

OPTIMIZATION OF NATURAL GAS GATHERING SYSTEMS AND GAS PLANTS

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ABSTRACT

Due to the increase in natural gas prices in the past few years, the benefits of optimizing natural gas gathering and processing systems have become substantially greater. These benefits can be observed from an analysis of the operating conditions, updating gas contracts, and adding gas to existing systems when excellent opportunities exist.

A new technique has been developed to accurately model gas processing systems to incorporate an economic simulation with the process simulation. This new technique utilizes an Excel interface with process simulation software to include economic factors with the simulation results. As a result, an extended analysis of the operating conditions of the facility as well as the economic conditions can be simultaneously combined to provide a complete model of the system. This methodology can be extended to include a parametric study of the available process and economic variables. Excel solvers may also be used to generate the economic optimum set operating conditions.

INTRODUCTION

Process simulation has been traditionally used to troubleshoot and maximize the performance of gas processing facilities. Economic considerations are often performed in spreadsheets disconnected from the process simulation model. As a result, economic models cannot be easily combined with the process model. In many instances, one person handles the day to day plant operations and uses the process model while the person who negotiates gas contracts uses the economic model. A new technique has been developed to combine the process and economic models in a seamless format which gives economic insight to general process simulation problems.

Once the two models are connected, process changes will be automatically reflected in the economics. Parametric studies or solvers may be utilized to determine the overall economic picture, but it is helpful to review the important drivers for the process and economics.

IMPORTANT FACTORS FOR GAS GATHERING AND PROCESSING SYSTEMS

Natural gas gathering systems are a unique product of continual changes from the addition and depletion of wells. Some gathering systems contain spare capacity from fields which never developed. Other gathering systems are pushing capacity constraints from fields which exceed expectations. As a result, modeling gas gathering systems is an art which can have many forms. Some of the major factors for consideration from both a process and economic perspective are shown below:

Pressure Drop / Compressor Fuel - Increased gas density at higher pipeline operating pressures allows for more gas to travel through a given line size. Higher pressure drops directly contribute to increased compression fuel costs.

Liquids in Pipelines - Produced gas generally enters the pipeline near its dew point. As a result, cooling of the gas through the gathering system can create liquids in the pipeline. These liquids can collect in low spots and increase the pressure drop through the pipeline. The value of the pipeline liquids may be significant.

A second source of potential liquids occurs when the gas is compressed and cooled. These liquids present challenges because they may not be stable at atmospheric pressure, but they need to be removed prior to a second stage of compression.

Wellhead Pressure - Many gas gathering systems require a low pressure at the wellhead to facilitate production. This can become a constraint for the operation of gathering systems.

Gas Contracts - The gas gathering contracts may have many forms including fees for compression, treating, or gathering. Many gas contracts operate on a percent of proceeds after processing. Gas collected by gathering systems may also have a mixture of ownership and contract terms.

Product Prices - The sales price of gas and liquid products is one of the most important factors in optimizing gas gathering and processing facilities. Historic price information is compiled on the Barnes and Click website¹.

GENERAL APPROACH FOR OPTIMIZATION

Traditional methods for optimizing gas process facilities are quite complex². These methods incorporate simplified process calculations in order to combine economics and process simulation techniques. An example simplification is the use of the Underwood³ method for separation of the light and heavy key components. All other components are not considered in the distillation. Sophisticated numerical techniques are required to complete the process model such as the method proposed by Box⁴.

Significant improvements in optimization evolved with the additional capability of process simulation programs to imbed an Excel workbook or other spreadsheet type application. With the addition of spreadsheets in process simulation models, the general approach is quite easy; link an Excel workbook to a process simulation program and transmit values back and forth. A process or pipeline facility can be modeled rigorously with the process simulation portion while the economic model can be set up in Excel. ProMax® was selected as an example for the application of this technique due to its ease of integration with Excel. An example of the importing and exporting feature is shown below in Figure 1. The following example illustrates this concept.

