NITROGEN-BASED OIL RECOVERY SOLUTIONS MAXIMIZE PROFITABILITY IN TODAY'S ENERGY MARKET

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ABSTRACT
The use of nitrogen to enhance the recovery of oil and gas reservoirs is becoming increasingly attractive. Recent examples highlight projects where large-scale nitrogen injection has been successfully implemented to increase both the production rate and recoverable reserves of oil and gas. Nitrogen-based techniques for improving oil and gas recovery include gravity drainage pressure maintenance, gas cap production, cycling of condensate reservoirs. attic oil production, driving gas for miscible slugs, and miscible nitrogen displacement. Methods for enhanced production employing nitrogen are discussed along with economics relative to the use of other gases, such as hydrocarbons or carbon dioxide. In many cases, project economics can be further enhanced by integration of the air separation (ASU) process with other processes on site (power plant, gas treatment, etc). The advantages of such an integration of nitrogen-based processes are discussed.

INTRODUCTION
Rising demand for energy in combination with a limited quantity of known reserves makes this one of the most challenging periods in the history of the oil and gas industry. The face of oil and gas recovery has changed significantly over the last century, evolving from primary recovery techniques to sophisticated tertiary recovery schemes which could involve the use of chemical or microbial agents to increase oil mobility. It is important to note, however, that the secondary and tertiary enhanced oil recovery (EOR) techniques which have stood the test of time typically make use of effective yet inexpensive materials, such as industrial gases.

The use of nitrogen can offer improvement to secondary and tertiary techniques in order to maximize the recovery of valuable energy assets in the most economically efficient manner. Nitrogen is cost-effective, environmentally friendly and non-corrosive, requiring little or no special handling facilities or treating equipment. A variety of successful secondary and tertiary nitrogen projects have been implemented, with recent projects having injection rates of up to 1.2 billion standard cubic feet per day.

GRAVITY DRAINAGE PRESSURE MAINTENANCE
In many cases, the use of nitrogen offers an advantage over conventional pressure maintenance techniques, such as associated gas reinjection and waterflood, to maximize the production rate as well as the total production of oil, associated gases and gas cap gases. Almost all oil reservoirs which contain a gas cap are potential candidates for the use of nitrogen pressure maintenance. Particularly good candidates for the use of nitrogen include fields located where there is a high demand for natural gas and fields which have a strong water drive that could lead to the isolation and loss of a portion of the oil or gas.

As the world demand for natural gas increases, and hence its value, new opportunities are created for nitrogen use by allowing associated gases and gas cap gases to be recovered for sale. If designed correctly, the injection of nitrogen can be performed with limited dilution of these valuable assets for a substantial period of time.

The use of carbon dioxide is another option that has been considered for pressure maintenance in locations where pipeline distribution is available and the reservoir pressure is sufficiently low so that miscibility is reduced. Due in part to a **low** compressibility factor, however, significantly more carbon dioxide is required for pressure maintenance than nitrogen (up to 50% more), making it difficult to justify the economics of carbon dioxide even when a relatively low-cost supply is available. Nitrogen cost is typically less than one-half that of carbon dioxide when a pipeline supply is not available.

Waterflood techniques have been used extensively in the past for secondary recovery. One unfortunate aspect of the use of water alone to maintain pressure is that a portion of the oil reservoir or gases in the gas cap can be isolated by water and rendered unrecoverable.. This can also be the case when a natural water drive is present. One approach to avoid hydrocarbon isolation in such cases is to make use of both water injection (or natural water drive) and gas injection. The use of these two driving fluids in concert is known as the Double Displacement Process, and this combination can provide for very high recovery efficiencies. Studies in the Hawkins Field of East Texas, where nitrogen is used in a Double Displacement Process along with the produced gas, have indicated that the gas drive gravity drain will have a recovery efficiency of over 80% compared to an efficiency from water alone of 60%. Figure 1 depicts this process for the East Block of Hawkins Field. The volume of the oil column is shown to increase as the column is pushed down by gas pressure because the residual oil saturation in the gas displaced region is much lower, at 12%, than that of the water invaded region, which has a residual oil saturation of 35%.

