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DISCUSSION PAPER NO. 259

An Economic Analysis of Oilsands Policy in Canada - The Case of Alsands and Wolf Lake

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- Ce document fournit une analyse économique de l'important projet Alsands, relatif à l'exploitation des sables bitumineux, et du projet de Wolf Lake, de moins grande envergure, qui vise la récupération in situ du pétrole contenu dans les sables bitumineux. Si la phase de construction a déjà commencé à Wolf Lake, le projet Alsands, par contre, a été reporté sine die en avril 1982.

- Il s'agit avant tout, dans les pages qui suivent, d'analyser l'efficacité des mesures fiscales proposées ou déjà en vigueur, relatives aux deux projets, dans le cadre de divers scénarios touchant aux prix du pétrole, aux taux d'intérêt, etc. Le document examine également certains changements qu'on pourrait apporter aux mesures fiscales et renferme des estimations du coût du pétrole éventuellement produit dans le cadre des deux projets. De façon générale, le document vise à déterminer si les politiques antérieures et actuelles en matière d'exploitation des sables bitumineux ont été ou sont appropriées.

- Les données sur les coûts et la production qui ont servi à l'analyse du projet Alsands et du projet de Wolf Lake ont été fournies respectivement par Shell Canada Resources Ltd et par BP Exploration Canada Ltd. Les hypothèses relatives aux prix, à l'inflation et aux taux d'intérêt sont conformes à celles qu'on trouve dans les monographies préparées par l'équipe sur l'énergie du Conseil économique du Canada. Elles n'ont été ni proposées ni appuyées par Shell ou BP. Les résultats et les conclusions sont ceux des auteurs et non des sociétés qui ont fourni une partie des données utilisées.

Le projet de Alsands

- Le projet Alsands devait permettre de produire environ 219 millions de mètres cubes (1,3 milliard de barils) de pétrole brut synthétique au cours de la période prévue de 29 ans. Le projet englobait toutes les étapes de production, soit l'extraction des sables bitumineux, la récupération du bitume et sa valorisation en vue de produire du pétrole brut synthétique ayant une densité de 34 à 36 API et une teneur en soufre d'environ 0,2 %.

- La planification du projet a été amorcée en 1977 et la production devait commencer en 1988, ce qui représentait un délai de démarrage de 11 années. La capacité de production maximale devait être atteinte en 1995, environ 18 ans après les premiers travaux de planification.

- En raison de sa très grande envergure, le projet Alsands, qui devait nécessiter des investissements d'un peu moins de

12 milliards de dollars (aux prix de 1982), devait être réalisé par un consortium de neuf sociétés pétrolières privées dirigé par Shell Canada. Toutefois, il existait une très grande divergence quant au traitement fiscal réservé aux sociétés membres de ce consortium, de sorte que les coûts réels après soustraction des impôts variaient beaucoup de l'une à l'autre.

- o En mars 1982, la participation du secteur privé avait diminué de 50 % et Petro-Canada avait acquis une participation de 17 %, de sorte que seules Shell Canada et Gulf Canada (dont les parts respectives étaient de 25 % et de 8 %) représentaient le secteur privé.

- o En avril 1982, le gouvernement fédéral et l'Alberta ont présenté une "offre finale" au consortium dans l'espoir d'intéresser de nouveau les sociétés qui s'étaient retirées conditionnellement ou de conclure une entente avec celles qui restaient.

- o La répartition des intérêts proposée dans l'offre finale était la suivante : participation de 50 % du secteur privé, de 25 % du gouvernement de l'Alberta et de 25 % du gouvernement fédéral, cette dernière part devant comprendre les intérêts de Petro-Canada.

o Toutefois, les deux gouvernements acceptaient de garantir des emprunts correspondant à 68 % des capitaux propres investis par les sociétés privées durant la période préalable à la production. Ces emprunts seraient remboursés en réservant 58 % des bénéfices nets des sociétés au paiement de la dette. En outre, les sociétés n'auraient à payer aucun impôt et seules des redevances minimales seraient réclamées tant que les emprunts garantis n'auraient pas été complètement remboursés. Une fois la dette acquittée, les bénéfices des sociétés seraient assujettis à l'impôt, soit à une taxe fédérale de 16 % sur les recettes pétrolières et gazières (TRPG), et ces sociétés devraient payer des redevances provinciales à raison de 5 % des revenus bruts ou de 30 % des revenus nets, le plus élevé des deux montants devant être retenu. Selon les modalités de l'offre finale, le niveau des impôts et des redevances dépendait essentiellement du remboursement des emprunts garantis. Ces impôts et redevances seraient relativement minimes avant que la dette ne soit acquittée mais plutôt élevés par la suite.

o Selon les estimations, le coût social du pétrole synthétique, à l'usine, varierait entre quelque 209 $ le mètre cube (33 $ le baril), en supposant un taux d'actualisation de 5 %, et environ 300 $ le mètre cube (48 $ le baril), en supposant un taux d'actualisation de 10 %. Un montant intermédiaire d'à peu près 241 $ le mètre cube (38 $

le baril) correspondant à un taux d'actualisation de 7 % pourrait être une estimation raisonnable à retenir. Le prix de ce pétrole à l'usine serait actuellement d'environ 229 $ le mètre cube (37 $ le baril), selon l'hypothèse retenue dans le scénario de référence utilisé ici, et si l'on suppose que ce prix demeurerait constant en dollars réels pendant toute la durée du projet, il n'y aurait pas de rente économique mais plutôt une perte de l'ordre de 12 $ le mètre cube (2 $ le baril). Si le taux d'actualisation était plus élevé, la perte pourrait devenir assez importante, pouvant atteindre 71 $ le mètre cube (11 $ le baril), par exemple, au taux de 10 %.

o En l'absence d'une hausse des prix réels du pétrole, les modalités proposées dans l'offre finale auraient apporté une contribution significative à la réalisation du projet, mais le secteur privé n'aurait pas été protégé contre les pertes. D'après le scénario de référence dans lequel on suppose que les prix demeurent constants en dollars réels, le taux réel de rendement social serait d'environ 6,2 % mais, pour les entreprises privées participantes, le taux de rendement atteindrait environ 15,7 %.

o Sur le plan du coût social réel, le projet atteint le point de rentabilité uniquement lorsqu'on suppose que les prix réels du pétrole augmentent, pendant la durée du projet, à un taux variant entre 2 et 4 % selon le taux d'actualisation social postulé.

- Si les prix réels augmentaient, les emprunts cautionnés pourraient être remboursés plus rapidement, le niveau de rentabilité des entreprises privées serait raisonnable et les gouvernements pourraient percevoir des taxes et redevances plus élevées. Dans ces conditions, la valeur actuelle de la part des revenus nets de chaque ordre de gouvernement et du secteur privé serait plus ou moins la même et elle demeurerait stable à divers taux d'actualisation.

- Une chute éventuelle des prix du pétrole aurait des conséquences graves pour le secteur privé, mais les mesures fiscales sont efficaces à cet égard, dans la mesure où les sociétés n'ont aucun impôt à payer et ne doivent verser que des redevances minimes. Dans le contexte d'une diminution des prix, les emprunts cautionnés ne seraient pas remboursés durant la période de production, de sorte qu'une dette de l'ordre de 10 milliards de dollars (aux prix de 1982) devrait être remboursée par le consortium ou effacée par les gouvernements.

- Les cautionnements de prêts prévus dans l'offre finale pouvaient placer les sociétés privées dans une situation délicate en présence d'une hausse des taux d'intérêt afférents à ces emprunts, puisque la part (58 %) des revenus nets d'exploitation devant être réservée au remboursement de la dette pourrait s'avérer insuffisante. Les partenaires au sein du consortium auraient donc une dette croissante à l'égard des gouvernements. Si cette dette était éventuellement effacée, le taux de rendement du secteur privé pourrait être plus élevé qu'il ne le serait si les taux d'intérêt étaient plus faibles. Si l'on suppose que les gouvernements assument la responsabilité de la dette, toute amélioration du taux de rendement obtenu par le secteur privé, dans le contexte d'une hausse des taux d'intérêt afférents aux emprunts, serait au mieux très anormale.

o Les sociétés privées auraient pu réaliser des revenus nets de 42 % mais, à la fin du projet, les gouvernements auraient pu être obligés d'absorber la dette. Le secteur public n'aurait perçu aucun impôt. Cette situation aurait été inacceptable tant pour les sociétés que pour les deux ordres de gouvernement.

o Dans un contexte de taux d'intérêt inférieurs à ceux du scénario de référence, les aspects économiques du projet deviennent nettement moins favorables, bien que les emprunts soient entièrement remboursés dans les deux scénarios. Dans le scénario où nous postulons des taux d'intérêt inférieurs, les emprunts sont remboursés 14 ans après le début de la production, au lieu des 26 ans prévus dans le scénario de référence. Les taxes et les redevances seraient donc versés plus tôt et le taux de rendement du secteur privé serait inférieur à celui qui découle du scénario de référence. Les résultats du scénario postulant des taux d'intérêt moins élevés font ressortir les décisions paradoxales que doivent prendre les sociétés privées.

o L'offre finale constitue, de toute évidence, une tentative inadéquate de mettre en oeuvre les politiques requises pour le projet Alsands. Bien que l'offre finale marque l'aboutissement de plus de deux années de négociations entre les deux ordres de gouvernement et les sociétés privées formant le consortium, sa formulation définitive témoigne d'un effort de dernière heure pour tenter de sauver le projet. En raison des conséquences que pouvaient entraîner les modalités financières prévues si la conjoncture économique venait à changer, il devenait très difficile, voire impossible, aux sociétés privées de prendre les décisions voulues.

o Le processus s'avérait donc très coûteux et allait déboucher sur une politique énergétique très différente de la politique conventionnelle. Étant donné que le projet a été abandonné, les efforts n'ont pas été fructueux; mais ils peuvent néanmoins avoir été profitables dans la mesure où ils ont permis de tirer des leçons utiles.

- Notre étude a révélé, en dernière analyse, que les modalités de l'offre auraient permis au consortium de réaliser le taux de rendement requis si les hypothèses posées dans le scénario de référence s'étaient concrétisées. Toutefois, les analyses de sensibilité ont montré que si certains paramètres avaient été modifiés, cela aurait pu signifier que la part de 58 % des revenus nets réservée au remboursement des emprunts n'aurait pas permis au consortium d'acquitter sa dette au cours de la durée du projet et qu'on n'aurait pu imposer une taxe quelconque ou percevoir toutes les redevances.

- D'après les résultats obtenus, l'aide gouvernementale sous forme de cautionnement des emprunts était d'une importance capitale du point de vue de la participation du secteur privé. La perception des taxes et des redevances complètes était différée et le remboursement des emprunts garantis incombait ultimement au secteur public.

- Si l'on fait abstraction de la responsabilité morale du consortium à l'égard du remboursement des emprunts, il est clair que le risque est assumé par le secteur public par le biais des cautionnements des emprunts. Si le financement du projet était essentiellement assuré par le secteur public, il y a lieu de se demander pourquoi la participation du secteur privé avait été fixée à 50 %.

- Toutefois, l'obligation du secteur privé de rembourser les emprunts demeure un aspect important. On ne saurait envisager la possibilité qu'une importante multinationale ou ses partenaires canadiens se dérobent à leur obligation en ne remboursant pas leur dette à la fin du projet.

- À la fin du projet, cependant, le secteur privé aurait pu avoir accumulé une dette correspondant à des milliards de dollars.

- Les problèmes relatifs au projet Alsands ne peuvent être ramenés à des politiques mal formulées ni à des lignes de conduite inefficaces. Le projet doit également être analysé dans l'optique de l'évolution conjoncturelle. Sa mise en oeuvre devait avoir lieu alors que le fléchissement des prix du pétrole et la hausse des taux d'intérêt devenaient de plus en plus évidents, soit au cours d'une période mal choisie pour le lancement d'un mégaprojet consistant à valoriser les sables bitumineux et à produire du pétrole brut synthétique. Cette période semblait toutefois favorable à la mise en oeuvre d'un projet de récupération _in situ_ du bitume (sans valorisation) en vue de le vendre pour la préparation de recouvrements des routes bitumées.

- Notre analyse révèle que l'offre finale n'offrirait des perspectives de rentabilité que si les prix s'accroissaient.

- Il existe malheureusement peu d'études détaillées sur l'échelle minimale de rentabilité applicable au projet Alsands. À moins qu'on ne puisse démontrer la rentabilité d'une échelle d'exploitation plus réduite, ce projet ne sera probablement jamais repris.

Le projet de Wolf Lake

- Le projet de récupération in situ de Wolf Lake est un projet commercial à échelle réduite visant à produire 1 100 mètres cubes (7 000 barils) de bitume par jour durant 25 ans. La production devrait commencer en 1985.

- Les immobilisations totales devraient atteindre environ 550 millions de dollars (aux prix de 1983). Les entreprises qui participent à ce projet sont BP Exploration Canada Limited et Petro-Canada Exploration Incorporated.

- Le projet de Wolf Lake sera assujetti à un régime fiscal négocié entre le gouvernement fédéral, le gouvernement provincial et les sociétés participantes.

