COSTAIN

Compressor of choice, part one

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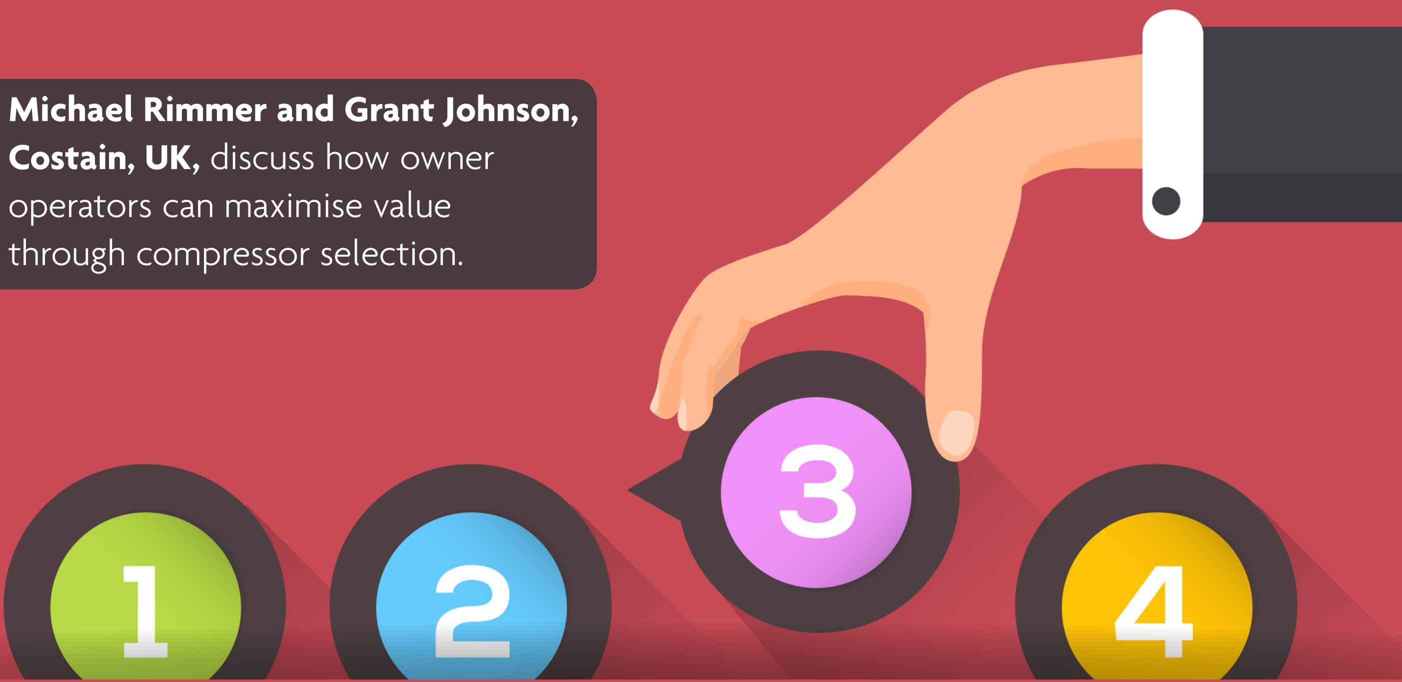
Michael Rimmer and Grant Johnson, Costain, UK, discuss how owner operators can maximise value through compressor selection.



COMPRESSOR OF CHOICE
PART ONE

Gas compression systems are an essential component of gas production, processing and transmission facilities, and have a significant influence on overall capital and operational costs. Compression equipment is also a major contributor to downtime and production loss. The proper specification and selection of compression equipment can therefore greatly improve economic feasibility.

In many cases, there are multiple operating conditions to consider and often uncertainty over long-term requirements. Poor choices, or failure to consider full lifecycle requirements, can lead to machinery that is not suited to eventual operating conditions, whether operating inefficiently, being a production bottleneck, or introducing excessive maintenance requirements.