The largest nitrogen secondary recovery project in the world is located at Pemex's Cantarell field in the Gulf of Mexico (Figure 2). The field is an excellent example of how nitrogen may be used to significantly improve the rate of production as well as the aggregate production of both oil and gas.' The Akal field contains the majority of oil and gas at Cantarell. This field has an amiable structure for gravity pressure maintenance as it has a relatively thick reservoir section and a gas cap. Reservoir pressure had fallen substantially over the years resulting in the need for increased installation of production wells and lift gas usage. In addition, gas cap pressure was needed to prevent a continued rise in the oil-water contact in the southern portion of the field which threatened to spill over a central high structure and isolate a portion of the oil in the northern part of the field. After an extensive comparison of pressure maintenance options, nitrogen was found to be the most economically favorable injection option, with a unit price per SCF which was 3 to 5 times lower than reinjection of associated gases and 4 to 8 times lower than the use of purchased natural gas.[3] The use of nitrogen will help to increase the production rate by some 60% and allow a substantial increase in aggregate production over the life of the field.

Large-scale pressure maintenance projects, such as that at Cantarell, are tremendously complex. This is illustrated by the fact that in 1997 the $1 billion-plus build-own-operate project at Cantarell was awarded to an international consortium, the Compania de Nitrogeno de Cantarell (CNC), which was led by UK-based BOC Group, with partners Marubeni Corporation of Japan, Westcoast Energy of Canada, Linde AG of Germany, and ICA Fluor Daniel **S.** de R.L. de C.V. of Mexico. Future projects of this type are likely to be conducted in a similar manner.

GAS CAP PRODUCTION

Natural gas is forecast to remain in high demand. Natural gas was the fastest growing fuel in 2000 with consumption rising 4.8% and pipeline exports rising by 8%. LNG trade increased by 10.3% in 2000.

Despite the value of gas cap gases, these gases are traditionally not recovered until oil production from the field has been concluded. The time value of this asset, however, is a strong driver to recover such gases sooner when possible. These gases typically remain in place in order to prevent the migration of oil into the cap where it could be trapped upon depletion, thus reducing aggregate oil recovery. Another common practice is to recover liquids from the gas cap gases while injecting gas plant residue and makeup hydrocarbon gases. Both of these practices result in a delay of gas cap sales. The use of nitrogen can advance the recovery of gas cap gases by 15 to 30 years;" allowing for a substantial benefit.

Even though the concept of gas cap production using nitrogen to displace more valuable hydrocarbons has been known for many years, few operators have taken advantage of this technique. Ryckman Creek field in Wyoming is a long-standing successful example where nitrogen has been injected into the gas cap to accelerate the recovery of gas cap gases. In that case, an additional incentive was that a strong water drive would have resulted in considerable gas cap loss during blowdown due to water influx. The economic driver for such cases is typically significant, however, even without taking blowdown-associated losses into account. This is especially true today with the increasing demand for natural gas.

Among the important parameters which determine the economic feasibility of gas cap recovery are the size of the gas cap, the value of produced gases, the composition of hydrocarbons in the gas cap gases, the level of impurities in the gas cap gases, the connectivity of fractures in the reservoir, and the level of nitrogen rejection required to produce sales gas.

When large-scale nitrogen production is employed, the value per SCF of gas cap gases can be up to several times the value of the injected nitrogen. This differential is further enhanced by the fact'that each SCF of nitrogen will occupy considerably more space than the hydrocarbon gases in the gas cap. Estimates for the Gandhar and Ryckman Creek fields, for instance, indicate that nitrogen occupies 23% and 38% more volume than the gas cap gases in these reservoirs.[10 11]

The composition of the gas cap gases determines the likelihood that valuable condensate liquids will be left in the reservoir upon blowdown or conversely upon gas cap replacement with nitrogen. As discussed in the next section of this paper, reducing the pressure in the reservoir can cause liquids to drop out of the gases and be rendered unrecoverable. Alternatively, it is possible in some systems for the addition of nitrogen to increase the dew point of the gas condensate considerably which could cause the heavier components to fall out as liquid. It is important to note, however, that such condensation will only occur where the nitrogen and gas cap gases mix. Depending on the structure of the reservoir, such mixing may be minimal. Case specific simulations are necessary to determine how a given system will react to nitrogen injection.

