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Research Article

Gas Compressor Station Economic Optimization

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When considering gas compressor stations for pipeline projects, the economic success of the entire operation depends to a significant extent on the operation of the compressors involved. In this paper, the basic factors contributing to the economics are outlined, with particular emphasis on the interaction between the pipeline and the compressor station. Typical scenarios are described, highlighting the fact that pipeline operation has to take into account variations in load.

1. Introduction

The economic success of a gas compression operation depends to a significant extent on the operation of the compressors involved. Important criteria include first cost, operating cost (especially fuel cost), life cycle cost, and emissions. Decisions about the layout of compressor stations (Figure 1) such as the number of units, standby requirements, type of driver, and type of compressors have an impact on cost, fuel consumption, operational flexibility, emissions, as well as availability of the station.

2. Capital Cost: First Cost and Installation Cost

Capital cost for a project consists of first cost and installation cost. First cost includes not only the cost for the driver and compressor, and their skid or foundation, but also the necessary systems that are required for operating them, including filters, coolers, instruments, and valves, and, if reciprocating compressors are used, pulsation bottles. Capital spares, operational spares, and start-up and commissioning spares also have to be considered.

Although not intuitively obvious, this is also the area that is affected by driver derates due to site ambient temperature and site elevation: the power demand of the compressor has to be met at site conditions, not at ISO or NEMA conditions.

Installation cost includes all labor and equipment cost to install the equipment on site. It is determined by component weights, as well as the amount of operations necessary to bring the shipped components to working condition.

3. Maintenance Cost

Maintenance cost includes the parts and labor to keep the equipment running at or above a certain power level. This includes routine maintenance (like change of lube oil and spark plugs in gas engines) and overhauls. Maintenance events can be schedule or condition based. A cost related to maintenance effort is the cost due to the unavailability of the equipment (see below). Maintenance affects availability in two ways. Many, but not all, maintenance events require the shut down of the equipment, thus reducing its availability. Scheduled maintenance has usually less of an effect than unscheduled events. For example, a scheduled overhaul of a gas turbine may keep the equipment out of operation for only a few days if an engine exchange program is available.

On the other hand, insufficient or improper maintenance negatively affects the availability due to more rapid performance degradation and higher chance of unplanned shutdowns.

4. Efficiency, Operating Range, and Fuel Cost

The performance parameters of the compressor and its driver that are important for the economic evaluation are efficiency and operating range. Efficiency ultimately means the cost

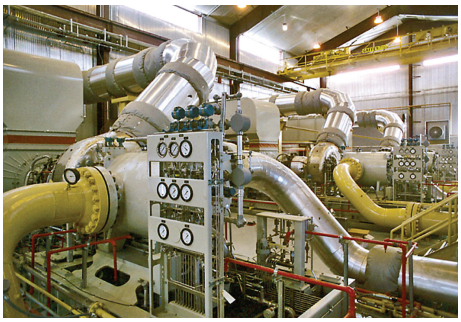

Figure 1: Typical compressor station with 3 gas turbine driven centrifugal compressors.

of fuel consumed to bring a certain amount of gas from a suction pressure to a discharge pressure. In technical terms, this would be a package with a high thermal efficiency (or low heat rate) for the driver and a high isentropic efficiency of the compressor, including all parasitic losses (such as devices to dampen pulsations, but also pressure drop due to filtration requirements) combined with low mechanical losses. This factor determines the fuel cost of the unit, operating at given operating conditions.

Operating range describes the range of possible operating conditions in terms of flow and head at an acceptable efficiency, within the power capability of the driver. Of particular importance are the means of controlling the compressor (e.g., speed control for centrifugal machines, or cylinder deactivation, clearance control, and others for a reciprocating machine) and the relationship between head and flow of the system the compressor feeds into. Operating range often determines the capability to take advantage of opportunities to sell more gas. It should be noted that there is no real low flow limit for *stations*, due to the conceptual capability for station recycle or to shutting down units. Unit shutdown, in turn, has to be considered with regards to starting reliability of the units in question, as well as the impact on maintenance. In this study, operating range and the upside potential are not specifically considered, mostly because no data regarding frequency and value of these upside potentials was available. Upside potential can be realized, if the equipment capability can be used to produce more gas, thus taking advantage of additional market opportunities.

The cost of the fuel gas is not automatically the same as the market price of the transported gas. It depends, among other things,on how fuel usage and transport tariff are related. The cost of fuel is also impacted by whether the operator owns the gas in the pipeline (which makes fuel cost an internal operating cost) or the operator ships someone else's gas. In some instances, the fuel cost might be considered virtually nil. Thus, the ratio between fuel cost and maintenance cost can vary widely. In most installations, however, the fuel cost may account for more than two-thirds of the annual operating cost.

The value of operational flexibility is somewhat hard to quantify, but many pipeline systems operate at conditions that were not foreseen during the project stage. Operational flexibility will result in lower fuel cost under fluctuating operating conditions and in added revenue if it allows to ship more gas than originally envisioned.

