

4.0 DRILLING

4.1 OVERVIEW

The Point Thomson Gas Cycling Project will be developed by drilling and completing approximately 13 production wells and 8 gas injection wells in the Thomson Sand, and one Class I disposal well to be drilled in the shallower Sagavanirktok from three onshore pad locations (Table 4-1). All wells will require directional drilling to reach the desired bottom hole. All bottom-hole targets lie beneath the lagoon except for the Class I disposal well and one East Well Pad production well (Figure 3-3).

The Point Thomson production and gas injection wells are considered long-life, very prolific, high-pressure wells (>0.8 pounds per square inch [psi] per ft vertical depth as defined by industry). The high pressure differentiates the Point Thomson wells from other North Slope wells. The working pressure requirements for blowout prevention equipment and producing wellheads and trees are 10,000 psi, while the requirements for the injection well trees are greater than 10,000 psi due to high-pressure compression of gas for reinjection. The working pressure of most equipment on the Slope is 5,000 psi or less.

Special emphasis will be placed on well design, procedures, communication, and training to ensure the wells can be safely drilled, completed, produced, and maintained. A minimum of two safety barriers will be in place at all times while work is progressing. For example, during drilling, the drilling fluid will act as one barrier and the blowout prevention equipment will act as another. In the case of producing the well, the surface controlled subsurface safety valve and the tree would act as barriers. If a barrier is compromised, work will be stopped and the barrier restored before proceeding with the work. The purpose of this philosophy is to prevent a single point failure from escalating.

**TABLE 4-1
WELL COUNTS**

PAD	APPROXIMATE NUMBER OF WELLS
West Well Pad	6 Production Wells + 2 Future Wells
Central Well Pad	8 Gas Injection Wells + 2 Future Gas Injection Wells 1 Disposal Well + 2 Future Disposal Wells
East Well Pad	7 Production Wells + 2 Future Wells
Total	22 to 30 Wells

The high pressure in the reservoir will require heavier (thicker-walled) casing and tubing than normally used on the North Slope. Connection testing and qualifications will be required for some of the heavy-wall casing and tubing for additional well security. Special emphasis will be placed on the selection of metallurgy to ensure the structural integrity for a long life at high pressure.

The production and injection wells will be large bore with 7-in.-nominal outside diameter tubing. Either one or two rigs will be used and likely mobilized to Point Thomson by barge a year before the CPF modules are delivered to Point Thomson.

It is anticipated that the Class I non-hazardous disposal well will be the first well drilled. This well will be used initially to dispose of the slurrified cuttings generated from the drilling of the development wells. In addition, this same well will be used to dispose of produced water, wastewater effluent from the camps, and exempt and other non-hazardous waste.

4.2 TARGET LOCATIONS

Figure 3-3 shows the preliminary target locations for the anticipated 8 injection wells, 13 production wells, and one Class I disposal well. It is anticipated that the actual target locations will change as additional reservoir data is obtained.

4.3 WELLS

Siting for the well surface locations and allocation of space on the well pads for drilling operations are governed by several criteria:

- Approximately 22 wells (21 production and injection wells and one disposal well) on three separate drilling pads,
- Flexibility in rig selection,
- Ability for future well interventions,
- Need for storage and handling of large quantities of consumables during freeze-up and breakup,
- Allowance for simultaneous drilling and production operations,
- Minimizing wellbore intersection possibilities,
- Mitigating collateral damage in the unlikely event of an uncontrolled hydrocarbon release, and
- Minimizing well departure.

The well spacing at each pad will be 40 ft. The well cellars for all wells will be lined with a 15-ft-square sealed container set in the gravel pad; 6 in. of cement will seal the base. At the conclusion of drilling, the cellar will be filled with gravel for personnel safety considerations.

4.4 WELL DESIGN

4.4.1 Well Profiles

The well profiles will be vertical through some of the permafrost and then deviated. This will provide additional separation from other wells as the hole is drilled deeper. It is envisioned that

surface casing will extend through the section of the hole that defines the well deviation angle. This maximum hole angle will be maintained all the way to the reservoir target. This profile will minimize the hole angle required to reach the reservoir target. It is anticipated that the maximum hole angle will be 67°. This hole angle will allow wireline and/or coil tubing work to facilitate completions and workovers.

