographical location (latitude), and to a lesser extent, burial depth of the line.

Glycol dehydration

Glycol dehydration is by far the most commonly used field gas dehydration method. For a conventional gas field development with large well spacing, eg. 640 acres, and vertically drilled wells, the glycol dehy would typically be located on the wellsite, ie. each well would have its own glycol dehy. In the author's experience, wellsite glycol dehydration is less common now than it once was, probably because there aren't many onshore conventional gas fields being discovered and developed anymore. In many cases, glycol dehydration has been displaced by methanol injection, which will be discussed later in this article.

Normally, a 3-phase vertical separator with metering of all three phases is installed upstream of the dehy, or can be incorporated into the bottom of the glycol contactor vessel as an "integral" separator. Any free water is dumped to an onsite storage tank and trucked out periodically. Condensate is typically – though not always – recombined with the dried gas and multi-phased to the gas plant. Normally, the condensate/free water separation is good enough – and the amount of condensate small enough – that downstream hydrate problems caused by water in the recombined condensate are not an issue. If necessary, a condensate "conditioner" - basically a liquid-liquid coalescer - is utilized if more efficient free water separation from the condensate is needed. Liquid handling is discussed further later in this article. A typical PFD of wellsite glycol dehy facilities is shown in **Figure 3**.

Figure 3 Gas well with wellsite glycol dehydrator



Conventional wells typically flow at reasonably high flowrates, eg. 5 – 50 MMSCFD, or more, and therefore flowing tubing temperatures are also usually fairly warm and can be quite hot for high rate wells. This normally will eliminate the need for a choke heater ahead of the dehy to handle the expansion temperature drop if the well is choked to control flow. Only high flowrate wells will have flowing temperatures too high for inlet into a glycol contactor, ie. > 120-130 F. In this case cooling of the wellstream ahead of the glycol unit will be required and potentially an alternative hydrate prevention strategy should be considered. Wellsite cooling of the wellstream is fairly rare, but may be required for high flow wells.

As discussed previously, compression will likely need to be installed at some point to reduce flowing tubing pressure in order to maintain deliverability, and also to allow for lower reservoir pressure and corresponding higher gas reserves recovery to be achieved. The wellsite facilities, eg. 3-phase separator and dehy unit should be designed with an allowance for future lower pressure operation in mind, eg. allowable gas velocities, higher saturated water content of the gas and potentially increased formation water volumes.

Glycol dehydration has been used to dry sour gas streams in the field, but normally these applications have been limited to less than, say, 5 % H_2S. The main concerns have been corrosion and emissions from the still overhead. Of course, all high H_2S wellsite facilities require adequate safety provisions, and these are typically unattended facilities. Glycol dehys have been used on much higher acid gas concentration streams, eg. acid gas reinjection schemes, but these are typically gas plant installations with supporting infrastructure, monitoring and operations personnel present.

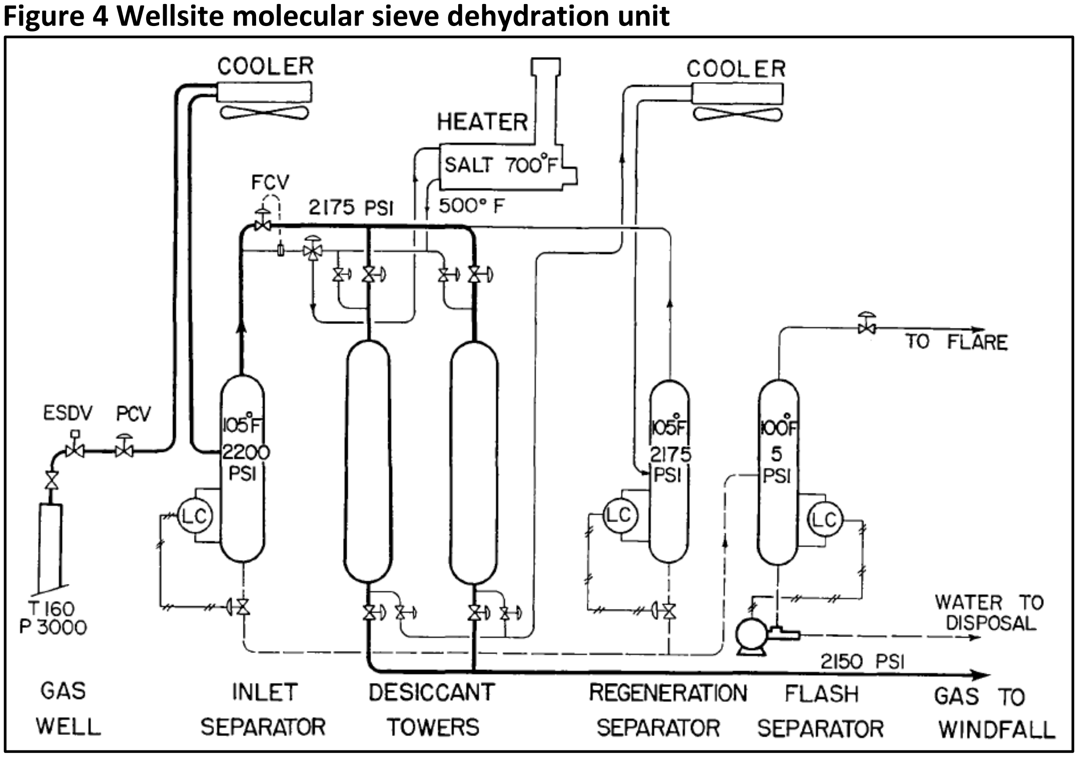
Wellsite glycol dehydration tends to be more cost effective – compared to methanol injection – for higher flowrates. There are significant economies of scale related to the CAPEX of a glycol dehydration unit as size increases whereas methanol costs increase approximately linearly with gas flowrate.

Methanol injection provisions at the wellsite should always be provided as backup for the dehy, cold startup conditions, etc.

Solid Bed (Mole Sieve/Silica Gel) Dehydration

Many will be surprised to learn that solid bed dehydration would even be considered for a field wellsite application, and for good reason. Solid bed dehydration is more complex and expensive than glycol dehydration and its main advantage over glycol – very low dried gas water content/dewpoint – is not normally needed in gas gathering operations. In the relatively few circumstances where a wellsite mole sieve system has been used, it has been for a high H_2S application, eg. typically > 20 % H2S. The main advantage of this process compared to glycol dehydration is that with high pressure regeneration, most, if not all, of the H_2S emissions can be eliminated. **Figure 4** shows a sour gas wellsite equipped with a solid bed dehydration system.

Figure 4 Wellsite molecular sieve dehydration unit



Union Carbide

Although these systems have occasionally been installed, they are uncommon. Most high H_2S gas fields tend to use heat for hydrate prevention instead of dehydration, and this option is discussed next.

ii) Increase/maintain the gas temperature above the hydrate temperature.

In this case, the gas will not be dehydrated but will be kept warm instead.

Although this is not a particularly commonly utilized hydrate prevention strategy, there are a few applications:

i) Low rate but high pressure gas wells with relatively short transport distance to a centralized processing facility.
ii) High rate, high pressure, high H_2S wells.

In some cases, a choke/line heater is required at the wellsite to deal with the large JT expansion cooling effect experienced by choked high-pressure wells, especially during start-up. This is a somewhat different application than prevention of hydrates in the GGS but there are some common aspects to the equipment utilized.

First, the hydrate temperature of the flowing wellstream is estimated. From **Figure 1**, for 0.65 SG gas and assuming any free water present is condensed/fresh water, the estimated hydrate temp at an assumed average GGS pressure of 1,100 psig is ~ 65 F.

The next requirement is to estimate the flowing tubing temperature for the well. This is not a straightforward calculation and is one that most facilities engineers have little experience with. In the authors' experience not many subsurface/production engineers have experience with this calculation either. It tends to "fall through the cracks" so to speak but is often important, especially for "near-wellhead" facilities work. The following equation provides an approximate method for estimating the flowing wellhead temperature for a given set of conditions:

$$T_{wh} = T_R - g_T\left[D - A(1 - \exp(-D/A))\right]$$

$$A = \frac{\Sigma m C_p}{\pi d_o U_o}$$

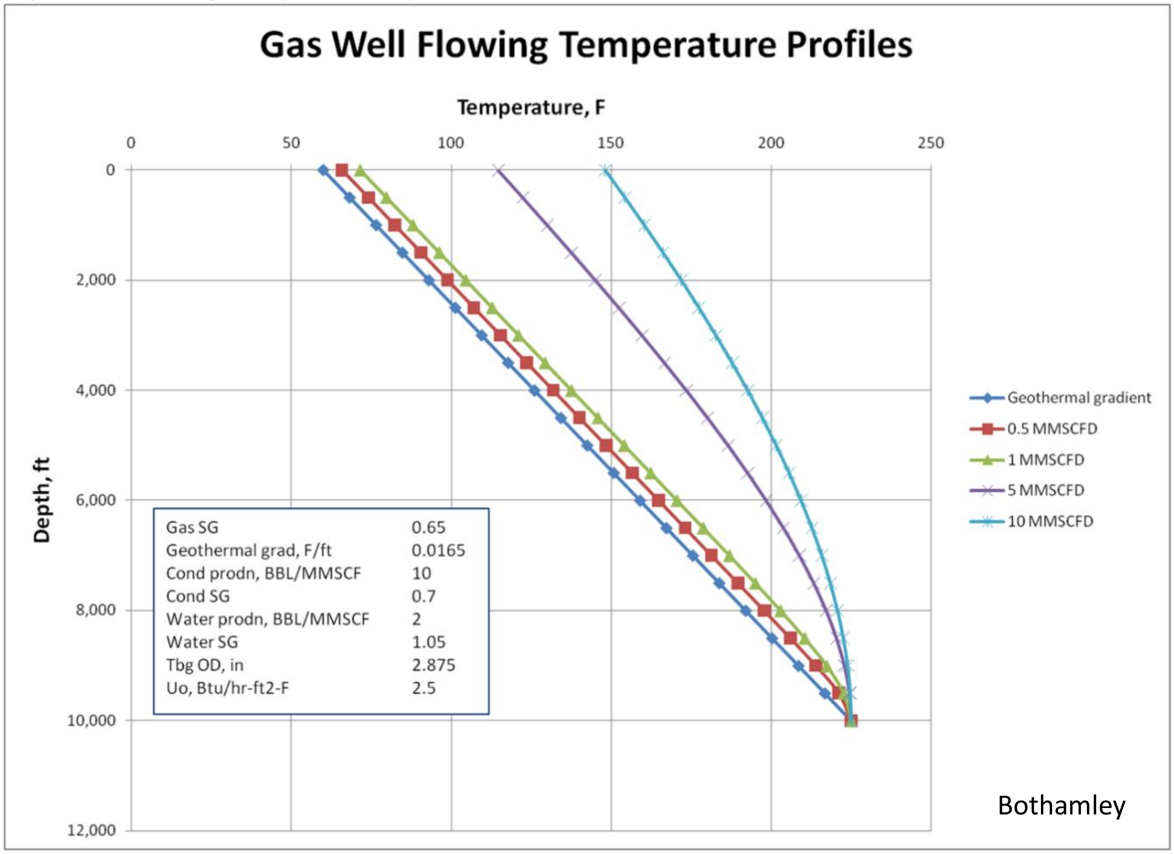
	FPS
T_{wh}, flowing wellhead temp	F

T_R, reservoir temp	F
g_T, geothermal gradient	F/ft
D, well true vertical depth	ft
m, mass flow	lb/hr
C_p, heat capacity	Btu/lb-F
d_o, tubing OD	ft
U_o, overall heat transfer coefficient	Btu/hr-ft^2-F

Theoretically, this is an unsteady-state heat transfer calculation due to the conductance of the "infinite earth" surrounding the wellbore. There are also several heat transfer resistances – conduction and convection – involved in the buildup of the overall heat transfer coefficient, U_o, associated with the tubing string, tubing-casing annulus/annuli, cement layers, the earth itself (normally different materials that vary with depth), etc. Suffice to say, trying to calculate U_o from "first principles" is not easy. Instead, U_o values in the 2 – 2.5 Btu/hr-ft^2-F range can typically be back-calculated from operating gas well data. The geothermal gradient varies regionally but a value of 0.0165 F/ft is typical.

