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

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

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Alaska Division of Oil and Gas
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Point Thomson Reservoir Study
Purpose / Scope

- PetroTel Inc. conducted an independent evaluation of the Point Thomson reservoir to determine the resources contained in the reservoir and analyze possible recovery methods

- Two main objectives:

  – Construct three-dimensional (3D) geologic models to evaluate the proven and potential hydrocarbon resource

  – Dynamic reservoir simulation to test potential development and off-take scenarios

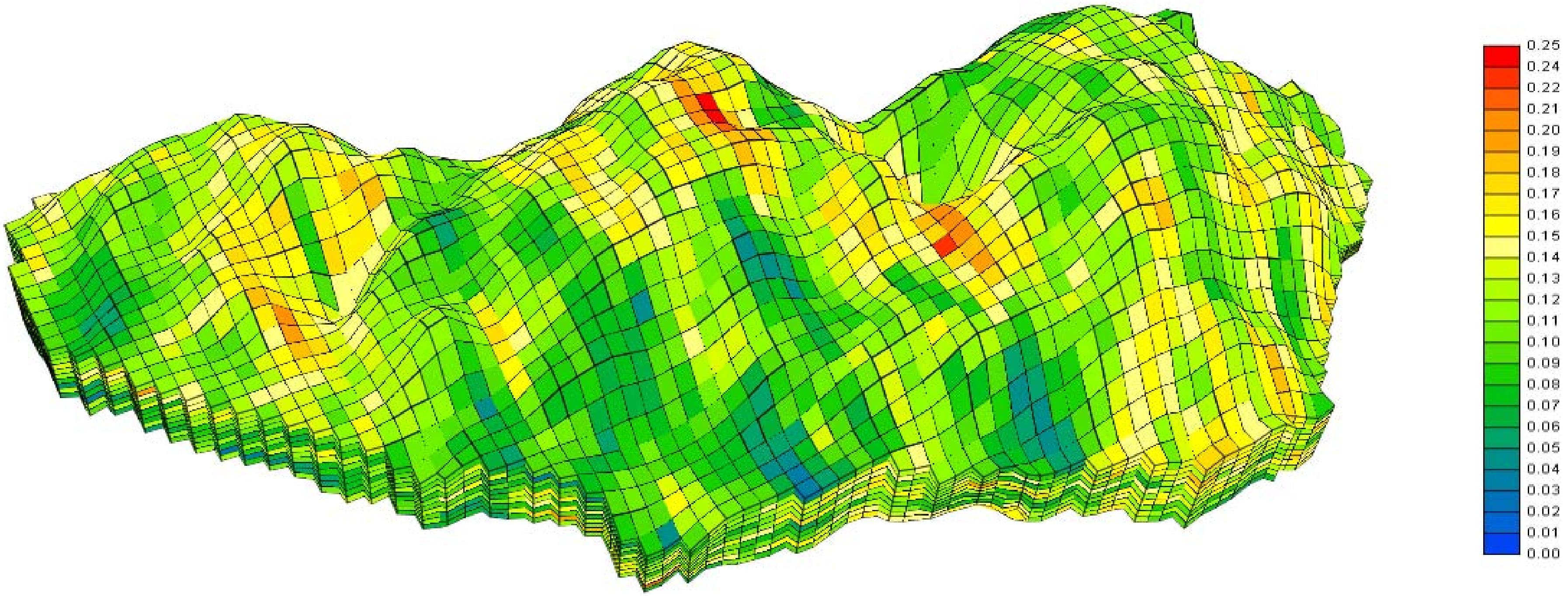
    – Determine the impact on ultimate recovery of both gas, associated condensate and oil

- Focused on the Thomson sand and does not include resources tested from the underlying Pre-Mississippian strata or overlying Brookian accumulations

