Summary of Findings for Resource Assessment and Field Development Study of the Thomson Sand, in the Point Thomson Area, North Slope Alaska

May 16, 2008

Commissioned by

State of Alaska, Department of Natural Resources, Division of Oil and Gas

For the purpose of evaluating the hydrocarbon resource of the Thomson sand and potential depletion scenarios to maximize oil and gas recovery.

Study completed by

PetroTel Inc.
5240 Tennyson Pkwy, #207
Plano, TX 75025
Investigators
Anil Chopra - Distinguished Reservoir Engineering Advisor
Fred Stalkup - Distinguished Reservoir Engineering Advisor
Qichong Li – Senior Reservoir Engineer
Ravi Sharma – Project Director
Thomas Phillips – Distinguished Geological Advisor
Thomas O'Brien – Distinguished Geological Advisor

Summary of findings prepared by

Division of Oil and Gas, Resource Evaluation Staff
Jack Hartz
Julie Houle
Steve Moothart

Introduction

In 2007, the Resource Evaluation section of the Alaska Department of Natural Resources (DNR) Division of Oil and Gas (DO&G) initiated an independent technical assessment of the Thomson sand reservoir. The Division o f Oil & Gas contracted with PetroTel, Inc. to perform geologic and engineering evaluation of the Pt Thomson sands reservoir. PetroTel is recognized worldwide as industry leaders in enhanced oil recovery, reservoir characterization and simulation, coalbed methane, production, and exploration technologies. PetroTel provides professional consulting and advisory services utilizing a staff of 80 professionals with combined 1100 years of industry experience along with integrated project management support to domestic and international petroleum companies. Activities span the entire spectrum of technical, project, and commercial functions along with all facets of the hydrocarbon exploitation cycle.

With state-of-the-art software and sophisticated geostatistical and object modeling techniques, PetroTel reservoir engineers and geologists have successfully tackled a broad spectrum of difficult reservoir engineering problems by the intelligent application of reservoir simulation. Through the integration of reservoir geology, rock/fluid interactions, the dynamic pressure-volume-temperature relationships of oil gas and water (PVT properties), and process mechanisms, PetroTel engineers deliver reliable predictions of reservoir performance. Company expertise includes determination of in place hydrocarbons and reserves as well as providing a plan of development for discoveries that includes integrated economics.

PetroTel also has significant expertise in the development of gas condensate reservoirs with thin oil rims. They specialize in solutions and diagnostic tools that can advance the development of potential or undeveloped reserves. PetroTel has extensive experience that deals with pressure maintenance and improving recovery from gas condensate reservoirs.

The Pt Thomson sand accumulation is recognized as a high pressure retrograde condensate reservoir, which also contains a relatively thin oil column. The Petroleum Engineering Handbook[1] states "Development and operation of these (gas condensate) reservoirs for maximum recovery require engineering and operating methods significantly different from crude-oil or dry-gas reservoirs. The single most striking factor about gas-condensate systems (fluids) is that they exist either wholly or preponderantly as vapor phase in the reservoir at the time of discovery. This key fact nearly always governs the development and operating programs for recovery of hydrocarbons from such reservoirs; the properties of the fluids in place determine the best program in each case. A thorough understanding of fluid properties together with a good understanding of the special economics involved is therefore required for optimum engineering of gas condensate reservoirs. Other important aspects include geologic conditions, rock properties, well deliverability, well costs and spacing, well-pattern geometry, and plant costs."

The Resource Evaluation Group, DO&G undertook the evaluation of the Pt Thomson reservoir to better understand the resources contained in the reservoir and get an independent analysis of the development issues associated with gas condensate. The study had two main objectives: 1) to construct three-dimensional (3D) geologic models to evaluate the proven and potential hydrocarbon

---

[1] Bradley, H.B., 1987, Petroleum Engineers Handbook, 1987 Society of Petroleum Engineers, Chapter 39 Gas Condensate Reservoirs.

resource and 2) to import the geologic model into a dynamic reservoir simulator to test potential development and off-take scenarios to determine the impact on ultimate recovery of both gas and hydrocarbon liquids in the form of condensate and oil from an oil-rim in the reservoir. It should be noted that this study focuses on only the resource contained in the Thomson sand and does not Include the resource tested from the underlying Pre-Mississippian strata or the overlying Brookian accumulations

Results of PetroTel's work are summarized below.