Figure 5 below shows the results of typical wellbore heat loss calculations and corresponding flowing wellhead temperatures using the equation provided.

Figure 5 Flowing temperature profiles.

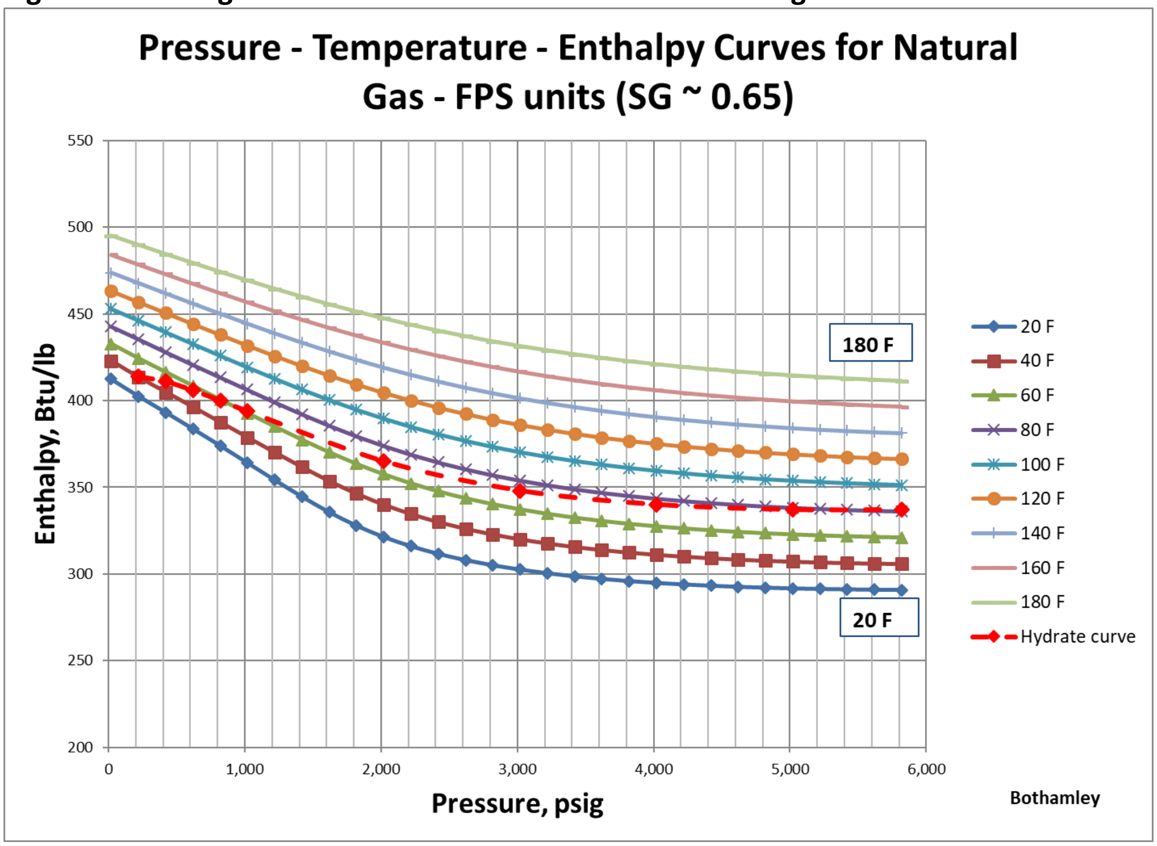


This calculation provides an estimate of the flowing gas (and associated liquids) temperature at the wellhead **upstream of the choke**. If the well is being choked for flow control and there is a large pressure drop across the choke, there will be a Joule-Thomson expansion cooling effect across the choke. There are a number of approximate hand calculation methods – mostly charts, eg. **Figure 6** – for estimating expansion temperature drop, but this is probably best done by a simulator. Clearly, low-rate, high pressure wells have the most hydrate risk. In fact, it is possible for these wells to hydrate off in the tubing below the surface of the ground, sometimes hundreds of feet below surface. These are typically high-pressure – though relatively low deliverability – wells, that are being choked to meet a low gas sales contract nomination. Flowing tubing pressures can easily be in the 1,500-2,000 psig range and higher. Combined with a low flowing temperature, the upper part of the tubing, wellhead and Christmas tree up to the choke are well inside the hydrate formation conditions region. Historically there have been a couple of ways to deal with this:

1. Inject methanol
    a. Down the tubing via a capillary string.
    b. Down the tubing-casing annulus assuming the well doesn't use a packer.
2. Install a bottomhole choke

a. this is basically a restriction nipple that is installed in the bottom of the tubing string to take the required pressure drop downhole where the temperature is warm rather than across the surface choke where it is much colder. This sounds good in theory but in the author's experience, often did not work too well in practice.

Figure 6 PTH diagram - useful for wellsite choke heater design.

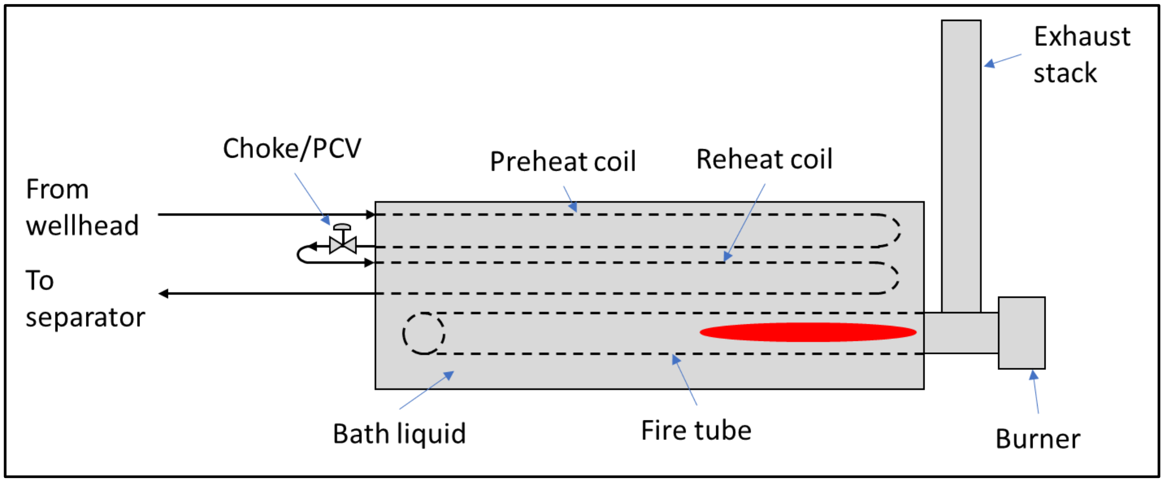


High flowrate gas wells can actually cause wellsite facilities/GGS problems by flowing too hot. What temperature is "too hot" ? There are several possible upper limit temperature constraints:

i) Max gas inlet temperature of ~ 120 F for glycol dehydration.
ii) Max temperature limit of ~ 140 F for flowline external coating (steel flowlines) or for the commonly used polyethylene layers of composite flowlines.
iii) Flowline thermal expansion/buckling issues.
iv) Increased volumes of condensed hydrocarbons and water in the GGS. The hydrocarbon liquids may not be a problem if they are going to be recombined with the gas anyway.

A typical wellsite choke heater is shown in **Figure 7**. These are glycol-water bath heaters that are often of split-coil design with a long-nose choke between the high and low pressure coils. A choke heater can be used to warm the gas from the wellhead thereby preventing hydrate formation associated with the expansion pressure drop. The temperature of the gas out of the low-pressure coil can be adjusted to improve wellsite separation/measurement or to heat the gas before putting it into the gathering system to keep the flowing gas warm on its way to the gas plant, as a hydrate prevention strategy. The bath liquid is typically a 50-50 mixture of water and ethylene glycol and operates at temperatures in the 180-190 F range.

Figure 7 Typical wellsite choke heater.



<u>Thermally insulated vs non-thermally insulated pipe.</u>

Heat loss and the corresponding temperature profile for gas flow through a buried pipeline can be calculated from the following equation:

$$T_2 = T_g + (T_1 - T_g)e^{-U_o A_o L / \sum m C_p}$$

$$A_o = \pi d_o$$

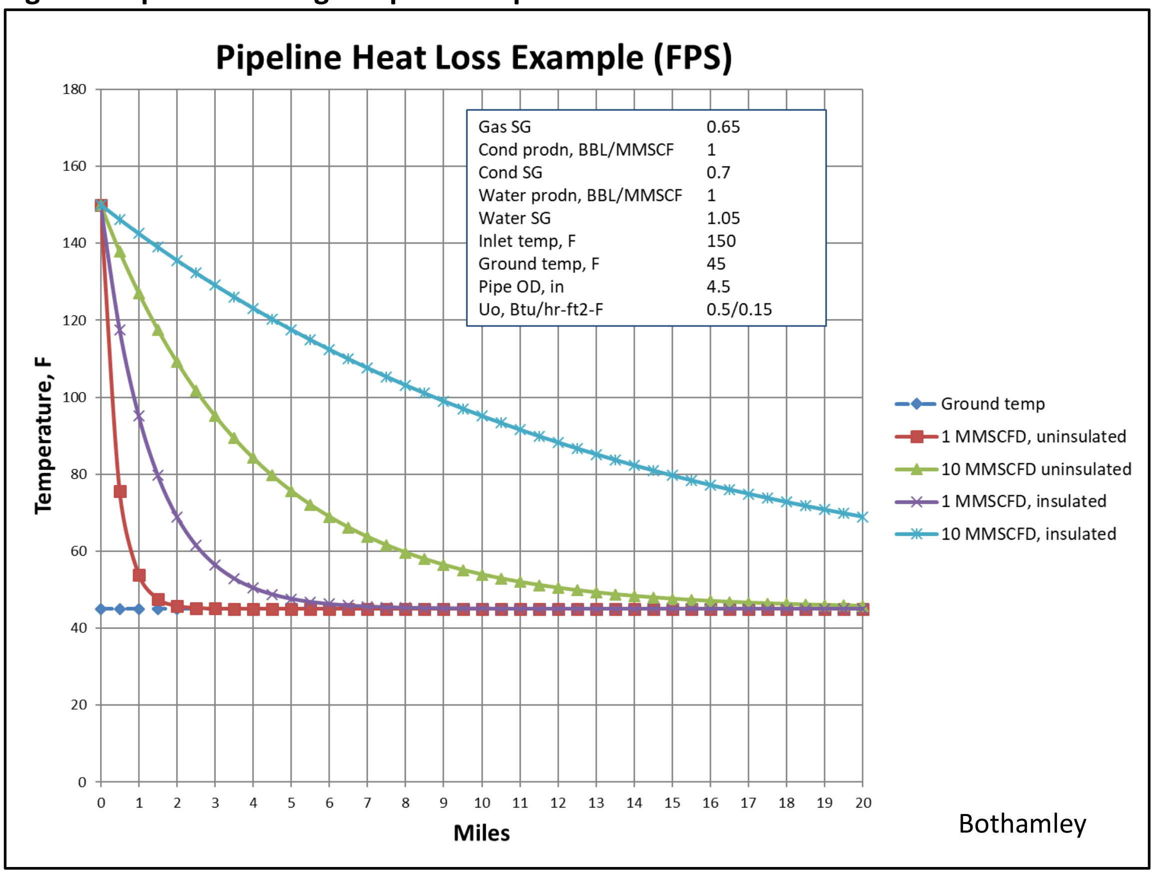
	FPS
T_1, pipe segment inlet temperature	F
T_2, " " outlet "	F
T_g, ground temperature at burial depth	F
U_o, overall heat transfer coefficient (outside area)	Btu/hr-ft^2-F

A_o, outside area/unit length	ft^2/ft
d_o, pipe OD	ft
L, pipe length	ft
C_p, specific heat	Btu/lb-F
m, mass flow	lb/hr

Area basis is pipe OD.