5. Emissions

Any natural-gas-powered combustion engine will produce a number of undesirable combustion products. NOx is the result of the reaction between Nitrogen (in the fuel or combustion air) and oxygen and requires high local temperatures to form. Lean premix gas turbines and lean premix engines reduce the NOx production. Catalytic exhaust gas treatments, such as SCR's, can remove a big portion of NOx in the exhaust gas, but also add ammonia to the exhaust gas stream.

Products of incomplete combustion include VOC's, CO, methane, and formaldehyde. Fuel bound sulfur will form SOx in the combustion process.

The combustion products above are usually regulated. For the economic analysis, the cost of bringing the equipment to meet local or federal limits has to be considered.

CO_2 is the product of burning any type of hydrocarbons. CO_2, and some other gases, such as methane, are considered greenhouse gases. Typically, all greenhouse gases are lumped together into a CO_2 equivalent. In this context, it must be noted that methane is considered about 20 times as potent a greenhouse gas as CO_2. Thus, 1 kg of methane would be considered as about 20 kg CO_2 equivalent. In some countries, CO_2 production is taxed, and there is a possibility that other countries, including the USA, adopt regulations that would give CO_2 avoidance an economic value. In this case, the amount of CO_2 or methane that is released to the atmosphere has to be considered as a cost in the economic evaluation.

It further needs to be considered that the engine exhaust is not the only source of emissions in a compressor station related to the compression equipment. There are also sources of methane leaks in the compression equipment that may have to be considered. In this case, one has to distinguish leakage that is easily captured and can thus be fed to a flare and leakage that cannot be captured easily. Further, it may have to be evaluated how frequently the station has to be blown down. For example, whether the compression equipment can be maintained and started from a pressurized hold determines the amount of unwanted station methane emissions.

Lastly, other consumables may have to be considered. The frequency and cost of lube oil changes, as well as lube oil replacements due to lube oil consumption, generate costs on various levels: first, the replacement cost for lube oil, second, if the lube oil is used in the combustion process, the resulting emissions, and third, if the lube oil enters the pipeline, the cost due to the pipe contamination, including possibly the increased maintenance cost of downstream equipment.

6. Availability

Availability is the ratio between the hours per year when the equipment is supposed to operate and actually can operate and the hours per year where the equipment is supposed to

operate. Availability therefore takes into account the entire equipment down time, both due to planned and unplanned maintenance events. In other words, if the operator needs the equipment for 8760 hours per year, and the equipment requires 3 shutdowns, lasting 2 days each for scheduled maintenance, and in addition also had to be shut down for 3 days due to a equipment failure, the availability of the equipment would be 97.5%. Other than MTBF, which describes the frequency of unplanned failures, the availability has a direct impact on the capability of an installation to earn money. Besides the type of equipment, the quality of the maintenance program and the measures taken to deal with environmental conditions (air, fuel, etc.) have a significant effect on the availability (and reliability) of the equipment.

The cost associated with availability is the fact that the station may not be able to perform its full duty for certain amount of time, thus not earning money. The loss of income can be due to the reduction of the pipeline throughput, the unavailability of associated products (oil on an oil platform, condensates in a gas plant), or due to penalties assessed because contractual commitments are not met. The value associated with the lost production is not necessarily the market value of the lost production. It may also be the loss of income from transportation tariffs, the cost from penalties for not being able to satisfy delivery contracts, or the cost for lost opportunity (i.e., due to the requirement to keep spare power to compensate for poor availability, instead of being able to use the spare power to increase contractually agreed deliveries).

Station availability can be improved by installing spare units, but this is an additional first cost factor.

7. Compressor Operation

The relationship between pressures and flows in any given application that employs gas compressors as well as some other factors may influence the arrangement of compressors in a station as well as the type of equipment used. The question about series or parallel arrangements in a station has to be considered both in the light of steady-state aerodynamic performance, as well as regarding transient behavior, spare strategy, and growth capabilities. Not only the full load behavior of the driver, but also its part-load characteristics influence areas like fuel consumption and emissions. Since greenhouse gas emissions from CO_2 for a given fuel gas are only influenced by the overall efficiency of the operation, there is a strong tie between efficiency and emissions.

Different concepts such as the number of units installed, both regarding their impact on the individual station and the overall pipeline and the necessity of standby units are discussed. The number of compressors installed in each compressor station of a pipeline system has a significant impact on the availability, fuel consumption, and capacity of the system. Depending on the load profile of the station, the answers may look different for different applications.

The operating point of a compressor is determined by a balance between available driver power, the compressor characteristic, and the system behavior. The compressor characteristic also includes the means of controlling the compressor, such as

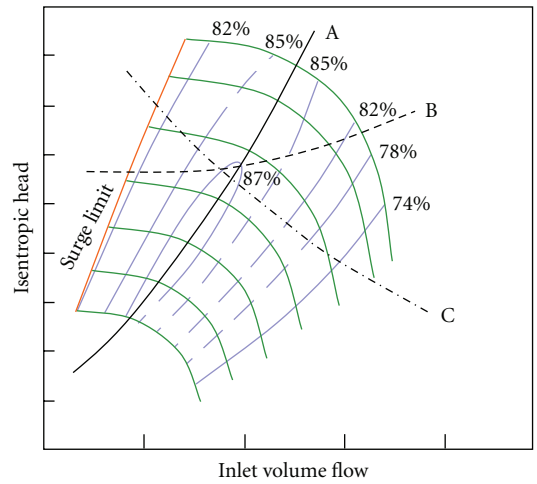

Figure 2: System characteristics and compressor map.

