About Compressor Drivers (OIL & Gas Patch)

Gas compressors in natural gas production and transmission are fundamentally of two types: Positive displacement- and centrifugal or turbo-compressors. Displacement compressors are reciprocating and rotary screw machines. They are designed to move relatively small quantities of gas at high pressure differentials and turbo-compressors convey gas in large quantities with a relatively low pressure rise. Smaller and medium sized reciprocating compressors, and for smaller gas flows, lately rotary screw compressors, are applied in gas production and gathering where high pressure differentials are required. Larger size turbo-compressors or "pipeliners" have been mostly utilized in long distance transmission service.

While there is an ongoing debate about whether to use large reciprocating compressors in gas pipeline compressor stations as opposed to turbo-compressors, one should keep in mind that the function of these two types of machines is based on completely different principles. Also, the efficiency of reciprocating compressors can be significantly lower than that of modern centrifugal pipeline compressors.[1]

The main parameters to be considered when matching a driver to a given compressor are size (bhp or kW) and speed (rpm). There are other secondary, albeit important, considerations such as speed-torque behavior, the ability to couple the driver directly to the driven machine, speed variability and others.

Reciprocating compressors in gas production and gathering range in size from below ~ 100 bhp (75 KW) to around 6700 bhp (5000 kW) with a median size from about 1300 bhp (1000 kW) to approximately 2600 bhp (2000 kW). Screw compressors used in oil and gas exhibit approximately the same size ranges.[2] Reciprocating compressor speeds range between 200 and 1500 rpm, with screw compressors at median speeds of about 1500 rpm.

There are three types of compressor driver available: Reciprocating gas engines, mechanical drive gas turbines and electric motors. A fourth choice has been steam turbine drivers which are used extensively in hydrocarbon processing plants and other industries with ample steam supplies.

Traditionally, direct coupled reciprocating gas engines have been the driver of choice for reciprocating and rotary compressors where remote access and absence of electrical utilities dictates the use of self-contained compression units. Table 1 illustrates the size distribution of natural gas fuelled reciprocating engines while at the same time demonstrating the lack of demand for small gas turbines – even though they are available.

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[1] Turbomachinery International • September/October 2008, P. 34

[2] Modern screw compressors have been produced in excess of 13,500 bhp (10,000 kW) for other industries. They have a MAWP limit of around 1500 psig (100 bar) with a pressure ratio of about 15 – reciprocating compressors have considerably higher MAWPs.

Table 1. Natural Gas Fuelled Mechanical Drive Orders – June 2007 to May 2008 & June 2006 to May 2007

	Recip. Engines		Gas Turbines	
	2007/8	2006/7	2007/8	2006/7
Output Range MW	Units Ordered #	Units Ordered #	Units Ordered #	Units Ordered #
0.50-1.00	360	523		
1.01-2.00	1359	1328	0	0
2.01-3.50	71	77	0	0
3.51-5.00	5	0	2	3
5.01-7.50	0	0	12	19
7.51-10.00	0	0	15	6
10.01-15.00			30	21
15.01-20.00			26	54
20.01-30.00			132	58
30.01-60.00			23	47
60.01-120.00			0	4
120.01-180.00			0	0
>180.01			0	0

Source: CompressorTech • December 2008 p. 62-66

Gas turbines have seldom or never been used as drivers for reciprocating and rotary compressors. The reason must be seen in the high specific investment costs ($/kW) of smaller gas turbines, their low efficiencies and their requirement for speed decreasing gearboxes as variable speed mechanical drive gas turbines normally operate at speeds in excess of 4000 rpm. Some reciprocating compressors could possibly be driven by microturbines. In the past, suppliers of microturbines had been targeting the reciprocating engine market. They soon realized that, for their costs, reciprocating engines were the lowest cost drive solution. Microturbines require 24/7 operation and a low maintenance load to be able to compete with reciprocating engines.[3] An electric motor drive, however, might well be considered in oil and gas producing locations and pipeline transmission stations where electrical power is available. The following facts need to be weighed in order to justify the use of an electric motor:

1. Capital cost of constant vs. variable speed motors. Choosing the first over the latter will increase technical complexity where reciprocating engines have inherently some degree of speed variability.
2. Electrical power cost - $/kWh
3. Constant annual electrical demand cost as a function of installed kW $/kW-yr.
4. Power Factor issues

[3] 2008 TMI Handbook, page 35

Given a favorable constellation of the above criteria, an electrical motor drive for reciprocating and rotary compressors could be more cost-effective than owning and operating a reciprocating engine driver.