- Le régime fiscal adopté pour le projet de Wolf Lake est un exemple de la politique en vigueur dans le domaine des sables bitumineux. Il témoigne d'une approche plus pragmatique à la formulation de politiques et aux négociations, de la part tant des gouvernements que de l'industrie. Le régime découle des changements apportés aux impôts pétroliers qui ont été intégrés aux budgets du gouvernement fédéral et il résulte en partie des négociations menées entre les gouvernements et les compagnies participantes.

o Ce régime semble être l'expression d'une politique type qui sera adoptée à l'égard d'un certain nombre de projets plus restreints d'exploitation des sables bitumineux. Nous sommes d'avis que les modalités établies pour les projets de Wolf Lake et de Cold Lake témoignent d'une nouvelle façon d'envisager l'exploitation des sables bitumineux.

o L'étude économique et les analyses de réactivité révèlent que le régime est très sensible à l'évolution de la conjoncture économique. Les recettes des gouvernements s'amenuisent de façon marquée lorsque la conjoncture économique se détériore.

o Une politique facilement applicable à différents projets d'exploitation des sables bitumineux, sans devoir recourir à des négociations longues et coûteuses, constitue sans doute une façon de procéder plus efficace que ne l'était la politique vague et inadéquate adoptée il y a quelques années. À l'heure actuelle, il semble que les modalités de base du projet de Wolf Lake fourniront aux sociétés participant à différents projets des paramètres qui serviront à négocier les aspects détaillés de la politique, compte tenu des caractéristiques de chaque projet. Lorsque ces projets auront permis d'acquérir une certaine expérience et qu'ils seront suffisamment nombreux, il faudra adopter une politique type pour les projets subséquents d'exploitation *in situ* des sables bitumineux. Soulignons que, pour tirer tous les avantages associés à une bonne politique générale, toutes les règles qu'elle renferme doivent être connues et comprises par tous dès le début. Ce n'est pas le cas à l'heure actuelle et il semble que l'évolution de la politique relative à l'exploitation des sables bitumineux ne soit pas encore terminée.

EXECUTIVE SUMMARY

- This paper provides an economic assessment of the large Alsands Project, an oil sands mining project and the smaller Wolf Lake Project, an oil sands in situ project. The Wolf Lake Project is presently under construction, while the Alsands Project was shelved indefinitely in April 1982.

- The main purpose of the paper is to examine the effectiveness of the fiscal measures, either proposed or in place, pertaining to the projects under various conditions of oil prices, interest rates and so forth. We are interested in the ability of the fiscal system to collect economic rents efficiently and in the flexibility of the system in response to changing levels of profitability. The paper also considers selected changes in the fiscal terms. In addition, estimates of the cost of oil from the projects, the supply prices, are provided. Overall the objective of the paper is to consider the appropriateness of past and present oil sands policy.

- The cost and production data for the Alsands analysis have been provided by Shell Canada Resources Ltd. and by BP Exploration Canada Ltd. for the Wolf Lake analysis. The price, inflation and interest rate assumptions are consistent with those being used in the Economic Council of Canada's Energy Group case studies. They have been neither suggested nor endorsed by Shell or BP. The results and conclusions are the responsibility of the authors alone and not of the companies who have provided some of the input data.

Alsands

- The proposed Alsands Project was designed to produce about 219 million cubic metres (1.3 billion barrels) of synthetic crude oil over its life span of 29 years. The project included all stages of production from the mining of the sands, extraction of the bitumen and finally its upgrading to a synthetic crude oil with a gravity of 34-36° API and a sulphur content of about 0.2%.

- Planning of the project began in 1977 and the first production was scheduled for 1988, an 11 year lead time. Full capacity was to be achieved by 1995, i.e. some 18 years after the beginning of project planning.

- Being such a large project, requiring capital investments of just under $12 billion, in 1982 constant dollars, the Alsands project was to be undertaken by a nine-member consortium of private sector oil companies, led by Shell

Canada. The consortium members, however, had quite different income tax positions which meant that the effective after tax costs varied considerably between partners.

° By March 1982, 50 per cent of the original private sector interests had conditionally withdrawn and 17 per cent had been taken over by Petro Canada, leaving only Shell Canada with 25 per cent and Gulf Canada with 8 per cent representing the private sector.

° In April 1982, the Alberta and Federal governments made a "Final Offer" to the consortium, hoping to retrieve the members who had conditionally withdrawn or to strike a deal with those remaining.

° The Final Offer contemplated a 50 per cent participation by the private sector, a 25 per cent share by the Alberta government and a 25 per cent share by the federal government, which would have included the Petro Canada interest.

° However, the two governments agreed to guarantee loans for 68 per cent of the private sector equity investments in the preproduction period. These loans would be paid back by assigning 58 per cent of private sector net revenues to loan repayment. In addition no taxes and minimum royalties would be levied until the guaranteed loans were fully repaid. After loan repayment there would be income taxes, a federal PGRT at 16 per cent and provincial royalties equal to the greater of 5 per cent of gross revenues or 30 per cent of net revenues. The essence of the offer was that taxes and royalties hinged around repayment of the guaranteed loans. They would be minimal before loan repayment but rather onerous afterwards.

° The estimated social supply cost ("supply price") of synthetic oil at the plant gate ranges from some \$209 per cubic metre (\$33 per barrel) at a 5 per cent discount rate, to some \$300 per cubic metre (\$48 per barrel) at a 10 per cent discount rate. A middle estimate of some \$241 per cubic metre (\$38 per barrel) at a 7 per cent discount may be a reasonable estimate to keep in mind. The plant gate price of this oil would presently be about \$229 per cubic metre (\$37 per barrel), as assumed in the paper's Base Case, and assuming that this price remains constant in real dollar terms over the project life there would <u>not</u> be an economic rent, rather there would be an economic loss of some \$12 per cubic metre (\$2 per barrel). At a higher discount rate the loss would appear large, for example at 10 per cent the loss would be $71 per cubic metre ($11 per barrel).

° Without rising real oil prices the Final Offer fiscal package would have significantly assisted the proposed project, although the private sectors would not have been immune to losses. In the Base Case analysis, with oil prices assumed to remain constant in real dollar terms, the estimated real social rate of return is some 6.2 per cent but the return to the private sector participants is about 15.7 per cent.

° On a real social cost basis the project would break even only if real oil prices were assumed to increase throughout the project life, at between about 2 per cent and 4 per cent per year depending on the assumed social discount rate.

° Rising real prices allow for the early repayment of the guaranteed loans, reasonable profitability for the private sector, and the governments collect increased taxes and royalties. The present value net revenue shares of each government and the private sector under these conditions are about equal and remain stable at various discount rates.

° Falling oil prices impact heavily on the private sector but the fiscal regime is effective in the sense of not taking taxes and imposing only minimal royalties. The guaranteed loans are not repaid during the production life of the project and a very large liability of some $10 billion (1982 $) remains to be paid by the consortium, or forgiven by the governments.

° Through the guaranteed loans the Final Offer placed the private sector participants in a delicate situation should interest rates on those loans increase, because 58 per cent of net operating revenues might be insufficient to service the debt. As a result the consortium would carry an enlarging liability to the governments. If this liability were eventually forgiven the private sector rate of return might be larger than with lower interest rates. Assuming that the governments were left holding the bag, an improvement in a project's private rate of return under a scenario of higher borrowing costs seems perverse to say the least.

° It would have been possible for the companies to collect 42 per cent of the net revenues but in the end the governments could have been left holding the debt load. No tax revenues would have been collected by the public sector. This situation would not be welcomed either by the companies or the governments.

- In a lower interest rate environment than in the Base Case the project economics deteriorate, although in both cases the loans are fully repaid. Our Case with lower interest rates on the loans shows them to be paid back in 14 years after production start up rather than 26 years in the Base Case. Taxes and royalties therefore begin earlier and the private sector rate of return would be less than in the Base Case. This outcome under lower interest rates illustrates the paradoxical decision making faced by the companies.

- The Alsands final offer was clearly a piecemeal approach to policy making. Although the final offer marked the end of over two years of policy negotiation between two levels of government and a private sector consortium, its final form reflected an eleventh hour crash attempt to save the mining project. The potential impact of the regime under changing economic conditions placed the private sector in a difficult if not impossible decision making situation.

- The process was costly and in the end a very non-conventional resource policy existed. To the extent that the project did not go ahead the effort was not fruitful. To the extent that lessons were learned there was perhaps some value in the effort.

- Our analysis has found that in the end the offer would have generated the company's required rate of return under the base case assumptions. However the sensitivity tests reveal that changes in certain parameters may have put the company in the position where 58 per cent of net revenues would not have been sufficient to repay the debts during the project life and no taxes or full royalties would have been imposed.

- Our findings show that the government backing through the guaranteed loans was crucial to the private sector's share of the project. The collection of taxes and full royalties was delayed and the public sector held the ultimate responsibility for the repayment of the loan guarantees.

- If one ignores for the moment a moral responsibility on the part of the consortium for the repayment of the loans, it is clear that the risk is shouldered by the public sector through the guaranteed loans. With most of the financing essentially through the public sector one might wonder why the private sector participation was supposed to be as high as 50 per cent.

° However, the issue of the private sector's obligation towards the repayment of the loans is important. It would be remiss to suggest that a high profile multinational or its Canadian partners would walk away from unpaid debts at the end of the project life.

° However, at the end of the project the private sector could have been faced with an outstanding debt worth billions of dollars.

° The problems for Alsands cannot simply be summarized in terms of inadequately formulated policies and inefficient policy approaches. The Alsands experience must also be explained in terms of a changing environment. The project was to have gone ahead in an era when it was quickly becoming apparent that oil prices were weakened and real interest rates rising, not a time to undertake a mega project, which was to include upgrading and produce synthetic crude oil. It was however a time when smaller in situ bitumen production (without upgrading) for sale as asphalt feedstock was beginning to look promising.

- Our analysis shows that the final offer itself would be robust only under conditions of rising prices.

- There are unfortunately few studies which detail the minimum scale at which Alsands could be mined. Unless it is found that the operation could be run at a much smaller scale, Alsands will likely remain on the side lines.

Wolf Lake

- The Wolf Lake In-Situ Oilsands Project is a small scale commercial project designed to produce 1100 cubic metres (7,000 barrels) per day of bitumen over a period of 25 years. Production is scheduled to begin in 1985.

- Total capital expenditure over the project life will be about $550 million (1983 $). The project participants are BP Exploration Canada Limited and Petro-Canada Exploration Incorporated.

- The Wolf Lake Project will be subject to a fiscal regime that has been negotiated between the federal and provincial governments and the project participants.

- The Wolf Lake regime is an example of the current state of oilsands policy. It reveals a more pragmatic approach to policy making and negotiation on the part of both government and industry. The regime has evolved from changes in petroleum taxation that have been incorporated into federal budgets and in part it is a result of government and individual company negotiations.

- It would appear that it is a generic sort of policy that will in fact be used on a number of small oilsands projects. We suggest that both the Wolf Lake and the Cold Lake projects exemplify this revised attitude towards oilsands policy making.

- The economic analysis and sensitivity tests reveal that the regime is quite sensitive to changing economic conditions. The government revenue takes are clearly smaller as economic conditions become less favourable.

- A policy that is readily applied to oilsands projects without lengthy and costly negotiation is surely a more efficient way to proceed than the hit and miss piecemeal approach of a few years ago. Currently it appears that the basic structure of the Wolf Lake regime will provide a basis around which companies from individual projects will negotiate the finer details of the policy according to the characteristics of each project. Once experience is gained with these projects and they become more numerous a policy that is generic in all respects should be put in place for in-situ oilsands projects. We note that the benefits of a good generic policy can only be maximized if the rules of that policy are known and understood by all from the beginning. This is not the case at the present time, and it appears that the evolutionary path of oil sands policy is still unfolding.

1. INTRODUCTION

This paper provides an economic assessment of the Alsands Project, an oilsands mining project and the Wolf Lake Project, an oilsands in situ project. The Wolf Lake Project is presently under construction, while the Alsands project has been put on the shelf.

The intent of this paper is to provide an overview of the technologies and assess the economics of the two projects individually recognizing that the production methods, the final products and the scales of the two projects are distinctly different. At the same time however, an attempt is made to compare the two projects to gain insights into the evolution of policy approaches to oilsands development.

The economics of the two projects are examined under a number of conditions of price, fiscal terms, and cost of money. One objective of the economic analysis is to show the effect of various fiscal measures and pricing assumptions on the corporate rate of return. Another is to show the share of revenues taken respectively by the federal and provincial governments and by the companies. Estimates of the social and private supply prices for oil from the projects are also provided. Conclusions regarding the appropriateness of past and present oilsands policy are then drawn from the economic analysis. The first half of the paper deals with Alsands. The second half deals with Wolf Lake.[1]

The paper proceeds with the analysis of the Alsands Project. The project is described in terms of the scale of the project, the technology which was to have been used, and the production profile and the cost structure of the project. The project is further described in terms of the corporate participants and the evolution of the fiscal package which was offered to the project group at the time of its final demise. Following the project description, the results of economic analysis are presented.

In the second half of the paper a description of the Wolf Lake Project is presented, again in technological terms and in economic terms. The general details of the fiscal regime under which the project will operate as well as the implications of that regime are outlined. Following the project description the results of the economic analysis are presented.

2. ALSANDS

2.1 The Alsands Project

After some 5 years of planning the Alsands Projet Group announced the suspension of its oilsands mining project in Alberta's Athabaska oilsands in April 1982. The development was to have produced 219 million cubic meters (1.3 billion barrels) of synthetic crude oil over a producing life of 29 years. The Alsands deposits are located on the east side of the Athabaska River 65 Km North of Fort McMurray.

2.2 The Technology of Mining Oilsands

Mineable oilsands deposits are those which lie under 250 feet or less of overburden. The Alsands deposits lie under about 40 feet of muskeg and other overburden material. Before any extraction can take place the muskeg must be drained and removed.[2] In this section we provide a general description of the technology that was to have been used to mine the oilsand.

The mining process for Alsands was to have employed a combination dragline/bucketwheel method of removing the overburden and oilsand. Four large draglines would be used for primary excavation and oilsands stockpiling while four bucketwheel reclaimers would transfer the stockpiled oilsands onto a conveyor transportation system.

The oilsands would be transported to an extraction plant where the bitumen would be separated from the sand by a process of mixing the oilsand with hot water, a caustic (sodium hydroxide) and steam. The bitumen would be held in revolving drums allowing the bitumen to separate from the sand. The bitumen would be placed in a settling tank where it would be floated and skimmed off. The bitumen product would then be fed to a froth treatment plant in which the bitumen would be diluted to provide a suitably upgraded feedstock for further processing.[3] Tailings result from the extraction process and would be piped in slurry form to a tailings pond enclosed by dikes.