New compression technologies continue to come to market. Improvements in large high speed motors, active magnetic bearings and variable frequency drives, have led to the availability of low maintenance oil free compression, without the need for gearboxes and journal bearings. On top of this, a number of manufacturers have solutions for the integration of the motor within the compressor casing, eliminating all rotating seals. New ground is also being broken in the development of machines capable of delivering high compression ratios, which could lead to more compact equipment. A drive to reduce atmospheric emissions has led to advances in the combustion technology in gas turbines and engines used to power compression systems, and catalytic systems to further reduce emissions are starting to become more commonplace.

Compressor and driver types

There are several types of compressor available, commonly categorised as either positive displacement or dynamic type (Figure 1). There are also choices to be made on driver selection to best match compressor rotational speed and power requirements. Positive displacement type compressors tend to have lower running speed and are typically driven by gas engines or electric motors. Dynamic compressors, with their higher rotational speeds, are typically driven by steam turbines, gas turbines or electric motors.

The most common dynamic compressor used in natural gas applications is the centrifugal type. Energy is transferred to the gas via an impeller, and the dynamic pressure is recovered in a diffuser section. Each impeller is capable of generating a relatively low increase in head, e.g. a single impeller pipeline

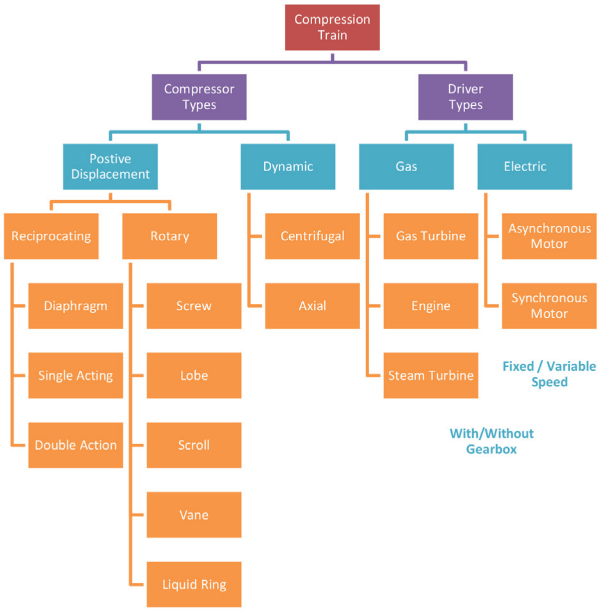


Figure 1. Compression train options.

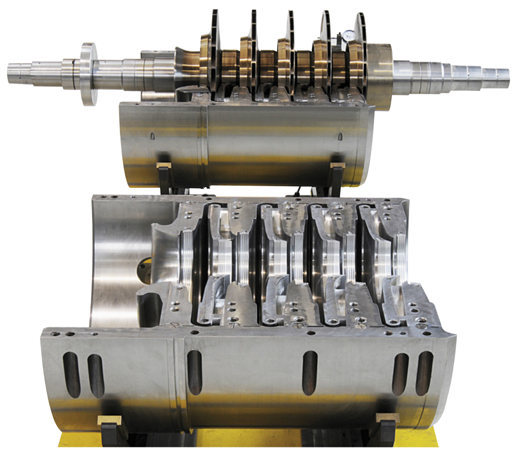


Figure 2. Centrifugal compressor cross-section (courtesy of GE Oil & Gas).

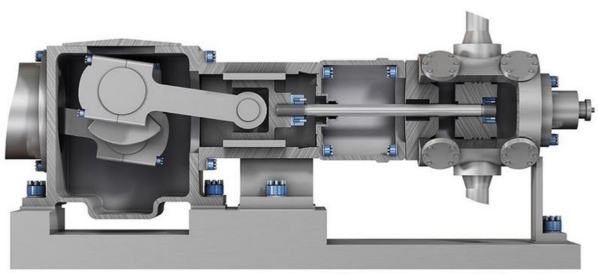


Figure 3. Reciprocating compressor cross-section.

compressor may, typically, generate a pressure ratio of approximately 1.3:1. Higher pressure ratios can be achieved with multiple impellers, either in a barrel casing or installed around a common bull gear.