1) The geologic and engineering analysis confirmed that gas cycling recovers more hydrocarbon than simple primary depletion based on known oil properties, gas properties, and reservoir characteristics.
2) Technical issues remain to be resolved; however, economic evaluation still needs to be done to validate conceptual conclusions and refine potential development scenarios.
3) Rigorous technical evaluation will be required as delineation of the reservoirs proceeds and additional physical information is acquired; more thorough and longer well tests are done; and as high quality reservoir oil, gas and condensate samples are acquired and analyzed.
4) Maximum recovery with gas cycling may require the import of gas in the form of waste CO2, captured inert gases, methane or natural gas from reservoirs outside of the Pt Thomson reservoir to replace voidage caused by fuel usage and shrinkage. Technical literature also suggests water can be injected into gas condensate reservoirs to maintain pressure, however, that process has not been addressed with this study.[1]
5) **Gas cycling delays gas sales, but results in greater ultimate recovery of both liquid and gas hydrocarbons. In contrast, primary depletion as a gas reservoir results in the lowest hydrocarbon recovery of a retrograde condensate reservoir. Gas blowdown[2] for sale can be done at any time after gas cycling and recovery of the hydrocarbon liquids.**
6) From the eleven static geologic models created, the volume of original gas in place (OGIP) ranged from 8.5-10.4 trillion standard cubic feet (TSCF). The volume of associated condensate ranged from 490-600 million stock tank barrels (MMSTB)[3] of condensate in place.
7) The range of original oil in place in the oil-rim varied greatly depending on the depth used for the oil-water contact. Publicly available data indicate that the interval between lowest possible gas and highest known water could vary from 60 feet to 145 feet in true vertical thickness, representing a wide range of potential oil column thickness in the oil-rim. The various geologic models produced a range of volumes of original oil in place (OOIP) in the oil-rim from 580-950 MMSTB.
8) Recoverable hydrocarbon resources for the Thomson sand were determined from dynamic reservoir simulation and are primarily a function of the development method employed. Over 70 scenarios were run to model a variety of development methods and well configurations within the reservoir simulator.

---

[2] Blow-down (also Blowdown) "A term applied to the commencement of production of gas for sale after the completion o a Cycling or Recycling operation. The term refers to the reduction of pressure in the formation as a result of the production of gas. … ". Martin, Patrick H. and Kramer, Bruce M., 2000, Manual of Oil and Gas Terms, Eleventh Edition, Lexis Publishing, page 101.

[3] Million stock barrels - MMSTB, Million standard cubic feet – MMSCF or MMSCFG/D – Roman numeral designation for million. Stock tank barrel is equivalent of 42 US Gallons liquid at 60°F and 14.65 pounds per square inch absolute, psia (1 atmosphere). Standard cubic foot is measured at 14.65 psia and 60°F

9) Development of the Thomson reservoir by primary depletion (blowdown) has the potential to recover 210-305 MMSTB of liquid hydrocarbons in addition to 6-7 TSCF of gas.
10) Gas cycling for 20 years prior to gas sales has the potential to result in the ultimate recovery of 620-850 MMSTB of liquid hydrocarbons and still recover 4.8-5.9 TSCF of gas.
11) Gas cycling, has the potential to significantly increase recoverable oil and condensate as much as 500 MMSTB of condensate and oil beyond recovery from primary depletion blowdown. This incremental recovery of oil is larger than the expected ultimate recovery from the Alpine Oil Field.

The length of time required for gas cycling prior to gas sales will be determined by the resource available in the oil rim and how fast the gas volume can be cycled. The major determining factor in this decision is the number of wells that can be economically drilled and operated. More injection and production wells could accelerate cycling and recovery of the condensate liquids and oil. There are an optimal number of wells that will economically recover the maximum amount of oil and gas within a reasonable drilling budget; however, the scope of this study did not include optimization of development but rather was designed to estimate resource volumes and quantify the range of recoverable resource using conceptual development scenarios. Hydrocarbon liquids could be produced and sold using mostly existing oil pipelines prior to the construction of a North Slope gas pipeline. Once production of liquid hydrocarbons is established from the Thomson reservoir, the production facilities could be utilized to produce oil from the Brookian Flaxman and Sourdough accumulations.

Petroleum Potential and Exploration History of the Point Thomson Area

Well log and production or drill stem test data indicate that much of the Point Thomson area is underlain by the Cretaceous (Neocomian) Thomson sand that contains abundant natural gas and hydrocarbon liquids in the form of gas condensate, ranging from 35º to 45º API gravity[4],[5]. In addition to gas and condensate, the Thomson sand also contains a thin and potentially discontinuous oil-rim at the bottom of the reservoir interval that has tested oil as high as 18º API gravity. The Point Thomson area contains the potential of hundreds of millions of barrels of oil in the shallower Tertiary Brookian reservoirs. Another potential productive reservoir is composed of carbonates and bedded metasedimentary strata in the "Pre-Mississippian" basement below the Thomson sand reservoir. The DO&G reported in their 2007 annual report that the Pt Thomson Area contained estimated undeveloped recoverable resources of 295 million stock tank barrels (MMSTB) of liquid hydrocarbons and 8 trillion standard cubic feet (TSCF) of gas.

Hydrocarbons were first discovered in the Point Thomson area in 1975 in the Alaska State A-1 well. This well tested a zone of the lower Tertiary Flaxman sand of the Canning Formation from 12,565 to 12,635 feet MD(measured depth) that flowed 23° API gravity oil at a rate of 2,507 BOPD (barrels of oil per day),

[4] API Gravity – "Specific gravity measured in degrees on the American Petroleum Institute scale. The specific gravity of oil is normally specified … in terms of API degrees. On the API scale, oil with the least specific gravity has the highest API gravity. … the higher the API gravity the greater the value of the oil." ". Martin, Patrick H. and Kramer, Bruce M., 2000, Manual of Oil and Gas Terms, Eleventh Edition, Lexis Publishing, page 52.