The upgrading process which was to have been used in the Alsands Project involved fluid coking whereby the bitumen would be thermally cracked in fluid cokers to produce gases, liquids and by-product coke. The cracked gases would be used as fuel in the utility plant which was to have been on site while the liquids would be upgraded to synthetic crude oil with a gravity of 34-36° API and a sulphur content of about 0.2%.[4]

The Alsands Project plan drew heavily on Syncrude's experience in matters of technical detail. This may have proved to be quite an advantage to Alsands in the sense of "learning by watching" as will be pointed out in section 2.3 below.

The Syncrude method of mining is essentially the same method as that planned for Alsands. The extraction methods are also similar. The novel feature in the Alsands plan was the proposed utilization of by-product coke as a source of process hydrogen in bitumen upgrading operations.[5] This process is called coke gasification and is not a part of the Syncrude scheme.

2.3 Production Profile and Cost Structure

While the Alsands project was in its planning stages during the late seventies it was clearly an example of the trend of the day. It was a mega project in every detail. The daily production at full capacity was to have been about 21,000 cubic metres (130,000 barrels). The total cost of the project at the time of its demise in 1982 was estimated to be about $12 billion (1982 $).[6]

Planning of the project began in 1977 and production was scheduled to commence in 1988. By 1989 the operation was scheduled to reach 50 per cent of planned capacity and the full capacity annual production rate of 7.6 million cubic metres (48 million barrels) was to have been achieved by 1995. Production shutdown was scheduled for 2018. Throughout the producing life of the project the operating costs were expected to be around $400 million annually (1982$).[7] Capital costs for the total project were estimated to be just under $12 billion (1982$).

The production profile is shown in Figure 2.2. The expenditure horizon is illustrated in Figure 2.1.

In this type of oilsands project the upfront capital investment is very large. The cost data used in this analysis suggest that roughly 90 per cent of all capital expenditures were to have been made in the pre-production years. A large portion of pre-production expenditures are incurred for overburden removal and mining activities. Other expenditures include construction of the bitumen extraction and upgrading units and the utilities plant. Another significant sum would be expended for such things as engineering and technology related fees, insurance, site access and development, fleets of buses and aircraft, and project staffing.

Capital expenditures in the post production years corresponded primarily to the installation of the POX unit (coke gasification unit) and to the replacement of capital equipment in the mine.

While we do not provide definitive cost comparisons between Alsands and Syncrude it seems reasonable to explain Alsands' significantly higher real dollar pre-production costs as a result of three factors. First, inflation clearly impacted on cost estimates for Alsands. Secondly, the scope of the two projects was somewhat different in that Alsands was to have included a coke gasification process. Thirdly and perhaps most significantly Alsands was able to benefit from the observation of problems met by Syncrude. In its initial operating years Syncrude was met by breakdowns and other interruptions. The problems resulted in further expenditures for Syncrude after production start-up. Through careful observance of such occurrences the same expenditures could be made by Alsands prior to its start-up date. Hence Alsands' estimated real dollar pre-production costs were greater than those incurred by Syncrude.

2.4 The Alsands Project Group (APG)

The APG began as a nine-member consortium managed by Shell Canada Resources Ltd. The original members and their project shares are as follows:[8]

Amoco Canada Petroleum Co. Ltd	10%
Chevron Standard Ltd	8%
Dome Petroleum Ltd	4%
Gulf Canada Ltd	8%
Hudson's Bay Gas and Oil Co. Ltd	8%
Pacific Petroleum Ltd	9%
Petrofina Canada Ltd	8%
Shell Canada Resources Ltd	25%
Shell Explorer Ltd	20%

The APG submitted its application to the Alberta Energy Conservation Board in December 1978. Final approval for the project was given by the Board in December 1979. In the winter of 1980 the APG proceeded to develop and prepare the project site.

2.5 The NEP and the Evolution of an Alsands Policy

In the fall of 1980 the NEP was announced at which time the consortium announced that the project would not proceed under the NEP pricing and tax regime. Spokesmen for APG stated that they were not prepared to proceed without full assurance of international prices.

Negotiations between the Alberta Government and the federal Government were held through the spring and summer of 1981. The province's demand was to permit a change in NEP which would allow oil from oilsands to receive the international price. The result of the negotiation was Energy Pricing Agreement of September 1981 in which the province's request was granted. It should be noted that retaliatory action had been taken by the Alberta government in response to the NEP. The provincial government announced in the fall of 1980 that approval for the Alsands project would be withheld. Given this action combined with the uncertainty of the NEP, the economics of the megaproject were quite obviously clouded by the time that the Alberta-Canada Agreement was signed ten months later in September 1981.

The Agreement also included an Alberta Royalty for Alsands (and Cold Lake) which was comprised of a pre-payout royalty phased in to 10 per cent of gross revenues and a 30 per cent royalty on net profits after payout.

Through Petrocan the federal government committed itself to a 17% equity interest, equal to the shares of Pacific Petroleum and Petrofina Canada, in the Alsands Project at the time of the September 1981 agreement.

Following the pricing agreement the consortium made it abundantly clear that further provisions to improve the fiscal package for Alsands would have to be made. In December 1981 the APG announced to both governments that in order for the project to proceed a 20 per cent nominal rate of return was required. The required rate was based on the perceived future inflation rates and costs of money.

In the months following, adjustments were made in order to accommodate that target. However during the process some participants began to withdraw from the project. On February 1, 1982 Amoco and Chevron with a combined 18 per cent ownership in the consortium conditionally withdrew. By the end of that month Shell Explorer (20 per cent) and Dome Petroleum (12 per cent including the initial Hudson Bay share) also conditionally withdrew stating that given their tax positions they were unable to remain in the project, unless fiscal changes were made.[9]

By March 1982, 50 per cent of the original private sector interests had conditionally withdrawn and 17 per cent had been taken over by Petro Canada, leaving only Shell Canada initially with 25 per cent and Gulf Canada initially with 8 per cent representing the private sector.

The Alberta government was adamant that the private sector participation in such a large project be at least fifty per cent. However at the same time it did believe that an oilsands plant at that time would be a sound equity investment for the Heritage Savings Trust Fund and in the end it did propose a 25 per cent provincial equity interest in the project.[10] A final fiscal package was presented to the consortium in April 1982.

2.6 The Final Offer

The final fiscal package, outlined in Appendix 1 and 2, and described below, that was put forth by Alberta and the federal government will be referred to simply as the Final Offer.

The offer was clearly a vast step away from the conventional method of taxation which provides tax deductions for pre-production capital expenditures to those who are in fully taxable positions and able to take advantage of the deductions from taxable income. However therein lies the problem for a consortium of nine members who are unlikely all to be in fully taxable positions. It has been suggested that the rates of return that could have been expected by those members who were not in a fully taxable position would be significantly lower than returns earned by members who were able to take full advantage of all available tax deductions. In terms of their tax positions not all partners were beginning on an equal basis.

The final offer attempted to give the partners an equal footing from the outset by replacing the normal depreciation allowances with loan guarantees which approximated the value of the standard tax deductions. We note that all businesses receive tax writeoffs in one form or another. No principal or interest would be repaid until after production start-up and no taxes nor the net revenue royalty would be imposed until after the loans were repaid. The final offer contained a number of important elements.

2.6.1 Capital Structure

The private sector would participate at least 50 per cent in the project but the two governments would provide loan guarantees for 68 per cent of private sector expenditures in the preproduction period. It may be noted that the Petro Canada 17 per cent interest would be viewed as part of the federal share. We assume that the project balance sheet would show the Consortium holding 50 per cent of equity and 50 per cent of the project although 34 per cent (50 per cent times 68 per cent) of the Consortium equity would itself be financed through guaranteed bank loans. Presumably, these loans would be through a banking consortium and would be floating rate prime loans.

Under these conditions, with the Alberta government and the federal government each with 25 per cent of the equity and 25 per cent of the project, the resulting capital structure would be approximately as follows:

	%	(1982 constant $) $ millions
Private Sector 50% Equity Interest:		
Consortium Equity at Risk	16	1,680
Consortium Guaranteed Loans	34	3,570
Public Sector 50% Equity Interest:		
Alberta Equity at Risk	25	2,625
Federal Equity at Risk	25	2,625
Total Pre-production Investment:	100	10,500

2.6.2 Loan Repayments

The final offer stated that no repayment of interest or principal on the guaranteed loans would be scheduled until after start-up. Interest would be capitalized and added to the guarantee. After production start-up 58 per cent of the net revenue accruing to the private sector Consortium would be paid on the loan guarantee. No taxes or royalties would be levied until after the loan was fully repaid.

We suggest that this arrangement would perhaps have been viewed as functioning roughly as follows; during the preproduction period the Consortium would draw down against its bank loans and the governments would recompense the banks for interest payable which amounts would be added to the Consortium's liability to the governments, to be repaid to the governments after the commencement of production. Repayment by the Consortium would take place at the rate of 58 per cent of its net revenue.

In effect we can visualize the governments as undertaking the bank loans on behalf of the Consortium and thus paying the terms required by the banks, but being repaid by the Alsands Consortium at the given rate of 58 per cent of net revenue, after the beginning of production.

Evidently should the (floating prime) interest rate, required by the banks, increase, the governments would have to pay more and the ultimate liability of the Consortium would rise but the Consortium would never pay back the loan plus interest in annual amounts higher than 58 per cent of net revenues.

Under these loan conditions it could occur, for example because of higher than expected prime rates or because of low oil prices, that while the banks would always be paid back, the governments may never be repaid by the Consortium. The Consortium Balance Sheet could carry a growing liability to the governments. What would happen to this liability? Could it grow to be large enough to upset the financial integrity of the Consortium participants? Would a ballooning liability eventually be forgiven? These are some of the concerns which were raised by the Consortium.

The final offer, being essentially a proposal, could not be expected to iron out all the details and we must assume that the package would have been refined so that it would not break down. However, while the governments guaranteed the loans to the banks we presume that the governments were not intending to forgive the Consortium's possible liability at the end of the project. We suppose that, in principle, the Consortium would have been liable to the governments for any unpaid balance and that the governments would only write off that debt if the Consortium (or its members) were not capable of paying it.

Clearly, the possible anomalies that might arise in this kind of three cornered agreement should not be unnecessarily accentuated in our analysis because the agreements could have been adapted and refined. However, the message seems to be that last ditch, apparently generous, offers by governments for project fiscal terms, may backfire. We will examine a number of interesting cases.

2.6.3 Taxes and Royalties

The central theme of the Final Offer on taxes and royalties was that no taxes and minimal royalties would be levied until the guaranteed loans were repaid. After loan repayment, the private sector's revenue share would be subject to income tax, PGRT (16%) and net revenue royalties. Before payout of the loans, Alberta would have a gross royalty, phased in after production of 5 million barrels at the rate of 1 per cent every 18 months to a maximum of 5 per cent. Thereafter, Alberta would have the greater of the 5 per cent royalty or a royalty equal to 30 per cent of net revenue.

2.6.4 Overview of the Final Offer

To summarize the foregoing points; in the final offer the governments effectively provided between 50 per cent and 84 per cent of the project financing. The Consortium, however, was faced with a number of ill-defined liabilities in respect to the guaranteed loans. The guaranteed loans were central to the package in a number of ways; 58 per cent of net revenues was assigned for their repayment, taxes and royalties would be minimal until the loans were repaid and hence a faster repayment of the loans would induce earlier taxes and royalties and the converse, the loans were the largest single chunk of the project investment, and consequently, they were liabilities which the Consortium viewed as a potential millstone around their neck.

It would appear that the interplay between the loans, their repayment and the other elements in the package could lead to anomalous results for the Consortium.

2.6.5 The Base Case

Our Base Case with the final offer includes a number of important assumptions, outlined in Appendix 5. Oil prices are assumed to remain constant in real dollar terms. Nominal interest rates and inflation are projected so that the average real interest rate is about 4 per cent per year. Project investment costs were provided by Shell Canada, at some $12 billion (1982$), and we assume that unit operating costs remain constant in real terms over the life of the project.

The impact of the final offer on the company's rate of return and supply price are reported in the following section.

2.7 Sensitivity Tests

2.7.1 Introduction

This analysis provides an assessment of the impact of the final offer on the private sector's, 50 per cent cost and revenue shares. Sensitivity tests are performed on certain parameters within the offer. The impact of the final offer is also compared to the impact of an NEP type tax regime and to the impact of a tax regime that is currently being used for smaller in situ oilsands projects. The assumptions for the fiscal regimes, prices, inflation and the cost of money are given in the Appendices. The Final offer is outlined in Appendix 1. Appendix 2 describes the nature of the loan that was to have been made to the company and the implications of that loan.

It has been suggested that the consortium viewed as critical questions; how sensitive was the rate of loan repayment to changes in various parameters? For instance would a decrease in the price of oil make the debt load impossible to carry? Would an increase in interest rates prevent the loans from being repaid during the life of the project which would in turn result in taxes and full royalties never being imposed? In answering these questions we hope to shed light on what conditions would have had to prevail in order to ensure that the final offer was a viable offer from the private sector's viewpoint. We should also be able to determine just how resilient this type of fiscal regime is to unforseen fluctuations. The key criterion for judging the project's economic viability from the consortium's viewpoint is based on their stated required nominal rate of return of 20 per cent, around which the final offer was constructed.

2.7.2 Results: Rates of Return

Given the base case assumptions of flat real prices and costs and the base case interest rates, the final offer base case does yield a nominal rate of return of 23.5 per cent (15.7 per cent real) which is viable given the criterion of 20 per cent.[11] At the time that the final offer was made it was expected to yield a rate of return for the private sector that varied between slightly less than 20 per cent and slightly more than 20 per cent depending on which price forecast was used.[12]

A final decision whether to proceed with this type of mega project will be based on a number of factors and will go beyond just a single base case rate of return. The final decision is more likely to be based on the sensitivity of this return to changes in the parameters surrounding the final offer.

