

# PRODUCTION EQUIPMENT EFFECTS ON GAS MEASUREMENT

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## **Introduction**

The drill bit penetrates a rock formation thousands of feet below the surface of the earth, a steel casing is slid into the hole, and perforations are made to the casing that reach into the surrounding rock. At that point, an escape route is created for anything in the formation that can be released to the surface, which has lower pressure, or that can be lifted by that process. The producer must be able to obtain enough of what comes up to the surface and conditioned to a marketable state to make it worthwhile. Obviously, the natural gas, natural gas liquids (NGLs), crude oil and condensates are the valuable commodities that are produced and sold. Unfortunately, other materials are included in what surfaces from inside the earth. Many of these require production equipment to remove the material or condition the product for sale, and the effects of some types of production equipment used can have an effect on measurement.

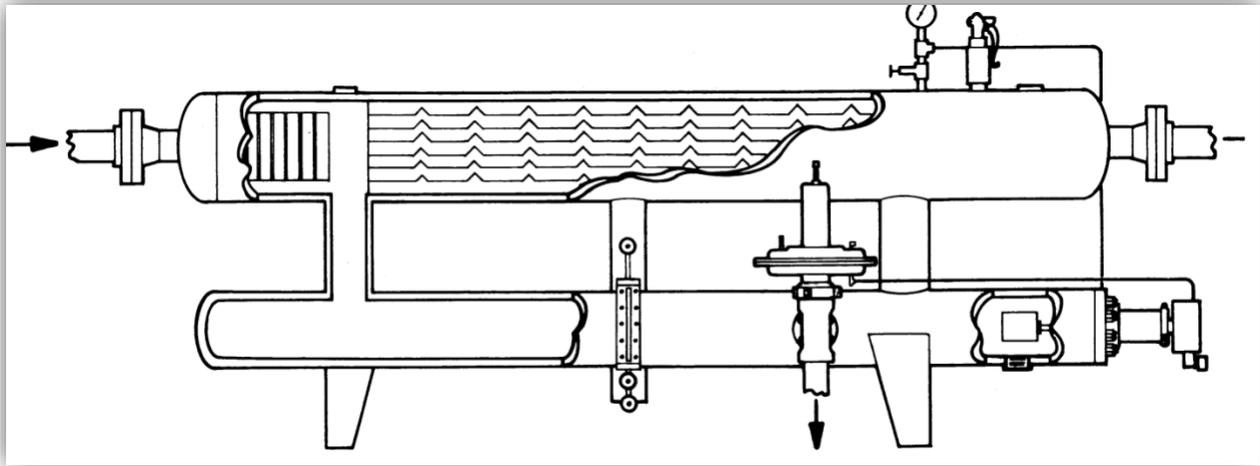
## **Basic Production Equipment**

For the sake of this discussion, production equipment will be divided into the three basic categories of liquid separation, gas treating, and production enhancement. Almost all natural gas wells, whether the gas is considered dry (primarily methane only), or considered wet (heavy hydrocarbons including C2 and beyond), will produce some water. If there is condensate or crude oil, the gas will need oil separation in addition to the water. There will almost always be liquid separation equipment at every well pad.

Many formations have high levels of acid gases which may be removed by production equipment, or at central facilities. Carbon dioxide can be corrosive to the internal surface of the pipeline and displaces space for hydrocarbons. Hydrogen sulfide can be included with the gas or oil production and is also a corrosive component and very hazardous in higher concentrations. Both of these acid gases must be reduced to contractual or pipeline tariff levels before delivery into a transmission pipeline. Water, in the form of water vapor, can be considered a contaminant because the gas must be below a specified water vapor level to be delivered to transmission or end users. This is typically 7 lbs. per 1 MMcf. Dehydration equipment is required to condition saturated or partially saturated gas to meet this specification.

Over the lifetime of a well's useful flow, production will begin to decline at some point. Production enhancement equipment may be installed to increase production temporarily, which may extend the life of the well. Well head or central compression is common for enhancement of production. As the production decreases over time, there may develop a requirement to use compression to lower the down-hole pressure for maintaining production or boost the pressure to overcome the downstream pipeline destination of the gas. Well head compressors are commonly installed to lower the pressure to the well bore and move the gas downstream to the gathering system.

