EUB Inquiry

Gas/Bitumen Production in Oil Sands Areas

March 1998

Alberta Energy and Utilities Board

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Published by
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EXECUTIVE SUMMARY

In late 1996, the Alberta Energy and Utilities Board (EUB) received submissions from several companies holding oil sands leases outlining their concerns regarding the potential adverse effects on the eventual recovery of bitumen if associated gas was produced in advance of the bitumen. Some oil sands leaseholders requested that all current and future associated gas production from affected oil sands deposits be curtailed. Given the broad implications of such a decision, the Board held a general inquiry on the issue to solicit the views of all segments of the industry.

Gulf Canada Resources Limited (Gulf) submitted a study showing the potential effects of associated gas production on the Steam Assisted Gravity Drainage (SAGD) bitumen project proposed for its Surmont leases. Other oil sands leaseholders raised similar concerns for other oil sands areas. The concerns focused on the effect of gas cap pressure depletion on bitumen recovery. It was contended that such pressure depletion could compromise the recovery efficiency of the SAGD process to such an extent that some bitumen projects might not be viable.

The Alberta Producers Group (APG), representing a group of gas producers, countered that there are ample opportunities for thermal bitumen projects in areas where associated gas production would not be an issue and therefore the activities of gas producers need not be constrained. Furthermore, the APG contended that if bitumen producers believe their projects may be at risk, they could purchase the petroleum and natural gas (P&NG) rights. The APG also contended that there could be adverse effects on gas recovery from SAGD operations. Specifically, the APG was concerned with contamination, pressure depletion, water influx, and geomechanical effects.

Although the effect of associated gas production on primary bitumen recovery had been raised as an issue prior to the inquiry, there was very little discussion of this issue at the inquiry.

The Board notes that there are currently little or no field data available on the effect of associated gas production on SAGD performance. The evidence submitted at the inquiry to evaluate this effect was based on reservoir modelling by extrapolating the experience at the Underground Test Facility. All four of the Athabasca-McMurray models presented at the inquiry predicted that associated gas production would have a detrimental effect on SAGD performance. Notwithstanding the models' limitations to accurately predict the extent of the effects — which would depend on the specific reservoir situation, economic circumstances, and operating strategy — the Board concluded that in some instances the effect on bitumen recovery could be significant.

In order to chart a prudent course for the future development of the gas and bitumen resources in the oil sands areas, the Board concluded that:

C although limited field data are available, sufficient evidence exists to suggest that associated gas production could have a detrimental effect on some bitumen resources, to the extent that significant volumes might never be recoverable;

C while it is possible that thermal bitumen processes could have a detrimental effect on associated gas recovery, such effects would likely be relatively minor;

C Alberta's current and prospective gas reserves and deliverability position would not be materially affected by discouraging some associated gas production in the oil sands areas in favour of conserving the bitumen resources; and

C an evaluation of the appropriate timing of producing gas associated with bitumen should be consistent with the Board's approach to evaluating the production of gas associated with conventional oil.

For these reasons, the Board has decided that some regulatory involvement is warranted, at least until such time as additional information becomes available to clarify the effect of associated gas production on bitumen recovery or alternative technology and/or economic circumstances reduce the risk of bitumen sterilization.

In determining a policy for gas and bitumen production, the Board must consider two distinct cases: currently producing gas wells and facilities developed in advance of this report and investments to be made in the future. In the first instance, the Board will generally allow associated gas production to continue from investments made up to 1 July 1998, unless the Board receives a complaint from an oil sands leaseholder and the subsequent investigation shows continued production from existing gas wells would not be in the long-term public interest. In the second instance, for any development of associated gas in the oil sands areas after 1 July 1998, the Board will require proponents to apply for a "concurrent production" approval. Such applications will be expected to include sufficient evidence to evaluate the scope of impact and provide a discussion of the efforts made by the affected parties to resolve the outstanding issues.

To summarize, the Board will:

C allow associated gas production in the oil sands areas from wells drilled and completed by 1 July 1998, subject to the resolution of any concerns raised by oil sands leaseholders or the Board on its own initiative;

- require concurrent production approval for the production of all associated gas in the oil sands areas from wells drilled after 1 July 1998;

- require, effective 1 July 1998, all new wells in the oil sands areas to be drilled to the base of the oil sands zone;

- develop a notification process, in consultation with the affected parties, to advise leaseholders of prospective developments;

- support modifications to the existing lease tenure system in the oil sands areas to reduce resource development conflicts; and

- investigate the means of conducting further research on the effects of concurrent gas and bitumen production.

1. INTRODUCTION

1.1 Background

In late 1996, the Alberta Energy and Utilities Board (EUB) received submissions from some segments of industry suggesting adverse effects related to associated gas production prior to bitumen production. Recognizing the broad implications of the issues and the possible impacts on existing and future gas and bitumen operations, the Board convened a general meeting on 21 January 1997 to consider the submissions and views on this matter. The meeting was well attended by a broad cross-section of parties.

On the basis of the information provided at the meeting and the submissions received, the Board issued a Memorandum of Decision (Appendix A) on 19 February 1997 advising that it intended to hold a general inquiry into the issues raised. This Memorandum of Decision also set out the terms of reference for the inquiry and had attached to it a letter from the Alberta Department of Energy (DOE) to the Board, indicating that the DOE would be proceeding with a parallel review of lease tenure policies that relate to gas/bitumen production.

The initial concerns raised by some oil sands leaseholders were related to possible long-term adverse effects on bitumen development in cases where associated gas production preceded a Steam Assisted Gravity Drainage (SAGD) bitumen project. While these concerns largely focused on a specific SAGD development proposed for the Surmont area, the parties agreed that there could be implications to all oil sands areas and that a broad review of the issues was warranted. Another issue raised was that in the oil sands areas the petroleum and natural gas (P&NG) leases are posted separately from the oil sands leases and involve different areal configurations.

The inquiry, held between 29 May and 20 June 1997, was conducted by F. J. Mink, P.Eng., J. D. Dilay, P.Eng., and W. J. Schnitzler, P.Eng.. A list of the inquiry participants is provided in Appendix B.

This report summarizes the views of the inquiry participants and gives the Board's conclusions on the various issues.

1.2 Geologic Setting and Development Issues

Accumulations of natural gas are sometimes found in geological strata directly above and in pressure communication with oil sands deposits. These accumulations are referred to as “associated” gas caps. They are generally not well defined with respect to size, continuity, and the degree of pressure communication with the underlying oil sands deposit. In some oil sands areas, particularly in parts of Athabasca, significant gas production has already occurred from oil sands zones and additional production is planned. In other oil sands areas, economic accumulations of gas are not evident or have not yet been developed. While the oil sands areas are large, the pace of development throughout these areas is expected to be rapid.

Generally, most of the thermal bitumen production to date has been through the application of the Cyclic Steam Stimulation (CSS) process. More recently, however, the application of the SAGD process has become the preferred method for many bitumen producers. Like the CSS process, SAGD relies on the effective containment of pressurized steam within the bitumen pay zone. However, bitumen producers are concerned that the viability of using a SAGD process may be adversely affected by steam losses into an overlying gas cap, and that the extent of any steam losses may be influenced by the size and pressure of the gas cap.

During the inquiry, bitumen producers argued that associated gas production in advance of thermal bitumen production would have detrimental effects on bitumen recovery. Consequently, they presented a great deal of evidence on issues such as the effects of gas cap pressure depletion on bitumen recovery, the “regions of influence” of any gas cap pressure depletion via communication with water zones, the need for and feasibility of repressuring a depleted gas cap or bitumen zone, and the minimum pressure required in the gas cap to facilitate SAGD operations.

Gas producers argued that associated gas production in advance of thermal bitumen production is unlikely to have serious adverse effects on bitumen recovery. Furthermore, if bitumen were produced in advance of associated gas, some contamination of the gas could result from the generation of hydrogen sulphide and carbon dioxide at elevated bitumen temperatures. The gas producers were also concerned about the potential resource loss due to associated gas migration to depleted bitumen zones following completion of SAGD operations.

The inquiry participants were also generally interested in the areal extent of common gas/bitumen zones throughout the oil sands areas.

1.3 SAGD Process

In the SAGD process, the oil sands zone is accessed by drilling horizontal well pairs from the surface. The horizontal well pairs are spaced several metres apart vertically as shown in the schematic cross-section of the process in Figure 1.

Upon commencement of the SAGD process, steam is injected into both the upper and lower wells. Once pressure communication has been established between the two wells, steam is injected into the upper well only and the lower well becomes the producer.

During SAGD production, steam injected into the upper well flows through the bitumen-depleted zone to the cold interface, where it condenses, heating the bitumen. Mobilized bitumen then drains by gravity to the lower well and is produced. As the pay zone is exploited, the steam chamber continues to rise and spread, eventually reaching the top of the bitumen-bearing zone.

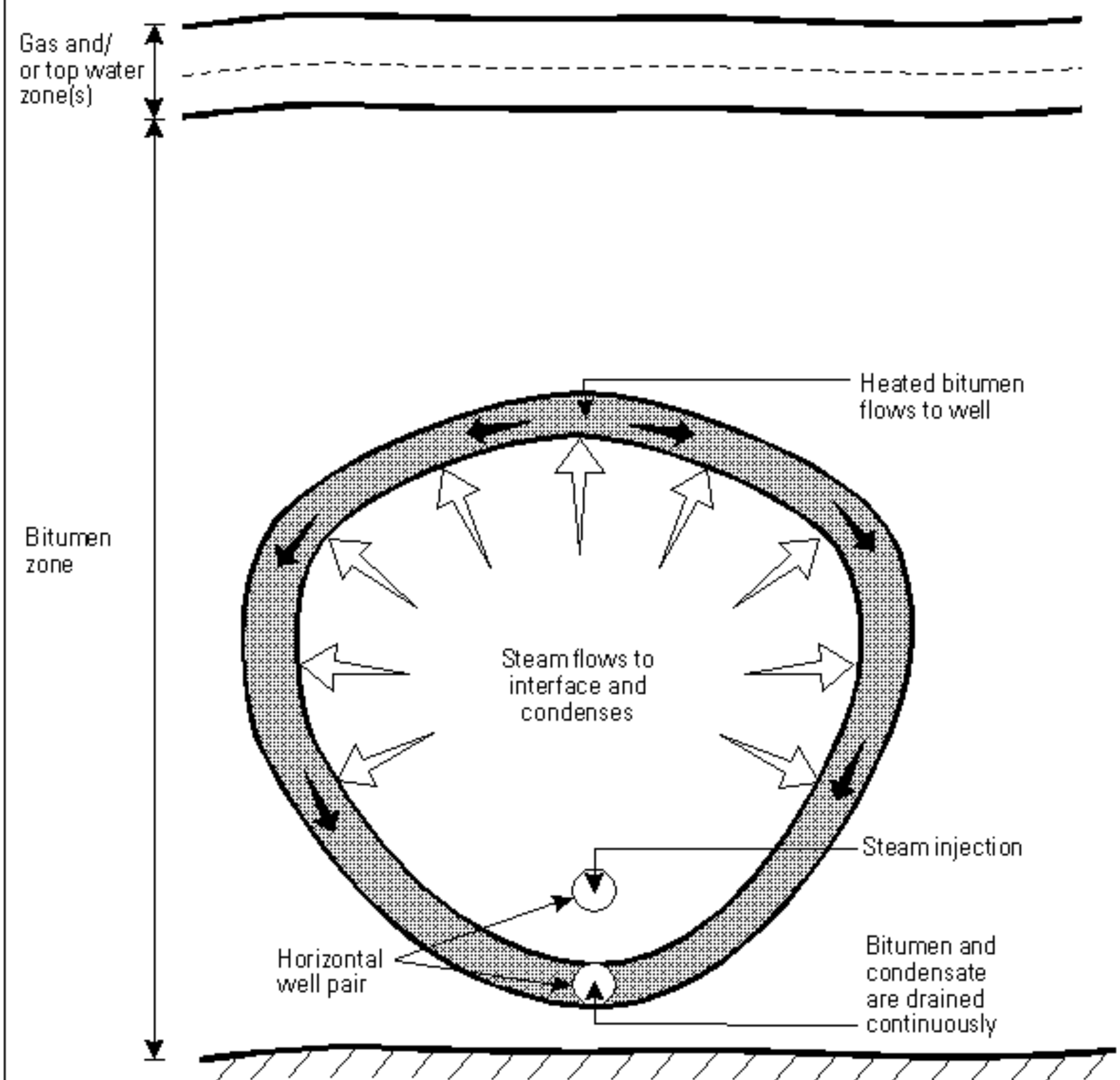

Figure 1- Schematic Cross-Section of the Steam Assisted Gravity Drainage (SAGD) Process

This stage of steam chamber development is considered to be the time during which steam breakthrough to an overlying gas cap is most likely to occur.

For those SAGD projects currently under development, several well pairs are arranged with 70 to 90 metres between adjacent well pairs. Using this configuration, neighbouring steam chambers eventually merge as the pay zone is depleted.

The Underground Test Facility (UTF) near Fort McMurray is aimed at testing the SAGD process for those oil sands deposits that are buried too deeply for surface mining, yet are too close to the surface for other in situ processes. Further applications of this process have proceeded in oil sands areas where the bitumen pay is at a comparable depth to CSS projects. This would also be the case for the proposed Surmont area development.

1.4 EUB's Authority and Conservation Mandate

The EUB's statutory authority for holding the inquiry is found in section 22 of the *Energy Resources Conservation Act* (ERCA). In accordance with section 22, what will arise from this report is a framework for the creation of preliminary guidelines by the Board regarding the development of gas and bitumen in areas where it is determined a conflict exists between production of the two resources. These guidelines are general in nature and are made without prejudice to future applications the EUB may receive respecting gas and bitumen production. Such applications will be considered on their own merits.

The EUB's broad conservation mandate, as set out in section 2(c) of the ERCA, is “to effect the conservation of, and to prevent the waste of the energy resources of Alberta.” More specifically, section 3(b) of the *Oil Sands Conservation Act* (OSCA) establishes that one of the EUB's purposes is “to ensure orderly, efficient and economic development in the public interest of the oil sands resources of Alberta.” A host of general provisions in the ERCA (sections 2.1, 15, 21, and 33), the OSCA (sections 4, 5, and 6) and the *Oil and Gas Conservation Act* (OGCA) (sections 7, 9, 26, 29, and 86) further charge the EUB with the requisite broad authority to effect these purposes.

The conservation mandate was a founding purpose for the formation of the Petroleum and Natural Gas Conservation Board in 1938, and interpretation of what conservation entails has evolved over time with the maturation of Alberta's oil and gas industry. An early definition of the conservation concept was articulated by a former Board chairman in 1950 as follows:

> Conservation involves the efficient use of natural resources, the development of these resources in such a way as to protect the interests of future generations, and the elimination of all economically avoidable waste. It may be defined as “the

> preservation of natural resources for economical use." The concept of the elimination of waste is paramount.[1]

Today, resource conservation in the context of the EUB's legislated mandate generally calls for "maximization of the resource through supervision of its development and extraction ... to guard against loss or waste."[2]

Given that the matters raised at the inquiry relate to conservation and efficient development of Alberta's oil sands and gas resources in the public interest, and given the EUB's extensive powers to regulate in this regard, the Board is satisfied that it has the requisite authority and jurisdiction to address the issues raised at the inquiry in the manner provided in this report.

2. GEOLOGY AND RESERVES

2.1 Extent of Affected Reserves

One of the issues identified in the terms of reference for the inquiry was the extent of affected reserves — that is, how much gas is associated with how much bitumen. The APG provided an overview of the gas reserves and bitumen resources in the three oil sands areas: Athabasca, Cold Lake, and Peace River. It also provided a detailed assessment of the gas reserves in the Surmont area. Gulf did not conduct a detailed assessment of the broader oil sands areas, but instead focused on the extent of affected reserves for its Surmont leases, which it contended is representative of the Athabasca oil sands area.

2.1.1 Reserves in Alberta's Oil Sands Areas

The APG study of the extent of affected reserves relied heavily on gas reserve and bitumen resource estimates from the publicly available EUB database. While the EUB's database does not identify the extent of direct communication between gas and bitumen, the APG, through manipulation of the available data, identified areas where gas and bitumen are potentially in communication.

The APG provided a summary of the initial volume of bitumen in place in the oil sands areas, excluding mineable bitumen, as of 31 December 1995. This is shown in Table 1.

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[1] G. W. Govier, "Oil and Gas Conservation," paper presented to the Canadian Institute of Mining and Metallurgy, Western Annual Meeting, Vancouver, 1950, p. 1-2.

[2] V. E. Bohme, "Developing an Effective Oil, Gas and Environment Conservation Programme," paper presented at ASCOPE 85, Kuala Lumpur, Malaysia, 1985, p. 2.

Table 1 - Initial Volume of Bitumen In Place[1]

Oil Sands Area	Initial Volume of Bitumen In Place (10^9 m^3)	Percent of Total
Athabasca	189	77
Cold Lake	32	13
Peace River	25	10
Total	245	100

1 Excluding mineable bitumen

The APG also provided a breakdown of the initial volume of bitumen in place in the oil sands areas at various average pay thicknesses, from which it concluded that a significant portion of the bitumen resources in each area are contained in thick oil sands deposits. This is shown in Table 2.