It should be noted that throughout this paper the social case looks at the project economics without any taxes, royalties, loans or subsidies etc., and the private case assesses the economics when taxes, royalties, etc. are imposed. It can be observed, from Table 2.1, by comparing the social and private real rates of return for the Base Case, of 6.2 per cent and 15.7 per cent respectively, that the final offer greatly assists the private sector's profitability in the project.

Price Increases

In this case real prices increase at an annual rate of 5 per cent. While this assumption may appear unlikely it does attempt to bracket an extreme limit for a range of future oil prices which are at best clouded in uncertainty. The fact that the results do not go through the roof suggests that without drastic price changes the interacting and offsetting features of the fiscal regime tend to mask the effect of rising prices. This price assumption is not presented as a forecast and should be considered as a tool that is used for analytical purposes only to see how the fiscal regime performs.

Rising real prices generate higher real revenues but because of the conditions of the final offer, the higher revenues do not translate directly into higher private rates of return. Rising real prices imply that the loans are paid off sooner. In the base case where prices remain flat in real terms, loans are repaid 26 years after production start-up, as shown in Table 2.2, and thus taxes and full royalties are not imposed until close to the end of the project. Under the rising price scenario, loans are repaid 8 years after production start-up at which time full taxes and royalties are imposed.

Rising real prices do cause a significant improvement in the private rate of return, from 15.7 per cent to 24.5 per cent, but the increase is dampened by the earlier repayment of loans and the imposition of full taxes and royalties. The improvement in the real social rate, from 6.2 per cent to 15.5 per cent, is proportionally greater, as shown in Table 2.1.

The relationship between higher prices leading to higher net revenues and therefore a faster repayment of the guaranteed loans, and the subsequent increases in taxes and royalties does introduce an automatic resilience into the fiscal regime under different price scenarios. With higher prices, the Consortium would be provided with a higher rate of return but, as shown in Table 2.3, their share of net revenues is reduced.

Price Decreases

In the declining price case, of a 5 per cent per year decline in real oil prices, no rate of return is calculated. However conclusions can be made about the general effects of declining prices. As shown in Table 2.2, loans are not repaid during the life of the project, and therefore neither taxes nor full royalties are ever imposed. Thus the effect of falling real revenues is lessened. Clearly falling prices impact heavily on the company's ability to carry the debt load. Of course in cases where the debt is not repaid during the project life, the issue of how, when or if the debt is repaid remains. For simplicity, discussion of the repayment of the outstanding loan balance is dealt with in a following section.

Higher Interest Rates

When interest rates payable on the guaranteed loans are higher by some 4 percentage points over the Base Case, the debt is not repaid and the project is never liable for taxes and full royalties. If subsequent repayment of the outstanding loan balance is not incorporated into the cashflow then the private rate of return improves significantly. We note that if the outstanding loan balance is ignored it is implicitly assumed that the Consortium is incapable of paying the outstanding balance at the end of the project and is forced to default on the loan. We stress that this scenario is carried out for analytical purposes only. It allows us to see the relationship between the inflowing loans and the outflowing repayments in present value terms. It is reasonable to assume that the Consortium would want to avoid such an outcome at all cost and the possibility of such an outcome is quite obviously one of the reasons that the Consortium did not proceed.

In effect this assumption suggests that the governments forgive the outstanding loan liability at the end of the project life. This anomalous result that the private rate of return actually improves when the interest rate payable on the guaranteed loans is higher, happens because the final offer specified that only 58 per cent of the private sector net revenues would be earmarked for loan repayment. As long as the 58 per cent is inadequate to pay back the loans the private sector continues to collect the remaining 42 per cent without taxes and minimal royalties. At the end of the project life the private Consortium members would have an outstanding liability to the governments. The social rate of return remains unchanged of course.

Assuming the governments are left holding the bag, an improvement in a project's private rate of return under a scenario of higher borrowing costs seems perverse to say the least. It denotes a very unconventional fiscal regime that was contrived in an eleventh hour effort to save the project at any cost. A tax and royalty regime that hinges around the point in time at which loans are repaid seems virtually bound to impact unexpectedly on the private sector's profitability in the event of a change in their ability to carry the debt load.

If the repayment of the unpaid loan balance is ignored, it implies that the private sector's share of the project is in fact subsidized. If the repayment of the unpaid balance is incorporated into the analysis, the private sector's economics deteriorate substantially. Our analysis assumes that the balance of the unpaid loans is repaid in the final year. This would tend to put downward pressure on the companies' rate of return and dampen the improvement gained in the absence of taxes and full royalties. The inclusion of the repayment of the remaining unpaid loan balance in the private sector cashflows changes the economics of their share of the project immensely, from a real rate of return of 22.7 per cent if the loan were forgiven, to a return of 5.3 per cent if the unpaid loan balance is paid off, as shown in Table 2.1.

Assuming the higher loan interest rates, by the 37th year of the project, some \$14 billion (1982\$) remains in the outstanding loan balance. At that time no principal repayment has been made. The 58 per cent of net revenues that are directed towards loan repayment are used in entirety to cover the interest costs.

The nominal rate of return is diminished to 11.6 per cent when the repayment of the unpaid balance is made in the final year. Clearly this return would not be adequate to meet the private sector criterion of 20 per cent.

While this situation is unrealistic because in the circumstances of higher real interest rates, some modifications would have been made to the agreement long before the last years of the project, it does illustrate the tenuous nature of such an offer. It demonstrates also that under this type of fiscal arrangement it was quite possible that the companies could collect 42 per cent of the net revenues generated within its share of the project (58 per cent is paid toward the loan) but in the end the governments could possibly have been left holding the debt load. No tax revenues would have been collected by the public sector. This situation would not be welcomed either by the companies or the governments.

Lower Interest Rates

In this scenario, with interest rates on the loans lower by some 4 percentage points under the Base Case, the project economics deteriorate to the point that the nominal rate of return falls to 18.8 per cent, which is below the criterion established by the consortium. It might be noted that the ex post criterion rate of return might be lower by the amount in which interest rates are assumed to be decreased. However, this would not alter the ex ante criterion and decisions of the Consortium. The loan is repaid 14 years after production start-up so that the onerous full taxes and royalties are imposed at an earlier date than in the base case. Unlike the Increasing Price scenario, in this case there are no increases in the real price to offset the impact of taxes and full royalties. Hence the project appears uneconomic to the private sector given the 20 per cent criterion for judging the project viability. The outcome under lower interest rates illustrates the paradoxical decision making situation which faced the companies, and ultimately the irrationality of this type of offer. Apparently, under more favourable general economic conditions, i.e. lower interest rates, the companies would earn a lower rate of return, suggesting a "regulated" aspect to the Final Offer.

Alsands: NEP Regime

In this case the project economics are assessed under a NEP type regime, outlined in Appendix 4, as it would likely have applied to the oilsands project in 1982. It should be noted that in this case and in the following case, the private sector has a 100 per cent interest in the project as no assumptions are made about government participation. Under the final offer assumptions the analysis looked at the private sector's 50 per cent share of the project.

Under the NEP assumptions two scenarios are tested. In the first scenario the assumption is made that all participants are in a fully taxable position and are therefore able to take full advantage of all tax write offs. In the preproduction years participants are assumed to be able to write off their capital expenditures and thereby receive tax reductions from those expenditures. Under this scenario taxation is done on a full flow-through basis.

Under this NEP type regime the project is dramatically less profitable for the consortium. The nominal rate of return drops to only 8.6 per cent, as shown in Table 2.1, although a maximum of normal tax advantages are assumed. While we do not present any sensitivity results for this case, previous analysis has shown that much of the risk falls on the shoulders of the company. It was also previously found that the PGRT which is based on net operating revenues and the royalty which is initially based on gross revenues and then on net operating revenues would severely limit the upside potential of the project under more favorable conditions.

The NEP regime is also tested under the income tax assumption of a "stand alone" corporation. Under this assumption the participants are assumed not to be in taxable positions at the time that project expenditures begin, meaning that they have no external income in the pre-production years against which they can apply the available tax write-offs. In this case they do not receive any pre-production tax reductions and the project economics are diminished further, to a nominal rate of return of only 6.2 per cent.

These analyses of the initial NEP fiscal regime show some of the reasons why government was forced into the position of attempting to devise an offer package which equalized the positions of partners in the Consortium with respect to taxes, and why such extensive government assistance was brought into the terms of the Final Offer.

Alsands: Wolf Lake Regime

In this final sensitivity test, the profitability of Alsands is assessed under a regime that has been recently negotiated for BP Canada's Wolf Lake Project. The finer details of the regime have yet to be legally finalized or publicized however a general description of the regime is given in Appendix 2.

Compared to the NEP regime, this regime alleviates some of the downside risk of lower prices and higher costs. Both operating and capital costs are deductible for purposes of the PGRT and the net royalty. The project economics do improve, however given the Consortium's criterion of a 20 per cent rate of return, the improvement is minimal.

This case is done under the assumption of full flow-through taxation, meaning that members of the Consortium are able to deduct all their allowable expenses for income tax purposes, against income earned outside the project, from the initial construction years. The Wolf Lake regime does not offer any protection to participants who are not in a taxable position. This could be a crucial problem for a project where the up front capital expenditures are as large as for Alsands, requiring by its sheer size a consortium of several large companies and possibly many smaller partners who would each have different income tax positions.

Alsands and Wolf Lake are two very different projects. Alsands was to have produced 21 thousand cubic metres per day of synthetic crude oil and was to include a very capital intensive upgrading process. Preparation of the mine site and construction of the extraction and upgrading units were to result in a lead time of about 10 years. Had the project proceeded at the time that the final offer was made no revenues would have been generated until 6 years after that point in time. Wolf Lake on the other hand will produce some 1.1 thousand cubic metres per day of bitumen and will not include the costly upgrading unit. The magnitude of the Wolf Lake operation is much smaller than that of Alsands, involving capital expenditures of about $300 million as against some $12 billion. The lead time is also very different. Revenues will be generated two years after the initial major expenditures are made in 1983. The proportion of capital expenditures that will be made in the pre-production years will be much smaller than that of Alsands.

The Wolf Lake regime has been tailored to a small in-situ bitumen producing project and not to a large mining project that produces synthetic crude. While it would not be expected that the Wolf Lake regime would solve the problems of Alsands it is shown, in Table 2.1, that some improvement in nominal rate of return to about 10.6 per cent would be realized, slightly better than the NEP regime. This information could prove useful in the future design of a fiscal regime for a large oilsands mining project.

2.7.3 Results: Net Revenue Shares

The share of each participant of the present value of net revenues, shown in Table 2.3, can show which participant has the greatest scope for improving the economic viability of the Alsands Project. Present value net revenues are defined as total revenues less operating and capital expenses discounted at a cost of money. The level of present value net revenues serves as an indication of the profitability of the project in total or to each participant, and shows whether any economic rent is available, after a chosen normal return to capital, for distribution between the governments and the companies.[13] For analysis of the final offer, the present worth of the guaranteed loans is added to the companies' present value net revenues, and subtracted from those of the governments.

It may be noted that in all cases and at all discount rates the present value of the loan guarantee under the final offer is positive and therefore provides a benefit to the private sector. The present values of the loan guarantee to the companies are very considerable and range from some $1.5 billion upwards depending on the case and discount rate, as shown in Table 2.3. These present values of the loan reveal the significant value of the loans to the companies.

The guaranteed loans in fact subsidize the private sector in a number of ways; first the funds are made available to the companies at the prime rate although they are in effect used for equity participation in the project. Without the government guarantee, this equity capital would be much more costly than the prime rate. The present value of the loans made available to the companies is greater than the present value of the repayments, even when the loans are fully repaid because the companies access funds at the prime rate which is some 3 per cent real in the long term in our analysis, but we are assuming a real discount rate for PV purposes of at least 5 per cent and around 10 per cent as a hurdle rate for the companies. In the base case in which the loans are fully repaid, at 10 per cent discount rate, the loans are estimated to be worth some $2.2 billion to the companies.

Secondly, if the loans are not repaid and are eventually forgiven, as under the decreasing price scenario, then they could be worth some $3.6 billion, at 10 per cent discount rate, to the companies.

It may be thought that the consortium seems to receive value from these guarantees without there being any offsetting cost to the governments: something for nothing? We do not believe that this is realistic because the project risk must be carried, not withstanding that the backing of government is made available. The cost would eventually be borne by governments through, for example, their own costs of raising money increasing fractionally on all their other debt. We accept however, that there are arguments which suggest that the cost to governments would be less than the gain to the consortium, although the cost to government could never be zero. In our analysis we assume that the cost to the governments equals the value of the guarantee to the companies. These considerations complicate any conclusions to be drawn from the analysis of present value revenue shares.

The Final Offer Base Case

In the final offer base case the companies receive the largest portion of the present value net revenues of the project over all discount rates. The provincial government fares better than its federal counterpart since a gross royalty is collected even before the loans are repaid. Because of the gross royalty the province never incurs a 0 per cent portion of net revenues nor a loss.

Increasing Real Prices

When real oil prices are rising, loans are repaid more quickly hence the province and the federal government gain some of the company's share of the net revenues as taxes and royalties are imposed. In this scenario revenues are more evenly dispersed over the three parties over all discount rates than in any of the other cases. It seems that an ingredient for the final offer to be robust was that real oil price would systematically increase.

Decreasing Real Prices

Under declining real oil prices federal taxes are never imposed hence the federal government does not have a share of net revenues. The companies are burdened by the operating losses and the province does not incur a portion of the loss. This again is because the gross royalties are collected even if loan is not repaid. In this case the repayment of the loan is incorporated into the cashflow.

The NEP and Wolf Lake Regimes

The net revenue shares for the Alsands project under the NEP regime and the Wolf Lake regime are similar. The two regimes are applied to the private sector's 100 per cent interest in the project. There are no loans made to the private sector under these two fiscal regimes. The net revenues are negative at real discount rates of 7 per cent and higher. The company carries the largest portion of the loss while the province is the only party who does not incur a loss. However for the Wolf Lake regime where both capital and operating costs are deductible for purposes of the PGRT and the net royalty, the company's loss is lessened and dispersed over the two other parties. But the province still earns positive net revenues.

