

# CONSIDERATIONS FOR THE ADDITION OF NON-CONDENSABLE GASES TO STEAM IN THE SAGD PROCESS

PRESENTED AT THE SPE CALGARY SECTION HEAVY OIL AND HORIZONTAL WELL SPECIAL INTEREST GROUP LUNCHEON

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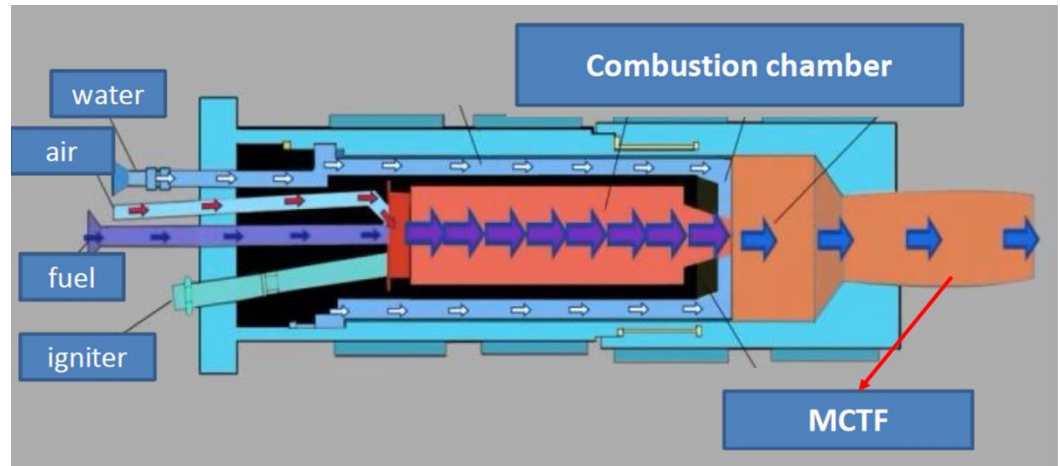
# MOTIVATION FOR NCG ADDITION TO STEAM IN SAGD



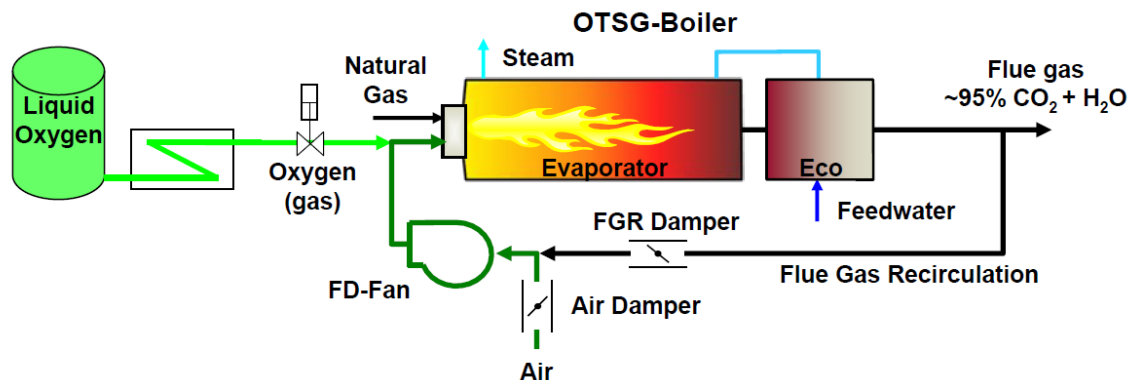
- Reduction in steam-oil ratio
  - Reduction in water and fuel requirements as well as GHG emissions
  - Reduction in cost and improved economics
- Increase in ultimate recovery
- Maintenance of reservoir pressure in late life
- Reduction of steam losses to high water saturation zones
- Sequestration of carbon dioxide (in the case of flue gas or CO<sub>2</sub> co-injection)

# SOURCES OF NCG FOR ADDITION TO STEAM

- CO<sub>2</sub> from carbon capture projects
- Boiler flue gas from steam generation
- Down hole steam generators
- Direct-fired boilers (CCS or injection)
- Steam/flue gas units on surface (e.g., MCTF)
- Natural gas from pipelines
- Compressed air or oxygen injection (In-situ combustion processes)