Depending on the impeller size, speed and arrangement, the range of volumetric capacity and pressure ratio achievable in centrifugal compressors is wide, potentially with suction flows of over 1 million Am^3/hr and overall pressure ratios in excess of 4:1. The discharge pressures needed in gas production, processing and transportation are also easily achievable with centrifugal machines. Overall, the main advantage of centrifugal compressors is their ability to deliver high volumetric capacity for a given weight and footprint.

Centrifugal compressors generally have few moving parts (Figure 2). In a barrel compressor, for example, only the main rotor moves and contacting components are avoided in stable operation. Centrifugal compressors therefore have inherently high reliability and availability, and with appropriate design of the compressor and ancillary systems they require little maintenance. Many centrifugal compressors in dry gas service can operate for many years without dismantling for intrusive maintenance. Depending on the type of driver selected, it can be advantageous to introduce a gearbox to run at a more optimal speed, which can reduce the size and cost of the compressor at the expense of introducing more wearing parts.

Reciprocating compressors, which are also widely found in natural gas applications, work by pushing a piston up and down inside a cylinder of fixed volume (Figure 3). As the piston moves, the volume that the gas occupies is reduced and pressure increases. The discharge valves then open, delivering the gas at the required pressure.

There are various types of reciprocating compressor, generally all operating at speeds below 1800 rpm, and capable of achieving pressure ratios of over 4:1 per cylinder. Again, reciprocating compressors have the capability to operate at pressures in excess of what is needed in the production and processing of natural gas. Reciprocating compressors generally have lower volumetric capacity than centrifugal compressors, but can achieve high pressure ratios for a given unit weight and footprint.

In order to convert the rotating driver motion into a reciprocating piston motion, a large number of lubricated moving components and bearings are required. In addition to this, mechanical seals are needed to stop the process fluid escaping and oil ingress. This will typically result in lower availability than a centrifugal compressor, due to the increased maintenance activities required to replace wearing parts.

Similar to reciprocating compressors, screw type compressors also work on the principle of positive displacement. As a female and male rotor turn, the process fluid is forced towards the discharge end, with the volume occupied by the gas reducing continuously (Figure 4). Use of rotors, rather than pistons, results in fewer moving and wearing parts, and typically lower maintenance requirements and higher availability than a reciprocating compressor.

Screw compressors are capable of operating from relatively dirty service, through to clean applications requiring oil free discharge. Depending on the process duty and conditions, screw compressors can be designed for flow rates up to 140 000 Am^3/hr and pressures of up to approximately 100 barg.

As screw compressors naturally operate with a fixed volume reduction ratio, in order to provide the necessary compressor and process control, either a sliding valve and/or variable speed drive is usually required. A sliding valve operates by altering the percentage of the rotor length used in compression, thus reducing the volume reduction ratio.

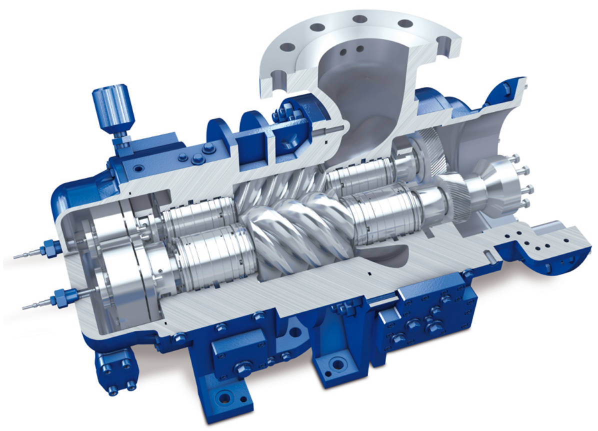


Figure 4. Screw compressor (courtesy of Aerzen).