2.7.4 Results: Supply Costs

The real dollar supply cost ("supply price") to produce a cubic metre of crude oil from a project is given by the total discounted real cost divided by the total discounted production. From society's point of view, the supply cost of a cubic metre of oil ignores taxes and royalties. The supply costs are given in Table 2.4.

For a required real rate of return of 10 per cent the social supply cost of $300/$m^3$ ($48/barrel) is well above the base case plant gate price of $229/$m^3$ ($37/barrel). In the context of the foregoing discussion of revenue shares, it should be noted that the difference between the real supply cost (without taxes and royalties) and the real price received is an indication of the amount of economic rent per cubic metre that is available for distribution between the owners of the resource. In the base case there is no economic rent, at a 10 per cent real discount rate, rather there is a substantial economic loss of some $\$71/m^3$ (\$11/barrel).

The real supply cost to the companies, i.e. the private supply cost, is the average real cost of producing a barrel of oil including any taxes or royalties that must be paid. The real supply cost to the private sector <u>under the final offer base case</u> is $\$198/m^3$ (\$32/barrel) at a 10 per cent real discount rate. This cost is less than the real selling price and less than the real social supply cost at all discount rates which reveals the value of the government backing to the private sector share. The difference between the social and private supply cost indicates the value of the assistance, which at a 10 per cent real discount rate is $\$102/m^3$ (\$16/barrel).

2.7.5 Conclusions to the Sensitivity Tests

The key findings of the sensitivity tests are that:

1. The final offer base case with constant real oil prices provides a sufficient rate of return under the criterion

on a 20 per cent required rate of return. Loans are repaid during the project life.

2. Higher interest rates prevent repayment of the loan during the project life and no taxes or full royalties are paid. If the loan guarantee liability is forgiven, a sufficient rate of return is generated, and the economics in this case are improved.

3. Lower interest rates ensure loan repayment within the project life. Taxes and full royalties are imposed. A sufficient rate of return is not generated in this case.

4. Increasing real prices significantly improve the project economics. Loans are repaid during the project life.

5. Decreasing prices significantly diminish the project economics. The loans are not repaid during the project life and no taxes or full royalties are paid.

6. Under an NEP type regime the Alsands project is not commercially feasible given the criterion of a nominal 20 per cent required return. The private sector economics are worse under an assumption of a stand alone corporation than under full flow-through taxation.

7. Under the Wolf Lake regime the economics are improved over the NEP regime but not to the extent that the project is considered economically viable under the established criterion.

Table 2.1

RATES OF RETURN: ALSANDS

	Private Return %[1]	Social Return %[2]
1. Final Offer Base (constant real prices)	23.5 (N) 15.7 (R)	13.2 (N) 6.2 (R)
Higher Interest Rates (unpaid loan balance is excluded)	31.3 (N) 22.7 (R)	"
Higher Interest Rates (loan balance is paid in final year)	11.6 (N) 5.3 (R)	"
Lower Interest Rates	18.8 (N) 11.5 (R)	"
Increasing Real Prices	32.9 (N) 24.5 (R)	22.9 (N) 15.5 (R)
Decreasing Real Prices	NS[3]	NS
2. Alsands: NEP Regime (full flow-through Taxation) (constant real prices)	8.6 (N) 2.1 (R)	12.7 (N) 5.6 (R)
(Stand-Alone Corporation)	6.15 (N) .19 (R)	"
3. Alsands: Wolf Lake Regime (constant real prices)	10.6 (N) 4.0 (R)	"

1. In the private case taxes and royalties are included (N) Nominal
2. In the social case no taxes and royalties are included (R) Real
3. No solution

Table 2.2

LOAN REPAYMENT FOR FINAL OFFER: ALSANDS

	Number of Years for Repayment (beginning in 1991)	Year in Which Taxes and Royalties Begin
Base Case	26	2016
Increasing Real Prices	8	2008
Decreasing Real Prices	Not repaid during project life	No taxes
Higher Interest Rates	Not repaid during project life	No taxes
Lower Interest Rates	14	2004

Table 2.3

PRESENT VALUE NET REVENUE SHARES (in millions of 1982$ (% of Total)) ALSANDS[1]

Real Discount Rate	To Governments				To Companies			Total Net Revenues[5]
	Provincial	Federal	Loan Guarantee	Total	Loan Guarantee	Revenue	Total	
1. Final Offer Base Case - Constant Real Price								
5%	507 (57)	125 (14)	-1558 (-174)	-926 (-103)	1558 (174)	263 (29)	1821 (203)	895 (100)
6.2%[3]	390	83	-1844	-1371	1844	-474	1371	0
7%	334[2] (-88)	66 (-17)	-1958 (509)	-1553 (404)	1958 (-509)	-789 (205)	1169 (-304)	-384 (100)
10%	197 (-14)	26 (-2)	-2217 (155)	-1999 (140)	2217 (-155)	-1644 (115)	573 (-40)	-1426 (100)
15%	90 (-4)	6 (-.2)	-2226 (109)	-2131 (104)	2226 (-109)	-2136 (105)	90 (-4)	-2041 (100)
2. Increasing Real Prices								
5%	6358 (36)	6686 (37)	-1219 (-7)	11825 (66)	1219 (7)	4795 (27)	6014 (34)	17839 (100)
7%	3998 (37)	4164 (39)	-1479 (-13)	6683 (63)	1479 (14)	2504 (23)	3983 (37)	10666 (100)
10%	2073 (44)	2122 (45)	-1703 (-36)	2492 (53)	1703 (36)	513 (11)	2216 (47)	4708 (100)
15%	767 (135)	755 (133)	-1813 (-319)	-291 (-51)	1813 (319)	-954 (-168)	859 (151)	568 (100)
3. Decreasing Real Prices[4]								
5%	155 (-3)	0 (0)	-2194 (43)	-2039 (40)	2194 (-46)	-5250 (103)	-3057 (60)	-5096 (100)
7%	113 (-3)	0 (0)	-2757 (61)	-2644 (58)	2757 (-61)	-4648 (103)	-1891 (42)	-4535 (100)
10%	73 (-2)	0 (0)	-2942 (75)	-2869 (73)	2942 (-75)	-4007 (102)	-1065 (27)	-3934 (100)
15%	38 (-2)	0 (0)	-2690 (131)	-2652 (129)	2690 (-130)	-3294 (160)	-604 (30)	-2048 (100)

Table 2.3 (Cont'd)

4. Alsands: NEP Fiscal Regime - Constant Real Prices

5%	1790 (100%)	2611 (146%)	752 (42%)	-1579 (-88%)
7%	-767 (100%)	1592 (-208%)	-206 (27%)	-2152 (281%)
10%	-2841 (100%)	714 (-25%)	-972 (34%)	-2581 (91%)
15%	-4080 (100%)	74 (-2%)	-1413 (35%)	-2741 (67%)

5. Alsands: Wolf Lake Regime - Constant Real Prices

5%	1790 (100%)	2165 (121%)	90 5%)	-465 (-26%)
7%	-767 (100%)	1235 (-161%)	-760 (99%)	-1242 (162%)
10%	-2840 (100%)	452 (-15%)	-1400 (49%)	-1892 (66%)
15%	-4080 (100%)	-88 (2%)	1702 (42%)	-2290 (56%)

Notes:

1. The net revenues in the first 3 cases apply to the private sector's 50 per cent interest in the project. In cases 4 and 5 the net revenues apply to private sectors 100 per cent interest in the project.

2. Note that when the total net revenues are negative, a negative share percentage indicates that the party did not incur a portion of the loss: i.e., this was the case for the province in case 1.

3. At a real discount rate of 6.2 (the social internal rate of return) total net revenues equal zero and at higher rates the become negative. The internal rate of return is the discount rate for which total revenues equal capital costs plus operating costs. No percentage shares are reported because TOTAL NET REVENUES are zero.

Table 2.3 Notes (Cont'd)

5. TOTAL NET REVENUES equal Gross Revenues - Capital Costs - Operating Costs. The shares earned by the governments through taxes, royalties and loan guarantees sum to the government total. The government total is shown as a portion of total net revenues and when summed with the companies' total equals TOTAL NET REVENUES.

6. The loan guarantee is reported in cases 1-3 of this table to illustrate that there must be an off-setting cost to the company's gain. The cost to governments is shown in the table by showing the value of the loan as a cost to the governments.

   Given that the responsibility for loan repayment ultimately lies with the governments, (through the guarantee) the cost could also be viewed as the fractional increase in the cost of debt to the governments that would be equal to the value of the guarantee to the companies.

   To illustrate, the fractional increase in the 1982 average long term bond yield for an average outstanding federal debt of some $98 billion assuming the federal government was responsible for half of the $2.2 billion Alsands loan (present value at 10% real) would be roughly 1/7 of a percentage point.

   For simplicity in this table we have assumed the cost of the guarantee to the governments as being equal in magnitude to the company's gain.

Table 2.4

REAL SUPPLY COSTS IN 1982 DOLLARS - ALSANDS

	Real Required Rate of Return	Supply Cost $/m³	($/barrel)
1. Social Supply Cost (without taxes and royalties	5%	209	(33)
	7%	241	(38)
	10%	300	(48)
	15%	425	(67)
2. Private Supply Cost (final offer)	5%	186	(30)
	7%	190	(30)
	10%	198	(32)
	15%	218	(35)
3. Private Supply Cost (NEP regime: full flow-through taxation	5%	247	(39)
	7%	264	(42)
	10%	293	(47)
	15%	361	(57)

Figure 2.1

Production and Expenditure Horizons

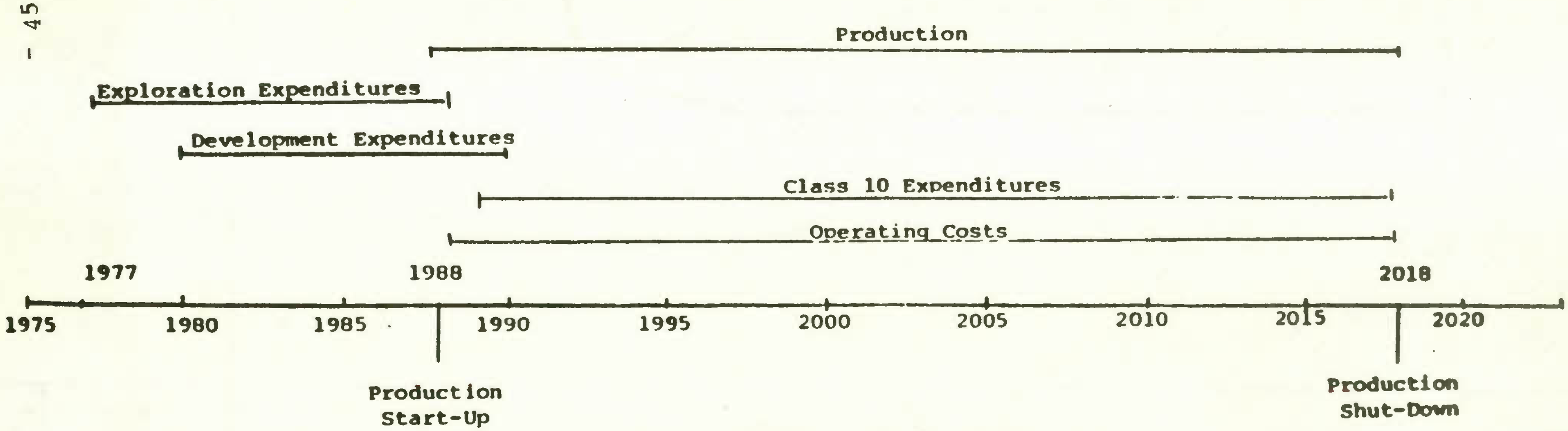
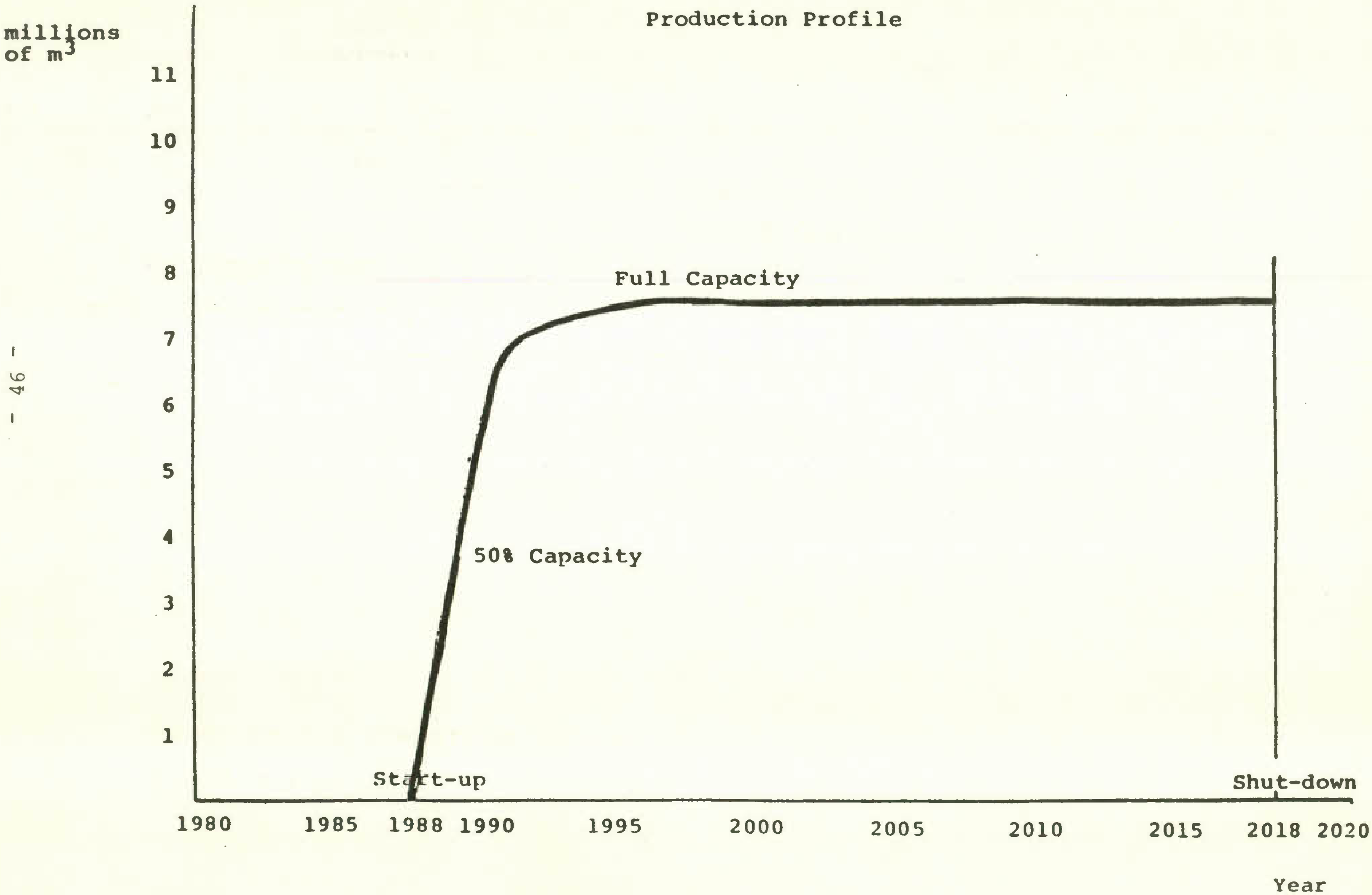