[5] Condensate API gravity typically ranges from 40-60 degrees and are light color compared to oil. Black oils typically have API gravity that ranges from 25-35 degrees. Lake, Larry W., 2007, Petroleum Engineering Handbook, Volume V, Society of Petroleum Engineers, Chapter 10,

2.2 MMSCFG/D,GOR 864 SCF/STB (gas/oil ratio, standard cubic feet per stock tank barrel) (USGS, 1987).

In 1977, a second discovery well, the Point Thomson Unit No. 1 well was drilled and conducted two flow tests in the Lower Cretaceous (Neocomian) Thomson sand. From a zone between the depths of 12,963 to 13,050 feet MD, the well flowed 18° API gravity oil at a rate of 2,283 BOPD, 13.3 MMSCFG/D, GOR 5,830. Between the depths of 12,834 to 12,874 feet MD, the well tested at a rate of 3.86 MMSCFG/D, 170 BPD condensate, 45° API gravity (USGS, 1987).

Over the next seven years, six additional wells were drilled to delineate the two Pt Thomson discoveries. As a result of the additional delineation drilling, two other hydrocarbon reservoirs were encountered. In 1978, the Point Thomson Unit No. 2 well tested the "Staines River sand," a local sand in the Tertiary Canning formation at a depth of 11,580 to 11,678 feet MD that produced 21° API gravity oil at a rate of 248 BOPD, 124 MSCFG/D, GOR 500, after acid treatment (USGS, 1987).

In 1982, the Alaska State F-1 well tested the Thomson sand at a depth of 13,940 to 14,316 feet MD at a rate of 4.2 MMSCFG/D and 284 BOPD condensate of 35.3° API gravity. The well also tested the under lying "Pre-Mississippian" metasedimentary basement from 13,940 to 14,316 feet MD that flowed at a rate of 2.9 MMSCFG/D with 152 BPOD condensate of 34.8° API gravity. This test identified a third potentially productive zone in the Point Thomson area (USDOE, 1993).

State lands east of Prudhoe Bay saw renewed exploration activity during the 1990s after the discovery of the Badami oil field within turbidite sandstones of the Tertiary Canning Formation. First estimated to contain 100-150 MMSTB of recoverable oil, production began at Badami in August 1998. Since that time, production has been sporadic with the field periodically shut in due to connectivity issues within the reservoir. To date, over 5 MMSTB of cumulative oil production from Badami has been reported to the Alaska Oil and Gas Conservation Commission (AOGCC).

In 1994, BP Exploration Alaska (BPXA) and Chevron drilled the Sourdough #2 well targeting Brookian sands of the Canning formation in the southern portion of the former Point Thomson Unit; the Sourdough #3 well was drilled as a follow-up in 1996. Although the data from these wells are still held confidential, BP announced the discovery of hydrocarbons within turbidite sandstones of the Tertiary Canning Formation that could potentially contain 100 million barrels of recoverable oil in a 1997 press release. The Sourdough project would require up to 35 miles of pipeline to link up with the Badami field (Peninsula Clarion, 1997).

Additional discoveries have been announced in the offshore federal waters of the eastern Beaufort Sea within the Mississippian Kekiktuk Formation (Liberty) and Tertiary sandstones of the Sagavanirktok Formation (Hammerhead and Kuvlum). Once developed, production from Liberty is expected to peak at 40,000 BOPD, with a recovery target of 100 MMSTB (Petroleum News, 2007). While data from the U.S. Minerals Management Service (MMS) indicates that while neither Hammerhead nor Kuvlum have been fully delineated, the agency estimates 100-200 MMSTB of recoverable oil at Hammerhead, and 160-300 MMSTB at Kuvlum (MMS, 2006).

The timing of development of these and other Brookian oil accumulations in the area will likely follow the commercialization of the gas and liquids reserves within the Point Thomson sand.

Geologic Setting of the Thomson Sand

The Thomson sand is an informal name that describes a sequence that is stratigraphically correlated with the Kemik Sandstone of Early Cretaceous (Neocomian) age (Figure 1). Both intervals commonly consist of preserved isolated accumulations of locally derived sediment overlying the regional Lower Cretaceous unconformity (LCU), whose composition is controlled by the local provenance eroded by the unconformity.

The Thomson sands contain significant detrital dolomite and quartz sand that are interpreted as Neocomian age fan-delta complexes that were sourced from a northern provenance composed of northerly-dipping pre-Mississippian metasedimentary units. The Thomson interval includes a broad range of rock types ranging from conglomeratic dolomite breccia to fine-grained sandstone and siltstone. In general, the coarser conglomerate facies of the Thomson sand are present to the north, proximal to the interpreted source area, while the finer-grained distal facies are more prevalent to the south. A block diagram (Figure 2) depicts a highly interpretive, schematic representation of the depositional setting of the Thomson sand during an advanced stage of transgression of the Neocomian Barrow Arch rift margin uplift and development of the Lower Cretaceous Unconformity (LCU).

Other sand occurrences are irregularly distributed along the LCU surface to the south of the Point Thomson area, depending on local thickening into accommodation space attributed to paleotopography created by the differential erosion of Ellesmerian and pre-Mississippian units below the LCU. North of the rift shoulder uplift, syn-rift sands may have been deposited as sediment gravity flows down fault relay ramps to accumulate in relatively deep water. Similar sands form major reservoirs in the Point McIntyre and Niakuk fields north of Prudhoe Bay, but the concept has not yet been tested with a drill bit north of the Point Thomson area.