Figure 8 shows flowing temperature profiles for buried flowlines/pipelines for an assumed set of conditions and operational parameters.

Figure 8 Pipeline flowing temperature profiles.



Gas flow through non-thermally insulated pipe cools off quite quickly, especially for low flowrates. Transport of the gas over much more than several miles, will typically require the installation of multiple line heaters for periodic reheating of the gas in order to remain above hydrate formation temperature. While potentially feasible, this is not done very often. This type of system is very sensitive to flowrate, especially turndown operation.

Thermally insulated pipe improves the situation significantly. The main problem with this option is that insulated pipe is very expensive compared to non-insulated pipe. Another sometimes unappreciated drawback to this option, is that the pipeline is operating warm and wet, which for steel pipelines at least, results in a significant corrosion risk, even with no H_2S and only 1-2 % CO_2. In particular, top-of-line CO_2 corrosion can be severe in downhill pipeline sections that predominantly operate in stratified flow. The author has personal experience with this problem which went undetected for years before rupture of the pipeline occurred.

Many high H_2S “conventional” gas field developments utilize wellsite line heaters and insulated gathering system pipe to keep the wellstream above hydrate formation temperature all the way to the gas plant. Needless to say, materials selection and the corrosion control strategy utilized are major issues but can generally be dealt with.

iii) Hydrate Inhibition via Chemical Injection

For this option, the focus will be mainly on the use of methanol for hydrate inhibition. Ethylene glycol is also an option but is rarely used in onshore gas gathering systems, though perhaps it warrants additional consideration. Low-dosage hydrate inhibitors (LDHI’s) are also an option, though they are also rarely used for onshore applications. LDHI’s are expensive and the space and weight savings associated with their lower concentration requirements are not critical onshore.

Methanol is a so-called thermodynamic inhibitor which is soluble in water and depresses the hydrate formation temperature. Hydrate temperature depression is dependent on the concentration of methanol in the aqueous phase.

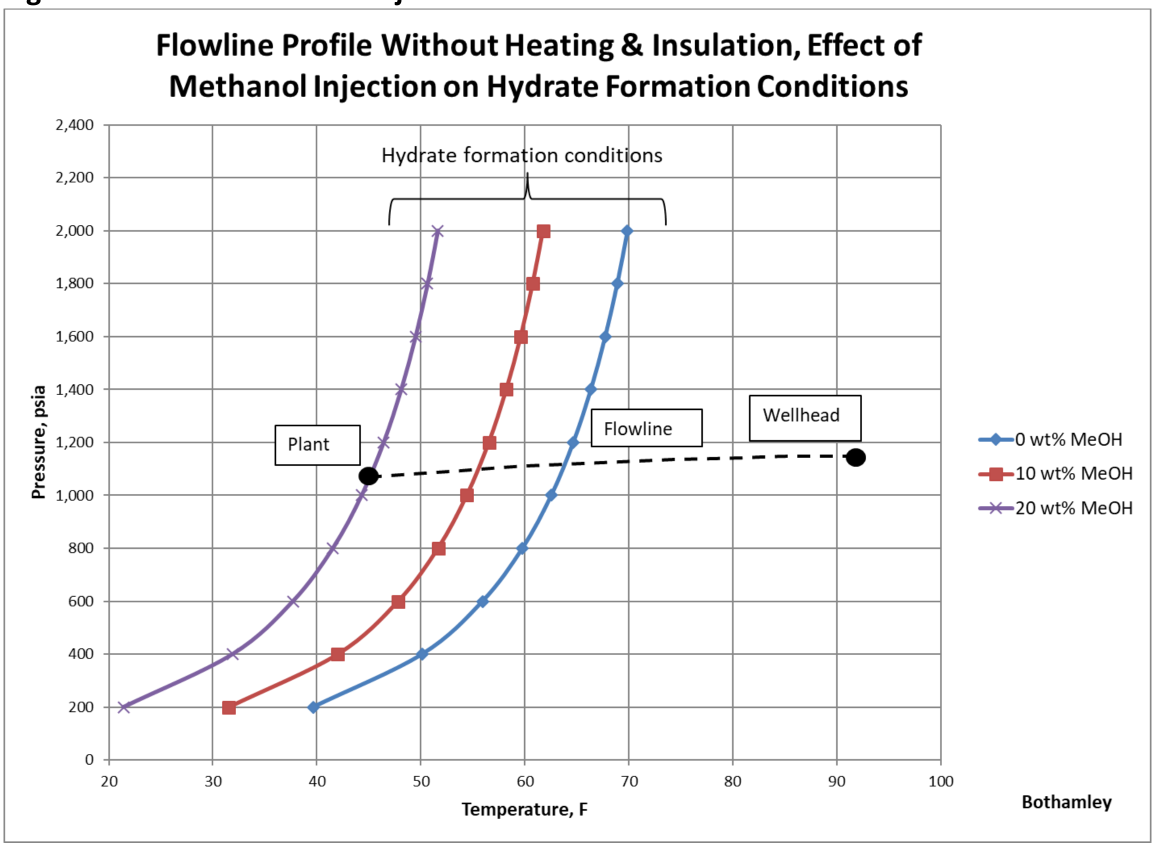
Methanol injection is typically the lowest CAPEX hydrate prevention option, often the main criteria for many companies, but of course has an ongoing chemical consumption operating cost. A significant consideration with the use of methanol is whether it is needed year-round or only in the colder winter months. As discussed previously, this mainly depends on geographical location (latitude). In the southern U.S. methanol injection in only the winter months is probably sufficient, while in northern Alberta, year-round injection – at least in high pressure systems – will be required.

The required methanol injection rate for a given application is dependent on several factors including:

i) The hydrate temperature depression required.
ii) The amount of liquid water present in the line.
iii) The amount of hydrocarbon liquid present in the line.

Methanol injection rates of 5 – 10 gal/MMSCF of gas are typical and can be determined more accurately by simulator or hand calculation. The methanol will distribute between the gas, water and hydrocarbon liquid phases. It is the methanol concentration in the water phase that is effective in preventing hydrates. The methanol volumes in the gas and hydrocarbon liquid phases are essentially "losses", though the vapor phase methanol can be helpful in certain operational situations, eg. "melting" hydrate blockages.

Figure 9 Effect of methanol injection



An additional drawback associated with the methanol injection option – at least for steel flow lines – is internal corrosion. First, the system is being operated wet so the usual internal corrosion mechanisms (CO_2, H_2S, O_2) are potentially active due to the presence of an electrolyte (water). Second, though not well – or widely – recognized, the presence of high methanol concentrations are known to actually increase corrosion rates under certain circumstances, especially in sour gas applications. Oxygen dissolved in the injected methanol is also a known contributor to internal corrosion.

In summary, as mentioned previously, methanol injection is probably the most commonly used hydrate inhibition strategy currently being used in most smaller flowrate, higher pressure, sweet gas gathering systems. In large flowrate systems, field located glycol dehydration units are more common. For high H_2S gathering systems, wellsite – and intermediate if required – line heaters and insulated pipe are quite commonly utilized. Methanol injection provisions are nearly always provided as a backup to these alternative hydrate prevention strategies.

3. Sweet vs Sour Gas

Most onshore gas production in North America is sweet (< 4 ppmv H_2S) but substantial volumes are sour (> 4 ppmv H_2S) with H_2S concentrations varying from 5-6 ppmv to 30+ %. Most tight/shale gas is sweet or at least < 100 ppmv H_2S. The higher concentration (>1 %) H_2S production tends to come from "conventional" fields. H_2S removal in the field is generally avoided due to the cost, complexity, environmental and safety issues involved. There are exceptions, and these usually take the form of H_2S scavenger systems, typically intend to remove ppm levels of H_2S and less than a couple hundred pounds/day of sulfur equivalent.

From a field facility/gas gathering system point of view, low H_2S gas can often be handled similarly to sweet gas, with extra attention paid to minimizing possible venting/emissions sources, with sweetening of the gas performed at a centralized processing facility. If the gathering system is operated by a separate company, they may accept, transport and process the gas with an additional "sweetening fee" charged, or may not accept the gas into their system, which would require the production company to install a scavenger sweetening system at the well/pad site.

Higher concentrations of H_2S are not economically treatable with scavengers. This gas basically needs to be transported to a centralized gas plant – or possibly a large field compressor station equipped with an amine sweetening system (typically) – for processing and disposition of the recovered H_2S/sulfur. As mentioned earlier, high H_2S produced gas can be dehydrated at the well site/pad source to avoid hydrates and minimize internal corrosion during transport to the gas plant, or alternatively, well/pad site line heaters and insulated pipe can be used – for hydrate avoidance – along with corrosion inhibitor injection to protect carbon steel pipe. Some operators will choose to utilize corrosion resistant alloys (CRA's) in these applications. They are expensive, but for large fields and long operating life, they will often result in life-cycle-cost advantages.