Point Thomson Reservoir Study
Geology / In-Place Volumetrics

- Eleven 3D geologic models were constructed
- In addition to gas and condensate, Thomson sand also contains a thin and potentially discontinuous oil-rim that tested over 18º API gravity oil
- No definitive, production test exists in the oil-rim of the Thomson reservoir
- Range of volume in the oil-rim varied in the models due to uncertainty of the depth of fluid contacts
- Original in-place hydrocarbon volumes from geologic models:
  - Gas = 8.5 – 10.4 trillion standard cubic feet (TSCF)
  - Associated condensate = 490 – 600 million stock tank barrels (MMSTB)
  - Potential oil (oil-rim) = 580 – 950 MMSTB

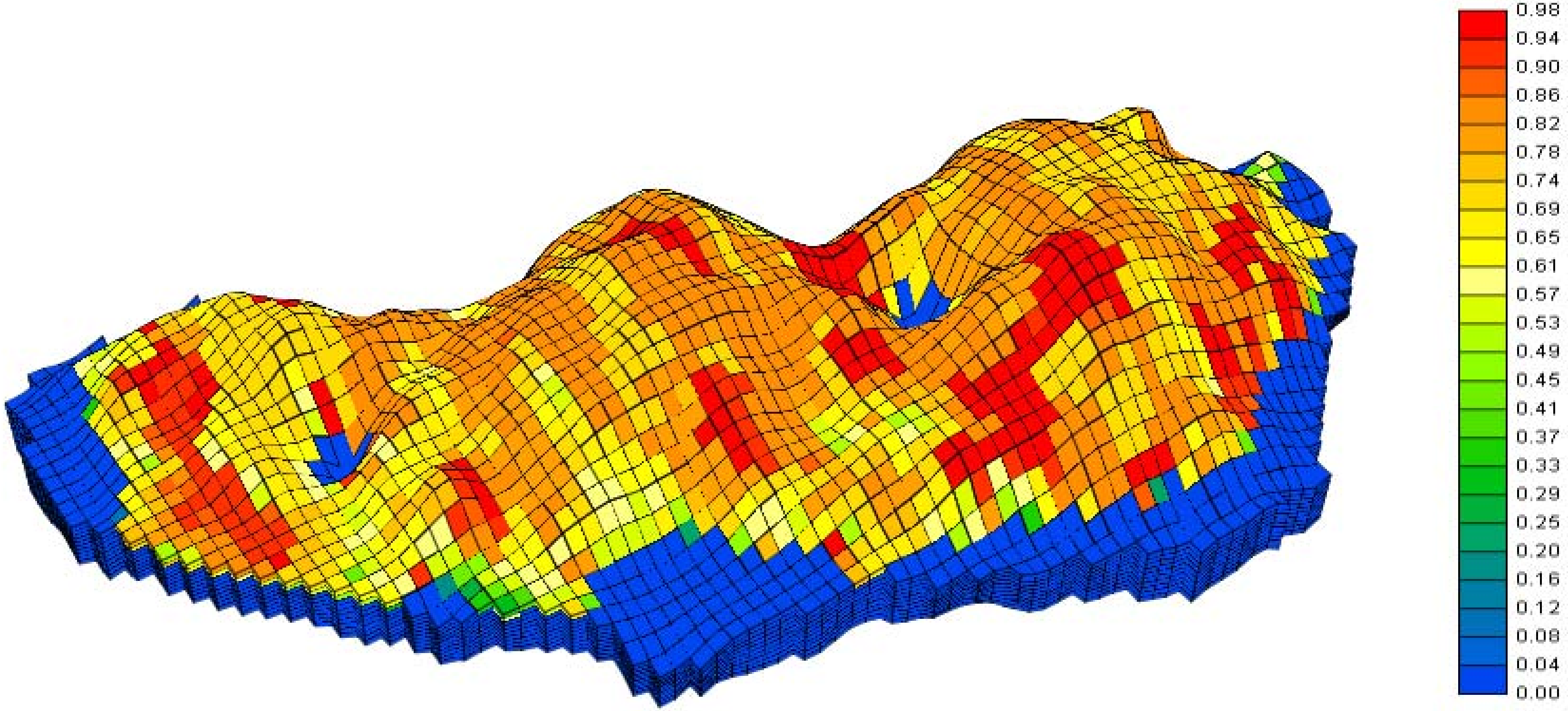
Simulation Model Porosity



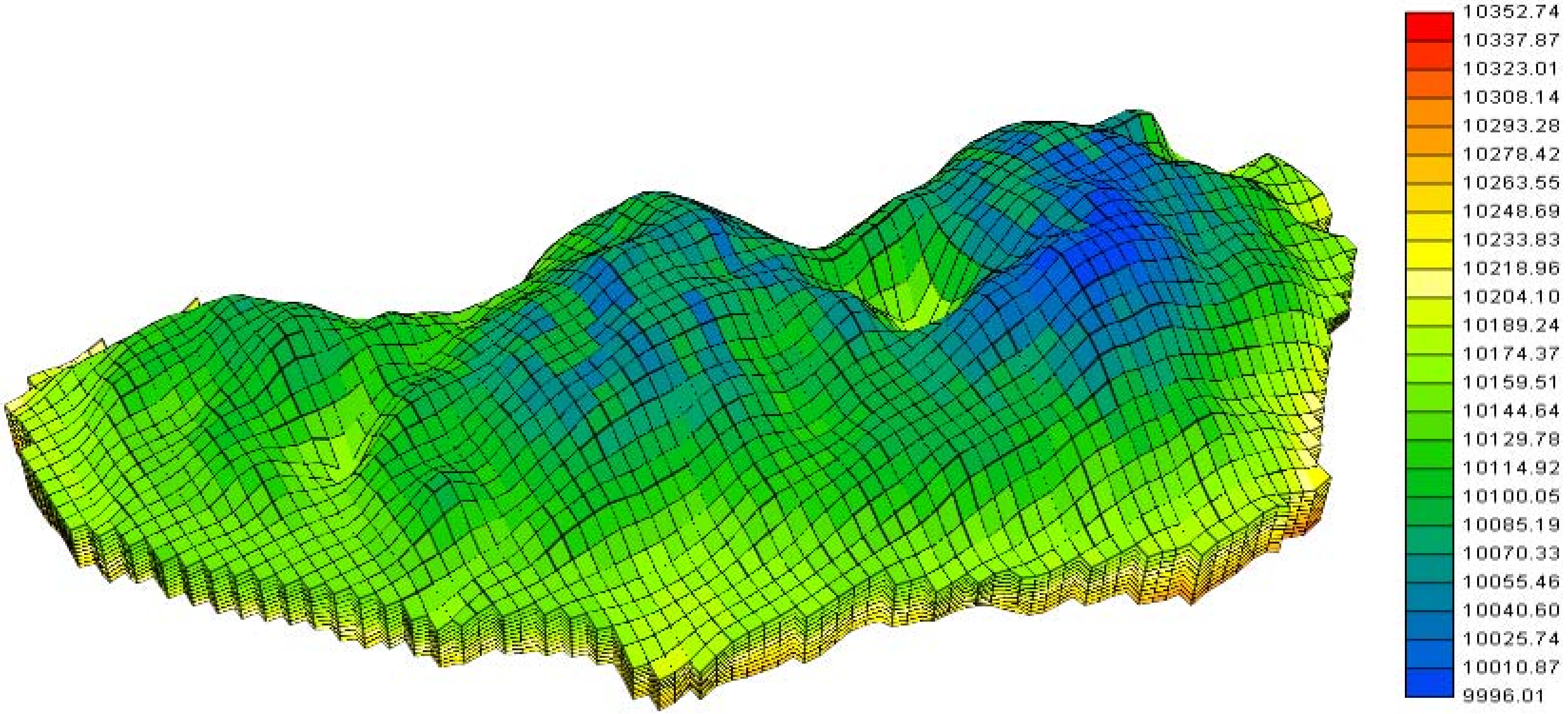
Alaska Department of NATURAL RESOURCES Division of Oil and Gas

