The Potential For CO2 Reductions From Additional Energy Efficiency

Esso Resources Canada Ltd.

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EXECUTIVE SUMMARY

There is growing concern that increasing atmospheric concentrations of greenhouse gases, including Carbon Dioxide (CO_2), may be leading to potential global warming. This report discusses Esso Resources Canada Ltd's (ERCL's) potential for reductions in CO_2 emissions from increased energy efficiency in oil and gas production operations.

Oil and gas production for Esso is geographically distributed across Alberta, Saskatchewan, British Columbia, and the North West Territories. Within this geographic area, a widely varying infrastructure of support facilities is required, a direct result of production from a number of different reservoirs, each with individual energy requirements. Natural gas and electricity are used in the production process to supply energy necessary to lift fluids, and condition or treat them prior to sale. In 1989 ERCL emitted approximately 4.4[1] M tonnes of CO_2 from its operations, with an additional 1.8 [2] M tonnes of CO_2 associated with electrical energy use by ERCL.

Esso Resources has already achieved significant energy improvements in it's operations in the past 2 decades. Energy efficiency improvements implemented after 1975, are estimated to have reduced ERCL's 1989 energy useage by over 20% relative to 1972 standards. Without these energy conservation measures, the cumulative incremental CO_2 emissions between 1972 and 1989 would have been an additional 7000 kt, with yearly emissions in 1989 close to an additional 1700 kt/yr.

The potential for further energy efficiency related CO_2 reductions has been estimated in this study for the years 1990 to 2005. Results are summarized in Figure 1 and Table 1 below, and indicate the degree of CO_2 reduction associated with two different levels of additional energy efficiency implementation:

* Implementation of opportunities that meet a simple payback of 5 years. (Curve C) These efficiency measures have economics that exceed the cost of capital.

* Implementation of all technically feasible opportunities. (Curve D)

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[1] Emissions exclude working % in operations by others (eg Syncrude).
[2] Assumes average electrical CO_2 emissions of 0.983 kt/GWhr

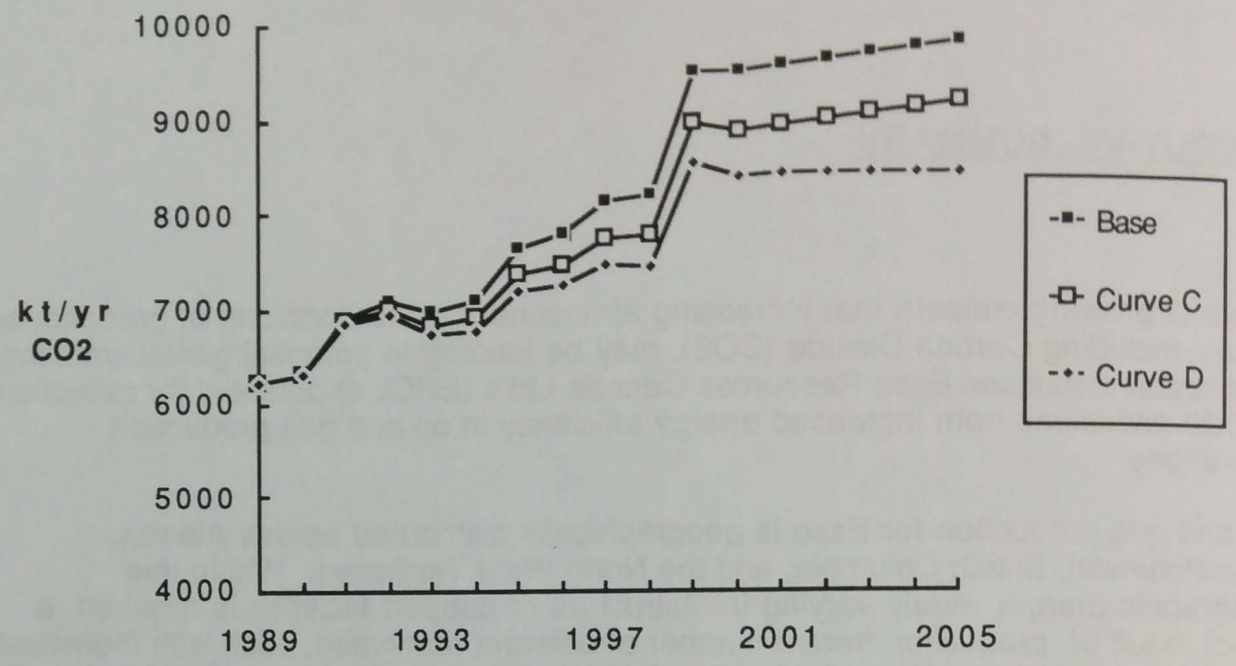

Figure 1 ERCL Projected Yearly CO2 Production

Table 1 Summary of Year 2005 ERCL Reduction Opportunities

	Reduction Potential		Costs			Payback
Description	Percentage (%2005)	CO2 kt/yr	Capital M$	Incr. Op. M$/yr	Net Op.* M$/yr	Years
Curve C	6.5	630	20	2.5	>4	<5
Curve C to D	7.5	730	425	14.5	17	>5
Total (Curve D)	14.0	1360	445	17.0	N/A	

* Average net operating savings = Fuel + Elect cost savings - Incremental operating costs

The baseline increase shown for CO2 emissions is consistent with Alberta Energy projections of 50 + % for the Alberta oil and gas production industry [3] and with ERCL's significant share of Alberta's crude bitumen and oil sands mining production. This baseline curve is highly sensitive to energy prices, and a wide range of baseline CO2 emissions is possible if higher or lower prices than those assumed were to occur. The potential range of baseline CO2 emissions arising from alternate energy prices may up to +/- 30% of emissions estimated.

From this baseline curve, full implementation of energy efficiency measures with less than a 5 year simple payback (Curve C), could reduce ERCL CO2 emissions by 6.5% relative to year 2005. These measures would cost 20 M$ (1990 $) capital, with an extra 2.5 M$/yr (1990 $) of other incremental operating costs to allow fuel and electrical cost savings to be realized. Significant energy efficiency opportunities under Curve C are:

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[3] Alberta Department of Energy. Energy Efficiency Branch. Energy Related Carbon Dioxide Emissions in Alberta 1988 to 2005, May 1990. Table 1.

- Operations and maintenance improvements from increased monitoring activities
- Improvements to burner controls
- Improved heat integration in the crude bitumen production sector

CO2 reduction potential shown between Curves C to D represents other technically feasible reduction measures with simple paybacks greater than 5 years. These measures which are not seen to be economic, have the potential to further reduce CO2 emissions by an additional 7.5 % in year 2005. Significant energy efficiency opportunities included under Curve C to D are:

- Cogeneration of steam and power in crude bitumen and gas plants
- Power generation from flared gas
- Other waste heat recovery schemes

Curve C to D opportunities require very high capital investments and incremental operating costs. These opportunities also reflect the difficulty in retrofit of new technology in existing facilities. Besides this high cost, the major barriers to implementation of most of these opportunities are:

- Reliability
- Current cost sharing arrangements with electric utilities
- Technology limitations

When compared with other projections by the Alberta Department of Energy [4] for the potential of energy efficiency related CO2 improvements for the oil and gas production sector, this study shows a significantly lower total reduction potential of 14% vs 29%. To the extent that the results of this study may be representative of other oil and gas companies, and recognizing that only about one half of these opportunities are economic, this large difference shows that governments need to be cautious when it comes to expectations that energy efficiency can significantly reduce greenhouse gas emissions in the oil and gas production sector.