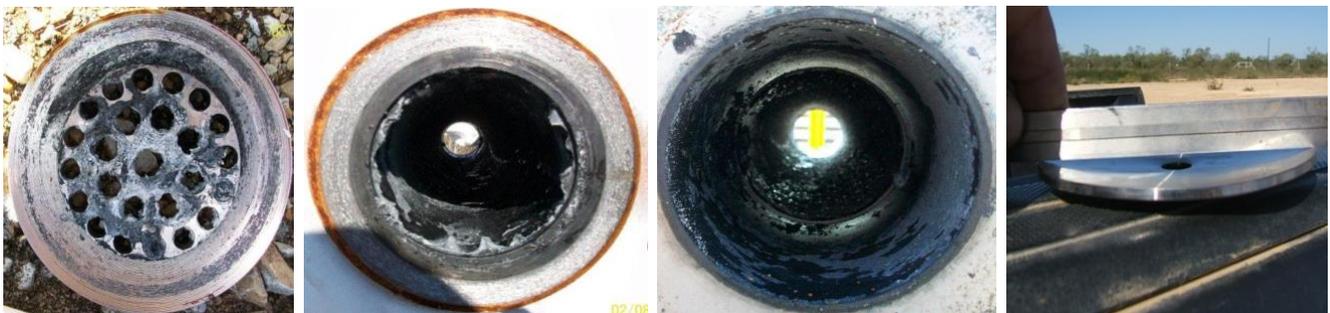
Other production enhancement equipment may be installed to assist the lifting of water and liquids to the surface. Intermittent and plunger lifts are types of equipment that shut the well production in for periods of time to allow bottom-hole pressure to build up and may include a device that pushes the column of liquid in the well bore to the surface. Sometimes the weight of that column of liquid, possibly several thousand feet, requires more force below it to lift than the producing well can provide. Once the well bore is unloaded, the gas can again flow freely until it loads up again. These types of equipment are typically tied to either timers or an RTU that can time the cycle based on various process variables that can be read. Gas lift compressors are also commonly used, especially with the horizontal well bore. They compress gas into the casing and special one-way valves on production tubing in the well bore allow the compressed gas into the tubing below the horizontal bend to force the liquid up the well bore to allow gas production from the formation.



