Heavy Oil Vent Gas Options Study

Final Report: February, 2001

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1. Executive Summary

The volume of methane vented from conventional heavy oil wells, is estimated to be between 1-2 million m3/d (35-70 MMSCFPD), emitted from over 12,000 sites in Alberta and Saskatchewan. With the rapid increase in natural gas demand and prices, this gas represents an untapped resource of significant value. As well as the economic opportunities represented by recovering and utilizing this gas, there is also the opportunity to reduce Canada's GHG emissions from this source which represents an estimated 2% of Canada's total GHG emissions on a tonne CO2(eq) basis.

This report summarizes a wide range of options that are considered technically and economically viable to reduce methane venting in Conventional Heavy Oil Operations, and replaces the Interim Report issued in August, 2000. The wide scope of options developed is necessary due to the wide range of variables that have to be addressed for conventional heavy oil applications.

Major challenges, which had to be addressed in the study, are related to:

- Highly variable vent flows over time periods of years, months and even hours.
- Vent volumes that are often considered of low value on a single lease.
- Highly variable development strategies utilized by producers.
- Highly variable commodity values for gas, power, oil and environmental credits
- Operations located in two provinces, causing variation in regulations, royalty and tax regimes.
- Some options are relatively simple, while others are technically and economically complex and require greater engineering support, and/or corporate assessment at a strategic level, prior to considering implementation.

Options Covered by the study covered a number of key areas, and included options to:

- Stabilize Vent Gas Flows to facilitate their recovery and utilization.
- Displace Purchased Gas or Sales Gas for meeting the energy needs of the production process.
- Distributed Power Generation using vent gas to supply producer or local power needs.
- Vent Gas Collection and Compression for Sales into local gas markets.
- Vent Gas for Enhanced Oil Recovery or Production Enhancement, either as an energy source or as a source of injectant.
- Conversion of Uneconomic Vent Gas to Carbon Dioxide to reduce GHG emissions and potentially generate emissions trading credits
- Odour Mitigation where odours might impact a producers ability to develop or operate a lease.

Tools Provided for participants use consist of:

- One Page Option Sheets – Describing 60+ individual options described in the study.

- Technical Assessment Tools – Tables (14) indicating technical factors influencing the choice of options for a particular type of application or strategic objective.
- Economic Assessment Spreadsheets – Excel based tools (4) to assist participant personnel in carrying out economic assessment and comparison of options.

Finally the report includes recommendations for future work to transfer the technologies identified into field application, and to further develop options, which show promise but require either further development or demonstration in a field application.

2. Background and Limitations

This report is based on work completed since early 1999, by New Paradigm, in considering options to meet the requirements of two Requests For Proposals (RFP's) issued by the Heavy Oil Sub-committee of the Petroleum Technology Alliance Canada in early 1999. The primary objectives of these RFP's were to allow the use of casing vent gas in heavy oil, single well battery, operations where:

a) Casing gas was available at a sufficient pressure to feed fire-tube heaters, but the heaters could not be operated through winter periods due to fuel line freezing. Suggested solutions in the RFP were looking for low cost dewatering/drying of the fuel gas.

b) Casing gas was available but at pressures less than 20-30 kPa (g) required by fire tube heaters. Suggested solutions were compressor systems to boost the gas or low pressure gas heater systems that could operate at a few inches of water column pressure.

In response to these RFP's, New Paradigm worked to help develop two catalytic heater systems, which allow the use of low pressure gas and can provide heat to keep units operating through winter conditions. While working on these options, New Paradigm recognized that there were other systems which could technically meet the requirements, but required little or no research or development to implement. This project was developed and launched to investigate and provide information on the various vent gas utilization options, on a consistent basis.

An Interim Report, issued in August, 2000, highlighted options which had already been utilized in conventional heavy oil operations, and discussed the factors producers should consider to facilitate assessment, purchase, installation and operation of those systems. That report was intended to quickly increase participant familiarity with the various demonstrated options, and encourage additional installations of these systems for trials during the winter of 2000-2001. Feedback from participants on the interim report has been quite positive.

In this final report for the project, we have combined the initial options for fuel gas displacement systems, with other options intended to deal with issues related to the gas flow characteristics, additional strategic opportunities through use of managed equipment to utilize gas surplus to the needs of the operation, and to address opportunities for low cost mitigation of any remaining methane or odours from these operations. While we have tried to include all practical options there are likely other options that could be developed. Since the intent of the project was to highlight options, it is left to the producers to continue the work, to evaluate options for specific applications and to work on resolution of any technical, economic, safety, environmental or regulatory issues that would facilitate use of any particular option. Where there is an apparent opportunity to continue with a focused development or assessment effort, New Paradigm is including information on additional projects we would be willing to undertake for individual producers or as new JIP's.

3. Current Situation Assessment

Generally in conventional heavy oil operations, where casing gas may be vented, the site will fall into one of three operating states as follows:

i) **Little or No Casing Gas –** Desired result is to operate very efficiently, with as little purchased fuel as possible to minimize operating costs. Preferred would be highly efficient heater and pump drive systems with the lowest cost purchased fuel, while providing some method of utilizing whatever casing gas there is, and/or importing surplus casing gas from other sites.

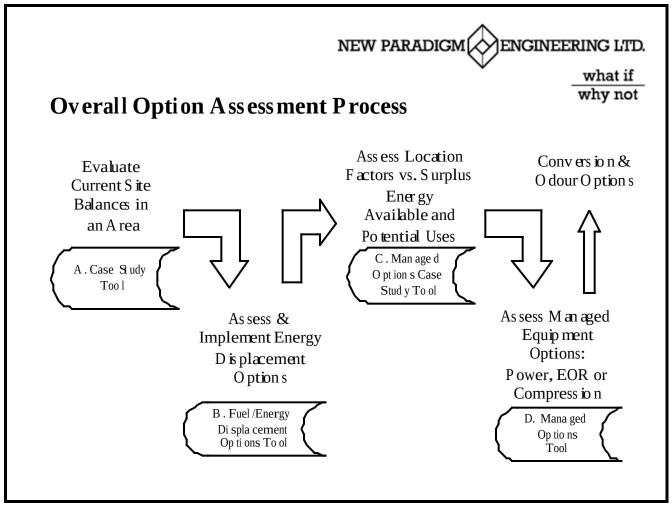
ii) **Some Casing Gas –** This is the most common situation. Generally there is enough gas to meet the energy needs of at least one of the main energy users on the site (pump drivers or production heaters) on a consistent basis, with small amounts of surplus vented. Preferred would be implementation of a group of options, which requires no purchased fuel and can utilize almost all of the produced casing gas so that there is little or no surplus to be vented. In this case energy efficiency is only a concern when the volume of gas available is close to the minimum required, once there is a small surplus of casing gas then the preferred action may be to reduce the energy efficiency to allow more gas to be consumed using existing lease equipment.

iii) **Significant Amounts of Excess Casing Gas –** Will be a situation where there is a pad of wells, or a single well producing significantly more gas than is needed for fuel on a site, and in amounts which begin to make it economic and desirable to collect and use the surplus gas rather than venting it.

For the interim report the primary target sites were those that had enough vent gas to supply their own needs with the surplus vented (Operating state ii). In the current, final report we will address the full range of operations, and to adapt operations as the situation changes through out a well's producing life. We will also address options to stabilize casing and tank vent gas flows so that more of the gas can be made available for use. Example calculations are provided in this report and EXCEL spreadsheets are provided which can be used to carry out some basic sizing or economic calculations for a given situation. For convenience we have tried to use measurement units that seem to be in most common use in heavy oil production operations and are a mix of metric (volumes, temperatures and pressures) and english (heat loads, mechanical energy, equipment/pipe sizes, lengths).

3.1. Overall Option Assessment Process

The overall assessment process used in this study and supported by various tools is shown in the diagram on the next page.



The process is based on first carrying out an overall assessment for a given operating area. This establishes the overall energy balance and can provide some information that will help with further assessment of options. The second stage evaluates options for specific cases within the area with a focus on: a) stabilization of the vent gas streams, b) initial lease equipment selection and c) displacing external fuel, or energy, which is being supplied to the lease.

The inherent assumption in the initial phases of the assessment is that energy displacement will provide the greatest return on investment, and will be applicable and economic for most wells. Our estimate is that this might consume between 60-80% of the vent gas supply available.

After all the lease energy needs have been met, then the surplus vent gas is assessed as a potential source of energy for managed options, which might allow the producer to generate and export additional energy from the lease in the form of gas, electrical power or increased production of oil. This is done first at a high level, to address strategic and practical limitations of the managed options for a particular production area, and to determine which managed option is the most beneficial or advantageous for the producer in that area. Once the preferred strategic export product(s) has been determined, a more detailed assessment is made to assess which particular vent gas use options should be implemented.

Finally, when all options for vent gas use on the lease or for export have been exhausted then a fifth assessment addresses what to do with any small amounts of remaining gas and addresses any issues related to lease odours which may have implications for the operation of a well on a given lease.

Overall this process is designed to proceed from the options with the quickest payout and widest application, to the final options, which focus mainly on environmental issues which may, or may not have direct economic factors associated with them, or which may only be a concern for a very limited number of leases. Hopefully, by the time the end of the process is reached, all of the vent gas will be managed in a way that is the most advantageous to the producer.

To help the assessment process, spreadsheet and technical comparison tools have been supplied to participants to help them work through the process and do the necessary assessments. These tools are covered in detail in Section 7.

3.2. Calculate On-Site Energy Available

On-site energy available is a calculation of the total energy that might be generated through combustion of the vent gas at a given site, and at a known or assumed heating value. The calculation is:

Energy Available = Gas Vented x Heating Value (HHV[1]) of the Vent Gas

It is estimated[2] that the average heavy oil well produces about 160[3] m3/d (Based on an average GOR of 59 and production of 2.9 m3 oil/day/well) of gas with a higher heating value of 900 BTU/ft3 for an average gross energy available of 210,000 BTU/hr/well. The range of gas produced per well is very high, however, so a given well might produce anywhere from <1m3/d of gas to >1,000 m3/d. In Saskatchewan, 850 m3/d of casing gas at a site is considered the point at which the wells should be considered for co-production, or be subject to the imposition of a conservation order by SEM.

3.3. Calculate On-Site Energy Demand

On most conventional heavy oil leases the main demands for energy are the driver for the artificial lift system and production heating for lease tank treating and to facilitate truck loading. The main factor affecting both these loads will generally be the volumes of water and oil produced by a well. For existing wells the easiest method of determining the demand is to track purchased fuel usage over the year as a function of fluid production when no casing vent gas is being used. When this information is not available the energy demand can be calculated for each use.

3.3.1. Artificial Lift

The energy required for artificial lift varies with the type of lift system on the well (beam, PCP, etc.), drive energy transmission system, well characteristics etc. These calculations are routinely carried out by producer production engineers for each well and are not going to be addressed in this study. What is of interest is the output energy demand requirement for a drive engine, or power generator/electric motor combination, that might be able to utilize casing gas. The energy demand calculation is simplified to:

[1] NB – The HHV or Gross heating value of methane is 1009.7 BTU/ft3 (approx = 1 GJ) at standard conditions where the combustion products are returned to standard conditions of 60 degree F and 14.696 psia. The Lower or Net Heating Value (LHV) of methane is 909 BTU/ft3 at standard conditions but excludes the energy that could be recovered if the water in the combustion product stream was condensed. Casing gas when vented is assumed to be sweet (no H2S) but may contain CO2 and will contain water vapour that will lower the HHV of the produced gas. The HHV of propane is 2316 BTU/ft3 of gas.

[2] CAPP and AEUB estimates.

[3] These numbers are based on an Air Quality Study carried out in the Lindberg area and used extensively by AEUB and others.

Pump Drive Energy = Mech HP Delivered (calculated) / Thermodynamic Efficiency

For example, an engine providing 40 hp to a lift system, will generally only deliver 33% of the gross thermodynamic energy from the fuel (the rest is lost as waste heat or through the exhaust) and would require about 300,000 BTU/hr of energy from the fuel stream. Artificial lift, gas driven engines in the Lloydminister area generally range in output from 20-90 HP and vary in type by producer and by well.

3.3.2. Production Heating

The largest energy demand on most sites is usually the fire-tube heater in the lease tank. Produced fluids from non-thermal operations are generally below 25 degrees Celsius and must be heated to allow in tank separation of oil, water and sand, as well as to allow relatively rapid loading of tanker trucks which haul the oil to central facilities. The most common method of heating the production is through use of on-lease tanks fitted with fire-tube heaters. Heating required consists of two main components:

- The energy required to warm production, from the temperature at which it is produced, to the desired tank temperature. This is usually the largest energy requirement and is proportional to production levels of oil and water.

- The energy losses from the tank through the tank walls, through air passing through the fire tube when it is not in use, and combustion losses at the burner, or inefficient heat transfer to the tank contents. These losses are a function of the tank configuration, type and control of burner, and size of burner relative to demand.

Generally producers[4] use a gross efficiency based on the relatively easy to measure variables of production, fuel use and degrees of production heating.

Fuel energy input = Energy to heat production + Energy losses

Overall Efficiency = (Energy to heat Production) / (Fuel Energy Input based on HHV)

While this is useful for gross monitoring of costs it results in highly variable results (Reported values range from <25% to >50% efficiency) for the calculated efficiencies. The apparent efficiency for a well producing at high volumes with the burner in continuous operation should be better than a similarly equipped well producing lower volumes of fluid and with the fire tube burner only in periodic operation. For this report calculations will be based on tank energy heat losses (should be relatively constant on an annual basis with consistent tank temperatures and tank designs) and production heating for which simplified formulas are available. This will have an overall heating efficiency applied to

[4] Based on Husky Oil procedures.

generate the gross energy demand for a given case. Combustion efficiency and heat losses from the fire tube are more difficult to assess. Therefore, the energy demand for tank heating will be:

Fuel Energy Input = (Production Heating + Tank Heat Losses) / Heating Efficiency

Producers can develop reasonable values for "Heating Efficiency" from their "Overall Efficiency" numbers by backing out the tank heat losses on a consistent basis.

Using standard formulas, an assumed "heating efficiency" of 40%, 45 degrees C of production heating for 50 m3/d of production at a WOR of 1 gives a production heating requirement of about 800,000 BTU/hr of which about 40,000 BTU/hr (5% of total) would be due to average annual tank heat losses. Note for a well producing only 5 m3/d of fluid at the same WOR and conditions the total energy required would be 116,000 BTU/hr of which 40,000 BTU/hr (35% of total) would be due to average annual tank heat losses. "Overall Efficiencies" in these two cases would be 38% and 26% respectively. The additional heat losses through the fire tube when the burner isn't in full operation might reduce the Overall Efficiency in the low rate well to as low as 20%.

3.4. Current Site Energy Balance

Using the values of energy available from casing vent gas and energy demands for the drive engine and production heating provides a current site energy balance. To make the most effective use of the casing gas energy the assumption is that the primary use for this gas is to use it to meet on-site energy needs and displace purchased fuel or power. The energy balance for a given site may vary significantly over the producing life of the well, requiring that the producers adapt the operation of the site as conditions change to minimize the need to purchase off-site energy. The potential impact of casing gas use on purchased fuel requirements can be seen in Figures 3.1 and 3.2 on the next page for a well with an assumed production profile and energy balance.

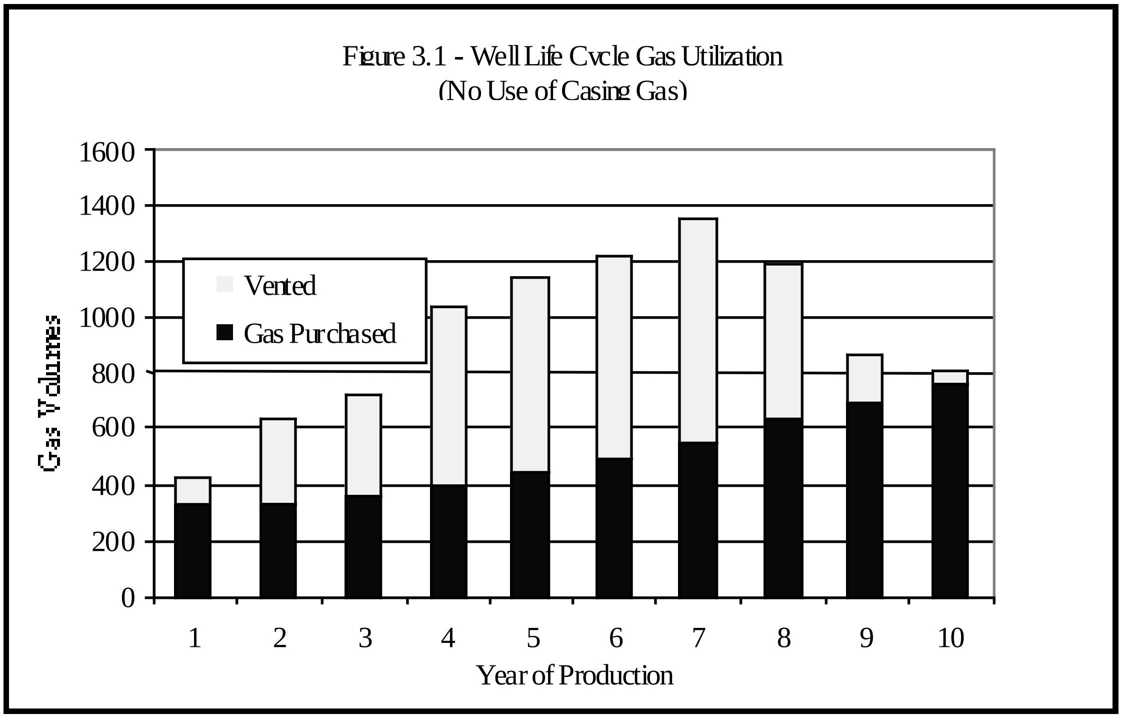


Figure 3.1 - Well Life Cycle Gas Utilization
(No Use of Casing Gas)

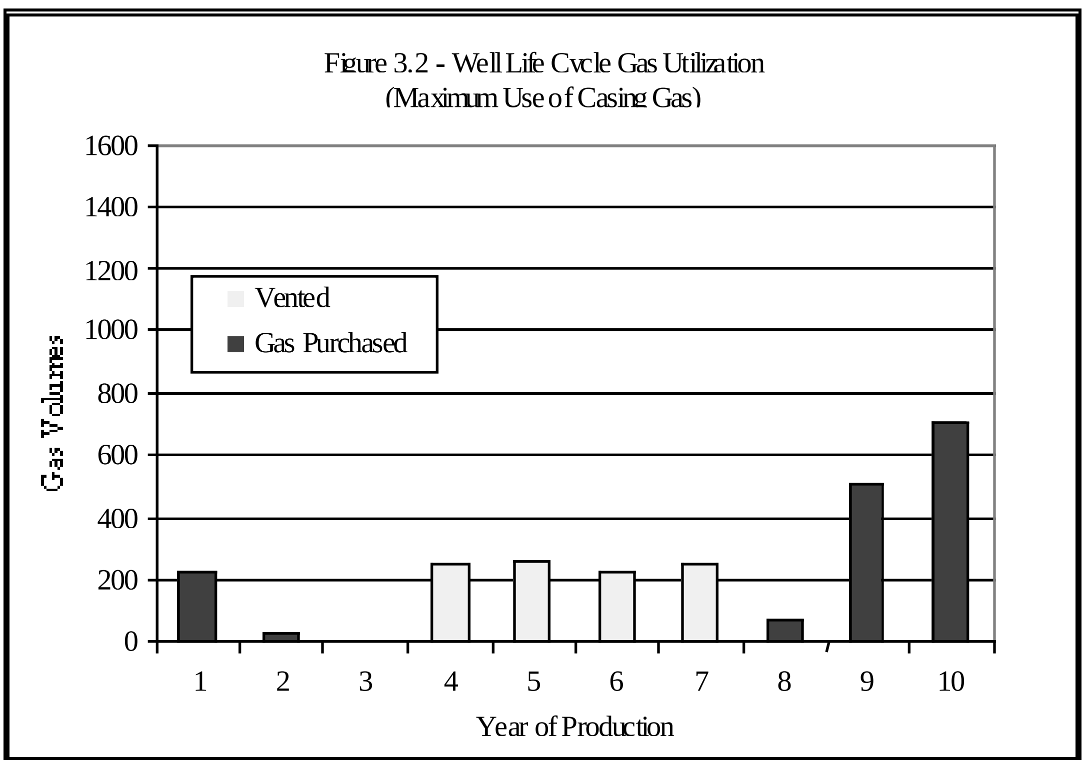


Figure 3.2 - Well Life Cycle Gas Utilization
(Maximum Use of Casing Gas)

3.4.1. Purchased Off-site Energy Required

In most cases the greatest demand for off-site energy to balance site supply/demand will be during initial well operation when there is often little casing gas produced, and at the end of the well life when oil production drops off and casing gas production declines. Initially most of the energy is used for heating oil for treating and to facilitate truck loading. In the later years, most of the energy is used to heat produced water, and reduced oil production causes a significant drop in profitability. In many cases new wells are set up with propane as the purchased fuel supply and then, once production is established, are reassessed to determine if it is worthwhile to bring in a natural gas line.

A basic question for new conventional heavy oil leases is the selection of the driver for the artificial lift system, with the two basic options being electric drive or gas engine drive. In this study we have not conducted a detailed assessment of how this choice has been made by producers in the past, when vent gas use may not have been considered in the decision. We will cover this choice as part of the Permanent Facilities Options and will provide for vent gas use options that support both, using vent gas as the energy source.

3.4.2. Site Energy Self-sufficient

Between the time production is well established and oil production significantly declines, the casing gas production rates can be quite variable in any given well. Currently there is very little long term or continuous gas production data for most wells as vent rates are often only checked on an annual or biannual basis, although the EUB study at Elk point and most field data seems to indicate that GOR's are usually in the 50-100 m3/m3 range. Also reporting of volumes is often for "paper batteries" so some public data base information is not useful for generating production vs. gas volume profiles. However, general indications are that most wells can likely achieve energy self-sufficiency for a considerable portion of their producing life.

3.4.3. Large Site Energy Surplus

In some cases a site will produce at a much higher GOR, than is encountered at other sites. This may be due to the produced oil having a higher in-situ GOR, it could be lighter gravity so heavier components may flash off, or there could be some periodic production from small gas pockets at the top of the pay zone that break-though to the producing well. Or a well may be producing at a very high oil rate with little produced water, so that even at an average GOR the total volume of gas produced is much more than can be utilized on site for artificial lift or production tank heating. Finally, the lease could be a pad of wells, where the small surpluses of vent gas above the lease needs, amount to a larger volume than would occur at a single well battery. This is the type of case where Managed Options should be considered to do something with the surplus gas to generate a new revenue stream.

The selection of the preferred managed options will be covered in Section 6. Generally the managed options would result in production of some form of energy to export, which might be electrical power, natural gas for sales, or incremental oil production from a small scale enhanced oil recovery scheme or production enhancement process. Directionally, the larger the volume of gas that can be produced, or delivered, at low cost to a single site, then the more economic the option will be. Some options generate additional benefits such as reducing foaming, reducing water handling costs, or facilitating sand removal.

3.5. Well Life Cycle and Production Considerations

In looking at various options for vent gas use, the major driving factor for facilities, is the need to be able to adapt the operation and facilities to match the current energy balance conditions, as the well production and vent gas flow characteristics change. As a result we have separated the potential vent gas options into four categories, which are:

Vent Gas Flow Characteristics – This is covered in Section 3.6 as it is an issue that is normally difficult to assess before the well goes into operation, but may prompt a change in the initial well completion or result in provision for options in the permanent facilities in case some action is required. Some options would potentially require modifications that can only be completed with a service rig.

Permanent Facility Options – Are covered in Section 4 and result from or influence decisions made when a well is first drilled, and initial facilities are installed, and affect artificial lift equipment, site layout, lease piping and operations. Generally these options are ones which would be installed and remain with the lease as long as it is in operation. These also might have very little “salvage value” after 5-10 years in operation. Most can be added to existing sites but are more economically provided with the initial installation.

Relocateable Equipment and Operating Options – Are covered in Section 5 and are local equipment or operations decisions which can be made as production progresses and the volume of casing gas produced increases and can be more or less determined for each lease. In response to the energy balance situation, changes can be made, by bringing in relocateable equipment to optimize casing vent gas use. In some cases, simple operating changes may be made to increase vent gas utilization or decrease purchased energy use.

Managed Equipment Options – These options, in Section 6, include larger portable components (power generators, compressors, power lines, pipelines, steam generators for EOR, etc.) that would be moved to leases where they can be most effectively utilized to collect and obtain an economic benefit from large volumes of surplus gas. They may also require strategic decisions for determining which option is best to pursue and can affect well use and overall economic recoveries achievable from each well.

We will cover options in each of these areas that we feel are most likely to have potential as technical and economical successful solutions in one of the many types of operating situations in this sector. Some options have been tried in conventional heavy oil, others have been tried in light oil or gas applications, and still others are new but considered to be valid options for consideration.

3.6. Vent Gas Flow Characteristics

The final major category of factor to consider in looking for a suitable vent gas option is the characteristics of the vent gas stream itself. The major stream is the production casing vent stream, which is estimated to make up 90-95% of the methane emitted from a lease, with the remainder from the lease tank vents. A major reason for many proven vent options not being widely applied is the known, high degree of variability in some vent gas flows and the condition of the flowing stream. The three main characteristics occasionally observed and reported[5] for wells are the need for extremely low casing pressures to increase production rates, the presence of very foamy flow in many wells and evidence that some wells only periodically flow gas and very little gas is available at other times. All three of these characteristics cause problems with vent gas utilization, which is best implemented for streams that flow at consistent rates and consistent pressures, preferably above 15-20 psig. (100-150 kPa)

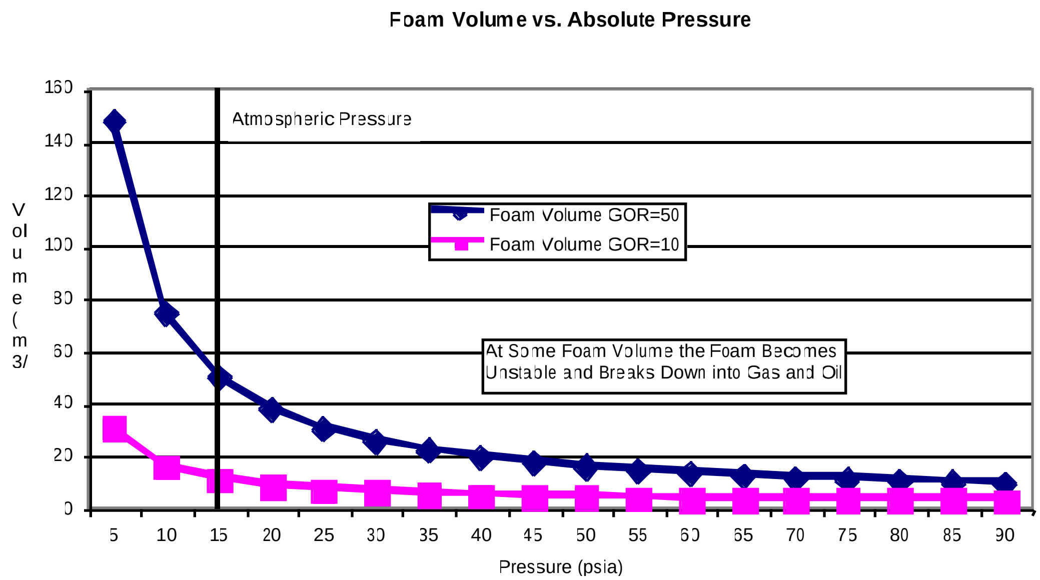
The three sections below are intended to try and offer suggestions to overcome these problems.

