# Point Thomson: Key gas field that's challenging to produce

By Bill White

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The Point Thomson gas field is like the kid who has all the potential to be a great adult, if he can just learn to control his erratic behavior.

Among Alaska's natural gas crown jewels Point Thomson is No. 2 behind the glamorous Prudhoe Bay field to its west, the nation's largest oil field and one of its greatest gas reservoirs, with about 24 trillion cubic feet of reserves.

Point Thomson has gargantuan gas reserves, too – about 8 trillion cubic feet. That's as much as the entire volume of Cook Inlet production since the first molecule of methane left the ground 43 years ago. Point Thomson alone, with no help from Prudhoe, could keep the proposed North Slope natural gas pipeline full for about five years, if the gas could be produced that fast.

Point Thomson and Prudhoe form the core gas reserves that could launch the multibillion-dollar pipeline project that would flow 4.5 billion cubic feet of natural gas daily for Lower 48 markets. Those two reservoirs together make the North Slope an attractive gas play, if the natural gas market price is high enough. They have enough gas to keep the pipeline full for about 15 years. Other fields and new discoveries could keep the pipeline full for decades more.

But as rich with potential as Point Thomson is, the undeveloped field is also rich with unanswered questions about how to technically produce the gas.

That's because Point Thomson is a rarity. It's not a conventional oil-gas field such as Prudhoe Bay. It's not a conventional dry-gas field such as the big Kenai or Beluga fields of Cook Inlet. Point Thomson is a "retrograde gas condensate reservoir," a kind of field that's far more challenging and expensive to engineer into production.

Compounding that challenge are a variety of other factors, from the presence of oil that might need to be produced before the gas to its isolated Arctic location off the grid of the North Slope's producing fields.

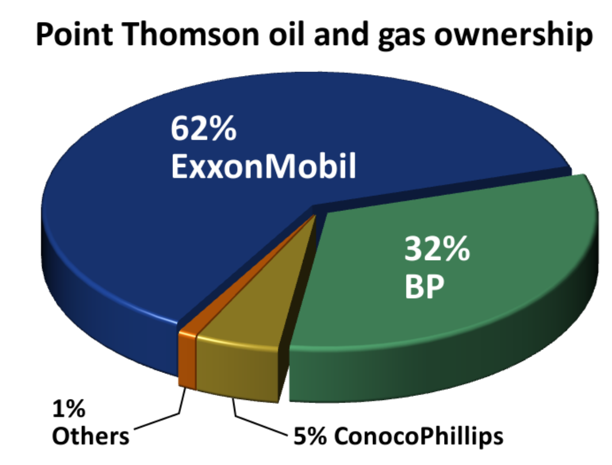
If developed, Point Thomson would be unlike any other oil and gas field in Alaska, and aspects of it would be unlike almost anything else in the world.

## Discovery

An Exxon well found the Point Thomson gas reservoir in 1977, around the time oil started flowing from Prudhoe Bay to launch Alaska's current oil era.

Oil companies had been drilling all over the central North Slope in the roughly 10 years since Prudhoe's 1968 discovery. The Point Thomson well was one of the most eastern wells drilled.

Exxon, BP and Chevron acquired significant stakes there. ConocoPhillips and some 20 other entities also collectively acquired a 6 percent interest. In 2012, ExxonMobil took over Chevron's leases, giving it a 62 percent interest. It would be the field operator.




The Point Thomson area is somewhat larger than the Anchorage Bowl. It lies about 60 miles east of Prudhoe, and about 22 miles east of the nearest point in the North Slope's oil pipeline network.

Most of the reservoir lies offshore in state coastal waters, but ExxonMobil and its partners propose the initial development from three onshore pads that would directionally drill under the seabed.

## The trouble with condensate

Natural gas comes in a variety of forms deep underground.

In a conventional oil reservoir, gas might be present as a liquid contained within the crude oil. It changes to a gas when it rises to the surface and some of the underground pressure is gone. The same concept puts bubbles in soda pop when the bottle is opened: The pressure change releases the dissolved carbon dioxide as a gas.