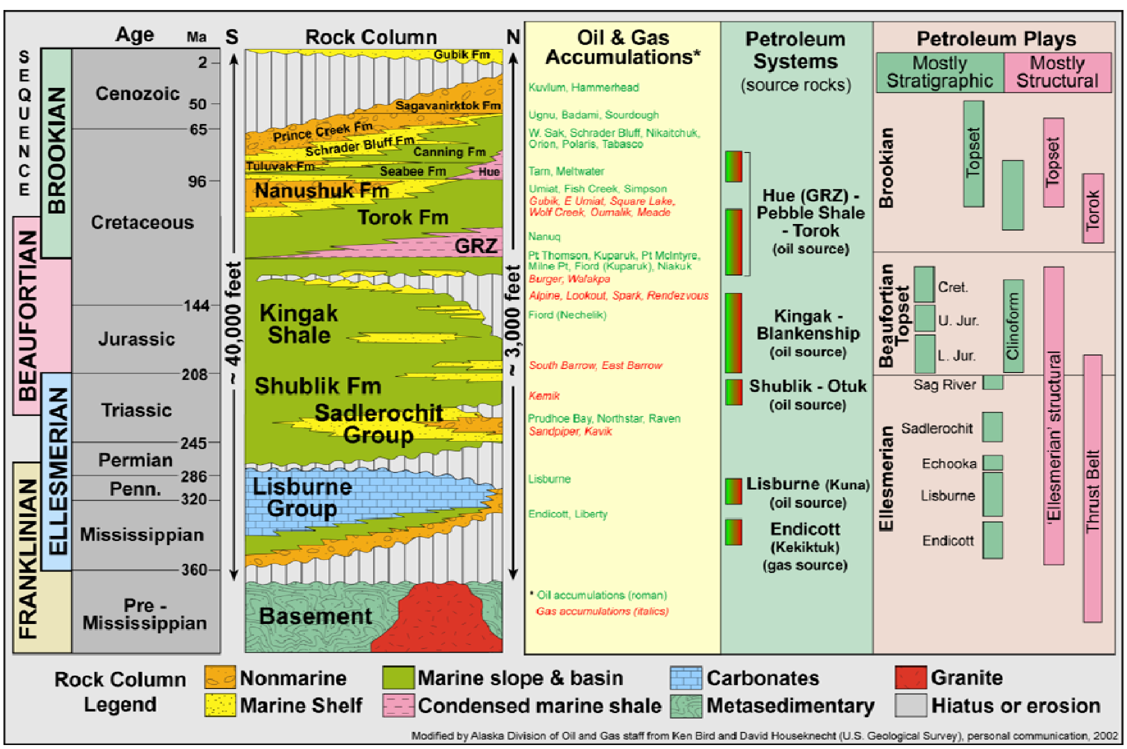

Figure 1, Alaska North Slope Stratigraphic Column

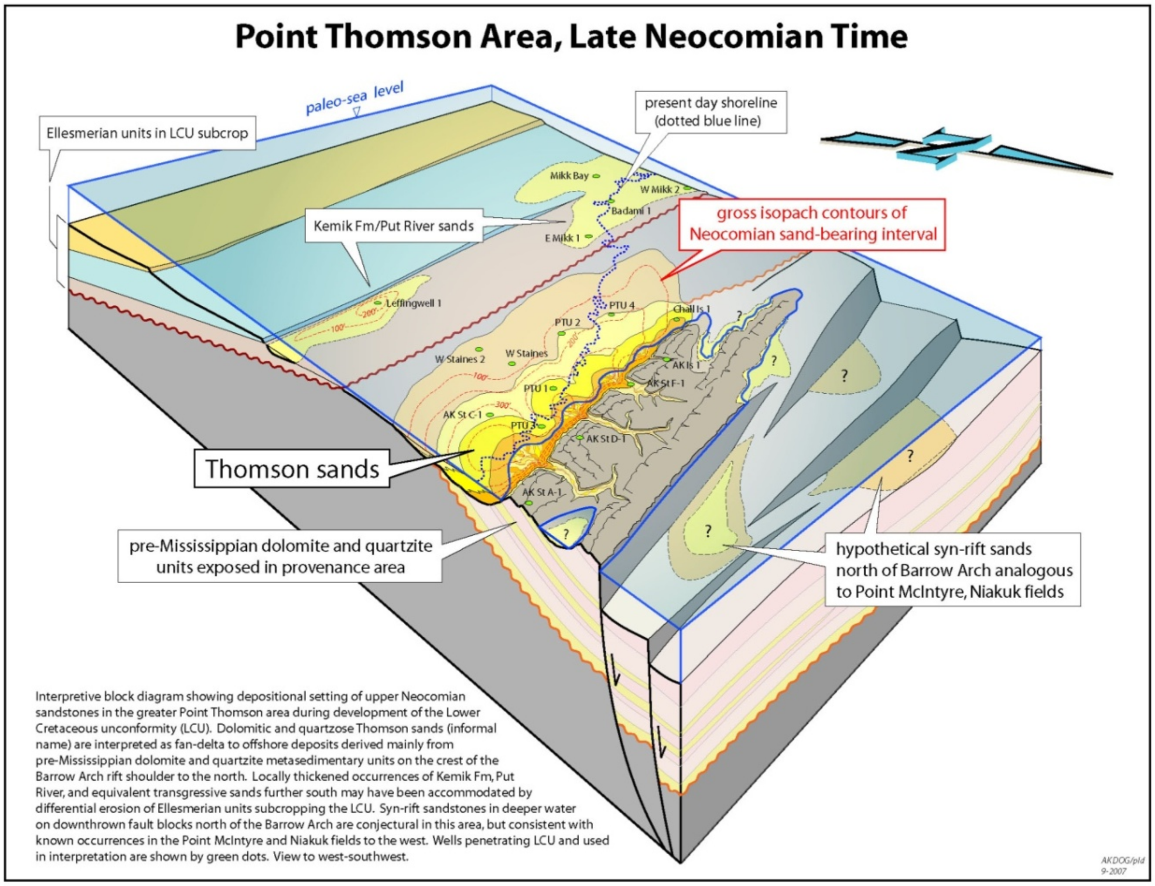

Figure 2, Block diagram of Point Thomson area in Late Neocomian time

First discovered in 1977, the oil, gas, and gas condensate contained within the Thomson sand is the largest proven, yet still undeveloped, field in Alaska. Between 1975 and 1996, a total of 17 wells have been drilled within the boundaries of the former Point Thomson unit.   1982 was the last time that a well was drilled into the Point Thomson reservoir. Although attempts were made to test most of the wells, tests were of short duration and were hampered by the high mud weights that were required to contain high reservoir pressure. Some of the tests were further complicated because they straddled both the gas and oil legs of the reservoir. No definitive, isolated test exists in the oil-rim of the Thomson reservoir. Additional wells are still needed to specifically delineate and test the productivity of Thomson oil-rim. Delineation wells in the oil-rim should include vertical pilot holes with horizontal laterals for production tests and include rigorous sampling for oil quality and PVT studies.

A number of the Point Thomson wells were drilled on the flanks of the accumulation and delineate the aerial extent of the core area of the Thomson reservoir. Along the western margin of the area though, no well has been drilled to demonstrate the western limit or trap of the reservoir or define the structural or stratigraphic continuity of the core reservoir from southeast to northwest. Additional wells are still required to adequately delineate the western limits of the hydrocarbon accumulation.

Thomson Sand Retrograde Condensate

The majority of the proven hydrocarbon resource in the Thomson sand is contained in the form of gas with entrained liquids known as a retrograde condensate. The Alaska Oil and Gas Conservation Commission (AOGCC) has released a paper entitled "Role of the Alaska Oil and Gas Commission in approving Pool Rules for the Point Thomson Field"[6] which gives an informative overview of the differences between a retrograde condensate reservoir and conventional gas and oil reservoirs. Retrograde condensate reservoirs tend to be deeper and have higher pressures and temperatures than conventional reservoirs. Due to the abnormally high pressures and temperatures, the fluid in a retrograde condensate reservoir does not behave like those in conventional oil and gas reservoirs. Pressure reduction in a conventional oil reservoir, causes the gas to expand and evolve out of solution from the oil. As gas evolves the oil becomes thicker (more viscous) and flows more slowly.