In an ideal reservoir system, nitrogen can displace gas cap gases with very little dilution of those gases over a significant portion of their recovery.'?The ability to transmit pressure through the reservoir in a reasonable time frame is necessary for such a displacement to occur, and a relatively homogeneous reservoir structure is useful to minimize the mixing of nitrogen with hydrocarbons. The connectivity of fractures affects how nitrogen moves through a reservoir upon injection. Nitrogen will move relatively slowly through low permeability regions and rapidly through the fractures. Thus, care must be taken in highly fractured systems to control and monitor the movement of nitrogen. If nitrogen were injected near a production well in such a system, for instance, breakthrough could result. Highly fractured reservoirs may also lead to a more rapid dilution of sales gases, resulting in an eventual need for nitrogen rejection.

Nitrogen rejection from hydrocarbon gases is a well-established low-cost technology. Cryogenic and physical absorption processes are available for large and medium-scale projects, respectively, yielding high purity product at a fraction of the value of the hydrocarbon. For lower flow rates, pressure swing adsorption is an efficient means of nitrogen rejection. The cost of removing nitrogen from produced gas depends on the flow rate and pipeline purity specification, as well as the concentration of nitrogen and the level of impurities (H_2S, CO_2, mercury, etc.) in the untreated hydrocarbon gas.

CYCLING OF CONDENSATE RESERVOIRS

Cycling of Gas Condensate reservoirs has been employed for over a half century as a means of accelerating the revenue from a gas reservoir when there was little or no market for the gas. Cycling of the large Katy Gas Field near Houston, Texas began in 1943 and is a good example of this technique. This strategy has allowed the early sale of the liquids from the gas while returning the dry gas to the reservoir and thus maintaining the reservoir pressure. Through the years, many other gas condensate reservoirs, as well as gas caps of oil reservoirs, have been cycled with dry gas. In the past, there was little market for the dry gas recovered with the condensate, and it was compressed and returned to the reservoir in the cycling project. However, in recent years the value of produced gas, like other hydrocarbons, has continued to rise so that today it is too valuable a commodity to return to the reservoir.

Liquid that forms in gas reservoirs and in the gas cap of oil reservoirs when the reservoir pressure is lowered is called retrograde condensate. A common method of preventing condensate from dropping out when pressure is depleted in such reservoirs is the re-injection of produced gas. However, in today's environment, dry natural gas is expensive and not always available for such purposes. Operators in the North Sea area have expressed concern over the use of this valuable produced gas in cycling projects. As a result, several studies, have been undertaken in Holland, Norway, and the UK to determine the viability of nitrogen as an alternate to natural gas. These studies have indicated that nitrogen could be supplied at the reservoir injection pressure for less that one-half the cost of natural gas and concluded that nitrogen is a viable alternative to produced gas.

Studies by Adler and Crawford have indicated that the injection of nitrogen into natural gas or condensate reservoirs subject to secondary recovery by either a natural water drive or water injection may result in a further increase in hydrocarbon recovery by 30% to 50%. The Water Alternating Gas (WAG) Process has been proposed as a method of improving recovery from cycling gas condensate reservoirs where premature breakthrough of gas has been a problem.

Nitrogen is a relatively inexpensive and readily available alternative to natural gas for cycling gas condensate reservoirs regardless of whether the condensate is caused by retrograde condensation or was present in the reservoir at initial production. Nitrogen injection has been used to increase recovery from a rich retrograde gas condensate reservoir in the Chunchula Field, Mobile County, Alabama. In many cases, because of the high reservoir pressure and volatility of the condensate, miscible flooding is possible with the injection of nitrogen. This was the case at Chunchula and also in the Anschutz Ranch Field on the Wyoming-Utah border. Many of the gas condensate reservoirs in the North Sea are considered to be in this same category, having nitrogen miscible condensate and oil, and are therefore good candidates for cycling with nitrogen. A mixture of methane and nitrogen has been used in the volatile oil and retrograde condensate reservoirs of the Fordoche Field of Louisiana to significantly increase recovery from the very high-pressure Wilcox sands.