For this gas, processing it at the surface also includes boosting the pressure and cooling the gas so that certain components – such as ethane, propane and butane – drop out of the gas and become liquid again. These gas liquids are valuable products in themselves, and entire industries have developed around them. One of the liquids is condensate, which sometimes has been termed "white gas" and compared to cooking oil, although it is not an actual oil.

Gas dissolved in crude oil is not the only form natural gas can take underground. It can be in a gaseous state within a conventional natural gas field. Condensate might be within the gas as a vapor. This is known as "wet gas." The condensate drops out as a liquid when the gas reaches cooler temperatures at the surface. "This is similar to what happens when someone blows warm breath onto a cold window and watches it fog up," said the Alaska Oil and Gas

Conservation Commission in a 2007 report on Point Thomson. "The water that exists as a vapor inside the warm lungs turns to condensation as it hits the cold window."

These are the two normal sequences for producing oil, gas and natural gas liquids. Once separated at the surface, the producer sends each of the hydrocarbons its separate way for further processing.

But Point Thomson is a retrograde gas condensate reservoir, and these work differently. In fact, the difference, when first theorized in the 1930s, so annihilated the industry's conventional wisdom about the physical laws of natural gas that it was met with profound disbelief.

For retrograde gas condensate reservoirs, it's not an increase in pressure that prompts the liquids to drop out, but a decrease. That contrariness stunned and confused the industry, and this phenomenon accounts for attaching the word "retrograde" to the reservoir. Causing further headaches: The underground high pressure and high temperature within these reservoirs is at or near the point that causes the condensate to become liquid. Simply producing the gas can lower the reservoir pressure. This can cause two big problems.

**Problem No. 1**: If the condensate becomes liquid underground rather than at the surface, it can cling to the rock particles and clog the area around the well bottom. This reduces the amount of gas that can flow to the well, costing the gas producer revenue.

**Problem No. 2**: Once the condensate becomes liquid down in the reservoir, less of the condensate will be produced. Again, this costs the producer revenue.

The solution is to keep the reservoir pressure from dropping too far. ExxonMobil and its partners propose to do that by "cycling" the gas production this way:

- Produce a relatively small flow of gas from Point Thomson – perhaps 200 million cubic feet a day.
- Extract from that about 10,000 barrels a day of condensate at a plant they would build at Point Thomson.
- Flow the condensate 60 miles to the trans-Alaska oil pipeline and on to markets. (Natural gas liquids have been mixed with crude oil and flowing through the pipeline for more than 25 years.)
- Recompress the rest of the gas and inject it back into the reservoir to preserve the pressure.

In this way, the partners think they can produce about 200 million barrels of condensate total, starting in a few years, while saving the dry gas for later, when the natural gas pipeline is finished.

They still expect that some condensate would liquefy within the reservoir during production, and they would lose it forever. But the companies hope this cycling plan will minimize those losses for themselves and the state, which owns a royalty share of the gas and oil production.

## Powerful pressure

The pressure within gas condensate reservoirs tends to be extraordinary. That's in part because gas condensate reservoirs typically are much deeper underground than more normal oil and gas fields.

The oil industry started discovering gas condensate fields 80 to 90 years ago as their search for crude prompted them to drill to ever deeper depths.

Point Thomson is deeper than the typical North Slope field, too. It lies about 12,000 feet underground, compared with Prudhoe Bay's less than 9,000 feet.

Some of the sediments holding Point Thomson gas were laid down an estimated 400 million years ago, a time when the Earth hosted three major continents rather than today's seven, and when four-legged animals first began to colonize the land. The rocks of Prudhoe Bay and some of the other key North Slope oil fields were created over the ensuing 150 million years, a time when the Earth's four-legged creatures came to include dinosaurs.

The pressure within the Point Thomson reservoir is enormous – over 10,000 pounds per square inch. By comparison, the first gas condensate fields discovered in the 20$^{th}$ century were at about 1,500 psi, and Prudhoe Bay is less than 5,000 psi. When production starts at Point Thomson, it will be the highest-pressure field in Alaska by far. Few fields in production worldwide have higher pressure.

This extreme pressure presents two key challenges.

First, the wells and related production gear must be heavier duty than normal. The drilling rig itself must be robust enough to handle the high pressure, the extreme well depth and the long well reach from an onshore drill pad to an offshore target. ExxonMobil and its partners say they have the technology to handle this job, but estimate one Point Thomson well will cost 10 to 15 times the price tag of a Prudhoe Bay well.