(i) variable speed control,

(ii) adjustable inlet guide vanes,

(iii) suction or discharge throttling,

(iv) recycling.

If variable speed control is available, for example, because the driver is a two-shaft-gas turbine or a variable speed electric motor, this is usually the preferred control method. It is often augmented by the capability to recycle gas. A typical compressor map for a speed-controlled compressor is shown in Figure (Figure 2). It shows the area of possible compressor operating points. The lowest flow possible is determined by the surge line. If the station requires even lower flows, gas has to be recycled. On any point of the map, compressor speed and power consumption are different.

Where on the map the compressor will actually operate is determined by the behavior of the system, that is, the relationship between head (pressure ratio) and flow enforced by the system (Figure 2). Line B depicts a system where suction and discharge pressure are more or less fixed and thus change very little with changes in flow. Examples are refrigeration systems or systems where the suction pressure is fixed by a required separator pressure, and the discharge pressure is fixed by the need to feed that gas into an existing pipeline. Line A shows the typical behavior of a pipeline, where any change in flow will impact the pressure drop due to friction in the pipeline.

Line C is typical for storage applications, where the pressure in the storage cavity increases with the amount of gas stored. If the compressor is operated at maximum power, the initial flow will be high due to the initially low pressure ratio. The more gas is stored in the cavity, the higher its pressure, and thus the required discharge pressure from the compressor becomes. Being power limited, the operating point then moves to a lower flow.

In case of a pipeline, the operating point of the compressor is always determined by the power available from the driver (Figure 3). In the case of a gas turbine driver, the power is controlled by the gas producer speed setting and the pipeline characteristic. We find this point on the compressor map at the intersection between the pipeline characteristic and the available power. Increasing the flow through a pipeline will require more power and more compressor head.

The change of operating conditions over time is due to many reasons, such as drop in field pressure, the pipeline gets looped or has to meet an increase in capacity. Looping the pipeline will change the characteristic of the pipeline to allow more flow at the same head requirement. So, any change in the pipeline operation will impact power requirements, compressor head or pressure ratio, and flow. Operational changes may move the compressor operating point over time into regimes with lower efficiency. Fortunately, centrifugal compressors driven by gas turbines are very flexible to automatically adapt to these changes to a degree.

As indicated, variable speed drivers allow for efficient operation over a large range of conditions. If a constant speed driver has to be used, the adjustment of the compressor to the required operation usually has to rely on the use of recycling and suction or discharge throttling. Either method, while effective, is not very efficient: throttling requires the compressor to produce more head than required by the process, thus consuming more power. On a compressor speed line, throttling will move the compressor to a point at lower flow than the design point. Recycling forces the compressor to flow more gas than required by the process and thus also consumes more power. It thus allows the compressor to operate at a lower head than the design head. In general, an electric motor for a constant speed drive has to be sized for a larger power than a motor for a variable speed drive under otherwise the same conditions. Furthermore, starting of constant speed motors requires to oversize the electric utilities, especially if a start of a pressurized compressor is desired.

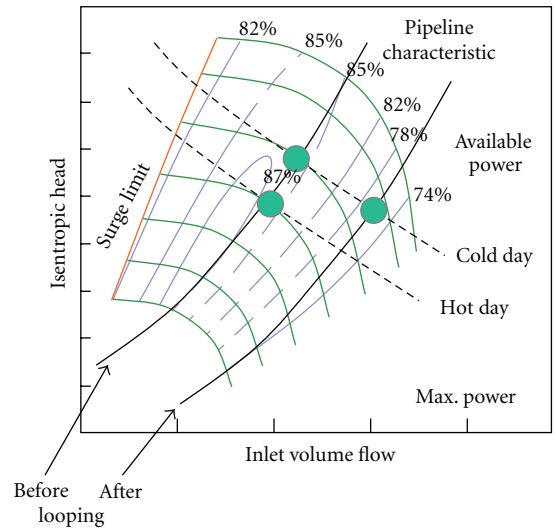

Figure 3: Operating point and driver power.

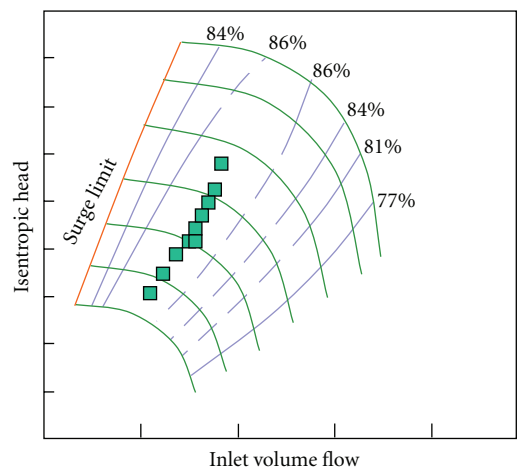

Figure 4: Typical steady state pipeline operating points plotted into a compressor performance map.