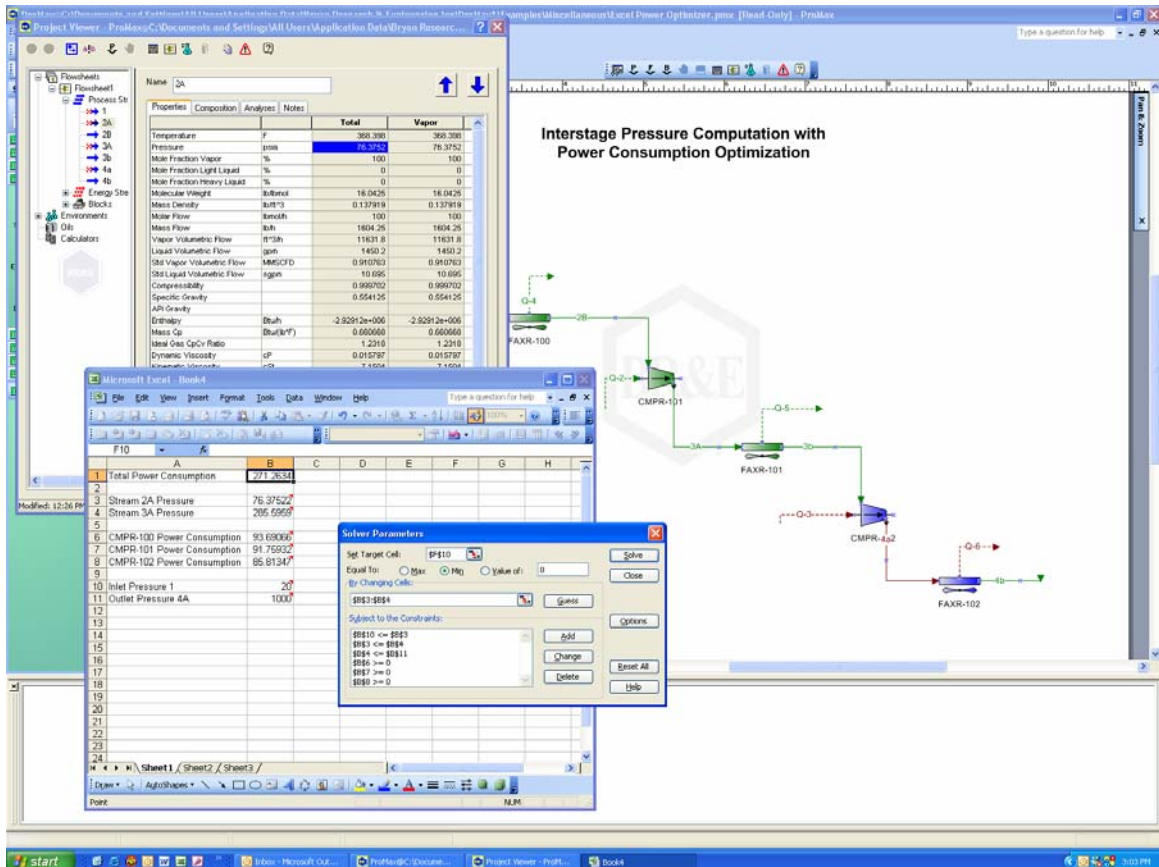


Figure 1: Importing and Exporting Values to an Imbedded Excel Workbook

OPTIMIZATION OF A NATURAL GAS GATHERING SYSTEM WITH A PROCESSING PLANT

In many instances, the operator may include the gas gathering and processing under one contractual arrangement. As a result, the gas processing facility must be included in the overall analysis. In this example, 50 MMSCFD of 10.8 GPM gas enters an existing 20 mile pipeline at 35 psig. The gas is field compressed to achieve 100 psig at the plant gate as shown in Figure 2. Up to 25 MMSCFD of additional 7.2 GPM gas is available. The pipeline transports and processes the gas under a fixed fee arrangement (\$0.25 per MCF) and the gas owner pays for the fuel.