**Fig. 1 Typical Double-Barrel Separator**

### **Liquid Separation and Measurement**

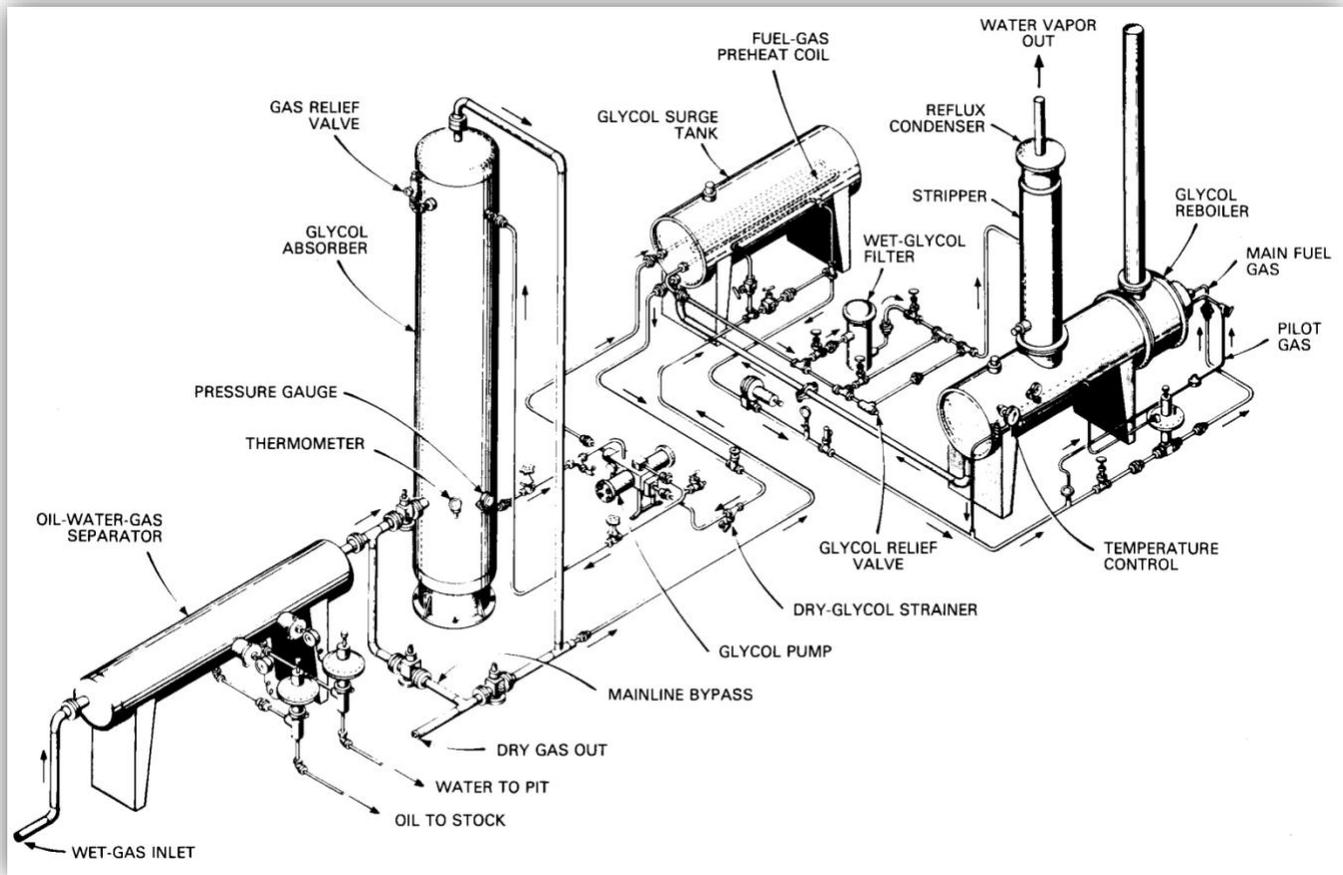
Adequately sized separators that are working properly do as much as anything to allow the metering system to provide measurement within the uncertainty that it was designed for. Keeping the gas in single phase and all free liquid from slugging through the meter are critical. Poorly sized equipment, either from a depleted well that has equipment sized for higher volumes, or undersized from production higher than expected, may allow slugs of free liquid into the meter. Or, the dump valve mechanisms may malfunction or freeze and allow free liquid to follow the gas stream through the meter. Free liquid distorts the internal geometry of the meter, can leave deposits on the surface, and can damage orifice plates, turbine blades or rotary meter internals. Liquid will often fully or partially plug static and differential pressure transmitter tap holes and gauge lines, which are a very common source of poor measurement.



**Fig. 3 Evidence of Liquid Flow through Orifice Meter**

### **Gas Treating Equipment and Measurement**

Gas treating equipment, while necessary to condition the gas to meet specifications for delivery to downstream transmission pipelines or end users, can also contribute greatly to higher measurement uncertainty. In addition to treating the gas, there may be continuous injection pumps or batch chemical treatment valves that allow corrosion inhibitors to be applied to production piping, some of which can remain in the gas stream as it passes through the meter. The result of this can be seen by buildup of materials on the face of the orifice plate and flow conditioner, and on the internal surface of the meter tube. The same result can be experienced by hydrogen sulfide or carbon dioxide treaters that are located upstream of the measurement when carry-over of the treating chemicals remain in the gas stream. These treaters and injectors require fuel and power gas to operate. If the tap for the fuel gas is located downstream of the meter and is not measured or at least estimated, there will be a built in loss due to the unaccounted for fuel. Dehydrators are commonly used in gas gathering systems to reduce water vapor to below 7 lbs. per 1 MMcf. The glycol used to contact the gas stream and remove water vapor can carry over and flow into the meter tube, coating the internal surface and the orifice plate.