The challenge for energy efficiency technology development is to widen the scope of influence that additional energy efficiency measures might have relative to total ERCL CO2 emissions. This effort will require particular focus on finding more innovative and cost effective technologies for reducing energy intensity in the production and processing of bitumen.

For energy efficiency reduction opportunities identified as having the potential to be economically feasible, it is recommended that additional detailed engineering studies be conducted consistent with the intent to implement these opportunities where possible. For operating and maintenance related improvements, a renewed focus within operating groups on energy efficiency is recommended to capture economic opportunities. However, CO2 reductions from economic energy efficiency improvements, are unlikely to stabilize projected ERCL CO2 emissions at 1990 levels.

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INTRODUCTION

The enhanced greenhouse effect has received much attention in the last several years in terms of its possible implications on potential global warming. Since the industrial revolution atmospheric concentrations of these greenhouse gases have been steadily increasing with growth of the predominant anthropogenic greenhouse gas, CO2, attributed to increased combustion of fossil fuels and deforestation.

In March of 1990 Imperial Oil Limited issued a position paper outlining recommendations to Governments on "Potential Global Warming". To further understand the implications of potential global warming, a seven point work program was undertaken within the company. This reports completes the ERCL commitment for item 2, namely:

> Determination of the technical and economic potential for additional energy efficiency opportunities in all of its operations, with and eye to reducing carbon dioxide emissions.

The scope of potential energy efficiency improvements is intended to include the reduction potential associated with both fuel and electricity from all facilities and fields where Esso is the operator. Reduction potential associated with ERCL working interest in production operations by others (eg Syncrude Canada Ltd.), and with contractor operations has not been included.

The accuracy of results is intended to be of scoping quality only.

DISCUSSION OF RESULTS

Historical Energy Efficiency

To estimate the potential for additional energy efficiency in upstream facilities operated by ERCL, it is important to understand that a number of initiatives have already been completed. Esso Resources Canada Limited started a formal energy conservation program in 1975. This program was implemented through the appointment of "Energy Coordinators" in each operating area who had the responsibility to monitor energy consumption and to identify areas for improvement. This program was particularly successful in tuning the burners in direct fired heaters and power boilers. It was also effective in understanding our electrical power usage, ensuring that power factor corrections were made, and optimizing electrical power contracts. A number of fuel meters were also installed at that time to monitor fuel consumption.

Since then energy conservation initiatives have been sporadic. Between 1979 and 1980 some emphasis was put on energy conservation in the gas processing plants. In particular, the glycol dehydration units, amine sweetening units, direct fired heaters and burners, and flare stack temperatures were optimized. In this program, the largest gain was made in burner optimization which showed a reduction of 5% of the fuel requirement simply by monitoring and adjusting the burners. In later years, little emphasis has been placed on energy conservation although burner surveillance programs and compressor optimization programs have continued. In the conventional oil and gas sector, the installation of updated instrumentation, particularly distributed control systems, and wellhead managers, has provided better monitoring, control, and optimization of the processes. In the crude bitumen sector, which is more energy intensive than either conventional oil production or natural gas processing, much more attention has been paid to energy efficiency. Over the years improvements have been made to burner controls, steam generator design, and steam utilization.

The energy utilized in the upstream facilities operated by Esso Resources between 1972 and 1989 is shown in Figure 2, in terms of the energy required as a percentage of the energy in the product. [5] There is little or no data on the actual fuel and electrical consumption in the conventional oil and gas sector except for 1989. Consequently, the data shown in Figure 2 has been recreated from annual production data, current energy consumption, and energy consumption data known for 1979 and 1975.

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[5] Includes ERCL estimated electrical end use energy requirements.

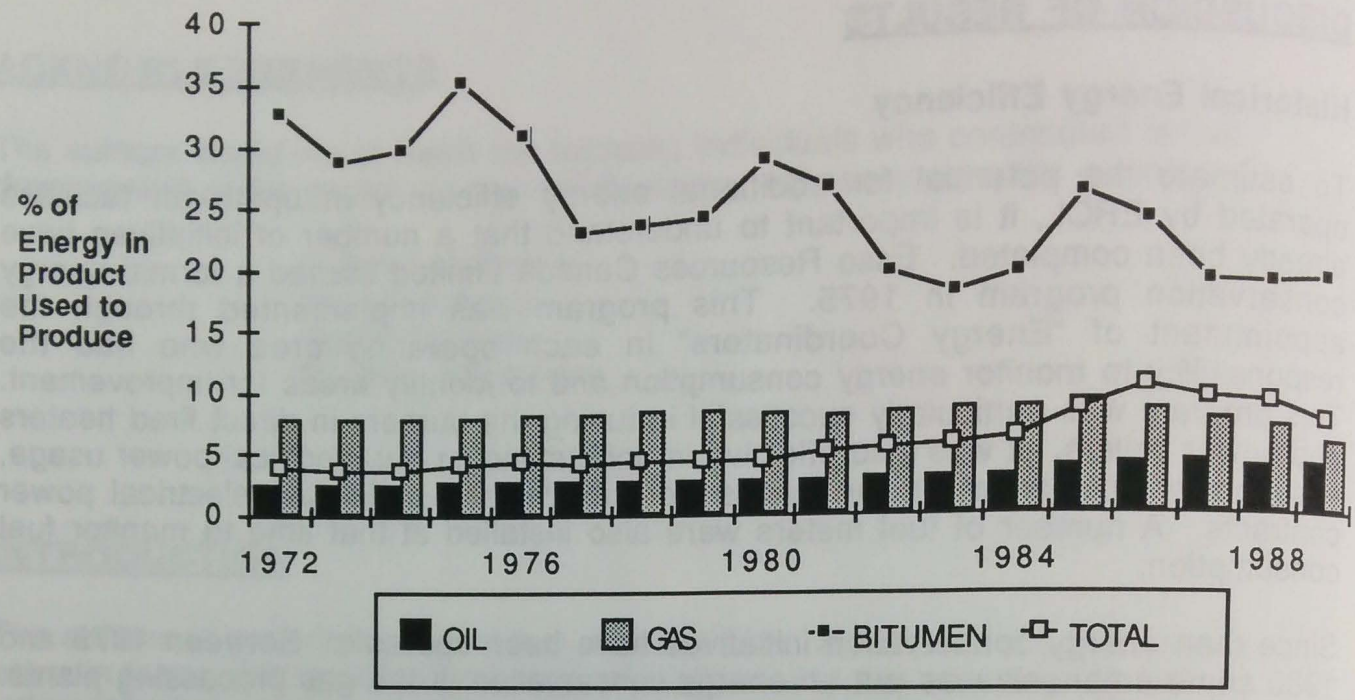

Figure 2 ERCL Energy Utilized for Production

From Figure 2, it can been seen that there has been an overall increase in energy utilization from 4 to 7.5 % of the energy produced over the 18 year period shown. Examining the energy utilization on a sector basis, indicates that the energy required to produce conventional oil has increased primarily due to the larger volumes of water that must be handled and processed as the reservoirs are depleted. The contribution of the crude bitumen production sector to the overall energy utilization is significant; particularly as the volume of crude bitumen has been increasing. The cyclic nature of the energy requirement in this sector corresponds to the intensive reservoir steaming that occurs as new production phases are brought on stream. The downward trend in energy required in the production of crude bitumen reflects the effect of the energy efficiency initiatives, production from higher quality oil sands, and the increased unit efficiency of a large scale operation. Lower gas sector energy utilization trends from 1986 to 1989 reflect improvements in gas plant capacity utilization and acquisitions of reserves with lower energy requirements for production.