Technical literature (Society of Petroleum Engineers) has abundant examples of how condensate reservoirs perform under primary depletion and gas cycling. As pressure drops in a retrograde condensate reservoir, vaporized hydrocarbon liquids will condense when the reservoir pressure decreases below a certain point (dew point). If this happens in the reservoir, the condensate will remain trapped in place and clog the pore space, causing reduction of relative permeability; reducing well productivity and ultimate recovery. During primary depletion, the reservoir pressure will steadily decrease below dew point and hundreds of millions of barrels of condensate will become trapped in the reservoir and never be produced. Once the condensate comes out of the gas in the reservoir, very little of it will return to a gaseous state even if the reservoir pressure is later increased. Ideally, reservoir pressure should be maintained above dew point to keep vaporized liquid entrained to condense in surface facilities, thereby maximizing recovery. Results of the Pt Thomson sand reservoir modeling confirm the losses of condensate recovery during blow down. The blow down cases at best recovered about one-half the condensate that cycling cases recovered. The difference is directly attributable to trapped condensate.

Prudent development practices require keeping the reservoir pressure high (near or above dew point) until all of the economically recoverable liquid hydrocarbons have been produced in order to maximize the recovery of both oil and gas in a retrograde condensate field. "Gas cycling" is considered the best method of producing a retrograde condensate reservoir. This process involves producing hydrocarbon gas; removing the condensate for commercial sales; and then re-injecting the "lean gas" back into the reservoir to maintain pressure and sweep more condensate to the production wells. Once most of the condensate has been recovered, all the wells can be converted to gas production wells and the gas sold to market.

In addition to the dry gas and entrained condensate, the Thomson sand contains hundreds of millions of barrels of oil in the oil-rim. The gas cycling process can be applied simultaneously to the Thomson oil-rim after delineation and development. These hydrocarbon liquids could be produced and sold using mostly existing oil pipelines before a North Slope gas pipeline is operational. Once production of condensate and oil begins from the Thomson reservoir, it is anticipated that this would facilitate the delineation, development and production of some of the outlying Brookian oil discoveries in the Thomson area.