ATTIC OIL PRODUCTION

Oil recovery from high relief reservoirs such as those that typically occur around piercement type salt domes can be increased significantly by down structure gas injection.,In high relief reservoirs, field development is complicated by lack of knowledge of the upper limits of the reservoir. To assure a successful completion, operators usually drill development wells a safe distance from the sand-salt interface. When a field has an active water drive, much of the updip oil will not have been displaced before the highest well in the structure waters out (Figure *3)*. Drilling new wells or sidetracking old wells is expensive and risky, and it would be almost impossible to locate wells to adequately drain updip oil. If a reservoir has steep dip and high permeability, injected gas will migrate to the most inaccessible locations, providing good lateral drainage (Figure 4). In attic oil recovery, injected gas is traded for crude oil. Research has shown that nitrogen works equally well as methane in displacing attic oil from most reservoirs.

DRIVING GAS FOR MISCIBLE SLUGS

The use of carbon dioxide to increase oil production is a well known and proven technique which has been used for many years in locations such at the Permian Basin in West Texas due to the relatively inexpensive carbon dioxide available from natural sources. Often, carbon dioxide injection is alternated with a driving fluid; typically this fluid is water. The driving fluid is applied to reduce the costs of carbon dioxide which is usually brought in by pipeline or truck. Nitrogen can also be an excellent driver for miscible carbon dioxide and the associated oil bank, particularly when alternated with water injection (Figure 5*)*. Nitrogen costs are significantly lower than those of carbon dioxide in most cases, and almost any size nitrogen generation facility can be constructed on site. The use of nitrogen as a driver for miscible slugs is particularly desirable in locations where water use is an issue.

MISCIBLE NITROGEN DISPLACEMENT

Nitrogen can have an economic advantage over carbon dioxide for miscible gas displacement of light oils when the reservoir pressure is relatively high (e.g. 5000 psig). ExxonMobil's Jay/LEC field in Florida is a long-standing example of such a case.

Ideal candidate reservoirs for miscible nitrogen use will contain light oils with API gravity higher than 35 degrees. The reservoir should be deep, generally over 10,000 ft so that relatively high injection pressures can be maintained. The oil should be rich in ethane to hexane.

In a typical nitrogen displacement process, nitrogen becomes miscible with the oil when enriched by the vaporization of light components from the oil. As the nitrogen moves through the reservoir, the miscible front is continually renewed by contact with fresh oil. An associated oil bank is formed with decreased viscosity, decreased surface tension, and increased swelling. Water slugs typically follow those of nitrogen to increase the sweep efficiency. **As** with other miscible gases, the use of the Water Alternating Gas (WAG) process is one means of improving the overall economic performance. Nitrogen may be separated from associated gases at the surface through various nitrogen rejection techniques.

INTEGRATED SOLUTIONS FOR NITROGEN GENERATION

A key aspect of obtaining the low-cost nitrogen needed for large-scale oil recovery projects is the integration of machinery, process and energy cycles. For instance, the air separation unit (ASU), air compressors, nitrogen compressors and other infrastructure may be balanced with the energy available from a simple, combined cycle or cogeneration solution, or a hybrid cogeneration solution using the gas turbine as the main air compressor driver. The power generation units are designed to produce energy in close balance with that required for the consuming equipment, thus allowing for minimum waste. For example, the electricity created from gas turbines may be matched with the needs of the air compressor and plant auxiliaries. Waste heat generated from the turbines could be used in duct-fired heat recovery steam generators to provide steam in order to match the demand of the steam turbines driving the nitrogen compressors and the demand of the ASU pre-purification unit regeneration heaters. ASU cycle pressures could be varied to allow optimum gas turbine and steam turbine matching.

The nitrogen production plant at Pemex's Cantarell field is perhaps the best existing example of such integration to date. Along with the ASU's which are designed to produce 1.2 billion SCFD of nitrogen, the plant operates nitrogen compressors as well as gas and steam turbines, which generate 520 Mw of power and 800 TPH of HP/MP/LP steam respectively. It is estimated that 80% of the energy consumption is used to drive the compressors and auxiliaries, while only 20% is process-related associated with the separation/purification of the gas.