8. Operational Flexibility and Standby Requirements

Operational flexibility under a larger number of different operating scenarios has to be studied. Demand varies on an hourly, daily, monthly, or seasonal basis. Also, the available gas turbine power depends on the prevalent ambient conditions (Lotton and Lubomirsky [1]). Similarly, transient studies on pipeline systems (Santos [2]) can reveal the often large range of operating conditions that needs to be covered by a compressor station and thorough analysis can often reveal which type of concept yields lower fuel consumption. Lastly, scenarios that arise from failures of one or more systems have to be considered (Ohanian and Kurz [3]). In any application, operating limits due to speed limits are usually undesirable, because they mean that the available engine power cannot be used. But, because a gas turbine can produce far more power at colder ambient temperatures, designs based on worst case ambient conditions may not be optimal. Optimization considerations can also be found in [4, 5].

The quest for operational flexibility can be satisfied on various levels: the compressor and the driver should have a wide operating range. Using multiple smaller units per station rather than one large unit can be another way. Here, the arrangement in series or in parallel will impact the flexibility. The gas turbines allow for immediate starting capability if the need arises.

In upstream and midstream applications, configurations usually need to cover a large range of operating points. Depending on the application, the operating points can vary on an hourly, daily, weekly, monthly, or seasonal basis. Contributing factors are supply (e.g., depleted fields or new wells) and demand, changes in gas composition or site available engine power. Often, flow demand and head requirements are coupled. This is very obvious for pipeline applications, where the pressure drop between stations (and thus the pressure ratio of each of the stations) is directly related to the flow (Figure 4).

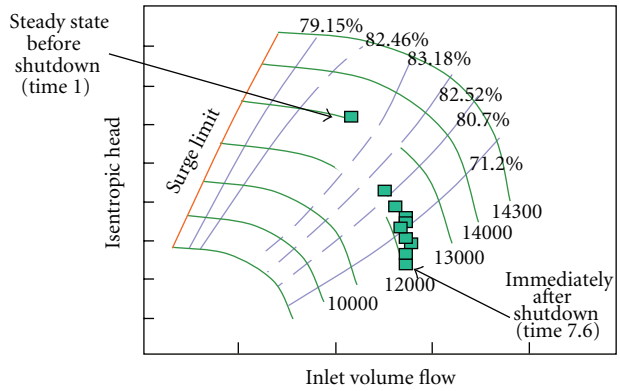

Figure 5: Typical operating points if transient conditions are considered, in this case due to the shutdown of one unit in a two-unit station.

In other applications, the compressor operating points are limited by the maximum available engine power. This is, for example, the case for storage and withdrawal operations. Here, the goal is to fill the storage cavity as fast as possible, which means that engine operates at its maximum power. Since the filling of the storage cavity starts at very low pressure differentials, the flow is initially very high. As the cavity pressure and with it the compressor pressure ratio increase, the flow is reduced. For applications like this, compressor arrangements that allow to operate two compressors in parallel during the initial stage, with the capability (either with external or internal valves) to switch to a series operation, are very advantageous. Incidentally, back-to-back machines cannot be used in this case due to their delicate axial thrust balance.

Dynamic studies of pipeline behavior reveal a distinctly different reaction of a pipeline changes in station operating conditions than a steady-state calculation (Figure 5). In steady state (or for slow changes), pipeline hydraulics dictate an increase in station pressure ratio with increased flow, due to the fact that the pipeline pressure losses increase with increased flow through the pipeline (Figure 4). However, if a centrifugal compressor receives more driver power and increases its speed and throughput rapidly, the station pressure ratio will react very slowly to this change. This is due to fact that initially the additional flow has to pack the pipeline (with its considerable volume) until changes in pressure become apparent. Thus, the dynamic change in operating conditions would lead (in the limit case of a very fast change in compressor speed) to a change in flow without a change in head (Figure 5).

Because the failure or unavailability of compression units can cause significant loss in revenue, the installation of standby units must be considered. These standby units can be arranged such that each compression station has one standby unit, that only some stations have a standby unit, or that the standby function is covered by oversizing the drivers for all stations. (Oversizing naturally creates an efficiency disadvantage during normal operation, when the units would operate in part load.) It must be noted that the failure of a compression unit does not mean that the entire pipeline ceases to operate, but rather that the flow capacity of the pipeline is reduced. Since pipelines have a significant inherent storage capability ("line pack"), a failure of one or more units does not have an immediate impact on the total throughput. Additionally, planned shutdowns due to maintenance can be planned during times when lower capacities are required.

Standby units are not always mandatory because modern gas-turbine-driven compressor sets can achieve an availability of 97% and higher. A station with two operating units and one standby unit thus has a station availability of $100\,(1 - 0.03^2) = 99.91\%$ (because two units have to fail at the same time in order to reduce the station throughput to 50%). A station with one standby unit and one operating unit also yields a 99.91% station availability. However, while failure of two units in the first case still leaves the station with 50% capacity, the entire station is lost if both units fail in the second case. Arguably, installing two smaller 50% units rather than one larger 100% unit could avoid the need for installing a standby unit.