Table 2 - Initial Volume of Bitumen In Place at Varied Average Pay

Oil Sands Area	Initial Volume of Bitumen In Place[1] (10^9 m^3)	Initial Volume of Bitumen In Place at Varied Average Pay[2] > 5 m (10^9 m^3)	%	> 10 m (10^9 m^3)	%	> 15 m (10^9 m^3)	%
Athabasca	189	182	96	152	80	123	65
Cold Lake	32	25	78	17	53	10	31
Peace River	25	10	40	8	32	5	20
Total	245	217	89	177	72	138	56

1 Excluding mineable bitumen
2 Approximate average bitumen pay thickness over 1/4 township blocks

The APG further provided a summary of the gas reserves in oil sands areas, which indicated that 7.2 per cent of Alberta's remaining gas reserves, as of 31 December 1995, are located in the oil sands areas. This is shown in Table 3.

Table 3 - Gas Reserves in Oil Sands Areas

	Gas Reserves in Oil Sands Areas (10^9 m^3)	Alberta Total Gas Reserves (10^9 m^3)	Percent of Alberta Total
Initial Gas Reserves	259	3651	7.1
Remaining Gas Reserves	105	1467	7.2

The APG indicated that these gas reserves are divided between each of the three oil sands areas, as shown in Table 4.

Table 4 - Distribution of Gas Reserves in Oil Sands Areas

Oil Sands Area	Initial Gas Reserves (10^9 m^3)	Remaining Gas Reserves (10^9 m^3)
Athabasca	180	63
Cold Lake	67	32
Peace River	13	10
Total	259	105

The APG determined that the majority of the remaining gas reserves (96 10^9 m^3) are within the bitumen-bearing stratigraphic intervals (Athabasca area, 96 per cent; Cold Lake area, 84 per cent; and Peace River area, 91 per cent). The APG further determined the portion of remaining gas reserves that lie in bitumen accumulations of various average pay thicknesses, as shown in Table 5.

Table 5 - Remaining Gas Reserves Within the Bitumen-Bearing Stratigraphic Intervals

Oil Sands Area	Remaining[1] Gas Reserves (10^9 m^3)	Remaining Gas Reserves ($10^9 m^3$) Located in Areas With This Minimum Average Bitumen Pay				Percent of Remaining Gas Reserves			
		> 0 m	> 5 m	> 10 m	> 15 m	> 0 m	> 5 m	> 10 m	> 15 m
Athabasca	60	50	42	26	21	83	70	43	35
Cold Lake	27	18	11	6	3	67	41	22	11
Peace River	9	7	0	0	0	78	4	4	1
Total	96	75	53	32	24	78	55	33	25

[1] Remaining gas reserves within the bitumen-bearing stratigraphic intervals

On the basis of this study, the APG concluded that the majority of the remaining gas reserves in the oil sands areas are located in areas having some bitumen pay. However, the majority of the remaining gas reserves are not in areas having high net bitumen pay, which are the most prospective for SAGD operations.

The APG used two primary indicators of gas/bitumen communication in the oil sands areas: gas in the same zone as the bitumen, and a gas/bitumen contact description flag in the EUB's gas pool database. The APG digitized the EUB's bitumen resource estimates on a quarter-township basis and identified areas of potential conflict as being wherever gas accumulations occurred in a quarter township.

The APG summarized the results of its determination of remaining gas reserves in potential conflict with bitumen resources, as shown in Table 6. The APG concluded that 35 per cent of remaining gas reserves in the oil sands areas are in the same formation as bitumen resources and that 12 per cent of remaining gas reserves have been flagged in the EUB's database as being in communication with bitumen resources. The APG indicated that this range reasonably reflects the range of gas in potential conflict with bitumen.

The APG also determined that 36 per cent of bitumen has gas in the same formation and that 15 per cent of bitumen is associated with gas in at least one well in each quarter township. Therefore, 15-36 per cent of the bitumen in place brackets the extent of affected reserves.

The APG maintained that by bracketing the percentage of gas and bitumen that might be affected, it accounted for any lack of identification of gas/bitumen interfaces in the EUB's database, as well as the fact that the gas/oil contact description flag in the database does not recognize “gas-over-water-over-bitumen” pools.

2.1.2 Reserves in the Athabasca Oil Sands Area

Gulf adopted the DOE's estimate that there are 142 $10^9\,m^3$ of bitumen in place in the Athabasca oil sands area, of which 56 $10^9\,m^3$ are economically exploitable by the SAGD process. This estimate of economic exploitability is from a technical paper that assumed a minimum overburden thickness of 30 metres, continuous 6 (or greater) mass per cent bitumen, and no shale stringers greater than 2 metres in thickness[3].

Gulf submitted that the best bitumen prospects in Athabasca are in the McMurray channel sands. The APG acknowledged that the majority of the bitumen resources in Athabasca exist in the Wabiskaw-McMurray stratigraphic interval, as shown in Table 7.

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[3] “Applicability of the SAGD Process to the McMurray/Wabiskaw Deposit, Athabasca Oil Sands Area,” by B. Anderson et al.

Table 6 - Summary of Remaining Gas Reserves and Bitumen Resources[1]

	Athabasca (10^6 m^3)	Athabasca % of Total	Cold Lake (10^6 m^3)	Cold Lake % of Total	Peace River (10^6 m^3)	Peace River % of Total	Oil Sands Areas (10^6 m^3)	Oil Sands Areas % of Total
Initial Bitumen In Place								
Non-Surface Mineable	188 742	100	31 907	100	24 579	100	245 228	100
In Areas Where Bitumen Potentially Economic [2]								
Total	182 311	97	31 907	100	10 419	42	224 637	92
Has Gas in Same Zone	65 951	35	21 448	67	162	1	87 561	36
Has Gas in Same Zone and Gas/Bitumen Flag	29 336	16	7 567	24	0	0	36 903	15
Remaining Gas Reserves								
Reserves Within Bitumen Interval	60 050	100	27 314	100	8 868	100	96 232	100
In Areas Where Bitumen Exists	50 324	84	17 586	64	6 983	79	74 893	78
In Areas Where Bitumen Potentially Economic [2]								
Total	41 500	69	17 586	64	319	4	59 405	62
Within Bitumen Zone	21 138	35	12 532	46	104	1	33 774	35
Within Bitumen Zone and Gas/Bitumen Flag	8 350	14	3 604	13	0	0	11 954	12

[1] Adapted from Table 4 - Summary of EUB Gas Reserves and Bitumen Resources, Gilbert Lausten Jung Associates Ltd. Report, APG Submission, Section 6.

[2] Based on average thickness of bitumen zone > 5 m in quarter township in Athabasca and Peace River, > 0 m in Cold Lake

Table 7 - Stratigraphic Distribution of Bitumen in the Athabasca Oil Sands Area[1]

Stratigraphic Interval	Initial Volume of Bitumen In Place (10^9 m^3)	Percent of Total
Grand Rapids	10	5
Wabiskaw-McMurray	119	63
Nisku and Grosmont	60	32
Total	189	100

1 Excluding mineable bitumen

Gulf maintained that the best bitumen and gas prospects co-exist in the same area because that is where the best reservoir sands are present. Gulf hypothesized that this may be due to the differential compaction of the shale-rich McMurray zone. This differential compaction of the shale-rich McMurray zone relative to the sand-rich McMurray zone is likely caused by diagenetic dewatering of clays. Sand-rich areas of the McMurray have mechanical competence due to grain contact. The competence of the sand-rich zone relative to the compressibility of the shale-rich zone could lead to structural entrapment of gas in sands directly overlaying sand-rich areas of the McMurray.

Gulf argued that in these areas of thick sand development the thickest gas and bitumen accumulations occur and the greatest potential for conflict between the two resource owners exists. Therefore, any area having thick gas and bitumen pay would be representative of the reserves in conflict in Athabasca. Given that some of the thickest channel sands in Athabasca are in the Surmont area, Gulf submitted that Surmont is representative of Athabasca.

Gulf stated that Surmont contains 5 per cent of the recoverable bitumen in Athabasca, equivalent to 2.4 10^9 m^3, and 1.7 10^9 m^3 of the remaining gas reserves. Gulf noted that gas at Surmont is found in both marine and non-marine sands and can be associated with bitumen directly or indirectly through upper McMurray water. The bitumen can also be associated with upper McMurray water in the absence of gas. Gulf also noted that closely spaced wells show the sudden lateral lithologic variability of the McMurray Formation. Gulf concluded that these characteristics of Surmont are representative of the gas and bitumen relationships that occur throughout Athabasca and thus make Surmont a viable example.

In contrast, the APG argued that Surmont is not representative of Athabasca. The APG submitted that Surmont is unique because of its location at the updip edge of the paleostructural high of the McMurray deposit, where the bitumen is richer and the gas pays are thicker than in other areas of Athabasca. As a result, the potential for conflict between resource owners is particularly high in that area. The APG found that in areas immediately west of Surmont the presence of gas in association with bitumen decreased. The APG provided a detailed review of the reserves in the

Wabiskaw-McMurray Formation for a 2 800 square kilometre area, which included the Surmont, Christina, and Hangingstone areas. It noted that a total of 82.3 per cent of this study area showed no conflict between gas and bitumen reserves and that the majority of the remaining gas reserves are not in the areas having high net bitumen pays, which are the most prospective for SAGD operations.

The study also showed that when moving back from the updip edge of the McMurray deposit, the potential for conflict declines significantly. The APG determined that in Surmont, gas is present over 36 per cent of the area. In contrast, in Christina, 19-39 kilometres back from the updip edge of the McMurray deposit, gas is found in only 27 per cent of the area, and even farther west at Hangingstone, gas is found in only 6 per cent of the area. The percentage of gas-over-water-over-bitumen pools also decreased to the west. This is summarized in Table 8.

Table 8 - Area Covered by Gas and Gas-over-Water-over-Bitumen Pools

Area		Gas Pools (% of Area)	Gas-over-Water-over-Bitumen Pools (% of Pools)
Surmont	(Twp 80-84, Rge 6-8 W4M)	36	69
Christina	(Twp 80-84, Rge 8-10 W4M)	27	47
Hangingstone	(Twp 81-85, Rge 10-11 W4M)	6	50

On the basis of its study, the APG concluded that Surmont is not representative of the study area or Athabasca in general.

Although the APG agreed that there were areas in Athabasca where gas development could occur without conflict, it expressed concern with the current uncertainty surrounding gas reserves yet to be found and whether they will be allowed to be produced.

2.1.3 Reserves in the Surmont Area

The APG and Gulf agreed that the McMurray Formation in the Surmont area was deposited by a series of fluvial and deltaic channels, interrupted periodically by marine flooding sequences. Gulf stated that the main bitumen pay interval was formed by stacked channel bars which appear to be active channel fill and occur as stacked point bar sands. Gulf estimated the oil sands zone within the channel sand complex to be 40-70 metres thick. Non-reservoir zones are comprised of shale-filled abandoned channels and interdistributary shale deposition. Gulf further stated that a striking feature of the McMurray in this area is the lateral discontinuity of shales within the oil sands zone. Its evidence demonstrated that the shales are not laterally continuous and as such, are not effective barriers to the transmission of declining pressures in overlying gas and water zones. The APG stated that the channel sands tend to be narrow and limited in areal extent. It further stated that the different facies found at Surmont are discontinuous both vertically and laterally and that sand and shale bodies that may appear contiguous are often truncated between wells over very short distances.

Gulf estimated the recoverable bitumen at its Surmont leases to be 2.4 10^9 m^3, based on a pay thickness of 20 metres or greater. Although Gulf stated that a minimum thickness of 15 metres of good-quality oil sands is necessary to apply a SAGD process, it also stated that a minimum thickness of 20 metres is needed when there is an overlying thief zone, such as a gas cap or a top water zone. Most of the bitumen resource at Surmont occurs where there is either direct bitumen/gas cap contact or indirect bitumen/gas cap contact through a top water zone. Gulf further estimated that at least 75 per cent of the gas at Surmont is in pressure communication with the underlying bitumen through a “region of influence” (see section 2.2 of this report). Based on rigorous mapping of currently available information, Gulf estimated that the area of bitumen reserve at risk from pressure depletion due to associated gas production in advance of bitumen production was 55 per cent of its Surmont leases. It submitted that this estimate would likely increase with further drilling and reservoir delineation in the area.

The APG estimated the bitumen in place underlying Gulf's Surmont leases to be 4.2 10^9 m^3, and the original gas in place to be 9.4 10^9 m^3. The APG further estimated that only 4 per cent of the bitumen in place is in direct contact with gas, while approximately 26 per cent is overlain by water and gas. It also identified several areas on the leases where there is no overlying gas or water. Although the bitumen pays in these regions are slightly lower than in gas-prone areas, the APG argued that the absence of overlying water and gas would result in higher recovery factors.

2.2 Regions of Influence

The APG and Gulf agreed that the regions of influence are defined as those areas within which bitumen resources would be adversely affected by a reduction in pressure due to gas production. The extent of these regions can be defined by the areal extent of the gas pools where the gas immediately overlies the bitumen or by the areal extent of the top water zone where the water zone is between the gas and bitumen zones. The APG and Gulf agreed that the critical issue is the extent and lateral continuity of the water zone, as this defines the extent of the potential for conflict and the volume and/or area of bitumen that may be affected.

The APG submitted that the distribution of the water and gas at Surmont is a result of stratigraphy and paleostructural position. Surmont is the Athabasca area that was structurally the highest at the time of oil and gas accumulation. The original gas caps have been naturally depleted and filled by formation water. Bacterial gas is currently accumulating as new stratigraphic accumulations by displacing the formation water in the upper water zones. The APG interpreted the gas and upper water at Surmont to occur in the upper McMurray zone, whereas the bitumen exists in the middle and lower McMurray zones.

The APG submitted that seismic interpretation appears to realistically delineate the areal extent of the gas pools at Surmont. It stated that back-calculated reservoir areas were on average only slightly greater than the areas indicated by seismic. Gulf disagreed with the APG's conclusion, and based on its own seismic, geology, reservoir engineering, and hydrodynamic interpretations, argued that the gas pools are larger.

The APG interpreted the edges of the upper McMurray channel to be relatively steep, indicating that the edge of the water, which represents the edge of the original gas accumulation, would probably be fairly close to the edge of the current gas accumulation. The water limits could actually be less than the current gas accumulation if the pool is inverted like a cup. Gulf argued that the APG used an unrealistic margin of error in the pressure data, resulting in smaller pools. Gulf determined the size of the top water zones based on hydrodynamics but did not provide a geological interpretation to support the larger water pools.

The APG submitted that the McMurray aquifer is a hydrodynamic regime with a sloping potentiometric surface. Regionally, the potentiometric surface elevation contours slope downward towards areas of natural pressure release, that is, towards outcrop to the north and northeast and towards the underpressured Grosmont to the west. The potentiometric surface elevation contours across Surmont decrease to the northeast in response to the outcrop. Through recent geologic time, the McMurray bitumen section has had limited success in reaching equilibrium with the lower-pressured areas, such as outcrop and the underpressured Grosmont. The APG stated that regionally it would appear that the McMurray bitumen section is very reluctant to flow because of very little movable water and the viscosity of the bitumen itself. There is no fluid flow, only a “potential for flow”.

In contrast, Gulf argued that Surmont is situated in the discharge area of a regional basin-scale hydrodynamic flow system that has equilibrated with outcrop. The regional system is locally overprinted by topographically controlled flow systems driven by recharge in the Stony Mountain uplands. Both flow systems are equilibrated to the present land surface and are actively discharging where the aquifers outcrop in the Clearwater and Christina river valleys. The observed range of virgin formation pressures across the area is due to flow in the aquifers. Potentiometric surface mapping using virgin formation pressures reveals extensive lateral hydraulic continuity within the McMurray Formation sands.

The APG argued that, since there is no fluid flow, the water within each water zone at Surmont would have equilibrated within the zone's areal limits over geologic time. Adjacent separate water zones should have their own hydrostatic potentiometric surface elevation, but any discrete water zone should have a constant potentiometric surface elevation within its boundaries. The potentiometric surface elevation boundaries then become one means for delineating the continuity of the water zones at Surmont.

Gulf agreed with the premise that each water zone at Surmont would have its own potentiometric surface elevation and also used this approach to delineate the extent of the water zones. Gulf, however, also argued that pressure depletion in the McMurray Formation due to gas production within a hydraulically continuous region of influence would transmit the decline in pressure through that region of influence at a rate of 10 kilometres per year through the gas phase and

1 kilometre per year through the water phase. Gulf further stated that a pressure decline would also be transmitted from one region of influence to neighbouring regions of influence, but did not know the time frame for this pressure transmittal. This transmission of pressure decline would be magnified if neighbouring regions of influence are also experiencing gas production. Gulf contended that the cumulative effect of pressure decline in several or all the regions of influence would be to deplete the pressure across all the oil sands leases at Surmont.

The APG and Gulf agreed that the pressure effects of gas production would extend laterally throughout the region of influence during the life span of a producing gas pool. The APG, however, argued that the effects would not be transmitted to neighbouring regions of influence within the time frame of gas production.

The APG estimated the extent of the water zones to be just beyond the limits of the overlying gas pool, given that this is likely an old gas cap that has bled off and the edges of the channel are probably relatively steep. It supported this view with seismic and pressure data. The residual gas in the water zone appears as an anomaly on seismic. The APG gave examples of where the seismic response shows that the gas effect is gone and a nearby offset wellbore has no water on top of the bitumen. From this, it concluded that the water zone ends within 50-100 metres of the edge of the gas pool. The lateral continuity of the water zones is defined by pressure data. The APG believed that the potentiometric head values within a single zone should be the same, within a margin of error of ±1 metre. On the basis of this criterion, the APG mapped many smaller water zones than defined by Gulf.