Figure 2.2


Production Profile
millions of m3
11
10
9
8
7
6
5
4
3
2
1
Full Capacity
50% Capacity
Start-up
Shut-down
1980
1985
1988
1990
1995
2000
2005
2010
2015
2018
2020
Year

3. WOLF LAKE

3.1 The Wolf Lake Project

The Wolf Lake Project is a small scale commercial project located northeast of Edmonton in the Marguerite Lake leases. The leases are about 50 Km. North of Bonnyville, Alberta. The project is another step along the way to the commercial recovery of bitumen from the Cold Lake oilsands deposits. We note that currently the commercial viability of the project is fragile in that the sponsors would likely not proceed if prices were to decline. The project is a break-even project under currently projected costs and recovery factors and assumed flat real oil prices. The project is designed to develop techniques developed during pilot testing which will optimize bitumen recovery and to use the technologies of directional drilling and water recycling.

The production life of the project is 25 years beginning in 1985 and ending in 2009. The current project is designed to produce 1100 m^3/day (7000 barrels/day) over 25 years.

3.2 Development of the Wolf Lake Project

The economic analysis provided in this paper deals only with the "half cycle" of the project beginning with the development stage in 1983. Our analysis does not include the costs of the pilot projects that were in fact the forerunners of the Wolf Lake Project. However an overview of the pilots is of interest.

In 1964 BP began experimenting with different technologies and techniques for recovering bitumen in the Marguerite Lake leases. Three experimental wells were drilled in early 1964 and later that year Phase I, a small pilot project began. This pilot project demonstrated that bitumen could be recovered by injecting steam. A second pilot, Phase II which was operational between 1967 and 1970 had some technical success but the results were not favourable enough to warrant commercial development of the area.

Rising oil prices in the early seventies made the economics of oilsands projects more favourable resulting in renewed interest in the Marguerite Lake leases. During this period BP began the field testing of a recovery technique combining cyclic steam stimulation followed by in situ combustion at a pilot called Phase A. Phase A commenced in 1976 and has been carried out by BP Exploration Canada Ltd. in conjunction with Alberta Oil Sands Technology and Research Authority (AOSTRA), Dome Petroleum Ltd and Pan-Canadian Petroleum Ltd. The project is to remain operational until 1985.

Based on the results of the Phase A pilot and additional drilling BP has made the decision to proceed with the Wolf Lake Project.[14]

3.3 The Technology of the Wolf Lake Project

The following discussion is intended to provide a very general overview of the Wolf Lake technology.

The oil bearing sands of the Marguerite Lake leases are part of the Cold Lake oil sands deposits and are found within the Mannville Group of the Lower Cretaceous age. There are four stratigraphic units within the Mannville Group:

i) McMurray
ii) Clearwater
iii) Lower Grand Rapids
iv) Upper Grand Rapids

All formations are present across the entire set of leases however it is the Clearwater Formation that the Wolf Lake project will develop. This formation is located 410-485 metres below the surface of the Marguerite Lake leases. The average pay thickness of the formation is 23 metres. There exist three separate sand bodies in the formation with silty shales of 1 to 3 metre thickness between the sand bodies.[15]

The Wolf Lake Project is currently planned as a cyclic steam stimulation project. However, there may be potential for steam flood or in situ combustion later in the life of the project. Cyclic steam stimulation has been chosen because it is the most efficient existing technology for lowering the viscosity of bitumen. When the viscosity of the bitumen is lowered it becomes mobile.

The process involves two distinct phases over time: an injection period and a production period. During the injection period, 80 per cent quality steam will be injected at a rate of 150-450 m^3/day for approximately 30 days. Maximum water requirements for steam generation will be 8,000 m^3/day. A further requirement of 1000-2000 m /day of water will be required for utility operations. When the project becomes fully operational it will be capable of recycling water at a rate of 3000 m^3/day initially. The remaining water requirements will come from ground water sources. It is anticipated that initially wells will be receiving 9 steam stimulations over a period of 7 years.[16] The cyclic injection of steam is repeated until there is no further economic return.

The primary fuel for steam generation will be natural gas. Approximately 460,000 m^3/day of fuel gas is required. We note that this estimate may be on the low side. The required gas will be from off-lease fields and transported to the project by pipeline.[17] The fuel cost portion of operating costs is an average of about 40 per cent. In order to reduce the operating costs attempts will be made to maximize produced gases as fuel supply.

Electrical power will be purchased from a utility company, but a standby generator will be installed to protect the surface facilities in the event of a power failure.

There are three distinct facilities components to the Wolf Lake bitumen operation: 1) wells, 2) field facilities, 3) central plant.

Steam is generated at a central plant and transferred to satellite sites through steam distribution pipelines. The satellite pads include wellheads, pumpjacks, a steam distribution manifold, and a well production manifold. Crude bitumen and produced water are sent from the satellite to the central plant via a gathering pipeline system.

Wells will be directionally drilled from multi well satellite sites. By January 1985, 192 injection/production wells will be drilled from 10 satellites. Drilling of the first wells began in mid-October 1983. Approximately 50 wells (2-3 satellites) will be added each year to offset production decline. On average 350 wells will be in operation at any one time.[18] Over the project life about 1200 wells will be drilled, each with a life of 5-10 years. The satellite layout is shown in Figure 3.1.

In an attempt to find the well pattern which maximizes bitumen recovery, 5 different well configurations will be used for the first 12 satellites. These will consist of 4 staggered line drive patterns and one line drive pattern as shown in Table 3.4.

Directional drilling from the satellite pads will be used. The maximum well angle will vary between 0° and 45°. Directional drilling is particularly applicable in this area since approximately 60 per cent of the surface is muskeg and the drilling method minimizes the surface disturbance.

There is estimated to be 51.4 million m^3 of bitumen in-place in the development area.[19] The average recovery factor for the project is 18 per cent of oil-in-place.[20]

The following features of the Wolf Lake Project are experimental: 1) well spacing and configurations, 2) steam injection rates, slug sizes and production cycle duration, 3) well drilling and operating schedules to ensure reasonably constant total field bitumen production, water production and steam injection rates, 4) water recycling technology, 5) produced water treatment.

3.4 The Production Profile and Cost Structure

The Wolf Lake Project is an example of a small in-situ oilsands project. Production is scheduled to begin in 1985, two years after initial drilling begins. In 1985 production begins mid year therefore during 1985 production is less than 500 m^3/d (3147 b/d). The designed capacity rate is 1335 m^3/d (8,400 b/d). By 1987 the daily rate of production reaches the planned average production of around 1100 m^3/d (7000 b/d), and remains relatively constant over the life of the project.

Given our pricing assumptions the real 1983 dollar annual operating costs are on average about $35 million. Fuel costs are a large portion of operating costs and in this analysis reflect the pricing assumption. The pre-production capital expenditures are estimated to be about $200 million (1983 $). Total capital expenditures over the project life will be about $550 million (1983 $).

In the pre-production years capital expenditures are made for development (primarily drilling expenditures), the steam distribution system, the product gathering pipeline system, the steam generation and the central plant. In the post production years further development expenditures are made for the construction of additional satellite pads and wells. Expenditures are also made for construction of further steam and product distribution systems. Components of the operating costs include expenditures for fuel, well workovers, pipeline, and well abandonment.

3.5 The Wolf Lake Fiscal Regime

It is publicly known that the participants in the Wolf Lake Project (BP Exploration Canada Limited 50 per cent, Petro-Canada Exploration Inc. 50 per cent) have negotiated and agreed upon a fiscal package with the Alberta and federal governments. It is also known that an agreement has been subsequently reached between the participants of another similar oilsands in situ project (Cold Lake) and the two governments. However the two agreements have not been passed into legislation and the precise details of the packages have not been released, but all media accounts suggest that very similar packages have been negotiated.

The general details of the package do suggest that a significant degree of pragmatism has entered into oilsands policy making. The fiscal package (Appendix 3) offers front-end PGRT relief until the projects have recouped capital and operating costs. Lower royalties are imposed and they are also sensitive to the project's costs. Both the royalties in the later years and the PGRT are applied to revenues net of operating and capital expenditures. The more conventional form of the PGRT as it was introduced in the NEP does not provide for the deduction of capital expenditures and is imposed as soon as production begins.

It might be concluded from the available evidence that oilsands policy is moving from the piecemeal approach of two years ago which involved time consuming and costly negotiations to a single policy that is applicable to all similar projects, that can be kept on the table, and that is known.

It would appear that both industry and government have gone through a learning period where both sides are beginning to recognize issues that are important to each other. In the face of lower oil prices governments have only recently begun to recognize the downside risk for companies and the potential for loss which is inherent in expensive developments.

There are however flaws that have yet to be remedied. Firstly, the rules of the game are not known, at least not in fully documented detail. The companies involved are not at liberty to provide the details of the offers and while the published accounts provide the flavour they are scant in detail. We understand that the provincial minister has indicated that policy for small in-situ oilsands plants will in fact be based on a Wolf Lake type structure or format but the parameters of the regime (royalty rates, payouts etc.) will be negotiated individually for each project according to the characteristics of each project. The advantage of this approach, as seen by industry is that marginal projects with less favourable economics will be taxed less heavily allowing them to go ahead while projects with more favourable economics will be taxed more heavily.

It is own understanding that the deals that are being struck are in fact legally binding contracts. Such contracts cannot be changed at the discretion of the minister as is possible with the more conventional regulation that applies to oil and gas activity. It is not entirely clear that this type of arrangement is more advantageous to either industry or government. While an element of security is added, the arrangement would be very inflexible in the face of drastic world price changes. There would probably be less scope for re-negotiation. Moreover, the legislation of this type of contractual arrangement can be a lengthy process - a situation that is not much of an improvment over the piecemeal approach of a couple of years ago.

It seems to us that it is poor policy for such deals to be struck, for contracts to be let for the projects and for other companies to consider similar projects, without the full fiscal terms being published. If in fact the negotiation process exists in order to recognize the differences (both physical and financial) between projects there appears to be no reason for these deals to be secret.

We suggest that given the small number of these projects currently under consideration, the present arrangement may be suitable for the time being. There is still a great deal of uncertainty surrounding this type of in-situ oilsands project therefore both industry and government are in a learning period. It occurs to us that at the present time, given a basic format for the regime, each project could individually negotiate the parametres for the regime but we see no reason why those parametres could not be made public. We believe that once experience is gained with these projects and they become more numerous a policy that is generic in all respects should be put in place for in-situ oilsands projects.

A second problem arises because the degree to which Canadian ownership ratings (COR) might influence the formulation of a generic and versatile oilsands policy is unclear. As will be shown in the sensitivity tests COR levels and the eligibility for APIPs grants impact significantly on the project economics and on the relative shares earned by the two governments and the companies. It occurs to us that the acceptability of a generic policy to both the government and the companies involved could be influenced by COR levels since the impact of a given policy will be very different depending on what COR levels exist. The impact of APIPs grants is discussed below.

A generic and versatile oilsands policy is only beneficial to the extent that its rules are known well in advance of any decision making and are known by all, and if it is generally applicable to any consortium. This may come to be the case in the future but at present it is not so.

3.6 Sensitivity Tests

3.6.1 Introduction

In this analysis we provide the results of the economic analysis of the Wolf Lake fiscal regime. Certain price and fiscal sensitivities are performed on the Wolf Lake regime. An assessment of the impact of the regime on the private sector's rate of return, supply costs and revenue shares is given. The assumptions for the fiscal regime, prices, inflation and the cost of money are given in the Appendices.

In the Alsands analysis the consortium's criterion for judging economic viability was a required rate of return of 20 per cent. This required rate of return entered into the formulation of the final offer. We do not have that sort of guideline for the Wolf Lake project. It is unknown to us whether or not negotiations centred around a required rate of return put forth by the companies. We do know however that given the negotiated fiscal package the project is going ahead. Further, the price assumptions of the companies account for a fall in the real price of bitumen during the mid eighties. This could occur if in fact, quality differentials change over the period or if nominal oil prices remain constant over the next few years.