3.6.1. Impact of Well Backpressure (Option Sheet 12.3.1)

One of the major problems related to utilization of vent gas is the extremely low well annulus pressure that is maintained on most conventional heavy oil wells. Even 10-15 psi of back-pressure on wells has been shown, in some cases, to impact well production rates and, as a result, it is often common practice to maintain low annulus pressures at all wells. In some areas producers have even installed vacuum pumps to reduce pressure below atmospheric. When venting to atmosphere this does not necessarily have negative consequences but with vent gas recovery options, low pressure venting can add significantly to costs and operating requirements. Also, some companies have had experience where production is not affected by 15-25 psi of annulus backpressure and others have indicated that in some cases they found that even higher annulus backpressures improve production.

However, most areas do have strong evidence that low annulus pressure improves production, even though there is little consensus about why it has this effect. In light oil operations a change in annulus pressure of a few psi would normally not be considered to have much impact on bottom-hole conditions, as it would only result in a slight change in the height of the fluid column in the well (about 1 joint per 15 psi). This should still be true in heavy oil so the change in production observed, we believe, is not likely due to a change in well inflow. What is affected by a small change in pressure, at low annulus pressures, is the behaviour of heavy oil foam (See chart "Foam Volume Vs. Absolute Pressure).

[5] Another source of concern has been periodic reports of liquids in the vent gas, however, we have been unable to find where these liquid volumes are significant, compared to the water which will naturally condense as the vent gas cools. Some operators report that occasionally a "tablespoon" or "cup" of heavy oil might come out the vent but these events are often reported after well annulus loading or flushing operations.



Foamy flow has been established as a source of anomalously high oil production rates and recoveries from some Lloydminster type heavy oil reservoirs[6]. Naturally occurring foams, like those encountered in conventional heavy oil operations are very difficult to predict or characterize. Their formation, stability and breakdown are affected by factors such as formation pore size (sets gas bubble size), flow rates, solution GOR, time, pressure, temperature, oil viscosity, the presence of small amounts of solids and/or chemicals which might stabilize the foam film. While the formation of stable foam in the reservoir appears to dramatically increase production rates and recovery, that same stability will cause problems in producing the oil from the well and separating the gas from the oil. The properties of foam and their effects on production may help explain the wide variation in operating experience regarding the impact of annulus pressure on production. With three potential results:

a) Foam breaks down at pressures above 20-25 psia annulus pressure – This would give the "normal" conventional oil situation where small changes in annulus pressure do not affect production. This would result in little change in production with annulus pressure and no foam problems in the production tankage.

b) Foam breaks down at 15-20 psia – This is reasonable as the foam volume will double as pressure drops from 30 to 15 psia, while foam bubble surface area will increase by 60%, increasing the probability that the foam will break down, especially at high GOR's. This would result in a significant change in production

[6] See "Role of Nonpolar Foams in Production of Heavy Oils" by Brij Maini and Hemanta Sarma published as Chapter 10 in "Foams – Fundamentals and Applications in the Petroleum Industry" American Chemical Society, 1994; Editor Laurier L. Schramm now at Alberta Research Council.

to surface (as a result of a large change in pumping efficiency) with a small change in backpressure, as the pump would either be pumping mostly foam or mostly oil. In this case even 1 or 2 psi may make a considerable difference in how much foam will break down in the annulus. While the foam is stable it will appear as though there is a high fluid level in the well.

c) Foam breaks down at <15 psia – In this case the options are to either reduce pressure below atmospheric with a vacuum pump (foam volume will double again between 15 and 7.5 psia), or increase the annulus pressure to shrink the foam volume so that it can be efficiently pumped to surface where the addition of heat in production heating will cause the foam to break down at a higher (atmospheric) pressure by weakening the film strength. This could show an increase in production at increased annulus pressure, as the pump would be able to move more production out of the well and lower bottom-hole pressure to allow more inflow.

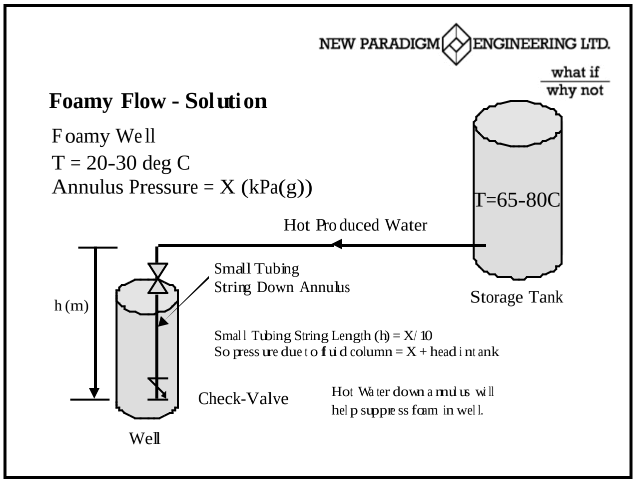
Based on the above it can be seen that establishing the foam break down characteristics of a given well is important to determining the optimum annulus pressure to maximize production. Where the foam breaks down also affects the gas distribution from the well since if the foam breaks down in the production tank the gas will be emitted from the vent, while if it breaks down in the well it will be emitted from the casing vent. Since each well, and even production from separate formations or strata in a well, might have different foam characteristics it is important to establish the specific well behaviour to facilitate decisions on vent gas mitigation.

Option sheet 12.3.1 describes a method of testing a well to try and determine the production/annulus pressure relationship, and determine where the gas is going so that better decisions can be made for handling the vent gas.

Future Project #1 - Further Research and Study by Producers: Producers should consider conducting testing based on 12.3.1 in their operations to better characterize the relationships between foam in the well and production. This may be helpful in determining better ways of breaking down foam to stabilize the vent gas rate and to reduce the costs associated with vent gas use. It may also indicate methods to allow increased oil production from foamy wells.

3.6.2. Foamy Flow Options (Option 12.3.2)

As covered in Section 3.6.1, foaming is a common production problem in conventional heavy oil. While foam generation in the reservoir can significantly increase oil production into the well it also result in loss of some of the benefits due to: a) loss of pumping efficiency, b) loss of effective tank storage capacity on the lease; and related problems due to the difficulty of breaking down foam in a storage tank. Another impact is that periodic generation of stable foams in the well can impact the flow of the casing gas, as gas will be diverted with the foam into the tank and eventually exit through the tank vent. Reducing annulus pressure is one method of breaking down foam, others require heating, addition of chemicals or providing more time for foam breakdown to occur. Given the availability of vent gas energy on the lease heating is an option to low annulus pressure. Breaking the foam downhole provides additional benefits.



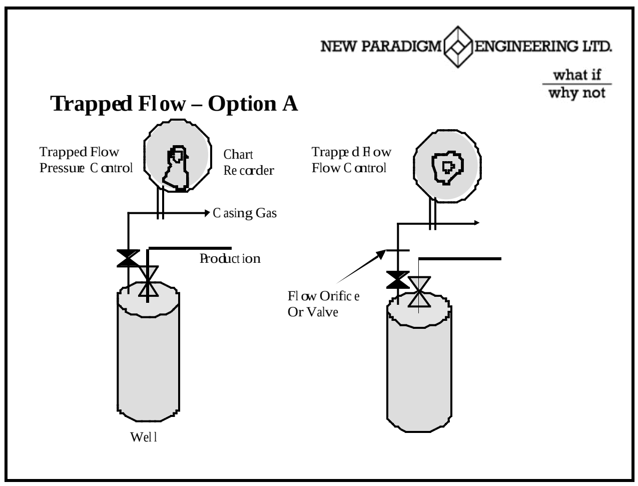
The diagram shows how hot water from a lease tank might be gravity fed into the well annulus, even if the annulus is not at atmospheric prssure. The hot water will warm up the foam down hole and will also wash it, which will enhance foam breakdown. The water flow required may be quite low but testing will be required to gain a better feel for this. Water injected must be pumped again to surface but is not consumed so there would be no net change in water production from the well, even though more water is going through the pump.

An additional option could be to add a line heater (Options 12.4.4 or 12.4.6) to further boost the water temperature before it enters the well and provide more energy to reduce foam with less water. A pump could be used to recycle water, if the well annulus pressure is very high or if, for some reason the annulus (macaroni) tubing string can't be used. Some producers have been reported to use produced oil cycle down the annulus to assist with lifting sand to surface, so there is a precedent for this type of solution to a production problem. This option might also replace the current practices of periodically "flushing" or "loading" the well annulus with trucked fluids, which can disrupt vent gas flow and requires production accounting adjustments if the loading or flushing fluids come from another well.

Future Project #2 - Further Research and Study by Producers: Producers should consider conducting testing to assess the option of recycling produced water to control foam down hole. Tests could be similar to those outlined in Option 12.3.1 but with the addition of warm or hot produced water in Day 2. Initially this could be done with a portable pump, with trial of the simpler tubing system after a better understanding is reached of the water volumes and temperatures required to affect foam in a well.

3.6.3. Trapped Gas Flow Options (Option Sheet 12.3.3)

Occasionally wells will show a tendency for vent gas to only flow periodically. This may indicate that the gas is separating in the reservoir and building up behind the casing. Over some period of time the gas pressure will build up to the point where it can force its way into the upper production perforations. Once flowing the gas pocket will de-pressure until oil production can force its way in to block the gas flow again. This may result in wells only flowing significant amounts of casing gas for a few hours a day, and may also lead to periods, after well work-overs or other changes in operating conditions, where little casing gas flow will occur. This periodic flow will likely still average out to a long term steady GOR, however, the flow characteristics make it more difficult to utilize the vent gas. Periodic flow is often given as a reason to not use casing gas, as it is very difficult to design a simple facility to handle periodic gas flows, especially when many of the potential uses for the gas require a steady and continuous supply to operate effectively.



The diagram shows the option to add an orifice to the vent gas stream to provide coarse regulation of vent gas flow and use the casing annulus as a gas surge bottle, as an alternative to maintaining constant backpressure on the well, which is the normal practice. Backpressure would then vary instead of the flow. A simple orifice may be better than a more sophisticated flow controller, as it also vents at a higher rate if pressure increases.

Other options might be to:

Increase the pumping rate, if possible so that the gas will continuously cone into the well rather than only enter periodically.

Add one or two perforations higher in the well or ensure that initial well perforations reach the top of the formation so there is no potential for a gas chamber to form.

If a multi-well pad or a system of single wells is linked with a low pressure pipeline, the gas surges may be taken up by the system to minimize the problem.

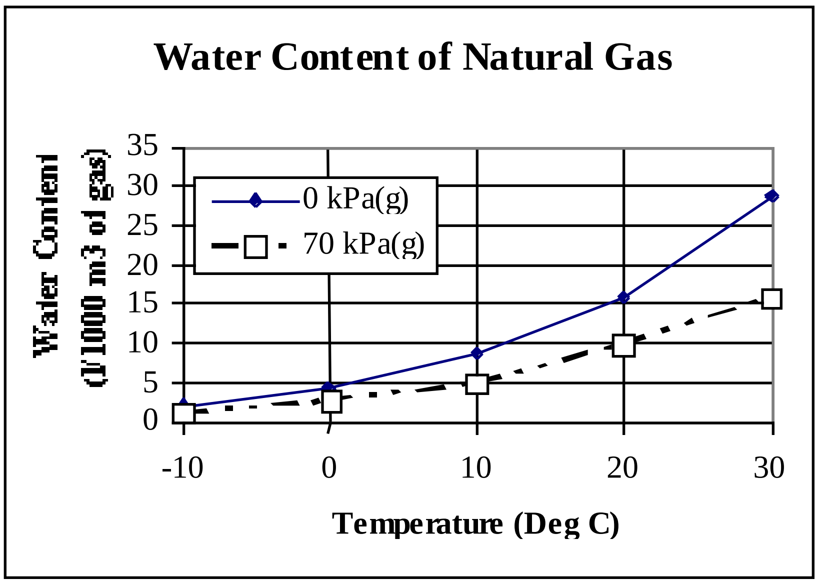
Future Project #3 - Further Research and Study by Producers: Producers should consider conducting testing to assess the option of using a flow regulation orifice on wells that exhibit the trap flow type of behaviour. Tests could be similar to those outlined in Option 12.3.1 to determine how the flow and production behaviour is affected.

4. Permanent Facility Options

As explained above, this section will look at options, which would best be considered for the life of the well operation, and would likely have little salvage value at the end of 7-10 years of operation.

4.1. Insulation and Dewatering (Option Sheets 12.3.4 and 12.3.5)

A major concern with casing gas utilization is that the casing gas lines might freeze off, or liquids could damage key equipment such as engines or burners. There is some indication that occasionally some small volumes (teaspoons to cups) of fluid may be produced from a well through the annulus vent, however, most indications are that the main source of fluid in the casing gas stream is from condensation of water contained in the vent gas. While this volume of water is small (see chart[7] below), it can build up and cause lines to freeze-off in cold weather or can cause slugs of fluid to enter fuel lines to engines. This option is really just an indication of some basic design features that should be used to avoid water related problems in casing gas systems.



Insulating Lines on the Lease (Option Sheet 12.3.4) – Small amounts of water vapour in a gas stream generally do not cause any major problems with combustion systems, with the main effect being a slight reduction in gas heating value, due to the presence of the water. As a result the best solution to avoid water problems is to prevent the gas stream from cooling off and causing liquid water to form. As can be seen from the above chart reductions in pressure as the gas cools will allow more water to stay in vapour form. Note that the water in the gas will be generally be set by the last condition in which liquid water and gas were in direct contact, so gas separated from liquid water at a high pressure can

[7] To use the chart – the volume of water condensed from a stream = water content at starting condition – water content at final condition. e.g. at a constant pressure of 70 kPa about 7 litres of water would drop out if the temperature of 1000 m3 of gas fell from 20 degrees C to 0 degrees C.

be cooled further without liquid water formation, if the pressure is also reduced (also see Option 12.5.1 on Manipulating Conditions). Even if water forms it can't become a freezing problem unless the gas stream is allowed to cool to a temperature below the freezing point, and if the ice that forms results in a solid ice plug that blocks gas flow or causes freeze-up of a gas control or regulator. Because of this we would recommend that all (especially above ground) lines that might be used to carry casing vent gas be insulated. There are several options for heat tracing the lines (covered in later sections), but gas lines can be insulated with other lines carrying warmer fluids, such as hydraulic lines or production lines, at relatively low cost. Gas lines can also be insulated to the production tank and an insulated housing can be used to keep piping around controls and regulators warm. Some options are shown at the end of this section and in Option sheet 12.3.4.

As a basic component of this option it includes the installation of any new piping that may be required to bring the casing gas to the engine or tank that will be burning it. Many leases only are equipped with vent valves at the wellhead.

Dewatering Lines (Option Sheet 12.3.5) - In some cases water will form and gradually build up in any low points in a line. If the water completely fills the line then it may freeze as a solid plug and stop gas flow, while a layer or small amount of flowing water may freeze and gradually build into a plug over a longer period of cold conditions. Avoiding undrained low points in lines will help to prevent frequent losses of gas flow by keeping the lines (especially above ground) free of liquid water. Eliminating liquid water build-up also reduces problems which liquids can cause in burners and engines even in warm weather, which could include extinguishing pilot or main burners in fire tubes, thermal shocking of hot fire tubes, or damage to drive engines.

Unless the water volume to be removed is very large, it is often possible to avoid having to install separator vessels by utilizing the separation that will occur in the gas lines and venting the liquid water with any surplus, or a small amount of, casing gas. Since this water is being vented when no casing gas is being used for fuel, continuing to vent the water while using the casing gas should not result in any incremental environmental concerns, and condensed water from sweet, low pressure gas streams should be of little environmental concern. Ideally the best strategy is to have the water in the lines drain to a location that stays warmer than ambient conditions and preferably above freezing, and separate the water at that point. Provision can then be made for either manually or mechanically draining the water off. Some examples of simple piping designs to preferentially purge liquid water from piping are shown on the option sheet. Since the main concerns are in protecting the operation of burners or engines, the main focus should be to try and minimize all water, liquid or vapour, entering the fuel gas systems. This also reduces the load on other winterization systems that might be installed to protect lines from freezing.

A special case for dewatering is for fuel lines to tank heaters, especially underground lines. Option sheet 12.3.5 shows how water builds up in an underground gas line to a tank heater. The gas line at the tank end, right up to the burner will, over days or weeks, become full of water with the fuel gas bubbling through it. If there is no provision made for draining this line the only place for the condensed water to go is into the fire tube burner, and if the line reaches freezing conditions the water will freeze as a plug and stop gas flow to the burner. The water build-up also increases the pressure that is required for the gas to reach the burner, as the gas must overcome the head of fluid in the line (10-15 feet of water head will add 4-6 psi or 30-45 kPa to the gas pressure required to use casing gas in addition to what is required for the burner operation). Freezing in this area, usually soon after ambient temperature drops below 0 degrees C, is the situation most commonly reported and removing the ice plugs that form is a major problem for the operators. To eliminate water build-up in this area we suggest the installation of a “straw” that can be used to drain water from the warmer, underground portions of the fuel gas line. Combined with insulating above ground portions, this alone should extend the use of casing gas and reduce flame-outs in burners or other fire tube problems caused by slugs of water when gas flow rates change. Adding a small orifice to the straw outlet to allow continuous venting would reduce the requirement for operators to check for water build up. The straw can be located at either end of the underground line but preferably at the low point, and with the low point at the well end of the fuel gas line so that any gas is vented away from the tank.

4.2. Pump Drive Engine Options

For leases where the artificial lift system is driven by a gas-powered engine, the casing gas can be used for engine fuel. Several producers indicate that they use casing gas year-round in engines by using hydraulic hoses and insulation to keep the vent gas line from the wellhead warm. This section covers issues related to how the casing gas is provided to the engine and potential use of waste engine heat and also the case where the pump drive is an electric motor.

A technical comparison tool for the three main pump drive options is included in 11.4.2.2.

Engine Fuel Treatment and Make-up Gas (Option Sheet 12.3.6) - Gas engine drives are the easiest to adapt to vent gas use, or to other fuels, as all that is required is a small amount of piping and provision for freeze-protection and removal of any liquid water. Engines require higher capital expenditure up-front, compared to electric motors, and normally also have greater maintenance costs with lower pump availability at any given lease. If external energy is required, then some method is needed to transport gas (methane or propane) to the lease. Capital requirements for fuel supply depend on who is providing the supply system, so could be paid for up front by the producer, or paid for by the producer as a hook-up fee charged by a supplier and recovered over a number of years. Energy costs for the fuel would be over and above the hook up fee and would likely be the main variable cost based on demand, location and the specific contract terms negotiated with the supplier.

Since casing gas is generally very similar to purchased natural gas, substitution or displacement of purchased gas from existing leases is relatively straight forward. A simple control system (see Option Sheet #12.3.6) can be installed to preferentially utilize casing gas, with line gas as a make-up fuel. Since oil production is affected by engine downtime, it is best that the system be set up so that the engine continues to run if the casing gas supply is interrupted by freezing, loss of casing gas during well annulus flushing operations, or a reduction in casing gas available from the well. With natural gas as the make-up fuel blending of casing gas to purchased gas is not a major concern, so can be considered even if there is insufficient casing gas to supply the entire engine demand.

If the alternate fuel supply for a lease is propane, the situation is not the same as propane gas has a heating value considerable different from natural gas (2500 BTU/ft3 vs 1000 BTU/ft3) and also, especially in winter, it will be supplied at a much colder temperature that will approach ambient air temperature. Vendors indicate that no change in operation (except fuel feed pressure) is required to switch from 100% methane to 100% propane for an engine, however, installing a control system, similar to that where natural gas is the make-up fuel, could result in an highly variable blend of methane and propane being supplied to the engine at a pressure suitable for 100% propane, which will significantly impact engine operation and might also cause longer term maintenance problems due to potentially rapid changes in engine fuel heating value. There is also a concern that without adequate preheating of the propane in cold conditions, blending of casing gas and propane may cause ice to form in the fuel supply system and result in engine shutdowns. There are options for propane/air blending (Option sheet 12.4.8), however these systems may be expensive for the short periods of time when the engine might see a blended vent gas/propane stream. We recommend that the choice of engine fuel, where propane is make-up, be kept as an either/or situation with the fuels manually switched. Therefore, casing gas use in engines would be limited to sites where there normally is sufficient casing gas to meet all the engine fuel demand, and where disruptions to the casing gas supply can be minimized.

In using casing gas or even non-commercial quality line gas supplies, it is recommended that a small separator be used upstream of the engine to ensure no liquid slugs can enter the engine. With insulation and dewatering as described in section 3, there should be very little liquid collected and this separator can operate at very low pressures and blending natural gas streams. If the separator is exposed to ambient temperatures, the engine fuel gas controls and separator should be housed or insulated and heat traced to prevent any possibility of freezing.

Engine Coolant for Engine Fuel Heating and/or Tracing (Option Sheet 12.5.4) - For gas engines approximately 1/3 of the fuel energy supplied results in the generation of waste heat (this does not include energy lost to the engine exhaust with is about another 1/3 of the input energy). Some of this waste heat is radiated from the engine components and can be used to keep an engine shack and any nearby piping or equipment warm and some is collected by the engine coolant and dissipated through the radiator. This creates the opportunity to utilize the engine coolant as a heating fluid to pre-heat engine fuel or to trace other production or fuel gas lines to the lease tanks. A line tracing system has been installed by one producer, on some new leases, and initial reports are that it is operating well. Another operator has used the engine coolant to heat a separator vessel. A key factor is to ensure that any potential for engine coolant leaks, from additional fittings, is minimized to avoid overheating, and to ensure the engine does not become over cooled. Work is still required to determine how much energy might be taken from this source and priority for use of the energy. Initially it is assumed that keeping the engine and engine fuel supply warm will be the first priority if the engine is operating on casing gas. If casing gas is used for tank heating there may be enough heat available to trace the above ground fuel gas lines to the tank heater and might even be enough to supply some production line tracing and heating.

Generator Set to Electric/Mechanical Drive (Option Sheet 12.3.7) - Many sites in conventional heavy oil operations have electric drives for the artificial lift systems. The decision to utilize electrical energy is usually based on factors such as relative cost and availability of power vs. an alternate fuel, and lower maintenance costs and operator attention for motors vs. engines. Once sites are electrified there is also the option to add features such as remote monitoring. All these factors essentially come down to increased availability and increased production days for the producing wells. The downside of electrification is that utilizing vent gas for the artificial lift becomes more of a challenge, and it makes it very difficult to proactively respond to large fluctuations or increases in power costs. This option addresses artificial lift systems where the electric drive is directly coupled, mechanically, to the pump system and where it would be difficult and expensive to alter the drive system. Examples are: electric drive beam pumps; PCP systems with the motor mounted on the wellhead driving the rods; and electric submersible pumping systems (ESP or PCP) where the motor is located downhole.

This option consists of installing a small, gas engine driven power generator (likely a recip engine genset see Option 12.8.5) on the lease and connecting it to provide power to the on-lease equipment, with energy supplied by the vent gas, but with the ability to switch to line power if the generator goes down. This would not eliminate the cost of maintaining the power supply and lines, but may be able to backout the variable energy use component of the cost. The system can be installed so that the drive would switch to line power if the generator goes down, so reliability should not be reduced and may even improve if the well is in an area where line power supplies are dependent on a single supply line, which might result in power outages due to electrical storms or other events on the grid. The maintenance costs for the generator engines should be lower than for gas engine driven systems alone as maintenance can be done on a routine schedule and repairs or shutdowns could be responded to on a planned basis instead of with callouts or with extra costs for expediting work to restore production. This option would not include the ability to send power into the grid.

Parallel Gas/Electric to Hydraulic Drive (Option Sheet 12.3.8) - Some sites use electric motors to power hydraulic lift systems. The use of the hydraulic energy transfer system allows for use of vent gas without the need to first generate power. Standard gas engines commonly used for PCP/hydraulic drives may be set up in parallel with the electric drive so that either system or, potentially, both, could be providing power to the artificial lift system.

This option consists of installing a vent gas fueled conventional gas engine/hydraulic drive in parallel with an electric drive. This would not eliminate the cost of maintaining the power supply and lines, but may be able to backout the variable energy use component of the cost. The system can be installed so that the electric drive would start up on loss of hydraulic pressure or if the gas engine goes down, so reliability should not be reduced and may even improve if the well is in an area where line power supplies are dependent on a single supply line, which might result in power outages due to electrical storms or other events on the grid. The maintenance costs for the gas engines should be lower than for gas engine driven systems alone as maintenance can be done on a routine schedule and repairs or shutdowns could be responded to on a planned basis instead of with callouts or with extra costs for expediting work to restore production.

Future Project #4 - Further Research and Study by Producers: Producers should consider conducting testing of the two systems proposed to reduce electrical power consumption to identify any operational or other issues that need to be resolved and to more closely examine the potential economic and reliability issues.

4.3. Production Heating System

The most obvious use for casing gas on a conventional heavy oil lease is for production heating. The primary method of heating, currently used, is a fire tube tank heater. A major factor in evaluating heating systems is the relative thermal efficiency, flexibility in operation and continuous operation to allow the maximum use of vent gas.

A technical comparison tool for comparing the main production heating options is provided in 11.4.2.3.

Fire Tube Heaters (Base Case – Option Sheets 12.4.1 and 12.4.8) - Flame arrested fire tube heaters are well known in conventional heavy oil operations due to their low cost and simple control system. However, they are also known to often be fuel inefficient as there is very little ability to control or monitor the combustion, and the properties of the produced oil and sand can have a significant effect on heat transfer to the production. Operation of the burner is usually controlled by a temperature switch in an automatic on/off mode or manually adjusted by operators at a given site. When the burner is on pilot or the flame is out there will also be a considerable amount of heat lost from the tank due to the continued flow of air through the fire tube and induced by the chimney effect of the heater stack. As indicated earlier overall efficiencies are usually used to assess performance, but these are very dependent on production levels, ambient conditions and the amount of time that the burners are actually in operation.