In contrast, Gulf determined the areal extent of the regions of influence by integrating three disciplines: hydrodynamic analysis of potentiometric surface values, areas of production-induced drawdown, and water chemistry. Gulf correlated areas as hydraulically continuous on a time scale of gas pool production life if hydraulic head values were within a range of ±3 metres. Accordingly, the resulting water zones were mapped to extend well beyond the edges of the overlying gas pool, and some were purported to underlie two or more gas pools.

3. RESERVOIR ENGINEERING

3.1 Effect of Associated Gas Production on Thermal Bitumen Recovery

The inquiry participants advanced two methods to evaluate the effect of associated gas production on thermal bitumen recovery: model studies and field experience. However, given the limited amount of field experience, the parties agreed that reservoir modelling was the main evaluation tool available at this time to estimate possible effects on resource recovery.

3.1.1 Model Studies

Four studies were presented during the inquiry regarding the effect of associated gas production on thermal bitumen recovery. DOE/EUB, Gulf, Petro-Canada, and the APG conducted the studies. SAGD was the only thermal bitumen recovery method modelled. All four studies used the Computer Modelling Group's Steam and Additives Reservoir Simulator (STARS). The DOE/EUB study evaluated SAGD in Athabasca-McMurray and Cold Lake-Clearwater type reservoirs, while the other three studies evaluated SAGD in only an Athabasca-McMurray type reservoir. A comparison of the main features of the Athabasca-McMurray model studies is summarized in Table 9. Similarly, Table 10 summarizes the main features of the two Cold Lake–Clearwater model studies conducted by DOE/EUB.

ATHABASCA-MCMURRAY MODELS

DOE/EUB Model Study

The DOE/EUB study was a modification of previous detailed reservoir simulation studies conducted for the UTF. A summary of the model description is provided in Table 9. Since the UTF model did not provide for a gas cap, modifications were necessary. The presence of a gas cap was modelled by extending the upper layer by 2.5-metre grid blocks, as required, to obtain 5-metre and 10-metre gas cap thicknesses. The model was three dimensional (3-D) and included a 400-metre “regular” layer and a 100-metre “short-circuit” layer to provide the ability to study early breakthrough of the steam chamber into the gas cap. The short-circuit layer had higher permeability than the regular layer. A top water zone was not included.

A pressure sink was modelled by simulating a horizontal well in the gas cap 367 metres laterally from the outside SAGD well pair. The main control placed on this well was a pressure limit. Two pressure cases were considered: a non-depleted reservoir case with an initial pressure of 1 800 kilopascals (kPa) and a depleted case with an initial pressure of 550 kPa. A maximum gas production rate limit was also set to stabilize the model, if necessary, during the period of time that the steam chamber contacted the gas cap. In the majority of cases, the gas production limit was high enough so that outflows from the gas cap were not restricted; however, some restrictions in outflow occurred in two of the 10-metre gas cap cases and one of the 5-metre gas cap cases. The APG noted that specifying a maximum gas production rate was inconsistent with the idea of maintaining the gas cap pressure at a specified value. Gulf also commented that only the optimized cases could be used because of the rate limit on the potential gas well.

The model was used to generate forecasts of steam injection and bitumen and water production for various reservoir configurations and operating strategies. Steam was injected until the well pair economic limit was reached. This limit was a relationship between the bitumen production rate and the steam-oil ratio (SOR); the relationship was obtained by equating the revenue from the bitumen production to the operating costs.

Table 9 - Comparison of Athabasca-McMurray Models

Feature	DOE/EUB	Gulf	Petro-Canada	APG
Symmetry Element	2 1/2 well pairs spaced 90 m apart; 549 m wide; 500-m horizontal wells	1/2 well pair; 50 m wide; 700-m horizontal wells	1/2 well pair; 40 m wide; 500-m horizontal wells	1/2 well pair; 40 m wide; 350-m horizontal wells
Reservoir Description:				
homogeneous or heterogeneous	heterogeneous	heterogeneous	homogeneous	homogeneous
k_h[1] (md)[2]	2 000 - 10 000	400 - 4 310	4 000	2 500
k_v[3] (md)	200 - 5 000	200 - 3 920	2 000	2 200
$h_b/h_g/h_w$[4] (m)	24/0,5,10/0	43.5[5]/3/3,10.5 24.5[5]/3,10/0,3	23/0,5,15/0	30/0,2.5,10/0,13
2-D or 3-D	3-D	3-D	2-D	2-D
Thief Zones Considered	gas	gas and water	gas	gas and water
Thief Zone Pressures (kPa):				
Native	1 800	1 338	1 750	1 338
Partially Depleted		800	700	
Gas Abandonment	500	200	400	400
How Thief Zone Was Modelled	Horizontal well in gas cap, located 376 m from outside well pair	Horizontal wells in gas cap and top water zone, located 200 m from1/2 well pair	Well (horizontal vs. vertical not specified) in gas cap, located 40 m from 1/2 well pair	2 vertical wells in gas cap, one directly above 1/2 well pair, other 40 m from 1/2 well pair
Criteria Used to Terminate Model Runs	Well pair bitumen production rate and SOR relationship	Combination of factors, including bitumen and water production rates and a 30-year operating limit	10-year operating limit	Bitumen production rate < 2 m^3/d or 10-year operating limit

[1] k_h = horizontal permeability
[2] md = millidarcy
[3] k_v = vertical permeability
[4] h_b = thickness of bitumen zone; h_g = thickness of gas cap; h_w = thickness of top water zone
[5] net bitumen pay thickness

Table 10 - DOE/EUB Cold Lake-Clearwater Models

Feature	Wolf Lake	Burnt Lake
Symmetry Element (other	2 ½ well pairs spaced 90 m apart; 1 490 m wide; 1 000-m horizontal wells	2 ½ wells pairs details not provided)
Reservoir Description:		
homogeneous or heterogeneous	heterogeneous	heterogeneous
k_h[1] (md)[2]	400 - 8 500	1 500 - 3 000
k_v[3] (md)	195 - 2 550	100 - 1 500
h_b/h_g[4] (m)	72/0,4,8	34/0,5,10
2-D or 3-D	2-D	2-D
Thief Zones Considered	gas	gas
Thief Zone Pressures (kPa):		
Native	2 500	3 100
Gas Abandonment	650	600

Note: The method used to model the thief zone and the criteria used to terminate the model runs were the same as those used in the DOE/EUB Athabasca-McMurray model.

[1] k_h = horizontal permeability
[2] md = millidarcy
[3] k_v = vertical permeability
[4] h_b = thickness of bitumen zone; h_g = thickness of gas cap

The results of the model study are summarized in Table 11. They suggested that when the gas cap was not produced, operating SAGD at the original gas cap pressure reduced bitumen recovery by only 2-3 per cent as the gas cap thickness increased. When the gas cap was produced, bitumen recovery was reduced when the SAGD process was operated at pressures comparable to those cases without gas cap depletion. The study found that to reduce the detrimental effect of associated gas production on bitumen recovery, the SAGD process would need to be operated at lower pressure to minimize steam leak-off to the gas cap. Although this approach was not fully optimized in the study, the researchers concluded that bitumen recovery for thicker gas caps may be lowered by about 10 per cent due to depletion of the gas cap in advance of bitumen production. Economic implications of such events are discussed in section 4 of this report.

The 10-metre depleted gas cap case, with the steam chamber pressure reduced to 1 000 kPa, was used to evaluate the effect of removing the short-circuit layer, resulting in a two-dimensional (2-D) rather than a 3-D model. There was only a small difference in the predicted performance between the 2-D and 3-D models, as indicated in Table 11. However, Gulf noted that the DOE/EUB model did not include a top water zone. Gulf believed that the effect of a short-circuit layer would be much less if only a gas cap was present. Gulf stated that a top water zone was much more of a problem for SAGD operations and a 3-D model was needed to model the effects of a top water zone.

Table 11 - DOE/EUB Athabasca-McMurray Model Study Results

Gas Cap Thickness (m) SOR	Initial Reservoir Pressure (kPa)	Steam Chamber Pressure (kPa)	Recovery (%)	CDOR (m^3/d)	Cum
0	1 800	2 600	82	79	2.7
0	550	2 600	81	80	2.7
5[1]	1 800	2 600	80	75	3.2
5	550	2 600	80	72	3.5
10[1]	1 800	2 600	76	76	3.6
10	1 800	1 800	79	71	2.6
10[1]	550	2 600	63	69	5.1
10	550	1 000	69	47	3.4
10[2]	550	1 000	68	44	3.53
10	550	550	41	25	1.91

[1] Cases that experienced some restriction in outflow from the gas cap
[2] 2-D rather than 3-D model run

From the model study the DOE/EUB concluded that when the injected steam reached the overlying gas cap, the steam mobilized bitumen near the gas cap and displaced it into the gas cap. The mobility of the steam decreased as a partial plug was formed by the cooling bitumen. The model indicated that there was less bitumen plugging in the 10-metre gas cap compared to the 5-metre gas cap.

The DOE/EUB study cautioned that the following factors needed to be considered in interpreting the results.

1. The cases were not optimized with respect to well-pair spacing, well length, operating pressure strategy, time at which steam injection was stopped, and wind-down method.

2. The cost for an artificial lift method capable of operating at low pressure was not included.

3. Gas cap thickness was only one of the many geological parameters affecting SAGD that was considered in the study.

4. The model lacked support from field data, since field performance of SAGD operations beneath gas caps and water zones was not available.

Gulf Model Study

Gulf based its model study on its Surmont oil sands leases. It derived the basic pay zone description, and the petrophysical and fluid properties from history matched models of the UTF site, which were quite similar to those used in the DOE/EUB model study. A summary of the model description is provided in Table 9. Gulf considered a 3-D configuration to be essential because early breakthrough of the steam chamber into the thief zone at a particular location along the wellbore could have a large effect on SAGD performance. Its model included two layers in the y-direction along the wellbore. One layer was 650 metres long and represented the bulk of the steam chamber. The other layer was a short-circuit layer, 50 metres long. The APG pointed out that the short-circuit layer was arbitrarily assigned to the 50-metre section at the heel of the horizontal wells and that this was only one of many possible representations of the reservoir.

Gulf considered three thief zone pressures in its study: the native thief zone pressure of 1 340 kPa; a partially depleted pressure of 800 kPa; and a gas abandonment pressure of 200 kPa. Gulf argued that 200 kPa was an appropriate gas abandonment pressure to use, based on experience in other areas and because of the high permeability of the reservoir. The APG responded that 200 kPa was unreasonably low and that the examples of low gas abandonment pressures cited by Gulf were only isolated examples, which did not, on balance, represent realistic pool abandonment pressures.

Gulf modelled the performance of a SAGD process in the presence of thief zones by applying a mitigating strategy for some cases and a “limited” mitigating strategy for other cases. The mitigating strategy included reducing the steam injection pressure close to the thief zone pressure prior to steam breakthrough into the thief zone, changing the steam injection pressure as a function of the ratio of produced water rate to steam injection rate, and use of a non-condensible gas blanket to maximize the ratio of horizontal to vertical steam chamber development. The limited mitigating strategy used the same approach, but the strategy was not optimized. It resulted in more aggressive steam injection. Gulf used a combination of factors, including the bitumen and water production rates and a 30-year operating limit, to determine when to terminate the model runs.

The results of the model study are summarized in Table 12. The model predicted that lowering the reservoir pressure had a significant negative impact on bitumen recovery, even with the use of mitigating strategies. If the gas cap was not produced, SAGD performance was promising despite the presence of gas and water thief zones. If the gas cap was produced to an intermediate pressure of 800 kPa with mitigating strategies, the bitumen production rate was reduced significantly, but the SOR was similar to that at the native thief zone pressure and the recovery factor was almost as high. If the gas cap was produced to an abandonment pressure of 200 kPa with mitigating strategies, the bitumen production rate was reduced considerably, the SOR was worse within the first 16 years of operation of a well pair, and the recovery factor was reduced significantly. Extrapolation of the model results to bitumen pay zones with net thicknesses less than 24.5 metres

Table 12 - Gulf Athabasca-McMurray Model Study Results

Bitumen Zone Thickness (m) Gross/Net	Thief Zone Thickness (m) Gas	Water	Thief Zone Pressure (kPa)	Injection Strategy	Recovery (%)	CDOR (m^3/d)	Cum SOR
52.5/43.5	3	3	1 340	M[1]	78.2	126.0	2.17
52.5/43.5	3	3	800	M	77.2	99.3	2.04
52.5/43.5	3	3	200	M	64.0	54.5	1.98
52.5/43.5	3	3	200	LM[2]	51.2	81.9	4.00
52.5/43.5	3	10.5	1 340	M	34.6	127.7	1.67
52.5/43.5	3	10.5	800	M	29.9	96.2	1.63
52.5/43.5	3	10.5	800	LM	25.4	130.5	2.51
52.5/43.5	3	10.5	200	M	21.6	79.1	1.80
52.5/43.5	3	10.5	200	LM	18.1	115.8	2.86
28.0/24.5	3	3	1 340	M	78.8	74.2	2.46
28.0/24.5	3	3	200	M	66.6	31.1	2.73
28.0/24.5	10	0	1 338	M	52.1	61.2	1.73
28.0/24.5	10	0	400	M	47.4	37.0	1.68

[1] M = mitigating strategy
[2] LM = limited mitigating strategy

indicated production of the gas cap would result in larger reductions in recovery performance than for thicker pay zones. Gulf commented that, while the simulations had not been completely optimized in terms of interwell distance, operating strategy, etc., they were sufficient to clearly indicate the negative impact of reduced reservoir pressure as a result of gas cap production. Gulf submitted that if the gas cap gas was produced to abandonment pressure, the technical risks with SAGD were increased such that it would not be advisable for companies to develop associated oil sands.

Gulf noted the model predicted that beneficial partial plugging effects would occur in the thief zones if the thief zones were not too thick or if only part of the steam chamber broke through into the thief zones and if the pressure difference between the steam chamber and the thief zones was not excessive. However, Gulf cautioned that the partial plugging effects had not been documented in field tests and it was possible that numerical simulators provided optimistic results.

Gulf noted that the following technical reservoir risks of operating at low pressure were not addressed in its model study.

1. Gravity drainage rates at low pressure may not follow predictions.

2. Reduction of the pressure below the bubble point of the bitumen prior to SAGD may increase the bitumen viscosity and cause relative permeability effects.

3. As the pressure is reduced, the rock expands, and this can reduce the porosity and permeability.

Petro-Canada Model Study

Petro-Canada's model study used the attributes of its Thornbury lease, but the viscosity and relative permeability curves were taken from the UTF. A summary of the model description is provided in Table 9. Petro-Canada did not include a top water zone in its model. It ran the model for 10 years to determine what it called a technical recovery factor.

The results of the model study are summarized in Table 13. The model predicted that increasing the gas cap thickness from zero to 15 metres at a fixed initial pressure reduced the technical recovery by 5-10 per cent. It also predicted that reducing the pressure in an overlying gas cap at a fixed thickness reduced the technical recovery by 20 per cent. The model indicated that in the presence of depleted and partially depleted gas caps, adjustments to SAGD steam injection pressure and rate can improve production rates.

APG Model Study

The reservoir description used in the APG model was prepared from data presented in Gulf's application to the EUB for an experimental scheme at Surmont[4]. A summary of the model description is provided in Table 9. The model was 2-D. The APG did not dispute Gulf's view that a 3-D model was essential for the proper design of a SAGD project. However, the APG stated that the objective of its study was not to design a field project but to understand the physics of the process and to develop approaches that could be applied in the subsequent design of a field project.

The APG model considered both unconfined and confined systems. The APG modelled the unconfined system by using two vertical potential wells (one directly above the horizontal well pair and the other at a lateral distance of 40 metres) perforated in the upper layers of the gas cap

[4] Application No. 960817, 16 October 1996

and assigned a minimum bottomhole pressure within 50 kPa of the gas cap pressure. Whenever the pressures in the perforated grid blocks exceeded the bottomhole pressure by 50 kPa, the APG allowed the wells to produce fluids (gas and/or water) until the pressures in the grid blocks

Table 13 - Petro-Canada Athabasca-McMurray Model Study Results

Gas Cap Thickness (m) (approx.[2])	Initial Gas Cap Pressure (kPa)	Steam Injection Pressure (kPa)	Post-Breakthrough Steam Injection Rate Limitation (m^3/d)	Recovery (%)	Cum SOR	CABR[1] (m^3/d)
0	1 750	2 750	300	80	80	4.54
0	1 750	2 750	declining	76[3]	65	3.28
5	1 750	2 250	300	73	84	5.40
5	1 750	2 250	200	72	68	3.77
5	1 750	1 766	200	72	61	3.57
5	400	900	80	53	37	2.20
5	400	416	150	56	39	3.33
5	400	416	100	53	37	2.41
15	1 750	2 250	600	70	68	11.10
15	1 750	2 250	300	73	80	5.26
15	1 750	2 250	200	72	64	3.70
15	700	716	100	51	36	2.70
15	400	900	300	46	32	8.33
15	400	900	150	52	36	4.08

[1] CABR = cumulative average bitumen rate
[2] Values read off graphs
[3] This case was run for 9.4 years instead of 10 years

dropped below the set limit. The APG modelled the confined system by shutting in the two potential wells so that the zonal pressure could rise to any level. It argued that in a fully developed multipatterned SAGD operation, the inner well pairs would be confined by the neighbouring wells, while the outer well pairs would be confined by the physical boundaries of the gas cap. As a result, the majority of wells would be confined in a reservoir that was fully developed using the SAGD process. The APG stated that the SAGD response at the inner and outer well pairs would be similar to that of the confined and unconfined cases respectively. Gulf argued that the APG's confined cases were not valid because when there was an upper thief zone, inner well pairs were not confined by the outer well pairs. Flow in the thief zone above inner well pairs could occur out past the ends of the well pairs and also out over the outer well pairs.