2. Liquids Handling

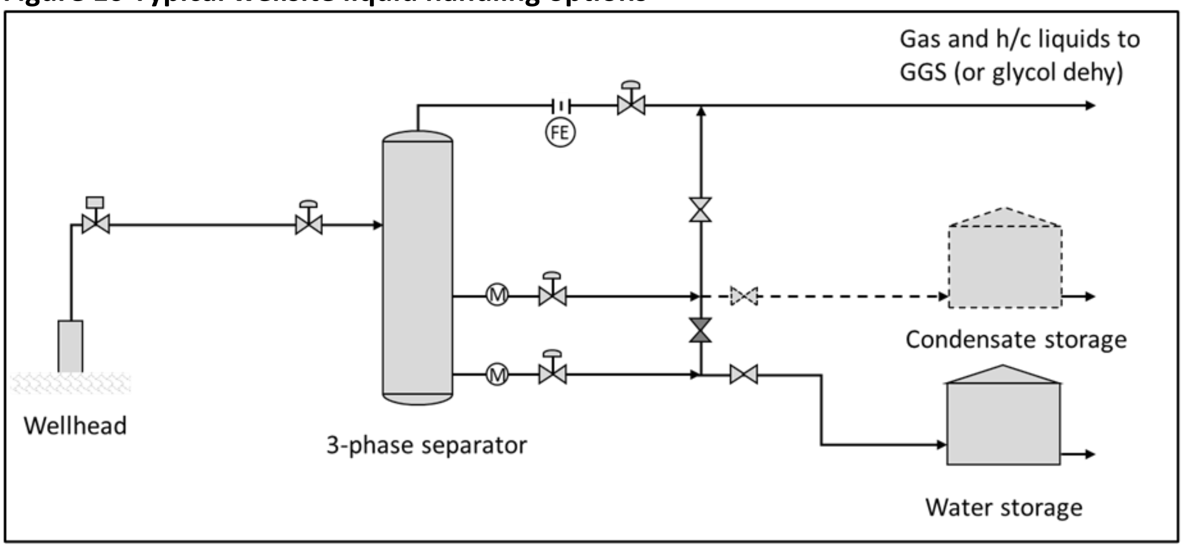
Most gas wells also produce varying amounts of hydrocarbon liquid and water that must be handled in some way. These liquid sources include:

1. Hydrocarbon liquids – mostly liquids that condense out of the gas due to temperature and pressure changes, but there may also be some free liquids that enter the well from the reservoir as well.
2. Free water – typically formation water and in early well life, flow-back water from the stimulation treatment. Produced formation water flowrates typically increase over time while flowback water production normally lasts for only a few months and is often separated at the well/pad site via temporary facilities. The specific aspects of frac flow-back water (and proppant) handling will not be discussed further in this article.

3. Condensed water – water vapor that condenses out of the gas phase mainly due to the drop in temperature of the gas as it moves up the well tubing and through the surface facilities.

For production accounting purposes, phase separation is typically required to allow measurement of the gas, hydrocarbon liquid and water (not all areas). Normally, “conventional” 2 or 3-phase separators are used. In some jurisdictions, individual wells are equipped with “wet gas” meters, basically orifice meters, with provisions – temporary or permanent – to periodically test the well with a conventional separator and meters. Multiphase meters are rarely used in onshore gas gathering systems. **Figure 10** shows a typical conventional well site liquid handling arrangement.

Figure 10 Typical wellsite liquid handling options



The types and amounts of liquid that are present in the gathering system are mainly dependent on separation/processing decisions implemented on the well/pad site. These include:

Hydrocarbon Liquid Handling

Depending on wellstream composition and flowing temperature and pressure, some amount of hydrocarbon liquid - typically 0 – 50 BBL/MMSCF - will also be produced from the well. There are two main options for handling this hydrocarbon liquid:

i) **Removal of free hydrocarbon liquids from the gas at the well/pad site**.

The free hydrocarbon liquids are separated, measured and temporarily stored in onsite tanks then shipped out by truck – usually – or pipeline. These liquids are typically quite light and volatile, normally requiring some form of stabilization process – often simple flash separation – to reduce vapor pressure, in addition to water removal. If the liquids are sour, additional processing and precautions are required. Even with free liquids removal at the well/pad site, some amount of hydrocarbon liquid condensation can be expected in the GGS due to temperature reduction.

ii) Hydrocarbon liquids are recombined with the gas.

The free hydrocarbon liquids are separated, measured and then recombined with the gas for transportation via the GGS to the central gas plant for processing. Some amount of additional hydrocarbon liquid condensation can also be expected in the GGS due to temperature reduction.

A major factor here relates to the facilities ownership question.

Option (i) is commonly employed for "pad well" developments and/or for single well per wellsite developments where there is a change of ownership between the wells/pad site facilities and the GGS. In these cases it is common for the gas gathering company to have a "no free liquids" requirement in the gas gathering agreement which prohibits recombination of free hydrocarbon liquids with the gas for transport to a centralized gas plant.

If the operating company owns and operates everything from the wells to the gas plant, the hydrocarbon liquids are often recombined with the gas and "multi-phased" all the way to the plant for centralized handling and processing per **Option (ii)**.

For many conventional gas field developments, **Option (ii)** is very common. While this option increases the liquid content in the gathering system, it has the following advantages:

i) Removes the need for hydrocarbon liquid storage at each wellsite.
ii) Removes the need for collection and trucking of hydrocarbon liquids.
iii) Eliminates flash vapor volumes, including potentially H2S, from the hydrocarbon liquid storage tanks.
iv) Transports the hydrocarbon liquids to a centralized gas plant where more efficient condensate stabilization and storage facilities are located.
v) Allows for a smaller wellsite footprint.

The main *technical* downside to recombining the hydrocarbon liquids with the dried gas is increased multi-phase flow related problems in the GGS, ie. higher pressure drops and slugging. Besides the potential multiphase flow issues, it will often be necessary, ie. for a wellsite glycol dehy system, to ensure that only minimal amounts of free water are entrained in the recombined hydrocarbon liquid. In rare occasions, asphaltenes and wax associated with the hydrocarbon liquids have also caused problems.

Shale gas wells are often equipped with packaged heater-separator units called Gas Production Units (GPU's). See **Figure 11**. The GPU consists of two parts – 1) an indirect glycol/water bath choke heater and a separator. The heater section heats the well stream to prevent freezing when the high pressure fluids are expanded across the pressure letdown choke and is also used to reheat the lower pressure fluids to the desired separation temperature conditions. Some GPU's are two-stage units – high pressure and low pressure – which helps with managing flash gas liberated from the hydrocarbon liquid condensate as it is reduced in pressure to storage tank conditions. Although GPU's are commonly used on shale gas pads, they could also be used for conventional wells as required.

Figure 11 Gas well GPU's on a shale well pad

While there are pro's and con's to each approach, these two hydrocarbon liquids handling options clearly have a large impact on gathering system line sizing and liquids handling.

Free Water Handling

Both of the dehydration methods outlined earlier remove water *vapor* from the gas stream.

There will normally also be *free* water in the wellstream, which comes from two sources:

i) Condensed water (fresh).
Potential volumes can be estimated with the use of a water content chart, shown earlier (**Figure 2)**. For high sour gas, some adjustments need to be made to the calculated water content. Condensed water volumes of < 0.5 BBL/MMSCF are typical.
ii) Formation water.
iii) Depending on the reservoir characteristics and well completion details, some formation water will also likely be produced. Typical water-gas ratios are in the 2-10 BBL/MMSCF range, though higher produced water volumes are also possible. Flowback water volumes after hydraulic fracturing treatments can be very large and last for a significant period of time. Unlike condensed water, formation water is normally quite saline with overall total dissolved solids (TDS) typically in the range of 50,000 – 150,000 ppmw (seawater is ~ 35,000 ppmw).

For sweet gas wells, any free water produced from the well – condensed and/or formation water – would typically be separated from the wellstream, dumped to an on-site storage tank, and trucked out on a periodic basis. For high sour gas content wells, water handling is a bit trickier. Free water can still be dumped to a storage tank and trucked out but provisions must be made to control H_2S in the vapor vented off the tanks. Very rarely, separated produced water is recombined with the gas and hydrocarbon liquid and all 3 phases are transported to the central gas plant for separation, treating and disposition. This has been done occasionally in high H_2S developments (using line heaters and insulated pipe) to eliminate potential H_2S releases from produced water storage tanks and truck loading/unloading operations. The corrosion/materials selection issues are even more difficult in this case.

Free water removal at the pad/well site combined with dehydration of the gas will result in a "water dry" gas gathering system which has significant benefits with respect to hydrate prevention and corrosion/materials selection.

Corrosion and Materials Selection

The main focus of this section will be on the flowlines/pipelines, which represent the primary components of a typical gas gathering system. Corrosion is essentially a *metallic* pipeline issue. Though non-metallic pipelines have potential degradation mechanisms as well, for the purposes of this article the discussion of corrosion is as relates to metallic pipelines. Both internal and external corrosion of metal pipelines need to be considered. External corrosion protection is relatively straightforward. The primary corrosive species is oxygen in moist soil, and the main protection measures are a good external coating supplemented with a cathodic protection system.

Internal corrosion control is more complicated and depends on several factors. Firstly, dehydrated systems – no free water – are usually free of internal corrosion, though there can be exceptions if occasional upsets introduce water into the GGS.

For wet systems (non-dehydrated), the main internal corrosion mechanisms are related to the presence of:

1. CO_2
2. H_2S
3. O_2

These may be present individually or in combination.

Microbiologically induced corrosion (MIC) can occasionally be an internal corrosion issue but is fairly rare and will not be discussed further.

While there are numerous factors that impact potential internal corrosion severity, the most commonly employed material/corrosion control strategy employed for onshore GGS's that choose to use metallic flowlines/pipelines, is carbon steel combined with a suitable corrosion inhibitor (CI). Corrosion resistant alloys (CRA) are rarely used – only for the most severe applications – due to their high cost. In fact, CRA's are probably somewhat underutilized. Application of CRA's is outside the scope of this article and will not be discussed further.

For mild to moderate corrosivity systems, ie. < 10 mpy uninhibited corrosion rate, carbon steel pipe, eg. API 5LX 42-52, combined with a nitrogen-based film-forming inhibitor is probably the most commonly employed "system". Typical injection requirements for GGS applications are 1 – 2 pints/MMSCF. The actual protection *effectiveness* of the corrosion inhibitor depends on a number of factors, including, but not limited to:

1. Relative and absolute concentrations of CO_2 & H_2S.
2. Temperature and pressure.
3. Hydrocarbon liquid and water flowrates and compositions.
4. Flow pattern/phase velocity effects.
5. Inhibitor availability.
6. System cleanliness.
7. Pigging program employed, if any.
8. Etc.

Except for the most severe applications (where a CRA of some type should be used) a properly designed and operated corrosion inhibitor program can be very effective, ie. 90+ %, in mitigating internal corrosion of carbon steel pipelines. The primary requirement is to ensure that the polar CI molecules contact and adhere to the inside pipe metal surface. This can be especially difficult if there are solids/deposits – including corrosion products – in the system, or if the flow regime prevents contact of the inhibitor with the metal surface, ie. stratified flow with the inhibitor in the liquid and none in the vapor phase to protect the upper part of the pipe. This is particularly a problem in downhill runs of pipe where the flow pattern is nearly always stratified, and the fluids in the pipe are cooling down. This is a major contributor to so-called top-of-line corrosion. This situation often requires batch pigging treatments, with the corrosion inhibitor between two pigs, to ensure 360 degree contact of the inside pipe wall with the inhibitor.

Internal corrosion due to oxygen can be a major problem but is usually, restricted to very low pressure gathering systems. Many mature gas fields have GGS's operating at low pressure – even sub-atmospheric – and oxygen ingress causes continuous problems, not just in the GGS but in the receiving gas plant as well. Many of the shale gas fields have vapor recovery units on their condensate tanks that inadvertently pull in air and cause difficulties with respect to the gathering system operators' oxygen specification limit. Many 3rd party gas gathering companies will not accept gas from a facility that utilizes a storage tank VRU.

Non-metallic flowlines

There are several "non-metallic" options for gas gathering system applications. To a large degree, non-metallics eliminate the corrosion concerns – both internal *and* external – associated with metallic – typically carbon steel – pipelines.