Some producers experience high rates of fire tube failure and there is little to adjust to allow for better combustion and flame control. Use of casing gas in tank heaters, especially during summer months, is a fairly common practice for some producers who are able to supply casing gas at a pressure sufficient for burner operation. As indicated in section 4, water condensation in the fuel lines may affect burner and fire tubes even in summer operations, while freezing is the major concern in winter.

As in the case of engines, the displacement of purchased gas with casing gas is relatively straight-forward for fire tube tank heaters and the two streams can be blended without significantly affecting burner operation. Also, for the same reasons as in the case of engines, there are impacts of blending methane and propane in these heaters with some strategies for this covered in Option Sheet 12.4.8. For heaters switching fuels requires a change in the orifice in the fuel gas supply feeding the burner to adjust the gas flow rate to match the fuel's heating value. Feeding propane into a burner with an orifice sized for natural gas would result in over firing and increase the potential for tube burnout and failure, as the heat generated would be much higher than design. Feeding methane gas to a burner set up for propane would reduce the amount of heat delivered by the burner. Normally operators are required to change the orifice in the fuel line when they change fuel type.

Enhanced Fire-Tube Controls (Option Sheet 12.4.2) - Often producers have a few standard sizes of burners installed on their leases – they are not specifically sized to match the heat load requirement based on the production of each well. The heat load varies from well to well, and also over the life of each well. In many cases there is a mismatch between the heat load required, and the burner output. This results in the burner cycling between full fire and pilot, rather than running continuously which is preferred. Over the life of the well there is a requirement to be able to adjust the burner output to optimize the use of casing gas and minimize burner cycling.

Typically the greatest demand for purchased fuel is in the last years of production. This is when oil and gas volumes drop off and the majority of the production is water. Water generally requires twice as much energy to heat as it would take for an equivalent amount of oil, while the benefits of heating the produced water are minimal.

While on an average basis there is sufficient casing gas to meet the average heating needs, the cyclic operation of the burner between full fire and pilot results in casing gas being vented when the burner is on pilot and additional fuel being purchased when the burner is on full fire. If the burner can be changed or adjusted to a continuous, lower rate, firing mode (perhaps with a high tank temperature shut-off), then use of casing gas is optimized. Methods of modifying the heater operation might consist of a combination of the following considerations:

Reduce Tank Temperature Set Point - An operating strategy to reduce tank temperatures as casing gas volumes decline would help to minimize purchased fuel use. For oil treating and loading it would likely be possible to just increase the tank temperature for one day a week prior to oil loading.

Manual Fuel Flow Control - Another consideration to reduce purchased fuel is to adjust the fire tube heater to a lower combustion rate that is more or less continuous. Typically burners have turndowns in the range of 3:1 – 5:1. If the burner fuel tree/manifold has an adjustable pressure regulator, the pressure can be adjusted, within manufacturer specified limits, to offer some adjustment of the burner output. The pressure can be increased or decreased as required depending on whether more or less heat is needed. The burner will have some maximum output determined by heat transfer from the firetube and safety considerations, and some minimum required to maintain the flame reliably.

Proportional Fuel Control on Temperature - A more advanced control system would allow automatic adjustment of the burner output and level off burner cycling. A proportional temperature control (instead of on/off control) and a control valve on the burner fuel line would be required. Electronic and pneumatic systems are available. The level of adjustment would still be limited by the burner turndown.

Install a Different Size of Burner - If the range of adjustability of the burner output does not match the required heat load for continuous fire, then another option is to install a smaller sized burner.

Future Project #5 - Further Research and Study by Producers & Vendors: Producers should consider conducting testing of various types of heater controls if they have not already done so, and with the view of leveling fuel gas demand so that vent gas use can be optimized.

Thermosyphon Systems (Option Sheet 12.4.3) - Thermosyphon heaters are an indirect heat transfer system, which utilizes an external burner and a bank of heat pipes, or thermosyphons, to heat production inside a storage tank or other process vessel. They are an alternative heating system to conventional burners and fire tubes for use in storage tanks and treaters, and can operate with low pressure <1/2 psig fuel gas, but are limited by their cost to systems that are over about 1 MMBTU/hr. At least two trials (PanCanadian and Husky) of these systems have been done for tank heater applications and others have been carried out for horizontal treater applications.

Catalytic Tank and Line Heaters (Option Sheet 12.4.4 and 12.4.5) - Catalytic Heaters have been commonly used throughout the oil and gas industry for hazardous area space heating. These options are based on using catalytic heaters to heat the production in the flow line before it goes into the storage tank, or heat it in the tank and keep the contents of the tank warm. This is a replacement option for firetube heaters which has the advantages of being modular and units designed for Class I Div I use could be used anywhere on the lease so lease size may be reduced by total replacement of firetubes. These systems are of greater benefit where production rates are low.

The catalytic line heater can handle the main part of the load. Several options are available for maintaining the temperature of the tank contents: 1) a small pump to recirculate fluid through the line heater; 2) catalytic tank heater(s) mounted on the tank wall preferably near truck loading nozzles and the bottom of the tank; or 3) a long and narrow catalytic heater unit designed to slide into a standard or enlarged firetube that would heat the tube wall.

These units also have an advantage for handling foam as the line heaters can preheat production before the tank to assist in foam breakdown or tank wall catalytic heaters could be mounted in the upper portions of the tank to specifically provide heat to floating foam.

New Paradigm Engineering Ltd has conducted trials of the line heater and is continuing with this work, which is being supported by Husky.

Fired Line Heater (Option Sheet 12.4.6) - Line heaters are commonly used in various applications in the conventional oil and gas industry such as hydrate prevention for gas, wax prevention in some oilfields, and oil/water separation as heater treaters at batteries. They could also be used as an alternative for production heating on heavy oil leases.

Co-Generation (Option Sheet 12.4.7) - The flue or exhaust gas from pump drive engines and/or power generators represent a significant recoverable waste heat source that could be used to heat production backing out purchased fuel for burners. The main cost for use would be the cost to provide the heat transfer equipment. The main limitations focus on the corrosion problems, which might occur if exhaust gases are over cooled.

Future Project #6 - Further Research and Study by New Paradigm Engineering Ltd.: Production of sand in the early stages of well production has led to concerns that heating production in a line heater (catalytic or fired), upstream of the tank, could lead to plugging of lines from the well due to sand fall out. New Paradigm is currently working on a small project funded by Husky Oil to determine if this is a problem for the catalytic line heater. This work has potential to be expanded into a study to determine methods of desanding upstream of the tank as an option to try and reduce sand clean-out costs and also to potentially allow for heavy oil pipelining in support of C-FER Technology Inc's Heavy Oil Gathering System (HOGS) project, which New Paradigm was previously involved with. Sand handling and management costs were raised as a significant issue at a PTAC Heavy Oil forum in June, 2000 and this is supported by discussions New Paradigm has had with pumpers in the field.

4.4. Odour Mitigation Options

The two main sources of vent gases on a typical lease are tank and casing gases. Indications from both producer participants and the AEUB are that there are very few instances where odour issues have been raised, associated with non-sour venting of conventional heavy oil, as the gas emitted is mainly methane which is odourless. The only indication was that odours may be caused if the tanks were heated to temperatures in excess of 85-90 degrees C, in which case heavy hydrocarbons would be emitted. Data from the case study (see 7.2.2.) indicates an average tank vent rate of only 10-20 m3/d. Odours have been raised as an issue during EUB hearings, but mainly based on reports from other conventional oil or sour gas production areas. In conventional heavy oil operations only odours from truck pits have been mentioned as a concern.

Even though this does not appear to be a problem in conventional heavy oil, some effort was put into identifying options if this ever becomes an issue, as the consequences of chronic odour complaints would be high (production shut in) so options need to be available in case they are even required. The gases are composed mostly of methane vapors. Odour causing components might be sulphur containing hydrocarbons, or heavier components, that may escape from tank vents if the tanks are over-heated. There are currently are no sample results that have identified the odour causing components. This makes the design of removal equipment more difficult due to the lack of definition of the components to be removed. The following solutions are proposed to treat, contain or dilute the casing gases from the tank vents and a technical comparison is provided in 11.4.2.13:

Option Sheet 12.11.1 Vapour Recovery – Conventional system with casing gas as make-up.

Option Sheet 12.11.2 Tank Vent Condenser – Condense heavy ends in any odour causing vapours coming off a hot tank.

Option Sheet 12.11.3 Incinerate in Fire Tube – Potentially could educt tank vent vapours into the existing fire-tube burners along with the combustion air.

Option Sheet 12.11.4 Catalytic Conversion – Catalytic heaters fueled by casing gas to convert any heavy hydrocarbons in the vent stream to carbon dioxide.

Option Sheet 12.11.5 Dispersion – Increase atmospheric mixing to reduce concentrations of odour causing components to the point where they are not detectable.

Option Sheet 12.11.6 Liquid Contacting – Contact vent gases with an “oil sponge” to absorb any heavy components which might cause odours.

Option Sheet 12.11.7 Activated Carbon Adsorption – Use activated carbon to adsorb odour causing components.

5. Relocateable Equipment and Operating Options

This section includes options that involve equipment which can be fairly easily relocated between sites with minimal impact on operations, or that only involve changes in operating procedures to allow optimal use of casing gas as the well production and site energy balance changes. These options are key to achieving significant operating cost and emissions reductions and will often be the highest payout. Section 5.1 focuses on the issue of getting the gas to the burner; Sections 5.2-5.5 look at winterization or utilizing gas for heating at low pressures; Section 5.6 looks at options to optimize operations through the wells life; and 5.7 looks at methods to reduce GHG emissions from any methane that can't be used for fuel displacement or other uses. Individual Site Compression Options are compared in 11.4.2.4; Individual Site Winterization Options are compared in 11.4.2.5 and Methane Conversion Options are compared in 11.4.2.14.

5.1. On-site Fuel Pressure Adjustment

In cases where a high backpressure can be held on the casing annulus, pressure adjustment may be a viable option to prevent or reduce water formation and line freezing. As was shown earlier a gas at higher pressure can hold less water in vapour form than a gas at low pressure. Therefore there is an opportunity to manipulate conditions to allow year-round vent gas use without any need for anything except the insulation and dewatering systems described in section 4.1 (Option Sheets 12.3.4 and 12.3.5). This option is generally described in Option Sheet 12.5.1.

Compression options are required where the pressure available at a site is insufficient to provide vent gas as fuel to the production heating equipment. As these casing gas options tend to be quite expensive, producers should be sure that increased back pressure (20-30 kPa(g)) actually does affect production (See Option 12.3.1).

Ideally, to minimize capital costs the system selected should be able to take power off an existing pump drive engine and is best done when there is a surplus of vent gas at a site and no opportunity to make use of a surplus for anything but conversion. Since the compressor will likely operate off an existing drive the throughput is going to be set by the speed of the drive engine and the compressor operating characteristics. For on-site fuel use the differential pressures required are very low, as are the gas volumes, so the incremental load on the pump driver is often within an acceptable range. Key factors for selecting a compressor should be to minimize the impact on the artificial lift availability to avoid production losses and maintenance costs. If the drive engine is operating on casing gas there would be little incremental cost to operate the compressors but the horsepower needed would have to be included in the site energy balance. If the engine is operated off purchased fuel then there is an incremental fuel cost.

As the options are all positive displacement systems, gas which isn't compressed must be vented upstream of the compressor, gas that is compressed and not used must either be vented downstream of the compressor or recycled to the suction. Since both vent gas flows and site gas demands for production heating can vary dramatically, in a short period of time, the compressors should be sized to handle a relatively large and constant feed stream. Care needs to be taken, especially if the casing pressure is near atmospheric, that air is not being drawn into the compressor through the suction piping, and the compressor feed piping should be designed to ensure that liquid slugs are avoided. The gas discharging from the compressor will have been heated through compression, which would likely provide enough heat to protect against winter freezing in the lines to the tank heaters, if the lines are adequately insulated, traced and dewatered, as indicated in section 4.1.

Three main types of compression system are normally considered in this flow and pressure range.

Reciprocating Compressors (Option Sheet 12.7.5 or 12.7.6) - The majority of compressors used in this application to date are generally those that can be operated off of the artificial lift drive. The main difference between the two options are that 12.7.5 is shown operating off a pump drive while 12.7.6 is stand alone and could be used at an electrified site where no gas engine drive is available.

Rotary Vane Compressors (Option Sheet 12.7.1) – Option covers systems supplied with a separate drive. These units are better to able small amounts of fluid so might be preferred for this application.

Beam Mounted Gas Compressors (Option Sheet 12.7.2) **–** Mainly for wells with pumpjacks.

5.2. Catalytic Heaters

Catalytic heaters now have been demonstrated in the field using casing vent gas as fuel. The characteristics of these heaters are that the combustion occurs at a much lower temperature than flame combustion so they can be located in hazardous areas; the heaters once started will continue to operate as long as fuel is supplied; operators are familiar with operation as they are the same as many of the heaters used in the oil and gas industry for process building heat; heaters only require fuel at less than _ psi pressure. The primary advantage is that these heaters require little or no routine operating attention or maintenance.

Winterization Heaters (Option Sheet 12.5.2) - One option for utilizing catalytic heaters is for heating fuel gas to tank heaters to prevent freezing. The heaters can be installed on any straight section of vent piping and will heat the gas sufficiently to help maintain water in vapour form and to keep the fuel gas stream above ambient conditions. These can be used for wells where there is sufficient pressure to operate the tank fire tube heaters in the summer, and the only concern is with fuel line freezing. Heaters can be started with 12V power from the pump drive engine battery or an operator vehicle battery.

Line Heaters (Option Sheet 12.4.4) - In situations where it is desirable to maintain a low well annulus pressure, where it is impractical to blend fuels, extra heat is required for wells with high foam production, or where short-term supplemental heating is required for a lease, a catalytic line heater may be used. This unit can be installed to heat the production stream, while it flows through an above ground production line, either at the wellhead or at the tank inlet. The heaters are portable and can be moved between sites as the heating loads change through the well's producing life. As the heater units can come in a number of sizes and heater increments the heat output can be varied by increments. Catalytic heaters can be supplied to run on either methane or propane.

5.3. Fuel Gas Dryers

An alternative to keeping water in vapour form and/or the gas stream warm enough to prevent freezing, is to remove the water vapour from the gas. This is a preferred system for long distance transportation of the vent gas, or for producing gas for commercial sale. For fuel displacement on an individual well lease, the calcium chloride dryers appear to be the most appropriate drying option, and could be considered as an option to gas heaters or tracing. Note that terminology can vary for various forms of gas dryers. In this report we will use the term "Calcium Chloride Dryers" for systems where water is absorbed by calcium chloride pellets and brine produced, which must be discharged from the system and disposed of.

Calcium Chloride Dryers (Option Sheet 12.5.7) - A number of trials of calcium chloride (CaCl) dryers have been carried out, as the basic concept is relatively simple and straight forward, in that the calcium chloride absorbs the water from the gas and turns it into brine, which is then removed on a daily basis. Generally this will provide more drying than is necessary for on-site use, unless the fuel gas lines are uninsulated and exposed to ambient temperatures. CaCl dryers require that liquid water be removed upstream of them and the CaCl must be replaced over time, with consumption a function of the volume of water removed. While CaCl dryers will remove water vapour from the gas to prevent downstream freezing, the dryer units themselves must be kept warm to prevent freezing of the CaCl bed and to allow the brine to be drained off. (In winter conditions the brine can be in the form of a thick sludge, which does not drain easily.) CaCl dryers are also sensitive to high temperature so should be installed downstream of a compressor only if the discharge temperature of the compressor is reduced or controlled.

5.4. Heat Tracing

One method of maintaining fuel gas temperature to prevent freezing is to heat trace the fuel lines. Earlier we indicated this can be achieved by insulating the fuel gas line with a warmer stream, such as the production line or engine coolant (Option 12.5.4). Other heat tracing systems are available, but electric tracing is a viable option as either 12-V or line power is available if the lease has artificial lift. A common characteristic for most tracing systems is that they are better for use on above ground lines where they can be easily inspected, repaired and maintained.

Electric Heat Tracing (Option Sheet 12.5.3) - Electric heat tracing is available which is suitable for use in hazardous areas and can be used to trace fuel gas lines and production lines. The main requirement is to provide a suitable source of power to match the tracing used. Power converters (12V to 120AC) are required to utilize 12V power from the drive engines and a suitable power supply circuit is needed for use of line power for the tracing. For leases with gas engines running on casing gas the power needed for tracing is low cost, whereas line power costs may be significant, depending on the billing method. If the tracing operates off the engine battery there may be a need to provide protection to ensure that the battery is not drained and damaged if the engine goes down, as this would delay restart of the engine and might result in damage to the engine battery. Care must be taken in using converters and tracing as their operation will be dependent on the engine operation, so power quality might be a factor limiting tracing or converter life. Many converters that are available for consumer use are not designed for the continuous (24 hr/d, 7 day/week) that is required for casing gas line tracing.

All electrical equipment and circuits should be reviewed carefully to protect equipment and operators. The least expensive electric heat trace installation would be the self-regulating heater cable type. This electric heater cable automatically increases its resistance as the gas line temperature increases in order to limit the amount of electric current being used and therefore the amount of heating provided to the gas line. In hazardous classified areas, it is critical to ensure that the temperature for an electric heating cable is less than the ignition temperature of the gases likely to be present. Therefore heat trace cable to be used in hazardous areas needs to be equipped with ground fault protection, which operates in the event that the heat trace cable overheats and breaks down. The design of the cable should also closely match the watts/meter required by the process line to ensure temperatures stay within acceptable limits. In some situations, where limiting the current flow and therefore the heat to the pipeline installation does not effectively maintain the heat trace cable at acceptable operating temperatures, below maximum rated exposure limit, other options exist, such as mineral insulated heater cable which can sustain higher exposure temperatures. Mineral insulated heat tracing cable is more expensive, and needs to be precut by the manufacturer to the exact length before shipping, making the installation more costly. However, exposure temperatures of over 800 F are possible with mineral insulated cable.

5.5. Anti-Freeze Chemical Addition

Methanol is commonly added in field facilities to prevent freezing where liquid water build-up is a problem. Other chemicals can be used as anti-freeze, however, they are generally more expensive or may cause problems in downstream equipment such as the fire tube burners.

Methanol Injection (Option Sheet 12.5.5) - Methanol is frequently used in casing gas streams when freezing occurs or is anticipated. The most common practice in conventional heavy oil operations is to batch methanol into a line through a simple, manual injector system or lubricator. This system is inexpensive from a capital point of view, however, there is often very little control over the rate of methanol injected, so over or under dosing can easily result. In conventional gas operations, using methanol injection, the methanol is injected with a gas pressure driven metering pump so that the rate can be adjusted based on the estimated amount of water that has to be treated for a given amount of freeze protection. The formula for determining the minimum methanol injection rate is approximated by the Hammerschmidt equation:

d = (1297 x W) / (3200 – 32W) where:

d = the desired lowering of the water dewpoint in degrees C

W = the weight percent methanol in the liquid phase

The methanol injected must be sufficient to prevent freezing of all the water in the gas stream, not just the liquid phase. Also as methanol has a high vapour pressure much of it will vaporize into the gas phase and be lost over time. Therefore to prevent freezing with methanol the amount of water needs to be determined and methanol injected at a relatively constant rate to ensure freezing does not occur. As methanol (wood alcohol) is a hazardous substance operators should be aware of its proper use and exposure to it should be minimized[8].

In heavy oil operations consideration should be given to using metering pumps (12V DC, AC or gas driven) to replace lubrication, so that injection rates can be better controlled and to minimize operator exposure to methanol.

5.6. Operating Options to Balance Demand vs. Casing Gas Supply

The final category of options for heavy oil vent gas use is to simply manage the operation to minimize costs or to maximize use of casing gas. These are driven by the life cycle energy balances results illustrated in Figure 3.2. The results in figure 3.2 assumed that the lease tank temperature was maintained constant throughout the life of the well. In the first few years when oil and sand production are at their peak the operating temperature will be driven by whatever is needed to treat the oil, allow the sand and water to separate out, and to allow for easy loading of the heavy oil into trucks. This temperature will likely have to be between 65-85 degrees C on a continuous basis. The operating options for optimum gas utilization will generally come later in the well life.

Reduce Purchased Fuel Required (Option Sheet 12.4.2) – These options were already covered to some degree in Section 4.3.

Increase Use of Surplus of Casing Gas (Option Sheet 12.10.1) - During years in which a well has a surplus of casing gas produced, the tank temperatures could potentially be increased (within the limits of the fire tube rating and operator/trucker safety considerations) to burn off as much casing gas as possible to reduce GHG emissions. The added temperature may benefit operations at the central production battery and is a very low cost method of reducing some casing gas emissions. This requires only an adjustment to the set point of the tank

[8] Note recent worker compensation claims related to exposure of transit workers involved with a trial of methanol as fuel in Lethbridge's transit buses.

temperature control, ideally under conditions of continuous firing as indicated above, or manual control if there is no temperature switch.

There are also ways to make the production heating system at a site more inefficient so that more casing gas can be converted in a heater. In a firetube heater the amount of excess air can be increased, or tank insulation removed to increase heat loss. If odours and product loss are not a problem then the water level in the tank might be increased to preferentially heat and boil off some of the produced water, if this can be done without increasing the risk of firetube failures. With catalytic heaters the heater can often just be redirected so that less energy is going to heating the tank or line. For thermosyphons the excess air could be increased or a barrier could be installed to reduce the heat transferred to the heat pipe.

5.7. Conversion of Surplus Gas

Once all options for utilizing vent gas on the lease to displace other forms of energy have been implemented, or if there are occasionally surplus volumes of gas that cannot be utilized by any of the Managed Equipment Options, covered in the next section. Then the final set of options to consider focus on converting the methane to carbon dioxide to reduce GHG emissions and, potentially, generate GHG emission credits, which might be used or sold elsewhere (See Section 7.1.5 later in the report for a discussion of how the GHG reduction benefit is calculated on a tonne of CO2(eq) basis and potential value and process for emissions trading).

The lowest cost option has been covered in section 5.6 (Option Sheet 12.10.1). Options for methane conversion at either individual well sites, or for a group of wells joined by a common pipeline system, that require the addition of equipment could be:

Flare Stack (Option Sheet 12.10.2) – Flaring is deemed preferable to venting for all reasonable volumes of combustible waste gas. In Alberta, when vented gas volumes are significant on a site (greater than 500 m3/d) operators should consider opportunities to eliminate or reduce vented volumes (AEUB Guide 60 Updates and Clarifications). The SEM currently has a 850 m3/d venting limit for heavy oil producing areas of Saskatchewan.

While flare stacks are under pressure in conventional oil and gas operations, this is mainly due to the presence in the flare gases of hydrocarbon liquids that may not be adequately oxidized in a flare. In the case of heavy oil vent gas that is currently being vented, liquids are not an issue so there is no technical reason to avoid flaring in stacks from an air emissions point of view. The practical concern with flaring in the conventional heavy oil situation is the large number of flares that would have to be installed in a very small area, due to closer well spacing, and the need to increase lease size to accommodate a flare. Flares also suffer by being expensive and are not usually able to handle a wide range of flows efficiently and would add significantly to operator effort to keep them lit at low vent gas flows. They may be an option at pads or to convert large volumes of surplus gas collected to a single flare site and that can't be utilized in other ways.

Enclosed Flares or Incinerators (Option Sheet 12.10.3) – Enclosed flares and incinerators are being used more in the conventional oil and gas operations to overcome the problems of incomplete combustion and to remove visible signs of flaring in response to public concerns. For combustion of a stream, which is primarily methane that would otherwise be vented, it is not felt that enclosed flares or incinerators would be of significant benefit over a standard flare stack.

Catalytic Converters (Option Sheet 12.10.4) - Catalytic conversion of methane to CO2 has potential to be an economic method of converting very low volumes of methane on a well lease. The units can be located in Class 1, Div 1 or 2 areas, are small, compact and easy to operate. A major advantage in this application is that they can be modular so that the capacity installed will match the capacity required. There is no visible flame and the lower reaction temperature does not result in the formation of NO or NOx which is normally formed with a combustion system. Existing commercial heater units are available which can provide this function but are expensive, as they are designed for use as building or enclosure heaters. New Paradigm Engineering Ltd is working, with support from IRAP, to develop a lower cost converter that will also be able to handle a wider range of gas flows without operator intervention.

Future Project #7 - Further Research and Study by New Paradigm Engineering Ltd.: Once a prototype design has been completed for a converter New Paradigm will be looking for industry support to conduct a field demonstration trial of a catalytic converter in a conventional heavy oil venting application. Timing likely the spring of 2001, with testing through the summer.

6. Managed Equipment Options

Generally the economics will show that the greater the transportation distance and higher the pressure required for utilizing casing vent gas, the less economic the solution will be. In this section options for utilizing the gas that is surplus to the needs of the basic on-site artificial lift and production heating needs will be addressed. The amount of gas surplus to immediate production needs might only amount to 20-30% in total and will tend to be found in some specific geographic areas where GORs are high and WORs are low. The three main managed options result in the vent gas energy being exported either as pressurized gas, electrical power or as increased production of heavy oil. Deciding which managed option is optimum for a given application is not straightforward, and all may generate some positive economics if the surplus gas volume is high enough and the commodity prices are high. There is also the potential, given the volatile and often seasonal markets for energy commodities to provide for flexibility. I.e. might generate power to meet high demand periods of the day on winter work weeks, supply gas during the rest of the winter season, and use gas for EOR during the summer, when power and gas prices tend to be low and heavy oil prices high.

6.1 Overall Assessment of Managed Options

Tools to assist with the overall assessment of the managed options will be covered later in the report and technical pro’s and con’s are given in 11.4.2.1. As indicated above there are many factors to consider, but the over-riding consideration is to look at what is available for outlets for the energy, and then look at the technology and potential infrastructure needed to implement managed options effectively.

6.1.1 Local Site Assessment – As indicated earlier using the vent gas near the source tends to provide more economic solutions as the cost to transport the energy is reduced or eliminated and the capital equipment and operating requirements also tend to be reduced. The first level of assessment is for a local site.

Single well batteries - managed options are fairly limited as the volumes of gas available will often be too small to justify much expenditure, there is generally no option for EOR with a single well, unless it is a horizontal well or has multi-zone access, and the effort to plan and implement the required installations will usually put these low on the priority list. Generally to take advantage of any surplus gas at a single well site it will have to be tied into a local gathering system, which can either take surplus gas or provide gas to the lease. If it is uneconomic to move the gas to a central location then options to convert the surplus gas should be considered for possible GHG emissions credits.