The historical fuel energy utilization for upstream operations (Figure 3) shows a significant increase over the past 18 years. This large increase is directly attributable to the significant change in scale of the operations as the volumes of crude bitumen, gas, and conventional oil production have increased due to the implementation of the Cold Lake Production Projects, the Norman Wells Project, and from acquisitions of producing properties.

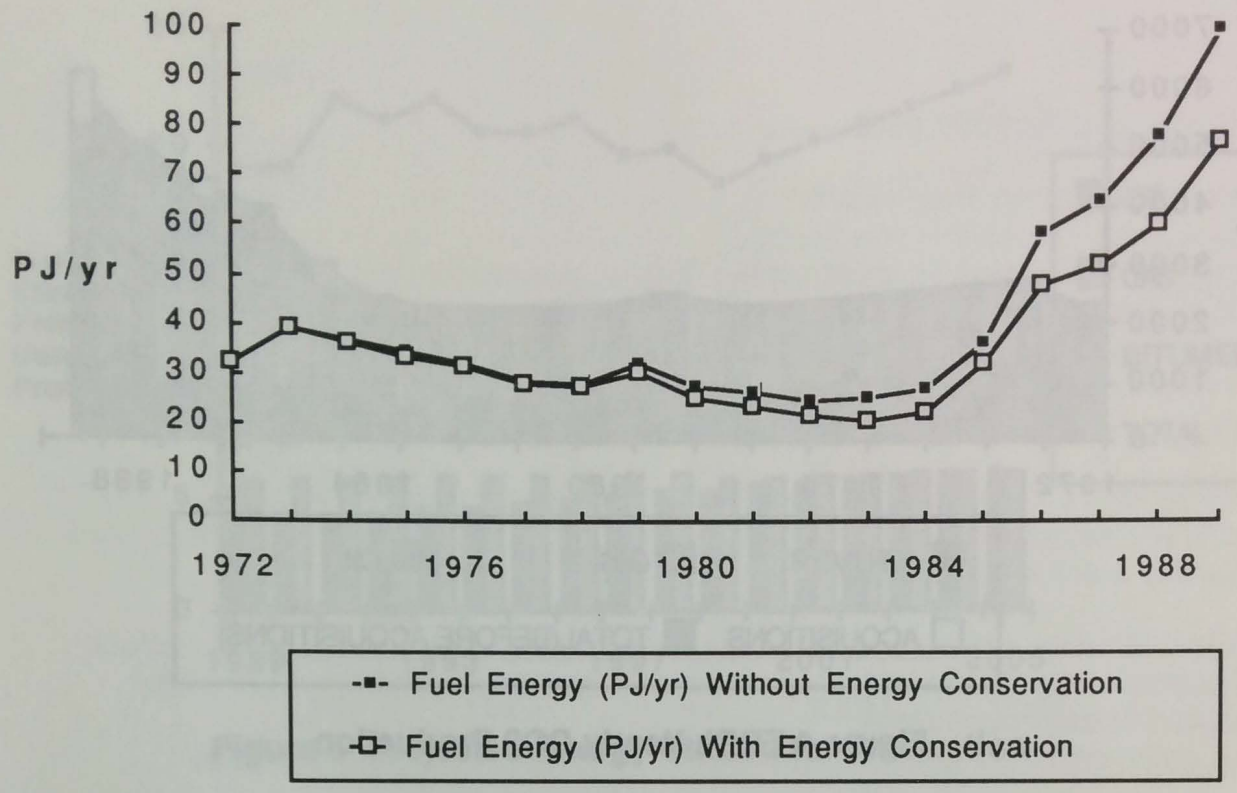

Figure 3 Effect of Historical Fuel Energy Conservation Measures

Also shown on Figure 3 is the total fuel energy requirement for upstream operations that would have been expected if none of the energy efficiency initiatives had been implemented. The implementation of these initiatives which included such items as; increased insulation levels, improved combustion controls in boilers and heaters, and improved automation and control, has been estimated to improve the total fuel efficiency for 1989 relative to 1972 by over 20 %. Without these energy conservation measures, it is estimated that incremental fuel related CO2 emissions in 1989 would be about 1000 kt/yr. As this study includes the potential for CO2 reductions from reduced electrical power useage, a similar energy efficiency improvement applied to historical electrical energy use results in a total cumulative incremental fuel and electrical CO2 related savings between 1972 and 1989 of 7000 kt, with yearly emissions savings in 1989 close to 1700 kt/yr.

The historical trend of estimated yearly total CO2 emissions, including CO2 emissions associated with electrical power consumption, is shown in Figure 4. As the overall energy utilization has increased, clearly the related CO2 emissions have increased. The large CO2 increases from 1985 to 1989 reflect a significant volume increase in the production of crude bitumen. Other CO2 increases between 1978 and 1989 are related to acquisitions associated with increased gas production and between 1988 and 1989 the acquisition of Texaco Canada Resources Limited. Since Esso Resources Canada Limited produces close to 70% of Alberta's total crude bitumen, a very energy intensive sector, and since the energy requirements in the conventional oil and gas sectors are increasing due to more production from depleting reservoirs, (ie increased water production and declining reservoir pressures,) it is expected that the energy requirements, and hence, CO2 emissions will continue to rise.