The plant inlet compression system compresses the gas to an operating pressure of between 800-900 psig and separates the methane from the heavier hydrocarbon products as shown in Figure 3. This figure also identifies several key parameters which significantly affect the operational efficiency and economics of the plant. These parameters are the inlet pressure, amount of inlet split for reflux to the column, the demethanizer pressure, the reboiler duty, and the chiller duty. The residue gas from the plant is recompressed to 700 psig for pipeline injection. The demethanized liquid is sold as a Y-grade product at \$0.55 per gallon. The residue gas value is \$ 5.50 per MMBTU. The plant charges small pipeline and marketing fees.

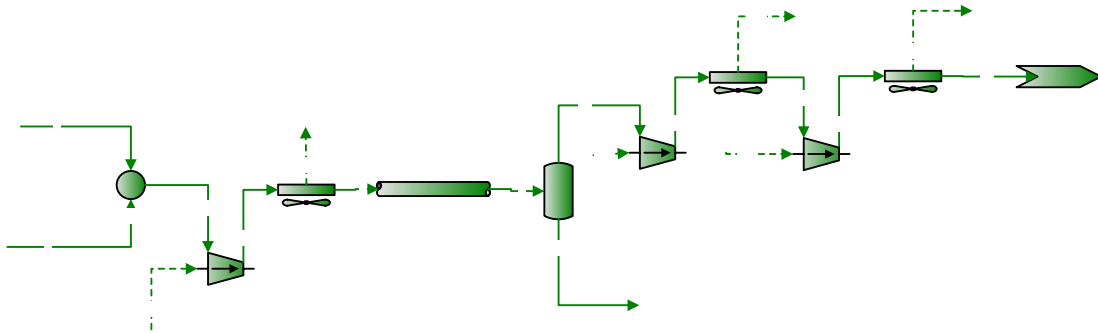


Figure 2: Gas Gathering and inlet Compression System

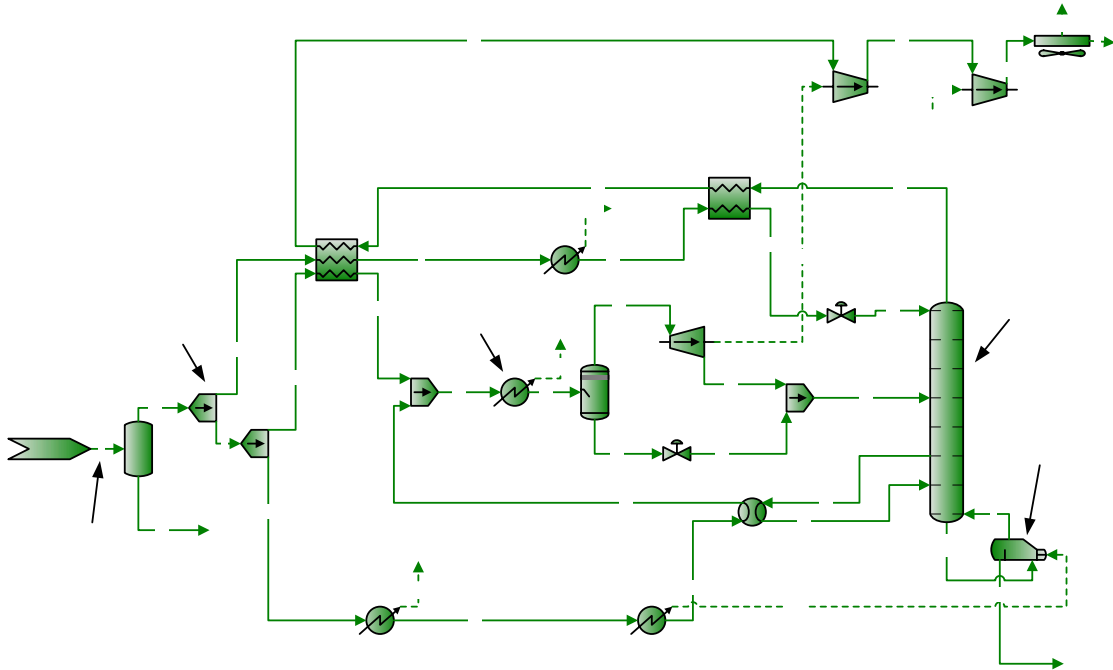


Figure 3: Expander Plant with Key Operating Parameters Identified

An Excel economic model was used to represent the economics for the gathering and processing facility. This spreadsheet was linked to a process simulation of both the gathering a processing facility simultaneously. Table 1 lists the parameters residing in Excel and shared with the process simulation. These parameters significantly affect the plant operation. Table 2 identifies the parameters calculated by the process simulation and shared with the Excel model.