China Offshore Services Limited – Multicomponent Thermal Fluid Boiler



ICO2N CO<sub>2</sub> Capture Project

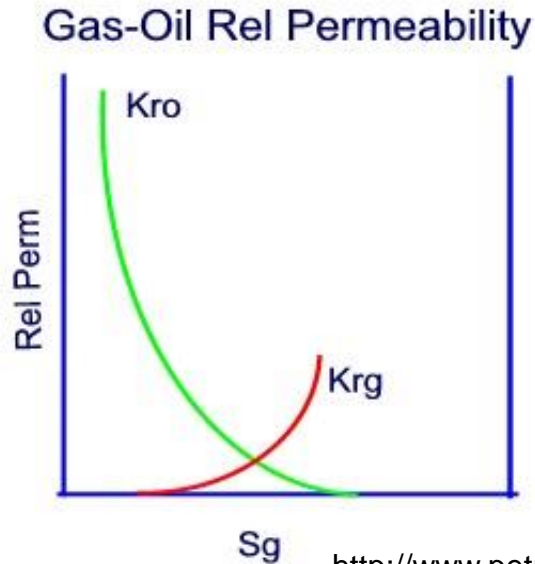
# CONSIDERATIONS REGARDING THE IMPACT ON RECOVERY PROCESS PERFORMANCE



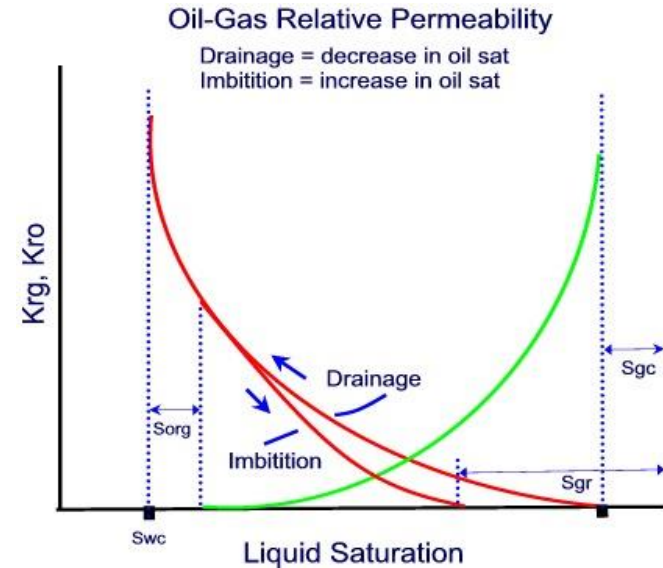
- Introduction of NCG's in the reservoir cause changes in:
  - Relative permeability of liquid phases
  - Fluid properties and phase behaviour
  - Heat transfer
- Process variables:
  - the type and concentration of NCG for co-injection
  - the timing of NCG introduction
  - the profile of NCG/steam ratio



# 3-PHASE RELATIVE PERMEABILITY EFFECTS



<http://www.petrocenter.com/reservoir/re02.htm>



- Relative permeability for each phase is a function of its saturation
- Fluids are not able to move until they reach their critical saturation
- As gas saturation increases, relative permeability to both water and oil decrease, reducing the ability of these phases to flow
- hysteresis in gas-oil rel. perm. behaviour: during imbibition in a water-wet system, trapped gas sat. ( $S_{gr}$ ) can be higher than critical gas sat. ( $S_{gc}$ )
- How well is 3-phase counter-current flow understood? How good is Stone's model?

# UNSTABLE DISPLACEMENT



Pentane (red color) displacing mineral oil by counter-current diffusion <http://www.ualberta.ca/~tayfun/eogrrc/Overview.html>



viscous fingering simulation for mobility ratio  $M = 33$  and  $Pe = 8000$   
[http://www.agu.org/meetings/fm10/fm10-sessions/fm10\\_H51C.html](http://www.agu.org/meetings/fm10/fm10-sessions/fm10_H51C.html)

- Viscous instability is well known in the displacement of oil by gas and water, depending on the mobility ratio.
- In-situ combustion drive processes have suffered from poor displacement efficiency, especially when heavy oils are involved, and air injection is used.
- In the case of NCG addition steam in SAGD, viscous fingering is needed to force NCG into warm oil near the top of the formation in order to displace it.
- Numerical simulation models are formulated using relative permeability concepts that do not account for viscous fingering

# FUNDAMENTAL PROPERTIES OF GASES AND LIQUIDS



	Water	Oil	Gas	
Density, kg/m <sup>3</sup>	Similar to oil 950 - 1000	Similar to water 900 - 1030	Steam	0.60 – 10.04
			CO <sub>2</sub>	1.81 – 21.95
			N <sub>2</sub>	1.15 – 13.63
			CH <sub>4</sub>	0.66 – 7.83
Viscosity, cp	~ 0.1 – 1.0	~ 10 <sup>1</sup> - 10 <sup>6</sup>	Steam	0.9 – 1.6 X 10 <sup>-2</sup>
			CO <sub>2</sub>	1.3 – 2.4 X 10 <sup>-2</sup>
			N <sub>2</sub>	1.6 – 2.6 X 10 <sup>-2</sup>
			CH <sub>4</sub>	1.1 – 1.6 X 10 <sup>-2</sup>
Specific Heat, kJ/kg.K	4.2 – 4.6	1.72 – 2.62	Steam	1.93 – 2.26
			CO <sub>2</sub>	0.80 – 1.05
			N <sub>2</sub>	1.04 – 1.07
			CH <sub>4</sub>	2.23 – 2.91
Latent Heat of Vaporization, kJ/kg	N/A	N/A	Steam	1886 – 2255

Most properties are in the range from atmospheric pressure and 25 °C to 2000 kPa and 220 °C

# FUNDAMENTAL PROPERTIES OF GASES AND LIQUIDS - SOLUBILITY

- Solubility of NCGs in oil and water depend on the T, P, oil properties, gas composition.
- Solubility decreases with temperature and increases with pressure.
- K-value data for a 26.8 °API oil at 200 °F. Gas mixture composition in mole %: N<sub>2</sub>(5%); CH<sub>4</sub>(40%); CO<sub>2</sub>(5%); H<sub>2</sub>S(5%); Crude Oil(45%)
- Phase behavior of gases in heavy oils:
  - Time-dependence of gases entering solution; related to oil density/viscosity
  - Foamy oil phenomena when pressure released

Pressure (psia)	Temperature (°F)	K <sub>N<sub>2</sub></sub>	K <sub>CH<sub>4</sub></sub>	K <sub>CO<sub>2</sub></sub>
500	100	30	8.1	3.5
500	200	32	10.0	5.0
1000	100	15	4.5	2.1
1000	200	18	5.2	3.0