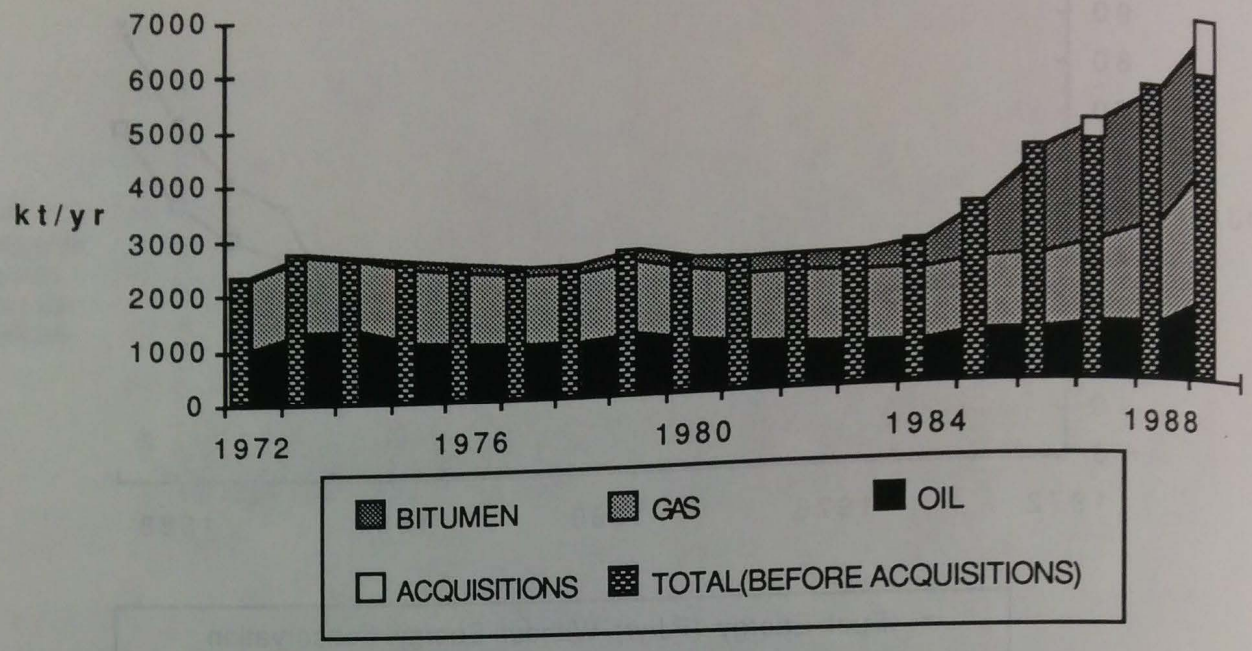

Figure 4 ERCL Yearly CO2 Production

Forecasted Energy Efficiency and Baseline CO2 Emissions

To estimate the potential for CO2 reductions a forecast of future baseline CO2 emissions was developed from a combination of energy needs on a per m3 of production basis, and from forecasted production volumes.

Future baseline total energy needs on a sector basis have been estimated up to the year 2005 as shown in Figure 5, in terms of the energy utilized for production as a percentage of the energy in the product. [6] This baseline energy requirement assumes current levels of energy efficiency implementation with no allowance (except crude bitumen) for future technology improvements which might significant lower energy requirements. For new facilities, current state of the art technology is assumed.

Total ERCL energy utilization for production is anticipated to continue to remain relatively flat as slight energy efficiency improvements in crude bitumen production are projected from continued development of existing high quality oil sands. This efficiency gain negates the effects of increased gas compression needs for the gas sector, and higher water oil ratios in conventional oil production. Increases in later years for crude bitumen reflect production from poorer quality oil sands and declining reservoir productivity.

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6 Includes ERCL estimated electrical end use energy requirements.

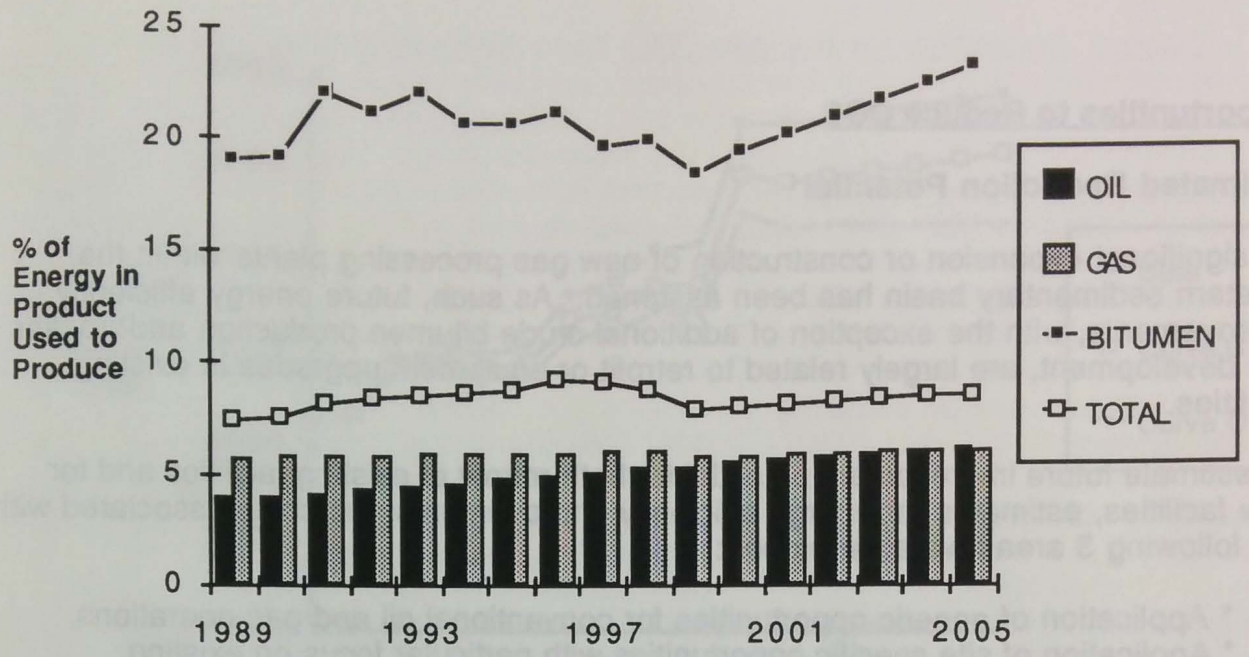

Figure 5 Projected Energy Utilized for Production

Given projections of relatively flat total ERCL future energy utilization, future CO2 emissions are then closely tied to production volumes. Although a summary of anticipated future production has not been provided, the following general assumptions were used to establish ERCL future production profiles that are consistent with Energy Mines and Resources' (EMR) 2020 [7] vision forecasts.

- Average oil prices remain relatively flat with only minor real price growth.
- Future production volumes for conventional oil are assumed to continue to decline, with higher cost secondary or tertiary recovery schemes remaining uneconomic.
- Natural gas production is assumed to increase from continued development of proven reserves including those in frontier areas.
- Continued divestment or shut in of uneconomic properties will occur as current fields continue to mature.
- The development of oil sands crude bitumen and mining projects will be required to assist in fulfilling Canadian and world wide energy needs. As such, significant production growth for crude bitumen is assumed to continue, with implementation of state of the art lower cost insitu thermal and other recovery technology.

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[7] Energy Mines and Resources Canada. 2020 vision, Canada's Long Term Energy Outlook, a Working Paper, 1989 issue.

Opportunities to Reduce CO2

Estimated Reduction Potential

No significant expansion or construction of new gas processing plants within the Western sedimentary basin has been assumed. As such, future energy efficiency improvements, with the exception of additional crude bitumen production and frontier gas development, are largely related to retrofit or equipment upgrades in existing facilities.

To estimate future improvement potential for both retrofit of existing facilities and for new facilities, estimates for energy efficiency improvements and costs associated with the following 3 areas were developed:

* Application of generic opportunities for conventional oil and gas operations
* Application of site specific opportunities with particular focus on existing crude bitumen operations
* An estimate of continued operations and maintenance improvements

The economic potential of each of these opportunities was calculated by simple payout based on constant 1990$. This is the number of years required before initial investment and additional (or other incremental) operating cost is offset by savings from fuel or electricity reductions. For economic calculations the following was assumed for both retrofit and new facilities:

* Project life 15 years
* Incremental electricity cost of 0.02$ / kw hr. (For cogeneration incremental electricity saved or generated was estimated at 0.045$ / kw hr)
* Incremental fuel gas cost of $70.60 / s m3.