Second, the produced gas must be recompressed to 10,000 psi before injection. During condensate extraction at a Point Thomson plant, the gas pressure will be reduced to around 2,700 psi. The technology to punch that back up to 10,000 psi is relatively new, with the first such re-compression operation starting up only in 2007, an ExxonMobil executive told the state during the following year. To squeeze the gas molecules back into tight formation before injection, the powerful compressors would burn a lot of produced gas.

Other challenges are logistic. How can the developers get a processing plant, super-compression machinery, a housing camp and other materials to a site that lies far from the Arctic oil-field road network? How do they get the condensate liquids to the trans-Alaska pipeline?

The partners have rejected the idea of extending a permanent road to the Point Thomson site. Instead, they intend to build a dock to receive ocean-going barges delivering building modules and other materials. As for piping the condensate away, they plan to install a 22-mile elevated pipeline to the Badami field, at present the easternmost North Slope field. Twenty-two miles is about the distance from downtown Anchorage to Big Lake, as the crow flies. From Badami, the condensate could flow through an existing pipeline the final 40 miles or so to the trans-Alaska pipeline. (A separate 60-mile gas pipeline to reach a gas treatment plant at Prudhoe would be needed later when full-scale gas production begins.)

## The oil below

The Point Thomson partners have at least one more major obstacle to surmount on the path toward development: What about that thin layer of low-grade crude oil that lies under the gas?

Point Thomson lies on state leases, and state regulators will want that oil produced. These regulators with the Alaska Oil and Gas Conservation Commission are charged with ensuring that no valuable state resources are left behind or otherwise wasted, and they can require that the gas wells also target the oil.

In fact, Point Thomson has two layers of oil: the larger one – although small by North Slope standards – lies under the natural gas. The other layer is much closer to the surface, with pockets of oil dwelling in a rock layer laid down about 55 million years ago – after dinosaurs became extinct.

The Point Thomson partners have drilled two of the five wells planned to solve some of the mysteries of the reservoir, including how thick the oil layer is beneath the gas and how permeable the gas and oil rocks are. And they want to know whether the resources flow freely throughout the reservoir or are there structural barriers to the flow. The partners say the five wells will answer how best to produce the gas and condensate, as well as whether the oil –both the deep and shallow layers – can be produced at all.

A BP executive told the state in 2008 that results from the 1977 Point Thomson discovery well suggest the oil is what's known as "heavy" oil, which is lower in quality than crude from Prudhoe Bay. When refined, heavy oil produces smaller quantities of high-value products such as gasoline.

The executive used a fish analogy. The crude from most North Slope fields is like king salmon and halibut compared to Point Thomson's arrowtooth flounder – "there's lots of it but when you cook it, it turns to mush."

If the partners do produce oil, the crude can flow through the same pipeline that would carry the condensate. The pipeline will be designed to carry up to 70,000 barrels a day of condensate and/or oil, the partners said.

ExxonMobil and its partners have not publicly disclosed the results of the two new wells they've drilled so far in their new five-well development regime.

They had hoped to start condensate production in 2014. But that schedule has slipped because the federal environmental impact statement on the proposed development is about a year behind the original schedule and now permit decisions are projected to be completed in August 2012.

Separate from the technical challenges, the state and oil company partnership led by ExxonMobil were enmeshed in a legal dispute over Point Thomson from 2005 to 2012. In 2005, the state commissioner of Natural Resources ruled that the oil companies had taken too long to start production from Point Thomson, and moved to dismantle the unification of their leases, a step that would impair the partners' rights to produce there in the future.

The oil companies challenged that ruling on several fronts. However, to show their commitment to Point Thomson, the companies in 2008 and 2009 devised a new plan to start-up the field: Drill five wells, strip condensate from the gas, reinject the gas to maintain reservoir pressure, and produce oil if possible. That plan is described in this article, and the state OK'd the delineation drilling while the legal dispute continued. As was mentioned, two of the wells were drilled.

In March 2012, the state and oil companies settled the dispute. First production of liquids now is planned for the winter of 2015-2016.