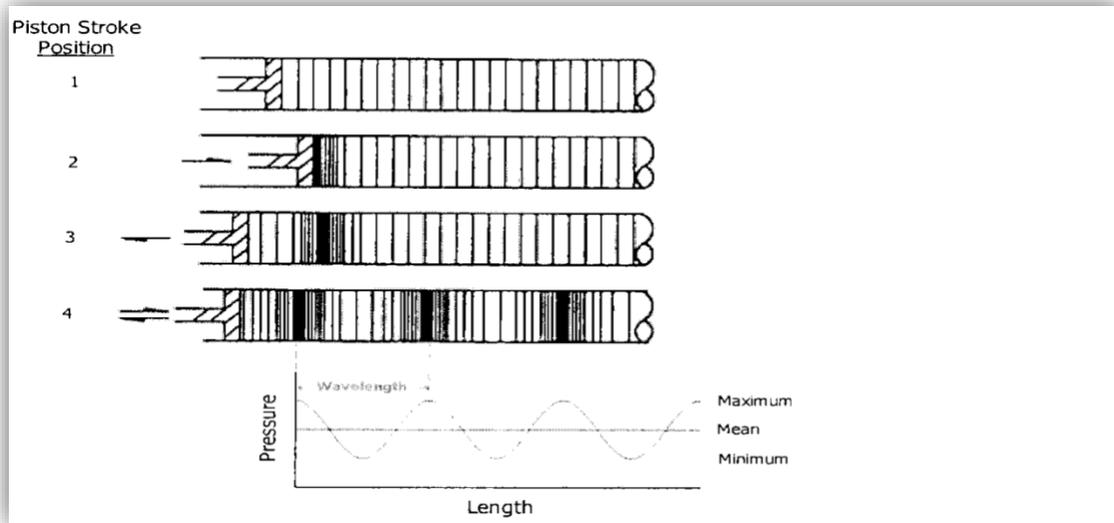
**Fig. 4 Typical Dehydration Unit**

### **Compression and Measurement**

Compression, while necessary to produce the gas, can be a very substantial contributor to poor measurement. The types of compressors used at well heads or in small gathering systems may create pulsation, which can be present at the meter's electronic sensing equipment. The challenge for the sensing and recording devices is to capture the accurate flowing differential pressure of the gas. Orifice meters are subject to square root error as the recorded differential pressure, sampled by the electronics at defined intervals, is averaged and a square root extracted for calculation of the volume. With the sine wave riding on the differential pressure following the curve going from positive to negative, and the extraction of the square root always being positive (multiplication and division of negative numbers always results in a positive), which will cause an overstatement of the differential pressure and resultant calculated volumes.

Well head compression located within close proximity to the measurement device may also be a source of vibration. Vibration is not always a direct indicator of pulsation; however the two are typically experienced together. Vibration leads to premature wear and tear on the meter installation, including stainless steel gauge lines, orifice fittings, etc. Gas being compressed into a smaller area will see a temperature increase. Very hot gas may introduce some uncertainty, as well as hot gas has the ability to carry more water vapor and heavy hydrocarbons in a gaseous phase. After travelling a distance into the pipeline, the cooling of the gas will typically see water and heavy hydrocarbons cool to their dew point temperature and they will fall out, causing some of the same issues with free liquids and was addressed in the separation portion of this paper.

As with treating equipment, compressors use fuel. If the tap for the fuel is located downstream of the meter and there is no meter or fuel not estimated, a loss will be experienced due to unaccounted for fuel use.



**Fig. 5 Pulsation Wave Generation Illustration**

### **Conclusion**

Production equipment is required in order for marketable gas to be extracted from the well and moved to a transmission pipeline to market. Due to the depletion curve of the typical well production, it is almost impossible to size liquid separation equipment for the full life of the well and conditions detrimental to the measurement cannot always be avoided. Gas treating will also be required to allow for off specification gas to be produced and moved to market, and internal corrosion treatment will be required to protect the investment and protect the public. Compression will always be a part of producing gas from wells, especially in later stages of the well's life.

Meter facility testing frequency standards are put in place to ensure that meter facilities get some regular attention based on the risk of uncertainty that increases with the time that passes between inspections. It is critical that the testing frequencies are observed and all testing and inspections are carried out. Since it has been observed that free liquids may leave residue in the meter tube, inspection and cleaning will be required to keep it at a minimum level. When an observed condition, such as a buildup of residue from an injected or treater chemical on the orifice plate, additional inspections and cleanings may need to be scheduled in addition to the regular testing frequency schedule.

Pulsation is an issue that can typically be avoided by the design of the compressor and the placement, piping, and additional mitigating devices that condition the pulsating signal. Once a compressor is installed and pulsation is discovered, it can be difficult to get the situation resolved due to the expense that is required to correct the problem.

Commitment and diligence by the technician responsible for the meter facility will always provide the best results in minimizing the effect on production equipment. Constructive feedback to the pumper or other production personnel about the working condition of dump valves or chemicals remaining in the gas stream can sometimes yield results. On new well sites, timely feedback to the central measurement or engineering groups when potential problems are seen, such as the early stages of a compressor being installed, can also provide the opportunity to avoid a pulsation problem before it begins.

### **References**

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