Table 1: Parameters which reside in Excel and Shared with the Process Simulation

- Plant Inlet Pressure
- Percent Split for Reflux to the Top of the Column
- Chiller Outlet Temperature
- Demethanizer Pressure
- Reboiler Duty

Table 2: Parameters Calculated by the Process Simulation and Shared with Excel

- Residue Composition and Flow
- Liquid Product Composition and Flow
- Compressor Energy Requirements
- Reboiler and Chiller Energy Requirements

Reflux Split

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Upon completion of the linkages, various process and economic factors were investigated as shown graphically in Figures 4-9.

The gross plant profit is shown in Figure 4 with variations in the reflux split. Splits from 22.5-30% yield the best results. There is a small benefit to operating at an optimal value of 25%.

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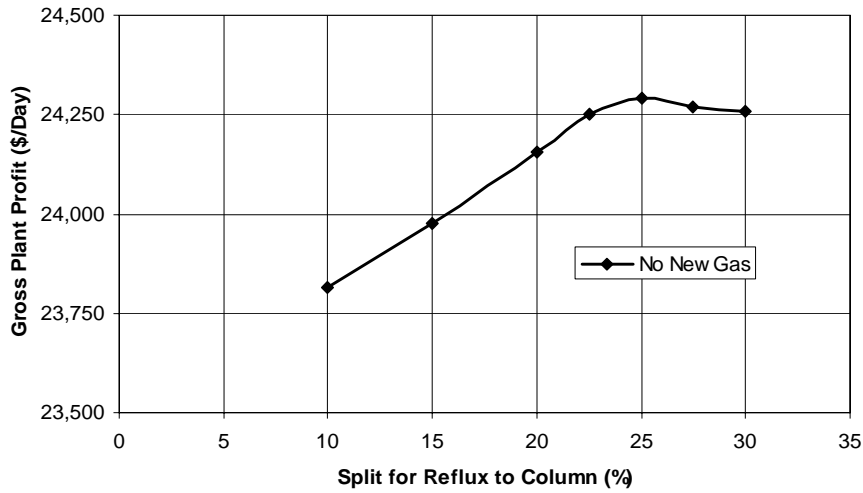


Figure 4: Plant Profit without New Gas for Variations in Reflux Split

The new gas stream is leaner containing 7.2 GPM compared to the 10.8 GPM existing gas stream. Figure 5 shows ethane recovery fluctuations with reflux splits from 10-35%. The plant will operate at better recoveries with the addition of the new gas.