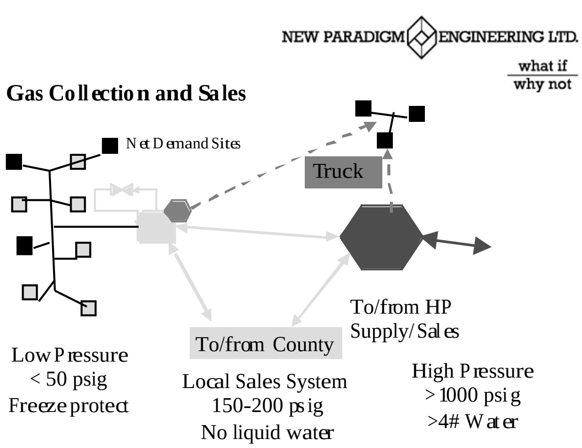
Pad wells - offer greater opportunities as the small surpluses on an individual well basis can add up to significant volumes. Pads tend to be more likely to have gas pipelines and/or power lines already coming into the lease, so offer more opportunity to export the energy as gas or power. Also the on-site access to more wells opens up the potential to easily implement many of the EOR or production enhancement options, which will be covered in section 6.4.

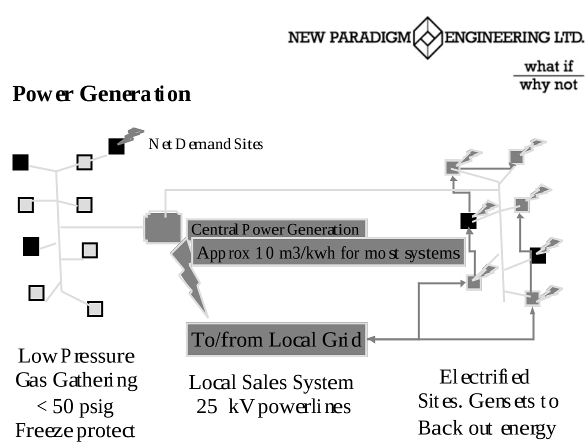
6.1.2 Regional Issues – If there is little opportunity to utilize vent gas energy at stand-alone sites then the next level is to consider options on a regional basis. Regionally there may be an opportunity for either single producers, or a group of producers in collaboration, to collect the vent gas to central sites where managed options can be economically implemented. Much of the assessment for regional options depends on what energy transportation infrastructure is already in the area and who controls that infrastructure. The return on any managed option(s) is very dependent on the selling price for the energy product produced and the ability to market it. Therefore, it is key that the producers assess all potential outlets and options for accessing those outlets from a strategic point of view to maximize their return. As these factors are highly variable between areas and between producers it is not possible in this report to make a specific recommendation so we have provided tools in section 7 to help producers assess the various managed options based on their own situation and opportunities. The remainder of section 6 will highlight some of the technical options, which might be considered.

6.2 Gas Collection, Sharing and Sales

To maximize return on surplus energy, the key is to concentrate the gas into locations where it can most effectively access available outlets. As energy commodity prices vary significantly over time it is likely best to target development of a central site where the maximum number of energy outlets will be available (e.g. power, gas or EOR). This may allow flexible facilities to be used to optimize return at any given time. For example a site could have gas driven engines or turbines that could drive either compressors or generate power, this might make it possible to attract top dollar for the energy by exporting power when local spot power prices are high, and exporting gas when spot gas prices are high. EOR or production enhancement options might be utilized year round if oil production increases make them more economic than gas or power sales, or they could be implemented on a seasonal basis, such as summer when costs to implement them are low and there is less return available from power or gas sales. Having more than one option for the energy outlet also allows the producer to negotiate from a position of greater strength with potential buyers of the energy.

To provide the maximum flexibility to maximize returns, the first technical issue to address on a regional basis is how to collect the smaller amounts of surplus gas from each site to a central location at a relatively low cost, as shown below.





The three elements, which need to be addressed for any off-site transportation of gas, are: transportation methods, compression methods and winterization or dehydration methods. In the following sections those elements will be addressed by first looking at gas transportation options, which are key to deciding what is needed to get the gas to a central site, and also often represents the largest cost, depending on how far apart the various sites are. After assessing the gas transportation options the first low pressure gathering system compression step will be covered, followed by methods for winterizing systems, to allow transport to a central site and dehydration to allow for gas sales. Finally the fairly standard facilities for local or high pressure gas sales will be addressed, along with issues related to custody transfer.

6.2.1 Gas Transport – One of the obvious problems to overcome in assessing the export of vent gas energy from a site is the transportation of the gas. Unlike oil and water it is more difficult, although not impossible, to transport natural gas by truck. The options covered below need to be assessed independently as the pressure requirements of the end gas disposition increase. Technical comparisons are found in 11.4.2.6.

Use of existing pipeline networks - If a purchased gas supply system already exists between wells, it may be possible to use all or portions of that supply system to create an internal casing gas supply network, and, where necessary, back-up that internal supply network with purchased fuel at a pressure maintenance control point. This would eliminate or minimize the amount of duplication of fuel supply lines to each well site. The main consideration, for changing the use of the system, will likely focus on ownership of the lines and if there are other users who may be affected by a change in use. In some cases producers may have oil pipelines to collect production and it may be possible to use these to also transport vent gas to a central battery.

Steel Pipelines (Option Sheet 12.6.1) - Conventional steel pipelines are the most common type of gas transportation used by producers. But is much more expensive to install than HDPE systems. Once installed it is also very difficult to recover so the potential for reuse is quite limited unless new producing wells are drilled in an area. As the gas pressure required increases it becomes more advantageous to install steel lines, and steel would be required at the compressor discharge for very high pressure applications.

HDPE (High Density) Polyethylene Pipelines (Option Sheet 12.6.2) - High Density polyethylene pipelines are becoming more popular in gas gathering and lower pressure gas distribution, because the material is cost competitive, relatively easy to install and has greater corrosion resistance. Although it has also has application for larger line sizes, use of polyethylene in smaller diameter lines, 6” and under for low pressure gas gathering applications is particularly attractive because of low material costs and because these small sizes can be plowed in from extended length reels. For moderate pressure sales pipelines HDPE is still applicable but will require a larger wall thickness (SDR of 9 or lower).

Modular Compressed Natural Gas Transport (Option Sheet 12.6.3) – Steel or composite material pressurized gas storage and transportation modules, are standard in the industrial gas industry and are becoming more widespread in the automotive industry to allow cars and other vehicles to operate off natural gas. While this option is not able to compete to move large volumes of natural gas out of an area, it may be worth assessing for transporting surplus vent gas or purchased gas to isolated wells which are not generating enough gas to meet their own needs. Economics would be driven by use of the modularized units to back out propane as make-up fuel. New Paradigm was unable to assess this option in great detail as we have not yet be able to obtain information on costs for the modules or the high pressure compression systems which would be required to fill them.

Future Project #8 - Further Research and Study by New Paradigm Engineering Ltd: Potential to further study modular compressed gas as an option to replace propane and/or gasoline in producer vehicle fleets. Might work with current vendors of propane.

6.2.2 Low Pressure Gas Sharing - This option would involve creating a small local casing gas pipeline network, see options above, to supply internal fuel needs by allowing transfer of casing gas from high gas producers/low fuel consumers to low gas producers/high fuel consumers. For the sake of this study, the network operating pressure has been assumed to be 350 – 415 kPa (50-60 psig). However, the actual operating pressure will depend on the geographical layout of the wells, availability of wells capable of venting at higher pressures, physical layout of the pipeline system, fuel consumer requirements, etc. The volumes that have been assumed, are very small, averaging 200 m3/d/well (7 mscfd) and, characteristically, because they are from single well sources, these flows may be quite variable. The actual conditions that have been assumed are summarized below:

Flow range from individual wells for compression	Average Flow from a well	Inlet Pressure	Outlet Pressure
Approaching 100 – 1000 m3/d (3.5 – 35 mscfd)	200 m3/d (7 mscfd) Highly Variable	Approaching 0 psig Higher suction pressure requirements will create backpressure on wells.	345 – 410 kPag (50 – 60 psig)

Increased Backpressure on Wells (Option 12.3.1) - The first step in evaluating a local network is to determine if there are one or more of the wells that can supply into such a network without requiring compression or that only require a minimum pressure increase. As impact on compression costs are significant, the amount of backpressure on the wells that can be tolerated is an important economic parameter and needs to be carefully evaluated.

Compression Options - In this small flow range, and for this range of conditions three types of compressors stand out: Single stage reciprocating, Rotary Sliding Vane compressors and Beam Mounted Gas Compressors. These have been listed in order of applicability. (Note that most of the options considered are covered in the GPSA Handbook, especially useful is Figure 13-3, at the end of the gas compression section of the handbook, which shows Compressor Coverage for various volumes and pressures.)

Reciprocating Compressors (Option Sheet 12.7.6) - For this low volume, low-pressure application, skid mounted reciprocating compressor packages are the most commonly used. These compressors are capable of handling a 0 kPa (0 psig) inlet pressure and delivering a discharge pressure of 50 psig keeping within a reasonable compression ratio (P2/P1 absolute) of 4. Meeting the lower end of the flow range 100 – 1000 m3/d (3.5-35 mscfd) assumed and providing a design that will adequately handle the flow variability will require a discharge to suction recycle. The amount of recycle will increase the cooling load, however it is typical in these mini-compressor packages to incorporate 100% recycle for the compressor package. The discharge temperature has an implication on the drying requirements downstream as will be discussed in subsequent sections. Reciprocating compressors are sensitive to liquids at the inlet. If the suction pressure to the compressor is maintained at 0 psig attention to liquids removal capacity upstream of the compressor is advised.

This type of compressor is widely used in the oil and gas industry. They are rugged and, although they have somewhat higher maintenance requirements than other compressor types, field operators will be very familiar with their maintenance and operating requirements. The average assumed flow of 200 m3/d (7 mscfd) results in a BHP of approximately 6.5. If spare drive capacity is available, it may be possible to operate belt driven from the existing well drive system or from a hydraulic drive system. Electric motor and natural gas engines are also available. Although the equipment cost for natural gas engines are significantly more costly, they do have the advantage of not requiring outside energy or power and can use vent gas as fuel.

Rotary Vane Compressors (Option Sheet 12.7.1) - This type of compressor technology has been traditionally used in vapor recovery systems and vacuum generation applications. More recently, in the oil industry they have been applied in reducing well backpressure. Rotary sliding vane compressors are once-through-oil vacuum pumps. They use oil to seal clearances and lubricate moving parts. The vanes are in slots in a rotor, mounted eccentrically to the pump chamber. As the rotor assembly rotates, centrifugal force pushes the vanes out of the slots and against the chamber walls, creating a pocket whose size varies. Because of this variation, suction draws process gas into the pump from the vessel (or well casing) being evacuated, and compression occurs as the vanes rotate towards the discharge side of the device, decreasing the area and forcing the gas and lubricating oil against the discharge valve. The discharge valve opens slightly above atmospheric pressure. Although more tolerant than reciprocating compressors, this type of compressor is still sensitive to liquids or condensable vapors at the inlet. At low suction pressures the potential for liquids from the well requires careful evaluation. These compressors can only provide about 175 – 205 kPa (25 – 30 psig) pressure rise per stage. So if the network requires operation at 345 – 415 kPag (50-60 psig) two compression stages are required. This compressor could also be used as a single stage booster compressor if lower compression is required. There is some operations monitoring required to ensure the oil levels are maintained. This type of compressor has somewhat higher maintenance costs. The local gas distribution network design would have to accommodate the presence of some carry-over of the seal oil with the discharge gas. Drive options are similar to the discussion under reciprocating compressors.

Beam Mounted Gas Compressors (Option Sheet 12.7.2) - These are reciprocating type compressors mounted on a stand and driven by the walking beam of a conventional pumpjack unit. These have been used to draw casing gas off of oil wells to reduce backpressure on the formation face and increase well productivity or as booster compressors. If there is an existing pumpjack, and it can handle the compressor load, the amount of gas that can be transferred will depend on the beam strokes/min and the size of the compressor. At the slowest beam rates, this type of compressor will cover the low end of the flow range between about 2 – 10 mscfd. If spare equipment is available, using a pumpjack operating independently of the well gives more flexibility to operate at a higher rate and increase the amount of gas that can be compressed. Modifying the beam rate can then also be used to optimize the operation of the compressor as casing gas flows vary over the life of the well. Other things that can be used to optimize the compressor throughput are changing from double to single acting and decreasing the stroke length. In either case, a recycle control loop is required to handle the variability in inlet gas flow. If operating at very low suction pressures is essential to well productivity, liquids carryover is a potential problem and an inlet scrubber should be considered to protect the compressor.

Other Gas Compressor Options - Rotary-lobed compressors are positive-displacement pumps that use no sealing fluid and as a consequence are limited to low pressure differentials of about 80 – 100 kPag (12 – 15 psig) because of temperature limitations. These compressors are more suited to boost gas pressures for on-site consumption. Liquid-ring Compressors would be very inefficient for this application because of the energy and equipment requirements for the seal fluid (generally water) handling. They would also require a source of seal fluid. These are usually limited to compressing gas streams that are excessively hot or dirty. Screw compressors will be discussed in the next section. They are too large for this gas flow range.

Liquid Eductors (Option Sheet 12.7.3) - If production is pipelined, collection of surplus gas at a central facility gives more flexibility in treating and distributing the gas for internal consumption or sales. Liquid eductors are venturi jet devices that use pressurized liquid to entrain, mix and pump gases. Eductors consist of two basic parts, the motive nozzle, which converts the pressure energy to kinetic (velocity) energy and the suction chamber/diffuser section where the entrainment and mixing take place. Using eductors applies in those cases where oil is shipped out by pipeline to a central treating facility. Depending on the pressure of the motive (oil/water) stream and the differential between it and the educted stream (casing gas), this application may be as simple as a draft tube eductor or may require taking a slip stream off of the pipeline and using a small booster pump to create the pressure drop in the eductor sufficient to entrain the casing gas. Eductors are standard equipment in vacuum generation technology. They are inexpensive, rugged, have no moving parts, and require almost no maintenance or operator attention.

6.2.3 Gas Drying or Freeze-Protection - A major concern with casing gas utilization is that liquids might accumulate and freeze off, or that equipment sensitive to liquids might be damaged. It is important in a system like this to include upstream liquid protection for sensitive equipment or to prevent pipeline freezing. There are three strategies: change the conditions to prevent liquid water condensing and freezing, prevent liquid freezing (in combination with separators upstream of equipment) and finally, use a process to remove water.

Custody transfer of casing gas will require additional processing to remove water vapour. Specifications in a high pressure sales gas system (1000 psig) will require that the water content of the gas not exceed 4 lbs/mmscf (a pressure dewpoint of approximately minus 10°C). This value is often also used by gas co-ops, and others, as their default water content, even though it may not be required to prevent water formation in their system. However, the requirements of a lower pressure system are technically different, especially if there are no third party users of the gas in the system, and can allow the commercial water content spec to be relaxed. Relaxing the spec for sales gas would increase the number of dehydration options available. A technical comparison is provided as 11.4.2.9.

Manipulating Conditions (Option Sheet 12.5.1) - Gas at equilibrium with liquids is saturated at the equilibrium conditions. This is true of casing gas off a reservoir, or gas off a compressor discharge bottle. Manipulating conditions by increasing temperature and/or dropping pressure can be an effective method of avoiding liquids condensing and potentially freezing. If distances in the network are small, in combination with insulation and dewatering for the casing gas consumers such as discussed in Section 4.1, these tactics may be enough to prevent freezing to the degree necessary to allow year-round operation.

Methanol Injection (Option Sheet 12.5.5) - This has been discussed in Section 5.5

Glycol Injection (Option Sheet 12.5.6) - The injection of glycol into a gas stream has the same effect that injecting methanol has of lowering the hydrate-formation point, or, in lower pressure gas streams, lowering the point at which the free water freezes. Although it is more expensive than methanol, glycol has a relatively low vapour pressure and is also relatively insoluble in hydrocarbon liquids and can be economically recovered and reused.

The glycol is injected into the gas stream using a chemical injection pump similar to the type of pump used for methanol injection. The rate of glycol injection can be adjusted and controlled based on the estimated water content of the stream versus the degree of freeze protection required. Additional equipment is required to recover and reclaim the glycol. A two-phase separator, at the gathering system outlet(s), separates the water and glycol from the gas. The gas off the separator is delivered to the sales line and condensate is stored in a collection tank. The water-glycol solution is sent from the separator to a glycol reboiler where it is reconcentrated. The glycol can then be trucked back to the original injection site for re-injection into the gas stream.

Calcium Chloride Dryers (Option Sheet 12.5.7) - Calcium chloride is discussed in Section 5.3. Calcium chloride on its own will provide a dewpoint suppression of 32°F and a multiple stage system using lithium chloride in the final stage will provide a deeper dewpoint suppression of 57°F assuming an inlet temperature of 80°F.

Pressure Swing Adsorption (PSA) Driers (Option Sheet 12.5.8) - Pressure-swing adsorption is a widely applied technology for separating components of a gas stream inexpensively. It can be applied in casing gas water removal and will also remove any heavy hydrocarbons present in the gas at the same time. Separation is achieved through selective concentration of the water vapor from the feed gas on a solid adsorbent, followed by a desorption step of the recovered water vapour. PSA systems cycle through the pressurization-adsorption, and depressurization-desorption steps, providing water removal on a continuous basis.

This type of drier should be designed for an inlet temperature no higher than 100°F, as they lose efficiency at higher temperatures. It is possible to dry at lower pressures than optimum, but the amount of purge gas required for regeneration increases. At an operating pressure of 150 psig the purge volume is about 10% of the feed stream. At 65 psig the purge increases to about 18 – 20 %. The capital cost of the equipment increases at lower pressures because of design limits for gas velocities through the bed.

Glycol Dehydrators (Option Sheet 12.5.9) - This technology incorporates a glycol contactor and regeneration system and provides excellent dewpoint suppression. It is applicable for much larger gas volumes and sales dewpoint suppression requirements because of the higher capital investment. A Tri-ethylene Glycol (TEG) or Di-ethylene Glycol (DEG) dehydration system is an absorption process and incorporates a glycol contactor, regeneration system and associated equipment: lean/rich glycol heat exchanger, glycol pump, surge tank and glycol filter. It is capable of providing reliable dewpoint suppression to high pressure sales requirements, less than 4 lbs/mmscf.

6.2.4 Compression – Local Gas Sales - This option involves a system to collect casing gas from a local collection/distribution network and transfer it into a low pressure sales gas distribution pipeline. This will require centralized compression of the casing case from a number of wells as well as any required water dewpoint suppression**.** The following is an example of the conditions that were considered for this type of application:

Range of flows from local well Network	Assume a typical flow of:	Inlet Pressure	Outlet Pressure
3000-20000 m3/d (105 – 700 mscfd)	20000 m3/d (700 mscfd) Somewhat Variable	30-50 psig	150-200 psig

Single wells Custody Transfer to Low Pressure Sales (150 – 200 psig) - This option would be a possibility for heavy oil wells or pads that have larger casing gas flows and that have a local low pressure sales distribution network available. This will require compression of the casing case at the individual wells as well as some water dewpoint suppression. Technical comparison of options can be found in 11.4.2.7. The flow of individual wells or a pad can be quite dynamic and also will tend to vary over the course of the well life.

Range of flow	Average well	Inlet Pressure	Outlet Pressure
1000 – 3000 m3/d (35 – 105 mscfd)	3000 m3/d (105 mscfd) Highly variable	Approaching 0 psig Suction pressure will create back pressure on wells.	150 – 200 psig

Beam Mounted Gas Compressor (Option Sheet 12.7.2) – Previously discussed in section 6.2.2.

Screw Compressors (Option Sheet 12.7.4) - Oil injected rotary screw compressors are positive displacement devices that consist of two rotors intermeshing to compress the gas. The gas entering at the suction flange is conveyed to the discharge port by continuously diminishing spaces between the convolutions of the two rotors. The result is gas compressed to the final pressure before it is discharged. The oil acts as a lubricant, separating the two screws and providing internal cooling.

The flow for this application is on the low side for screw compressors but it can be applied in the high end of this range by slowing the unit down and recycling discharge gas to the suction of the compressor. For a screw compressor to maintain stable operation, the inlet and outlet pressure must be controlled. An expensive alternative is to use a variable speed drive. Hydraulic, electric, and natural gas engines are available as drive systems for these types of compressors. Screw compressors are attractive because they are very low maintenance and are simple in design relative to other types of compressors.

Two stage, reciprocating compressors (Option Sheet 12.7.7) - Compression ratio limits (approximately 4) require two stages of compression for this compression from atmospheric pressure into a system operating above 50 psig and requires inter-stage separators and inter-coolers. If reservoir performance is not compromised, capital investment can be reduced, by increasing the well casing pressure to about 30-40 psig. At this inlet pressure a single stage of compression only is required.

If spare drive capacity is available, it may be possible operate belt driven from existing well drive system or from a hydraulic drive system. This application is in the 20- 25 Hp range so availability of spare driver capacity may not be as likely. Electric motor and natural gas engines are also available although natural gas engines are significantly more costly, they do allow for vent gas use as compressor fuel.

Single stage reciprocating compressors (Option Sheet 12.7.8) - At an inlet pressure of 50 psig, a reciprocating compressor would be preferred for this application and only a single stage of compression is required. For higher volumes, use of spare driver capacity is not possible. Electric motor and natural gas engines are available although natural gas engines are significantly more costly from a capital cost point of view they would use vent gas as fuel to reduce operating costs.

Other Gas Compressors Options - Rotary-lobe, rotary sliding -vane, rotary liquid compressors are all too small and/or compress to too low a pressure differential for this application.

6.2.5 Compression – High Pressure Sales (Option Sheet 12.7.9) - This option involves a system to collect casing gas from a local distribution network and transfer it into a high pressure sales gas pipeline. This will require centralized compression of the casing gas, as well as processing to meet a water content pipeline specification of 4 lbs/mmsf. In discussing this option with vendors it was felt not to be a practical option at the low volumes anticipated from a local vent gas supply alone. Based on this the likely scenario is that the low pressure gathering or sales network would have to be tied into a local gas well gathering system, so that the combined stream will be economic to collect and compress. We have not covered this option in any detail or in the tools as the technical and cost issues for large gas gathering and compression systems are well known. See 11.4.2.10 for a technical comparison.

6.2.6 Custody Transfer – In all of the above systems where there is a change in control or ownership of the gas custody transfer will be an important consideration. Metering systems are available which should be able to deal with all the options listed above and are not covered in detail. The largest potential for problems with custody transfer is likely to be a result of fluctuating pressures and rates at the transfer points and potentially meeting any water content specifications if they are part of the custody transfer.

6.3 Power Generation Managed Options

A number of options are currently commercially available, and more are under active development, many of which can facilitate generation of electric power in small quantities from natural gas at geographically dispersed locations, and in so doing, make more efficient use of natural gas resources while substantially reducing emissions. Some of the options include:

Microturbines – which have recently become commercially available from several manufacturers

Gas Turbine Gensets - have been commercially available for some time

Reciprocating Gas Engine Driven Gensets – extensively commercially available

Thermoelectric Generators – have been commercially available for many years

Fuel Cells – have recently become commercially available, and are also under significant development

Gas Turbine - Fuel Cell combinations – currently under extensive development

A technical comparison of the above options is provided as 11.4.2.11.

The term Distributed Generation has come to mean geographically dispersed small power generation, either in parallel to the utility electricity grid or used for stand-alone purposes. These generators can be suitable for base load, peak shaving and cogeneration applications.

The economies of mass producing small power generators are now becoming competitive with the economies of scale previously presented by large centralized power generating stations, often located remotely at the mine mouth, and requiring extensive transmission and distribution networks. Unbundling of the utility rate structures, through the electricity deregulation process, into separate generation, transmission and distribution components will mean the elimination of cross subsidization between customer classes and a more accurate economic measurement of the value of alternative sources of generation. According to the U.S. based Electric Power Research Institute (EPRI), “By 2005, as much as 40% of the new U.S. capacity required could be met by distributed generation.”

Powerlines - Power line costs vary dependent on capacity, type of terrain, arboreal growth and distance covered. For rural distribution lines over relatively flat and clear terrain, the cost to construct a three-phase overhead 25 kV powerline, with wooden poles at standard 100 meter spacing, is approximately $22000 per km. This cost would not include any other additional utility charges, such as cost of studies, application processing fees or project management charges, which may be levied at the discretion of the particular utility. Buried cables over similar distances are generally more expensive, except for very short distances. For short distances around the immediate battery site, it will be cheaper to bury high voltage cable. The cost of 1/0, 25kV, 3 phase cable suitable for direct burial is approximately $85/m or $85000 per km, excluding installation cost which can add a further $10/ meter.

Noteworthy is the fact that much of the 25kV overhead rural electric utility distribution system in Alberta was built without a grounded shield wire above the three phases. The grounded shield wire, when present, acts as a shield against thunderstorm lightening discharges. Also, without the shield wire, outages due to increased bird and tree contact with the live phases can occur. This can result in increased downtime for the utility supplied power. Onsite generation can potentially reduce many of these outages.

Commercial Terms - The contract for the supply of electricity should address the usual provisions for payments, measurement, force majeure, and the responsibilities of each party. The contract should also have provision for the following items:

- electricity supply quality and reliability
- equipment failure provisions
- environmental credits
- term of fuel supply at each location
- gas supply quality and reliability
- pricing of co-gen heating supplied to the host facility

When selling co-gen heat to a process facility, the question arises as what value to attach to co-generated heat. If the facility was initially using a gas fired heater with an efficiency of 70%, and the cost of gas is assumed to be $5/GJ, then the value of heat to the facility could be as much as $5/70 X 100, i.e. $7.14/GJ. The price of heat, however, would still be a negotiated price. Additionally, if power is being sold not only to the host facility, but also to the Power Pool over the distribution system, additional agreements would be required as follows:

- an interconnection and operating agreement with the distribution utility or “wires” company in the area
- an agreement with the Power Pool of Alberta

Saskatchewan vs Alberta - SaskPower is, at the present time, still looking to procure power in their Province and are doing it on a case by case basis. This is in addition to previous RFP’s (Requests For Proposals) for larger power increments in the over 100 MW range. SaskPower has, on an ongoing basis, been accepting up to 20MW of power per year in up to 10 MW increments from small IPP's (Independent Power Producers) as part of their policy. They have issued a guideline, “Non-Utility Generation Interconnection Requirements at Voltages 72 kV and Above” and have issued, in draft form, their guideline, “Non-Utility Generation Interconnection Requirements at Voltages 25 kV and Below.” The latter guideline considers tieing in generation in increments of as low as 100 kW or less. No RFP will be issued for these small increments below 10 MW.