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This meant that inner well pairs had to be modelled with an unconfined thief zone just like the outer well pairs. Gulf also stated that the APG's modelling of the thief zone was problematic, since it did not extend past the pay zone, and use of vertical wells had the potential to distort SAGD performance. A vertical well in a grid block 350 metres long would act as if it had a very large skin, and this could limit outflow and allow unintended increases in pressure. The APG responded that it believed that the use of vertical wells was justified because a pressure drop of less than 1 kPa was observed in the gas cap during the SAGD operation.

The APG model included a 200 cubic metres per day (m^3/d) liquid rate constraint, based on information contained in Gulf's Surmont pilot application, in which Gulf proposed this constraint for a 350-metre horizontal well. Gulf commented that this constraint affected the predicted SAGD performance in at least one of the APG's model runs. Gulf argued that a production rate constraint could have a large effect on SAGD performance, since there could be a build-up of liquids in the steam chamber, which would reduce gravity drainage.

APG conducted several scoping model runs to determine the effect of an unconfined, overlying gas cap and/or water layer on the production performance of a SAGD operation. Additional runs were made to determine the effect of overlying zone confinement and to tailor the steam injection rates and pressures to improve the performance. In response to Gulf's comment that an insufficient mitigating strategy was used, APG acknowledged that its tailored runs were not fully optimized. APG terminated the model runs when the bitumen production rate dropped to less than 2 m^3/d or after 10 years of operation.

The results of the model study are summarized in Table 14. The model indicated that the application of a SAGD process in the presence of a gas cap and/or top water zone resulted in reduced recovery, regardless of the pressure level in the gas or water zone. The effect increased with increasing thickness of the gas or top water zone and increasing operating pressure. A top water zone had a greater impact on bitumen recovery than a gas cap of the same thickness. Gulf argued that the impact of an overlying water zone was more severe than the impact of an overlying gas cap only if the gas was not produced (i.e., only if the gas and water zones were compared at the same pressure). The APG acknowledged that the pressure of the gas cap did have some impact but stated that the thickness of the water zone had a significant influence on the performance of the SAGD process for both depleted and undepleted gas cap pressures. To maximize the performance of the SAGD process with an overlying gas or water zone, it was essential to tailor the process to the reservoir environment. The APG believed adequate time and opportunity existed to tailor field operations so that an oil sands reservoir overlain by a gas cap could be successfully exploited using SAGD even when the gas cap was depleted to a pressure as low as 400 kPa. The APG concluded that the impact of producing the gas cap in advance of producing the bitumen was likely to be small and manageable.

The APG stated that it did not have the appropriate reservoir description mechanisms to model any partial plugging effects of bitumen. It also pointed out that the model did not consider the lifting of fluids to surface; that is, no wellbore hydraulics with lifting capabilities were included in the model.

Table 14 - APG Athabasca-McMurray Model Study Results

Thief Zone Thickness (m) Gas	Water	Initial Gas Cap Pressure (kPa)	Steam Injection Pressure (kPa)	Gas Cap Confinement	Injection Strategy	Recovery (%)	CDOR (m^3/d)	Cum SOR
0	0	1 466	2 500	C[1]	T[2]	84	54.5	2.58
2.5	0	2 200	2 637	C	T	78	50.9	2.39
2.5	0	2 200	2 637	UC[1]	T	82	53.6	2.26
2.5	0	400	826	C	T	71	45.7	1.92
2.5	0	400	826	UC	T	65	41.5	2.16
10	0	1 338	1 571	C	T	72	47.3	2.58
10	0	1 338	1 571	UC	T	74	47.9	2.39
10	0	1 338	1 571	C	NT[2]	52	33.6	1.94
10	0	850	1 083	C	NT	49	31.4	1.77
10	0	850	1 083	UC	NT	65	42.6	4.61
10	0	400	827	UC	T	58	37.7	2.41
10	0	400	633	C	T	66	42.6	2.10
10	0	400	633	C	NT	46	30.2	1.65
10	0	400	633	UC	T	53	34.4	2.74
10	13	1 338	1 700	UC	NT	43	28.8	8.74
10	13	850	1 211	C	NT	21	25.9	3.25
10	13	850	1 211	UC	NT	21	26.7	4.16
10	13	400	761	C	NT	19	24.2	3.27

[1] C = confined; UC = unconfined
[2] T = tailored; NT = non-tailored

COLD LAKE-CLEARWATER MODELS

The DOE/EUB model study included an evaluation of the effect of associated gas production on the SAGD process in two Cold Lake-Clearwater reservoirs: Wolf Lake and Burnt Lake.

Wolf Lake Model Study

The reservoir characterization used in the model was obtained from technical reports and well log and core data. A summary of the model description is provided in Table 10. A top water zone was not included.

The results of the model study are summarized in Table 15. The predicted recoveries for the depleted gas cap cases were the same as or higher than those for the non-depleted gas cap cases. These results, which appear to contradict the results from the Athabasca-McMurray model, were attributed to solution gas effects present in Wolf Lake bitumen but not in Athabasca bitumen. Based on the small increase in predicted recovery, the model indicated that depletion of gas caps may not be detrimental to SAGD performance at Wolf Lake. However, the DOE/EUB cautioned that this result must be qualified by the uncertainty about the effect of solution gas and the accuracy of the model, considering that the Wolf Lake model was more complicated than the Athabasca-McMurray model and a proven model was not available. Gulf commented that the DOE/EUB's conclusion that depleting the gas cap pressure from 2 500 kPa to 650 kPa yielded essentially the same bitumen recovery ignored the fact that the calendar-day oil rate (CDOR) was reduced by almost one-half and the SOR was worse. Gulf argued that in comparing different cases, it was more appropriate to compare recovery performance (i.e., recovery, bitumen production rate, and SOR), not just recovery.

Table 15 - DOE/EUB Wolf Lake-Clearwater Model Study Results

Gas Cap Thickness (m)	Initial Reservoir Pressure (kPa)	Steam Chamber Pressure (kPa)	Recovery (%)	CDOR (m^3/d)	Cum SOR
0	2 500	2 500	57.7	93	3.55
0	650	750	64.3	52	3.89
4	2 500	2 500	59.2	91	3.49
4	650	775	61.6	51	3.93
8	2 500	2 500	58.5	93	3.29
8	650	800	58.4	52	3.86

Burnt Lake Model Study

The DOE/EUB Burnt Lake model study was a modification of the model study reported in the technical paper "Numerical Study of the SAGD Process in the Burnt Lake Oil Sands Lease"[5]. A summary of the model description is provided in Table 10. A top water zone was not included.

The results of the model study are summarized in Table 16. Bitumen recoveries decreased marginally with increasing gas cap thickness for depleted and non-depleted cases. Bitumen recoveries were approximately 6 per cent better for the depleted zero metre and 5-metre gas cap cases than for the non-depleted cases. However, the bitumen recovery for the depleted 10-metre gas cap case was poorer than that for the non-depleted case. The DOE/EUB noted that the SAGD operating pressure was not reduced as much in the Burnt Lake study as it was in the Wolf Lake study when the gas cap was depleted. This resulted in high steam losses to the gas cap and was not considered a valid operating strategy. Therefore, the DOE/EUB did not obtain definitive conclusions about the effect of gas cap depletion on SAGD performance for the Burnt Lake-Clearwater reservoir. Uncertainties about the accuracy of the model in representing Burnt Lake, particularly with respect to pressures and the influence of solution gas, limited the DOE/EUB's confidence in the validity of the predictions.

Table 16 - DOE/EUB Burnt Lake-Clearwater Model Study Results

Gas Cap Thickness (m)	Initial Reservoir Pressure (kPa)	Steam Chamber Pressure (kPa)	Recovery (%)	CDOR (m^3/d)	Cum SOR
0	3 100	3 100	75.1	74	2.88
0	600	~ 2 800	81.7	99	3.47
5	3 100	3 100	72.7	54	2.74
5	600	~ 1 000	78.4	88	4.20
10	3 100	3 100	71.3	56	2.67
10	600	1 300	65.5	84	4.73

OTHER COMMENTS ON MODEL STUDIES

Although Amoco did not present a model study, it commented that without the benefit of history matching actual field performance to validate simulations, it believed that it was imprudent to rely heavily on simulations or models in order to draw general conclusions or to formulate policies or guidelines. Amoco noted that there were very little non-proprietary field data

[5] SPE et al International Heavy Oil Symposium, June 1995

available that were of any assistance in quantifying the impact of the presence of and production from gas caps (or the presence of water zones) on bitumen recovery. Amoco also commented that, from its experience, model predictions were generally optimistic in that they overpredicted recovery rates; however, Amoco was not able to quantify the overprediction.

3.1.2 Field Experience

Two field cases of thermal bitumen operations in the presence of gas caps or top water zones were submitted.

KEARL LAKE PILOT

Gulf submitted the Kearl Lake case as an example of the effect of a top water zone on a thermal bitumen operation. The Kearl Lake pilot was conducted by Husky in the Athabasca-McMurray Formation. While the pilot was designed as a steam-drive process with central vertical injectors surrounded by vertical producers, in the later stages the process became a steam-override process through the overlying water zone. The main recovery mechanism became gravity drainage. Although the wells were vertical and the geometry of the steam chamber was different than that for SAGD, Gulf interpreted the main recovery mechanism to be quite similar to that for SAGD. The APG did not agree that the Kearl Lake pilot resembled a SAGD process, but it acknowledged that there was a gravity drainage component to the recovery mechanism of the pilot.

There was a 5-metre top water zone but no gas cap present at the Kearl Lake pilot. Gulf stated that the presence of the top water zone limited the steam zone pressure, which resulted in poor performance. Although the water zone had at least 30 per cent bitumen saturation, steam injection did not create a viable partial plugging effect. Once a confinement process was developed (which involved injecting natural gas into surrounding wells to increase the pressure from 700 kPa to 1 200 kPa), the bitumen recovery performance improved significantly. Gulf concluded that the low thief zone pressure had to be increased in order to make the SAGD-type recovery method at Kearl Lake viable. The APG stated that it believed the Kearl Lake pilot was irrelevant to the gas/bitumen issue since the pilot was not a SAGD process. However, in closing argument, the APG accepted that some extrapolations could be taken from the Kearl Lake pilot: that is, depletion of an overlying gas zone would impact SAGD operations.

COLD LAKE PRODUCTION PROJECT

Imperial submitted the Cold Lake case as an example of the effect of associated gas production on thermal bitumen recovery. Imperial's Cold Lake operation, conducted in the Clearwater Formation, is a commercial application of the CSS process and operates at steam injection pressures as high as 10 000-12 000 kPa.

Four separate gas caps overlie the bitumen zone and have thicknesses ranging from 2-5 metres. The gas caps were depleted to pressures as low as 800 kPa. The injected steam from the CSS operation entered the gas caps. Although bitumen production during the first two cycles was only one-half that expected from areas without gas caps, more normal bitumen production was observed in the third cycle. Imperial submitted that high-pressure steam injected into the bitumen zone would enter the gas caps regardless of whether or not the gas caps were produced. Imperial believed that a small amount of bitumen was swept to the gas cap and that this was effective in diverting subsequent injected steam to the bitumen interval. As a result, CSS performance improved in later cycles. Although it was still too early to assess the impact of the gas caps on final recovery, Imperial anticipated bitumen recovery levels would exceed 75 per cent of the recovery in areas without a gas cap and that production of the gas caps would not have a material effect on the final recovery estimate.

Imperial stated that its current understanding of the effect of gas caps on the CSS process was:

1. when the gas cap was less than 2 metres thick, the presence of a gas cap had little effect on CSS performance;

2. when the gas cap was 3-5 metres thick and the volume was large, the presence of a gas cap impaired the performance of the process.

3.2 Mitigation of the Effect of Associated Gas Production on Thermal Bitumen Recovery

A number of participants offered possible mitigative measures to reduce the detrimental effects of associated gas production on thermal bitumen recovery. Among these measures were: the feasibility of effectively implementing the mitigative strategies used in the model studies; the feasibility of operating SAGD at low pressures; the feasibility of repressuring a depleted gas cap; and the feasibility of using alternative technologies.

Some of the participants also commented on the possibility of establishing cut-off criteria (such as a minimum bitumen zone thickness, a minimum thief zone thickness, or a minimum reservoir pressure) to determine when production of a gas cap might be a significant concern for thermal bitumen recovery.

3.2.1 Feasibility of Implementing Mitigative Strategies Used in Model Studies

Gulf commented that the mitigative strategies used in its model study may be difficult to duplicate in the field. If they turned out to be less practical in the field than in the simulation, the actual SAGD performance would be worse than predicted.

Imperial noted that the DOE/EUB model study suggested that SAGD performed best in the presence of an unconfined gas cap when the steam chamber and the gas cap pressures were in balance. Imperial stated that to date no feasible means to achieve and then sustain this balance over multiple years in a multi-well development had been advanced. Once a means to balance the steam chamber pressure and the gas cap pressure was developed, Imperial stated that the probability of success with a thermal process would be increased if the gas cap pressure was high and not affected by depletion.

3.2.2 Feasibility of Operating SAGD at Low Pressure

Gulf submitted that no artificial lift technology had been developed to date to operate at pressures as low as 200 kPa. It specifically pointed out that a steam chamber pressure of 200 kPa was too low to allow the operation of gas lift for the depth of the McMurray Formation at Surmont. The APG noted that it was not clear from Gulf's submissions what Gulf considered to be the minimum feasible operating pressure for a gas lift system.

The APG submitted that gas lift was a feasible and attractive lift system for low-pressure SAGD operations. It estimated that the minimum operating pressure at 250 m^3/d/well was around 600 kPa. The completion configuration required to achieve a 600 kPa operating pressure would cost about $36 300 more than that required to operate down to 1 558 kPa at 250 m^3/d/well. Since the gas lift requirements at a 600 kPa operating pressure could exceed the fuel gas requirements, a closed loop gas lift system might be desirable. This system would require an additional capital cost of $630 000 for a compressor and dehydrator to circulate gas through two wells. The APG considered other alternatives to a gas lift system, including jet pumps, conventional rod pumps, and high-temperature electrical submersible pumps (ESP). It considered the ESP to be the most promising alternative but noted that it would add about $300 000 to the completion costs. Regarding the alternatives considered by the APG, Gulf argued they would all require significantly more capital and operating costs, making the economics of oil sands recovery at Surmont unattractive. They would also add an unacceptable degree of risk and would limit the operating flexibility needed to handle changing production conditions at Surmont. Gulf noted that the ESP was not proven in high-temperature applications and that even if it was technically feasible, the cost would be prohibitive. The APG agreed with Gulf that the costs and risks of operating an artificial lift system for SAGD increased significantly at pressures below 400 kPa and that it would be very difficult to operate at a pressure around 200 kPa.

3.2.3 Feasibility of Repressuring a Depleted Gas Cap

Gulf evaluated the use of five different fluids to repressure a depleted gas cap: natural gas, nitrogen, carbon dioxide, water, and flue gas. On the basis of a comparison of the advantages and disadvantages of using each fluid, Gulf concluded only natural gas, nitrogen, and carbon dioxide were technically realistic options, with natural gas being the most attractive option. However, Gulf argued that it was impractical and illogical to produce the gas cap, repressure it with natural gas, produce the bitumen, and then produce the gas cap again. Gulf submitted that all the repressuring options had a significant negative impact on the economics of a SAGD project. Also, the geomechanical effects (reduction in porosity and permeability) that could occur when the reservoir pressure was reduced, as well as the dissolution of solution gas (with the resulting increase in bitumen viscosity and relative permeability effects), might not be reversible with repressuring. Gulf acknowledged that solution gas volumes were generally small in bitumen deposits, but it believed solution gas did contribute to the reservoir drive, such as at Peace River. Finally, Gulf questioned whether an oil sands operator could inject a fluid into a zone for which it did not have the lease rights and raised the question of who would own the injected natural gas.

Petro-Canada stated that it would be very difficult to repressure with natural gas and expect the gas to saturate the bitumen to the initial level, if at all. In its view, if the reservoir was depleted and then repressured, there was no guarantee the reservoir would be restored to its original conditions.

The APG believed that it was feasible to repressure a depleted gas cap to minimize any detrimental effect of reduced pressure on bitumen recovery. It argued that there was a difference between conventional oil and bitumen with respect to the feasibility of repressuring a depleted gas cap. In conventional oil, the dissolution of solution gas causes a large reduction in the relative permeability to oil, which impedes the flow of oil, and this effect is irreversible. In the case of bitumen, there is only a minor decrease in the relative permeability to bitumen and a minor increase in bitumen viscosity. Therefore, the APG believed that it was feasible to repressure a depleted gas cap in the case of bitumen. The APG also submitted that purchasing and injecting natural gas to repressure a depleted gas cap was more economic than installing and operating artificial lift facilities as a form of mitigation.