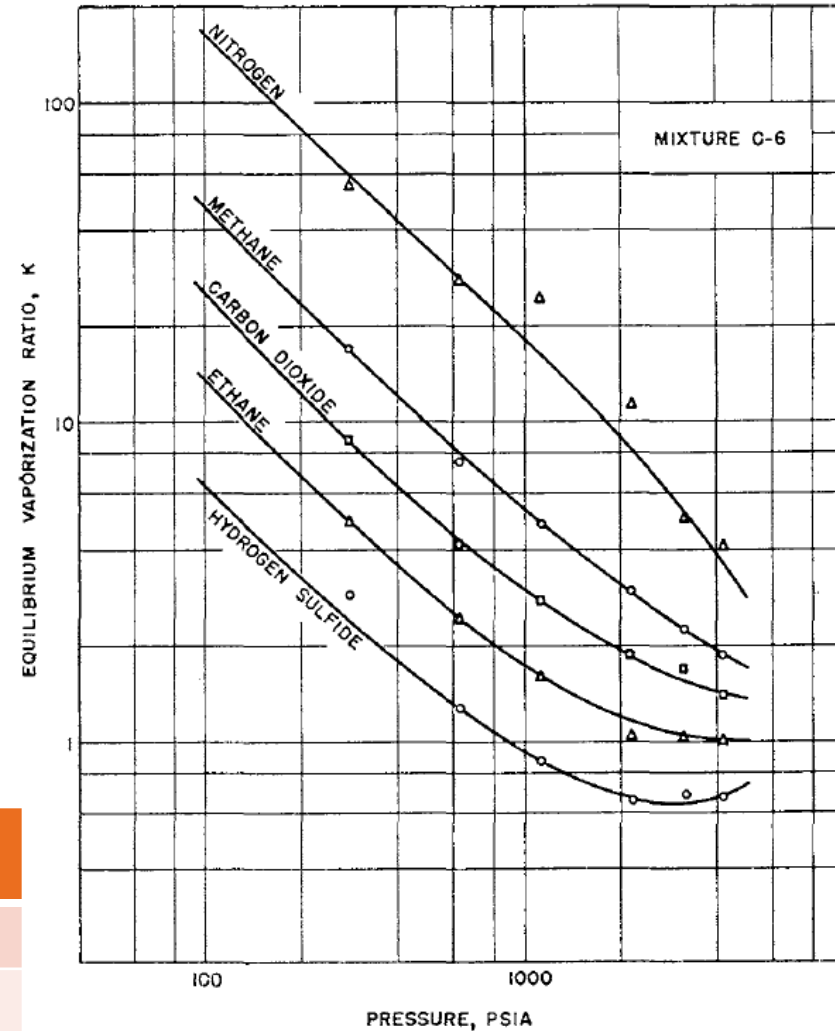


FIG. 9 — K VALUES IN CRUDE OIL MIXTURE C-6 AT 200°F.

Jacoby, R.H. and Rzasa, M.J.: *Trans. AIME*, V.195, 1952, pp. 99-110.



## Gas in solution causes swelling of oil

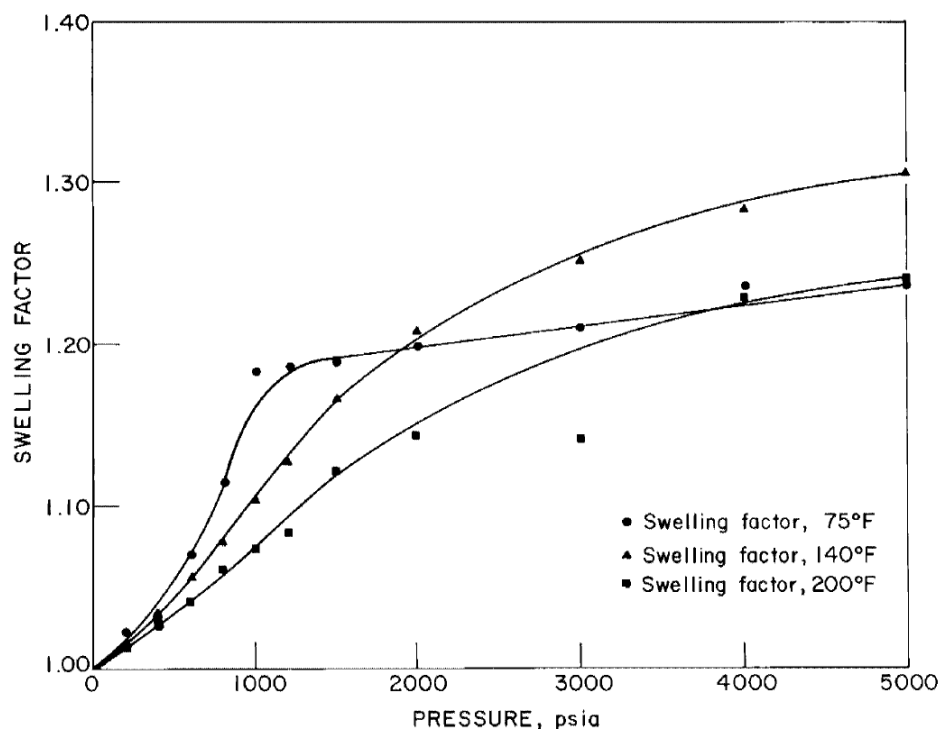


Fig. 5 - Swelling or Factors of Wilmington Oil (17° API Gravity) at 75° F, 140° F, and 200° F.

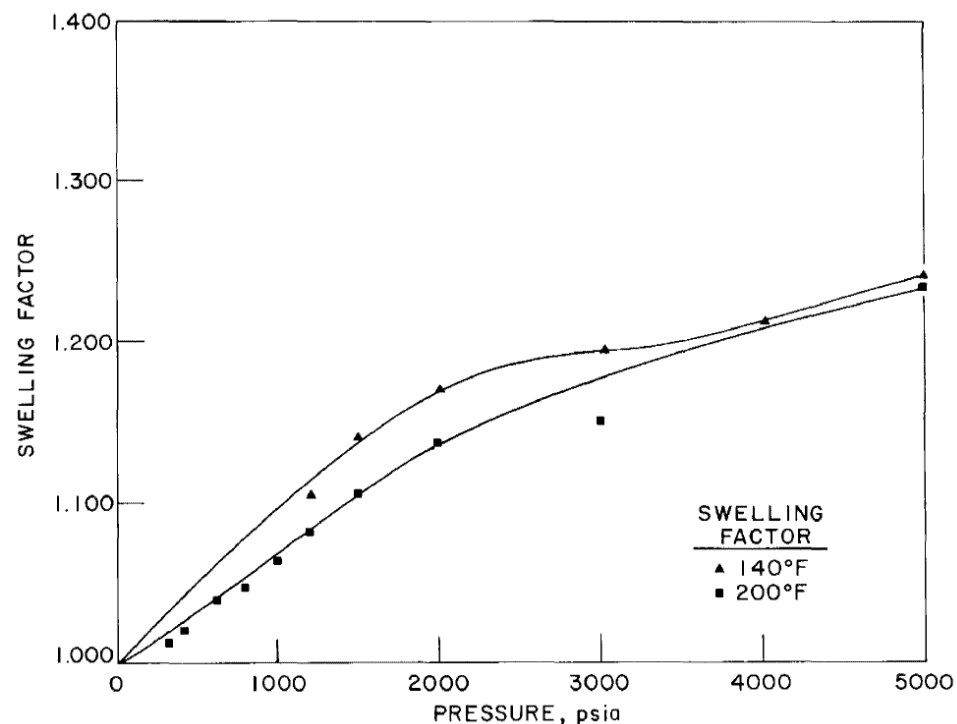


Fig. 9 - Swelling Fractors of Cat Canyon Oil (10° API Gravity) at 140° F, and 200° F.