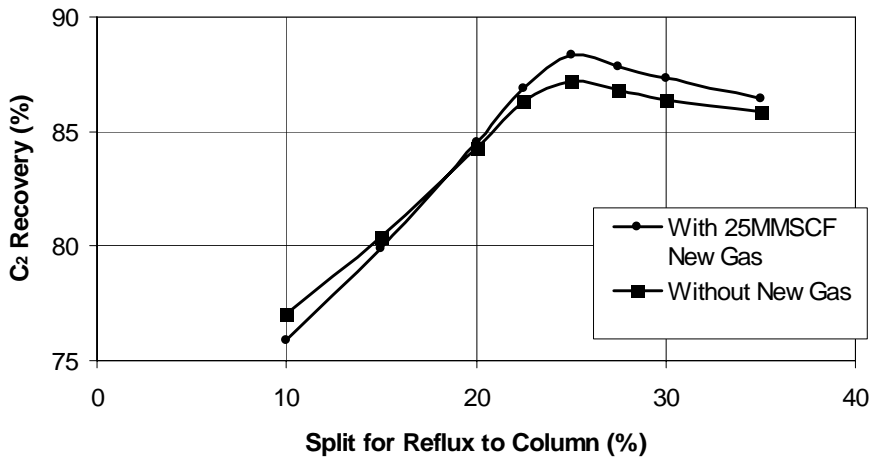


Figure 5: Plant C₂ Recovery with/without New Gas

Figure 6 shows the demethanizer pressure effects on plant profitability with demethanizer pressures from 180-220 psig. The optimum for the percentage of liquids scenario is the lowest demethanizer pressure. The lowest demethanizer pressure yields the greatest change in pressure through the expander and generates the coldest

temperatures and best recovery. Since the plant does not have to pay for fuel in this case, the additional fuel required for recompression does not affect the economics. If the plant is processing the new gas under a keep whole arrangement, recompression costs are important and favor operating the demethanizer at higher pressures.

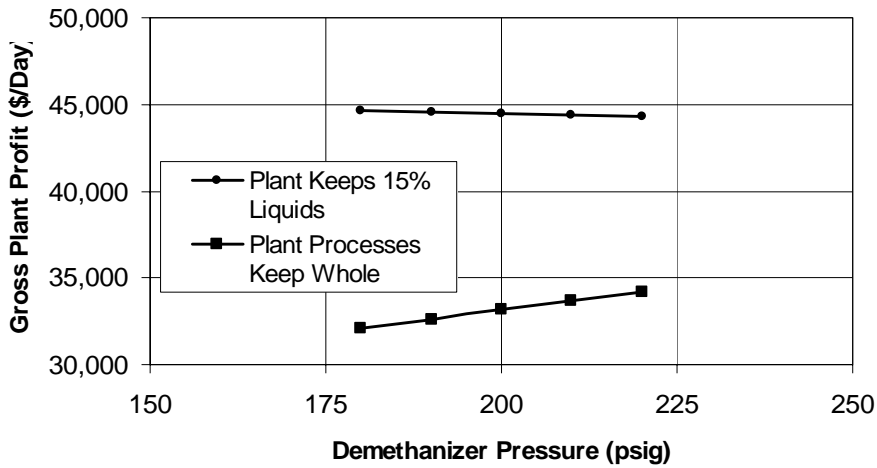


Figure 6: Demethanizer Pressure Influence on Plant Profitability

The economic response to changes in the inlet pressure is shown in Figure 7. Higher inlet pressures are optimal for keep whole processing despite the added fuel costs

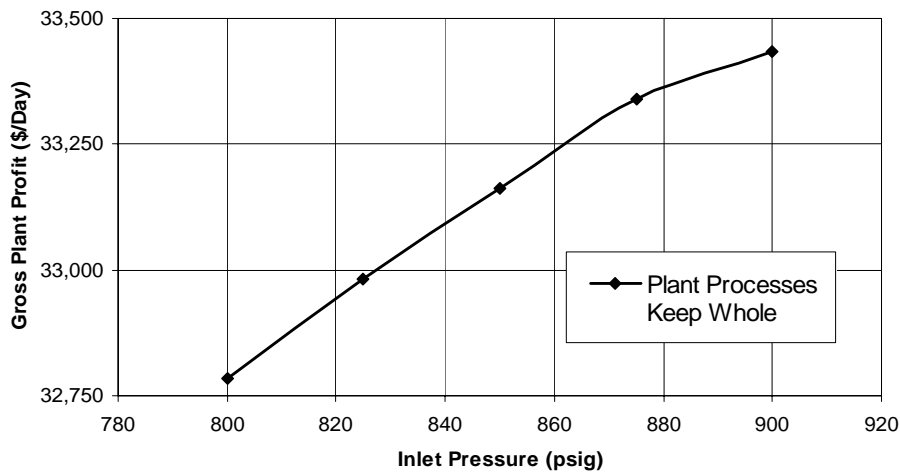


Figure 7: Inlet Pressure Influence on Plant Profitability with Keep Whole Processing

The inlet pressure effect on the plant profitability with a percentage of liquids contract shows a similar response to that of the keep whole contract as shown in Figure 8. Higher inlet pressures contribute to increased liquids recovery.