Amoco stated that it was producing associated gas at its Wolf Lake project but believed that, if necessary, it was feasible to repressure the gas cap. Amoco argued that the gas cap at Wolf Lake, which was about 5 metres thick and covered an area of about seven sections, was well contained and not like the large regions of influence referred to in the Surmont area. Amoco indicated that if it was to repressure the gas cap at Wolf Lake, it would potentially repressure with flue gas. Amoco was not inclined to repressure with water, because the water could act as a heat thief due to its high heat capacity. While Amoco speculated that there should not be a technical problem with repressuring a gas cap, it acknowledged that there could be effects it may not be aware of. It noted that the oil sands had probably been pressured and depressured a number of times over the history of their existence. Amoco believed that solution gas played a very small role in a thermal bitumen recovery process.

Imperial submitted that it planned to inject water into the depleted gas caps at its Cold Lake CSS operation in order to reduce the amount of injected steam that would enter the gas caps during steam stimulation. Gulf speculated that water injection might be appropriate at Imperial's Cold Lake operation but not at Gulf's planned Surmont project, because the gas cap was much thinner at Cold Lake; the permeability of the gas cap was lower, so that the injected water would not drain down into the steam zone; and the thermal processes to be used were different (CSS versus SAGD).

3.2.4 Feasibility of Using Alternative Technology

Gulf stated that as steam or other solvents tend to rise in the reservoir due to the laws of physics, natural forces must be overcome to develop a recovery technology that would offset low thief zone pressures. At the time, no known technology was available or was even being developed that would offset the effect of lower thief zone pressures. Gulf concluded that it was unlikely that technology would be able to offset the negative impact of reduced reservoir pressure.

The APG noted that, considering the time frame when commercial SAGD projects may be developed, if they proved to be successful, new artificial lift methods for operating at low pressures may be developed and that several alternatives to gas lift were already in the field test stage of development. The APG also stated that, considering the relatively recent evolution of horizontal well technology in the SAGD process, it appeared likely that additional technological developments would occur and that some of these advancements would be of the kind that would make it more effective to recover bitumen underlying a gas cap without the conflict that exists today. Other methods of reducing bitumen viscosity, such as solvents and electrical or radio frequency heating, may be refined to the point of commercial applicability within a reasonable time frame.

Amoco commented that artificial lift was probably one of the areas of technology that could be relied on to improve in the future. It also raised the possibility of using non-thermal processes, such as the Vapor Extraction (VAPEX) process, and noted that a lower pressure was advantageous to such a process since it operated at the dew point pressure of the solvent. Amoco estimated a propane-based VAPEX process could require an operating pressure of 600-700 kPa.

3.2.5 Cut-off Criteria

Gulf maintained that for a good-quality bitumen zone, SAGD might be feasible in a bitumen zone as thin as 10 metres, even if a gas cap was present, but only if it was not depleted. If a top water zone was also present, the minimum bitumen zone thickness would need to be greater than 10 metres. Gulf did not indicate how much greater the thickness would have to be to implement an effective commercial project. It qualified these comments by saying that the minimum required bitumen zone thickness would be somewhat site specific. The minimum cut-off would also be influenced by the extent of the thief zone and the risk of impacting a neighbouring bitumen area in the event the gas cap was produced in advance of the bitumen. Gulf recognized that technological developments might make it possible to develop thinner bitumen zones in the future. Hence, a minimum bitumen zone thickness cut-off was very much technology specific.

Gulf commented that if no top water zone were present, there might be a minimum gas cap thickness of about one metre where bitumen plugging effects might make the detrimental effects of gas cap production on SAGD quite small. However, establishing such a cut-off would require further study.

Gulf commented that its model study indicated there was a reduction in bitumen recovery when the gas cap pressure was reduced from the native pressure of 1 340 kPa to an intermediate pressure of 800 kPa. Gulf pointed out that there was still some question of how the actual performance of a SAGD operation at 800 kPa would compare to that predicted by the model study, although its Surmont pilot should provide some further insight on this matter. However, Gulf noted that the reduction in bitumen recovery due to gas cap production would depend on the specific reservoir situation.

The APG believed that "associated gas" in the context of an assessment of bitumen exploitable by SAGD should not include a gas zone that overlies a bitumen zone with an average pay of less than 15 metres. However, the APG commented that the single-well SAGD process could provide access to thinner bitumen zones than those suitable for SAGD. The APG also believed that associated gas should not include a gas zone that overlies a significant water zone that, in turn, overlies a bitumen zone, since the water zone would likely preclude commercial bitumen development, regardless of the stage of depletion of the gas zone.

Amoco stated that at this point in the evolution of the industry, it did not believe it was possible to develop cut-off criteria. Amoco believed the gas/bitumen issue had to be looked at on a site-specific basis.

3.3 Effect of Associated Gas Production on Primary Bitumen Recovery

Gulf stated that conservation of reservoir energy, in order to avoid waste, has dictated that oil be produced before gas and that orderly development is equally valid when applied to the circumstance of concurrent production of overlying gas reservoirs which may adversely affect the recovery of the bitumen resources. Gulf submitted that the sequence of producing associated gas after the oil may be even more relevant to heavy oil developments and primary bitumen projects than to thermal bitumen projects.

The APG did not address the effects that associated gas production may have on primary bitumen recovery. However, it acknowledged that primary bitumen production in the Lindbergh area has similarities to conventional oil production and that a reduction in relative permeability due to solution gas evolution is a significant factor in conventional oil production.

Amoco acknowledged that it held some large oil sands leases in the Lindbergh and Elk Point areas and that the majority of the bitumen production in these areas was due to primary depletion. Amoco further acknowledged that it did not hold the P&NG rights in these areas and, consequently, in cases where bitumen was associated with gas, bitumen production was restricted to ensure the associated gas was not produced with the bitumen. As a result, bitumen resources were lost in some cases.

Amoco indicated that primary bitumen recovery is a function of "foamy oil" and "worm-hole" mechanisms. Amoco described the foamy oil concept as being a phenomenon where solution gas is retained within the bitumen. This differs from a conventional oil reservoir where at the bubble point the gas comes out of solution and can form a separate phase. In the foamy oil situation, the major issue is getting the bitumen to the wellbore. This is usually accomplished through the creation of worm holes in the reservoir by way of sand production. Amoco pointed out that in some cases associated gas production would have no detrimental effect on bitumen recovery. An example of this would be a high-viscosity bitumen that has no primary production potential and is contained in a reservoir that is too thin for a gravity drainage process.

Husky submitted that in areas subject to cold production, the depletion of reservoir energy can clearly be demonstrated to impact oil recovery. Alternatively, in areas with true bituminous crude, production of associated gas will have a minimal effect on ultimate bitumen recovery.

3.4 Effect of Thermal Bitumen Processes on Associated Gas Recovery

3.4.1 Contamination

Laboratory experimentation and field testing have demonstrated that appreciable amounts of gaseous contaminants such as hydrogen sulphide and carbon dioxide are generated as a result of thermal bitumen recovery processes. The related chemical reaction in the bitumen is referred to as aquathermolysis, which means to break down by heat and water. Given that SAGD bitumen production involves the creation of a high-temperature steam chamber within the bitumen zone, it is arguable that acidic off-gases (i.e., hydrogen sulphide, carbon dioxide) would be generated. This conclusion is supported by reports from the UTF indicating that the average hydrogen sulphide concentration in the SAGD produced gas is in the order of 6 000 parts per million.

Aquathermolysis is a temperature-dependent process. As the temperature increases, the rate at which aquathermolysis reactions occur also increases. The amount of carbon dioxide generated as a result of steaming an oil sands zone can be considerably greater than the amount of hydrogen sulphide generated, since in addition to the carbon dioxide generated from aquathermolysis, the carbonate in the oil sands itself releases substantial quantities of carbon dioxide. In contrast, virtually all of the hydrogen sulphide is generated from aquathermolysis. Therefore, the chemical composition of the bitumen should provide an indication of how much hydrogen sulphide is likely to be generated.

The APG submitted that acid gases generated during SAGD bitumen operations could migrate into overlying gas caps and contaminate the existing sweet gas to the extent that it would require processing before it could be marketed. In contrast, Gulf offered the view that the acid gases generated at its proposed SAGD project are likely to be confined to that scheme, making the probability of contamination of the overlying gas cap remote. Amoco stated that contamination of overlying gas caps due to thermal bitumen recovery operations has not been demonstrated, although it acknowledged that the potential for such an occurrence does exist.

The APG contended that a region of high-saturation, non-condensible gases would form at the top of the steam zone as a result of aquathermolysis. Therefore, if the bitumen zone is in direct contact with the gas cap, the release of these gases into the gas cap at breakthrough of the steam chamber would be virtually immediate, since this gas would be at a higher pressure than the overlying gas cap. In situations where there is an intermediate water zone between the bitumen and gas zones, the water zone would act as a buffer slowing down the release of these gases into the gas cap. The APG indicated that a precise quantification of the degree to which the intervening water zone may affect the kinetics is not possible, although it is expected that the overlying gas cap would eventually be contaminated within the productive lifetime of a SAGD operation. The APG argued that even after breakthrough, the off-gases being generated by further steaming of the oil sands zone would continue to diffuse upward and into the gas cap. Furthermore, fingering of acid gases from the steam chamber to the gas cap may occur even before the bulk of the steam chamber has broken through into the gas cap.

Gulf contended that little non-condensible gas would build up in the steam zone or be allowed to enter the producing wellbore, since SAGD operations are conducted in such a manner that control of pressure differentials prevents free gas from entering the producing wellbore. In support of its position, Gulf argued that a region of high-saturation, non-condensible gases has not formed at the top of the steam zone at the UTF SAGD operation and that all off-gases have been produced via dissolution in water. Furthermore, Gulf stated that the steam zone would not allow significant acid gas leak-off before breakthrough of the steam chamber because of hot bitumen plugging, and that if the off-gases are retained in the water, fingering of acid gas into an overlying gas cap is unlikely in any event.

The APG countered that there is no concrete evidence available from the UTF site to support the Gulf position. However, it did acknowledge that a large portion of the acid gases generated by aquathermolysis would be produced in the water stream.

Gulf argued that aquathermolysis occurs mainly above 200-300°C, and that below this range the reactions involved are too slow to be significant in generating acid gas. Gulf pointed out that its proposed SAGD project is expected to have a steam zone temperature of 240°C during the initial phase, but only 175°C thereafter. Therefore, given that the steam zone does not contact the gas cap during this initial phase, almost all the hydrogen sulphide generated would be produced in the water stream. This is because aquathermolysis would cease and the constant replenishment of pore space water would ensure almost total production of the off-gases in the water stream. In contrast, the APG submitted that aquathermolysis reactions may be significant below 200°C with regard to the generation of sufficient acid gases to contaminate an overlying gas cap.

Gulf submitted that bitumen operators should be responsible for rectifying or cleaning up any gas cap contamination that may be caused by thermal bitumen operations and that it would be prepared to make such a commitment with respect to its thermal bitumen operations. The APG stated that it would be satisfied with a commitment from a bitumen operator that it would rectify or clean up any gas cap contamination that resulted from thermal bitumen recovery operations.

However, the APG pointed out that, as a policy issue, it is not recommending that a bitumen owner compensate a gas owner for any changes in the composition of associated gas.

3.4.2 Pressure Depletion

The APG submitted that during SAGD bitumen production, the steam chamber pressure would be maintained by steam injection. However, once steam injection ceased, the pressure would begin to fall gradually with the continued withdrawal of fluids. Eventually the reservoir would cool enough to cause the steam to condense, at which time the pressure in the SAGD chamber would begin to decline dramatically (i.e., the steam chamber would collapse). As the pressure within the collapsing steam chamber declined, the gas cap reservoir pressure would decline in tandem. Accordingly, the gas cap recovery factor would also decline.

On a theoretical basis, Gulf acknowledged that the concerns of the APG are valid. However, on a practical basis, Gulf argued that the impact of prior SAGD bitumen production on subsequent gas production would be relatively minor. That is, the collapse of the steam chamber at the end of SAGD production, and the subsequent pressure drop in the gas cap, would impact gas recovery to a far lesser extent than reduced pressure would impact bitumen recovery.

Gulf contended that this impact would be mitigated if the depleted steam chamber were used for water disposal, which is its current plan at Surmont. Gulf estimated that up to 5 per cent of the produced water from its proposed SAGD pilot project would not be recyclable and that it would need to be disposed. Gulf stated that it had not done the detailed calculations necessary to determine if enough excess water from its proposed steam generation plant would be available to fill up collapsing steam chambers. However, it indicated that one of the short-term goals of its pilot project would be to get a better understanding of the water-processing facilities that might be needed for a commercial SAGD operation. Furthermore, Gulf stated that it would be reasonable for the Board to require that the reservoir pressure be maintained once a steam chamber begins to collapse, although it submitted that fluids other than water could be used for achieving this objective.

On a theoretical basis, the APG agreed that injection of water into a collapsing steam chamber would maintain pressure in the reservoir, thereby mitigating gas recovery losses. Amoco also agreed that injection of water into a collapsing steam chamber to maintain reservoir pressure is technically feasible. However, Amoco questioned whether this is a practical option given potential economic constraints (i.e., value of the recoverable gas versus the cost of maintaining the reservoir pressure).

3.4.3 Water Influx

The APG submitted that if a SAGD project is initiated under a gas-over-water-over-bitumen producing gas pool, gas recovery could be detrimentally impacted once communication between the steam chamber and water zone is established. When a steam chamber establishes contact with an overlying water zone, the steam chamber pressure is reduced but kept above the pressure of the water zone to prevent flow from the water zone into the steam chamber. Consequently, steam would flow into the water zone and condense. The water zone thus would become active in the hydrodynamic sense, which could result in a SAGD-induced water flood, causing premature watering-out of gas wells and/or portions of the gas cap becoming isolated.

Gulf contended that in order to maintain economic SAGD bitumen production, the pressure differential between the steam chamber and overlying thief zone would have to be minimized (i.e., less than 100 kPa) to avoid steam losses. Therefore, the potential for the watering-out of the gas cap would be eliminated. Gulf stated that to ensure that such a small pressure differential is maintained over the life of a commercial SAGD operation, the produced water/steam ratio and the steam/oil ratio would be monitored.

3.4.4 Geomechanical Effects

The APG submitted that when an oil sands reservoir is subjected to pressure or temperature changes, stress changes and deformations occur within it. Therefore, wellbore and general gas cap seal integrity may be compromised by the dilation heave and subsidence caused by SAGD operations.

Gulf submitted that SAGD operations employ continuous low pressures well below reservoir fracture pressure. Therefore, wellbore and general gas cap seal integrity would not be compromised.

4. ECONOMICS

4.1 Economic Impact of Depleted Gas Cap on SAGD Performance

Gulf submitted that associated gas production at its Surmont leases would reduce reservoir pressure to such an extent that there would be a significant impact on the economics of bitumen production. Gulf evaluated the effect of pressure declines on project cash flow under a variety of production scenarios, all of which showed a negative effect on cash flow in excess of 50 per cent when gas is produced in advance of bitumen. Specifically, Gulf's simulation analyses of a pressure decline from 1 340 kPa to 200 kPa for its pilot, primary, and secondary projects resulted in a drop in cash flow of $177 million, $103 million, and $229 million respectively. The results of the simulation showed that the levelized bitumen production cost increased by about $2 per barrel (bbl). Cumulative gas recovery was expected to be about the same in all cases, albeit with a different production time frame.

Gulf concluded that changes in reservoir pressure would be a significant factor in the commercial viability of bitumen production from an overall Alberta perspective. A negative impact would be noticeable after reservoir pressure declined to below 800 kPa. However, if associated gas were produced to an abandonment pressure of about 200 kPa, SAGD recovery performance would fall significantly and would likely be uneconomic, especially if added technical risks are taken into account.

Petro-Canada submitted that economic recovery of bitumen by SAGD is unlikely in areas where bitumen is in contact with partially or completely depleted gas caps.

In contrast, the APG argued that the economic impact of a depleted gas cap on SAGD recovery performance would likely be relatively small. It suggested that the mere presence of a top water zone and/or gas cap impacts the performance of a SAGD process more so than the pressure of these zones. To illustrate this statement, the APG ran several economic scenarios representing depleted gas cap pressure conditions, as summarized in Table 17.

Table 17 - Cash Flow of Bitumen Production Under Depleted Gas Cap Conditions

	Case 19	Case 8A	Case 9A	Case 24C	Case 16B	Case 26	Case 27A
Gas Zone (m)	10	10	10	10	10	2.5	2.5
Water Zone (m)	13	13	-	-	-	-	-
Bitumen Zone (m)	30	30	30	30	30	30	30
Pressure (kPa)	400	400	400	400	400	400	400
Confined	yes	no	no	no	yes	no	yes
Net Cash Flow ($/bbl) (Discounted at 15%)	0.67	0.61	0.66	1.04	0.74	1.15	1.16

The best economic results using a SAGD process with depleted gas cap pressure occurred in a reservoir with a thin gas cap and no water zone (cases 27A and 26). The discounted net cash flow amounts to about $1.16/bbl in the case of a thin gas cap (case 27A), compared to about $0.74/bbl in the case of a thick gas cap (case 16B). This evidence supported the APG contention that bitumen zones with thick gas caps are likely to be less attractive to bitumen operators and, therefore, need not be accorded special regulatory treatment.