The long run real bitumen price in the company forecast is lower than the real price in our analysis. We note that the higher assumed price has been reflected in the fuel component of operating costs for the purposes of the study. We assume therefore that under our estimated nominal private return for the Wolf Lake project of some 19 per cent in the base case the project proceeds. It should be noted that the decision to invest was based on the companies' forecast of lower prices and not on our assumed base case conditions.

We note that a robust analysis of the adequacy of the rate of return would take account of the costs of debt and equity and the expected rates of inflation. In addition, the discussion of an adequate rate of return for this type of project would necessarily involve an analysis of risk. The Wolf Lake Project is very much a pioneering type of project. There are several experimental aspects of the project as we have mentioned in Section 3.3. This clearly adds to the risk. An additional risk factor is the predicted shortage of diluent that will hamper the economics of upgrading and therefore affect the potential for this type of project. For our purposes we will use the 19 per cent as a base case around which we will perform sensitivity analysis.

3.6.2 Results: Rates of Return

Given the base case assumptions (Appendices 2 and 3) of flat real prices and costs, the nominal rate of return generated under the Wolf Lake regime base case is 19.2 per cent (11.5 real), as shown in Table 3.1.

The social rates of return where taxes and royalties are ignored, of 17.3 per cent nominal and 9.9 per cent real, are lower than in the private base case. In the private base case 50 per cent of capital expenditures are eligible for APIPs. The fiscal regime tends to subsidize the project when APIPs are granted. When no APIPs are paid to the project the private returns are similar to the social returns suggesting that without APIPs the fiscal regime just preserves the favourable economics of the project and does not overshoot its role of attempting to collect above normal profits.

Price Increases

The private economics of the project under rising real prices are noticeably improved but the improvement is not astronomical. Real prices increase at a real rate of 5 per cent annually. The rationale for this assumption is given in section 2.7.2.

What is particularly interesting is the comparison between the private returns and the social returns. Unlike the base case, the private economics of the project are somewhat less favourable than the social economics. This suggests that the fiscal regime is capturing above normal profits under more favourable economic conditions. Under more favourable conditions the fiscal regime takes a greater share of net revenues. The imposition of the fiscal regime impacts more heavily as prices rise.

Given that the analysis looks only at the "half cycle" of development and production, some of the above normal profits must accrue to the companies in order to sustain re-investment in further projects which creates jobs and increased government tax revenues. The profits retained by the companies above a normal cost of money can also be considered as a reward for past investment in land acquisition and technology development.

Whether or not the fiscal regime should work to capture above normal profits under more favourable conditions will in part depend on what is being done with the above normal profits. If rising real oil prices indicate scarcity of the resource, the logical use of the resulting profits would be re-investment in non-conventional oil.

It should also be noted that the higher prices for bitumen are a mixed blessing for the companies because they mean in addition, a higher fuel cost component in operating costs in this analysis. This factor also dampens the increase in the return somewhat. However we note that a change in the price of bitumen may not result in a change in fuel gas prices if in fact bitumen prices are changing because of changes in upgrading costs, or in the demand for asphalt/heavy oil rather than because of changes in crude oil prices.

Price Decreases

In the declining price case no rate of return is calculated. However at a 10 per cent real discount rate the net cashflow reveals a loss of $55 million as compared a $101 million profit in the base case. Prices decline at an annual real rate of 5 per cent in this case and again the assumption reflects an attempt to bracket the extreme limits for a range of prices. Given the evidence of the base case and the increasing price case it is likely that a degree of protection is assured by the fiscal package in that the government revenue takes are lessened. Again operating costs are affected. Declining prices cause fuel costs to decline for the purposes of this study. It should be noted that as in the increasing price case fuel prices may not change proportionally to a change in the real bitumen price.

No PGRT Relief

In this sensitivity the PGRT holiday until payout is ignored and capital is not deductible from the PGRT base. In other words a current NEP brand of PGRT is tested. Under this assumption the economics are markedly diminished in comparison with the private base case. In this case the private rate of return is below the social return suggesting that without the PGRT relief the project would not be commercially viable.

NO PGRT

When no PGRT is imposed the project economics are slightly improved over the base case. This suggests that the newly revised PGRT and PGRT holiday have been devised to minimize the damage to project economics from the normal PGRT, when the private nominal rate of return is around 19 per cent.

Full APIPs

In this sensitivity full APIPs are applied at a rate of 20 per cent to all capital expenditures. Only 50 per cent of the project is in fact eligible for APIP grants owing to Petrocan's 50 per cent participation, However for the purpose of sensitivity testing APIPs are granted to the entire project to observe the potential impact.

The private returns are greatly improved as would be expected. APIPs are particularly beneficial in the pre-production years when more than a third of the capital expenditures are made.

No APIPs

When APIPs are removed from the project, the private returns are less than the social returns. The real private return is almost 3 percentage points lower than the real private return in the base case.

3.6.3 Results: Net Revenue Shares

The significance of the net revenue shares has been outlined in section 2.7.3 of the Alsands analysis. The present value net revenue shares are given in Table 3.2.

The Wolf Lake Base Case

In this case the company fares best at all real discount rates because of the APIP grants that it receives. The province is the second largest recipient of revenues but incurs present value losses at a 15 per cent real discount rate. The federal government only earns a positive share at the 5 and 7 per cent real discount rate.

Increasing Prices

The shares are more evenly distributed amongst the participants in this case. The company now receives the smallest revenue share. The federal and provincial governments' shares are improved over the base case reflecting the design of the fiscal regime which increases government revenue takes as the price conditions become more favourable.

Decreasing Prices

In this case all participants share in the present value losses and earn negative revenues. Royalties are earned but they are offset by negative provincial income taxes that arise, therefore even the province shares in the present value losses. At lower discount rates the federal government is burdened by the largest portion of the loss. We note that the loss is in the form of foregone tax revenue and not an out of pocket expense for the federal government. The risk lies with the investor. If the conditions are such that no rents are being generated then there is no room for excessive taxation.

No APIPs

When no APIPs are paid to the project, the province is by far the largest recipient of the present value net revenues.

Through its royalty collection it is able to receive a positive share of revenues over all discount rates. The company is the second largest recipient incurring losses at real discount rates of 10 and 15 per cent. The federal government fares most poorly over all discount rates. In this case revenues are transferred from the company to the province.

Full APIPs

When full APIPs are granted to the entire project a large portion of the province's revenue is transferred to the company and the province experiences a negative revenue share at all discount rates. We note that regardless of the province's direct revenue take from the project provincial benefits will still be enjoyed as part of the 'private' revenues from any oilsands project will be re-invested in Alberta. However, such interplay between the APIPs-COR grants and special fiscal regimes shows the difficulty of devising generic fiscal regime as long as the APIPs-COR grant system exists. The grant system is discriminatory and introduces rigidity and arbitrariness into the fiscal arrangements.

Conclusions

The main conclusion after looking at the revenue shares is that the fiscal regime is quite responsive to the economic conditions under which the project operates. As the conditions become more favourable the governments receive more revenues. However the fiscal package is a long way from a generic fiscal regime that would generally be applicable to this type of project.

3.6.4 Results: Supply Costs

The derivation and implications of supply costs are given in section 2.7.4 of the Alsands analysis. The supply costs for Wolf Lake are given in Table 3.3.

For a required real rate of return of 10 per cent the social supply cost of Wolf Lake bitumen is $180/m^3$ ($28/barrel) and is approximately equal to the real dollar selling price. The social rate of return for the base case is 9.3 per cent suggesting that the supply cost should be marginally higher than the selling price at the 10 per cent rate. The difference is due to rounding.

In the base case the private supply cost is approximately $176/m^3$ ($28/barrel) at a real discount rate of 10 per cent. The private real rate of return is slightly above 10 per cent hence we would expect a private supply cost that is less than the selling price.

When full APIPs are applied the real dollar supply cost to the company of producing a cubic metre of bitumen falls. A portion of its costs are offset by the province. At the 10 per cent real rate of discount the private supply cost is $\$171/m^3$ (\$27/barrel) which is below the selling price of $\$180/m^3$ (\$28/barrel). This means that APIPS on 100 per cent of the project are worth about $\$9/m^3$ to the companies. APIPs on half of the project are worth about $\$4/m^3$.

3.6.5 Conclusions to the Sensitivity Tests

The key findings of the sensitivity tests are that:

1. The base case for the Wolf Lake regime with constant real prices generates a nominal rate of return of about 19 percent. The project receives some subsidization in the form of APIPs. Further relief to the project comes in the form of foregone or deferred tax revenues.

2. The economics are noticeably improved when real prices increase. The fiscal regime in this case impacts more heavily on the project and captures some of the above normal profits from higher prices.

3. Decreasing prices diminish the economics greatly. It is estimated that the fiscal regime cushions the project to some extent from falling prices. There remains, however, considerable price risk in the project economics which will largely be borne by the companies.

4. The normal PGRT would probably make the project commercially uneconomic, but the PGRT relief in the fiscal package appears to minimize the effect of PGRT when the nominal rate of return to the companies is about 18 per cent.

5. APIPs improve the project economics considerably and redistribute revenues from the province to the company. The fiscal package as it is applied to the BP-Petro Canada 50 per cent Canadian ownership situation suggests that it could not be generic for any other partnership situation. The interplay between APIPs and the complexity of the fiscal package makes the whole arrangement inflexible. This particular aspect of the arrangement detracts from what is otherwise a good framework for a generic fiscal regime for oilsands projects.

6. Oil supply costs (when APIPs are excluded) are about $\$180/m^3$ ($28/barrel), at a 10 per cent discount rate, which is about equal to the assumed prices for bitumen, therefore there is little room for economic rent unless the oil prices increase over the life of the project. Alternatively, declining prices would render the project uneconomic. Oil from the Wolf Lake Project is relatively high cost oil and since there are a number of experimental features, the project is subject to potential technological failure (experimental features can also lead to

technological improvement). A simple fiscal regime consisting of profit sensitive taxes and royalties but without the complexities introduced by the APIPs system and its interplay with the fiscal regime might be more productive in showing the way towards generic fiscal regimes for all projects.

Table 3.1

RATES OF RETURN: WOLF LAKE

	Private Return %	Social Return %
1. Base (Constant real prices)	19.2 (N) 11.59(R)	17.3 (N) 9.9 (R)
Increasing Real Prices	28.0 (N) 19.7 (R)	30.1 (N) 21.8 (R)
Decreasing Real Prices	NS[1]	NS
Normal PGRT (without deductions and beginning with production)	14.9 (N) 7.6 (R)	17.3 (N) 9.9 (R)
No PGRT	20.6 (N) 12.8 (R)	"
APIPs on 100% of Project	22.2 (N) 14.3 (R)	"
No APIPs	16.7 (N) 9.3 (R)	"

(N) Nominal, (R) Real

1. No Solution

Table 3.2

PRESENT VALUE REVENUE SHARES: WOLF LAKE
in millions of 1983 dollars (per cent of total)

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
1. Wolf Lake Base Case - Constant Real Prices-APIPs on 50% of Project				
5%	123 (100%)	33 (27%)	20 (16%)	70 (57%)
7%	67 (100%)	18 (27%)	5 (8%)	44 (65%)
10%	9 (100%)	3 (35%)	-10 (-112%)	16 (77%)
15%	-45* (100%)	-10 (22%)	-22 (49%)	-13 (29%)
2. Wolf Lake - Increasing Real Prices				
5%	760 (100%)	264 (35%)	267 (35%)	229 (30%)
7%	546 (100%)	190 (35%)	190 (35%)	166 (30%)
10%	332 (100%)	165 (35%)	114 (35%)	101 (30%)
15%	135 (100%)	51 (38%)	46 (33%)	39 (29%)
3. Wolf Lake - Decreasing Real Prices				
5%	-171 (100%)	-38 (22%)	-84 (49%)	-50 (29%)
7%	-164 (100%)	-36 (22%)	-75 (46%)	-52 (32%)
10%	-154 (100%)	-34 (22%)	-66 (42%)	-55 (36%)
15%	-144 (100%)	-31 (22%)	-55 (38%)	-58 (40%)
4. Wolf Lake - No APIPs				
5%	123 (100%)	69 (56%)	4 (3%)	50 (41%)
7%	67 (100%)	50 (75%)	-9 (-13%)	26 (38%)
10%	9 (100%)	31 (348%)	-22 (-244%)	-.35 (-4%)
15%	-45* (100%)	14 (-31%)	-32 (71%)	-27 (58%)
5. Wolf Lake - Full APIPs				
5%	123 (100%)	-2 (-2%)	36 (30%)	89 (72%)
7%	67 (100%)	-14 (-20%)	19 (28%)	62 (92%)
10%	9 (100%)	-25 (-277%)	2 (22%)	32 (355%)
15%	-45 (100%)	-34 (75%)	-12 (27%)	1 (-2%)

* Note that when the total net revenues are negative, a negative share percentage indicates that the party did not incur a portion of the loss: i.e., this was the case for the province in case 1 at a 15% discount rate.