The non-metallic flowline options that are typically used in gas gathering systems include:

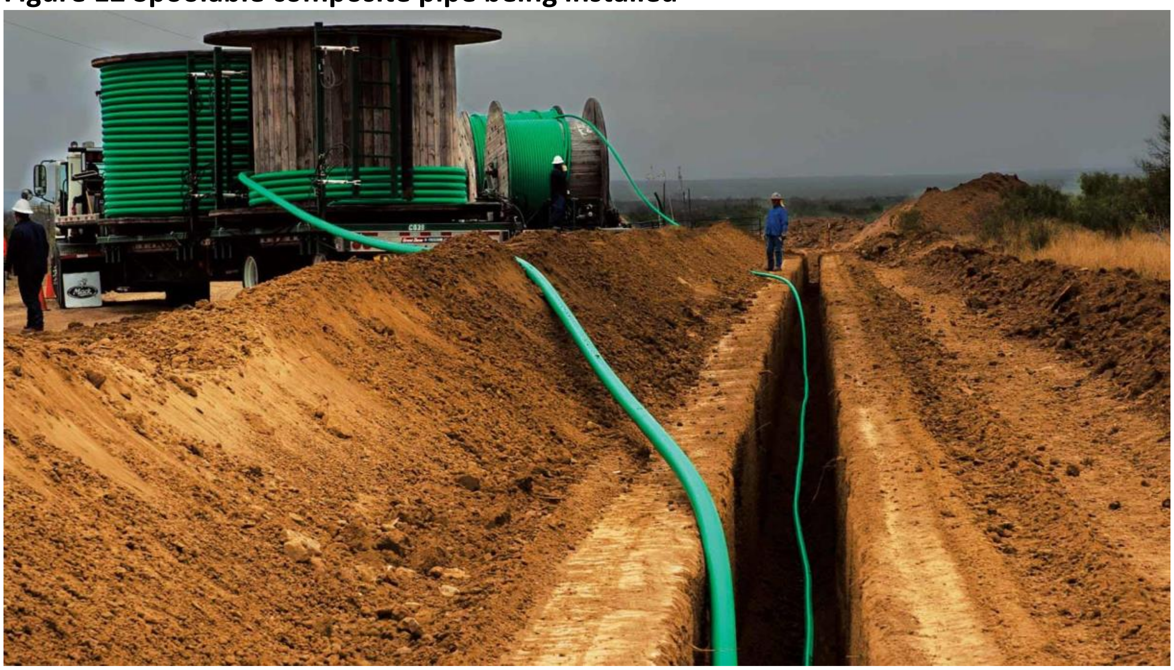
1. High density polyethylene (HDPE), often referred to as "plastic" pipe. Normally used for low pressure gas gathering systems only. Quite commonly used in coalbed methane applications. HDPE will not be discussed further in this article.
2. Spoolable Composite Pipe (SCP).

SCP typically consists of:

1. An inner thermoplastic liner (usually HDPE).
2. One or more reinforcing layers – glass/aramid fibers, or steel.
3. An outer "protection" layer (usually HDPE).

See **Figure 12**.

Figure 12 Spoolable composite pipe being installed



Some of the main manufacturers/products include:

1. Fiberspar.
2. Flexpipe.
3. FlexSteel.
4. Soluforce.

Available sizes typically range from 2 – 8", with design pressures as high as 1,500-3,000 psig, depending on the product and diameter. Design temperature limits of 140 F are typical, though some manufacturers offer products with higher temperature ratings. Depending on pipe diameter, 1,500 – 5,000 feet of pipe can typically be accommodated on a single spool.

The primary advantage of SCP – compared to steel – is the potential for significantly reduced life cycle cost. Savings are achieved through lower installation costs, mainly related to the faster laying of the spoolable material, and reduced operating costs associated with the material's corrosion resistance –

internal and external. The smoothness and corrosion resistance of the internal liner typically also leads to lower friction factors and thus reduced pressure drop compared to equivalent steel pipelines, though this is mainly a secondary benefit.

Due to the size limitation of SCP – less than or equal to 8" depending on the product – utilization of this material may sometimes be limited to lower flowrates, eg. individual well flowlines and/or lower capacity trunklines. For high capacity systems, the smaller diameter SCP lines can be connected to larger diameter steel pipelines, or much more rarely to "stick" pipe composite pipelines. Stick pipe composite – generally fiberglass reinforced plastic (FRP) pipe – is available in large diameters, but would not typically be used in moderate to high gas gathering or transmission service.

There are also some downsides to the use of composites in general:

1. Pressure rating dependency on time and temperature is less well defined than steel.
2. Typically more fragile and subject to damage during installation.
3. There can be issues associated with gas permeation through the inner liner, especially at high pressure.

While the advantages of SCP outweigh the disadvantages in most applications, the utilization of SCP for gas gathering in the upstream oil and gas industry is still fairly limited. Its use has been increasing in recent years but there remains some hesitancy to move away from steel, which has provided mostly good experience for a long time.

Line Sizing

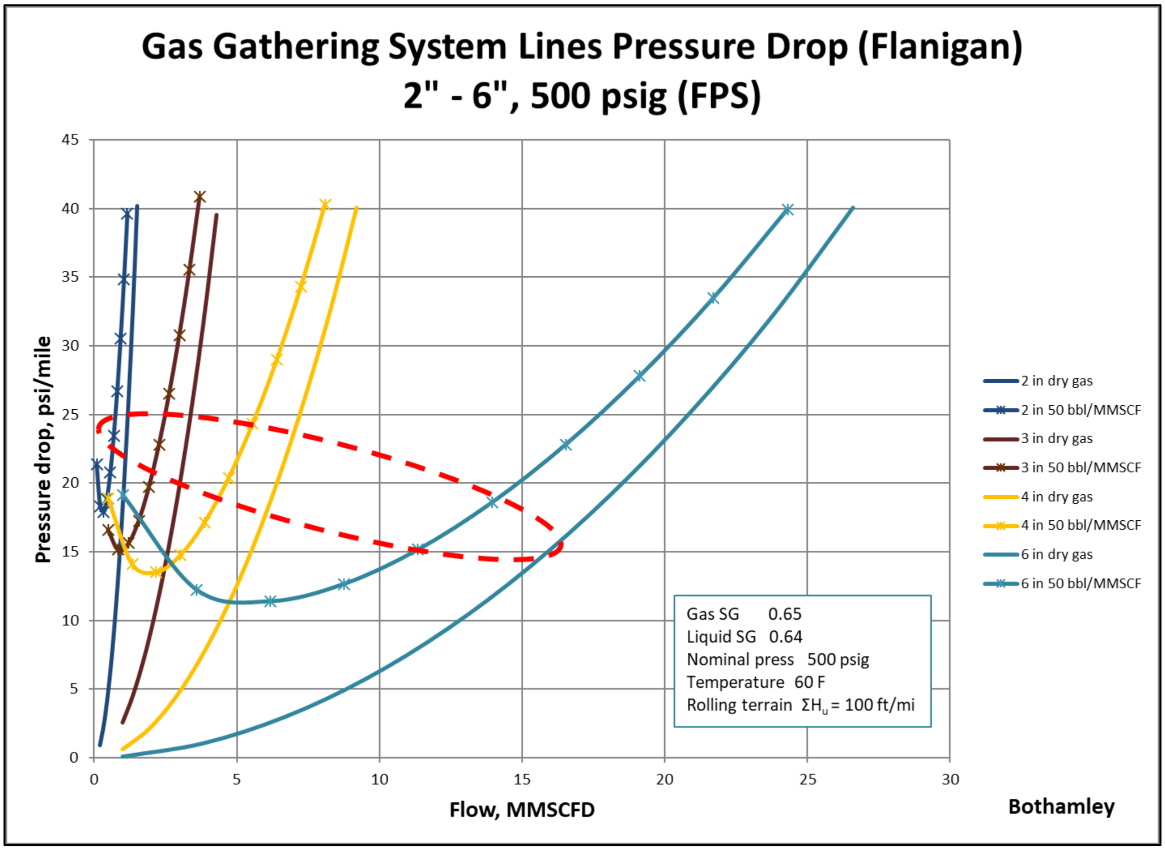
This is another large subject area.

The sizing of gas gathering system lines is usually a compromise. For a given flowrate and composition, bigger pipe costs more, but it will generally have a lower frictional pressure drop. For GGS applications this often means less backpressure on the wells and therefore higher well flowrates. However, larger pipe diameters – and the associated lower velocities – also typically have more problems related to liquid holdup/unsteady multiphase flow, eg. slugging, and potentially, solids deposition.

Most conventional/shale/tight gas wells produce gas with liquid contents (at typical in-situ pipeline flowing conditions) in the range of 5 – 50 BBL/MMSCF. A small percentage of gas fields fall outside of this range. Some very high H_2S fields produce quite low amounts of hydrocarbon liquids, but at high pressure and low temperature also result in significant volumes of liquid-phase H_2S.

Given the number of variables involved – including changing conditions over time – the typical uncertainties associated with many of these variables, and the fact that pipe is available in discrete sizes (and large differences in cross-sectional flow area) it is probably not worthwhile to attempt to size lines to three-decimal place accuracy or allocate much time to selection of the latest multiphase flow code and/or simulator. **Figure 13** is an example of a line sizing chart that the author uses for conceptual design work. The chart is based on the modified-Flanigan method which basically provides an adjustment factor to a dry gas flow equation based on the amount of liquid in the line, and also includes a simple liquid holdup calculation to account for terrain effects. For each pipe diameter covered – 2, 3, 4 and 6" – two lines are shown: a "dry gas" line and a line that represents 50 BBL/MMSCF of hydrocarbon liquid at flowing conditions. An "eyeball" interpolation can be performed for liquid contents between 0 and 50 BBL/MMSCF. This particular chart is for a nominal operating pressure of 500 psig. Other assumptions are shown in the Figure. Of course, more rigorous sizing methods should be used when warranted.

Figure 13 Example GGS line sizing chart



Line Sizing Criteria

Various line sizing criteria have been proposed and used over the years, mainly based on allowable velocity and/or allowable pressure drop guidelines. Often these guidelines are simple rules-of-thumb and may be fine for a given application, ***if their basis is understood***.