# FUNDAMENTAL PROPERTIES OF GASES AND LIQUIDS – VISCOSITY REDUCTION

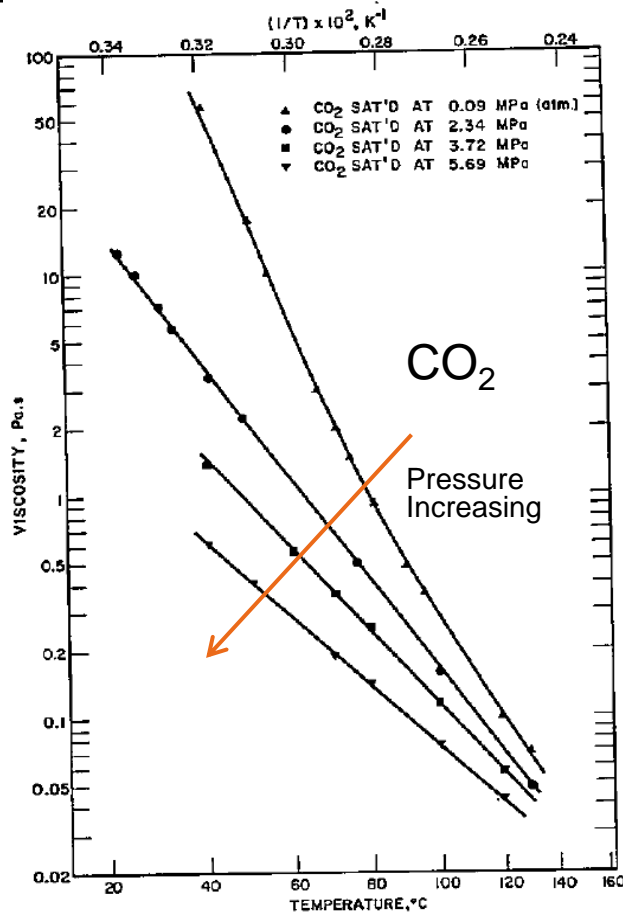


FIGURE 4. Viscosity of CO<sub>2</sub>-saturated bitumen.

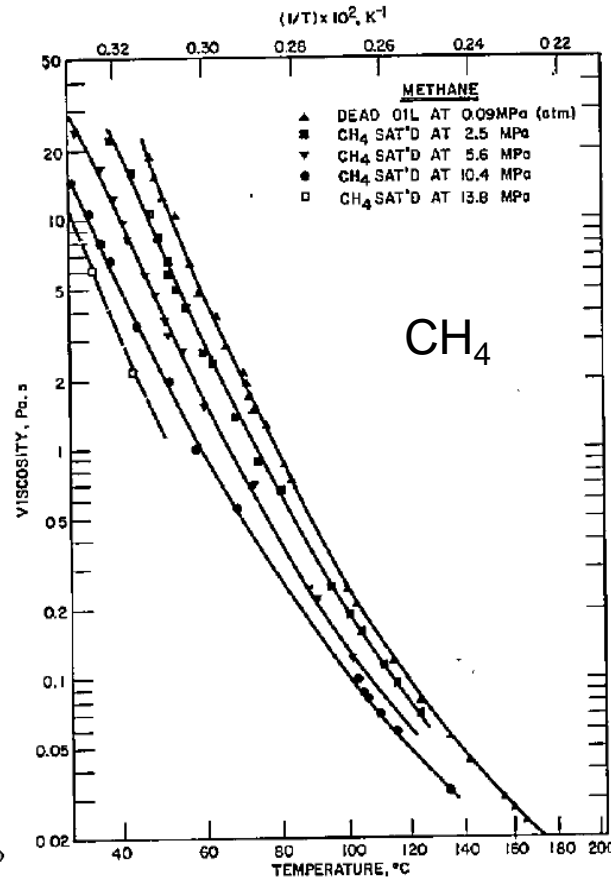


FIGURE 6. Viscosity of methane-saturated bitumen.

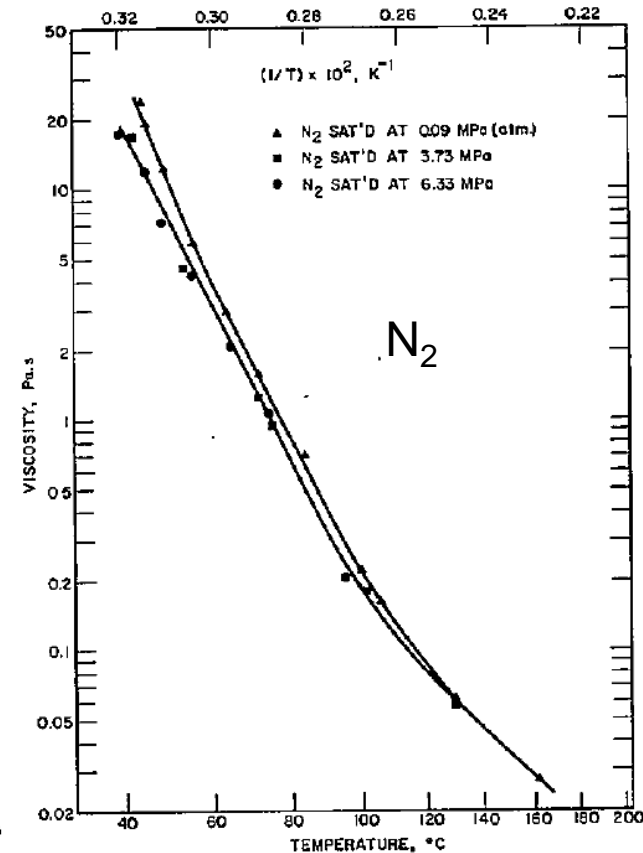


FIGURE 7. Viscosity of N<sub>2</sub>-saturated bitumen.