4.4.2 Casing Seats

Development well design, including casing seat locations, is based on Point Thomson exploration and appraisal data, and on North Slope drilling practices. A typical Point Thomson development well is anticipated to have the following casing seats (Table 4-2):

- *Conductor*: The conductor hole will be drilled, and the conductor will be cemented in place for all wells at approximately 80 ft true vertical depth (TVD). This will be done during pad construction. Conductors will be insulated and designed to minimize thawing of adjacent permafrost.
- *Surface Casing*: This casing will be set in the Sagavanirktok Formation (about 4,500 ft TVD).
- *Intermediate Casing*: This contingent casing will be used as required to ensure the protective/production casing can be set in the pressure transition zone or to isolate weak formations in the shallow intervals.
- *Protective/Production Casing*: This casing will be set when the mud weight required to drill the intermediate hole has reached a pre-determined level that indicates the formation mechanical strength is appropriate to support drilling through the productive interval.
- *Production Liner*: The well will reach total depth at the base of the Thomson Sand reservoir at approximately 13,300 ft TVD.

TABLE 4-2
TYPICAL PRODUCTION AND INJECTION WELL CASING PROGRAM

CASING / HOLE SIZE		SETTING DEPTH (TVD)	FORMATION
Low-Angle Well	High-Angle Well		
34 x 20-in. Conductor (Preset)	34 x 20-in. Conductor (Preset)	±80 ft	N/A
13-5/8-in. Surface Casing/ 16-in. Hole	13-5/8-in. Surface Casing/ 16-in. Hole	±4,500 ft	Sagavanirktok (Tertiary)
N/A	11-3/4-in. Intermediate Casing/14-3/4-in. Hole	As Required	Sagavanirktok (Tertiary)
9-7/8-in. Protective/ Production Casing/ 12-1/4-in. Hole	9-7/8-in. Protective/ Production Casing/ 12-1/4-in. Hole	±10,800 ft	Canning (Lower Tertiary)
7-in. Production Liner/ 8-1/2-in. Hole	7-in. Production Liner/ 8-1/2-in. Hole	±13,300 ft	Thomson Sand (Lower Cretaceous)

Setting depths may be adjusted with new interpretation of mud weight and fracture predictions. Emphasis has been placed on reducing conductor and surface casing size to minimize cuttings waste discharge. Detailed well designs will be included in the Permit to Drill applications submitted for approval by the Alaska Oil and Gas Conservation Commission (AOGCC).

4.4.3 Drilling Fluids

The anticipated drilling fluids program provided in Table 4-3 will be further refined based on wellbore stability analysis. The stability analysis will also help determine if an underreamed 14-3/4-in. contingency hole and 11-3/4-in. liner will be required in the higher-angle well to help build formation integrity for drilling the next hole interval. Refinements to the hole sizes will be made once the well has been optimized and final casing selection is made.

**TABLE 4-3
TYPICAL DRILLING FLUIDS PROGRAM**

HOLE SIZE/SECTION		DRILLING FLUID TYPE	DRILLING FLUID WEIGHT RANGE (ppg)
Low-Angle Well	High-Angle Well		
34 x 20-in. Conductor (Preset)	34 x 20-in. Conductor (Preset)	N/A	N/A
16-in. hole	16-in. hole	Fresh Water Gel	8.8 to 10.0
N/A	14-3/4-in. underreamed hole	Non-Aqueous Fluid	8.8 to 13.0
12-1/4-in. hole	12-1/4-in. underreamed hole	Non-Aqueous Fluid	8.8 to 14.0
8-1/2-in. hole	8-1/2-in. hole	Non-Aqueous Fluid	14.0 to 16.0

4.4.4 Class I Disposal Well

One EPA-regulated Underground Injection Control (UIC) Class I disposal well is planned for Point Thomson. The well will have approximately 3,800 ft of separation from any other well at approximately 5,700 ft TVD (the top of the injection zone). The well will be used primarily for disposal of cuttings and wastewater effluent initially and subsequently for disposal of wastewater, produced water, and exempt and other non-hazardous wastes.

The current Class I well design includes 20-in. conductor at about 80 ft, 10-3/4-in. surface casing set at approximately 4,000 ft TVD, and 7-5/8-in. casing set at approximately 6,700 ft TVD. The casing will be perforated through the injection zone and sealed with a permanent packer. It is anticipated that 4-1/2-in. tubing will be used for injection. Table 4-4 provides expected waste volumes of mud and cuttings for each well type.