PetroTel Leaders in Oil and Gas Technology

Simulation Model - Sg



Simulation Model - Pressure



Point Thomson Reservoir Study
Reservoir Modeling- Over 70 simulations

- Cases were run to model different recovery methods including primary depletion, gas cycling, and oil rim production
- Scenarios were designed to test and evaluate key sensitivities to recovery method
  - Well configurations
  - Operating constraints
  - Number of development wells
- Evaluated impact of variables on ultimate recovery with development method
- No physical constraints such as location of surface drill sites and facilities or drilling departures were modeled

Point Thomson Reservoir Study
Reservoir Simulation - Primary Depletion

- Primary depletion (gas blowdown) fastest - but recovers the least total hydrocarbons
  - Up to 70% of gas recovered (6-7 TSCF) with 22 wells in 12-15 years
  - Condensate recovery is approximately 26% of the in place volume (127-156 MMSTB)
  - The majority of the condensate is left in the reservoir by condensation below dew point
- Pressure maintenance required to increase condensate recovery
- Reduction of reservoir pressure during primary depletion significantly reduces potential recovery from the oil-rim
- Gas blowdown and sale of the gas can be done at any time <u>after</u> cycling and recovery of the condensate and oil

Point Thomson Reservoir Study
Reservoir Simulation - Gas Cycling

- Maintain reservoir pressure until all economically recoverable condensate and oil are produced

- Gas cycling applied in the gas cap in conjunction with development and gas injection in the oil-rim

- Gas cycling for 20 years increases the oil recoveries:
  - Condensate - 76% (370-450 MMSTB)
  - Oil Rim - 43% (250-400 MMSTB)

- Gas cycling for 10 years results in oil recoveries of:
  - Condensate - 62% (300-370 MMSTB)
  - Oil Rim - 39% (225-370 MMSTB)

- Subsequent blowdown of the gas cap after 10 and 20 years cycling recovers 57% and 56% (4.8-5.9 TSCF) of original gas in place