6 URL: http://www.state.ak.us/local/akpages/ADMIN/ogc/Gas/PtThompson_Pool_Rules.pdf, Retrieved April, 2008,

Studies of gas cycling in both the gas cap and oil rim were conducted using static geologic models and dynamic reservoir simulations to estimate recoveries under different development schemes. Results of those studies are documented later in the Reservoir Simulation section of this report.

DNR Evaluation of the Thomson Sand

Geologic Model Results

A total of eleven 3D geologic models were constructed of the Thomson sand. The distribution of facies and reservoir properties were varied in the different cases to account for the uncertainty between the well control points. A range of depths for the fluid contacts was also used to capture the uncertainty in identifying those contacts in the well logs or from available test data. The volume of original gas in place (OGIP) from the eleven static geologic models ranged from 8.5 – 10.4 trillion standard cubic feet (TSCF).

The volume of associated condensate ranged from 490 – 600 million stock tank barrels (MMSTB) condensate in place. Publically available well test data from the Thomson sand indicate condensate yields of 44-75 barrels condensate/MMSCF gas produced. The average yield was 64 STB/MMSCF.

The potential for a significant volume of oil in place below the gas cap in the oil-rim was also identified. The range of original oil in place in the oil-rim varied greatly depending on the depth used for the oil-water contact. Publicly available data indicate that the interval between lowest known gas and highest known water could range from 60 feet to 145 feet in true vertical thickness. This is the range of thickness available to be occupied by oil in the oil-rim. The range of volumes of original oil in place (OOIP) in the oil-rim varied in the models from 580 – 950 MMSTB.

All the volumes reported out of the geologic model are original hydrocarbons in place for the Thomson sand reservoir and do not include the hydrocarbons tested from the bedded carbonates of the Pre-Mississippian basement or those hydrocarbons tested from the overlying Brookian intervals. Reservoir properties within the Pre-Mississippian strata are not as well constrained by the available data as in the Thomson sand.

Because the Thomson sand directly overlies bedded carbonate strata of the Pre-Mississippian, it is likely in communication with the Pre-Mississippian. Recoverable volumes for the Thomson sand were determined from the dynamic reservoir simulation and were demonstrated to be a function of the development method employed. Neither the Pre-Mississippian nor Brookian reservoirs were included in the reservoir simulation. Both should be considered as considerable upside since they have been successfully tested in multiple wells. Further delineation drilling is required to fully access the resources in-place and production impacts of these reservoirs on future development.

Reservoir Simulation Results

Upon initialization of the reservoir simulation model, over 70 scenarios were run to model a variety of development methods and well configurations. The development methods included primary depletion (gas blowdown), gas cycling followed by gas blowdown, and development of the oil-rim. Numerous cases were run for each type of development to test different well configurations such as horizontal wells, well constraints such as rate limits and operating pressures, and the number of development wells. In this way, we were able to judge the relative impact the different variables had on the ultimate recovery of the resource within each type of development. All model cases were run out to thirty years of production. It should be noted that no physical constraints to the development wells such as location of surface drill sites and facilities or drilling departure from surface location have been applied during the modeling. At this stage of the analysis scenarios were designed and run to discover and evaluate the key sensitivities to recovery, rather than to derive optimal production economics.

Primary Depletion (Gas Blowdown)

Gas blowdown can be done at any time after cycling and recovery of the hydrocarbon liquids. In the following cases, gas blow down is done first without pressure maintenance or gas injection. Six primary depletion cases were run in the reservoir model. Three cases contained a fixed number of wells at startup and three cases included additional wells that were added later. Gas producers were constrained to a maximum rate of 150 MMSCF/D and a minimum bottom-hole pressure (BHP) of 3000 psi. Cases were run with 8, 16 and 22 wells. Initial gas production rates for these three cases varied from 0.4 – 1.2 BSCF/D[7]. Additional cases included: 12 initial producers with 4 new producers drilled after 4 years, 16 initial producers with 3 additional wells drilled after 8 years, and 16 producers with 6 additional wells drilled after 4 years. Initial gas production rates for these three cases ranged from 0.8 to 1.2 BSCF/D. Three more primary depletion cases were run in both gas cap and oil rim. Cases were run with 22, 13 and 13 gas producers in the gas cap and 4, 30 and 20 oil producers in the oil rim. Oil producers were constrained to a maximum rate of 7000 STB/D and a minimum bottom-hole pressure (BHP) of 3000 psi. Initial gas production rates for these three cases ranged from 1.0 to 1.2 BSCF/D

With a BHP limit of 3000 psi, gas recovery can approach 60% for the 16- producer and 22-producer cases. The recovery can reach 70% at lower BHP of 2000 psi. The 8-producer case can recover 45% of the gas in 30 years. The number of wells and timing of drilling could be optimized to meet gas demand or gas sales contracts. Twenty-two wells could drain the gas in the reservoir in 12-15 years.

Condensate recovery during primary depletion of the gas cap is only about 25% of the in place volume after 30 years. The majority of the condensate is lost in the reservoir because the reservoir pressure drops below dew point. Pressure maintenance and gas recycling is needed to recover more condensate. Primary depletion is also detrimental to any future recovery from the oil-rim due to loss of energy within the oil by the reduction of reservoir pressure. Oil rim recovery ranged from 3-16% in the cases of primary depletion in both gas cap and oil rim if primary depletion is the only recovery method.