Furthermore, the APG expressed optimism that the application of existing and future technology would overcome any detrimental effects that might occur as a result of pressure depletion. One alternative would be to repressure the reservoirs, at an estimated cost of $100 000 per SAGD well pair. Rather than penalize gas producers in the near term for the sake of bitumen projects that have not yet been identified, the APG urged the Board to consider one of the following approaches:

- require bitumen producers to purchase undepleted gas caps if it is believed that pressure depletion would jeopardize bitumen development (a 10-metre gas cap would cost about $45 000 per SAGD well pair);

- rely on alternative technology, such as repressuring a depleted gas cap, to overcome any detrimental effects that might result from pressure depletion; or

- accept that, in the context of Alberta's total bitumen resources position, the conservation losses from operating at a lower pressure in a few areas would likely be small.

The DOE/EUB study examined the economics of a prototype SAGD bitumen project producing 4 770 m^3/d. The calculated supply cost reflected a levelized cost per barrel before taxes and royalties at a discount rate of 10 per cent. The results indicated:

- general agreement with Gulf's analysis that depletion of thick gas caps in the Athabasca-McMurray Formation may result in a loss of bitumen recovery of about 10 per cent and an increase in bitumen production costs of up to $1.50/bbl;

- in the Cold Lake-Clearwater Formation at Wolf Lake, bitumen production costs are expected to be consistently lower in reservoirs where the gas caps are not depleted;

- the difference in bitumen production costs for depleted and non-depleted reservoir pressures increases from $0.03/bbl (4-metre gas cap) to $0.18/bbl (8-metre gas cap);

- the relatively small differences in bitumen production costs at Wolf Lake, offset by some improvement in bitumen recovery, suggest that depletion of gas caps at Wolf Lake may not be as detrimental to SAGD performance as in the Athabasca-McMurray Formation, although there were no data to verify this opinion; and

- model uncertainties, due to a lack of field data, prevented the authors from reaching strong conclusions about the effect of gas cap depletion on SAGD performance in the Cold Lake-Clearwater Formation at Burnt Lake.

4.2 Economic Impact of Deferring Gas Cap Depletion

Gulf argued that the economic gains from maintaining reservoir pressure for bitumen recovery more than offset the economic losses from deferring gas production. Gulf also offered the view that deferring gas production in an area such as Surmont would be strictly a regional impact and would not affect Alberta's total gas supply, since additional gas production would be forthcoming from other parts of the province.

The APG suggested that it is not necessary to defer gas production to produce bitumen, since the economics for bitumen production are not improved significantly. Furthermore, the APG expressed the following concerns:

- contamination of associated gas due to thermal bitumen recovery would necessitate the replacement of gathering and processing facilities, jeopardizing the economics of gas recovery in the oil sands areas;
- production of bitumen resources using the SAGD process could potentially sterilize the gas resource in the oil sands areas; and
- dramatic reservoir pressure decline at the end of SAGD bitumen production would have a negative impact on gas recovery.

On the basis of numerical simulation, Petro-Canada concluded the following:

- economic recovery of bitumen using the SAGD process would be possible in the presence of a gas cap; and
- reducing the gas cap pressure could render the use of the SAGD process uneconomic.

4.3 Short-Term Delay in Gas Production at Surmont

Gulf submitted that gas production in the Surmont area should be delayed for a period of 2-3 years to determine the optimal method of developing the entire hydrocarbon resource at Surmont. Gulf stated that a short-term delay of gas production would be justifiable, because postponed revenues from gas production would be more than offset by the revenues from bitumen production. Gulf submitted that such a short-term delay could increase Alberta's net social benefit by $12 million in the pilot area, $56 million in the primary commercial target area, and $170 million in the secondary commercial target area. On the basis of these results, Gulf concluded that the additional information obtained during a delay in gas production would allow for production of bitumen at lower costs with optimal recovery.

5. POLICY

5.1 Views of Gulf

Gulf submitted that the technical and economic evidence at the inquiry supports the development of a policy to govern concurrent production of bitumen and gas, similar to the existing regulations for conventional oil and gas. As noted, section 29 of the OGCA reads:

> No well may be produced as a gas well from a pool which, in the opinion of the Board, is or could be commercially productive of oil except in accordance with a scheme for concurrent production of the pool approved under section 26, or in some other manner approved by the Board as not detrimental to the recovery of hydrocarbons from the pool.

Gulf stated that this requirement incorporates factors of commercial productivity and the obligation to conserve hydrocarbons by ensuring their recovery would not be harmed. It urged the Board to consider these factors in developing a policy governing the concurrent production of bitumen and gas.

As part of its submission, Gulf set out a recommended policy that is included as Appendix C of this report. In brief, Gulf submitted that a policy should:

- allow for the consideration of the issues of bitumen and gas production largely on a case-by-case basis;

- create obligations on the part of the gas producer wanting to commence or expand gas production to establish that the gas production would not take place at the risk of bitumen recovery;

- place the onus on the bitumen producer to demonstrate its commitment to development of that resource where there is existing gas production in hydraulic communication with bitumen; and

- subject the bitumen producer to ongoing monitoring to ensure that the commitment continues and sufficient progress is being made.

Gulf asserted that combining the oil sands and associated gas rights would allow the common owner to establish its own priorities with respect to gas and/or bitumen production, which would minimize the potential for future conflicts. However, Gulf acknowledged that changing the lease tenure rules so that oil sands and P&NG rights are combined is only one avenue to achieving common ownership. Furthermore, Gulf acknowledged that it would be difficult to determine whether the gas is associated with bitumen before the lands are actually leased and drilled. To address this issue, Gulf submitted that the rights would only be combined in areas where there was a high probability that the gas is associated with bitumen. With respect to establishing areas with a high probability of conflict, Gulf stated that it would be more appropriate to deal with that issue through the DOE. Gulf acknowledged that an alternative approach to address the issue of lease retention would be to revise the lease tenure rules so that the expiry dates for oil sands and P&NG leases would coincide.

Gulf maintained that during the period in which gas production may be shut in, the licensee would continue to be responsible for the well facilities and any maintenance that might be required. However, Gulf stated that if a well is going to be shut-in for a long period of time, then the bitumen producer's development plan would have to address this with respect to compensation. Furthermore, Gulf indicated that, if appropriate, costs incidental to the shutting-in of gas (e.g., gas plant, fixed transportation charges, sales contracts) would also need to be addressed with respect to compensation. Gulf submitted that the issues of whether compensation would be warranted, how much, and who pays would have to be addressed on a site-specific basis, although it indicated that it would be more appropriate to deal with these issues through the DOE.

In response to questioning, Gulf maintained that if a gas producer plans to do some drilling or additional work in an area, then the onus would fall on the gas producer to determine whether gas is associated with bitumen. Similarly, if a bitumen producer planned to develop a particular lease or area, then the onus would fall on the bitumen producer to determine if the bitumen is associated with gas. Furthermore, Gulf pointed out that, although not explicitly stated in its recommended policy, a bitumen producer should also be required to demonstrate that bitumen production would not be detrimental to gas recovery.

Gulf stated that it would support a requirement for notification and consent of gas rights' holders prior to bitumen development, and vice versa. Furthermore, Gulf stated that it would also support notifying offset leaseholders if they are considered to be affected parties.

5.2 Views of the APG

The APG submitted that where a commercial bitumen project is found to underlie an associated gas pool, normal business economics should prevail and the priority of production should be determined on the basis of economics as determined by the parties impacted, with the EUB acting as mediator if and when required. That is, each party has an economic position with respect to the rights that it owns, and after coming to a common resolution, they would all be in more or less the same position through additional property or perhaps the exchange of money. The APG stated that this process should occur on a project or site-specific basis and allow for the more economically viable bitumen project to acquire the less economic gas project, or vice versa. The APG contended that under this scenario, the more economic project would proceed and parties would be protected for their substantial risk taking and investment. It submitted that changing the current policy, which has existed for over 20 years and has fostered considerable gas development, would undermine investor confidence and have serious economic and legal implications. In that regard, the APG contended that Gulf's recommended policy would not offer a reasonable degree of certainty either to gas or bitumen producers, since it would remove from their control the ability to make economic choices.

To maintain a balance between gas and bitumen development and conservation, the APG suggested the following factors should apply in the future:

- There should be no constraints on gas production except those imposed by the market or by the owners of those resources.

- The EUB should not adopt an economic test that would result in the shut-in of gas production.

- The EUB should adjudicate in the event of a conflict between gas and bitumen when the owners cannot resolve it themselves.

- If there is to be compensation to a gas producer resulting from a conflict with a bitumen developer, that compensation should come from the bitumen developer.

- Any adopted solution must respect property rights and the rights of the owners to use their property.

Furthermore, the APG submitted that associated gas, in the context of an assessment of SAGD-exploitable bitumen, should be characterized as a gas layer over a bitumen zone but should not include:

- a gas layer over a bitumen zone that has an average pay of fewer than 15 metres,

- a gas layer over an effective shale barrier over a bitumen zone, or

- a gas layer over a significant water layer over a bitumen zone.

The APG submitted that where gas and bitumen are in conflict, common ownership would resolve the issue. Furthermore, it contended that in situations where the parties involved are unable to achieve common ownership through negotiations, the EUB should be provided with the legislated authority to ensure that outcome. However, the APG argued that combining the P&NG and oil sands rights at the leasing stage as a solution to the problem would be problematic and would only, by coincidence, resolve the issue between gas and bitumen development. The APG submitted that the lateral extent of the resource base in question would always be subject to some debate and that it would be a coincidence if future oil sands leases were able to keep within their boundaries all the regions of potential conflict. Therefore, the mere combining of the P&NG and oil sands rights would, at best, mitigate some conflict but not eliminate all conflict. The APG asserted that the combined rights would serve as a solution to the conflict only if the oil sands leases were large enough and the bitumen projects were to occur far enough away from the lease boundaries. Furthermore, combining the P&NG and oil sands rights would also have the effect of sterilizing future potential gas production by smothering development with a blanket-lease approach, which may not be necessary for resource conservation. As a result, the substantial benefits the province has realized through bonus payments, royalty payments, and taxes from gas exploration, development, and production would be significantly reduced. The APG recommended the removal of the addendum currently placed on P&NG licences and leases that states: "approval for the drilling for natural gas in the oil sands zones, identified within the EUB's oil sands designation areas, is currently subject to regulatory review by the EUB and may not be granted."

The APG asserted that bitumen owners are not entitled to any compensation for reduced bitumen recovery resulting from historical associated gas production, since SAGD technology did not exist in the past. Furthermore, it submitted that it does not support the concept of shutting in gas or bitumen to maintain the status quo while a matter is under adjudication, because if a bitumen developer asked for gas production to be shut in, all of the detrimental effects would fall on the gas producer. With respect to the impact continued gas production would have on bitumen recovery, the APG argued that continued gas production over such a short period of time (i.e., while the matter is before the EUB) would not materially affect bitumen recovery. In any event, the APG submitted that it does not believe the EUB currently has the authority to shut in a gas well in the event of a conflict between gas and bitumen resources.

The APG stated that, in the future, potentially impacted gas owners should be notified of proposed bitumen projects. Similarly, it stated that potentially impacted bitumen owners should be notified of applications for gas processing plants, compressor stations, and gathering systems. The APG contended that an adequate mechanism already exists for notification of individual wells through the EUB's publication of well licences on a daily basis.

In response to questioning, the APG withdrew from its submission the recommendation stating that “Thermal recovery projects in a bitumen zone that may negatively impact on an overlying gas zone should be allowed to proceed only if the bitumen developer has acquired the rights to the gas pool that may be negatively impacted.”

5.3 Views of Amoco

Amoco submitted that it would be difficult, if not impossible, to draft guidelines or policies or to establish procedures of a general nature that would be of much assistance. Amoco maintained that the EUB's existing regulatory process and procedures provide the best means for resolving issues surrounding gas and bitumen production.

Amoco contended that, if at all possible, gas and bitumen conflicts should be avoided. In unleased portions of the oil sands areas and in areas where the oil sands rights have been leased but the P&NG rights have not, this can be accomplished by recombining the P&NG and oil sands rights. Amoco indicated that this recommendation is based on the assumption that a single owner would attempt to maximize the value of the total resource under lease. However, Amoco acknowledged that conservation issues may need to be monitored by the EUB through the application process to ensure that commercially exploitable bitumen reserves are not adversely affected or treated as expendable.

Amoco stated that in areas where established production exists, gas and bitumen operators should be allowed to continue producing unless it can be clearly demonstrated that such production contravenes the EUB's conservation mandate. In areas of existing conflict, Amoco contended that negotiated solutions should be pursued. Furthermore, consideration for co-development options should be encouraged to allow for the production of both resources in a manner which would maximize the total resource.

5.4 Views of Petro-Canada

Petro-Canada submitted that the EUB has the legal authority and responsibility to prevent waste of the bitumen resource and, therefore, should adopt its historical approach to conservation issues in conventional oil pools to the oil sands areas. Furthermore, Petro-Canada contended that because of changing circumstances for each reservoir, bitumen and gas conflicts should be handled on a reservoir or site-specific basis. Similarly, due to the variables that affect production, including the price of oil and gas and the level of technical recovery, the EUB should not adopt the APG's recommendation of an arbitrary 15-metre bitumen pay threshold for the definition of associated gas. Instead, the EUB should include bitumen as part of its definition of crude oil for the purpose of defining associated gas in this situation.

Petro-Canada described a complaint and review process that it believed would promote efficient recovery on an equitable basis from both bitumen and gas reservoirs. Petro-Canada contended that this would not differ significantly from the EUB's current processes and would focus on site-specific problems. This process would consist of the following:

- Where correlative gas and bitumen interests exist, the EUB should require gas and bitumen interest owners to notify the other owner of any intention to drill or produce their resource, in order to promote early resolution of any potential conflict. This notice should be a mandatory prerequisite to the well-licensing procedure, with the purpose of determining whether a conflict actually exists. If a conflict does exist, then the objective of the notification would be to promote discussion between the parties concerning the issues of orderly and efficient recovery with the aim of finding accommodation for the interests of both parties.

- Where a site-specific conflict between gas and bitumen production occurs, affected parties would first attempt to reach a resolution on their own with a view to determining a mutually agreed-upon development strategy.

- Failing such agreement, and upon receiving a complaint from either a gas or bitumen owner supported by a technical submission outlining the impact that the proposed development activity would have on the correlative resource, the EUB would suspend production and convene a hearing.

- In an effort to reduce the potential for such conflicts, the P&NG and oil sands rights should be combined in the future.

Petro-Canada argued that the above approach would identify potential concerns at an early stage, promote flexible solutions between the affected parties, avoid arbitrary thresholds, and prevent unfairness by permitting an objective hearing, if one were required.

5.5 Views of Other Participants

CanOxy submitted that the Board must be mindful of its mandate to effect the conservation of and prevent the waste of Alberta's energy resources. Therefore, notwithstanding cases where common ownership of gas and bitumen exist, the Board must ensure that development occurs in such a manner as to maximize the recovery of both resources. If the Board sees merit in allowing a bitumen project to proceed to the detriment of gas recovery, the Board must take into account the economic impact of doing so. On the matter of compensation, CanOxy argued that if the gas is owned by a party other than the bitumen owner, the bitumen owner should compensate the gas owner for its lost opportunity. CanOxy further submitted that the Board should assess each situation on a case-by-case basis.

AEC submitted that the existing tenure provisions are generally satisfactory to provide for the development of both the gas and bitumen resources and that the potential for conflict would be relatively small, given the small size of oil sands areas with overlying gas. AEC indicated that disputes should be resolved privately between the parties, and that if this was not possible, a mechanism should be established that allows the oil sands leaseholder to acquire the P&NG rights on a site-specific basis, provided the oil sands leaseholder has a bonafide project and the P&NG leaseholder is fully compensated. Furthermore, AEC submitted that it is not in support of the recent blanket policy where an addendum is added to P&NG sale parcels on a non-site-specific basis, because this creates uncertainty about whether future drilling for gas will be allowed. The current consultative process for approval of oil sands projects whereby applicants must demonstrate that reasonable efforts to contact the affected parties were made is adequate.

Husky submitted that all future oil sands lease dispositions should include the P&NG rights since the optimum recovery of both resources would be best served by one operator. If desired, the P&NG rights holder could apply to the EUB to produce the associated gas, conditional on it being able to demonstrate that doing so would have a minimal impact on bitumen recovery. Furthermore, Husky submitted that the EUB should provide guidelines that include reservoir properties and processes to ensure maximum recovery of bitumen and gas using existing recovery techniques. Given the different processes involved, Husky indicated that it did not believe that there is a single resolution to this issue and that the impact of associated gas production on bitumen recovery in these situations can range from a potential improvement in recovery to a significant detriment. Husky indicated that the EUB should encourage existing mixed leaseholders to develop mutual exploitation plans. However, in the event that mixed leaseholders are unable to come to an agreement, the EUB should adjudicate a solution based upon written application and a hearing, if necessary. Husky submitted that implementation of processes used in conventional areas to resolve issues and disputes would provide an acceptable basis for dealing with the disputes related to associated gas and bitumen production.

Imperial submitted that the P&NG and oil sands rights for a given zone should be recombined for all new leases, since single-owner exploitation would better ensure that conservation of both resources is considered. Imperial indicated that, where P&NG and oil sands rights are held separately, individual solutions would be required to recognize differences in development timing, recovery process and specific reservoir properties, and the available mitigative measures. Furthermore, Imperial submitted that, at the very least, provision should be made to ensure that pressure maintenance of gas caps would be an option.

Numac submitted that to avoid future problems arising from split rights holders, P&NG rights should be combined with oil sands rights where no development has taken place. Furthermore, Numac submitted that if gas is determined to be in pressure communication with bitumen and is continuous over the area of development, the Crown should intervene to determine the production priority of each resource.