In terms of deregulation, they are planning in the fall of 2001 to have open access at the 72kV transmission level for wheeling power on the grid. At this point deregulation is not down to the retail level, as will be the case in Alberta starting 2001, but independent generators will be allowed to supply power to three entities, Saskatoon, Swift Current, and Saskpower.

Saskatchewan has in the past provided a 20% line loss credit for generating power in the west of the Province as compared to a 20% line loss on generation in the south east. However, as loss patterns change over time with the advent of new generation, these loss patterns will be re-examined and revised as new plants come on line.

Power Generation Equipment Options – are covered in the following sections. Microturbines and reciprocating gensets are considered to be the options with the widest potential application and are, therefore, considered in more detail.

6.3.1 Microturbines (Option Sheet 12.8.3) - The sizes of the more commonly available microturbines range as follows: 30kW, 45 kW, 60 kW, 75kW. Gas consumptions of these range from 10 MCF/D to 20 MCF/D (285-570 m3/d) at rated power output and assuming a gas heating value of 1000 BTU/SCF or 37.7 MJ/Sm^3. Up to 200 kW is generally referred to be in the microturbine range. No 200kW microturbines have been commercially readily available, although some manufacturers currently have plans to provide units in this size range and larger.

Capital costs for these units can range from $1000/kW to $1500/kW. Additional installation costs, such as utility interconnections and gas conditioning and compression costs can still add further to the total installed cost. The units themselves come packaged complete with synchronization and controls to allow for automatic synchronization onto the grid. Because of their modular nature, installation can be relatively easy.

From a mechanical perspective, many of the microturbines available are designed for low maintenance and ease of operation. A single shaft design, with permanent magnet electrical rotor, centrifugal air compressor and radial gas turbine all integral to the shaft make for very low maintenance, as the unit has essentially only one moving part. There is no lubrication system to maintain as the more common units run on air bearings.

In general, gas turbine maintenance costs can be as low as one third of the maintenance costs of a similar rated natural gas reciprocating engine. Microturbine maintenance costs thus far, as this is relatively new technology, are low, constituting no more than replacement of consumables such as filters, and scheduled overhauls. A major maintenance overhaul is scheduled after 10 000 hours of operation. It remains to be seen, though, how equipment life will be affected over the long haul as a result of corrosive hydrogen sulphide environments or the impact of other operating conditions in vent or flare gas applications. At this point, the technology is too new to accurately forecast unplanned maintenance, however, early results have been very promising, at least for those operators installing the units within prescribed operating guidelines. Combustion efficiency ranges in excess of 99.5%, and so virtually complete incineration of the hydrocarbon input stream is achieved, to produce essentially only water vapour and carbon dioxide. Low emissions and NOx levels of less than 25 ppm are readily achievable.

The microturbine units are often equipped with integral recuperators to improve efficiency. These devices remove heat from the exhaust gas stream and transfer it to the compressed air being injected into the combustion chamber. Energy utilization efficiencies of approximately 25% to 30% are achievable on straight generation, and in cogeneration applications, efficiencies of two to three times higher are potentially achievable, depending on the host facility heating load requirements.

One of the issues to be dealt with by the designers of any microturbine installation required to run on raw or unprocessed gas, is the avoidance of free liquid droplets in the fuel gas stream to the microturbine. This can potentially result in damage to the unit, especially during cold start up conditions. Particular attention is therefore to be paid to having a liquids knockout vessel or separator ahead of the unit, as well as attention to the gas velocities in the fuel gas line coming from the well head. Using a smaller diameter fuel line can increase velocity and assist in keeping the fuel gas line free of liquid slugs. Too low a velocity can result in liquid build up in low spots of the line and subsequent slugging of liquids into the unit. The potential for liquid ingress can also further be mitigated by heat tracing or using line heaters, upstream of the turbine unit, where liquids may be considered a potential issue. Some operators have utilized fin tube heat exchanger tubing in the fuel line inside the turbine cabinet to collect ambient heat and so provide further fuel heating.

One particular microturbine unit has logged over 10 000 hours without any breakdown or unplanned maintenance, giving it 99.9+% availability in that period of just over one year. The units are relatively simple to operate and come completely equipped with protection and control to allow for automatic synchronization onto the utility grid. Well over 50 units have in this year (2000) been installed in oilfield applications, and results are very positive to date. Microturbines have been used on site to drive pumpjacks, submersible pumps, and to export power onto the grid. The units can operate in power export mode in parallel to the grid, or in stand-alone mode when the grid is down. The majority of the units are third party owned and operated by small independent power producers. Depending on the choice of manufacturer, input gas pressures range from 5 psig to 75 psig. For less than 5 psig pressure, fuel gas pressure booster options are available.

Future Project #9 - Further Research and Study by New Paradigm Engineering Ltd and Vendors: At the start of the current project Mercury Electric offered to supply equipment and support for a demonstration pilot for a microturbine unit in this application. Producers should consider conducting this testing if they have concerns about the viability and operability of this technology. Alternatively more work could be done in a paper study to assess microturbine performance in other conventional oil and gas applications and project potential performance in a casing vent gas application.

6.3.2 Reciprocating Gas Engine Driven Gensets (Option Sheet 12.8.5) - Diesel gensets can be configured to accommodate a wide variety off fuels, including low pressure natural gas ranging from 1.5 psig to 48 psig, dependant on the type of machine selected and whether the unit is naturally aspirated or turbocharged. Air fuel ratios have considerable flexibility and can be programmed to optimize onsite performance, such as emission levels. For a specific engine model, when running on natural gas instead of diesel, the engine rating must be derated by approximately 50% to account for the lower heating value of the gaseous fuel. Where insufficient gas is available to run the machine at the required power output, propane can be used as a substitute or for make up fuel.

The initial capital cost of a gas fired reciprocating genset may be of the order of one third to one half the cost of a similarly rated turbine driven genset, however, the reciprocating engine will incur approximately three times the maintenance costs that a turbine will incur. Whereas the maintenance costs of a turbine may be around 0.5c/kWh, the maintenance costs of a similarly rated reciprocating genset could be around 1.5c/kWh, dependant upon operating conditions. The turbine will also have higher availability as a result of the lower maintenance requirement.

6.3.3 Other Power Generation Systems – Microturbines and reciprocating gensets are the most likely systems to be considered for managed options in the range of surplus vent gas that would normally be expected in a given area. However, some areas may have larger volumes of vent gas, or it may even be economic to generate power for sale from local gas well gas, in which case larger generating systems might be economic. At the other end of the scale smaller systems may be attractive for providing power for smaller loads on a particular lease.

Gas Turbine Driven Gensets (Option Sheet 12.8.7) - Gas turbine driven gensets are well proven technology and have long been used in primary power applications in remote areas where the utilities were unable or not inclined to supply power. Many of the turbines used are aero derivatives, and therefore have more favourable power to weight ratios than comparable reciprocating gas engines, which facilitates packaging and transporting them as modular units. Sizes can range from around half a megawatt to upwards of thirty megawatts.

Installed capital costs can be as low as $1000/MW, or lower. Operating costs and maintenance costs, on a unitized basis, can also be lower than the microturbines, because of some economies of scale. Larger gas volumes would be required than with microturbines, and so their application is more likely to occur where the gas from a number of wells can be aggregated. For example, at multi-well pads, or where low-pressure gas can be gathered relatively simply. One option to consider would be ploughing in inexpensive low-pressure plastic gathering lines into the sub-soil for this purpose.

Approximately 400 MCFD (approximately 11000 m^3/d) of gas with a heating value of 1000 BTU/ft^3 will produce approximately 1.2 MW of electric power for export onto the grid or for local consumption.

Thermoelectric Generators (Option Sheet 12.8.1) - Thermoelectric Generators (TEG's) are used for a variety of remote power applications in the oil and gas industry and the pipeline industry. They are known for safe and reliable operation, but are very low in efficiency, and can be below 5% electrical conversion efficiency. Other uses include cathodic protection, remote SCADA operations, etc. Sizes range 15 W to 550 W for individual TEG units. Gas consumption varies respectively from 1.5 m^3/d to 48 m^3/d for individual units, assuming a gas heating value of 1000BTU/SCF or 37.7 MJ/Sm^3. Larger multiple generator installations have also been utilized to further increase output to as much as 5000 W, i.e. 5kW. Generally TEG's are effective for generating small amounts of power, but are not economic for large power requirements.

Fuel Cells (Options Sheet 12.8.9) - The Fuel Cell combines hydrogen and oxygen to produce electricity and water. The energy conversion efficiency of a fuel cell can exceed 50%. Fuel cells have been in existence for over 150 years, but are only now gaining widespread interest because of their very low emission levels. Sizes are expected to range from several kW to over several MW. The first commercial fuel cell was developed by ONSI Corporation, and produces around 200kW. At a cost of approximately $6000/kW, fuel cell options are still prohibitively expensive. There are over 20 companies currently developing this technology and these prices are therefore likely to reduce.

6.3.4 Cogeneration (Option Sheets12.8.2, 12.8.4, 12.8.6, 12.8.8.) - Cogeneration is defined as the generation of electric energy and commercial or industrial quality heat or steam from a single facility. The efficiency of the overall cogeneration process greatly exceeds the efficiency of a conventional stand-alone power station in that much of the heat coming off the gas turbine can be utilized in the host facility. In a cogeneration plant, almost 100% of the electrical energy is usable and, depending on the host facility heating requirement, up to 70% + of the exhaust heat energy is usable. This potentially gives the cogeneration plant an overall energy utilization efficiency of 65% to 80% +, as compared to the conventional power station efficiency of around 30% - 35%.

When comparing a gas-fired cogenerator to a stand-alone coal fired power generation facility, we can expect a 60 percent reduction in carbon dioxide emissions, a 95 percent reduction in nitrogen oxide emissions and 100 percent reduction in particulate emissions for the same amount of electrical power generated. In regard to using solution gas for cogeneration vs. flaring it in a conventional flarestack, cogeneration results in a 99.5%+ combustion efficiency as compared to a potential 66 percent combustion efficiency when flaring the gas. This is true whether we applied cogeneration or just straight generation with gas that is currently being flared.

The incremental installed cost of a cogenerator over straight generation is usually the cost of the heat recovery system, which can be a Heat Recovery Steam Generator (HRSG), or an Air-to-Liquid heat exchanger or an Air-to-Air Heat Exchanger, depending on the host facility process heating requirements. Hot glycol can be used for building heating or hot exhaust gas can be used for process treating of product.

Future Project #10 - Further Research and Study by New Paradigm Engineering Ltd and Vendors: Potential to pilot a cogeneration option as part of Mercury Electric pilot in future project #9. Test ability of gas from microturbine heating production or tankage.

6.4 Enhanced Oil Recovery (EOR) Options

One use for vent gas, which is not often considered, is as a resource to increase oil production. While the vent gas volumes are relatively small in volume they represent a significant amount of energy, which can be used at very low supply cost to fuel an oil production enhancement process. Since methane or methane derived gases and/or water are also some of the primary injectants considered for production enhancement, their free availability on a conventional heavy oil lease leads to an opportunity to take advantage of this as an opportunity to generate greater production from streams which would otherwise be considered as waste.

There are a good number of options for utilizing these streams. To emphasize a key distinction we have split them into three areas. Flooding or Continuous Injection options might use portable equipment and may only operate in periods when there is surplus vent gas available, but they are based on continuous injection into designated wells at a pad or in a given operating area. Pressure Cycling covers options, which may use the same equipment as continuous processes, but injection would occur on a cyclic basis to stimulate production in an individual producing well. Finally the last section considers some of the merits of operating a number of processes in parallel with the potential to increase benefits. A technical comparison of these options is included in 11.4.2.12.

Gas Collection – As with other managed options it will likely be an advantage to increase the availability of larger volumes of surplus vent gas to allow an EOR project to achieve maximum benefits while still allowing greater flexibility to relocate equipment to match the changing well availability and EOR opportunities in an area. The first level of this would be to look at pad operations where there are multiple wells, one or two of which might be in a more advanced stage of primary depletion than others. However, linking gas supplies between pads and even between single well batteries offers considerably more flexibility in applying EOR or Productivity Maintenance options, as the gas can be delivered anywhere in the area covered by the low pressure collection network.

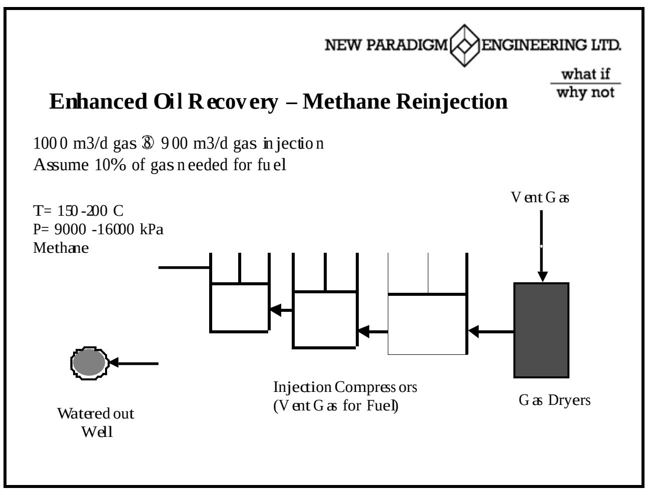
Number of Wells and Well Types – The number of wells that can be considered as a vent gas EOR site, expanded with the availability of a low pressure gas collection network, will tend to set whether a continuous or cyclic process will be viable. For continuous processes it is obvious that there is a need to have simultaneous production of vent gas and injection of the products of vent gas use. Similarly a cyclic process with vent gas cannot work on single well battery that has to be shut-in during injection, unless there is an external source of vent gas, possible supplemented with purchased gas. This can potentially be accommodated by more complex completions in horizontal wells (e.g. heel to toe floods), however, such options also add to the cost and risk. After some experienced is gained in EOR applications it may be possible to justify drilling more wells to facilitate EOR or production enhancement activity, but initially, due to the current high turnover in wells, it is assumed that there will usually be an older well in a given area that can be used as an injector.

Oil Recovery Potential – In this report we are not going to attempt to analyze potential performance of the various processes in a given reservoir. There are commercial reservoir models available that should serve as tools to conduct initial evaluations of the processes, and these will have to be verified by actual field results, as some models may not be able to handle the options being proposed. In this report we are outlining the facility options and what types of injectants might be delivered by the various options, what some issues might be and what input should go into the reservoir assessment. The approach is different, as we are developing what can be supplied, so that the reservoir engineers can predict the potential effect with a given supply of vent gas, capital and water. In the economic and technical analyses we are going to build on an assumed surplus vent gas increment of 1000 m3/d of methane. This appears to be an increment that might be expected on a pad level and, where there are multiples of 1000, allow for modular facilities with a common capacity to facilitate comparison and for practical aspects of flexibility.

6.4.1 Flooding or Continuous Injection – The options covered in this section comprise the basic EOR processes that might be considered utilizing the resources available in any conventional heavy oil operating area. Basic resources are vent gas, air, produced water or fresh water. Since all of these materials are available in an area at relatively low cost they present the greatest potential for producing an economically viable production process. As indicated above we will try and develop the options based on 1000 m3/d of gas increments, however, there is potential to consider larger or smaller increments in some cases.

Methane Reinjection for Pressure Maintenance (Option Sheet 12.9.1) - Some producers are proposing or even initiating methane reinjection schemes for pressure maintenance. A surplus or watered out well could be utilized as an injector and compressors (see gas collection and compression options) could be used to generate high-pressure (1200-1500 psig assumed) gas for injection. Injection volumes could be adjusted to match the amount of casing gas available or could potentially be supplemented with gas from other sources if a constant injection rate was preferred.

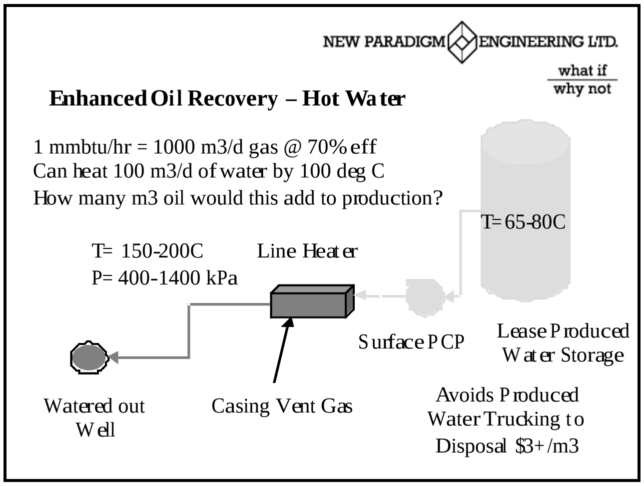
The benefits of this process are that: the equipment required is conventional technology; units can be leased, rented or purchased and moved easily between sites; casing gas can supply the engine fuel as well as being the injectant; gas may be produced later on at a higher rate that would be more economic to recover; and, gas compressors are familiar equipment to operators in the area.



The disadvantages are that: gas injection is not usually as effective for high viscosity oil as it is for light oil; most heavy oil wells are completed near the top of the producing zone to avoid water breakthrough, this will make them more susceptible to gas breakthrough between wells, especially if there was a pre-existing gas zone at the top of the formation; gas breakthrough would make gas production and venting volumes much more difficult to predict for surrounding producers.

Hot Water Injection (Option Sheet 12.9.2) - In cases where a site has a surplus of produced water and vent gas, as well as a watered out producing well, or a section of horizontal well that might be isolated for water injection, it may be advantageous to reinject the warm (65-80 degree) produced water as well as heating it further with surplus gas. The produced water has already been heated to allow for oil/water separation and can be heated further utilizing a line heater and surplus casing gas. As the two feed streams (water and gas) are already on the lease there is little on-going operating cost to run such a system. A surface PCP or other positive displacement/metering type pump, powered from the artificial lift system or a separate gas engine, could be used to pump the water to a higher pressure, so the water can be heated to a higher temperature without forming steam. The assumption is that this low cost energy added to the producing formation would result in some incremental oil production, and enhance recovery from the formation through other wells in the area.

In the case of a pad lease where one well has watered out and can be used as an injector, the tank for that well can become a water storage tank and receive water transferred from the other producing tanks or potentially even trucked from other nearby leases. The water would be pumped out of the tank by a horizontal surface PCP through a line heater and the water sent to injection.



The line heater would operate off surplus casing gas from the producing wells. Metering of the water transfers would be required but can be done with standard positive displacement meters. Operators could transfer water before loading oil to trucks so that pumps would not be necessary to transfer water between tanks.

Generally any energy that can be added to a producing formation will result in increased production from the formation. Normally any EOR method would have energy and injectant supply costs associated with it. Payouts on the capital invested may be very rapid. This method would contribute to increased production in a number of ways by:

- Adding heat to the reservoir. With heavy oil, viscosity is usually a log function with respect to temperature so even a small increase in temperature in the formation will significantly reduce oil viscosity and surface tension to increase relative permeability.
- Water Displacement will move the heated oil to producing wells from the injector.
- Water will replace voidage and help maintain reservoir pressure.
- Water reinjected will not have to be trucked and disposed of elsewhere so unit operating costs will be reduced. This is a significant factor in the economics of this option.

- Use of casing gas will generate GHG emissions credits while at the same time generating incremental oil revenue.
- Gas used for increased oil recovery is usually royalty free.
- An additional benefit can be realized from watered out wells and abandonment can be postponed.

While the injected water would be hot it can be limited to temperatures allowable by the original well completion materials.

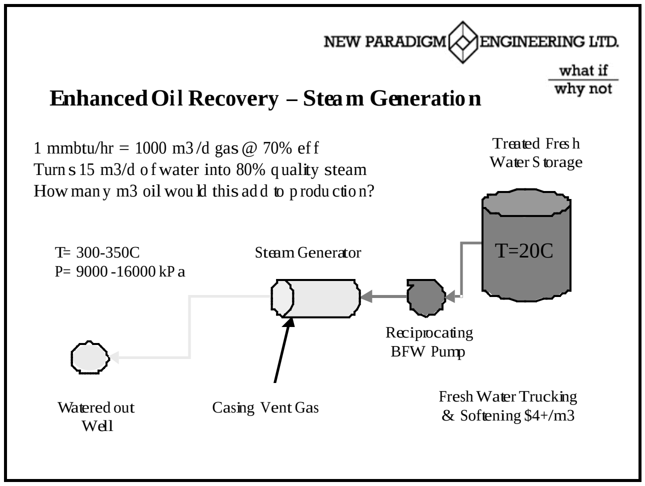
To implement this system, incremental capital would have to be invested to convert a well to receive disposal water, convert a production tank to water service; install piping and equipment (traced and insulated for freeze protection) to allow metered or measured water transfer from production tanks to the water tank; installation of a new pump with connection to a drive energy source and a conventional or catalytic line heater to heat the pressurized water before injection.

However, all of the equipment used can be portable and relocated to other leases as production of gas, oil or water declines at any given lease. Most of the incremental operating effort will be involved in transferring of water to the water disposal tank and ensuring that the water is relatively clean. As long as injection rates into any individual well are kept relatively low, and the water hot, the injection pressures required and the amount of water clean-up required should be low as the fluid head of the water in the tubing will provide much of the pressure energy. Other costs would be just maintenance costs for the incremental water injection pump and line heater.

Testing would be required to determine how much the produced water can be heated while avoiding formation of scale, which is more likely to form as the temperature increases.

Conventional Steam Injection (Option Sheet 12.9.3) - Generally steam injection is preferred if there is a shortage of a low cost source of water for hot water flooding. Steam will transfer more energy to the reservoir for a given mass of water, however, steam generation requires a much higher degree of water treatment, higher pressures and higher temperatures and therefore requires more equipment at a higher cost. Also as the steam temperatures are higher, a greater amount of the energy is lost to the well bore in the injector well. Fresh water would have to be brought to the site as it would not likely be cost effective to attempt to use produced water, although some processes, such as “thermo-sludge”, where produced water is softened as it passes through the steam generator, might be considered. Conventional tube boilers require that the water be softened to prevent scale build-up on the tubes. For fresh water this can be accomplished with a portable ion exchange water softening plant that is regenerated with salt. Packaged water treatment and boiler units are available or can be fabricated in a range of sizes and skid mounted to allow them to be transported between sites. Another downside to steam injection is that the injector well casing would have to be designed to withstand the high steam temperatures and pressures, and there may be potential for loss of producer wells if steam breaks through and they are not designed for thermal operation.

The volume of steam injected can be matched to some extent with the amount of surplus vent gas available in an area to maximize use of the casing gas. Heat energy will likely have a greater impact on production than pressure maintenance.



Steam generation facilities will require greater operating attention and 24 hour monitoring, either on-site or remotely depending on the situation and regulations. As a minimum a standard control system would be required to ensure the generator will shutdown if there is a disruption in water supply or if the gas supply drops below the point where the generator can operate. Hauling of fresh water will be relatively high cost depending on the distance from the source. Centralized softening would lower the capital and operating costs to some degree but it would be more difficult to avoid contamination of the softened water during trucking unless trucks were dedicated to this service. Softener regeneration waste would have to be disposed of and regeneration salt and other treatment chemicals, such as oxygen scavenger would have to be supplied.

Main limitations will be capital costs for the equipment, hiring and training of operators, and the need for thermally completed wells.

Flue Gas Injection Steam Generator (Option Sheet 12.9.4) - This option would make use of downhole steam generation technology which was developed in the 1970's, but use it to generate steam at surface. Downhole steam generators require that the fuel and combustion air be compressed so that combustion occurs at the same pressure as the steam generation. Energy transfer to the water is through direct contact, so heat transfer tubes are eliminated which may allow produced water to be used for steam generation. The major cost is for air compressors, however, casing gas could be used as compressor fuel. Steam generation fuel could be diesel to avoid gas compression, or it could be compressed casing gas if there were sufficient volumes available. As in the case of steam flood, injector wells at least, would have to be thermally completed, and injection of CO_2 with possibility of oxygen and CO would require that corrosion issues be addressed.

This option does not result in any GHG emissions as all combustion gases are injected. Efficiency would be high as more of the energy generated goes into the well. CO_2 and nitrogen will enhance pressure maintenance and will assist with viscosity reduction.

Potentially no need for water treatment and ability to utilize produced water available on the site to avoid trucking of water

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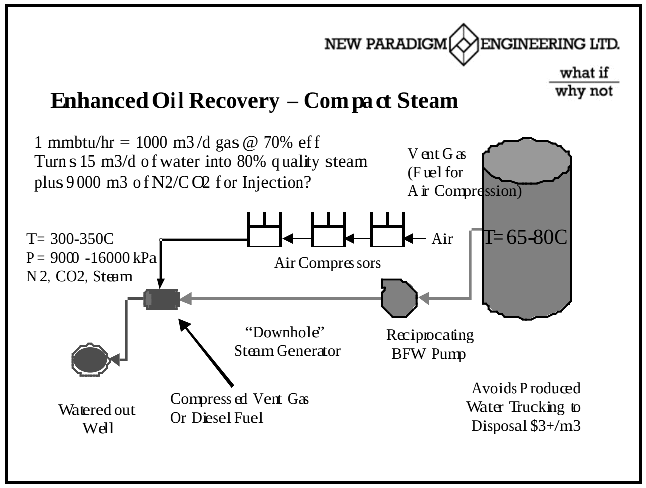


End result is more injectant for similar capital and operating cost as compared to steam

These systems are compact and some were operated in the U.S. and in Russia. Reportedly, the Russians ran tests with untreated fresh water with the generator on surface and did not encounter any major concerns with corrosion. Their concept was to inject steam in a "huff-puff" mode so that no one well was exposed to the stream for a long period. Operation of high pressure air compressors can be hazardous as special lubricants and operating procedures are required.

To utilize casing gas as fuel it would have to be compressed to the steam generation pressure. Generally, compression of gases is much more expensive than pumping liquids. This option would require the development or acquisition of downhole generators, which are not likely in production at this time, and would require considerable engineering time and testing to develop and prove the feasibility. Might be a better option for SAG-D type operations where pressures are lower.

CO2/Nitrogen Injection (Option Sheet 12.9.5) - A recent process development is a design for a compressor system where the exhaust engine gases are treated and compressed for injection. This provides a CO2/N2 stream with little or no exhaust emissions. The major advantage over methane injection is that a greater volume of gas is injected for the same amount of methane. I.e. the volume of gas injected could be 9 times higher based on the stoichiometry:

$$CH_4 + 2O_2 + 8N_2 \rightarrow CO_2 + 2H_2O + 8N_2$$

Details of this process have not yet been determined. Option is based on an article in Nickel's New Technology Magazine (December, 1998) for an underbalanced drilling system developed by Underbalanced Drilling Systems Limited of Calgary, which was designed to use propane to generate N2/CO2 for underbalanced drilling operations. At the time the article was written UDSL had 3 units in operation and it was claimed that the system would reduce the cost of supplying Nitrogen to half the cost of direct supply. Substituting casing gas methane for propane should be feasible.