Gas Cycling Followed by Gas Blowdown

The model cases run demonstrate that full scale gas cycling should be initiated early in order to achieve maximum recovery of the condensate and any other potential hydrocarbon liquids in the gas cap. Cycling also maintains reservoir pressure for development of the oil-rim. In a gas cycling project, the ultimate recovery of condensate and timing of subsequent gas blowdown is a function of the rate at which the in place volume of gas can be produced and recycled. This can be optimized by the number of development wells in place.

7 BSCF/D – Billion standard cubic feet per day.

Four base cases of cycling the produced gas for 30 years with a different numbers of wells were run to test the impact of well count on the potential ultimate recovery of condensate. Additional cases with gas blowdown commencing after 10 and 20 years of cycling were run to test how much condensate could be produced prior to blowdown for gas sales.

The four base cases consisted of: a minimum development case of 4 producers and 2 injectors; a case with 8 producers and 4 injectors; a 16-producer with 5-injector case; and a case with 22-producers and 8 injectors which resulted in the highest hydrocarbon recovery of the four cases. Producers were constrained to a maximum rate of 150 MMSCF/D and a minimum BHP of 3000 psi. The injectors were limited to a maximum rate of 300 MMSCF/D and a maximum injection pressure of 15000 psi. In all cases 90% of the produced gas was cycled back into the reservoir.

Condensate recovery after 30 years for the four cases ranged from only 24% of the in place volume for the 4-producer case, to 86% recovery for the 22-producer case. At the end of cycling the injectors can be converted to gas producers. Gas blowdown with the 30 wells producing subsequent to gas cycling can recover up to 70% of the remaining recycled gas within 12 years.

Additional cases were then run with gas cycling for both 10 years and 20 years before blowdown. For the 22-producer and 8-injector development, after 10 years of cycling 62% of the condensate is recovered and then 57% of the original gas in place (OGIP) is recovered during the ensuing blowdown. Cycling for 20 years recovers 76% of the condensate and then 56% of the gas (OGIP).

Oil-rim Development

One of the key results of the study was that it became obvious that oil rim development had to be done during a gas cycling phase. Because there is uncertainty about the quality of the oil and reservoir rock in the oil-rim, to preserve reservoir energy and sustain maximum oil producibility oil rim reservoir pressure must be maintained. The oil-rim is a relatively thin zone of the reservoir that lies between the gas cap and underlying aquifer. For this reason the use of dedicated horizontal wells will be required to avoid coning of the adjacent gas or water. Injection of the recycled gas into the oil-rim will help reduce the viscosity, improve swelling, mobilize and displace the oil.

Model cases were run that included production wells in the oil-rim as part of both a primary depletion and gas cycling developments. Individual cases in both development strategies varied the number of oil-rim producers from 4 to 20 and ultimately 30 oil wells. Sensitivities were also run on gas- oil ratio (GOR) cutoffs for the producers, minimum BHP, and the use of offsite gas for supplemental gas injection.

In a primary depletion scenario, adding four wells into the oil-rim recovered 3% of the original oil in place. Increasing the number of oil-rim wells to twenty or thirty upped the recovery to almost 16% of OOIP. In a gas cycling scenario, the addition of four wells in the oil-rim achieved 11% recovery after 30 years of cycling, going to gas blowdown after 10 or 20 years of cycling recovered 7% and 9 % of the oil-rim OOIP respectively.

Increasing the number of oil-rim wells during gas cycling development in the model increased the recovery of oil significantly. In a case with 13 gas producers, 18 gas injectors and 20 oil-rim producers, recovery of oil from the oil-rim approaches 50% of the in-place volume after 30 years of cycling. This is 3-15 times better recovery than during primary blowdown. By varying the length of time of cycling before gas blowdown from 5 to 10 and then 20 years in the same development scenario the recoveries from the oil-rim drop to 31%, 39% and 43% respectively.

Modeling of development scenarios for the oil-rim demonstrates that to achieve maximum recovery of the oil resources located below the gas cap in the oil-rim reservoir pressure maintenance by gas cycling is crucial. The difference in recovery from the oil-rim between primary depletion and a cycling project that maintains reservoir pressure can be as much as **35% more** of the total in-place volume.

Use of Offsite Gas

Production from the oil rim increases the voidage within the reservoir. The results from model cases involving large scale development of the oil-rim (30 horizontal producers) indicated that due to the increased off-take, reinjection of 90% of the produced gas will not be sufficient to maintain reservoir pressure. A decrease in reservoir pressure below dew point results in lower condensate recoveries and the reduction also decreases oil-rim recovery.

Gas from outside sources (offsite) could be imported and injected into the Thomson reservoir to help maintain reservoir pressure. Offsite gas can be in the form of carbon dioxide (CO2), inert gas such as nitrogen, methane or natural gas.

The use of CO2 for pressure maintenance may have multiple benefits depending on the source and availability.

- CO2 is commonly removed as a byproduct from produced gas in a gas treatment plant prior to sale.
- If enough CO2 is available for pressure maintenance, it could allow sale of some Point Thomson gas before gas blowdown.
- CO2 should be fully miscible with the Thomson oil and thus reduce the viscosity and further increase recovery.