Camberly submitted that the EUB should identify certain specific areas where bitumen production appears to be feasible in the short to medium term, and that within these areas bitumen development would take precedence over gas exploration and development. In the remaining oil sands areas, gas exploration and development should be allowed to proceed without restriction.

Suncor submitted that the gas producer should be required to submit a study prior to the approval of any new development of gas overlying bitumen showing that the gas production would not negatively impact on bitumen production.

Nova Gas Transmission Ltd. submitted that the extent to which its facilities may be affected by a shut-in order is unknown at this time. However, a loss of transportation services in the affected areas as a result of a shut-in order would lead to a reallocation of the revenue requirement.

6. VIEWS OF THE BOARD

The Board notes that the application of thermal bitumen processes, such as SAGD, presently offers the greatest promise for the eventual development of Alberta's in situ oil sands resources. The Board also recognizes that a critical factor for the successful application of such processes is the reservoir pressure. Accordingly, the Board believes that it is important to consider and understand the issues raised at the inquiry as part of its conservation mandate. The Board appreciates the assistance provided by the inquiry participants to further our knowledge in this area.

6.1 Extent of Affected Reserves

The Board appreciates the regional statistical review provided by the APG regarding the potential conflict of gas and bitumen production in the oil sands areas. However, the Board is concerned with the limitations of the EUB database upon which the APG based its study. Specifically, the Board is concerned that the database does not recognize all of the gas drilled to date and gas yet to be discovered. The addition of any unevaluated gas reserves and/or new gas reserves in the statistical analysis would increase the percentage of bitumen potentially at risk. Furthermore, it appears to the Board that the majority of the bitumen resources identified by the APG as being potentially at risk are generally in regions where the oil sands are of a better quality and thickness.

The Board notes that, as presently estimated, the Athabasca oil sands area contains the bulk of Alberta's in situ bitumen resources (77 per cent) and the majority of the remaining gas reserves (60 per cent) found in the oil sands areas, making it potentially the most vulnerable to the effects of associated gas production. Sixty-three per cent of these bitumen resources are in the Wabiskaw-McMurray Formation, the formation targeted for SAGD development. Furthermore, the presence of top water in association with gas and bitumen in the Wabiskaw-McMurray Formation increases the lateral extent of the bitumen potentially at risk. This is particularly the case in the Surmont area.

Although the inquiry participants did not agree that Surmont is typical of Athabasca, the Board accepts that it is representative of areas with a high degree of risk where bitumen resources would be adversely affected by associated gas production. The Board further notes that the thickest and best-quality McMurray sands exist along the eastern edge of Athabasca. Although the APG showed that the presence of gas in association with top water and bitumen decreases west of Surmont, thereby reducing, but not eliminating the potential risk to bitumen resources, the Board expects that there are likely other areas that could have similar characteristics to Surmont due to the variable nature of the oil sands deposit.

While there was not much discussion at the inquiry about conflicting gas and bitumen production in the Cold Lake oil sands area, the Board notes that it contains significant bitumen resources and gas reserves. On the basis of the EUB database and the evidence provided at the inquiry, the Board is not aware of top water in association with gas and bitumen in the Cold Lake area. However, the Board notes that the APG's study indicated that 24 per cent of the initial bitumen in place has both gas in the same zone and a gas/bitumen flag, and 67 per cent of the initial bitumen in place has gas in the same zone. The Board believes that this is significant in that it suggests that substantial quantities of bitumen in Cold Lake are potentially at risk from associated gas production.

Currently, there is very little gas known to be associated with bitumen in the Peace River oil sands area. However, the Board has not dismissed the possibility that more gas could be discovered in that area.

The Board accepts that the effects of pressure depletion in a gas cap would be transmitted throughout a region of influence. Furthermore, the Board takes the region of influence to be the extent of the gas pool in the case of gas directly overlying bitumen or the extent of the water zone in the case of gas overlying water overlying bitumen. The Board notes that the APG has interpreted the water zones at Surmont to be restricted to the size of the overlying gas pools, whereas Gulf has interpreted the water zones to be more laterally extensive, at times encompassing several gas pools. The Board believes that these alternative interpretations bracket two extremes and that the more plausible interpretation lies somewhere in between. The Board notes Gulf's suggestion that the effects of pressure depletion within one region of influence would be transmitted to other regions of influence, thereby affecting the bitumen in all its leases. However, the Board does not expect that this would result in a material effect on bitumen recovery, since geological heterogeneities in the bitumen horizon are unlikely to allow equilibration of the hydrodynamic regime within the time frame of development of both resources. Rather, the Board agrees with the APG that the effects of pressure depletion would remain confined to each region of influence, whatever its size may be.

6.2 Effect of Associated Gas Production on Thermal Bitumen Recovery

The Board recognizes that there are limited field data available on the effect of associated gas production on thermal bitumen recovery. However, the Board notes that at the Kearl Lake pilot it was necessary to increase the pressure in the top water zone to make the modified steam-drive process viable and that at the Cold Lake Production Project the presence of a gas cap with a thickness greater than about 3 metres impaired the performance of CSS, although this would likely have occurred whether or not the gas cap was produced. The Board further recognizes that there are currently no field data available on the effect of associated gas production on SAGD performance and that the only method used to evaluate the effect was reservoir modelling. The Board notes that all four of the Athabasca-McMurray models predicted that associated gas production would have a detrimental effect on SAGD performance. The Board acknowledges the conflicting predictions from the Wolf Lake-Clearwater and Burnt Lake-Clearwater models, but notes the cautions expressed by the authors of that study regarding the predictions.

On the basis of the evidence submitted at the inquiry, the Board accepts that associated gas production would have a detrimental effect on SAGD performance. Although the extent of the effect would depend on the specific reservoir situation, economic circumstances, and operating strategy, the Board believes that in some instances the effect on the ultimate bitumen recovery could be significant. In that regard, the Board accepts the basic economic evaluations presented by Gulf. While the Board acknowledges that some mitigative measures might become feasible, such as repressuring a depleted gas cap, the Board is not prepared to rely on these measures until it has been proven that their implementation is practical. Similarly, while the Board acknowledges that some alternative technology may be developed that would offset the effect of a depleted gas cap on bitumen recovery, the Board believes that the development of such technology is unlikely in the foreseeable future. Furthermore, the Board believes that it would not be in the public interest to risk significant volumes of bitumen resources on the presumption that alternative technology will be developed.

The Board believes that field tests in the future would increase confidence in predicting reservoir behaviour and could reduce the risk to bitumen resources. Such information would be invaluable for any future review of the issue.

6.3 Effect of Associated Gas Production on Primary Bitumen Recovery

The Board notes that there was very little discussion at the inquiry on the effect of associated gas production on primary bitumen recovery. This was somewhat of a surprise to the Board, given that a number of bitumen producers had raised concerns on this matter prior to the inquiry. In any event, the Board notes that the evidence presented suggests that the concurrent production framework currently in place for conventional oil recovery could be adopted for primary bitumen recovery. However, the Board recognizes that foamy oil and wormhole mechanisms for primary bitumen recovery differ from those for conventional oil recovery: that is, since the solution gas is less likely to evolve from bitumen than conventional oil under reduced pressure, the effect of associated gas production would likely be less for bitumen. Consequently, the effect of associated gas production on primary bitumen recovery is not well understood, and the Board believes that additional analysis is required.

6.4 Effect of Thermal Bitumen Processes on Associated Gas Recovery

The Board accepts that the amount of acid gases generated at a thermal bitumen project as a result of aquathermolysis would be a function of that project's operating temperature. The Board further accepts that these acid gases could migrate into overlying gas caps. However, the Board believes that, if necessary, cleaning up the gas should be feasible, albeit at an additional cost. The Board believes that, from a public interest perspective, mitigating this effect would be less costly and more successful than trying to mitigate the effect of associated associated gas production on thermal bitumen recovery.

The Board accepts that the collapse of the steam chamber after completion of steam injection and the subsequent pressure drop in the gas cap would result in reduced gas recovery. However, the Board believes that this effect might be partially offset by the injection of water or another fluid into the collapsing steam chamber. While the Board recognizes that the technology and economics of implementing this have not been established, the Board expects prior production of bitumen would affect gas recovery to a lesser extent than prior production of associated gas would affect bitumen recovery.

With regard to water influx and geomechanical effects, the Board accepts Gulf's arguments that there is not much potential for these to occur.

6.5 Economic Considerations

In view of the findings in section 6.2 of this report, the Board acknowledges the difficulties in arriving at definitive conclusions regarding project economics, especially since geological and technical unknowns are compounded by the uncertainties of forecasting prices and costs. However, so long as the Board believes that commercial oil sands deposits could be rendered uneconomic from associated gas production, it is not prepared to put this resource at risk. Consequently, the Board does not accept the APG contention that oil sands deposits with associated gas should be regarded as secondary candidates for bitumen recovery when compared to oil sands deposits without associated gas. Putting such a philosophy into practice would imply that the resource is expendable, even before the effect of associated gas production on thermal bitumen recovery is fully understood. Furthermore, the Board is reasonably certain that if gas production were to be curtailed in the oil sands areas, gas production in other parts of the province would, at least temporarily, make up the difference. Therefore, the net effect on total gas production in Alberta would be negligible.

The Board acknowledges that its policies could impose financial hardship on some gas producers who initiated their activities with the expectation that gas production would be allowed. Therefore, the Board believes it is reasonable and necessary to weigh that potential effect in the broad context of resource development.

6.6 Policy Considerations

The Board believes that an important issue that requires resolution in this matter is whether regulatory involvement would be in the public interest or whether existing market mechanisms could be relied on to optimize resource recovery. This question is fundamental to the EUB's mandate to ensure that Alberta's energy resources are developed responsibly. In other words, if the Board concludes that associated gas production would affect the economic production of some bitumen resources to the extent that those resources might be rendered unrecoverable, what role should the Board play in ensuring its mandate is properly fulfilled? The Board has carefully considered the positions advanced by the inquiry participants and, at the risk of oversimplification, believes the substance of the arguments to be as follows.

The bitumen producers likened the EUB's responsibility in the oil sands areas to its role in other areas of the province where conventional oil pools are overlain by gas caps. In these situations, the Board assesses whether or not associated gas production would significantly affect oil recovery and, accordingly, either directs industry to conserve reservoir pressure by leaving the associated gas in place while the oil is produced or, where such pressure depletion would not significantly affect oil recovery, permits concurrent production of both the associated gas and oil. The evidence submitted by the bitumen producers strongly favoured the conclusion that pressure depletion, via associated gas production, could jeopardize SAGD bitumen recovery to the point where significant bitumen resources could be sterilized. Even though technological solutions might exist — or might evolve — that could overcome the effects of pressure depletion, such technology is likely to be more expensive than is warranted by overall project economics, with the inevitable result of sterilized bitumen resources. The bitumen producers conceded that in assessing the economic value of bitumen resources the timing of prospective developments is one factor, among others, that could be considered. For example, Gulf agreed that if a bitumen resource was not likely to be developed within the next hundred years, then for all intents and purposes the net present value of such a resource is zero.

In contrast, the APG focused on the vastness of the bitumen resource base under consideration. In those cases where there is a potential conflict between gas and bitumen producers, it appeared to be the APG's view that there are ample alternative sites for bitumen producers to develop where they would not be in conflict with gas producers. Therefore, bitumen producers should be obliged either to purchase the associated gas reserves at fair market value to protect their interests or move to any number of equally lucrative bitumen resource areas where pressure depletion is not an issue. The APG further argued that existing and future technology could offset the effects of pressure depletion without imposing excessive costs on bitumen projects.

The Board notes that there are appealing elements within each of these arguments. If the Board believed that the effect of associated gas production on thermal bitumen recovery could be so severe as to have an appreciable effect on Alberta's recoverable bitumen resources, then there would be a strong case for regulatory involvement. Even if the APG view is ultimately proven to be true — that there are ample alternative sites for bitumen producers to develop where they would not be in conflict with gas producers — the logical implication of this argument is that some potentially recoverable bitumen resources are expendable in the interest of near-term gas production. By the same token, regulatory involvement might not be in the public interest if its net result were to preserve some bitumen resources for the possibility of production well into the future.

In defining an appropriate role for public policy, the Board is mindful of the following:

- although limited field data are available, sufficient evidence exists to suggest that associated gas production could have a detrimental effect on some bitumen resources, to the extent that significant volumes might never be recoverable;

- while it is possible that thermal bitumen processes could have a detrimental effect on associated gas recovery, such effects would likely be relatively minor;

- Alberta's current and prospective gas reserves and deliverability position would not be materially affected by discouraging some associated gas production in the oil sands areas in favour of conserving the bitumen resources; and

- an evaluation of the appropriate timing of producing gas associated with bitumen should be consistent with the Board's approach to evaluating the production of gas associated with conventional oil.

As mentioned above, one approach the Board could adopt would be to rely exclusively on oil sands leaseholders to protect their interests through negotiations with P&NG leaseholders, perhaps ultimately resulting in a Board hearing. The Board rejects this approach as it would assume that the long-term interests of oil sands leaseholders are exactly aligned with the long-term Alberta public interest. Resource conservation has historically shown that this is not necessarily the case. Rather, the Board has decided that some regulatory involvement is warranted, at least until such time as additional information becomes available to clarify the effect of associated gas production on bitumen recovery or alternative technology and/or economic circumstances reduce the risk of bitumen sterilization. Therefore, the Board believes that a concurrent production framework similar to that currently in place for conventional oil should be adopted for bitumen.

6.7 Policy Implementation

The Board believes that there are important similarities and differences between the policy that it already has in place for concurrent production in conventional reservoirs and a policy that would be appropriate for Alberta's oil sands deposits. One important similarity is that the database for either resource is not amenable to defining areas where conventional oil or bitumen development would take precedence over gas development. To alleviate some of the administrative burden, which could prove to be considerable, the Board considered if criteria could be adopted to narrow the scope of a concurrent production requirement, such as defining geographical areas of interest or a minimum bitumen pay thickness. However, in view of the limited information on which to base these decisions, the Board concludes that it would be premature to identify such criteria, as they would be quite arbitrary. Although such a database for bitumen may evolve, the Board expects that, in the meantime, each case where bitumen recovery is potentially at risk from associated gas production would be considered on its own merits. One important difference related to the evaluation of these reservoirs is that the Board has more experience in considering concurrent production in conventional reservoirs than in oil sands reservoirs; the practices with respect to conventional reservoirs have thus been established over time. Therefore, the Board is not in a position at this time to articulate criteria that might be used to determine when associated gas production would pose a significant risk to future bitumen recovery. Project specific data would have to be considered and field experience would be helpful.

The impression conveyed by some of the inquiry participants regarding the Board's approach to concurrent production in conventional reservoirs was rather more cut-and-dried than is actually the case. Granted, the Board often requires associated gas to be shut in when there is a significant risk to oil recovery. However, depending on the circumstances, equity considerations have sometimes prevailed over conservation considerations, and the Board has occasionally allowed associated gas production with the knowledge that modest amounts of oil reserves may not be recovered. Therefore, adapting the principles applied by the Board to conventional reservoirs to oil sands reservoirs would leave it with the following alternative solutions for resolving issues on a case-by-case basis:

- shut in associated gas to minimize the risk to bitumen recovery;

- allow associated gas production to continue until the existing gas facilities have been paid out; or

- allow associated gas production to continue without conditions.

The Board can envision circumstances where any of the above alternatives could be a reasonable course of action and, at this point, is prepared to comment on only some of the principles that would likely have a bearing on the matter.

First, the Board does not believe it is reasonable and prudent to “force” bitumen development by requiring leaseholders to demonstrate, along with performance requirements, commitments to bitumen projects within a given time frame. Conceivably, this might cause ill-timed investment in bitumen projects and, in any event, such a requirement would imply that the public interest is driven by specific operators' plans for bitumen projects. The Board believes that its conservation role must consider a broader set of issues than the immediate plans of any one company or industry sector.

Second, the Board heard arguments at the inquiry that, in the event that existing associated gas production were to be curtailed, some form of compensation would be warranted. Some proposals were advanced for effecting this, such as requiring P&NG and oil sands rights to be combined when a conflict exists, with a third party such as the Board acting as arbitrator if required. The Board notes that these matters would need to be resolved with the provincial government.

In determining a policy for gas and bitumen production, the Board must consider two distinct cases: currently producing gas wells and facilities developed in advance of this report and investments to be made in the future. In the first instance, gas operators drilled wells and installed facilities in good faith with the reasonable expectation that gas production would be permitted; the risk that gas production would be shut in because of a bitumen-related conservation issue was not contemplated by the P&NG leaseholders in the oil sands areas. Therefore, although there may be some impact on future bitumen recovery, the Board will generally allow associated gas production to continue from investments made up to 1 July 1998, unless the Board receives a complaint from an oil sands leaseholder and the subsequent investigation shows continued production from existing gas wells would not be in the long-term public interest. Suitable recognition would have to be given at that time to the cost/benefit of shutting in existing associated gas production. In some instances the Board may also initiate such a review.

In the second instance, for any development of associated gas in the oil sands areas after 1 July 1998, the Board will require proponents to apply for a “concurrent production” approval through a process to be designed in consultation with affected parties. The Board will exercise jurisdiction over concurrent production involving oil sands pursuant to its general authority and seek legislative authority should the general authority be considered to be inadequate. Applications for concurrent production will be expected to include sufficient evidence to evaluate the scope of impact and provide a discussion of the efforts made by the affected parties to resolve the outstanding issues. Furthermore, to facilitate a proper evaluation, the Board expects new wells in the oil sands areas will need to be drilled to the base of the oil sands zone.