This method may have other advantages as evidence from ARC's "AWACT" technology is that injecting gas might shut off some water production at producing wells.

Key design issue is matching energy required to compress the exhaust gases with the energy supplied by the methane. At high pressures the methane supply may not be sufficient to compress all the exhaust gas so some exhaust might have to be vented.

Exhaust treatment process to remove water vapour and other contaminants appears to be proprietary information and may be difficult to assess.

Breakthrough concerns would be similar to methane option and there is the additional concern that breakthrough of CO2 and N2 to the producing wells will lower the heating value of the casing vent gas at other wells and cause elevated corrosion in the production equipment. Most heavy oil wells are completed near the top of the producing zone to avoid water breakthrough, this will make them more susceptible to gas breakthrough, especially if there was a pre-existing gas zone at the top of the formation.

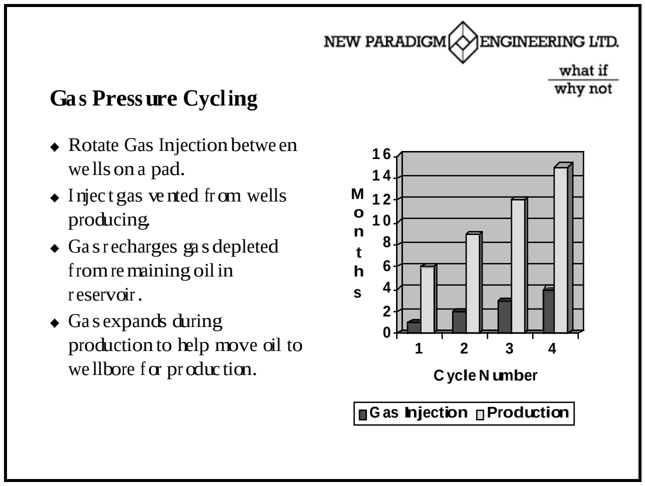
Future Project #11 – Investigation of EOR Facility Options - Further Research and Study by New Paradigm Engineering Ltd. These options were not allocated a great deal of effort in the original study proposal, however, this study shows considerable potential for these options to be viable alternatives to increase heavy oil production and recoveries, while reducing operating costs and environmental issues. A proposed extension of this work would be to continue to work on these options and obtain more information on equipment possibilities, costs, potential for modularization and the pro's and con's of the various options. Efforts could be focus on one or two of the best methods, or to cover all options for a consistent comparison.

6.4.2 Pressure Cycling

Injection Pressure Cycling (Option Sheet 12.9.6) - Methane pressure cycling has been considered as a viable method of stimulating production of heavy oil by charging the reservoir with methane then allowing it to depressure. This enhances foam production to move oil to the well bore and has been suggested for heavy oil applications in thin reservoirs, which are not normally considered suitable for thermal processes. In this option we are extending this as a variant on methane, N2/CO2 or short-term steam injection. The equipment would be used on individual wells or horizontal wells. Vented gas or combusted vent gas would be injected to stimulate production and may also help shut-off water by a process similar to ARC's AWACT treatment. Equipment would be similar to the continuous injection option but injection would be moved between wells and some production would be lost during the injection cycle. This process is facilitated by a low-pressure gas distribution system to allow single well sites to receive gas fro the stimulation, supplied by other wells in the area.

Facilities similar to methane, N2/CO2 and steam injection systems. See Options 12.9.1, 12.9.3, 12.9.4 and 12.9.5.

May provide a more rapid response and the equipment could be used at single well batteries or at isolated wells. Avoids problem of gas breakthrough as there is no sustained injection, although the gas will be produced back through the well it was injected into.

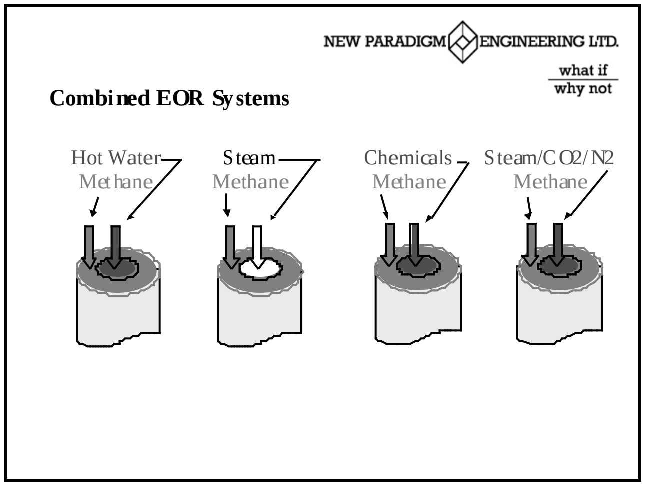


The equipment required can be leased or rented for a trial and no wells have to be dedicated to injection. However, production is lost while injection is underway so there must be demonstrable gains in production. Vent gas is only utilized while the equipment is at the venting location or where there is a gas collection system that can be utilized to supply gas to the compressors.

Future Project #12 – Investigation of Pressure Cycling Options - Further Research and Study by New Paradigm Engineering Ltd. with a third party research provider. The basic gas injection options could lend themselves to pressure cycling as a form of production enhancement. SRC has been doing some work on pressure cycling with methane in horizontal heavy oil wells. This work might be enhanced by considering pressure cycling for vertical wells and with N2/CO2 streams. The basic process would enhance foam formation in the reservoir to increase production.

6.4.3 Other Combinations of EOR Methods

Other Combinations (Option Sheet 12.9.7) - In cases where the supply of produced, or other water, is limited there may be potential for combined processes. For example: any water that is available could be pumped and heated to 150-200 degrees C (see Hot Water Flood base process). The remaining vent gas could be compressed (see gas compression options) and injected down the well annulus to provide a simultaneous gas/hot water flood. Annulus gas injection would be preferred as: gas injection, with the water, through the tubing would increase the water pressure required as the fluid column in the tubing would be significantly reduced; maintaining a gas column in the annulus will insulate the hot water from the wellbore and therefore reduce injection energy losses; separate injection flows can be controlled for gas and hot water, which can be used to improve overall sweep efficiency and changing gas flows would provide some of the benefits of a WAG (Water Alternating Gas) injection process; gas injection pressure will also give a direct indication of bottom-hole pressures.



The equipment would be similar to that proposed for the base gas EOR options and could be kept quite simple and skid mounted. Operation can be adjusted based on what injectants are available or which would provide the greatest economic benefit at any given time.

Prediction of reservoir effects will be more difficult due the varying flows which would be based on optimizing use of injectants and/or equipment instead of being pre-determined for the flood scheme. As in all EOR methods the process and system must be easily adapted and portable between sites to maximize return on capital and optimum use of equipment in an area.

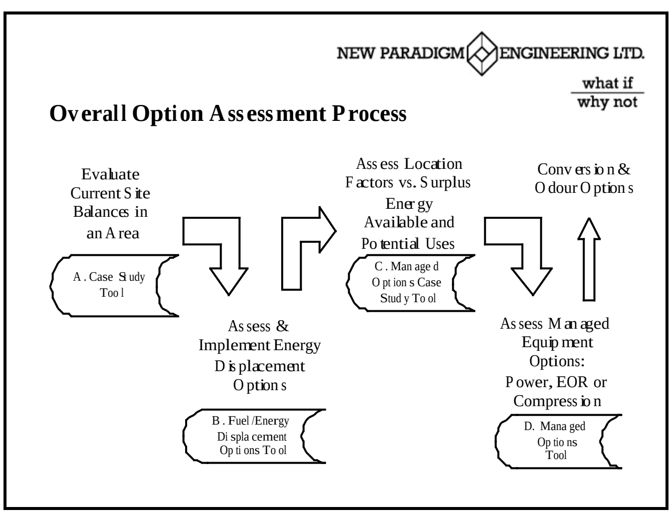
7. Technical and Economic Assessment Tools

While economics has not been the primary factor behind the utilization of casing vent gas in the past, there is a growing awareness that casing gas use can significantly reduce operating costs. Our assessment is that it will likely be economic to utilize casing gas at most venting wells to meet on-lease energy needs and that in many cases the payouts on capital invested will be less than one year. While we have put considerable effort into addressing the economic impacts and costs, there is still a need to achieve management and operational staff buy-in to demonstrate the value of converting sites to casing gas.

The purpose of this section is to provide some information and tools to allow producer staff to easily determine the economic benefits and evaluate the various options. Due to the large differences between how various producers account for and track costs, and the economies which can be realized by producers with larger numbers of wells, or more favourable commercial terms with suppliers, many of the key data can be input to the spreadsheets by the producer. We have provided some ranges of costs for various components based on our discussion with suppliers and feedback from producers.

7.1 High Level Comparison of Options – Use of vent gas to back-out purchased fuel is assumed to be the preferred first use of vent gas as it has excellent economic returns and the quickest payout of all the options considered. Also, at normally expected GOR's, there are times in a conventional heavy oil well's production life when there is no surplus gas available. Therefore, management of vent gas must be considered from a strategic point of view, and all potential opportunities assessed to allow for the development of a robust strategy to maximize the return from the vent gas energy with the minimum cost and effort. In some cases an option may look very good based on current operations, but may not stand the test of time as variables change. This section is intended to provide the initial high level overview and suggest a logical approach to addressing all the variables and levels of work that need to be undertaken.

7.1.1 Assessment Process – The assessment process proposed attempts to maximize return and allows for producer staff to focus on the various options when and where appropriate. The four basic steps are covered by four tools, which are being developed and will be further enhanced in follow-up work:



- Tool A – Case Study (see 11.4.4.1.) focused on assessing the overall supply and demand situation and parameters for a given producing area. This tool takes known data concerning an existing operation and provides an energy balance for the area. It also produces graphs and charts to highlight sites with large surpluses of vent gas, and attempts to produce fuel use correlations to help define fuel use for sites where that information is not readily available. This is best used by field production personnel, to prioritize sites for fuel displacement, to provide the economic incentive, and to provide information for estimating fuel use. The fuel use information and net supply/demand balance can also be output to producer staff to assess the utilization options for any large surplus of vent gas. This tool is unchanged from the Interim Report but will be upgraded to a Beta version as described later.

- Tool B – Fuel/Energy Displacement Option Assessment (see 11.4.4.2.) focused on assessing the costs of all the various fuel displacement options. This is also intended for production support staff to help budget for and assess the various options for a given area. Many options are similar in cost, so often it may be operator preference or a drive to standardize the operations that finally determine the systems used. This tool provides input to that decision and tools to assess options.

- Tool C – Managed Options Case Study (see 11.4.4.3.) focuses on the strategic decision of what to do, or what might be done, with gas that is surplus to an area's own energy needs. The basic tool has been developed and is included in this report. Input's are commodity prices, well information, some indication of other sites in the area which impact managed options decisions (e.g. water disposal sites) and some rough values for the cost of equipment for about 1000 m3/d of gas (1 MMBTU/hr of heating). Recommended values are given, however, these can be varied, to determine sensitivities or to reflect actual costs, which might be available from various sources. The main output is a plot of the cumulative cash flow (over seven years) for each main managed option, as well as fuel displacement and methane conversion of unuseable surplus gas. This plot helps to compare the economics for a given current situation and is combined with other technical comparison tools to help select a strategy for an area. In the current version there is no facility for adjusting the output based on changes in well operating conditions based on production profiles. We hope to build that into the final version. A second managed case spreadsheet is provided, however, which allows parameters for fuel use vs. fluid production to be input, so that oil, gas and water rates can be manually changed to run scenarios assessing the effects of increasing water production, decreasing oil and gas as a producing area is depleted.

- Tool D – Managed Options Assessment is more complicated than we had originally thought, so we have decided to forego issuing a draft version until features can be improved in the final beta version. This is based on the original project scope, which had tools as an add-on, and we did not want to delay the main report and fuel displacement tools, which provide 80% of the benefit. The main feature which will make the tool more useful is some nodal mapping capability to allow the user to set-up the current situation with existing wells (by LSD), well production profiles, support sites, pipelines and power lines. This is necessary to optimize decisions to maximize return on new capital facilities, which might be added to utilize more gas. E.g. a common occurrence is where a site already has a county owned, sales gas line coming into the site. In this case it may be better to have more compression sites than to duplicate a pipeline system. Also many of the options covered are either: a) standard equipment, such as pipelines, generators and compressors, or b) new equipment for which little reliable cost information is available. As a result of a) many options can already be assessed by standard engineering practice and tools and b) requires more information to be developed. The main advantage is to provide a means to compare the options on a more or less equalized basis or identify conditions under-which a particular option might make it worthwhile to switch options. (e.g. if oil and gas prices dropped, but power rates remained high). Our feeling is that the benefit of this tool is longer term, and that most of the immediate effort, will be supported by the tools already developed and included in this report.

7.1.2 High Level Pro's and Con's – 11.4.2.1 provides a high level assessment of the pro's and con's of each strategic use of vent gas. Key factors are capital costs, commodity prices, royalty and tax issues and potential impacts on oil production for the EOR options. We believe that this analysis supports our view that efforts should be focused on wide spread implementation of fuel displacement, followed by a strategic move into one, or more, of the managed options, after the options have been evaluated. This table also lays out some of the more intangible risks and potential impacts of the various option areas, including control, extent of external negotiation and/or contracting required to implement the options, and the ease of gathering information to make decisions.

7.1.3 Flowsheets – A set of flowsheets are provided in section 11.3, which were used extensively to develop this report and prioritize or group options. They should also be referred to ensure options are being considered in appropriate applications. Our intent is to use the flowsheets as a map to help people access the one page option sheets that will be of most use at any given stage of implementing vent gas options.

7.1.4 Economic Assessment for Comparison of Options – With widely fluctuating commodity prices and the wide range of situations it was felt best to limit economic assessments to simple cash flow analyses. The scope of this project does not allow for assessment of potential for future changes in economics, however, the tools do allow users to input their own values for most parameters that might be subject to real or projected changes, so that cases can be easily run on a consistent basis.

Future Project #13 – Case Studies - Further Research and Study by New Paradigm Engineering Ltd. and Producers. A key strategy to increase the use of these options for vent gas mitigation is to prepare and present case studies similar to the one contained in this report. These studies could be prepared by New Paradigm based on producer data or the producers could prepare them directly.

7.1.5 Valuation of GHG Credits – An opportunity to generate additional revenues for mitigating vent gas emissions is represented by the growing practice of trading, buying and selling Greenhouse Gas Emission credits. For conventional heavy oil applications it is difficult to fully assess the financial benefits, which might come out of this, however, it should be worthwhile for producers to consider learning more about the potential.

GHG credits result from reducing emissions on a per tonne of CO2 equivalent basis. A tonne of methane emitted is usually assessed as being the equivalent of emitting 21 tonnes of carbon dioxide. This is the conversion factor generally recommended, by convention, and used by Statistics Canada and other Canadian governments to track GHG emissions. Converting methane to carbon dioxide and water vapour, through combustion or oxidation reduces the net GHG emissions by a factor of 18 tonnes of CO2(eq) for each tonne of methane normally vented, and 21 tonnes of CO2(eq) if that methane is used to displace the use of another hydrocarbon fuel. The calculations are based on stoichiometry and mass balances, shown below:

$CH_4 + 2O_2$ ---> $CO_2 + 2H_2O$ + energy (stoichiometric basis)

1t of CH_4 + 4t of O_2 ---> 2.75t of CO_2 + 2.25t of H_2O (mass basis)

21t of CO2(eq) ---> 2.75t of CO2 (GHG basis – ignoring GHG water and oxygen)

Green House Gas Trading Credits - Green house gas trading is still in its infancy, but it shows great promise for the overall reduction of environmental pollutants from all industries. The premise behind trading is that some industries will be able to reduce their emissions below the regulatory requirements for less cost than other industries, or perhaps a large improvement in emissions can be realized when an improvement to meet regulations is completed, leaving an "excess" reduction of emissions. These reductions below the required limits can then be sold to other companies who are either having trouble meeting the current guidelines, or require additional reductions for future licensing. For example a high volume producer may have utilized the current available technology for cleaning a waste stream, but the actual mass flow of the pollutant is unacceptable for their regulatory requirements. Purchasing credits would be an optimal solution for this producer.

There are several green house gas trading exchanges in operation in North America. In Alberta, GERT (Green house gas Emission Reduction Trading pilot) is a pilot trading exchange where participants can gain experience in trading and may have potential for a future full scale trading system. The KEFI exchange is a private exchange house that operates based on the Kyoto protocol coming into effect. Air Bank and Cantor Fitzgerald are trading companies operating in the U.S. Based on a review of some of the projects offered for trade on these sites, the budget allowances from historical trading reductions in NO_x emissions are worth $420 US per ton and are expected to rise. Sulphur dioxide (SO_2) emissions reductions are worth $150 per ton, and CO_2 (and equivalent) reductions are worth $.50 to $2.00 US per ton. (Some trades have higher prices, ranging from C$4.50 to C$17.00 per tonne) The value of a reduction is dependent on the location of the reduction and the legislation in effect on trading in that area. For example a reduction in NO_x in New Jersey was traded at $1200 US per ton. All trades must be verifiable, indicating that a real measurement of the reduction will be required for validating the trade. Sometimes third party evaluations of the reduction are helpful in verifying the emission reduction.

On the GERT exchange a reduction for credit is defined as follows:

A GHG Emission Reduction is:

- the reduction of emissions from an existing source or sources;
- the avoidance of an increase in emissions that would otherwise have taken place; or
- the sequestration of GHGs that would otherwise have remained in or been released into the atmosphere.

An emission reduction project or activity is an identifiable measure, or combination of, measures, implemented specifically to reduce, avoid, or sequester GHG emissions.

Trading can be accomplished by defining the reduction, estimating the available tonnes for the particular project on an annual basis, the estimated life of the reduction and the offer price for the credits. A written description of how the reduction is being achieved is also necessary. The Credit offer can then be classified and listed on the exchange. Each exchange has specific requirements for making an application to their exchange. Some exchanges may have fees for trades.

There are three types of trades: open market trades, offset trades and allowance trading. Open market is the type that is currently operating in Alberta under pilot conditions. A trade is offered, by the seller of the credit, and the final conditions are negotiated between the buyer and the seller. There is some risk associated with these trades, because there is no legislation governing what will be accepted by the regulatory agencies as credit for air licenses in the future. However the trend in regulation is to have more stringent requirements and lower emission levels even on older plants. Offset trading happens when an emission source operation reduces emissions to a level below that required in the operating license, creating a credit situation. Allowance trading is done in the US. Geographic areas are allowed a certain amount of emissions with each operation having an allowance of emissions. If an operation has less emissions than it is granted in it's allowance it can trade the excess allowance to another operation in the area for a price.

Currently there is some risk associated with trading as the legislation is not in place, however, at the meeting of Canadian Environment Ministers October 19 and 20, 1998, the following developments occurred:

- Ministers noted the progress being made by the Credit for Early Action Issue Table.

- Ministers endorsed the Statement of Goals and Principles for the design of a credit for early action system developed by the Table as a basis for moving forward.

- Ministers agreed that to the extent possible, all those taking early action that results in verifiable reductions in greenhouse gas emissions would receive credit against any future emissions obligations.

Although trading can be done internationally, it may be advisable to trade locally for the maximum benefit, and the highest likelihood of the credits being recognized by local regulating bodies.

Recently, Canada has publicly reaffirmed it's commitment to Kyoto, at the CoP 6 conference in The Hague. Agreement has been achieved on the broad principles in the ways countries may earn and exchange greenhouse gas emission trading credits. One of the three key mechanisms, the International Emissions Trading (IET), permits industrialized countries to buy and sell emissions credits among themselves. This would seem to indicate that the risk for buyers in early action is low, possibly driving the prices of green house gas credits even higher. Some are forecasting $40 per tonne in the future.

Based on the above discussion we believe it is valid to assign some value to GHG emissions reductions. In the spreadsheets tools we have included GHG reduction calculations on both a tonne of $CO_2(eq)$ basis and as a potential cost benefit, with a value per tonne of $CO_2(eq)$ input by the user. To remove this revenue the value per tonne just needs to be input as zero. We have generally used C$0.50/t as a minimal value, however, as indicated above national and international developments may increase this. Based on current estimated costs for most CO2 sequestration projects any cost less than about C$20-25/tonne will likely be more attractive than sequestration.

Future Project #14 – GHG Trading Demonstration - Further Research and Study by Producers. To assist in assessing the practicality of GHG emissions trading a demonstration project should be considered. A producer would reduce GHG emissions by one of the options, document the reduction achieved and attempt to trade credits. This demonstration, if successful could be used as a model for others to follow.

7.2 Pool Fuel Displacement Assessment

To optimize efforts directed at reducing purchased fuel use through casing gas utilization options, an overall assessment of the current operations on a pool by pool basis will help to quantify the prize and prioritize the well sites which should be considered for casing gas use. This is best done with up-to-date and consistent input information on production levels (oil, water, gas) and current fuel demand. As production changes the fuel demand will also change so this needs to be addressed in the overall assessment.

7.2.1 Gas Conservation, Energy Efficiency and the Environment

As indicated in previous sections one of the problems hindering casing gas utilization is the wide range of applications, energy demand and wide range of gas production volumes. Also a factor is the large number of individual wells involved. This economic assessment allows for consideration of the effects of gas conservation by backing out purchased fuel demand, energy efficiency by making better use of the energy generated on a lease, and environment through reduction of GHG emissions. For GHG emissions we have included a factor titled "GHG Credit", but this may be an internal value placed on reducing GHG emissions, rather than a firm sale of the credits. Gas conservation is the primary economic benefit by reducing operating costs, and will have other intangible benefits associated with it. Energy efficiency is only a factor when a site does not have gas being vented and must purchase make-up fuel.

7.2.2 Case Study – Tool A

As an illustration of the type of impact casing gas can provide, a case study, based on one set of recent data provided by one of the participants, is shown in Figures 7.1 to 7.6. This data was for operations in one area for 15 operating wells that had recently been tested for vent gas volumes. Total fuel cost savings for the 15 wells from use of casing would be almost $200,000/yr at only C$3/GJ. The case seems to be fairly representative of the range of variation that is often seen in a producing operation, but can be used to develop some area specific indications of energy use and economics. A CD is provided which contains this spreadsheet so that producers may input their own data in boxed areas to generate their own plots. The following describes each figure:

Data For All Wells – shows data received from the operator, with plots of "Lease fuel vs. Fluid Production" and relative volumes of vent gas vs. purchased gas. Three wells use propane fuel but the purchased gas volume is shown for an equivalent amount of natural gas. None of the wells in this case study currently use any casing gas. One well, #11, has an extremely high gas rate and has been taken out of the averages and "Vent & Purchased Gas" plots as it skews the numbers.

Purchased Fuel Gas Use Data – shows fuel use for wells where the producer also supplied values for engine fuel use. This can provide rough plots of the fuel use components vs. fluid production in a given area, which can then be used as input for other wells that should have similar operating characteristics.

Generic Economics (Line Gas) – This spreadsheet allows some analysis to determine rough economics for utilizing casing using various assumptions for purchased fuel costs, casing gas heating value and GHG credit value. Costs are input for assumed first year capital and operating cost to allow casing gas to be used. Based on the values input for the case study only one well did not have enough casing gas to meet it's total energy needs and payouts ranged from 2.4 to 15.5 months depending on the well. Fuel savings average $12,000/well, with a similar value of casing gas still surplus.

Payout vs. Site Fuel Use (Line Gas) – this shows a plot of the payout vs. site fuel use assuming $3/GJ for purchased line gas. Three curves are shown ("power" just indicates the curve is a non-linear curve) which show "winter", "summer" and "overall". This is to show that the changes required to utilize casing gas during the (7 assumed) warmer months of the year should be considered separately from the cost of winterizing the vent gas which requires more investment to cover the remaining months (5) and the net result of doing both in the "overall" case. The data points off the curve are for the well that did not have sufficient casing gas to meet it's energy needs, which reduced the benefit.

Generic Economics (propane) – Similar to the table in Fig. 7.3. Generally payout is quicker for wells using propane, although they are also fringe or new wells that have lower gas producing rates. Again one of the wells shows a negative surplus balance value as it has insufficient casing gas to meet its own needs. Average savings in this case are $19,000/well.

Payout vs. Site Fuel Use (Propane) – Similar to the plot in Fig. 7.4., and again the plot is skewed by the well which still required purchased gas and the fact that only three wells are included. In all cases the sites with the higher fuel demand, show the greatest benefit from casing gas use. If the expenditure per lease is the same.

Using the above plots the implementation of casing gas utilization could be planned to go after the highest payout wells first, or to just go after the wells that have a payout better than a set hurdle rate (e.g. less than 1 year payout). This type of analysis requires that vent gas measurements be made to allow the optimization, and might be a good justification for increase frequency of vent gas measurement.

7.3 Permanent and Relocateable Equipment Options for Specific Wells

Section 7.2 helps to evaluate which wells can benefit the most from vent gas utilization. The next step is to assess which option(s) might be used at a given site. Additional information on each option is provided in the one-page option sheets included with this report. While most of these should be technically feasible in many locations, each specific site in a given area should be at least generally assessed before options are selected. We have not attempted to propose or recommend a single "best solution" as there is likely no one option that will work in every situation. In some areas, e.g. wells with electric drives and no lease tanks we have included one page options to address these cases, but have not yet upgraded the spreadsheet to include these. We have prepared an EXCEL workbook to help assess options as described below.

7.3.1 Flexibility and Adaptation to Changing Needs

The assessment process we developed is intended to be used for all options. We have structured it to try and make it expandable while keeping some basic economic factors relatively constant. The four main cost components covered are: a) capital cost; b) operating cost for materials; c) operator and maintenance time and d) risked incident costs. Capital costs are based on current vendor input on price per unit with adjustments made, where appropriate, for units where capacity significantly affects capital cost. Operating costs for materials are mainly for options requiring on-going expenditures for Calcium Chloride or Methanol, etc. Operator and maintenance time is included, even though in some areas this might be very difficult to assess and is also very dependent on the well location and the operator, but it is felt all options should be compared on the same basis, and against the current situation, and that ultimately there is a cost when work is added on a routine basis, and a savings if work is reduced. Finally, the “risked incident costs” are an attempt to allow for consistent, quantitative recognition that problems, or benefits, may occur occasionally that add to, or reduce, the cost of various systems. The risk will be assessed as a single per incident cost multiplied by a frequency of incidents per year. Benefits will be assessed based on reduced purchased fuel demand with the ability to take GHG credits based on the value assigned to this by the producer. In most cases we assume that casing gas will be fully used before purchased gas is required, however, where the volume of casing gas is low this may not be the case due to other operational factors. Therefore this should be considered as a rough economic comparison only.