It has often been assumed that for two-unit stations without a standby unit, a parallel installation of the two units would yield the best behavior if one unit fails. However, Ohanian and Kurz [3] have shown that a series arrangement of identical compressor sets can yield a lower deficiency in flow than a parallel installation. This is due to the fact that pipeline hydraulics dictate a relationship between the flow through the pipeline and the necessary pressure ratio at the compressor station. For parallel units, the failure of one unit forces the remaining unit to operate at or near choke, with a very low efficiency. Identical units in series, upon the failure of one unit, would initially require the surge valve to open, but the remaining unit would soon be able to operate at a good efficiency, thus maintaining a higher flow than in the parallel scenario. Given the fact that the gas stored in the pipeline will help to maintain the flow to the users, a series installation would often allow for sufficient time to resolve the problem.

Operating multiple units (either in parallel or in series) can be optimized on the station or unit level by load sharing controls. If the units are fairly similar in efficiency and size, control schemes that share load such that both units operate at the same surge margin of the compressors can be advantageous and will usually result in a good overall efficiency. Similar (or identical) units in general achieve the lowest overall fuel consumption if both are about evenly loaded. The fuel savings from running one unit at high load (and thus higher gas turbine efficiency) is more than compensated by running the other unit at low load and lower efficiency. In other words, running two units at 75% load results in lower overall fuel consumption than running one unit at 100% and one unit at 50% load.

On the other hand, if the units are dissimilar in size, or of very different efficiency, it may be best if the larger, or the more efficient, unit carries the base load, while the smaller, or the less efficient, unit is responsible to provide power for load swings.

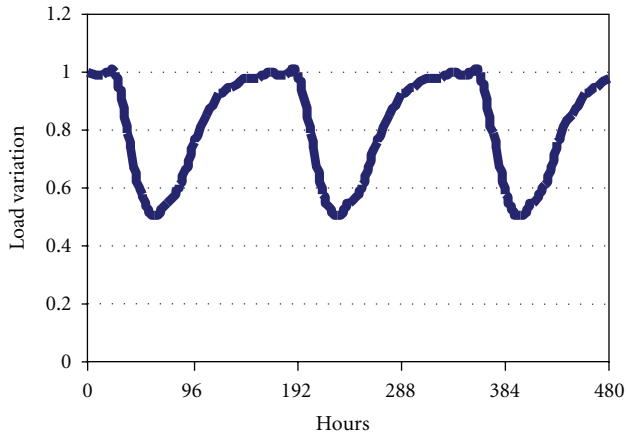

Figure 6: Averaged load variation for four stations of an interstate pipeline in South America during summer and winter scenarios.

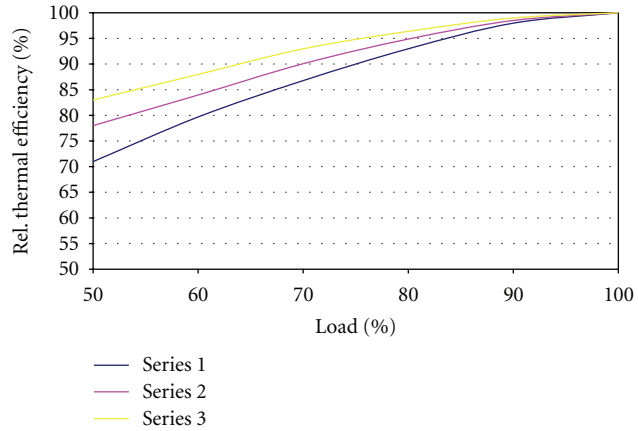

Figure 7: Typical Change of Efficiency with part load for 3 different industrial gas turbines.

Pipelines with load swings (Figure 6) can often benefit from using multiple smaller units as opposed to single big units.

While analyzing the performance of the entire package it is important to understand how to distinguish the unit with the best overall efficiency. The turbocompressor performance depends on efficiency of two main components—gas turbine and the centrifugal compressor. The best efficiency compressor does not always provide the overall lowest unit fuel consumptions as the very important piece of the equation is the turbine efficiency. Also, the relationship between the compressor running speed and the power turbine optimum speed at the required given compressor load must be considered. The main goal during the compressor selections process is to find the stage selections that not only provides the highest compressor efficiency but also would yield the highest overall package efficiency, which is achieved, when the fuel consumption for the duty is minimized. As we know from diagram in Figure 7 the lower the turbine part load is-the lower the turbine efficiency will be. As such, the higher loaded turbine should generally provide the better turbine and overall package efficiency.

The relationship between compressor efficiency and fuel consumption can mathematically be derived as follows.

For a given operation requirement, defined by standard flow, suction pressure, suction temperature, gas composition, and discharge temperature, this operation requirement precisely defines the isentropic head H_s and the mass flow W.

The power consumption of the compressor P_{compr} then only depends on its isentropic efficiency η_s and the mechanical losses P_{mech}, as follows:

$$P_{\text{compr}} = W \cdot \frac{H_s}{\eta_s} + P_{\text{mech}}. \tag{1}$$

In other words, for a given duty, the compressor with the better efficiency will always yield a lower power consumption, since the mechanical losses tend to be very similar for different compressors.