To differentiate those energy efficiency opportunities that were thought to have potential for cost of capital recovery, opportunities with a simple payout of 5 years or less were grouped together. Opportunities with greater than 5 year simple payout represent the maximum potential for energy efficiency and were not assumed to be economically attractive to the private sector.

A summary of the overall potential within Esso Resources for CO2 reduction from increased energy efficiency is shown in Figure 6 below and indicates the degree of CO2 reduction associated with these 2 levels of additional energy efficiency implementation:

* Implementation of opportunities that meet a simple payback of 5 years. (Curve C)

* Implementation of all technically feasible opportunities. (Curve D)

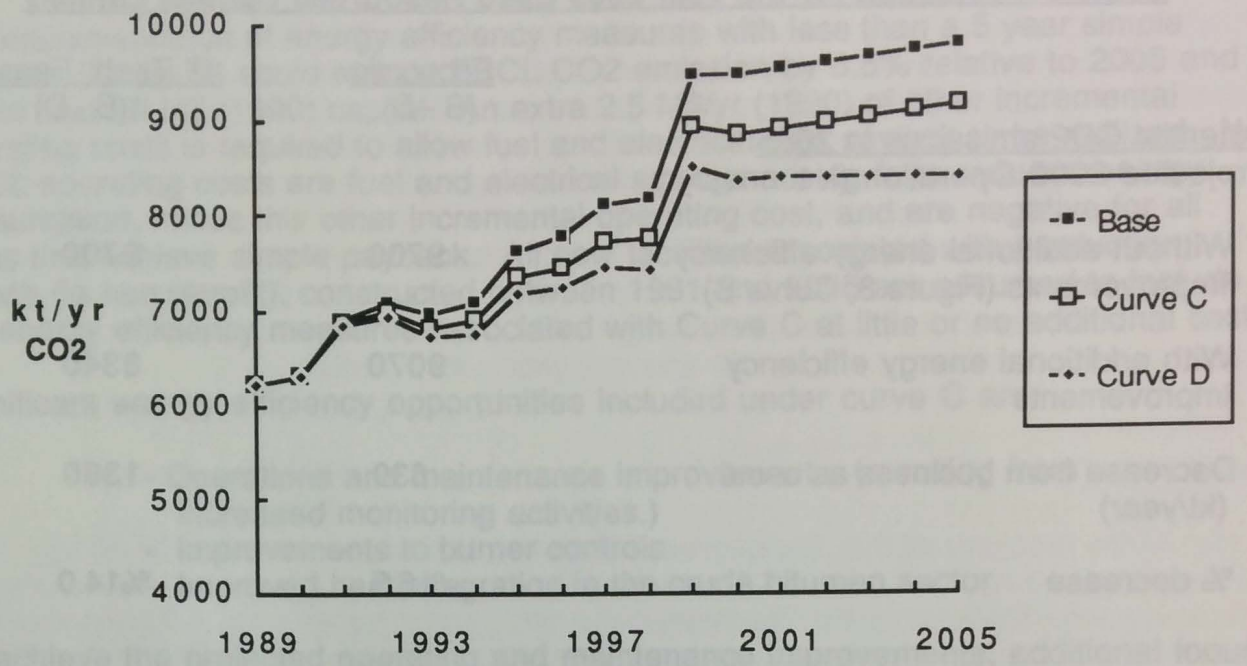

Figure 6 ERCL Projected Yearly CO2 Production

Increases in ERCL total CO2 emissions (base case 1989 to 2005), assume current levels of energy efficiency implementation. This baseline total increase of 50% is consistent with Alberta Energy projections of 50 + % for the Alberta oil and gas production industry, and with ERCL's significant share of Alberta's crude bitumen and oil sands mining production.

Reductions in CO2 emissions from the baseline curve as shown by Curves C and D, reflect a phased in implementation of identified efficiency measures. Retrofit efficiency improvement measures with less than a 5 year simple payout were assumed to require 10 years for 100 % implementation. For new facilities constructed between 1990 and 2005, energy efficiency measures with less than a 5 year simple payout were assumed to be incorporated into these facilities as they were constructed.

For retrofit opportunities with greater than a 5 year payout, a 15 year implementation period was assumed for 100% implementation in existing facilities. For new facilities constructed between 1991 and 2005, opportunities with greater than a 5 year simple payout were also assumed to be included with these facilities as they were constructed.

With reference to Figure 6, results for the year 2005 are summarized in tabular form below :

Table 2 Projection for the year 2005 Esso Resources Canada Limited

	Economic (B - C)	All Tech. Feasible (B - D)
Potential CO2 emissions in 2005		
Projected 2005 Operation (k tonnes/yr)		
- Without additional energy efficiency Improvements (Figure 8, Curve B)	9700	9700
- With additional energy efficiency improvements	9070	8340
- Decrease from business as usual (kt/year)	630	1360
- % decrease	%6.5	%14.0
Energy Consumption (Fuel Gas and End Use Electricity)		
Projected 2005 Operation (Petajoules/yr)		
- Without additional energy efficiency improvements (Figure 8, Base)	133	133
- With additional energy efficiency improvements	124	118
- Decrease from business as usual (PJ/year)	9	16
- % decrease	%6.5	%12.0
Costs (1990$'s) To Achieve Savings		
- Additional Capital (M$)	20	445
- Incremental Op. Cost (M$/yr)*	2.5	17.0
- Range of Capital Cost per tonne of CO2 saved (1990$/t/yr)	20 - 100	100 - 10000

* Excludes fuel and electrical operating cost savings. Net operating cost savings would include fuel and electricity and are of course (-)ve as required to payout capital.

Full implementation of energy efficiency measures with less than a 5 year simple payback (Curve C) could reduce ERCL CO2 emission by 6.5% relative to 2005 and would cost 20 M$ (1990) capital. An extra 2.5 M$/yr (1990) of other incremental operating costs is required to allow fuel and electrical cost savings to be realized. Net ERCL operating costs are fuel and electrical savings arising from reduced energy consumption, minus this other incremental operating cost, and are negative for all items that achieve simple payback. All new facilities associated with production growth (ie non retrofit), constructed between 1991 and 2005 are assumed to include the energy efficiency measures associated with Curve C at little or no additional cost.

Significant energy efficiency opportunities included under curve C are:

- Operations and maintenance improvements, (resulting from increased monitoring activities.)
- Improvements to burner controls
- Improved heat integration in the crude bitumen sector.

To achieve the projected operating and maintenance improvements, additional focus is required in all operating areas. This will require at least initially, the appointment of operating personnel dedicated to energy efficiency. The estimated 2.5 M$/yr additional operating cost includes an estimate of this manpower cost.

Full implementation of energy efficiency measures with greater than a 5 year simple payback (Curve C to D) could reduce ERCL CO2 emissions by a further 7.5% relative to year 2005 and would cost 425 M$ (1990) capital with an extra 14.5 M$/yr (1990) other incremental operating cost. Those opportunities listed between Curves C to D represent other technically feasible reduction measures up to the estimated maximum improvement potential. Based on the fuel gas and electricity costs assumed, Curve C to D includes several minor opportunities and one major opportunity (elimination of flare gas makeup for sour gas flaring), that do not recover their projected costs (i.e. don't meet a simple payback criteria). The more significant efficiency measures for Curve C to D that do meet the simple payback criteria include:

- Cogeneration of steam and power in crude bitumen and gas plants
- Power generation from flared gas.
- Other waste heat recovery schemes

Approximately 20% of the projected CO2 reductions associated with Curve C to D are related to potential implementation of these measures in new facilities.