**TABLE 4-4
EXPECTED WASTE VOLUMES FOR POINT THOMSON WELLS**

WELL TYPE	CUTTINGS WASTE GENERATED (bbl)	TOTAL SLURRY INJECTED (bbl)
<17,000 ft (measured depth)	~7,500	~ 34,000
>17,000 ft (measured depth)	~14,000	~57,000
Disposal Well	~3,000	~12,000

The total slurry injected includes waste mud and water used to dilute slurry for injection. A 25% safety factor will be added to the total slurry injected volume to allow for rig washing, cement rinsate and other allowable non-hazardous waste fluids. Annular injection of drilled cuttings on each pad is being planned as a means to reduce the amount of solid-laden material injected into the Class I disposal well.

4.4.5 Well Control

Two types of development wells are planned for Point Thomson: production and gas injection. All wells will have surface-controlled subsurface safety valves (SCSSV) in the completion string, and all wells will have Christmas trees consisting of:

- Master valve (actuated),
- Surface safety valve (actuated),
- Wing valves (actuated), and
- Swab valve (actuated).

The Thomson Sand reservoir is abnormally pressured to about 10,250 psi, and the maximum anticipated surface pressure with a gas column to surface is about 8,300 psi. The top of the onset of abnormal pressure varies from about 11,600 ft TVDSS (true vertical depth subsurface) in the east to as shallow as 9,700 ft in the west. No shallow hazards have been encountered in any of the previous 19 exploration wells drilled in the Point Thomson area. All development wells will use a diverter for drilling surface-hole sections until it can be demonstrated that shallow hazards do not exist on each pad. A stack with four rams and one annular preventer will be used to drill below surface casing. The rams and annular preventer in the blowout preventer (BOP) stack will be rated to 10,000 psi working pressure.

All well control training, operational practices, procedures, rig equipment, and testing will be in accordance with AOGCC regulations and ExxonMobil standards.

In the unlikely event that a well control incident escalates to a blowout, surface intervention (i.e., dynamic kill, bullheading, well capping, etc.) will be the primary means of controlling the blowout. The well will be voluntarily ignited in the event of a major blowout to minimize environmental damage, and surface intervention will then be used to control the well. Well capping, which is part of surface intervention, has proven to be extremely effective in bringing wells under control and facilitating well kills, and is much more expedient than a relief well.

Killing the well after capping can be completed without a rig (i.e., bullheading kill weight mud) through the existing wellbore. (It should be noted that all wells in Kuwait were successfully capped following the Gulf War.) Information detailing best available technology (BAT) for controlling a blowout will be presented in the ODPCP to be submitted to the Alaska Department of Environmental Conservation (ADEC) and other agencies. Efforts to drill a relief well will be pursued in parallel with the surface intervention techniques.

4.5 WELL TESTING

Well testing is planned for some of the wells located on the East, West, and Central Well Pads before process facilities are operational. A typical well test would be conducted through a portable separator, flaring the gas until facilities are operational, at a maximum rate of approximately 60 million standard cubic feet per day, for a maximum duration of 4 days. It is envisioned that condensate will be reinjected during well testing.

4.6 DRILLING EQUIPMENT AND MATERIALS

At present, the use of one or two drilling rigs is planned for drilling and completion of the wells. Preliminary rig specifications are:

- *Design:* Arctic conditions;
- *Top Drive System (TDS):* 100 rotations per minute @ 62,000 foot-pounds of torque;
- *Drawworks:* 2,000 or 3,000 horsepower (hp);
- *Mast:* 1,200,000 pounds;
- *Mud System:* 2,500 bbl (1,500-bbl active and 1,000-bbl reserve);
- *Blowout Prevention Equipment (BOPE):* 10,000 psi, 4 rams plus the annular;
- *Shale Shakers:* 3 to 4 linear motion;
- *Mud System:* Three 1,600-hp mud pumps;
- *Drillpipe:* 5-1/2-in., 5-in., 4-1/2-in., etc. (S-135 as a minimum); and
- *Extra Diesel Storage:* 20,000 gallons per rig.

These requirements will be better defined once well optimizations are made. The specific rigs to be used will not be known until after December 2003.

Initially the rig power would be from diesel-powered generators. As soon as possible, the rig will convert to natural gas from the Thomson reservoir and would continue to use the natural gas as a means of providing power.

4.7 DRILLING SCHEDULE

The drilling rig and associated equipment will be mobilized by barge from the Prudhoe Bay area during July to August 2005. Drilling is scheduled to start in October 2005 and will continue through July 2008. Figure 4-1 provides the proposed drilling sequence for production, disposal, and gas injection wells.