P_{compr} is the power that must be produced by the gas turbine. In turn, the gas turbine efficiency is a function of the relative load, that is, what percentage of gas turbine full power $P_{\text{GT,max}}$ available at the given ambient conditions and the required compressor speed is required by the centrifugal compressor (Kurz and Ohanian [6]):

$$\text{Load}(\%) = \frac{P_{\text{compr}}}{P_{\text{GT,max}}} \cdot 100. \tag{2}$$

The relationship between gas turbine power, fuel flow FF, heat rate HR, and gas turbine efficiency η_{GT} is as follows:

$$\text{FF} = P_{\text{GT}} \cdot \text{HR} = \frac{P_{\text{GT}}}{\eta_{\text{GT}}}. \tag{3}$$

For the compressor applications this means that, for a better compressor, the reduced power consumption indeed causes a small increase in gas turbine heat rate or reduction in gas turbine efficiency. However, the result of lower load and higher heat rate is always a lower fuel consumption.

Other important issues must be considered when analyzing overall package efficiency. In many instances it has been requested by the end user to use the gas turbine heat rate as an indication of the overall package performance efficiencies and as the basis for the package guarantees. Higher turbine load will correlate with a higher turbine efficiency. This relationship is correct however; the turbo compressor user should recognize some underlying circumstances that can lead to the wrong conclusion.

The peculiar thing is that operating at lower compressor efficiency the centrifugal compressor will require more compression power to do their duty that will ultimately increase the turbine load. If we account that higher part load will lead to the better engine efficiency we discover that compressor with lower efficiency will force turbine operate at better heat rate! This is the fact that is being overlooked in many instances if the comparison between the vendors is done solely based on driver's Heat Rate. The question is how to avoid this trap. The simple and the straight forward answer is that overall unit comparison should be done not on turbine's heat rate, which is simply just a number, but rather on direct value-turbine fuel consumption. In this case the

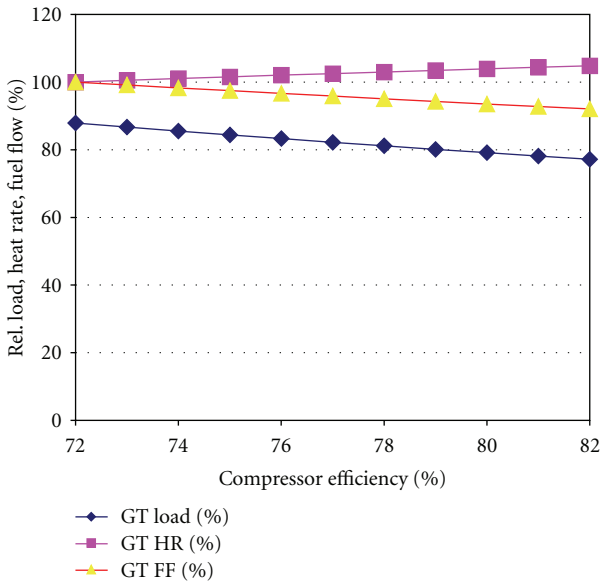

Figure 8: Impact of compressor efficiency on GT Load, heat rate (HR), and fuel consumption (FF).

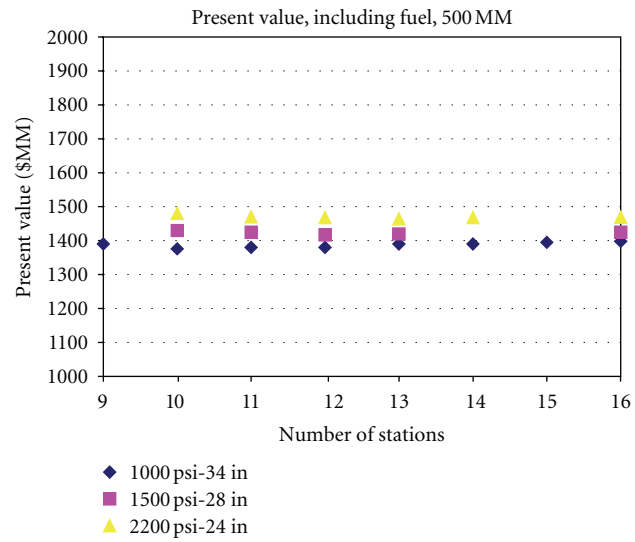

Figure 9: Optimum number of stations and optimum maximum operating pressure (MAOP) for the 3220 km (2000 mile), 560000 Nm^3/h sample pipeline. The lowest cost configurations for each MAOP solution are marked (from [7]).

lower compressor efficiency will drive higher turbine power, and, despite the fact that the turbine's heat rate and efficiency will be improving, the actual turbine's fuel consumption will be going up.

In the end, the only measure that is taken into account when calculating package overall operating cost (OPEX) is the fuel consumption whereas the turbine's heat rate or the turbine's simple cycle efficiency remains only numbers on the paper (Figure 8).

9. Pipeline Sizing Considerations

Kurz et al. [7] evaluated different options for pipe diameters, pressure ratings, and station spacing for a long distance pipeline. A 3220 km (2000 mile) onshore buried gas transmission pipeline for transporting natural gas with a gravity of 0.6 was assumed (Figure 9).