Natural gas compression applications

There are many applications for compression systems in natural gas production, processing and transmission systems, as summarised in Table 1.

Centralised field gas compression

Barrel type centrifugal compressors with gas turbine drives have been the conventional selection in field gas compression, whether on offshore platforms, within onshore production facilities, or at reception terminals.

The use of electric motor drives has increased, particularly onshore, with the environmental advantages of lower local emissions, lower maintenance requirements, and the potential for higher availability than gas turbines.

The evaluation of optimum driver selection needs to consider environmental, economic and operational criteria, and both gas turbine and electric motor drives continue to be selected depending on the specific application, location, process requirements and constraints.

Table 1. Compression applications in the oil and gas chain

Application	Description	Typical compression requirement
Field gas booster	Compression of field gas, potentially offshore or onshore, either distributed around field or in a central facility	• High flow • Varying pressure ratio • High pressure ratio at end of field life
Flash gas	Re-compression of flash gas from pressure let-down of amine solvents or from condensate stabilisation, to combine with main gas flow	• Low flow • High pressure ratio • Low suction pressure
Fuel gas	Compression of low pressure gas to a suitable pressure for use in gas turbine fuel	• Low flow • Medium pressure ratio • Potential low suction pressure
Product gas	Compression downstream of natural gas processing, e.g. NGL plant residue gas or nitrogen rejection unit product gas service	• High flow • Medium-to-high pressure ratio • Potential side streams
Refrigeration	Ranging from very large refrigerant systems in LNG service to smaller units, e.g. chilling gas in dehydration or dew-pointing service	• Potential high flow • Potential high pressure ratio • Potential multiple streams • Low temperature
Pipeline booster	Compression in transmission and distribution systems delivering gas from production facilities to end users	• High flow • Low pressure ratio • Typically varying conditions
Oil production	Compression of low pressure gas in oil production to manage viscosity, maintain pressure, or provide gas lift	• Low flow • High pressure ratio • Potential varying composition • Contaminated gas
Recycle reinjection	Recycle of lean gas to a rich condensate reservoir for pressure maintenance	• Medium flow • Medium pressure ratio • Typical high discharge pressure • Gas typically already processed
Disposal injection	Compression of CO_2 or H_2S for injection into a depleted reservoir or other geological formation for disposal	• Low flow • High pressure ratio • Typical high discharge pressure

At a UK onshore gas terminal, Costain installed a field gas compression system configured to operate over a wide range of conditions throughout the life of an offshore gas field. Gas arriving at the terminal, following separation of any liquids and solids, was to be compressed to a relatively constant pressure of 87 barg, allowing downstream processing and delivery to the gas transmission system. The inlet pressure to the compression system was, however, highly variable, based on a strategy of maximising production by allowing onshore arrival pressure to fall from up to 75 barg in initial operation to 7 barg at the end of field life.

Two barrel type centrifugal compressors, each driven by a gas turbine, were specified to operate initially in duty/standby configuration, followed by a period of parallel operation and, ultimately, in series operation. All necessary piping and valves, safeguards, and control configurations were implemented from day one.

In the initial operating mode, an optimal bundle was supplied for the duty compressor, minimising suction throttling and fuel consumption. To limit the number of compressor bundle replacements, the standby machine was supplied with a bundle capable of delivering higher head, requiring greater suction throttling when operating in this initial standby mode, but being suitable for the subsequent parallel operation as the arrival pressure fell.

Development of the compression strategy early in the project life cycle allowed the design of the compressor to accommodate the future re-wheeling, and the system design to accommodate re-configuration without costly modifications.

Conclusion

As noted previously, the proper specification and selection of compression equipment can therefore greatly improve economic feasibility. This idea will be explored further in part two of this article, which is due to appear in the December issue of *Hydrocarbon Engineering*.