7.3.2 Option Assessment – Technical Comparisons

Technical comparison of the various options, where more than one option might be considered, are covered in section 11.4 in a series of tables that should be used along with the flowsheets in section 11.3 to address options at the appropriate time. For instance, it adds little value to consider glycol dehydration for winterization of vent gas for on site fuel use, however, it is a key option for some of the managed options.

7.3.3 Option Assessment – Economic Worksheets – Tool B

A workbook, containing a number of useful calculations has been developed and included on the CD in the appendix. Boxed cells indicate where the user can input their own site specific data. Other cells are protected which use calculations to ensure values are more or less consistently used in the spreadsheets. A printout of the worksheets is provided as Figures 7.7 to 7.12 which has been completed with some values in each box, which we feel might be representative for one of the wells from the case study. As we are trying to give representative values for all options, all the boxes are filled in, and the end result in Figure 7.12 is not a valid output. The intent is for the user to insert their own values and try different calculations if they want to look at various options for a given site. Some sheets also provide information or charts, which might be useful on their own. The beta version of the spreadsheets to be issued later in 2001 will make this workbook easier to use.

The following is a description of each sheet:

Generic Economic Factors – This sheet is for input of some generic economic factors which should be common to all cases and should not change between wells in a given area. We recommend that the user input the best values they can for this chart and then leave them alone as they go through options for any given site. Note that the cost factor for only one make-up fuel type is allowed. Our values are very rough, so a reality check should be made against actual costs incurred by the producer for a similar activity.

Case Specific Factors – This sheet looks at the site energy balance based on user input for oil, water and gas production, and onsite energy use. In cases where a set of conditions (e.g. engine fuel use) is known the input values can be adjusted to match. The user should try and use input information from the best available source. Output is the energy balance and also potential benefits in fuel and GHG savings.

Variable Cost Factors – The main variable cost factor, for some options, is in the calculation of the amount of water in a gas stream. This sheet allows the amount of water to be calculated. The user may have to interpolate on the graphs and input water content of the gas. Other sections are used to calculate costs for methanol or CaCl for a given amount of water. The plots could be printed out for the use of operators, where desired.

Tracing and Gas Heating – This plot is provided more for information when looking at the energy required to heat up, or compensate for heat lost, from a gas stream.

Option Specific Factors – This is the primary sheet for inputting data for a specific option. The user inputs data into the boxed cells to match the units indicated. The spreadsheet uses previously calculated or input values to calculate the capital, operating and risk event costs for that option. Values should be filled in for all the options which would be installed so that the final assessment is on the total cost. Again Figure 7.11 gives some initial suggestions for each option, but the user should try and input values based on their own experience wherever they can. Capital costs are generally based on input received from vendors but should not be considered as quotes. For any case where an option is selected that requires capital ensure that the capital value is at least $1. If the option is not being considered for a given case input 0. This sheet also has calculations of risk events. Not all options have the same risks and we have only allowed one, predetermined, type of risk event for each option. The user can try other risk events just by substituting their own values.

Summary of Options – The only input on this sheet is for the probability (#/yr/well) for the risk events. The risk input is likely to be highly subjective. The highest cost per event risk will be those that result in lost production or major repairs, but these should be infrequent. While other events may have low impact per event but add up over time as they are higher frequency. At the bottom of the sheet the costs and benefits are output with a simple cash flow for the first year (capital) and second year (on-going annual), as well as an estimated payout in months. As indicted above the values in Figure 7.12 are not for a valid case as they include all options.

7.4 Managed Equipment

Once all sites have facilities in place to displace purchased fuel the next step is to evaluate the economics of using the remaining surplus and exporting the energy as gas, power or as incremental oil production. Again for this assessment we have used simple cash flow analysis to assess options.

7.4.1 Strategic Uses for Surplus Vent Gas

As indicated earlier the use of vent gas is a strategic decision and there are many factors which may impact the economic success of a strategic direction. Even the attitude of the negotiations with a third party can affect the value generated. For instance if a producer's attitude is that the vent gas is an environmental problem, that they just want to get rid of it at little or no cost, then they are not likely to obtain fair value for the energy contained in the gas. Also if the third party, such as a gas or power consumer, believes that the producer has no other options to utilize the gas then they will likely be able to negotiate a lower price. By contrast if a producer can negotiate to provide energy only at times when the value of the energy is at a peak, and use the gas elsewhere when prices are low, then revenues might be significantly higher overall.

The ability to obtain premium prices for the energy output is driven by the willingness and ability of the producer to pay attention to those various commodity markets. Generally a producer would likely not be able to negotiate from strength in a market that is new to them, such as power or GHG emissions. In those cases it may be necessary to bring in outside help to negotiate the agreements. If the deals are favourable enough it may also lead to other opportunities using other gas produced in the area.

The main message here then is that the vent gas should be treated as a valuable resource that can be used in many ways and use that to advantage.

7.4.2 Option Assessment – Technical Comparisons

As in the case of the previous option areas technical comparisons for managed options have been completed and included in section 11.4 and the flowsheets in 11.3.

7.4.3 Managed Options Case Study – Tool C

As described above this tool is to provide a strategic assessment of where any surplus gas might be used to best advantage. The tool should be used to analyze as broad an area as possible that includes the key components of venting wells, gas and power lines, water disposal and older or depleted wells that may be candidates for small scale EOR methods. As in the case of Tool A this is an overall assessment to determine priority for consideration. There are actually two workbooks provided at this point, as in one version well fuel demands are input (Tool C – Why Not) while in the other site fuel demands are calculated base on a user input relationship between fluid production and fuel demand (Tool C – What If). As such one tool is used for assessing a current condition and assuming it continues, while the second allows a series of snapshots of the operation to be generated based on changes in production of gas, oil or water.

The following is a description of each sheet:

C1 – High Level Variable Costs and Revenues – This sheet is for input of some generic economic factors, mainly commodity (buy and sell prices) and transportation costs, which should be common to all cases and should not change between wells in a given area. We recommend that the user input the best values they can for this chart and then run cases to generate sensitivity cases. Note that we are not showing propane as a fuel option as it plays a small part in larger scale assessments and most producers are already moving to reduce propane use.

C2- Case Study Well Data – This sheet allows for input of well information on production, fuel use, power use, distances to main support facilities and annulus pressures. This is the only sheet that changes between the two spreadsheet options. With the main difference being that one (Why Not) is for consistent actual data on production and fuel use from the field, while the second (What If) allows production to be input and varied for a case with fuel demand calculated based on an assumed linear relationship, with user provided slope and intersect. The slope and intersect values can be developed by using the "Why Not" spreadsheet with actual data. This sheet includes charts indicating the fuel to fluid production relationship generated or input, and also shows the supply/demand balance for each well.

C3 – Energy Displacement – This sheet is similar to one in Tool A with some extension and changes to allow the costs and benefits for a low pressure gathering system to be assessed. The user can input values for number of months of summer or winter, a surplus vent gas volume cut-off, a cut-off for pressure for the gathering system, and some assumed costs for on-site fuel use with or without compression. The sheet then uses information from previous sheets to determine basic information to define what wells are tied-in, which need compression, etc, that feeds into the managed option sheets. It also indicates how much of the available vent gas can be used for fuel displacement, how much surplus gas can be managed and how much remains to be converted.

C4 – Low Pressure Gathering – This sheet calculates costs and a cash flow profile for a low pressure gathering system. Most of the data comes from previous sheets. This system and profile are added into all the managed options on the assumption that a common need will be to make as much surplus gas as possible available for the managed options at a smaller number of sites. In a real case where some facilities or low pressure pipelines already exist, they can be excluded by modifying the inputs in sheet C2 to show zero distance to the tie-in point.

C5 – Power Options – This sheet calculates a generic power generation case, main inputs are power generation costs per kW capacity, operating costs and distance to a 25 KVA power line from the generation site.

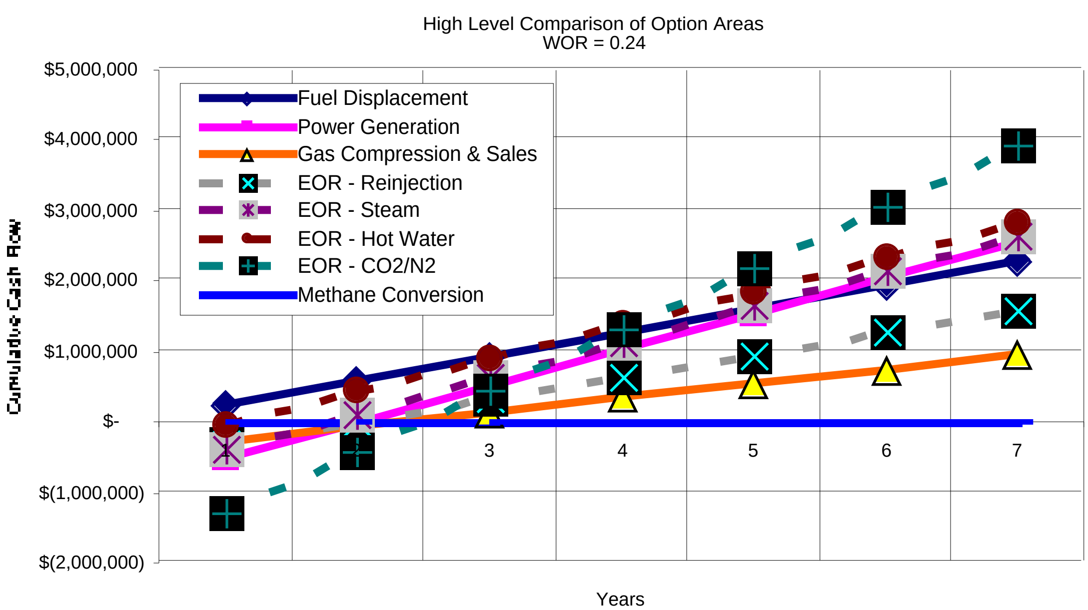
C6 – Compression Options – This sheet calculates a generic compression case for sales. Main cost factors are pipeline costs which are a function of size and distance to a tie-in for sales, and compression and dehydration equipment.

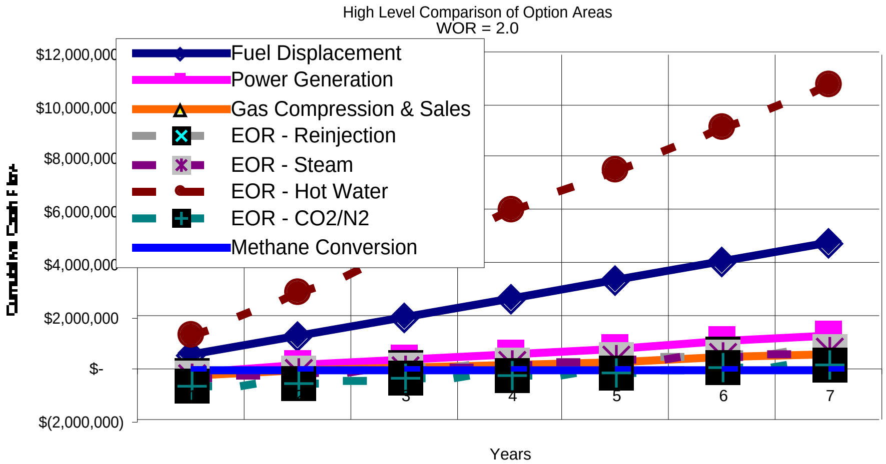
C7 – Basic EOR Options – This sheet combines calculations for the four basic EOR methods considered as options: Methane Reinjection, Mini-Steam Generation, Hot Water Flood and CO_2/N_2 Injection. Each process has unique parameters. A major difference between the options is that hot water flood includes injection of warm water from the production tanks, with the managed gas providing some incremental heating. At higher WOR's this difference significantly enhances this option due to the reduction in water trucking costs (see figures below). This should be separated out in the next version of the tool as the warm water could be reinjected locally in all cases with separate injector wells and pumps. An advantage is that if you are already set up to reinject produced water then injecting warmer produced water using surplus vent gas is relatively easy to add.

C8 – Methane Conversion – This sheet calculates what it might cost to convert any methane not used by the other methods. Right now it assumes that any wells not tied-in to the low pressure gathering system would be fitted with equipment to convert surplus gas. In reality there may be times when even gas entering the low pressure gathering system will be unusable, due to lack of capacity in the managed equipment or equipment being out of service.

C9 – Comparison Options – This sheet summarizes some basic information from a given run in numerical form. Throughout the tool we have used a seven year time frame at constant rates, to help give an indication of time to payout at constant conditions, however, it is unlikely with conventional heavy oil wells that conditions would remain static over this long a period. Therefore they should not be taken as any more than rough trends.

C10 – Plot of Options – This chart shows the relative cumulative cash flows of all the options including fuel displacement and methane conversion. As can be seen in the examples below, (only variable changed is the WOR) the outcomes show that options for the case study will generally all eventually payout but can be very sensitive to EOR recovery factors and WOR changes. In most runs the best options for vent gas use (based on early payout and cumulative cash flow) appear be fuel displacement and hot/warm water flooding to use up surplus gas.





7.4.4 Option Assessment – Economic Worksheets – Tool D

This tool is still under development. To effectively evaluate managed options in more detail there is quite a bit of additional information, which must be input and considerably more calculations done. Given that the Alberta Energy Research Institute is providing funding to upgrade the spreadsheet tools, New Paradigm Engineering Ltd, felt that it will be more effective to develop this tool in it's final form, rather than in two stages. Also it will provide more time for us to collect some more representative cost information from some vendors on options such as compressed gas transportation.

We are planning to complete the spreadsheet enhancement project by mid-April and will reissue the tools at that time. Meanwhile, the rough forms of tools A, B and C can be effectively used to meet the primary objectives of implementing fuel displacement options and to begin strategic assessments for the managed options. The April issuing of the final tools should be in time to help in more detailed planning, coming out of the use of the first three spreadsheet tools. When developed tool D will provide:

Additional Generic Cost and Contract Input – The two areas where input is still needed is for other options for equipment, and for potential third party contract terms. These are necessary to allow assessment of options where the producer does not provide the capital facilities, but instead rents, leases, contracts or enters into some other sharing agreement with a third party for use of power lines, pipelines, compression and/or power generation equipment. This will result in some loss in commodity value but result in earlier payout and will also include provision for buying back waste heat for cogeneration opportunities.

Well and Facilities Information – Ideally we will be able to restructure the data input to allow easy illustration and calculations for pipeline networks, powerline networks and other facilities such as water disposal sites. This information would be common to all tools, with one route of analysis using measured field data and another route for forecast data. We will also work to make provision for inputting production profiles for wells so a more realistic 5-7 year outlook can be generated.

Low Pressure Gathering Network – Expand on the system in Tool C to allow for use of existing lines and possibly some gas being transported through lengths of line at higher pressures.

Compression Design – We do not plan on putting a lot of effort into this area as most producers would deal with gas compression facilities as a normal part of their business. This section may not be greatly different from the existing sheet in Tool C and would serve as a control case to compare against the other options.

Power Design – Again not a lot of detail. Generally our assessment is that a third party with expertise in power generation and transmission would likely be involved, so the tool will focus on options for business terms for power generation, transmission, load trade-offs, and co-generation with waste heat. The assessment of the cogeneration option requires a recycle to the fuel displacement step as the gas could be used first to generate power, then the waste heat used to free up more gas to generate power.

EOR Water/Steam Processes – These are most affected by water handling issues and considering steam generation with produced water may be a possibility. As a minimum the warm/hot water injection option needs to have the two components (warm 80 degrees and hot 100 degree plus) options separated.

EOR Gas Processes – The methane reinjection process is relatively straight-forward, however, this and the other gas options and process cycling have some impacts on the nature and volumes of the gas vented from producers so could be handled a bit differently. For the combustion gas injection system we still do not have information on costs from the vendors/providers of the system.

Methane Conversion – This area requires the inclusion of an option for centralized conversion of surplus gas as well as more detailed consideration for single site conversions. Not a lot of effort will be placed on this tool as the incentive to take action will be low unless GHG emissions credits or regulatory changes drive wider implementation of these options.

Overall Results and Combinations – In many areas the actual development will likely be a mix of systems including fuel displacement, compression, power generation, EOR and conversion. In this tool we would like to provide some way to accommodate relocation of equipment to maximize benefit. As the funding for this work will be limited this may not be achievable by April but may come about through future enhancements to the tools.

8. Regulatory Issues

As indicated earlier it is not the intent of this project to suggest or recommend specific regulation changes or royalty assessment changes. Most producers are continually working with the regulators on these issues. This section is intended to provide some background information and contacts if producers wish to discuss regulatory or royalty changes which might help them to implement vent gas mitigation options.

8.1 Royalty and Tax Implications of Vent Gas Use

8.1.1 Alberta

Alberta currently has no firm limits on venting and relies on the producers to set their own limits, based on the economics of vent gas recovery and production. However, given the high volumes being vented some limit might be set as a guideline to encourage conservation. At the same time some interim directives have been issued to reduce the paperwork and lead time required to install small compressor systems.

Currently the Alberta Government policy on gas diverted from flaring is that no royalty would be applied to this gas, even if is used to generate profits. It is assumed that the same type of rule would be applied to vent gas.

Producers interested in reviewing regulation issues in Alberta should contact:

Mr. W. Earl Martin, Senior Engineer
Alberta Energy and Utilities Board
Corporate Enforcement and Surveillance Operations Group
Production Operations
640 – 5th Avenue SW
Calgary, Alberta T2P 3G4
Phone – (403) 297-6510 Fax – (403) 297-2691
E-mail: earl.martin@eub.gov.ab.ca

Producers interested in reviewing royalty issues in Alberta should contact:

Mr. Jerry MacPherson, Director, Business Development
Alberta Department of Resource Development,
Oil Business Unit
14th Floor Petroleum Plaza, N Tower
9945 – 108th Street
Edmonton, Alberta T5K 2G6
Phone – (780) 415-1283 Fax – (780) 422-0975
E-mail: Jerry.MacPherson@gov.ab.ca

8.1.2 Saskatchewan

Venting for an individual well is limited to 850 m3/d. Above this value the gas should be conserved and a request must be submitted for co-production.

Saskatchewan does not have a royalty on solution gas.

Producers interested in reviewing royalty or regulation issues for Saskatchewan operations should contact:

Mr. Bruce Wilson, Executive Director
Petroleum and Natural Gas Division
Saskatchewan Energy and Mines
7th Floor, 2010 Scarth Street
Regina, Saskatchewan, S4P 3V7
Phone – (306) 787-2591; Fax – (306) 787-2478
E-mail: bwilson@sem.gov.sk.ca

Currently the Saskatchewan Government collects sales tax on purchased fuel for on-site tank heaters, which are required for oil treating and shipping, while engine fuel is exempt from sales tax as it is required for oil production. This tax has not been taken into account in our economic spreadsheets. It is assumed that no sales tax would be applied if casing gas is used in the tank heaters.

8.2 Implementation Issues

The main impediment to implementation raised by producers, beyond economic considerations, is the issue of rapid approval for use of options. As the vent gas may only be available for short periods of time it is necessary to be able to move quickly. In Alberta the EUB has issued a guideline making it easier for producers to install small (under 100 hp) vent gas compressors to collect vent gas. Producers may find similar guidelines necessary for low pressure collection systems, power generation facilities and EOR facilities. A recommendation from the EUB was that producers should include potential vent gas uses in their initial development permit applications for a lease, rather than modifying them later. The permit might allow for a range of options to mitigate vent gas, or implement some types of small scale EOR or productivity enhancement that would not require producers to apply to modify the permit at a later date when they actually begin to implement a vent mitigation solution.

8.3 Emissions Trading

Emissions trading has been covered earlier in section 7.1.5. Any progress made in formalizing the regulations and rules for trading would help to firm up the additional benefits that might be generated for methane conversion and the reductions in GHG emissions that will result from implementation of any or all of the options contained in this report. Also, it may become clearer what value will ultimately be placed on GHG credits. It is generally anticipated that the value of credits will increase over time and may reach levels considerable higher than the C$0.50/t used in most of the spreadsheet tools as a conservative initial value. If GHG emissions reduction methods, such as CO2 sequestration, become necessary then the value of other emissions reduction may approach $20/t CO2(eq). It should also be noted that many people disagree with the value of 21 normally used to assess the CO2(eq) value of methane as this is estimated to be the value over a 100 year time span. A value often quoted for a 20 year span is 65, in which case this could triple the size of potential GHG credits if it was decided to use the shorter term values.

9. Next Steps

Due to the widespread venting of methane from conventional heavy oil production sites and the pressing need for the industry to respond to the increasing regulatory and public pressure to implement solutions to reduce emissions. It is critical that progress be made on moving options into use in the field. As indicated in previous sections, there are many options that will solve the problem, however, not all options provide the same economic or environmental benefit. The main focus of the next steps is for participants and other in the industry to develop well thought out strategies and implementation tactics to achieve higher returns from this resource and avoid wasted or counter productive activity. The following actions are proposed to help move the industry in those next steps, to support the general movement to action, which is being reinforced by the regulators in Alberta and Saskatchewan.

9.1. Technology Transfer

The first need is to make everyone in the participating organizations, and in the industry in general more aware of the wide range of technologies, opportunities and options that are available to them. Many of those options might be more productively addressed by companies collaborating to install low pressure gas systems, implementing some of the fuel displacement options and conducting further strategic assessments and testing to determine if the casing gas properties (i.e. pressure) can be adjusted. The following strategy will be implemented by New Paradigm Engineering Ltd to help with this technology transfer process.

9.1.1. Use of New Paradigm Generated Materials – While New Paradigm retains control of the intellectual property related to this study we have granted participants the right to freely copy and distribute all the materials generated to others within their own companies or organizations. New Paradigm encourages all participants to distribute the materials provided with this report, or additional copies, as appropriate to support your organizations efforts to manage the change to reduce methane venting in all your operations. The only limitation is that the information should not be shared with third parties until New Paradigm Engineering Ltd has undertaken to make the contents public. It is our intent that eventually all materials will be in the public domain, however, we believe contributing participants should be allowed some period of time to make use of the materials (6-12 months) to provide them with a competitive advantage in return for their financial support. If a participant feels some content should be made public sooner, then New Paradigm will consider requests to accelerate moving material into the public domain.

9.1.2. Transfer to Public Domain – As indicated above New Paradigm Engineering Ltd will gradually move all materials to the public domain to support technology transfer. This is also a requirement contained our agreement with AERI for their funding support, which stipulates that material will be public within 1 year of the issue of the final report. Generally, we intend to use the internet, through our New Paradigm Engineering Ltd website, www.newparadigm.ab.ca as the primary access point to the information, and will encourage organizations such as CAPP, PTAC, CASA, SEM, AERI and others to link to that site for information and updates, or to order materials such as copies of reports and other deliverables that might be difficult or too expensive to maintain on the website. It is intended that a similar process will be followed for all future phases of this project as well.

9.1.3. Courses and Workshops – While documentation can serve to help get information out to those who need it, it is very difficult to incorporate all the knowledge and information generated into any static document. Also we continue to receive new information on improvements to equipment available or more information on experience gained by applying options. Therefore we feel that courses and workshops are critical to transfer the technology into practice, and for us to continue to improve and support this effort. Funding to provide courses is not part of the scope of this project, so all courses will be self-supported and organized by New Paradigm Engineering Ltd, potentially in collaboration with other organizations, such as PTAC, CIM, CHOA, Lakeland College, etc. New Paradigm Engineering Ltd will provide courses on mitigation options and tools as long as there appears to be demand for them. Our current plan will be to hold the following courses in the next six months:

- Spreadsheet Tool Workshops – In the next six months these will be limited to participants only, unless there is no participation, in which case they will be open to the public. An initial session will be organized by mid-March to review the current spreadsheet tools and discuss improvements needed for the beta-version. This initial workshop will be covered by AERI funding and will be held in Calgary. Later sessions will be held in Calgary and Lloydminster.

- Methane Mitigation Options Workshops – These should begin in March, 2001 and will be held in Calgary and Lloydminister. They will be open to the public and will focus on providing attendees with an appreciation of the wide range of options available and go through the flowcharts and technical comparison tools. They will likely be one day sessions, with Lloydminister sessions emphasizing fuel displacement options and Calgary sessions emphasizing managed equipment options. New Paradigm Engineering Ltd will attempt to coordinate these workshops with other activities and will seek support from CAPP and other organizations to help encourage attendance. Costs will be set to cover the costs of the course preparation, delivery and materials, any surplus funds generated will be used by New Paradigm Engineering Ltd to maintain and periodically update public materials on the website.

- **Other Presentations and Technology Transfer –** New Paradigm Engineering Ltd will also take some of the results of the study out on a broad basis to increase understanding and awareness of the issues.

9.1.4. Beta Version of Spreadsheet Toolkit – As of late January, New Paradigm Engineering Ltd entered into an agreement with AERI to further develop and improve on the spreadsheet tools. The target date for completion of the upgrade is mid-April, 2001. With this tight schedule it was felt that Tool D and upgrades to other tools will be left for the Beta version. There are still some funds of the original $90,000 in industry funding remaining and these will be used to supplement the AERI funding. Once the Beta version is completed all project participants will be provided with copies on CD-ROM to add to this report and copies will also be distributed directly to those who attend the initial spreadsheet workshop mentioned earlier.

9.2. Follow-up on Issues – Some key business issues should be addressed, by participants, to support implementation of methane vent mitigation options. These issues are mainly strategic business issues but can have a major impact on the mitigation options selected and the return which producers might be able to realize from vent gas energy use.

9.2.1 Regulatory – As indicated previously producers should begin applying for new well development permits with provision in them for future application of a wide range of options for vent gas use. This avoids having to reapply at a later date to change the approvals and should allow producers much more flexibility on what they do with the vent gas throughout the life of each producing well. They should also be working to identify any regulatory requirements in Alberta or Saskatchewan that may be hampering implementation for existing leases. It is likely that regulators and other stakeholder in any operation will be interested in facilitating vent gas mitigation.

9.2.2 Business Options with Third Parties – The issue of using third parties to provide capital investment, management and operating expertise, to help implement some solutions such as power generation or providing vent gas for local markets, should be addressed. It may be advantageous for this to be approached as a joint initiative in various operating areas to minimize the duplication of effort and maximize the benefits for everyone. Again it is the industry participants that need to take the initiative to do this. Collaborative efforts to address methane venting are actively being promoted by the AEUB, SEM and others to ensure that all producers will have outlets for their vent gas energy, and so they will all be able to economically reduce emissions.