As a result of the rigorous approach taken to develop a solution which integrated the machinery and energy requirements, the energy consumption at Cantarell is over 30% lower than Pemex's target as defined in their RFQ. This demonstrates the importance of incorporating machinery and energy integration as part of the overall nitrogen-based oil recovery

CONCLUSIONS

The need for improved utilization of valuable energy assets is driving an increased usage of nitrogen for secondary and tertiary recovery. Applications in pressure maintenance, gas cap production, miscible floods, and the like have demonstrated the cost effectiveness and technical viability of using nitrogen to improve the recovery of both oil and gas. Benefits of recent nitrogen-based oil recovery projects have included increased production rates, higher aggregate production of both oil and gas, and a significant acceleration in the recovery of reservoir gases. In large-scale projects, integrated solutions further drive the use of nitrogen for best overall economic performance. For large projects, nitrogen is typically available at a cost of less than one-third that of purchased natural gas. These factors, in combination with improved technologies for nitrogen production and rejection from hydrocarbon gases, have made the economic benefits **of** nitrogen use better than ever.

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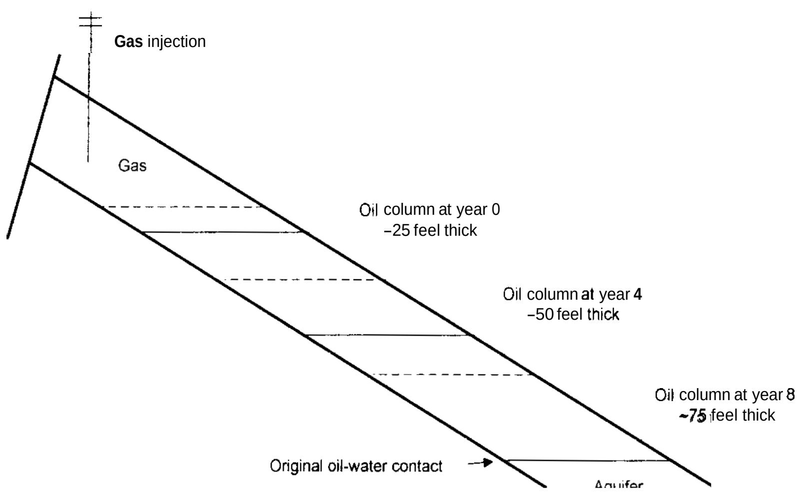

Figure 1 - Schematic Cross-Section of East Fault Block at Hawkins Depicting Double Displacement Process

Figure 2 - CNC $1 Billion Nitrogen Production Facility with Integrated 520 Mw Gas Turbine Cogeneration Unit