Assuming that pipes will be available in 2′-diameter increments from pipe mills, the nearest even increments of the above-mentioned theoretical diameters were selected (24′, 28′, and 34′ for 152 bar, 103 bar, and 69 bar (2200, 1500, 1000 psia) pressures, resp.) and analyzed by varying the number of stations along the pipeline. The result of this refinement is shown in Figure 9, where present value is plotted against number of stations for each pressure level. The minima for each is shown in the chart with present value total horsepower, and number of stations. In this study, the 69 bar (1000 psia) pipeline has the lowest present value thus would be the most cost-effective solution.

In actual practice, for commonality reasons, identical size units will be installed in the stations. In order to have identical power at each station, the station spacing will be adjusted (dependent on the geography) since the stations at the beginning of the line will consume more power than the stations at the end of the line due to the power required for fuel compression. Identical power at each location also depends on site elevation and design ambient temperature, which would define the site available power from a certain engine.

One of the key findings is that the optimum is relatively flat in all cases. This means in particular that certain considerations may favor larger station spacing, with higher station pressure ratios and higher MAOP in situations where pipelines are routed through largely unpopulated areas.

10. Typical Application

For a case study we consider an international long distance pipeline. The total length of the line is about 7000 km. The pipeline consists of two 42′ parallel lines which turn into single a 48′ line at the crossing of an international border. The pipeline design throughput is 30 billion Nm^3 per year and maximum operating pressure of this pipeline is 9.8 MPa. There are 10 compressor stations planned in one area and over 20 stations in the receiving country. After first gas, it takes 5 years to build up to full capacity.

When we compare operations of the compressor station we need to recognize two main approaches. We can either operate with fewer of larger turbocompressor units (Case A, 2 large units) or with a higher quantity of smaller turbocompressor units (Case B, 4 small units). The following factors need to be considered when selection of either option is decided. In evaluating the system reliability and maximum throughput the impact of unit outages needs to be considered. If we were to consider two large 30 MW units the failure of one of them will result in 50% reduction of power available whereas if we consider 4 smaller 15 MW units the failure of one of them will result in only 25%

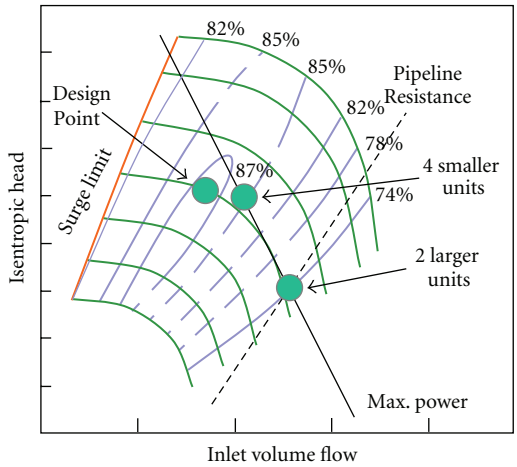

Figure 10: Impact of loss of one unit for the 4 unit and the 2 unit scenarios.

power reduction. Figure 10 outlines the basic fact that, if the surviving units run at full load to make up as much flow as possible, the operating point for the Case B will be close to the highest efficiency island so the remaining on-line compressors will be working more effectively compared to Case A when the single remaining large unit will be working in the stonewall area. It is obvious that pipeline recovery time will be shorter in Case B.

Based on an analysis by Santos et al. [8, 9], Case A can represent even more problems. The amount of gas that the single remaining 30 MW unit will have to process is so big that it will put this remaining unit into choke, and thus for practical purposes out of operation. The amount of fuel that the remaining unit is going to burn will not justify that negligible increase in head that this unit will provide. So, practically, when one larger turbocompressor will be out of operation, the second will have to be shut down and the station will be bypassed. Station configurations with the single oversize driver and either no standby or standby on each second or third station are often advocated. The arguments in favor of this method are very high pipeline availability (99.5%) and high efficiency (40–42%) of the larger 30 MW turbocompressor units. In fact, designing for a turbine oversized by 15% will lead to normal operations at part load conditions almost all the time (99.5%) where there will be negative impact on turbine efficiency and, as a result of it, increased fuel consumption Another negative impact of this approach is that normally this pipeline would operate at lower than MAOP pressure, whereas the highest operational pipeline pressure produces less pressure losses and, therefore, lower requirements for the recompression power. The reason for that is the maintenance schedule for the turbocompressors on the stations with the single units without standby. In order to perform maintenance on these units the pipeline, linepack will have to be maximized up to MAOP, so that unit can be taken off line and the pipeline throughput will not be impacted. Therefore, the normal pipeline operations have to be based on a lower MAOP. Also worth mentioning is the pipeline capacity when considering the single turbocompressor approach. Many pipelines transport gas owned and produced by different commercial entities. As such the gas fields development time and gas availability depend on many technological and, lately, political factors that may potentially have negative impact on pipeline predicted capacity growth. In these conditions the single oversized turbocompressor will either be working into deep recycling mode until the expected amount of gas will become available or start operation with smaller capacity compressor stages which will subsequently require a costly change of the internal bundle.