- Data for gas-saturated Athabasca bitumen
- Temperature reduces viscosity and the solubility of gas in oil
- Pressure increases amount of gas in solution and the viscosity reduction at fixed temperature

# EFFECT OF DISSOLVED GAS AND TEMPERATURE ON OIL VISCOSITY

Viscosity of CO<sub>2</sub> – crude oil mixtures with thermal stimulation  
by definition

$$K = \frac{\text{mole fraction of CO}_2 \text{ in oil}}{\text{mole fraction of CO}_2 \text{ in gas phase}}$$

The empirical relationship between K, pressure (P), and temperature (T)

$$K = A \rho \exp (B/T)$$

where A and B are constants. The viscosity of the CO<sub>2</sub>-oil mixture is

$$\mu_m = (\mu_{oil})^{X_{oil}} (\mu_{CO_2})^{X_{CO_2}}$$

where

$X_{oil}$  = mole fraction of oil in mixture,

$X_{CO_2}$  = mole fraction of CO<sub>2</sub> in mixture.

For the curves in Figure 41-6 the constants A and B have values  $1.64 \times 10^{-6}$  and 3486.63 respectively.

Source: Bader et al: "The Potential of Downhole Steam Generation to the Recovery of Heavy Oils", First UNITAR International Conference on the Future of Heavy Crude Oils and Tar Sands, Edmonton, June 4-12, 1979, pp. 369 – 377.

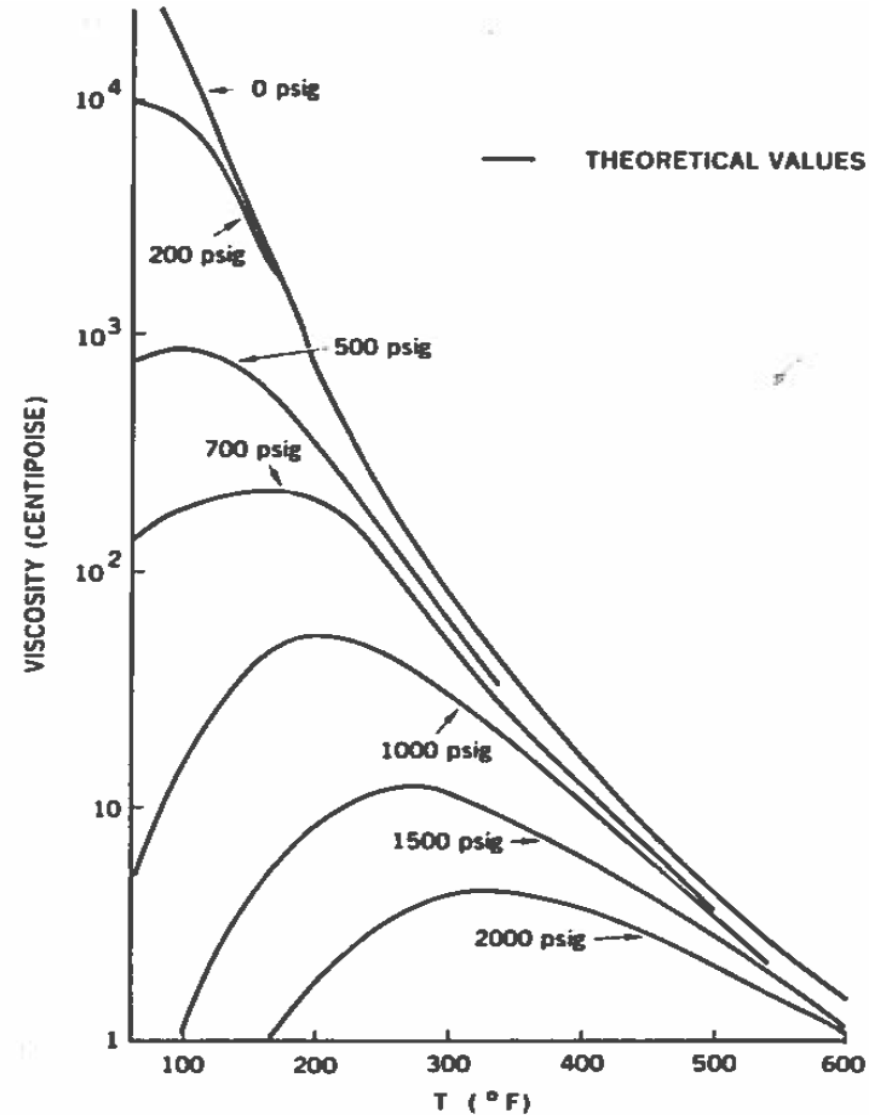


Figure 41.6

Crude oil viscosity as a function of temperature and pressure

# PHYSICAL MODELING OF NCG/STEAM CO-INJECTION – ALBERTA RESEARCH COUNCIL (AITF)



- Redford (1982) reported on 20 of 42 large-scale, 3D, physical model tests of steam stimulation using various additives. A pressure cycling process was employed using mixtures of solvents and CO<sub>2</sub>
  - Used methane, ethane, propane, butane, pentane, gas condensate, naphtha, synthetic GCOS crude. Gases were injected at ratios to steam of about 2.8 mole%. Pure hydrocarbon liquids at between 6 and 8 volume%.
  - Marked improvements in recovery obtained with no reductions in permeability observed.
- Canbolat et al (2002) used CO<sub>2</sub>/steam co-injection – found that SOR was reduced but also oil production rate.
- Zhao et al (2005) – 2D lab experiments, N<sub>2</sub> injection late in life after steam. Steam chamber continued to expand and additional 12.5% of OOIP recovered.
- Yuan et al (2011) found that NCG accumulates at the front of the steam chamber. Also noted difficulty using temperature to define size of steam chamber because of vapour composition variation and partial pressure effects.