A detailed listing of all energy efficiency measures considered is included in the Appendix.

Comparison to Other Estimates of Energy Efficiency Reduction Potential

When compared with projections by the Alberta Department of Energy for the potential of energy efficiency related CO2 improvements for the oil and gas production sector, this study shows a significantly lower reduction potential of 14% vs 29%. The major difference in reduction potential is related to the assumptions for cogeneration in the gas processing and oil sands areas within the oil and gas sector.

To the extent that the results of this study may be representative of other other oil and gas companies, this large difference shows that governments need to be cautious when it comes to expectations that energy efficiency can significantly reduce greenhouse gas emissions in the oil and gas production sector.

Barriers

It should be recognized that the degree to which actual implementation of energy efficiency measures will occur, is influenced by many other factors than the energy efficiency improvement alone, eg manpower and capital constraints. Furthermore, most of the projects identified as having greater than a 5 year simple payback are unlikely to be implemented unless technology development can significantly reduce the costs of implementation. As such 100 % implementation of all energy efficiency measures is very unlikely.

The major barrier to faster implementation of those opportunities included under Curve C is their ability to compete with other economic opportunities for scarce capital resources.

Although Curve C to D opportunities have the potential to further reduce CO2 emissions by 7.5 % in 2005, they require very high capital investment and incremental operating cost. These opportunities also reflect the difficulty in retrofit of new technology in existing facilities. Besides this high cost the major barriers to implementation of most of these opportunities for both retrofit and new facility applications are:

- Reliability
- Current cost sharing arrangements with electric utilities
- Technology limitations

A significant portion of the reduction potential for Curve C to D is associated with electric power savings from cogeneration or electric generation from flare gas. To allow these projects to proceed, a cogeneration policy suitable to both electric utility companies and oil and gas producers needs to be developed.

For the opportunities included under Curve C to D, there appear to be limited potential for improved economics as a result of synergies associated with construction of new facilities. One exception to this appears to be waste heat recovery measures, where incorporation in original designs may allow additional waste heat recovery to become more economically feasible.

Energy Efficiency Potential vs Potential Supply / Demand Response

Given current assumptions on growth and energy utilization, it is clear that energy efficiency improvements will not be able to stabilize projected ERCL CO2 emissions at 1990 levels. In addition it should be noted that a wide range of ERCL CO2 emissions is possible if higher or lower energy prices that those assumed under EMR's 2020 vision were to occur. The potential range of CO2 emissions and the effect that possible energy efficiency measures might have to base projections for overall CO2 emission levels for ERCL is shown in Fig 7 below for a +/- emission scenario of 30%.

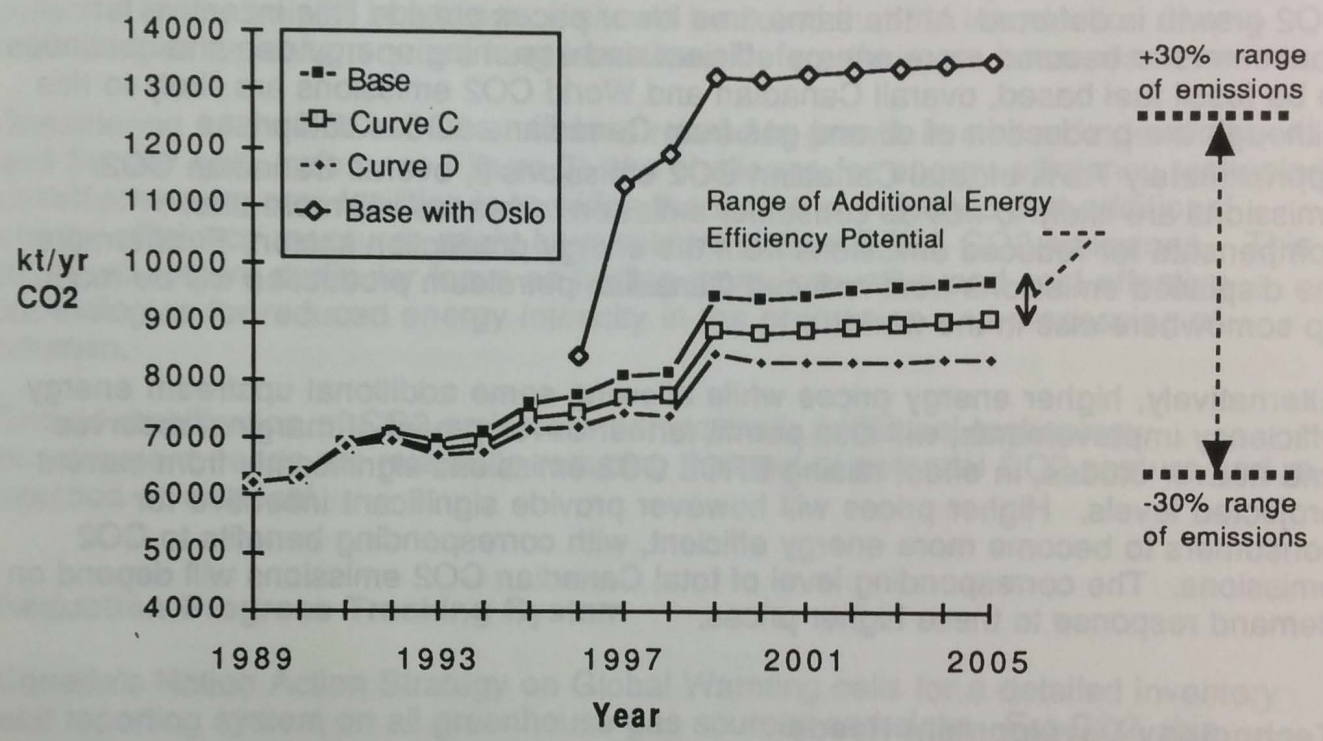

Fig. 7 Effect of Possible Emission Ranges vs Energy Efficiency Potential

Overall the range of emissions for CO2 is consistent with a supply / demand response to Canadian and world energy demands. The +30 % range of potential CO2 emissions reflects a potential price environment with significant real oil price growth, which is reflected in significant increases in production of heavier crudes and natural gas. The lower limit of potential CO2 emissions reflects shut in of marginal reserves and deferred oil sands and frontier gas development, and is generally consistent with EMR's alternate price scenario in the 2020 vision forecast. Should ERCL become the operator, the potential effect of inclusion of 100% of the OSLO project's CO2 emissions on ERCL's base operating emissions is also shown.

The net effect of these price sensitivities to total Canadian and World CO2 emissions is summarized below.

Sensitivity	ERCL CO2 Emissions	Energy Eff Incentives	Total Canadian CO2 Emissions
1. Lower prices	Lower	Lower	Higher
2. Higher prices	Higher	Higher	?