Finally, the current lease tenure system where P&NG rights are leased separately from the oil sands rights presents a number of regulatory conflicts that need to be resolved. The Board would support modifications to the system that would remove those anomalies.

7. CONCLUSIONS

To summarize, the Board will:

- allow associated gas production in the oil sands areas from wells drilled and completed by 1 July 1998, subject to the resolution of any concerns raised by oil sands leaseholders or the Board on its own initiative;

- require concurrent production approval for the production of all associated gas in the oil sands areas from wells drilled after 1 July 1998;

- require, effective 1 July 1998, all new wells in the oil sands areas to be drilled to the base of the oil sands zone;

- develop a notification process, in consultation with the affected parties, to advise leaseholders of prospective developments;

- support modifications to the existing lease tenure system in the oil sands areas to reduce resource development conflicts; and

- investigate the means of conducting further research on the effects of concurrent gas and bitumen production.

Dated at Calgary, Alberta, on 25 March 1998.

ALBERTA ENERGY AND UTILITIES BOARD

F. J. Mink, P.Eng.
Presiding Member

J. D. Dilay, P.Eng.
Board Member

W. J. Schnitzler, P.Eng.
Acting Board Member

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

GAS/BITUMEN PRODUCTION REVIEW **Memorandum of Decision**
TERMS OF REFERENCE **Proceedings No. 960952 and 960953**

1 INTRODUCTION

1.1 Submissions

The Alberta Energy and Utilities Board (Board) received submissions from Gulf Canada Resources Limited (Proceeding No. 960952) and Norcen Energy Resources Limited (Proceeding No. 960953) requesting that the drilling for and/or production of associated gas on specific oil sands leases be prevented. Gulf also requested that a general review of the impact of associated gas production on bitumen recovery on its oil sands leases be conducted. Concern was that pressure depletion of the gas cap in association with the oil sands zone will adversely affect bitumen recovery operations.

The Board subsequently requested and received submissions from the gas owners affected by the applications providing their views on the issue. Upon review of the information the Board denied the immediate requests by Gulf and Norcen to restrict production on the leases in question. However, recognizing the broad implications of the issue on existing and future operations, the Board issued General Bulletin GB 96-15 advising that it would convene a general meeting of all interested parties to discuss the scope of a general review. Subsequent to the meeting, Norcen withdrew its request to cease drilling and production pending the results of further drilling on its leases. The Board will re-consider the Gulf application upon completion of the general inquiry.

1.2 Meeting

The issue was considered at a public meeting on 21 January 1997 at the Board's office by F. J. Mink, Presiding Member, J. D. Dilay, Board Member, and W. J. Schnitzler, Acting Board Member.

A list of the meeting participants is provided below.

THOSE WHO APPEARED AT THE MEETING

Principals (Abbreviations used in Report)	Representatives
Gulf Canada Resources Limited (Gulf)	F. R. Foran, Q.C. N. Dilts M. Krause
Northstar Energy Corporation (Northstar) NAL Resources NAL Energy Inc. Canadian Forest Oil Ltd. UMC Resources Canada Ltd. Paramount Resources Ltd. Wascana Energy Inc. Giant Grosmont Petroleum Ltd.	K. F. Miller
Giant Grosmont Petroleums Ltd.	R. Watson
Wascana Energy Inc.	P. Sidey
Paramount Resources Ltd.	R. Duncan
Norcen Energy Resources Limited	B. Dozzi S. Sills M. Jennings B. Kurtz
Campbell River Engineering Ltd. Elk Point Gas Ltd.	D. Campbell
Petro-Canada	G. Sinclair
Mobil Oil Canada	D. Searle K. Dembicki N. Amoozegar
Canadian Occidental Petroleum Ltd.	J. Wansleeben
Talisman Energy Inc.	J. Harding
Tarragon Oil and Gas Limited	R. Rosine

THOSE WHO APPEARED AT THE MEETING (cont'd)

Principals (Abbreviations used in Report)	Representatives
Minerals Tenure Branch of the Alberta Department of Energy (ADOE)	D. Coombs
Rio Alto Exploration Ltd.	R. Cones
Ranger Oil Limited	D. Drall
Alberta Energy and Utilities Board Staff	G. Dilay K. Sadler T. Byrnes

2 MATTERS RAISED

The matters raised at the meeting fall into the following general categories:

- the identification of interested parties,
- the issues to be considered, and
- the process and timing.

3 IDENTIFICATION OF INTERESTED PARTIES

Some 105 individuals from 58 companies registered for the exploratory meeting.

At the meeting, the representatives identified the following parties that should take an interest in and participate in an inquiry of the matters before the Board.

- Alberta Department of Energy,
- the holders of oil sands leases,
- the holders of natural gas leases overlying and owners of facilities in the vicinity of oil sands leases,
- Nova Gas Transmission Ltd. (NGTL),
- Elk Point Gas Ltd., and
- gas distribution utilities.

The Board accepts the list of interested parties as put forward as those having a particular interest in the subject and will direct correspondence of the proceeding to them. The Board will include mineral rights holders and owners of other facilities operating in oil sands areas. The Board intends to issue a general notice of the inquiry purpose and scheduling in order to allow for the broad participation of all segments of the industry.

4 THE ISSUES

4.1 The participants at the meeting submitted the following issues for consideration at the proposed Board inquiry:

- the efficiency of and advancements in bitumen recovery technologies,
- the effect of depletion of gas caps in association with oil sands zones on bitumen recovery,
- the recovery of resources, on an energy basis, of gas caps and the affected oil sands under various options of recovery,
- evaluation of the economic benefits of both natural gas and bitumen production under various options of recovery,
- policies and procedures to maximize the production of hydrocarbons where oil sands have overlying gas caps or water sands in communication with gas caps,
- policies and procedures for future leases of hydrocarbon lands where oil sands have overlying gas caps or water sands in conjunction with gas caps,
- identification and assessment of the possible impacts of in situ oil sands projects on associated gas development,
- identification and assessment of possible mitigative measures for potential in situ oil sands projects using currently available technology that could avoid detrimental effects,
- discussion of gas and bitumen production priority in the event that concurrent production is not desirable, and
- if gas or bitumen production is prevented, how the appropriate resource holder will be compensated and by whom.

4.2 The Board has reviewed the issues put forward and believes that the following list should form the basis for the proposed inquiry:

(a) Extent of Affected Reserves

- Methodology used to establish the presence of "associated" gas.
- Tabulation of the amount of recoverable reserves, on an energy basis, of associated gas caps and the potentially affected oil sands.

(b) Impact on Recovery

- Identification of factors and evaluation of the possible effect of depletion of associated gas caps on bitumen recovery if mitigative measures are not used.

- Identification of potential mitigative measures and discussion of relative effects if mitigative measures are used to optimize resource recovery.

- Study of the possible effect of bitumen recovery on associated gas caps, whether or not the gas is produced.

- Evaluation of the efficiency and advancements in primary and thermal bitumen recovery technologies that could impact the resource recovery.

(c) Economic Impact

A cost/benefit evaluation showing the optimum depletion strategy for recovering the resources. Such studies should include:

- a production and price forecast of the gas and oil sands reserves,

- an assessment of the likely timing of resource recoveries,

- an evaluation of the possible loss of revenue, gas contract obligations, and capital investment,

- an evaluation of the possible impact on gas distribution companies whose gas supplies are mostly from the affected fields. This should include discussion on the issue of security of supply, alternative supplies, and cost of accessing them, as well as the size of possible stranded investment, and

- an assessment of the impact on NGTL's facilities servicing the affected gas producing areas as a result of a shut-in order.

(d) Policy Considerations

- If co-development is not possible, an identification of the priority of development and reasons for the preference.

- Views on resource conservation policies and procedures to maximize the recovery of hydrocarbons where oil sands have overlying gas caps or water sands in communication with gas caps.

- An identification of possible regulatory changes that could provide for optimum co-development of hydrocarbon resources.

(e) Guidelines

- Rules and procedures to be used for specific development applications in terms of contacting oil sands or P & NG leaseholders and providing opportunities for objection.

(f) Lease Tenure and Related Issues

Discussion of land tenure and related matters are issues outside the jurisdiction of the Board. The Board understands that the Department of Energy will be conducting its own review of current leasing policies and procedures in parallel with this inquiry (see attached letter). The Board recognizes the interest by parties submitting evidence to this proceeding to discuss all implications of the subject before the Board. If the parties see some merit in tabling information on these issues, the Board will summarize this information and related findings from the inquiry and forward it to the government for consideration in context of the conclusions by the Board.

4.3 The Process and Timing

On the basis of the suggested process from the participants and the nature of the issues raised at the 21 January 1997 meeting, the Board is prepared to proceed with the general inquiry of gas/bitumen development. The participants requested that the Terms of Reference be finalized and that the proceeding get underway as soon as practical. The Terms of Reference for the inquiry are laid out under section 4.2 of this report and the Board will adopt the following timetable to receive submissions and to consider the evidence.

Filing of coincident initial submissions	25 April 1997
Filing of responses to initial submissions	9 May 1997
Commencement of inquiry	27 May 1997

With respect to interim procedures for oil sands or gas applications for projects and/or facilities, the Board proposes to consider these under its normal rules and procedures. That is, in the absence of valid objections, the Board will continue to issue approvals for wells, facilities, etc., in the oil sands areas. Parties should recognize that affected facilities are subject to normal regulatory risks that may result from the finding of the inquiry. Where objections have been filed related to the Terms of Reference for this inquiry, the Board will hold these applications in abeyance pending the outcome of the inquiry. The Board also takes this opportunity to remind operators that it is their responsibility to monitor developments which may be of interest to them.

On the matter of costs related to the preparation of submissions and for the retention of experts in specific fields, the Board's view is that each party filing a submission will be responsible for all associated costs. This includes costs for the preparation or review of submissions as well as those for appearing at the inquiry.

5 CONCLUSION

The Board is prepared to proceed with a general inquiry into the issue of gas/bitumen development and invites interested parties to submit information on any or all of the items noted in the Terms of Reference. The inquiry will commence on 27 May 1997 at the Board's office in Calgary, Alberta. The Terms of Reference will be as set out under section 4.2 of this report. A Notice of Inquiry will be published in Alberta newspapers and distributed broadly.

DATED at Calgary, Alberta, on 19 February 1997.

ALBERTA ENERGY AND UTILITIES BOARD

F. J. Mink, P.Eng.
Board Member

J. D. Dilay, P.Eng.
Board Member

W. J. Schnitzler, P.Eng.*
Acting Board Member

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* Mr. Schnitzler was not available but agrees with the contents of the report.

Appendix B - Inquiry Participants

Principals and Representatives (Abbreviations used in Report)	Witnesses
AEC East (AEC) K. Mathewson	
Alberta Producers Group (APG) A. L. McLarty	K. Adegbasan, Ph.D. of KADE Technologies Inc. B. Nzekwu, Ph.D. of SAGD Technologies Inc. J. Hyne, Ph.D. of Hyjay Research & Development Ltd. R. Pearson, P.Eng. of Adams Pearson Associates Inc. M. Weatherhead, P.Eng. of Northstar Energy Corporation J. Smith, P.Eng. of Northstar Energy Corporation D. Lausten, P.Eng. of Gilbert Lausten Jung Associates Ltd. H. Jung, P.Eng. of Gilbert Lausten Jung Associates Ltd. P. Ziff of Ziff Energy Group L. Bondar of Ziff Energy Group P. Sidey, P.Eng. of Wascana Energy Inc. D. Flint, P.Geol. of Wascana Energy Inc. C. Riddell, P.Geol. of Paramount Resources Ltd. D. Lehmann, P.Eng. of Paramount Resources Ltd. R. Watson, P.Geol. of Giant Grosmont Petroleums Ltd. H. Lies of Hydro Petroleum Canada Ltd.

Appendix B - Inquiry Participants (continued)

Principals and Representatives (Abbreviations used in Report)	Witnesses
Amoco Canada Petroleum Company Ltd. (Amoco) D. A. Holgate	C. Patel, P.Eng. R. Sendall, P.Eng. E. Jensen, P.Eng.
Camberley Energy Ltd. (Camberley) D. Warkentine	
Canadian Occidental Petroleum Ltd. (CanOxy) W. Hope-Ross J. Wansleeben, P.Eng.	
Gulf Canada Resources Limited (Gulf) F. R. Foran, Q.C. R. W. Block N. Dilts	M. Krause III, P.Eng. B. Lounds, P.Eng. J. Anders, P.Eng. G. T. Stabb, P.Geol. K. Kisman, Ph.D. of Rangewest Resources Ltd. J. Doyle, P.Eng. of JADE Resources G. Demke of Demke Management Ltd. H. Thimm, Ph.D. of H. F. Thimm and Associates Ltd. B. A. Rottenfusser, P.Geol. of Redfoot Enterprises Inc. P. A. Esslinger, P.Geol. of Rakhit Petroleum Consulting Ltd. L. Mattar, P.Eng. of Fekete Associates Inc. M. P. Mansell, P.Geoph. of Mansell Exploration Ltd.
Husky Oil Operations Ltd. (Husky) W. P. Ogrodnick, P.Eng.	
Imperial Oil Resources Limited (Imperial) B. Carey, Ph.D. B. Harschnitz, P.Eng.	

Appendix B - Inquiry Participants (continued)

Principals and Representatives (Abbreviations used in Report)	Witnesses
Mobil Oil Canada Limited (Mobil) R. Lane	
Numac Energy Inc. (Numac) F. Morrissey	
Petro-Canada Oil and Gas (Petro-Canada) S. R. Miller	G. Sinclair, P.Eng. J. H. Fong, P.Eng. R. W. King, P.Eng.
Suncor Energy Inc. (Suncor) K. C. Yeung, P.Eng.	
Alberta Department of Energy (ADOE) D. Brezina	W. K. Good, P.Eng. D. Coombs
Alberta Energy and Utilities Board staff T. Donnelly (Counsel) D. Larder (Counsel) G. W. Dilay, P.Eng. K. Sadler, P.Eng. K. F. Schuldhaus, P.Eng. K. Johnston M. Connelly, P.Geol.	

Appendix C - Gulf Recommended Policy

Definition

1. Associated natural gas is gas which is in the same or adjacent formation and is in direct contact with bitumen or is indirectly in pressure communication with bitumen through an intervening water zone.

Policy

1. For all future leases, the oil sands and associated natural gas rights would no longer be separated.

2. Associated gas development would only be permitted where it can be clearly demonstrated by the gas producer that gas production would not be detrimental to the recovery of bitumen.

3. All new associated gas production, including the further development of existing leases, no matter what the circumstance of lease ownership, would be required to follow point 2 above.

4. Any new wells drilled would be required to drill to the base of the prospective bitumen zone to confirm hydrocarbon quantities and types.

5. Any wells completed in bitumen areas would be required to be thermally cemented.

6. If only an oil sands lease has been issued for a given area, the associated gas rights should be attached to the oil sands lease.

7. If only a P&NG lease has been issued for an area, the lease holder should be put on notice that it is required to comply with point 2 above. Should the lease holder feel that this is too onerous, the Crown should be prepared to reacquire the lease.

8. Where both an oil sands lease and a P&NG lease has been issued for an area, future associated natural gas development will be subject to point 2 above. Should the P&NG lease holder feel that this is too onerous, the Crown should be prepared to reacquire the lease.

9. Where associated gas development has already occurred and production is taking place, production through existing facilities would be allowed to continue except when the Alberta Energy and Utilities Board, at the request of a bitumen operator or on its own volition, is satisfied that:

    (a) The associated gas is within the area of an oil sands lease or multiple adjacent leases owned by one oil sands operator to a maximum size of 20 miles in any one direction.

    (b) Data and studies show that the lease contains bitumen that is commercially recoverable, the gas is in communication with the bitumen and the reduced pressure due to gas production would materially impact on bitumen recovery.

Appendix C - Gulf Recommended Policy (continued)

(c) The oil sands operator has definite plans for further delineation drilling and the development of a bitumen recovery project and makes a commitment to proceed with those plans in an expeditious manner.

(d) Although the plans may not be specific as to the particular bitumen deposits that will be developed, the gas to be shut in is in communication with a commercially viable bitumen deposit which has a reasonable probability of being produced.

(e) The work associated with the development plan (outlining delineation drilling, pilot project if needed, anticipated commercial development) as filed by the oil sands operator will begin within one year with commitment to continue.

10. Plans respecting item 9 would be reviewed at a hearing or meeting if the gas producer(s) so wishes.

11. If gas is shut in pursuant to item 9, it would remain shut in where the following occurs:

(a) the operator carries through with the delineation and development plans, and
(b) the further delineation and ongoing work continue to confirm that communication with the gas exists and gas production would negatively impact on bitumen recovery, and
(c) the long range development plans, or their equivalents, remain in place.

12. The review required by item 11 (to confirm performance of plans and ongoing intent) would take place initially after 18 months and thereafter every three years.

13. If the Board is not satisfied that the data and the extent of the ongoing plans warrant continued shut-in of the gas production, the prohibition of gas production would be withdrawn.

14. Where gas is shut in and rights are returned, compensation would be available from the Crown.

15. Where compensation is available, the owners of the gas would have the options of holding the gas lease for future value (no lease rental payments would be required during this period), negotiating for the sale of the gas lease to others (the oil sands owners), or receiving compensation from the Crown in return for the lease.