While the information presented in **Figure 13** is only approximate, some interesting observations can be derived from it. For example:

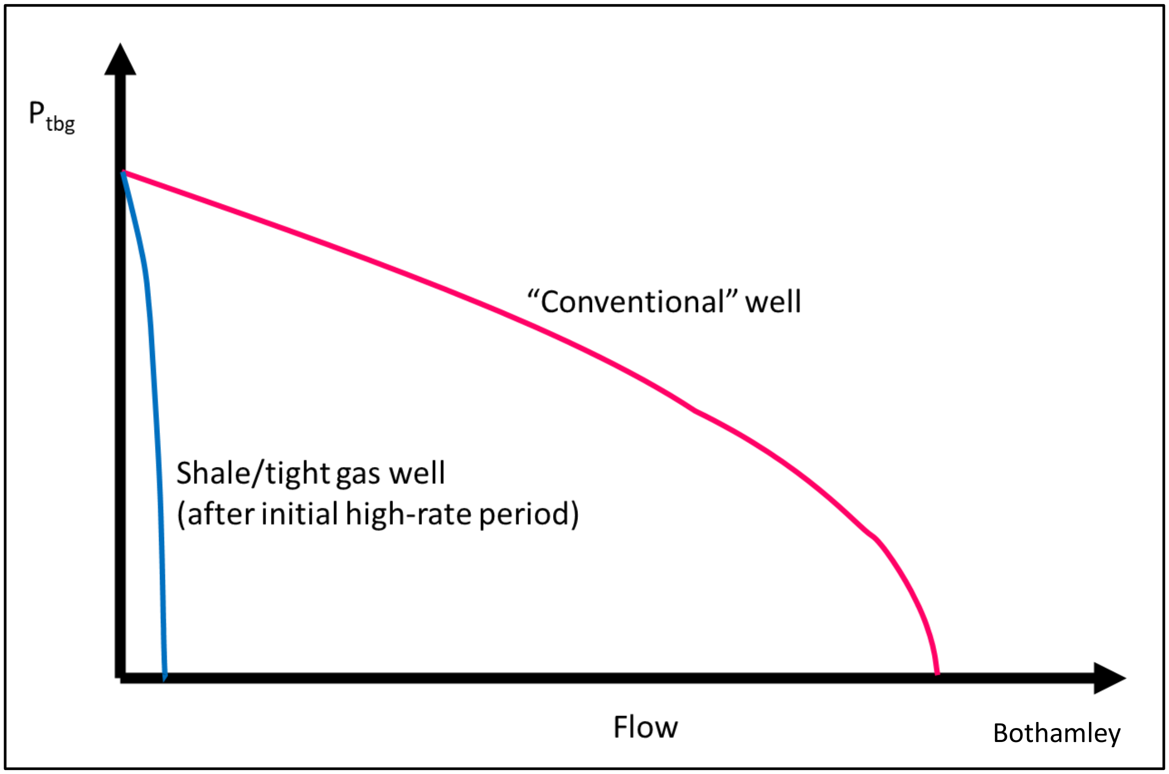
1. The dry gas lines show only frictional losses. The 50 BBL/MMSCF lines show combined frictional (including liquid effects) and hydrostatic liquid accumulation affects (where the pressure drop lines begin to flatten out and eventually curve upwards with decreasing rate, assuming somewhat hilly terrain.
2. The dashed red ellipse indicates suggested preferred operating conditions which avoid the liquid loading regions and yet also minimize pressure drop due to excessive friction. Operating pressure drops of 15-25 psi/mile are indicated. This is a reasonable value and agrees with other published guidelines in the literature. Lower pressure operation, eg. 100-300 psig would likely warrant a design pressure drop in the 10-15 psi/mile range. Larger diameter, longer, higher capacity trunk lines would also typically be designed for somewhat lower pressure drops.
3. Each line size has fairly narrow capacity ranges between the liquid loading and high friction loss regions, especially the smaller diameters, ie. 2" – 4".
4. There are some significant gaps in flowrate coverage evident. For example the 10-15 MMSCFD flowrate range is too high (frictional losses) for a 4" line, but too low (liquid accumulation effects) for a 6" line. As 5" pipe is not really an option, other factors would have to be taken into account to allow a selection between 4" and 6" to be made, eg. near future changes in flow and/or pressure. Generally speaking, for multiphase applications higher velocity is better.

Provisions for Future Drawdown/Reduced Pressure Operation to Maximize Deliverability and Reserves Recovery

Deliverability

Figure 14 shows conceptual deliverability curves for a conventional gas well and a shale/tight gas well, with flowing tubing pressure (P_{tbg}) on the vertical axis rather than the more traditional bottomhole flowing pressure (P_{wf}). These curves combine the reservoir flow characteristics with a tubing pressure drop calculation for the given operating conditions. This "surface IPR" is more useful when discussing the effects of surface facilities/gathering system options.

Figure 14 Typical well "surface" IPR (excluding liquid loading effects at low rates)



For relatively high permeability conventional reservoirs, gas wells reach a "pseudo-steady state" producing condition where the well drainage region is effectively bounded – usually by adjacent well drainage areas – and average reservoir pressure declines with depletion. The surface IPR curve represents a point-in-time relationship between flowrate and flowing pressure, described by the reservoir parameters used in the radial flow equation and the parameters used to describe the tubing string, eg. inside diameter, measured/true vertical depth, etc. As reservoir pressure (P_R) declines with time, the IPR curve drops as well – **Figures 16** and **17**. Notice the time parameter for the various curves in the two charts. The well deliverability curve "decreases" much quicker for the shale gas well even for minimal change in the static reservoir pressure. This behavior is mainly a reflection of the "flush" high production from the well's stimulation treatment fractures and the very near rock surface adjacent to the fractures. The native permeability of the shale, which is very low, becomes limiting in a relatively short period of time. Early life prediction of flowrate vs tubing (and gas gathering system) pressure for shale gas wells can be difficult.

The IPR relationship and prediction of reservoir pressure decline can be combined with assumptions re: well/pad site facilities, gathering system configurations and compression timing/location to estimate well and field production rates and pressures vs time. As mentioned previously, an *Integrated Asset Model* can be very useful for performing the network-wide nodal analysis modeling and time-stepping (to capture reservoir depletion) calculations typically required.

Figure 16 Change in IPR vs time (conventional well example)

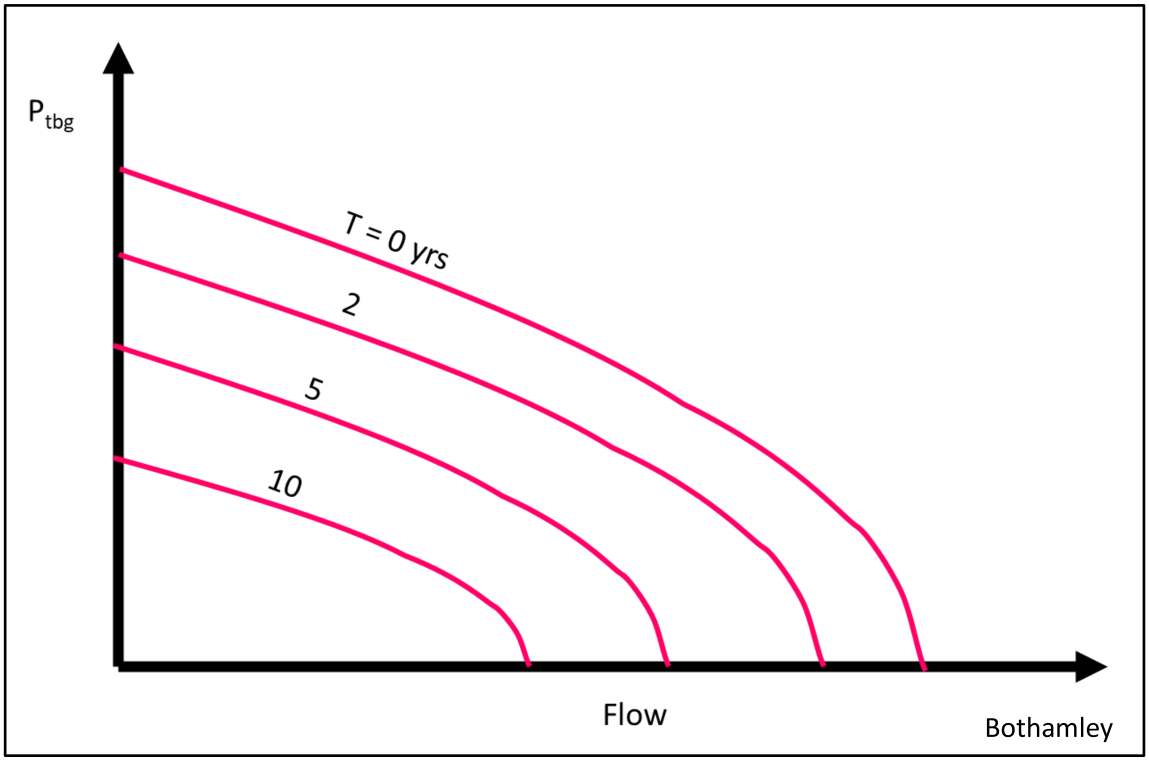
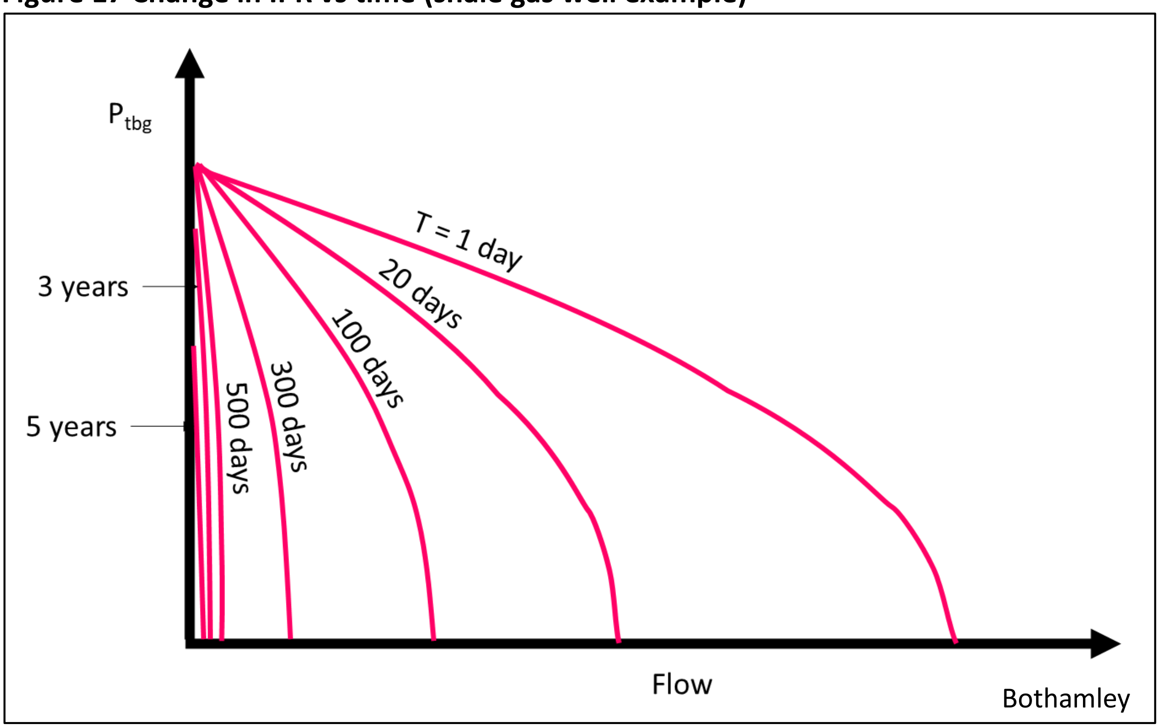