In general, lower energy prices will reduce total ERCL CO2 emissions as marginal production is shut in and development of heavier crudes, a major component of the CO2 growth is deferred. At the same time lower prices provide little incentive for consumers to become more energy efficient and assuming energy demand continues to be fossil fuel based, overall Canadian and World CO2 emissions are likely to rise. Although the production of oil and gas from Canadian sources comprises approximately 7.5% of total Canadian CO2 emissions [8], overall Canadian CO2 emissions are likely to rise as consumer emission increases will more than compensate for reduced emissions from the energy production sector. Furthermore the displaced emissions from reduced Canadian petroleum production will be made up somewhere else in the world!

Alternatively, higher energy prices while allowing some additional upstream energy efficiency improvements, will also permit further development of marginal reserves and heaver crudes, in effect raising ERCL CO2 emissions significantly from current projected levels. Higher prices will however provide significant incentive for consumers to become more energy efficient, with corresponding benefits to CO2 emissions. The corresponding level of total Canadian CO2 emissions will depend on demand response to these higher prices.

Technology Development Needs

Esso's retrofit energy efficiency improvement potential mainly focuses around more efficient combustion and waste energy utilization, with various technologies already developed for these applications, but not in wide use due to cost and reliability. As such, technology development needs for retrofit are primarily related to making the delivery cost of these technologies lower.

The more highly leveraged areas for improvement include:

Combustion Equipment Upgrades:

- More efficient reciprocating engine combustion (eg high temperature materials needed)
- Higher efficiency burners in firetube applications
- Process control and other automation improvements (eg combustion controls)

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[8] Based on estimated oil and gas CO2 production of 40 Mt/yr to Canadian totals of 530 Mt/yr. Includes estimated CO2 emissions from electricity use.

Waste Energy Utilization:

- Power generation from flared gas
- Alternate H2S recovery and flare technologies to reduce fuel gas make up volumes

Other:

- Reduced wellbore heat loss (steam stimulated crude bitumen production)
- Improvements to hydrate control

The effect of other as yet unidentified technologies could improve the efficiency potentials noted in this report, however it is impossible to identify the magnitude of this potential or the timing. In addition, it should be noted that the introduction of new technologies typically requires long lead times before their use becomes economic.

Considering future ERCL CO2 emissions related to growth in oil sands development and frontier gas, (reference Figure 7), the challenge for energy efficiency technology development for new facilities is to widen the scope of influence that additional energy efficiency measures might have relative to total ERCL CO2 emissions. This effort will require particular focus on finding more innovative and cost effective technologies for reduced energy intensity in the production and processing of bitumen.

Should stabilization of CO2 emissions be required, additional technology development needs are related to reducing the cost of potential CO2 capture and re-injection or disposal.

Reduction Progress Tracking System

Canada's Nation Action Strategy on Global Warming calls for a detailed inventory and reporting system on all greenhouse gas sources and sinks. For CO2, this reporting system and its application to the oil and gas production industry has yet to be determined. However, historical tracking of the effects of future energy efficiency improvements on CO2 emissions will likely be necessary to establish the contribution of these measures to CO2 trends.

It is recommended that ERCL through its participation in industry associations, work towards establishment of the appropriate level of energy efficiency and CO2 reporting for the oil and gas production industry. Any reporting systems developed will have to recognize the potential for masking of CO2 improvements from energy efficiency with emissions increases due to production growth.

CONCLUSIONS & RECOMMENDATIONS

- Stabilization of ERCL CO2 emissions from energy efficiency measures is unlikely for the conditions assumed. Further study is recommended on alternate CO2 reduction opportunities, such as the use of CO2 for enhanced oil recovery.

- Full implementation of energy efficiency measures with less than a 5 year simple payback could reduce ERCL CO2 emissions by 6.5% relative to year 2005 and would cost 20 M$ (1990) capital with an extra 2.5 M$/yr (1990) incremental operating cost required to realize fuel or electricity cost savings. Additional detailed engineering studies are recommended for these opportunities, consistent with the intent to implement projects where possible. Additional operating manpower focus on energy efficiency will also be required to capture economic operating and maintenance measures.

- The maximum potential for CO2 reduction (100% implementation - including uneconomic measures) is 14% based on year 2005 levels.

- A significant portion of the maximum reduction potential is associated with cogeneration of power and steam. To allow cogeneration projects to proceed, a cogeneration policy suitable to both electric utility companies and oil and gas producers needs to be developed.

- Technology development for energy efficiency within ERCL should focus on new energy efficient technologies for bitumen production and processing, and on combustion related equipment retrofits. These requirements should be included in ERCL's technology planning process.

- CO2 reduction estimates from energy efficiency in this study are significantly lower than government projections for the oil and gas production sector. To the extent that the results of this study may be representative of other oil and gas companies, this large difference shows that governments need to be cautious when it comes to expectations that energy efficiency can significantly reduce greenhouse gas emissions in the oil and gas production sector.

- A wide range of CO2 emissions is possible, consistent with price / supply demand requirements. The effect of energy efficiency on this range is relatively small. A significant technology breakthrough in bitumen production and processing, or in conventional oil tertiary recovery is required to reduce potential emissions growth.

- Through its participation in industry associations, it is recommended that ERCL work towards establishing the appropriate level of energy efficiency and CO2 emissions reporting for the oil and gas production industry.

GLOSSARY / ABBREVIATIONS

Amine Sweeting	A process for removing Hydrogen Sulphide (H2S) from natural gas streams
Crude Bitumen	Heavy oil obtained from steam stimulated oil sands deposits
CO2	Carbon Dioxide
EMR	Energy Mines and Resources Canada
Encon	Energy conservation
ERCL	Esso Resources Canada Limited
ERCB	Alberta Energy Resources Conservation Board
Firetube Heaters	Fired heaters with combustion products directed through the inside of heat exchanger tubes
Flare gas make-up	Natural gas added to flare streams to ensure complete combustion
GJ	Gigajoule (1 E +09 joules)
Glycol Dehyration	A process to remove water from natural gas streams
Hydrates	A water lattice in which light hydrocarbon molecules are embedded. Hydrates normally form when gas streams are cooled below their hydrate formation temperature.
Insitu Thermal	A reservoir recovery process utilizing heat to assist in the production of hydrocarbons
k	Thousand
kw hr	Kilowatt hour
M	Million
MJ	Megajoule (1 E +06 joules)
m3	Cubic meter
s m3	Standard cubic meter
Sour Gas	A gas containing an appreciable quantify of hydrogen sulphide, mercaptans, and/or carbon dioxide
OSLO	Other Six Leases Operations Project
PJ	Petajoule (1 E +15 joules)
Properties	Oil and Gas mineral leases
t	tonne
Tertiary	Enhanced oil recovery
Upstream	Oil and gas production operations
Wellhead Manager	An automated control system for oil field pumping units

APPENDIX 1: METHODOLOGY

ENERGY CONSUMPTION

Calculation Procedures: Historical Energy Consumption

Since there is no record of the actual fuel used in the production and processing of conventional oil and gas in the upstream facilities operated by Esso Resources Canada Limited, a method was devised to estimate the historical consumption from production volumes reported in the annual reports, Alberta Oil and Gas Industry Annual Statistics (ERCB ST89-17), and known energy requirements in 1989 and 1979. The estimated historical fuel requirements for conventional oil and gas were then added to the fuel data available for crude bitumen production, the estimated energy consumed by flare, and an estimate of the total electrical power requirements, to give the total Esso Resources Canada Limited historical energy consumption. The method and assumptions used in reconstructing the historical energy consumption is outlined in the following steps 1 - 12.