Gas turbines come into their own as compressor power requirements increase. Approximately above 10,000 bhp (7500 kW) – sizes as shown on Table 1 – gas turbines become less expensive in terms of lower $/kW and increased thermal efficiency. It makes good sense to apply them to drive centrifugal pipeline compressors where speed requirements are much higher than those for reciprocating and rotary compressors. In most cases a gearbox would not be required as gas turbine speed is matched to that of the centrifugal compressor. The following criteria must be looked at when choosing a gas turbine:

1. Capital costs
2. Operations-and-maintenance requirements and costs
3. Thermodynamic efficiency
4. Turndown capability
5. Emissions performance

A decision maker would be assessing these general points common to all compressor drivers:

1. Suitability/Fit for purpose
2. Foot print consideration
3. Power-to-Weight ratio
4. Operation and maintenance considerations
5. Operational flexibility, i.e. speed range
6. Emissions
7. Life Cycle Costs (LCC)

Table 2 analyzes the cost of ownership of three median range compressor drivers, the reciprocating gas engine, the gas turbine and the electric motor.

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Table 2. Cost Analysis – Compressor Driver Alternatives

1.0	Common Variables					
A	Gas Pricing	(Input)	$/MMBtu*	3.47	$/GJ	3.29
B	El. Power	(Input)	$/MWh**	48.60		
C	Monthly El. Demand Charge	(Input)	$/kW	20		
D	Annual Operating Hours	(Input)	hr.	7000		
E	Operating, Surveillance & Monitoring (OS&M)	(Input)	$/hr.	75		
2.0	Operating Characteristics			**Engine**	**GT**	**E-Motor*** **
F	Capacity	(Input)	BHP	2000	2000	2000
G	Capacity	(F X 0.7457)	kW	1491	1491	1491
H	Efficiency	(Input)	%	37.0	25.5	95.0
I	Inspection, Mtc., Repair & Overhaul (IMR&O)	(Input)	$/hp/yr.	40	60	5
J	Nox Emissions	(Input)	mg/m3			
3.0	LCC Evaluation					
K	Specific Purchase Price (fob)	(Input)	$/kW	553	750	134
L	Investment	(K X G X E-3)	k$	825	1,119	200
M	Installation & Commissioning	(0.5 X L)	k$	412	559	100
N	Fuel Gas/Power Costs	(****)	k$/yr.	334	485	534
O	Demand Charge - El.Motor	(C X G X 12 X E-3)	k$/yr.			358
P	Total Energy Costs	(N+O)	k$/yr.	334	485	892
Q	IMR&O Costs	(F X I X D/8760 X E-3)	k$/yr.	64	96	8
R	OS&M Intensity	(Input)	%	50	75	25
S	OS&M	(D X E X R X E-5)	k$/yr.	263	394	131
4.0	Summation					
AA	Total Investment	(L+M)	k$	1,237	1,678	300
BB	Operating & Mtc. Costs	(P+Q+S)	k$/yr.	661	1,070	1,039
CC	Interest Rate	(Input)	%	6		
DD	Operating Years (Project Life)	(Input)	yr.	15		
EE	Capital Recovery Factor	PMT(CC,DD,1)	-	0.103	0.103	0.103
FF	Capital Cost	(AA X EE))	k$/yr.	127	173	31
GG	Cost of Ownership	(BB+FF)	k$/yr.	788	1,243	1,070

Notes:

* Henry Hub Spot 7/28/09

** Mid-Columbia Spot 7/28/09

*** WPII Induction, 900 rpm

**** For engines & gas turbines: (A X D X G X 0.3412/H X E-3)

For e-motors: (B X D X G/H X E-4)

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