Point Thomson Reservoir Study
Reservoir Simulation - Oil Rim Development

- Oil-rim not adequately delineated or tested
  - Additional wells are needed

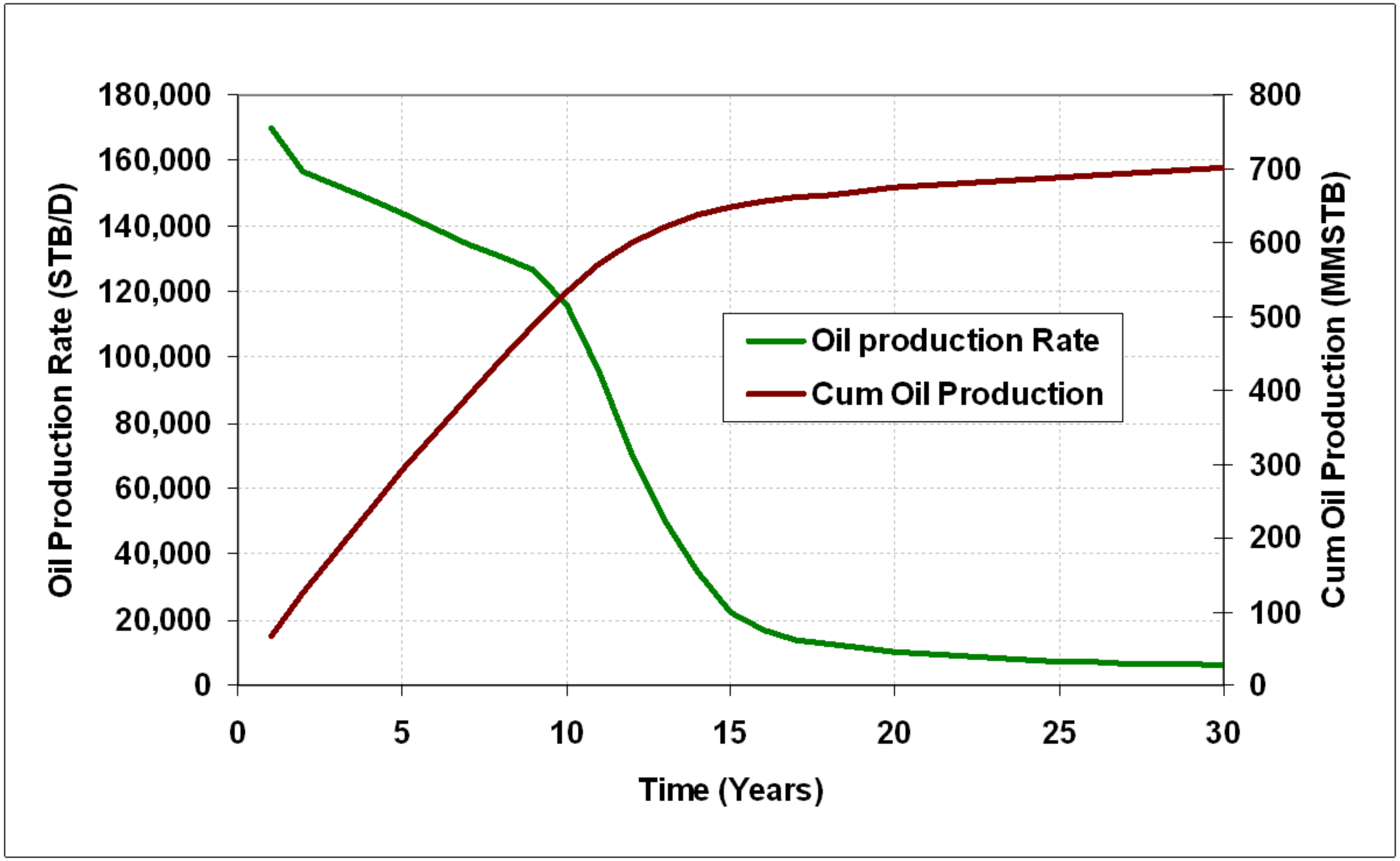
- Oil Rim Production:
  - Would likely require of horizontal wells
  - Requires pressure maintenance to sustain maximum oil producibility
    - Gas cycling, direct lean gas injection, miscible gas injection (CO_2), water injection or aquifer encroachment
  - Gas injection helps reduce the viscosity, improve swelling, and mobilize oil
  - Use of offsite gas, such as dry gas or waste CO_2 from Prudhoe, may maximize recovery

- In primary depletion potential oil-rim recoveries varied from 3-16% (30-150 MMSTB) of original oil in place depending on number of wells drilled
    - Gas cycling for 20 years could potentially recover close to 45% (250-400 MMSTB) of the in-place volume of the oil-rim

- Uncertainty in the original oil-rim volume and potential ultimate recovery
- Delineation of the oil-rim during gas cycling will determine the scale of development

Oil Production Rate and Cumulative Oil Production

BHP=3000 psi



Point Thomson Reservoir Study
Conclusions

- Primary depletion may recover 6-7 TSCF of gas and 210-305 MMSTB of condensate and oil
  - Results in the lowest hydrocarbon recovery of a retrograde condensate reservoir
  - Gas blowdown can be done after gas cycling and recovery of the condensate and oil
- Gas cycling for 15-20 years and subsequent blowdown may recover about 6 TSCF of gas and 620-850 MMSTB of condensate and oil
  - Gas cycling may delay gas sales, but can potentially increase recovery of condensate and oil by over 500 MMSTB
- Additional wells needed to delineate and test the Thomson oil-rim
  - Delineation of the oil-rim during gas cycling will determine scale of development
  - Pressure maintenance required to sustain maximum producibility and recovery of oil and condensate