Redford, D.A., The Use of Solvents and Gases with Steam in the Recovery of Bitumen from Oil Sands, *J. Can. Pet. Tech.* **21**(1): 45-53.

Canbolat, S., Akin, S., and Kovscek, A.R. (2002), A Study of Steam-Assisted Gravity Drainage Performance in the Presence of Noncondensable Gases, SPE 75130, presented at the SPE/DOE Improved Recovery Symposium, Tulsa, Oklahoma, 13-17 April 2002, 10 pp.

Zhao, L., Law, D.H-S., Nasr, T.N., Coates, R., Golbeck, H., Beaulieu, G., and Heck, G. (2005), SAGD Wind-down: Lab Test and Simulation, *J. Can. Pet. Tech.* **44**(4): 49-53.

Yuan, J.-Y., Chen, J., Pierce, G., Wiwchar, B., Golbeck, H., Wang, X., Beaulieu, G., and Cameron, S. (2011), Noncondensable Gas Distribution in SAGD Steam Chambers, *J. Can. Pet. Tech.* March 2011, pp. 11-20.



- NCGs added to steam in low concentrations to enhance SAGD. Gas of less than 1 volume% of the steam injected was deemed to be required.
- Concept: that NCG will rise to centre and top of steam chamber; rise of NCG will reduce or eliminate gas coning tendency
  - high temp. maintained in lower part of the steam chamber
  - lower temperature in the main and upper part of the steam chamber due to partial pressure effects of the NCG, resulting in:
    - Reduced heat loss to overburden
    - Lower energy requirement for SAGD
    - Reduced steam-oil ratio (SOR)
- Found that oil rates slightly reduced but SORs substantially lower.
- Hoped that SAGP would make SAGD more economical and extend SAGD to lower quality (marginally economic) reservoirs.

Butler, R.M. (1999), The Steam and Gas Push (SAGP), *J. Can. Pet. Tech.*, **38**(3): 54-61.

Jiang, Q., Butler, R.M., and Yee, C-T. (2000), Steam and Gas Push (SAGP) – 2: Mechanism Analysis and Physical Model Testing, *J. Can. Pet. Tech.* **39**(4): 52-61.

# STEAM AND GAS PUSH (SAGP) (CONTINUED)

- Jiang et al (2000) suggested that SAGP could:
  - use injection wells near the top of the formation
  - improve application of SAGD to reservoirs with top water.
- Butler et al (2000): surmised that in SAGP much of the oil displacement is caused by ‘fingers of gas/steam rising counter-currently to the draining oil’, pushing oil down.
- Butler et al (2001): showed that gas fingers can rise more readily than steam in layered sands, and are able to penetrate low-permeability layers better, and improve drainage from these layers.
- Butler (2004) : argued that “gas can move relatively easily, in small fingers, through the reservoir beyond the steam chamber.”

Jiang, Q., Butler, R.M., and Yee, C-T. (2000), Steam and Gas Push (SAGP) – 2: Mechanism Analysis and Physical Model Testing, *J. Can. Pet. Tech.* **39**(4): 52-61.  
 Butler, R.M., Jiang, Q., and Yee, C-T. (2000), Steam and Gas Push (SAGP) – 3: Recent Theoretical Developments and Laboratory Results, *J. Can. Pet. Tech.* **39**(8): 51-60.  
 Butler, R.M., Jiang, Q., and Yee, C-T. (2001), Steam and Gas Push (SAGP) – 4: Recent Theoretical Developments and Laboratory Results Using Layered Models, *J. Can. Pet. Tech.* **40**(1): 54-61.  
 Butler, R.M. (2004), The Behaviour of Non-Condensable Gas in SAGD – A Rationalization, *J. Can. Pet. Tech.* **43**(1): 28-34.