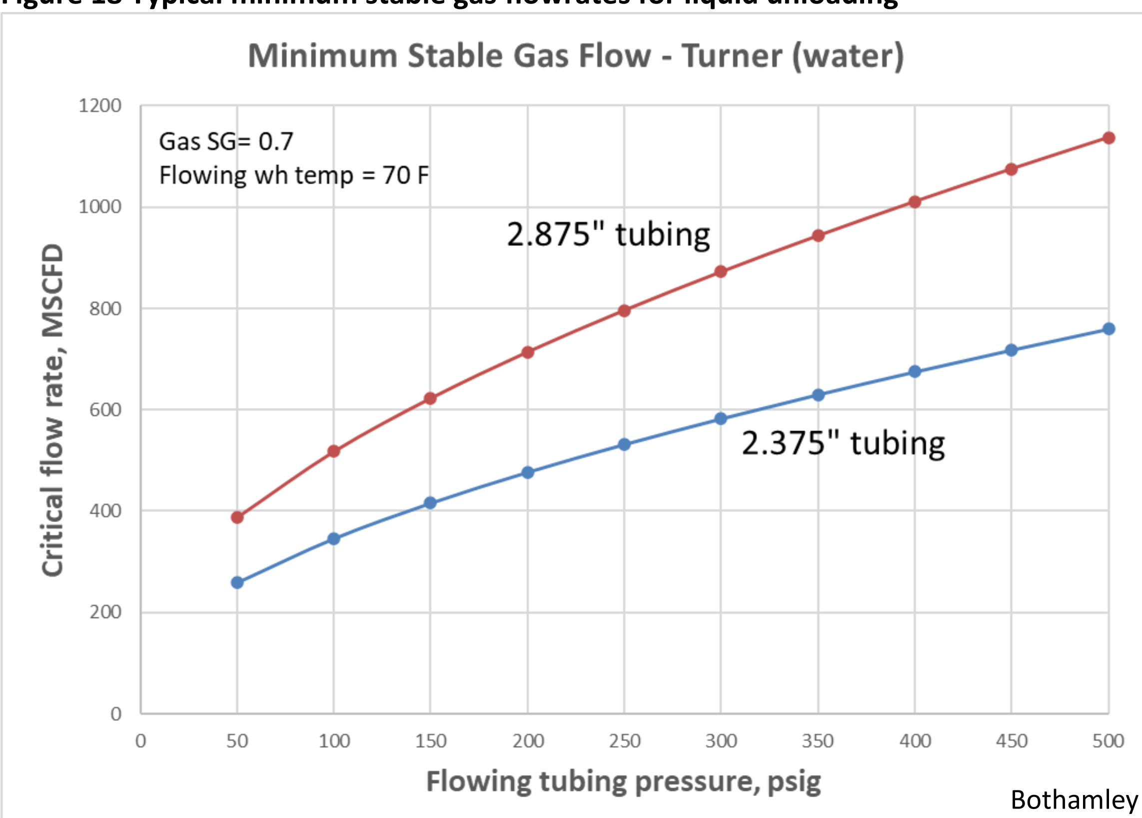
Figure 17 Change in IPR vs time (shale gas well example)



The shale/tight gas well IPR presented in **Figure 14** would seem to indicate that the well's flowrate is relatively insensitive to back-pressure. This behavior is typical of tight (low permeability) reservoir wells. However, experience gained from existing shale gas developments has indicated that these wells are in fact quite sensitive to surface facilities back-pressure, at least after the initial rapid decline period (**Figure 17**). This sensitivity is probably more related to liquid loading effects combined with the effect of pressure on gas density and velocity in the well tubing string, as opposed to the effect of flowing bottomhole pressure on reservoir deliverability (see **Figure 18**). In many shale gas plays, flowrates have declined to < 1 MMSCFD within 2-3 years. Flowing tubing pressure ranges of 100 – 300 psig are typical for most shale gas field developments. These pressures can be achieved via pad-located compression or gathering system compression, depending on the system configuration.

Both conventional and unconventional gas wells can experience reduced - or complete loss – of deliverability due to liquid loading at low flowrates. This is typically a late-in-life effect for conventional wells but may occur fairly early in the life of unconventional wells due to their rapid decline rate. While there are various artificial lift options available to deal with liquid loading, the impact of surface facilities on flowing tubing pressure is an important consideration. Lower backpressure on the wells helps inflow performance and also increases gas velocity in the tubing for a given mass or standard volumetric flowrate of gas.

Figure 18 Typical minimum stable gas flowrates for liquid unloading



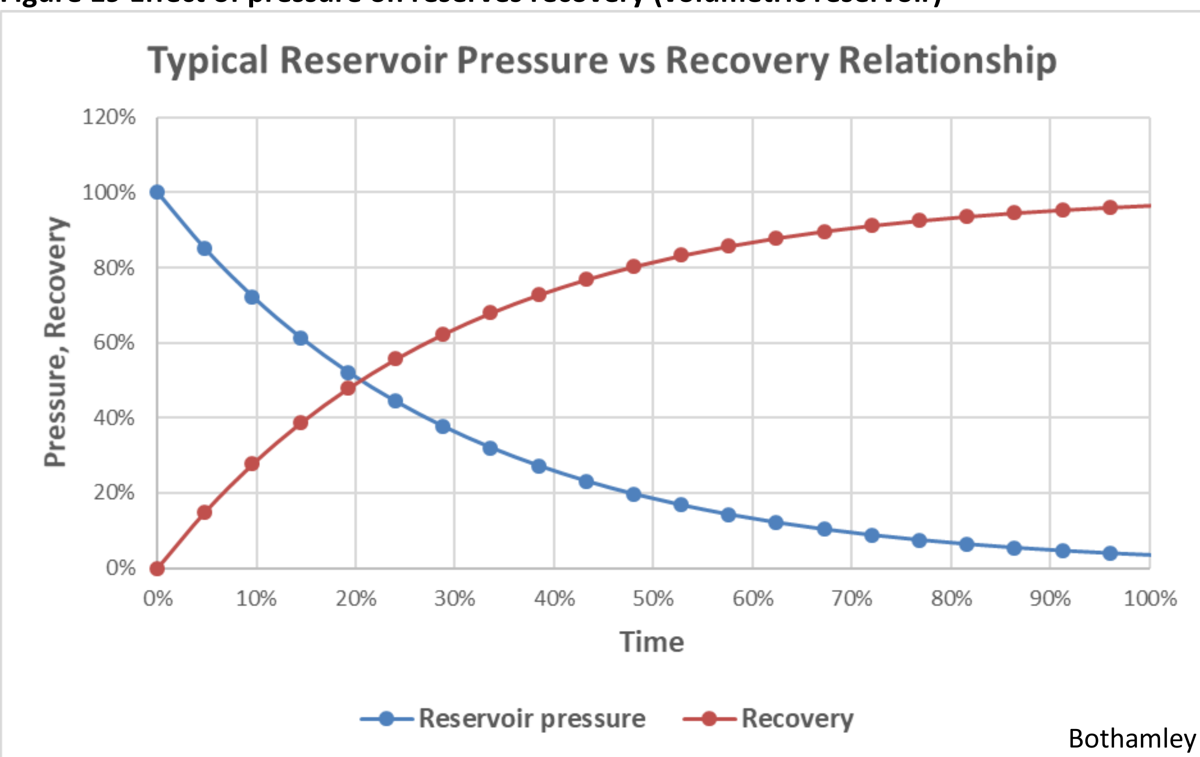
Reserves Recovery

The effect of GGS pressure on flowing well tubing pressure – and ultimately reservoir pressure – on recovery is fairly straightforward, at least for conventional "volumetric" reservoirs, with minimal aquifer pressure support. For these reservoirs, ultimate reserves recovery is directly related to reservoir abandonment pressure, as shown in **Figure 19** for a hypothetical reservoir. The actual abandonment pressure will be dictated by minimum economic production rates for individual wells and the development as a whole.

Simplistically, recovery for a volumetric gas reservoir can be described as follows:

$$\text{Recovery, \%} = 100\left(1 - \frac{\text{Final reservoir pressure}}{\text{Initial reservoir pressure}}\right)$$

Figure 19 Effect of pressure on reserves recovery (volumetric reservoir)



Well flowing tubing pressure and gas gathering system pressure are not the same thing, with the key factors being the location of compression – if utilized – and well flowline/gathering line pressure drop.

Tight gas reservoirs have pressure-reserves relationships similar to conventional reservoirs with the gas volumes lower due to generally lower porosity. Shale gas reservoirs behave somewhat differently. They contain both "free" gas and adsorbed gas. The free gas volume is similar to the gas volumes in conventional and tight sand reservoirs but the adsorbed gas volume behaves differently. Similar to coalbed methane reservoirs, quite low reservoir pressures are required to recover the adsorbed gas fraction from shale reservoirs.

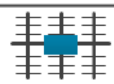
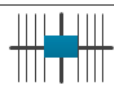
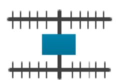
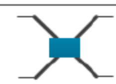
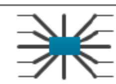
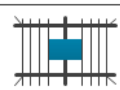
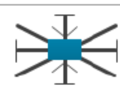
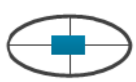
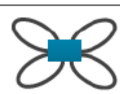
System Architecture

For the purposes of this article "system architecture" will be taken to mean the arrangement of gathering lines, compressor stations, etc., connecting the wells/well pads to the receiving gas plant. There are a wide variety of architectures possible due to the number of variables involved, including:

i) Geographical dimensions of the gathering area/reservoir.
ii) Acreage dedicated to the GGS.
iii) Individual vs pad drilled wells and locations of well/pad sites, ie. well/pad spacing.
iv) Well deliverability and pressure vs time.
v) Wellstream composition.
vi) Hydrate prevention strategy.
vii) Liquids handling strategy.
viii) Topography.
ix) Ambient temperature.
x) Provisions for compression.
xi) Facilities ownership.
xii) Etc.

Iqbal outlines some potential gas gathering system layout options (**Figure 20**), including high-level pro's and con's.

Figure 20 Potential gas gathering system layout options.

Title	Schematic	Analysis
Grid		**Pros:** Flexible, adaptable and expandable Several main headers allows easy configuration and construction **Cons:** High total line length
Single Header		**Pros:** Initial CAPEX is generally lower **Cons:** Limited flexibility due to fewer entrance lines to CPF Higher liquid holdup and increased pigging frequency Increased line length to CPF
H Manifold		**Pros:** Flexible, adaptable and easily expandable **Cons:** Higher initial CAPEX due to limited inlet lines to CPF Limited flexibility
X Manifold		**Pros:** Simplified constructability and operability **Cons:** Higher initial CAPEX due to limited inlet lines to CPF Limited flexibility
12 Leg Spider		**Pros:** Lower initial CAPEX as fewer inlet lines required at startup Increased flexibility and operability Decreased liquid holdup **Cons:** Higher total CAPEX
Single Manifold Spiral		**Pros:** Ease of construction due to consistency of header diameter **Cons:** Minimal flexibility or adaptability Large liquid holdup
Snowflake		**Pros:** Greater flexibility due to wide header distribution Lower initial CAPEX **Cons:** Difficult operability and constructability
Complex Grid		**Pros:** Increased flexibility over simple grid allows lower initial CAPEX **Cons:** Additional lines increase liquid holdup and pigging requirements
8 Spokes		**Pros:** Increased flexibility due to several inlet lines to CPF Lower initial CAPEX due to variability of construction **Cons:** Often results in difficult operability due to variation in system Varied line sizes result in difficult construction
Single Ring Main		**Pros:** Higher initial CAPEX due to limited number of inlet lines to CPF **Cons:** Header line size variation may reduce ability to pig properly
Quadrant Ring Main		**Pros:** Several inlet lines to CPF result in variability and adaptability Ease of construction due to symmetry **Cons:** Higher liquid holdup Well pattern does not often fit this model of symmetry