9.3 Follow-up Work Recommended and Funding – The current study has been able to highlight a number of options for vent gas use. However, many of these require further testing and or development before they can be properly assessed. Some of the work is best left to the producers and is mainly centered around the options to stabilize gas flows and to determine if low annulus pressure is required for given leases. Some work is a logical progression from the current study and would fit well with New Paradigm's experience and expertise. Finally there is development work on some commercial systems to modify the commercial products to better meet the needs in the specific applications and these are best left to the appropriate vendors to look after. The potential future projects have been highlighted through out the report and are listed in Section 11.8 in the Appendix. The 14 proposed projects are sorted below based on the group, which could take a leadership role in the work with support from others.

9.3.1 Producers – Generally producers should take the lead in the projects, which have the greatest impact on the day to day operations and on business issues. Projects 1-3 focus on stabilizing the vent gas flow or increasing vent pressure while avoiding negative impacts on production. Project 4 focuses on determining the economics of using vent gas to displace electrical power. Projects 13-14 take the form of case studies or demonstration projects to help firm up the economic case for vent gas mitigation.

Future Project #1 – Impacts of Foam on Production

Future Project #2 – Continuous Foam Suppression by Water Recycle

Future Project #3 – Flow Regulation to Stabilize Casing Gas Rate

Future Project #4 – Electrical Power for Artificial Lift

Future Project #13 – Case Studies

Future Project #14 – GHG Trading Demonstration

9.3.2 New Paradigm Engineering Ltd – These projects would allow New Paradigm Engineering Ltd to continue with some of the work started by the options study to help further develop some key options. Project 6 is necessary to help assess permanent production heating options, which involve heating upstream of the tank with a side benefit of potentially lowering the costs of dealing with the problems of sand in production tankage. Project 8 looks at a further study on fuel displacement options for replacing gasoline and would require partnering with other consultants with experience with industrial gases and/or the use of natural gas in the transportation industry. Projects 11-12 would likely be the highest payout projects in helping to determine the facilities required and optimum use of facilities for the various EOR or Production Enhancement options. New Paradigm hopes to issue proposals for these projects over the next 4-6 months.

Future Project #6 – Pre-Tank Desanding

Future Project #8 – Modular Compressed Gas to Replace Propane and Gasoline

Future Project #11 – Investigation of EOR Facility Options

Future Project #12 – Investigation of Pressure Cycling Options

9.3.3 Vendors – The final projects are more directly related to specific technologies where there are vendors who may be interested in working with their clients to improve the systems they provide or to help develop new options that will require demonstration testing in the field. Projects 5 and 9 are new equipment systems that could be applied in conventional heavy oil and which are likely simple adaptations of what is used in other areas or industries. Project 10 would require more work to determine how best to transfer the heat energy, produced by a power generator for use in production heating, but is still relatively standard technology requiring adaptation. Project 7 is a system developed by New Paradigm with the objective of lowering the cost and increasing the flexibility to use catalytic heaters to convert methane.

Future Project #5 – Heater Control Testing

Future Project #7 – Catalytic Methane Converter Trial

Future Project #9 – Microturbine Demonstration Pilot

Future Project #10 – Co-Generation Pilot

10. Summary and Conclusions

This report has documented a wide range of over 60 technical options, which should assist producers in reducing operating costs through use of vent gas from their conventional heavy oil operations. The main option areas covered are:

Flow Stabilization – These options offer suggestions to help address flow variability and low annulus pressure concerns that hinder the use of other options, or significantly impact the cost and operability of the options.

Fuel Displacement – Use of casing gas to reduce purchased energy or displace imported energy on the producing leases is the most economically beneficial use of the vent gas. The main site uses that can be displaced are: fuel (propane or natural gas) for tank heaters and energy (propane, natural gas or power) for artificial lift energy. Many of the options covered have already been demonstrated in field applications, but are still not in widespread use, or have to be used in combination with other options to realize the benefits while avoiding operating problems. These options should be the first systems to be implemented. Low costs should result in payouts of less than a year and potentially less than one month at some sites, with minimal capital expenditures at each site.

Gas Compression – These options are fairly straight-forward applications of conventional gas compression technologies. The main challenge is the relatively high cost of pipelines and compression to collect low volumes of surplus gas from each site. Some of these options may have widespread application where a producer already has a gas collection or distribution system connected to the producing well. Generally, however, payouts and economics will not be as favourable as the fuel displacement options. A basic use of these systems is for low pressure gathering of a large number of source sites to central locations where the surplus gas can be economically used to export gas, power or increase oil production.

Power Generation – There are power generation options which cover a wide range of generator sizes, from standard oil field generator sets to large power generation turbines. A key consideration in implementing these options is that the producer must be familiar with the power generation and distribution business and be able to take advantage of the benefits of distributed power generation. These options are greatly affected by which province the operations are located in, due the need to be able to sell power at a value reasonably close to market value to make it worthwhile compared to other options.

Enhanced Oil Recovery or Production Stimulation – A relatively novel use for casing gas is to utilize the gas as energy for small scale enhanced oil recovery processes. As the gas is already in the area and requires capital investment to move it out, the potential to use the gas to generate increased production may be very attractive. In some options, such as hot water flooding, it may be possible to lower other major operating costs associated with water trucking and disposal. The combined economics for local hot water reinjection may be better than fuel displacement at higher water oil ratios and even if there is no surplus gas available.

Methane Conversion – Once fuel displacement and managed options have been implemented to maximize the economic return from vent gas, there will likely still be some sites, or some volumes of gas which do not present large economic opportunities. For these situations options were developed for converting any remaining methane to carbon dioxide, which has the potential to generate GHG emissions credits which might be tradeable. The economic payout of these options is small, but if the cost of the systems is small enough they may be able to pay for themselves over a 5-10 year life. These options should be the last to be considered as the same benefit can be achieved by using the gas first, and the long term future of emissions trading is still relatively undefined.

Odour Mitigation – Odour issues have been raised at hearings for conventional heavy oil developments but have generally been assessed as of low significance in these operations. All the gas emissions are sweet and generally contain methane, which is odourless. Options have been provided which may be useful if odour problems do arise.

Due to the wide range of options and the wider range of operating situations, it was not possible to recommend a single solution or even a small range of best solutions. Each application is dependent on what equipment has already been installed and what can be cost effectively done with it. In other cases, for new leases, there are more options which might be considered to help in the use of vent gas and which could be installed at a lower cost during the initial site development. Because of the wide range of options flowcharts, technical comparisons, one page options summaries and simple economic spreadsheets have been developed to help with the assessment of the various options. The spreadsheet tools will be issued in the coming months in a Beta Version, with enhancements provided through funding from the Alberta Energy Research Institute.

It is recommended that the results of this study be quickly communicated to field personnel to assist them in planning and obtaining budget approvals for the necessary changes. Suggested distribution of materials is as follows:

Report Copies – At least one copy for each main office and field operations office for reference or circulation.

PowerPoint Presentations – Should be used by operations and/or environmental managers in head offices to encourage management support of funding for conversion of operation to vent gas. Should also be provided to field offices to familiarize key production, facilities, operations and maintenance personnel with the general results and to make them aware of the report.

Single Page Option Sheets, Flowcharts and Technical Comparisons – These should be reproduced and provided as supplemental information to field personnel attending the PowerPoint presentations, to provide them with more detailed information, ideas and vendor contact for implementation of the systems. They also assist in highlighting the need for the implementation of the systems to be well thought out to avoid higher than necessary costs or operational problems.

Spreadsheet Tools – Copies of the tools should be provided to field personnel looking after producing areas to allow them to plan for implementation for casing gas conversion and review the economics of the various alternatives. They should also be provided to head office staff to assist in the development of a strategic assessment of how to utilize any surplus casing gas to maximum corporate advantage.

New Paradigm Engineering Ltd believes that the widespread use of the options contained in this report will benefit all stakeholders in the conventional heavy oil sector and will be working to transfer the technology as widely as possible. Participants may make copies of the above materials for their own internal use, or New Paradigm can provide additional copies at cost, if requested. Participants have all agreed to ensure these materials are used for internal purposes only and they are not to be shared with personnel from companies who have not contributed to the study.

11.5 Producer Field Contacts

Husky

Joel Lefebvre, Production Engineer, Lloyd, (306) 825-1250, joel.lefebvre@husky-oil.com
Brock Blakely, Production Coordinator, Lloyd, (306) 825-1131
Dean Lypkie, Production Engineer, Lloyd, (306) 825-1241, dean.lypkie@husky-oil.com
Rob Brandt, Production Engineer, Lloyd, (306) 825-1184, robert.brandt@husky-oil.com
George Leer, Kevin Josuttes, Pumpers, Westhazel Field Office, (306) 845-2362

Anadarko

Tony Paradoski, Field Engineer, Elk Point, (780) 724-6023
Darrell Wickham, Production Coordinator, Elk Point, (780) 724-6004

Petrovera

Glenn Reiter, Facilities Technologist, Lloyd, (780) 871-7815, glenn_reiter@petrovera.com
Ron Tochor, Facilities Engineer, Lloyd, (780) 871-7820, ron_tochor@petrovera.com
Jamie Carlson, Exploitation Engineer, Lloyd, (780) 871-7823, Jamie_Carlson@petrovera.com

Nexen

Garth Bird, Manager, Lloyd, (780) 871-8718
Kelly Bohnet, Environmental Coordinator, Lloyd, (780) 871-8760, kelly_bohnet@nexen.com
Ken Oberg, Production Engineer, Lloyd, (780) 871-8749, ken_oberg@nexen.com

Anderson

Ron Anderson, Production Technologist, Lloyd, (780) 875-9837, anderrd@axl.ca

Mobil

Wilf Kenyon, Cold Lake, (306) 825-1475
Darren Walker, Celtic, (306) 825-1454

CNRL

Dave McNamara, Bonnyville, (780) 826-8207, davidmc@cnrl.com

11.6 Vendor Contacts

This list is not an endorsement by New Paradigm Engineering Ltd. of the products or services provided by the suppliers. It is not a complete listing of all potential suppliers for any product or service - it is intended as an example only (additional suppliers can be found in the Canadian Oilfield Service and Supply Directory). In some cases individuals from companies kindly provided New Paradigm with information for this project, and are also listed, as they would be useful contacts for producers.

Firetube Heaters:

Kenilworth Field Service, Islay, AB, Per Westergaard, (780) 744–3974, kworth@telusplanet.net
A-Fire Holdings, Lloydminster, (780) 875-0672, a-fire@telusplanet.net
Zirco, Calgary, Marty Schlager (403) 259-3303, info@zirco.com

Enhanced Firetube Controls:

Kenilworth Field Service, Islay, AB, Per Westergaard, (780) 744–3974, kworth@telusplanet.net
Canalta Controls, Red Deer, (403) 342-4494, canalta@canalta.ab.ca

Thermosyphon Systems

Hudson Products Corp., Edmonton, Sam Chapple, (780) 438-3267, sam.chapple@mcdermott.com
Universal Industries Corp., Lloydminster, Les Unrau, (780) 875-6161, uilloyd@telusplanet.net
Delta Combustion Corp., Calgary, (403) 520-3500

Catalytic Line and Tank Heaters

Scott-Can Industries Ltd., Edmonton, Peter Howie, (780) 463-5505, info@scottcan.com

Fired Line Heaters

Select Oilfield Leasing, Edmonton, (780) 461-7677
NWP Industries, Blackfalds, AB, (403) 885-4656
Bilton Welding and Manufacturing, Innisfail, AB, (403) 227-7799
Laren & D'Amico Mfg, Edmonton, (780) 434-9475

Propane for Heater Fuel

Kenilworth Field Service, Islay, AB, Per Westergaard, (780) 744–3974, kworth@telusplanet.net (burner fuel manifolds)
Gas Equipment Supplies, Edmonton, (780) 468-4454 (propane/air mixing)
Canalta Controls, Red Deer, (403) 342-4494, canalta@canalta.ab.ca (electronic burner controls)

Winterization Heaters

Scott-Can Industries Ltd., Edmonton, Peter Howie, (780) 463-5505, info@scottcan.com

Electric Tracing

Weatherford, Lloydminster, Les Charters, (780) 871-2333
Pyramid Corporation, Lloydminster (780) 875-6644; Elk Point (780) 724-3071
PowerComm Inc., Lloydminster (780) 875-5241, info@powercomm.ab.ca
Thermon Heat Tracing Service Inc., (403) 563-8461

Coolant Tracing

Weatherford, Lloydminster, Les Charters, (780) 871-2333
Northern Industrial Insulation Contractors Inc., Bonnyville, (780) 826-6110
Albrico Services Ltd., Bonnyville, (780) 826-7959, insulate@albrico.com
Excel Insulations, Lloydminster (780) 875-9398

Methanol Injection (Chemical Injection Pumps)

Arrow Specialty Co., Edmonton, (780) 437-4368
BDM Supply Ltd., Edmonton, (780) 465-2200
Bruin Instruments Corp., Edmonton, (780) 430-1777
Norda-Tech Services Ltd., Edmonton, (780) 436-7755
Panama Enterprises Inc., Edmonton, (780) 452-5757

Glycol Injection

Argo Sales Ltd., Nisku, Reg Slaymaker, (780) 955-8660, slay@argosales.com
Alco Gas and Oil Production Equipment, Calgary, (403) 243-5505

Calcium Chloride Dryers

Argo Sales Ltd., Nisku, Reg Slaymaker, (780) 955-8660, slay@argosales.com
Ironhorse Compression Ltd., Edmonton, Rick Riopel, (780) 462-6847, ironhse@telusplanet.net;

Pressure Swing Adsorption (PSA) Dryers

Eagle Pump and Compressor Ltd., Calgary, Ed Albers, (888) 831-2777, ealbers@eagle-pc.com

Glycol Dehydrators

Argo Sales Ltd., Nisku, Reg Slaymaker, (780) 955-8660, slay@argosales.com
Alco Gas and Oil Production Equipment , Calgary, Phone: (403) 243-5505

Steel Pipelines

CE Franklin Ltd, Edmonton, (780) 944-1000

Plastic Pipelines

Polytubes Inc., Edmonton, (780) 453-2211
Enerline Restoration Ltd., Calgary, (888) 377-6677
Rangeland Oilfield Inc., Calgary, (403) 261-1071

Compressors

Daval Industries, Nisku, Rod Berry, (780) 955-7547, rberry@davalindustries.com
Secure Oil Tools, Calgary; (403) 264-6663, sales@secureoiltools.com
Eagle Pump & Compressor Ltd., Calgary, Ed Albers, (888) 831-2777, ealbers@eagle-pc.com
Ironhorse Compression Ltd., Edmonton, Rick Riopel, (780) 462-6847, ironhse@telusplanet.net

Eductors

Schutte & Koerting, Pennsylvania, (215) 639-0900, www.s-k.com
Fox Valve Development Corp., New Jersey, (973) 328-1011, www.foxvalve.com

Thermoelectric Generation (TEG)/Co-gen

Suppliers:
Global Thermoelectric: Telephone: (403) 236-5556

Out Source:
Prologic Controls: Telephone: (403) 250-3266
Syndicated Technologies: Telephone: (403) 543-4060

Microturbines/Co-gen

Suppliers:
Honeywell Power Systems Inc.
Capstone Turbine Corporation
Elliott Energy Systems

Out Source:
Mercury Electric Corporation, Vern Mantery, Tel: 403-261-8611, v.mantey@mercuryelectric.com
Mariah Energy Corp., Tel: 403-264-2880
Secure Power Systems., Brad Dorigatti, Tel: 403-232-6599, bd@securepower.com

Co-Gen:
Unifin International, London, Ontario Tel: 800-349-7820

Mariah Energy Corp., Tel: 403-264-2880, has developed an integrated heat recovery system with the 30 kW Capstone unit

Reciprocating Engine Gensets/Co-Gen

Suppliers:
Caterpillar
Cummins
Ingersoll-Rand Canada Inc.

Out Source:
Canadian Hydro Developers Inc. Tel: 403-269-9379
Encore Energy Solutions L.P, Tel: 403-297-0342
Mercury Electric Corporation Tel: 403-261-8611

Co-Gen:
Caterpillar, Cummins, Ingersoll-Rand Canada Inc., Unifin International, London, Ontario Tel: 800-349-7820

Gas Turbine Gensets/Co-Gen

Suppliers:
Solar Turbines
General Electric
Westinghouse

Out Source:
Canadian Hydro Developers Inc. Tel: 403-269-9379
EMF Corporation, Tel: 403-547-8259 / 403-208-2000
Encore Energy Solutions L.P Tel: 403-297-0342

Co-Gen:
Babcock & Wilcox
20 S. Van Buren Avenue
Barberton, Ohio 44203-035
United States of America

Innovative Steam Technologies
200 Avenue
Galt, Ontario N1R 8H5

International Unifin, Inc
1030 Clarke Side Road
Boxes 5395 Stn. B
London, Ontario

Fuel Cells

ONSI Corporation, South Windsor, Connecticut.
Ballard Power Systems

Flare Stacks

Tornado Technologies Inc., Calgary, Jerry Smolarski, (403) 263-8011, jerrysmo@cadvisions.com

Enclosed Flares and Incinerators

Tornado Technologies Inc., Calgary, Jerry Smolarski, (403) 263-8011, jerrysmo@cadvisions.com

Total Combustion Inc.; Calgary; Tom Wiseman, Tel: 403-216-8218; twiseman@acpe.net

Questor Technology Inc.; Calgary; Tel: 888-571-9642, info@questortech.com

Central Production Testing Ltd., Calgary, (403) 571-5171, info@cptl.net

Catalytic Conversion

Scott Can Industries Ltd., Edmonton , Peter Howie, (780) 463-5505, info@scottcan.com

Vapor Recovery

Tornado Technologies Inc., Edmonton, Peter Kociolek, (780) 417-5151, kociolek@connect.ab.ca

11.7 References Library

Documents starting in bold are currently held by New Paradigm

EUB: (www.eub.gov.ab.ca)

ST-16A Alberta Field/Pool Production and Injection Monthly Supplement – Nov 99 $10

Gives oil, gas, and water production by field and pool, and also water and gas injection by pool.

ST-18 Alberta's Reserves of Crude Oil, Oil Sands, Gas – 1999, Vol 1 of 2 $125?

Heavy oil pools are grouped together and gives reservoir data (temp, pressure, density etc.), initial volume in place, recovery, reserves, cumulative production etc.

ST-28 Alberta Electric Industry Annual Statistics - $40

ST-60 Crude Oil and Crude Bitumen Batteries Monthly Flaring, Venting, and Production Data - $25 for single issue (monthly) on diskette

ST 2000-60B Upstream Petroleum Industry Flaring Report (for year ending December 31, 1999) Free download on EUB web site.

Company rankings, flared and vented volumes, oil production, # wells, GORs. Data is grouped by company and also EUB field area (e.g. Bonnyville).

ST-78 Pipeline Location Plats - $2,500 complete set on microfiche

Guide 60 Upstream Petroleum Industry Flaring Guide – free download

88 – A/E88001 Small Power Inquiry – Mar 1988 – no charge

97-A Policy Review of Solution Gas Flaring and Conservation in Alberta – Jun 1997, no charge

Map 88 Pipelines Map – high pressure by township $6/township

Map 90 Designated Oil and Gas Fields, Oil Sands Deposits, Main Pipelines, Refineries, and Gas Processing Plants – 40 miles/inch, 1997 - $15

Rural Gas Utility Franchise Areas (map) – 54x87, Jan 1998, $15

Pipeline Location Plats (low pressure by co-op name) – show gas co-op and county gas distribution systems, 1:20 000, Individual co –op $6

Low Pressure Pipeline Mapping Series – 1:50 000, shows general locations of all rural gas distribution pipelines, $6/map

SEM: (www.gov.sk.ca/enermine/)

Petroleum Development Map of Saskatchewan – 1: 1 000 000, $20

Shows pools, major pipelines, gas plants.

Reservoir Annual – 1998, $70

Gives location of pools, reservoir data and reserves – heavy oil pools grouped together.

Monthly Oil and Gas Production Report – March 2000

Gives oil, gas, and water production, # of wells by pool/unit. Heavy oil grouped together.

Oil and Gas Conservation Act

Township Plats – 1: 31 680 - $5/page

Well Location Maps – 1: 100 000 – out of Calgary now (private companies)

CAPP: (www.capp.ca)

CAPP Pub. #1999-0010 CH4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry Vol 1-4 – 1999

Options for Reducing Methane and VOC Emissions from Upstream Oil and Gas Operations – 1993

CAPP Pub. #1999-0014 Recommended Practises for Flaring of Associated and Solution Gas at Oil Production Facilities – Sept 1999

Upstream Oil and Gas Industry Options Paper – Sept 1999

Upstream Emission Reduction Cost Analysis

ALBERTA RESOURCE DEVELOPMENT: (www.resdev.gov.ab.ca)

Electricity:

Electric Utilities Act – free download

Transmission Planning Guidelines – free download

Industrial Systems Policy – free download

Natural Gas:

Acts & Regulations – free download

Regulatory Review – free download

Rural Utilities – Rural Gas Program – free download

ESBI ALBERTA LTD.: (AB's Independent Transmission Administrator) (www.eal.ab.ca)

Transmission Development Plan Report – free download

Maps – of AB Interconnected Electric System – available by request

POWER POOL OF AB: (www.powerpool.ab.ca)

SASK POWER: (www.saskpower.com)
1999 Annual Report – free download
1999 Environment Review – free download
Climate Change Action Plan 98/99 – free download
Small Power Producers Policy – free download

SASK ENERGY: (www.saskenergy.com) (distribution)

TRANSGAS: (www.transgas.sk.ca) (transmission and gathering for SaskEnergy)

Annual Report – free download

Map of lines – available online, not too scale, new paradigm also has hard copies.

EXCALIBUR-GEMINI GROUP: (www.excalibur-gemini.com)

Private firm in Calgary providing data and maps

11.8 Listing of Follow-up Projects

Future Project #1 – Impacts of Foam on Production - Further Research and Study by Producers: Producers should consider conducting testing based on 12.3.1 in their operations to better characterize the relationships between foam in the well and production. This may be helpful in determining better ways of breaking down foam to stabilize the vent gas rate and to reduce the costs associated with vent gas use. It may also indicate methods to allow increased oil production from foamy wells.

Future Project #2 – Continuous Foam Suppression by Water Recycle - Further Research and Study by Producers: Producers should consider conducting testing to assess the option of recycling produced water to control foam down hole. Tests could be similar to those outlined in Option 12.3.1 but with the addition of warm or hot produced water in Day 2. Initially this could be done with a portable pump, with trial of the simpler tubing system after a better understanding is reached of the water volumes and temperatures required to affect foam in a well.

Future Project #3 – Flow Regulation to Stabilize Casing Gas Rate - Further Research and Study by Producers: Producers should consider conducting testing to assess the option of using a flow regulation orifice on wells that exhibit the trap flow type of behaviour. Tests could be similar to those outlined in Option 12.3.1 to determine how the flow and production behaviour is affected.

Future Project #4 – Electrical Power for Artificial Lift - Further Research and Study by Producers: Producers should consider conducting testing of the two systems proposed to reduce electrical power consumption to identify any operational or other issues that need to be resolved and to more closely examine the potential economic and reliability issues.

Future Project #5 – Heater Control Testing - Further Research and Study by Producers & Vendors: Producers should consider conducting testing of various types of heater controls if they have not already done so, and with the view of leveling fuel gas demand so that vent gas use can be optimized.

Future Project #6 – Pre-Tank Desanding - Further Research and Study by New Paradigm Engineering Ltd.: Production of sand in the early stages of well production has led to concerns that heating production in a line heater (catalytic or fired), upstream of the tank, could lead to plugging of lines from the well due to sand fall out. New Paradigm is currently working on a small project funded by Husky Oil to determine if this is a problem for the catalytic line heater. This work has potential to be expanded into a study to determine methods of desanding upstream of the tank as an option to try and reduce sand clean-out costs and also to potentially allow for heavy oil pipelining in support of C-FER Technology Inc's Heavy Oil Gathering System (HOGS) project which New Paradigm was previously involved with. Sand handling and management costs were raised as a significant issue at a PTAC Heavy Oil forum in June, 2000 and this is supported by discussions New Paradigm has had with pumpers in the field.

Future Project #7 – Catalytic Methane Converter Trial - Further Research and Study by New Paradigm Engineering Ltd.: Once a prototype design has been completed for a converter New Paradigm will be looking for industry support to conduct a field demonstration trial of a catalytic converter in a conventional heavy oil venting application. Timing likely the spring of 2001, with testing through the summer.

Future Project #8 – Modular Compressed Gas to Replace Propane and Gasoline - Further Research and Study by New Paradigm Engineering Ltd: Potential to further study modular compressed gas as an option to replace propane and/or gasoline in producer vehicle fleets. Might work with current vendors of propane.

Future Project #9 – Microturbine Demonstration Pilot - Further Research and Study by New Paradigm Engineering Ltd and Vendors: At the start of the current project Mercury Electric offered to supply equipment and support for a demonstration pilot for a microturbine unit in this application. Producers should consider conducting this testing if they have concerns about the viability and operability of this technology. Alternatively more work could be done in a paper study to assess microturbine performance in other conventional oil and gas applications and project potential performance in a casing vent gas application.

Future Project #10 – Co-Generation Pilot - Further Research and Study by New Paradigm Engineering Ltd and Vendors: Potential to pilot a cogeneration option as part of Mercury Electric pilot in future project #9. Test ability of gas from microturbine heating production or tankage.

Future Project #11 – Investigation of EOR Facility Options - Further Research and Study by New Paradigm Engineering Ltd. These options were not allocated a great deal of effort in the original study proposal, however, this study shows considerable potential for these options to be viable alternatives to increase heavy oil production and recoveries, while reducing operating costs and environmental issues. A proposed extension of this work would be to continue to work on these options and obtain more information on equipment possibilities, costs, potential for modularization and the pro's and con's of the various options. Efforts could be focus on one or two of the best methods, or to cover all options for a consistent comparison.

Future Project #12 – Investigation of Pressure Cycling Options - Further Research and Study by New Paradigm Engineering Ltd. with a third party research provider. The basic gas injection options could lend themselves to pressure cycling as a form of production enhancement. SRC has been doing some work on pressure cycling with methane in horizontal heavy oil wells. This work might be enhanced by considering pressure cycling for vertical wells and with N2/CO2 streams. The basic process would enhance foam formation in the reservoir to increase production.

Future Project #13 – Case Studies - Further Research and Study by New Paradigm Engineering Ltd. and Producers. A key strategy to increase the use of these options for vent gas mitigation is to prepare and present case studies similar to the one contained in this report. These studies could be prepared by New Paradigm based on producer data or the producers could prepare them directly.

Future Project #14 – GHG Trading Demonstration - Further Research and Study by Producers. To assist in assessing the practicality of GHG emissions trading a demonstration project should be considered. A producer would reduce GHG emissions by one of the options, document the reduction achieved and attempt to trade credits. This demonstration, if successful could be used as a model for others to follow.