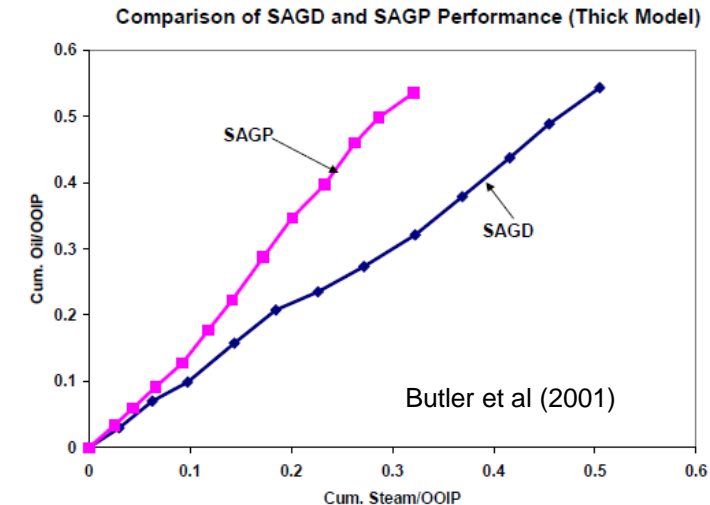


Figure 8

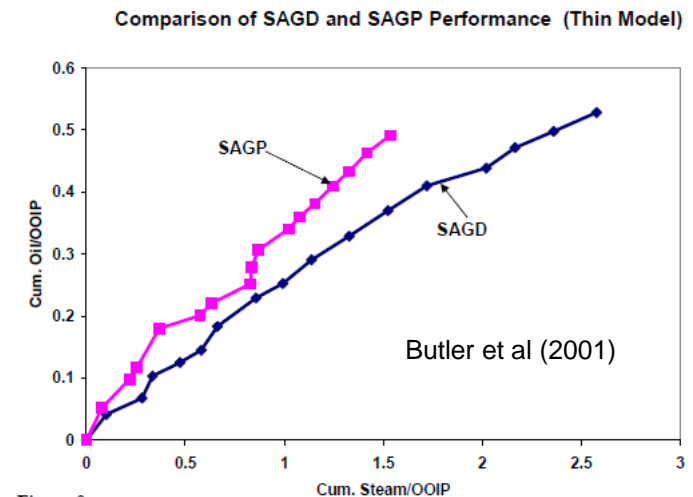


Figure 9

# FIELD RESULTS – DOVER PHASE B



- Birrell (2001) noticed ‘anomalous’ heat transfer ahead of the steam chamber resulting in temperatures of 40 to 70 °C ahead of the steam zone attributed to convective heat transfer. From thermocouple and pressure data, it appeared that the pressure front associated with the steam chamber travels 5 to 12 metres ahead of where it would be expected to be – also attributed to the effect of NCG.
- Yee and Stroich (2002) - Extra production attributed to drainage from IHS beds in the upper part of the reservoir, aided by the NCG, and prolonging well pair life.
- Analysis by Aherne & Maini (2008)
  - Suggest that NCG flowed into the reservoir ahead of the steam chamber since cooling of the steam chamber did not occur.
  - Found evidence of fluid movement ahead of the steam front through examination of observation well pressure and temperature data
  - Bitumen production exceeded simulation predictions.

Aherne, A., and Maini, B. (2008), Fluid Movement in the SAGD Process: A Review of the Dover SAGD Project, *J. Can. Pet. Tech.* **47**(1): 31-37.

Birrell, G.E. (2001), Heat Transfer Ahead of a SAGD Steam Chamber: A Study of Thermocouple Data from Phase B of the Underground test facility (Dover Project), SPE 71503 presented at the Annual Technical Conference and Exhibition, New Orleans, 30 Sept. – 3 Oct. 2001.

Yee, C.-T., and Stroich, A. (2004), Flue Gas Injection into a Mature SAGD Steam Chamber at the Dover Project (formerly UTF), *J. Can. Pet. Tech.* **43**(1): 54-61.

# FIELD RESULTS – JACOS HANGINGSTONE



- Ito and Chen (2010) and Chen and Ito (2012) reviewed many SAGD projects and found that steam chambers are often unable to rise to the top of the formation. Production performance observed was attributed to NCG assisting with drainage of bitumen from above the steam chamber. Field pilots have generally used a ratio of NCG/Steam of 0.5 to 2 mol%
- JACOS Hangingstone
  - 12-month test in 2007 with CH<sub>4</sub> co-injection at 1 - 3 mol%
  - Results encouraging and JACOS plans to use as method to manage SOR in late life as part of wind-down strategy
  - Reported that within one-month of cessation of gas injection, gas accumulated at top of formation ‘vanished’

Chen, J., and Ito, Y. (2012), Effect of Oil-Viscosity-Gradient Presence on SAGD, *J. Can. Pet. Tech.*, March 2012, 95-105.

Ito, Y., and Chen, J. (2010), Numerical History Match of the Burnt Lake SAGD Process, *J. Can. Pet. Tech.*, 49(5):40-49.

Japan Canada Oil Sands Limited (JACOS) (2009), Hangingstone SAGD Demonstration Project, Application for Amendment of Approval 8788G for Non-condensable Gas Injection, submitted to the Alberta Energy Resources Conservation board, Calgary, December 2009.

Japan Canada Oil Sands Limited (JACOS) (2010), Application for Approval of the JACOS Hangingstone Expansion Project, 29 April 2010, 463 pp.

Japan Canada Oil Sands Limited (JACOS) (2012), Hangingstone Demonstration Project 2011, Thermal In-Situ Scheme Progress Report, Approval No. 8788I, February 9, 2012, 100 pp.

Wang, J., and Harschnitz, B., The Impact on Non-Condensable Gas (NCG) Co-injection on a SAGD Project – A Case Study of the JACOS Hangingstone Field Pilot Test, World Heavy Oil Congress 2011, Edmonton, Alberta, 14-17 March 2011, pp. 953-959.



# FIELD RESULTS – CENOVUS CHRISTINA LAKE AND FOSTER CREEK



- Cenovus Christina Lake
  - Testing started in 2004-2005 with methane at ~ 1.5 mol%.
  - Improved SOR with no negative impact on production or recovery.
  - Can resume steam-only injection from NCG co-injection with no negative impacts
  - Simulation study conducted to examine the effect of NCG on drainage from IHS beds
- Cenovus Foster Creek
  - CH<sub>4</sub> co-injection tests in 4 pads first starting in Q3 2010
  - Using a ‘rampdown’ strategy where steam volumes are gradually reduced while NCG rates are maintained. Allows recovery of additional oil at low SOR leaving reservoir in ‘pressure-maintained’ condition
  - Planning to implement field-wide as part of wind-down strategy

Cenovus Energy (2012a), Christina Lake In-situ Oil Scheme (Approval No. 8591) 2011-2012 Update to the ERCB, June 20, 2012, 302 pp. <http://www.ercb.ca/data-and-publications/activity-and-data/insitu-progress> , FINAL Cenovus Christina 8591 RMR 2012 – Subsurface.pdf

Cenovus Energy (2012b), Foster Creek In-situ Oil Scheme (Approval No. 8623) 2011-2012 Update to the ERCB, May 24, 2012, 386 pp. <http://www.ercb.ca/data-and-publications/activity-and-data/insitu-progress> , FINAL Cenovus Foster Creek Subsurface.pdf; Cenovus Foster Creek Rampdown #3 Presentation.pdf; Cenovus Foster Creek Rampdown #4.

# FIELD RESULTS - MEG ENERGY CHRISTINA LAKE



- Future plans include NCG co-injection with steam
- Pilot commenced in Q4 2011 in 3 well pairs at 1.5 mol% NCG
- Steam chamber pressure reduced to near original reservoir pressure to reduce tendency for gas to leak off.
- NCG is injected to improve SOR and not as a wind-down method
- Report that NCG co-injection does not have noticeable impact on bitumen production rates despite significant reductions in steam injection rates (i.e., decreases in SOR)
- MEG plans to continue using NCG co-injection along with ‘infill’ wells that are steam stimulated

MEG Energy (2012), Christina Lake SAGD Regional Project Commercial Scheme Approval No. 10773, 2011-2012 Performance Presentation, June 2012, 188 pp.