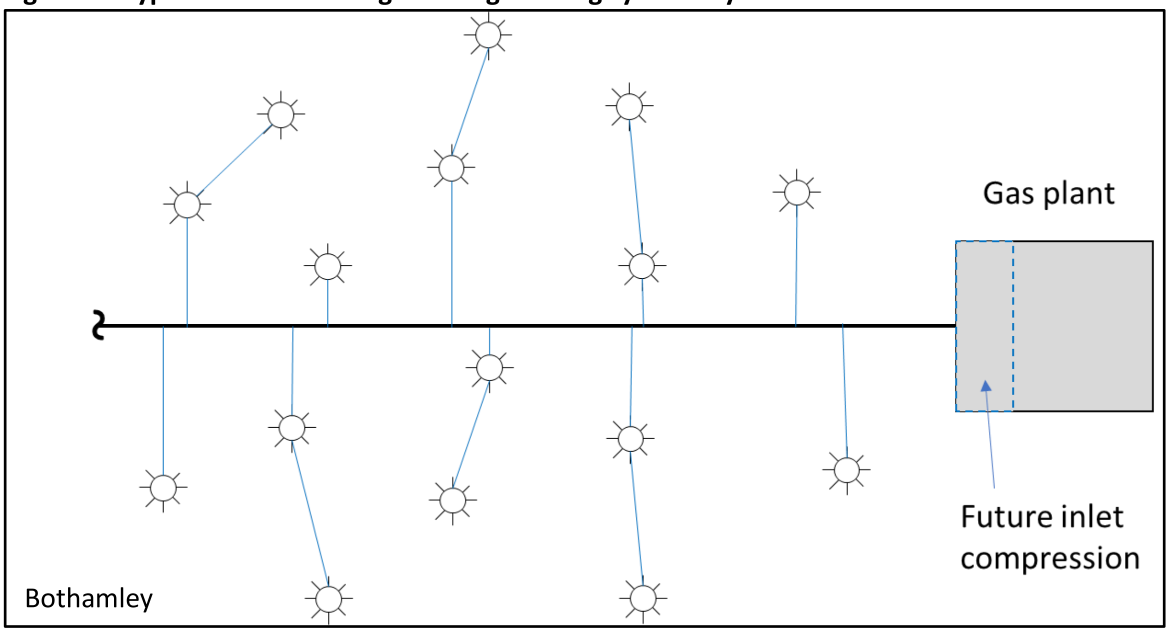
Iqbal, Worley Parsons

While there are a fairly large number of potentially feasible options, relatively few of these are applied in practice.

Conventional gas developments

As discussed previously, "conventional" gas fields typically feature relatively high well flowrates, high pressures – at least early in the field life – a relatively long, eg. several years, drilling/development program, and in particular, large, ie, 160 – 640 acre well spacing and primarily vertically drilled wells. Most onshore conventional gas fields are also usually much smaller in areal extent than typical shale gas fields. In the author's experience, the vast majority of "conventional" high permeability, high pressure, high well flowrate gas fields have utilized a gas gathering system design similar to that shown in **Figure 21.**

Figure 21 Typical conventional gas field gathering system layout



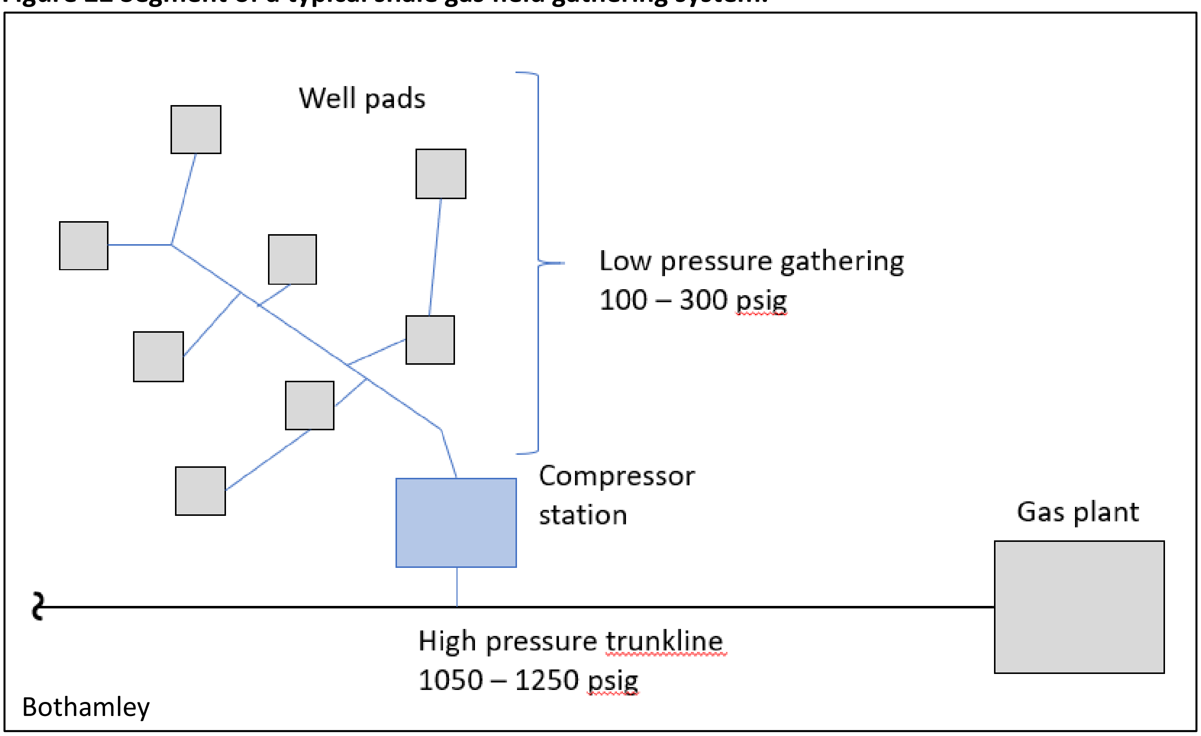
Individual well laterals are tied into a larger main trunk line that transports the gas (and associated hydrocarbon liquids) to a centrally located gas plant. Wells further removed from the main trunkline are often “daisy-chained” to other well flow lines, sometimes in a fairly haphazard manner. While this saves money, it can also lead to bottlenecks, especially during early-life high flow years. The GGS in this case would typically operate at pressures of 1,100-1,300 psig. Over time due to reservoir pressure depletion, well deliverability will decline. At some point – often years in the future – installation of compression at the plant location to pull down the gathering system pressure in order to maintain delivery and increase reserves recovery would be typical. Installing field compressor stations would not be common except for fields of large areal extent, eg. > ~ 20 miles from the farthest wells to the central plant. At distances much greater than this, the ability of the centralized plant compression to effectively lower flowing wellhead/bottomhole pressures diminishes significantly, with the key variables being: single well and total flowrates, the target pressure level, main trunk line and lateral diameters, liquid loading and terrain/elevation profile. Selection of potential future field compression locations is not easy and is fairly dependent on the initial gathering system layout selected. It is very difficult to accurately account for all of these variables, given the uncertainties in reservoir areal extent, well locations and productivity, changes over time, etc. in the early stages of field development. In particular, selection of line sizes will involve compromises between early and late field life operation. Smaller diameter pipe is less expensive and higher velocities are typically advantageous in multi-phase systems. In the future, after compression has been installed and line pressures are lower, velocities will increase but these should be somewhat offset by declining field deliverability. In the future, GGS debottlenecking options can be considered if and when the need arises, but up-front pre-investment to accommodate these potential requirements is normally not warranted.

Shale/tight gas developments

Most shale gas development so far has occurred in the United States, though production from Alberta and British Columbia (Canada) has been increasing in recent years. Many other countries have large shale gas reserves but to date these have been minimally exploited.

Shale gas gathering system architecture is typically quite different than used for "conventional" gas. **Figure 22** is typical of many shale gas area developments. In this configuration a glycol dehydrator would typically be located at the compressor station after the compression discharge. Any liquids recovered by the compressor station are usually trucked out. Fairly large slug catchers are sometimes needed at the inlet to the compressor station.

Figure 22 Segment of a typical shale gas field gathering system.



One of the main differences between shale gas and conventional GGS layout is the common use of field compressor stations in the shale gas systems. Shale gas fields are often very large in areal extent which typically leads to fewer gas processing plants and longer average distances between well pads and the plants – too far for plant inlet compression to be effective or for low-pressure transport of gas and associated liquids to be practical. Another key difference is that in shale gas developments, the compression is often needed fairly early to reduce back-pressure on the pads/wells. As discussed previously, lower back-pressure helps reduce liquid loading problems on its own, and can often defer the need for artificial lift. is also more compatible with the various artificial lift methods that are typically eventually employed. Ultimately, lower pressures are also required to recover a reasonable amount of the “adsorbed” gas fraction from the shale.

A reasonable argument could be made for installing compression at the well pad locations. This would allow the compression to have the maximum impact on flowing tubing/bottomhole pressures, by minimizing pressure loss between the wellheads and the compressor suction. In some areas this is done, but in general, this practice is not common. There are several reasons for this:

i) The difference in ownership between the wells/pad facilities and the gathering system.
The wells/pad facilities are often owned and operated by smaller drilling and production oriented companies. These companies are usually comfortable with simple pad surface facilities but are less keen on the design, installation, operation, maintenance (and CAPEX) of more complex facilities, including one or more multi-stage reciprocating compressors. They would rather let the gathering company deal with compressors, dehydration, etc and pay a fee for the gathering and processing service.
ii) Individual pads typically have 4-8 wells that each have highly variable flowrates, at least initially. This leads to variable total gas flow from an individual pad, which makes matching of compressor capacity to flowrate, ie. number and sizes of individual units, difficult. Having multiple pads with different on-stream dates and variable gas delivery profiles combined together, helps smooth out flows and pressures supplying larger, more centralized compressor stations.
iii) Economies of scale favor fewer, larger compressor stations.
iv) Emissions permitting and noise issues are more easily dealt with for fewer, larger compression installations compared to hundreds of well pad installations.

One of the major drawbacks of the arrangement shown in **Figure 22** for the pad producer is that they are somewhat at the mercy of the GGS operator with respect to the back-pressure at the pad. It is not uncommon in some areas for wells to be shut in because they cannot flow against the gathering system pressure.

Compression

The utilization of compression, including type, location and timing is dependent on many factors, several of which have been previously discussed in this article.

Except for the very largest gas fields where centrifugal compressors are typically utilized, reciprocating compressors are most commonly used for onshore gas gathering. For the most part, these compressor utilize gas engine drivers, though electric motors are also used. Screw compressors are also occasionally used for lower discharge pressure gas boosting applications.

There are too many variables involved to provide specific recommendations on compression utilization for either conventional or unconventional gas field development, but a few observations can be made.

In the author's experience, conventional onshore gas fields typically utilize plant inlet compression to pull down gathering system – and wellhead – pressures. This arrangement is shown in **Figure 21**. While there are pressure drop inefficiencies associated with increasing distances between the compressor suction and the wells, there are many advantages to this configuration. Gas fields with very large areal extent will likely require the use of field-located compression or multiple gas plants with inlet compression. This is the typical scenario for shale gas field developments (**Figure 22**).

As far as compression *timing* is concerned, this is mainly determined by reservoir characteristics, in particular pressure and deliverability, especially for conventional gas fields. Some conventional fields produce for years at high pressure before compression is required. Some shallow/low pressure fields need compression from day one. As discussed, compression has both an instantaneous impact on deliverability as well as a longer term impact on reservoir abandonment pressure and reserves recovery. Optimizing the gathering system design, compression location, timing and cost to fully take advantage of these two effects is complicated but worth the effort when feasible.

For many of the shale gas plays where the ownership of the wells and gathering system are different, integrated optimization of the entire system is often not practical. Even without the change in ownership, given the number of variables and uncertainties involved, the main objective should be installation of a functional and flexible system that will work satisfactorily over a wide range of conditions. The high pressure trunklines and compressor stations are usually installed, and the system extended, based on acreage development by the various production companies. Compression is often installed fairly early to accommodate wells that are already past their high pressure, high flow early years. These systems can be designed to be fairly flexible and expandable.

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