11. Fuel Comparison

It is increasingly important to evaluate all seasons conditions when making a comparison between two different station layout cases. For the subject pipeline different design organizations were involved in the pipeline feasibility study. One of them has used summer conditions only and came to the conclusion that larger turbines are preferred option. Another source used annual average conditions and came to the opposite conclusion. The reason for that was the fact that during winter, fall, and spring months, which cover total of 9 out of 12 months of operation, one of the smaller turbo compressors was put in the standby mode. Due to lower ambient temperature the amount of power available from the remaining 3 units was enough to cover the 100% duties due to high compressor efficiency. This was not true for Case 1 (based on same explanation above) and both 30 MW units had to work in the deep part load with unsatisfactory turbine efficiency. The fact that operational mode became 3 + 2 for Case B gave additional benefits worth mentioning. Since two turbocompressors were in standby mode there was an opportunity to do all maintenance work during this time of the year. It means that availability of this system becomes superior compared to Case A, especially if we were to consider summer months of operations.

12. Maintenance and Overhauls

Another advantage of operating only 3 out of 5 units for a significant part of the year (i.e., 9 out of 12 months) is the extended time between overhauls. Based on the calculations below, the total number of hours for each turbocompressor unit per year was reduced from 7008 to 5694, and, therefore, the time between overhauls could be extended. Based on 4+1 units operating during 3 summer months and 3 + 2 units operating during the rest of the year (9 months), if the units were used so that they all ran exactly the same number of hours each year, each unit would run for 5,694 hours every year. Whereas if we account for 4 working units with one standby throughout the year the number of working hours will be as follows: 8,760 × 4 units running = 35,040/5 units available = 7,008 total hours per unit/year.

Note that all units run for an equal number of hours to make the calculation simple. However, the customer could push lead machines to reach the agreed time between major inspections (TBI) first, so that all engines do not come up

for overhaul at the same time, and this would help with the overhaul cost, helping to distribute the overhaul cost over the 30 year cycle. We can even make step further and will see additional benefits of this approach. Accounting for the normal year around operation with 4 units online, each turbocompressor will get 7,008 × 30 year = 210,240 required hours of operations, whereas considering 3 + 2 setup for 9 months the total number of the required hours of operations reduced down to 170,820 hours. With modern turbines technology it is not uncommon to see that lifetime operation reaches 150–180,000 hours. It means that for the lifetime of this project (30 years) there will be no need to buy new set of equipment. This alone makes huge favorable impact on projects economics.

13. Station versus System Availability

It is important to recognize the difference between station and pipeline availability. For economic assessments, misunderstanding this issue can lead to the wrong conclusion. Station availability calculations are easy, straight forward and based on simple statistical equations. It is easy to see that fewer units on a compressor station will yield higher availability, assuming the threshold for availability is 100% of the flow. But is this true for the entire pipeline system? The answer is not easy and requires additional investigation including extensive hydrodynamic analysis using of the statistical methodology. The Monte Carlo method [9] has proved to be the good methodology to determine the pipeline system availability. The statistical portion consists of generating multiple random cases of equipment failure on single or two consecutive compressor stations. The hydrodynamic portion will calculate the maximum throughput that pipeline is available to carry when these failures occur. Based on this extensive and in-depth analysis it can be shown that availability of a pipeline, configured with smaller multiple units, delivers better overall results. The main reason for that outcome is the fact that shutdown of the smaller unit makes lesser impact on the behavior of the entire pipeline. Of course, to have fair results, the availability of the single turbocompressor unit, either smaller 15 MW or larger size 30 MW, was identical. It is easy to understand that in our particular case the availability of the station setup with smaller units (Case B) was greatly enhanced because of the presence of extra standby unit during winter and fall/spring months when stations setup has 3 + 2 configuration.

14. Effect of Large Unit Shutdown

Examples of the vulnerability are demonstrated based on a typical pipeline scenario with 4 stations. Each station has 2 compressor trains without spares. If one unit in station 2 is lost, the pipeline flow is reduced by 12%. However, the same 12% flow reduction can be maintained by also shutting down the surviving unit in station 2. This is due to the necessarily inefficient operation of the surviving unit in station 2, which is forced to operate in choke. If both units are shutdown, stations 3 and 4 will be able to recover the flow, but at a much higher overall efficiency. Thus, shutting both units down reduces the pipeline fuel consumption compared to the scenario with only one unit shut down in station 2. The point of this example is, the failure of one of two large units in a compressor station has more significant consequences than the failure of a smaller unit in a station with three or more operating units. Or, in other words, scenarios with 3 ore more units per station without spare units tend to have a higher flow if one of the units fails or has to be shut down for maintenance, than scenarios with 2 units per station without spare units.

15. Conclusion

The paper has illustrated the different influence factors for the economic success of a gas compression operation. Important criteria include first cost, operating cost (especially fuel cost), capacity, availability, life cycle cost, and emissions. Decisions about the layout of compressor stations such as the number of units, standby requirements, type of driver and type of compressors have an impact on cost, fuel consumption, operational flexibility, emissions, as well as availability of the station.

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