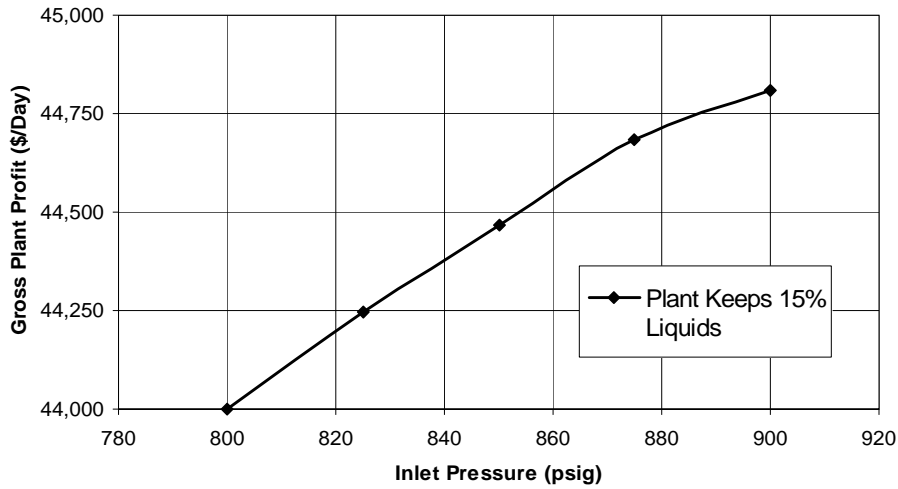


Figure 8: Inlet Pressure Influence on Plant Profitability with Percent of Liquids Processing

The amount of new gas was varied with different contract scenarios as shown in Figure 9. The plant receives the smallest amount for processing the gas at the same \$0.25 per MCF gathering and processing fee. At current price levels, the keep whole processing arrangement is only marginally better. The best scenario is to process the gas while retaining 15% of the liquids without charges for fuel.

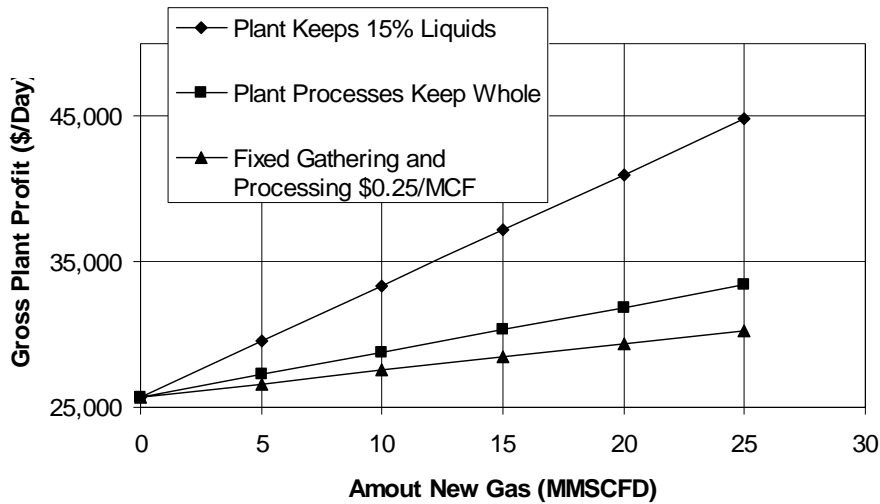


Figure 9: Plant Profitability with Different Contracts for the New Gas

In summary, the technique of combining a process simulation with an Excel representation of the economics can be very helpful in predicting plant economic performance. This technique must be reapplied periodically for changes in the gas, product prices, and contracts.

Literature Cited

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