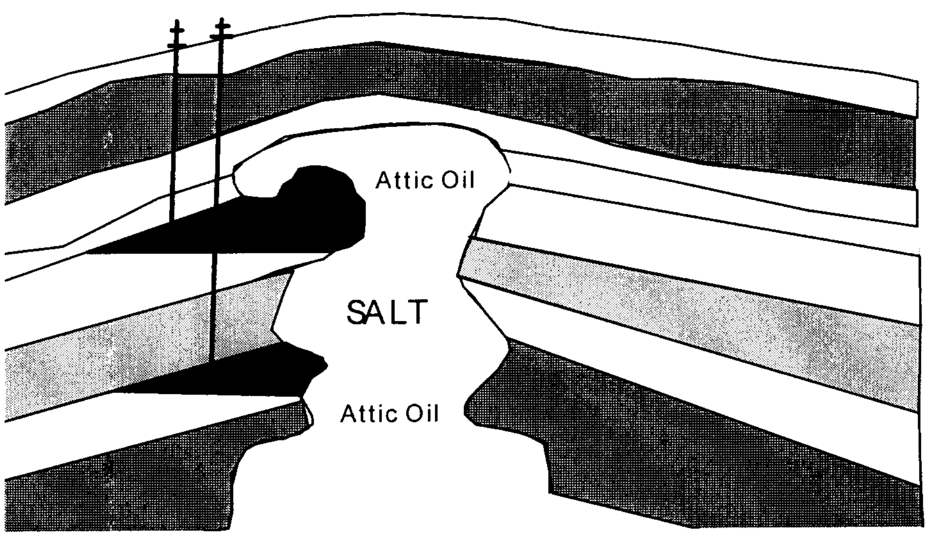

Figure 3 - Cross-Section Showing Attic Oil Deposits Before Gas Injection

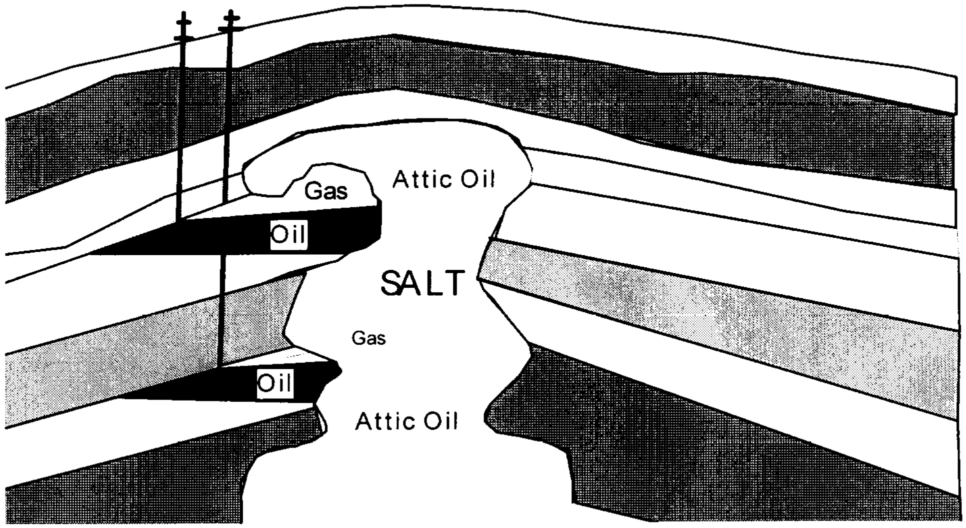

Figure **4** - Cross-Section Showing Attic Oil Deposits After Gas Injection

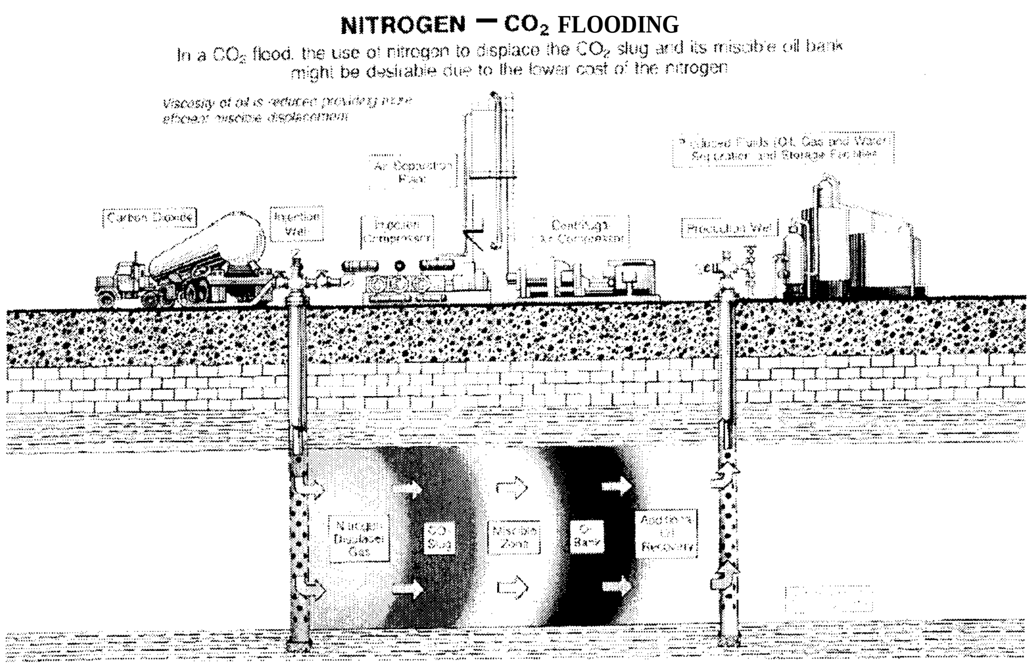

Figure 5 - Nitrogen - Carbon Dioxide Flooding. Courtesy of The **U.S.** Department of Energy, NPTO