CO2 is considered a “green house gas” and re-injection into a reservoir is a method of sequestering carbon and as such government tax incentives may be available in the form of carbon credits to offset and/or mitigate CO2 re-injection costs,

Although the importation of offsite gas would require the construction of a gas line to Point Thomson, once gas cycling is completed, the line would be available for gas sales.

The large scale oil-rim development cases that needed supplemental pressure support indicated a volume of 200-500 MMSCF/D would be required in addition to the Thomson gas during the cycling process. A comparison of cases with and without offsite gas showed an increase in condensate recoveries from 33% to 60% of the original condensate in place. This is a potential increase of 130-160 MMSTB.

Conclusions from Geologic and Reservoir Modeling

1. In addition to gas, the area contains hundreds of millions of barrels of hydrocarbon liquids. These hydrocarbon liquids exist in the form of condensate liquids; a thin and potentially discontinuous oil leg at the bottom of the Thomson sand reservoir; and oil in the overlying Brookian sediments. Exploration wells drilled prior to 1982 have tested oil from each of these reservoirs. Adequate infrastructure to transport these liquids to market exists within thirty miles of this reservoir.

Therefore, the potential development of the Point Thomson area should not be limited to production of the dry gas.

2. Evaluation of the potential hydrocarbons in place in the Thomson sand reservoir by DNR and PetroTel's 3D geologic models results indicate the following volumetrics:
    - Original gas in place of 8.5-10.4 TSCF.
    - retrograde condensate - 490-600 MMSTB in place
    - Oil rim - 580 to 950 MMSTB original oil-in-places.

3. Reservoir simulation of the Thomson sand reservoir evaluated various development scenarios for the reservoir. These scenarios included primary depletion of the reservoir (gas blowdown), production and re-injection of the gas after recovering the condensate (gas cycling), and the addition of dedicated horizontal production wells into the oil-rim in both gas blowdown and cycling cases. Over 70 individual cases where run in the reservoir simulator varying the number of development wells and operating constraints in an attempt to determine the optimum recovery for each development scenario.

4. The producible liquids contained in the Thomson reservoir could technically be developed before a gas pipeline is built.

5. In order to maximize the recovery of the hydrocarbon liquids in the reservoir it is necessary to keep the reservoir pressure high until all of the economically recoverable liquid hydrocarbons are produced. This is most often accomplished through gas cycling. In the reservoir simulator cases run, gas cycling was applied in the gas cap for 30 years in conjunction with development and gas cycling of the oil-rim.

    - Gas cycling recovered 86% or 420-516 MMSTB of condensate.
    - Recovery from the oil-rim was close to 50%, 290-475 MMSTB.

6. Shorter duration Gas Cycling:
    - Cycling gas for 10 years prior to blowdown results in recoveries of:
        - Condensate - 62% or 300-370 MMSTB
        - Oil Rim - 39% or 225-370 MMSTB of the oil-rim

    - Cycling the gas for 20 years increases the recoveries:
        - Condensate - 76% or 370-450 MMSTB
        - Oil Rim - 43% or 250-400 MMSTB.

    - Subsequent blowdown of the gas cap after 10 and 20 years cycling recovers 57% and 56% or 4.8-5.9 TSCF of gas reserves.

7. Primary depletion is the fastest method to produce the gas from the reservoir but recovers the least hydrocarbons. Simulation results showed: 70% of gas recovered or 6-7 TSCF with 22 wells in 12-15 years.
    - Condensate recovery is approximately 26% of the in place volume, or 127-156 MMSTB
    - Oil-rim recovery during primary depletion is only 3-16% 30-150 MMSTB of oil.
    - The majority of the condensate is left in the reservoir by condensation below dew point.
    - Pressure maintenance and gas recycling is needed to maximize condensate recovery.

- Primary depletion reduces recovery from the oil-rim due to loss of energy by the depletion of reservoir pressure.
- Gas blowdown and sale of the gas can be done at any time after cycling and recovery of the hydrocarbon liquids.

8. A gas blowdown scenario could recover over 500 million barrels less than a gas cycling scenario. This difference is larger than the expected ultimate recovery from the Alpine Oil Field.

9. There is uncertainty in the original oil-rim volume in place and the ultimate recovery of that oil, even though it has flowed during testing of the PTU-1 exploration well.
   - Even if the oil rim was discounted entirely, the difference in condensate recovery between primary depletion (blowdown) and gas cycling for 20 years is potentially over 300 million barrels.
   - This represents three times the targeted recovery from the proposed off shore development of the Liberty Field.
   - During the period of gas cycling, further delineation of the oil-rim will determine the scale of development needed to maximize recovery from that portion of the resource.

In summary, gas cycling delays gas sales, but it is through this process that the maximum recovery of the condensate in the gas cap and any other liquid hydrocarbons can be achieved. Cycling also maintains reservoir pressure for development of the oil-rim and is a viable recovery mechanism. The length of time required for gas cycling prior to gas sales will be a combination of the resource available from the oil rim and the rate at which the in place volume of gas can be produced and recycled. A large factor in this will be the number of development wells that can be economically drilled and operated. More wells equals faster cycling and faster recovery of the condensate liquids. These liquids could be produced and sold before the construction of a North Slope gas pipeline. Production of liquid hydrocarbons from the Thomson reservoir could facilitate oil production from the other discovered reservoirs such as the Brookian Flaxman and Sourdough accumulations.