Table 3.3

REAL SUPPLY COSTS IN 1983 DOLLARS - WOLF LAKE

	Real Required Rate of Return	Supply Cost $\$/m^3$ ($/barrel)
1. Social Supply Cost (without taxes and royalties)	5% 7% 10% 15%	158 (25) 166 (26) 180 (28) 202 (32)
2. Private Supply Cost (Wolf Lake Fiscal Regime)	5% 7% 10% 15%	168 (27) 171 (27) 176 (28) 187 (30)
3. Private Supply Cost (Wolf Lake Regime with APIPs on 100% of Project	5% 7% 10% 15%	164 (26) 167 (27) 171 (27) 181 (29)

TABLE 3.4

EXPERIMENTAL WELL SPACINGS FOR THE FIRST TWELVE SATELLITES

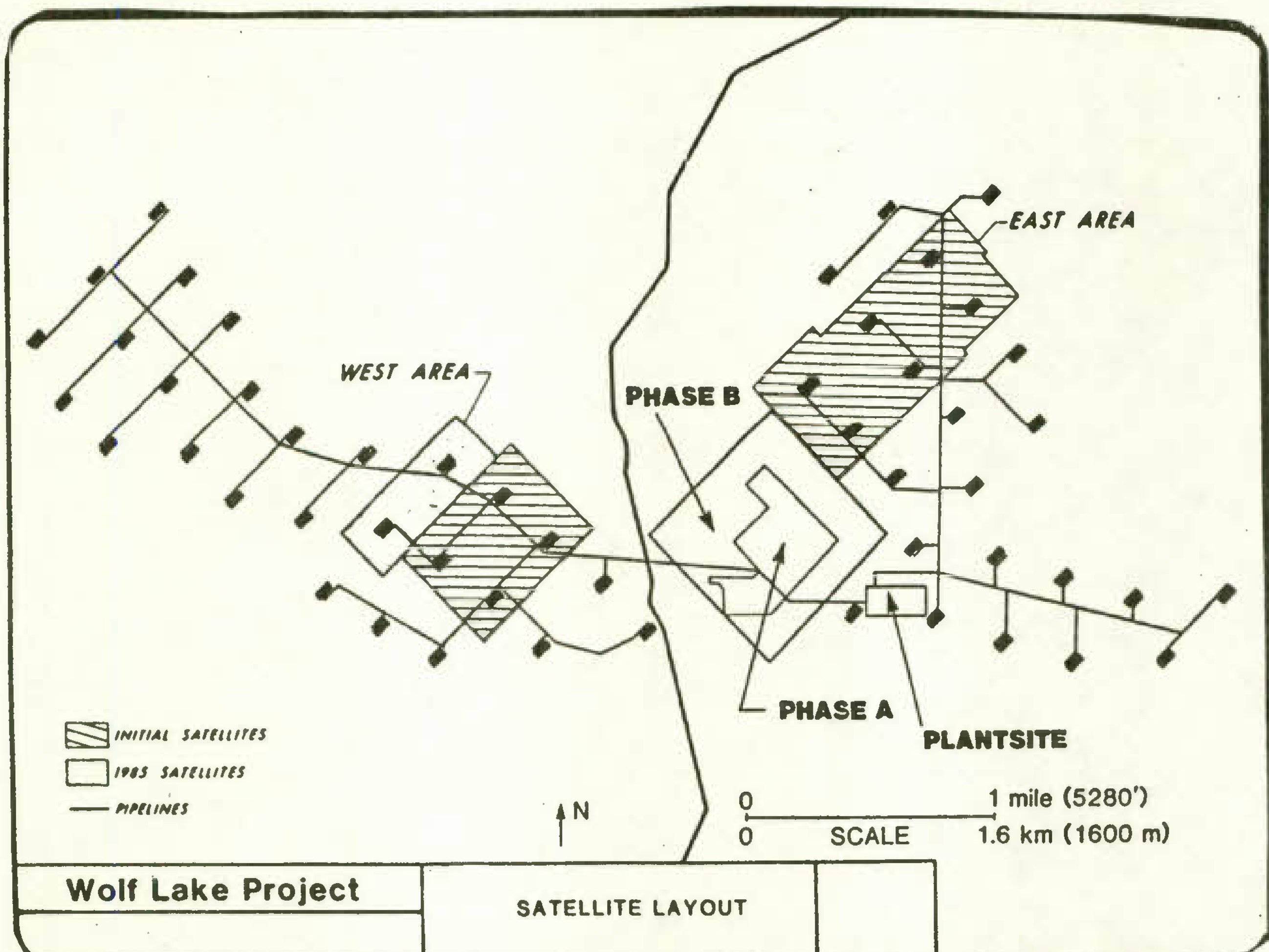
	Pattern	Well Spacing (Hectares)	Distance L1* (m)	Distance L2* (m)	No. of Wells
I	Staggered Line Drive	0.66	220	30	39
II	Staggered Line Drive	0.88	220	40	50
III	Staggered Line Drive	1.1	220	50	96
IV	Line Drive	1.1	220	50	35
V	Staggered Line Drive	1.32	330	40	33

* L1 = Distance between wells in a row

* L2 = Distance between rows

A row will be oriented in a northeast-southwest direction

Figure 3.1



Source: BP Exploration Canada Ltd., "Application to Construct and Operate An Oil Sands In Situ Experimental Thermal Project", Application to the AERCB

APPENDIX 1

The Final Offer

The offer presented jointly by the Governments of Canada and Alberta to the Alsands companies was as follows:

1. Private sector participation would be at least 50 per cent, but in lieu of normal tax write-offs the two governments would provide loan guarantees for 68 per cent of private sector expenditures in the pre-production period.

2. No repayment of interest or principal would be scheduled until after start-up. Interest on the guaranteed loan could be capitalized and added to the outstanding loan balance, and the guarantee increased accordingly.

3. After production start-up, 58 per cent of the net revenue accruing to the private sector would be paid on the loan guarantees. Net revenue is equal to gross revenue minus 110 per cent of operating costs minus capital additions minus the Alberta 5 per cent gross royalty.

4. Net revenue accruing to the private sector would not be subject to income tax or to other taxes or to Alberta's net revenue royalty until the loans are paid. After loan repayment, the private sector's revenue share would be subject to income tax, PGRT and royalties.

5. Alberta's maximum 25 per cent equity interest would not be subject to taxation by the federal government. Alberta would have a gross royalty phased in after the five million barrels at the rate of one per cent every 18 months to a maximum of 5 per cent until the guaranteed loans are repaid. Thereafter, Alberta would have the greater of a 5 per cent royalty or a royalty equal to 30 per cent of net revenue.

6. The federal government's equity interest, to a maximum of 25 per cent, would pay provincial taxes and the same royalty as the private sector interest.

7. When the PGRT becomes effective after the guaranteed loans are repaid, the rate of the tax would be 16 per cent, but the private sector's liability for the tax would not exceed its royalty liability.

8. These proposals would replace all provisions relating to the Alsands project in the Canada/Alberta agreement of September 1, 1981 except for those relating to the price to be received for the project's synthetic oil output.

9. Synthetic crude production would receive such quality price premiums that it could obtain in the market, and production would not be prorated to demand.

APPENDIX 2

Guaranteed Loans in the Final Offer

Loan guarantees for 68 per cent of private sector expenditures were to be provided by the two governments. Interest on the guaranteed loan could be capitalized and added to the outstanding loan balance and the guarantee increased accordingly. This would occur in the pre-production years before the generation of revenues and in the event that 58 per cent of net revenues would not be enough to carry the interest charges. If at the end of the project the loan had not been repaid the two governments would assume responsibility for the unpaid balance if in fact the company was not capable of doing so.

It has been suggested that at the time that the offer was rejected, the precise details of what form the loan would take had not been worked out. The likely lenders would have been a consortium of banks with one lead bank. Because the loan was guaranteed it is likely that the loans could have been obtained at close to the prime lending rate. The long-run real rate of interest used in this analysis is 3 per cent.

Loan Guarantees and Net Revenue Shares

The present value of the loan stream is positive and has been added to the company's net present value cashflow however the loan is excluded from the total net revenues. The present value of the loan stream is greater to the companies than the present value of repayments, even when the loan is fully repaid, because the companies access funds at the prime lending rate, but we are assuming a real discount rate for PV purposes of at least 5 per cent, which is effectively some 2 to 3 percentage points higher than prime. The PV of the loan is also worth more at higher discount rates.

APPENDIX 3

The Wolf Lake Fiscal Regime

The following is a summary of the general details of the fiscal package that has recently been negotiated between the federal and Alberta governments and BP Canada Inc. and Petrocan for the Wolf Lake Project. Not all features of the royalty package have been finally legalized nor publicized and therefore not all details can be presented.

Corporate Income Tax (CIT)

All capital expenditures pre and post production are classified as Canadian Development Expense or Class 10 and are deductible for CIT purposes at a rate of 30% p.a. on a declining balance basis. Cl. 10 assets receive the 10% Investment Tax Credit and will also be subject to the Half Year Convention (as per Federal Budget, November 1981). All capital expenditures are eligible for depletion at a rate of 33.33 %. Taxation is done on a full flow-through basis.

Petroleum and Gas Revenue Tax (PGRT)

The project will be allowed PGRT relief consisting of exemption from payment of the tax until the accumulated value of the PGRT base becomes positive (PGRT base = Gross Revenues - Capital Costs - Operating Costs). At that point the PGRT equals 12% of the PGRT base (as per federal budget, April 1983).

Royalty

The royalty package consists of a graduated royalty phased in over three stages. The initial royalty will be a phased in percentage of gross revenues. Afterwards the royalty will be a percentage of the royalty base. Capital and operating costs are deductible from the royalty base.

APPENDIX 4

Alsands - NEP Regime

1. Income Tax Rate: Federal = 36%
   Provincial= 11%

2. Depletion is earned at a rate of 33.3 per cent on cl. 28. Depletion on exploration is phased out by 1984. (Allowable to a limit of 25 per cent of resource profits.)

3. Investment Tax Credit = 10% for expenditures on tangible assets except CEE.

4. C.C.A. : CEE 100%
   Cl 10 30%
   Cl 10 30%

5. Resource Allowance = 25%

6. Royalty Rates = phased in royalty to 10% on gross revenues before payout, 30% of net revenue after payout.

7. Royalty Tax Credit
   = (provincial income tax rate x royalty) - resource allowance.

8. No Canadianization grants are paid to the company in the case of Alsands. In the Wolf Lake base case 50 per cent of the project capital expenditures earn PIPs at a rate of 20 per cent.

9. The PGRT is levied at an effective rate of 12 per cent on net operating revenues for Alsands and on the PGRT base for Wolf Lake.

10. Taxation is done on a full flow-through basis.

APPENDIX 5

Price, Inflation and Interest Assumptions

1. Synthetic Crude Price for Alsands = $\$229/m^3$ (\$37/barrel) in 1982 \$.
   Base Case: Price remains flat in real terms.
   Increasing Price Case: Price increases annually at a rate of 5 per cent in real terms.
   Decreasing Price Case: Price decreases annually at a rate of 5 per cent in real terms.

2. Bitumen Price for Wolf Lake = $\$180/m^3$ (\$28/barrel) in 1983 \$ based on a price of $\$252/m^3$ (\$40/barrel) delivered at Montreal for light Crude, 38° API.
   Base Case, Increasing and Decreasing Price Cases are the same as for Alsands.

3. Inflation is assumed to be 10% in 1982 then 8.8%, 7.8%, 7.2%, 7.0%, 7.3%, 7.0%, 6.9%, 6.5% and 6.0% thereafter. The inflation forecast for 1983-1987 is taken from the Economic Council's Candide Forecast, Nineteenth Annual Review.

4. The base case interest rates at which the loans are paid back in the Alsands analysis are as follows: 15.8% in 1982 then 11.40%, 11.10%, 11.24%, 11.14%, 10.98%, 10.50%, 10.00%, 9.50%, and 9.00% thereafter. The forecast for 1983-1987 is taken from the medium term forecast of the Conference Board, April 1983. In the higher interest case interest rates are 4 percentage points higher. In the lower case they are 4 percentage points lower.

5. The base cases for Alsands and Wolf Lake assume that both prices and costs remain flat in real terms.

6. There are no PIP grants paid in the Alsands base case. In the Wolf Lake base case 50 per cent of the project earns PIP grants at a rate of 20 per cent on all capital expenditures.

FOOTNOTES

1. The production and cost data for the Alsands analysis has been provided by Shell Canada Resources Ltd. The production and cost data for Wolf Lake Analysis has been provided by BP Exploration Canada Ltd. The authors are grateful to both companies for their assistance and advice. All remarks and conclusions in this paper are the responsibility of the authors and not of the companies.

2. R.E. McRory, Oil Sands and Heavy Oils of Alberta, Department of Energy and Natural Resources, 1982, p. 36.

3. The Alsands Project Group, information circular, the Alsands Project Group, Public Affairs Department.

4. Ibid.

5. Energy Resources Conservation Board, Alsands Fort McMurray Application, ERCB Report 79-H, December 1979, p. 13.

6. Energy Mines and Resources Canada, Communique, "Minister Comments on Alsands Suspension", Ottawa, April 30, 1982.

7. All dollar figures quoted for Alsands are given in 1982 constant dollars in order to assess the project as it stood at the time of the final offer.

8. ERCB Report 79-H, p. 12.

9. Premier Peter Lougheed, Ministerial Statement to the Alberta Legislature, April 29, 1982, p.p. 1-3.

10. Ibid, p. 3.
    In the Ministerial Statement, the Alberta Government recognized that economic benefits would be enjoyed by the province however many jobs would have to be filled by people migrating to Alberta. For discussion concerning Alsands employment benefits see:
    G. Douglas and J. MacMillan, Interregional Impacts of Alberta Alsands Project, Canadian Energy Research Institute, Calgary, 1982.

11. For the analysis of the final offer all pre-1982 expenditures (about $200 million) are considered to be sunk and are ignored.

12. Merv Leitch, Letter to the Editor of the Calgary Herald, May 12, 1982.

13. On an industry level economic rent can be thought of as surplus revenues in excess of industry earnings necessary to cover all costs including investment costs, operating costs plus an adequate return to capital and risk taking. When the return to capital and risk taking is just sufficient to keep those factors in their current employment, normal profits are being earned. If the return to capital and risk taking is in excess of their opportunity costs, above normal profits are earned.

14. The description of the background to the Wolf Lake Project is taken from a BP public information circular, "Wolf Lake Project-Public Information Program", May 1982.

15. BP Exploration Canada Ltd., "Application to Construct and Operate an Oil Sands In Situ Experimental Thermal Project", application to the AERCB, 1982, p. 8.

16. Oilweek, Heavy Oil Report, Maclean Hunter Publication, Calgary, Vol. 34, No. 39, September 26, 1983, p. 12.

17. Application to the AERCB, p. 15.

18. Oilweek, p. 12.

19. Application to the AERCB, p. 5.

20. Ibid, p. 9.