# FIELD RESULTS - SUNCOR FIREBAG/MACKAY RIVER



- Results from methane co-injection pilot (2006-2007) in Pad 101, pair 8, at Firebag indicate that only about 25% of injected gas produced back; concluded there was substantial volume that leaked away from chamber
- NCG co-injected at 0.7 to 1.3 volume %
- Increased methane production rates were observed as far away as 320 metres from the NCG test well.
- Bitumen rates, SOR and pump performance were unaffected
- Planning a staged pilot approach to developing wind-down strategies utilizing NCG
- Suncor has applied to use NCG with steam at MacKay River for wind down and pressure maintenance.

Suncor Energy Inc. (2008), 2008 ERCB Annual Review – Suncor Firebag, April 30<sup>th</sup> 2008, 162 slides.

Suncor Energy Inc. (2012), Suncor Firebag 2012 ERCB Performance Presentation, Commercial Scheme Approval No. 8870, May 15-16, 2012, 342 pp. <http://www.ercb.ca/data-and-publications/activity-and-data/insitu-progress> , FINAL Suncor Firebag Project 8870 – 2012 Directive 054 – Annual Performance Presentation.pdf

Suncor Energy Inc. (2005), Amendment Application for MacKay River Expansion, Vol. 1A Project Description, Section 4 Recovery process, November 2005.

Suncor Energy Inc. (2010), Application for Non-condensable Gas Injection, Section 26 Test Project, MacKay River Project, submitted to the Alberta Energy Resources Conservation Board, Calgary, Alberta, 19 July 2010.

Suncor Energy Inc. (2011), 2011 ERCB Performance Presentation – Subsurface, Commercial Approval No. 8668, October 25, 2011, as well as Amendments 8668C, 8668H, 8668I, and 8668L to allow NCG injection at MacKay River pads and to raise limits on mole % NCG injected

- Nexen co-injected methane with steam in 3 well pairs in the Pilot Pad (Pad 1) at Long Lake between 2005 and 2006. The purpose was to reduce water mobility in lean zones to reduce losses and allow higher operating pressures. Natural gas was injected in slugs of 3 mmscf. The effects of the NCG injection were positive but short-lived.
- Nexen received permission in 2012 to co-inject NCG with steam into the injectors of 6 well pairs in Pads 7 and 8. It is planned to continuously inject NCG in these field trials rather than in slugs. The purpose is again to reduce steam losses to lean zones while also reducing heat losses to the overburden and helping to drain heated oil from the upper parts of the formation.
- These new Long Lake NCG co-injection trials commenced in October 2014. NCG injection rates will not exceed 10,000 sm<sup>3</sup>/d/well.



# CARBON DIOXIDE SEQUESTRATION?



- $\text{CO}_2$  is highly soluble in both oil and water, decreasing at higher temperatures
- $\text{CO}_2$  could be used as an NCG and would be as effective as  $\text{CH}_4$  except that the additional solubility of  $\text{CO}_2$  in water would need to be accounted for
- Assuming that all pore space originally occupied by bitumen is replaced with  $\text{CO}_2$ , that the reservoir is abandoned at original reservoir pressure and that no gas leaks off, calculations indicate that only about 4 to 5 percent of the  $\text{CO}_2$  produced during steaming operations could be sequestered in the formation (assumes an oxy-fired boiler).
- By increasing reservoir pressure or injecting additional NCG to maintain pressure as the reservoir cools, 5 to 8 percent of the produced  $\text{CO}_2$  can be stored

# OBSERVATIONS

- Late life NCG injection in SAGD can extend well-pair life and recover additional oil while maintaining reservoir pressure and managing SOR.
- Small amounts of NCG, around 0.5 - 2 mol%, have beneficial effects but larger amounts may be detrimental because of multi-phase flow effects. From a direct-fired oxygen combustion boiler, NCG/steam ratio would be at least 5.3 mol%. However, the greater solubility of CO<sub>2</sub> in water will reduce the amount of free gas
- NCGs appear to accumulate mainly near the top of the steam chamber. Once there, they reduce gas/steam mixture temperature by partial pressure effects reducing heat loss to the overburden.
- There is growing evidence of the possibility of NCG being able to move into the native state, cold reservoir ahead of the steam chamber. Edmunds (2007) has called this a 'missing gas removal mechanism'. JACOS reported the disappearance of NCG after only one month following cessation of gas injection. This has implications for wind-down/pressure maintenance. More information is needed to assess the amounts of NCG that leak away from the steam chambers.

## OBSERVATIONS (CONTINUED)

- NCG co-injection may assist bitumen drainage from IHS beds and promote upward and lateral growth of the steam chamber.
- NCGs appear to improve drainage of warm bitumen from above the steam chamber.
- NCGs may inhibit leakage of steam condensate into lean zones by reducing the effective permeability to water.
- NCGs may improve convective mixing and heat transfer near the edge of the steam chamber promoting more rapid growth of the steam chamber.
- NCGs have some solubility in bitumen and will provide some viscosity reduction. Solution gas drive or foamy oil effects may be noticed as pressure is decreased on the bitumen as it travels towards the production well. These effects are likely less important than the fluid flow aspects.
- Most of the NCG created with steam must be produced. The ability to sequester CO<sub>2</sub> produced in steam generation is limited.
- While useful tools, the limitations of numerical simulators should be kept in mind when modeling NCG/steam processes, particularly with regards to multi-phase flow relative permeabilities, unstable displacement, and complex, time-dependent phase equilibria.

# RECOMMENDATIONS



- Conduct gas injection/fall-off tests in various reservoir facies to determine native-state effective permeability to gas.
- Prior to use of direct-fired boilers (using oxygen) for steam generation, it would be advisable to test the effects, on SAGD SOR and bitumen production rate, of NCG co-injection at levels of 5 and 10 mole percent, which are considerably above the normally contemplated level of 1 to 2 mole percent NCG.



# QUESTIONS?



## Thank You for Your Attention