1) Find Historical (Annual Report) Production Volumes.

Production volumes for conventional oil, gas, NGL, and crude bitumen were taken from the Imperial Oil Limited Annual Reports for 1972 thru 1989.

2) Determine Volumes Processed in 1989.

Since it is recognized that the volumes reported in the annual reports include volumes that are produced by others and credited to Imperial Oil's account, and do not include volumes that are processed by Esso Resources Canada for others, some estimate was required to determine the volumes actually processed in the upstream facilities operated by ERCL. To do this, the volumes of conventional oil and gas processed in 1989 (reported as part of the greenhouse gas inventory project) were compared to the annual report production volumes. This indicated that ERCL only processed 85% of the oil volumes reported yet processed 150% of the gas. Similarly a comparison of the gas volumes processed in 1979, and the volumes reported in the 1979 annual report, indicates that, Esso Resources processed 18% more gas than was reported as Imperial Oil production in 1979.

3) Calculate Volumes Processed in ERCL Operated Facilities.

The volumes processed in the ERCL operated facilities were calculated assuming the volumes of conventional oil processed prior to 1986 (i.e. before major acquisitions) were equal to the volumes produced as reported in the annual reports. Volumes of gas processed prior to 1986 were assumed to be constant at 118% of the total gas produced to Imperial Oil's account. Between 1986 and 1989 it was assumed that Esso Resources processed substantial quantities of gas for others while more of Imperial Oil's conventional oil was actually being produced and processed by others. The resulting factors used to calculate the actual volumes processed in the facilities operated by ERCL were as follows;

Ratio of Processed to Produced Volumes

Year	1972-85	1986	1987	1988	1989
Oil Processed to Produced	1.00	0.90	0.88	0.88	0.85
Gas Processed to Produced	1.18	1.35	1.40	1.40	1.50

4) Determine Industry Conventional Oil and Natural Gas Energy Use

It was assumed that the overall fuel energy required by Esso Resources to process conventional oil and gas would be essentially the same as that reported for the industry in Alberta. The fuel gas used by the industry is reported in the Alberta Oil and Gas Industry Annual Statistics (ERCB ST89-17). Raw gas production, conventional crude production, condensate, and pentanes plus production are also listed. To determine the overall industry energy consumption, the total gas, conventional oil, condensate and pentane plus production was converted to their energy equivalents and the total fuel used expressed as a fraction of the total energy produced.

5) Calculate Total ERCL Conventional Oil and Gas Energy Production

The volume of conventional oil processed by ERCL was converted to its energy equivalency by multiplying by a factor of 42.53 GJ/m3. A separate factor was not used for the NGL production but rather these liquid volumes were included with the conventional oil volumes. A conversion factor of 40.48 MJ/s m3 of gas was used to estimate the energy content of both processed gas and fuel gas. This factor was based on the assumption that the higher heating value of gas with 90% methane and 10% ethane would be representative.

6) Determine Fuel Requirements for Conventional Oil and Gas Processing

The overall fuel requirement for conventional oil and gas processing was assumed to be the same as industry and the factors obtained under Item 4 above were applied to the volumes processed. The fuel required for processing of natural gas was taken as a percent of the raw gas processed on the bases of the 1979 and 1989 known requirements. Some adjustment was made between 1986 and 1988 for the acquisitions (which had a high proportion of gas processing) and for the fact that the utilization in the gas processing facilities was high during this period. An adjustment was also made for the effect of energy conservation programs in 1979-80 such that the resulting factors were as follows;

Fuel for Processing Natural Gas

Year	1979	1980	1981-85	1986	1987	1988	1989
Fuel as % of Raw Gas	7.26	7.0	6.65	6.0	5.7	5.7	4.99

The energy required for processing conventional oil was taken as the difference between the total energy required and the energy required for processing natural gas.

7) Incorporate Crude Bitumen Historical Data

The fuel energy used to produce crude bitumen was taken from internal ERCL data, and was added to the energy required to process conventional oil and gas to give the total fuel energy required by Esso Resources in their upstream facilities. In determining the fuel gas equivalents, since some crude bitumen was burned in the early years along with natural gas, a higher heating value for the bitumen was assumed to be 41.4 GJ/m3 and the higher heating value for the gas was assumed to be 37.4 MJ/s m3.

8) Back Extrapolate 1979 to 1972 Energy Requirements

To back extrapolate from 1979, it was assumed that the percent fuel energy to process conventional oil would be unchanged at 2.51% and that the energy required to process natural gas would also be unchanged at 7.26% of the raw gas volumes. The percent energy used as fuel for crude bitumen from 1972 - 75 inclusive was assumed to be directly related to the oil/steam ratio and taken as 32.0% in 1972, 28% in 1973, 29% in 1974 and 34.4% in 1975.

9) Add Energy of Flare and Electrical Consumption

The volume of gas flared as reported in the greenhouse inventory study was converted directly to energy equivalents and added as a constant factor for each year. Similarly what information was available for end use electrical power consumption was converted to the energy equivalence and added to each year to get the total ERCL energy requirements.

10) Calculate Percent Energy (Total)

The percent total energy used in the processing of conventional oil, natural gas,and crude bitumen, was calculated by adding the total electrical, flare, and fuel energy requirements and dividing this total by the total energy in production (step 5). A summary total for each of these production sectors was also determined by this applying this same method to each production sector.

11) Calculate CO_2 Emissions

The CO_2 emissions from energy used within ERCL were calculated by using a factor of 49.7 kilotonnes of CO_2 / PJ of gas energy burned. The CO_2 contributions from electrical power usage were calculated by using an average factor of 0.983 kt CO_2 / GW hr of electrical energy use. Total ERCL CO_2 emissions were the sum of gas and electrical emission totals.

12) Normalize CO_2 Emissions

The normalized CO_2 emissions were calculated for conventional oil processing, gas processing, crude bitumen production and the overall ERCL by dividing the

appropriate CO2 emissions from each segment by the total energy produced in that segment.

Calculation Procedures: Energy Consumption Without Energy Conservation Initiatives

An estimate was made of the energy consumption that would be required if no energy conservation initiatives had been implemented above normal design practices at the time. In essence this meant that burner efficiencies in the conventional oil sector were ignored, electrical power and boiler efficiencies in the gas processing sector were ignored as were significant improvements in the gas to steam performance for crude bitumen. The following steps 1 - 5 illustrate methodology used.

1) Estimate the percent energy used as fuel for conventional oil and gas

For conventional oil and gas a base year of 1979 was taken to represent the energy requirements without energy conservation. Consideration was given to the fact that water production has increased since 1980 and that the Norman Wells project came on in 1985. Some consideration was also given to the effect of better facility utilization in the gas facilities between 1986 and the present. As a result the factors used were as follows;

% Energy Used for Production Factors

Year	1972-79	1980-84	1985	1986	1987	1988-89
% Energy for conv. oil	2.51	2.53 to 2.61	3.26	3.5	3.5	3.5
% Energy for gas	7.26	7.26	7.26	6.6	6.3	5.6

2) Estimate fuel requirements for crude bitumen production

The fuel requirements for crude bitumen, without any energy conservation initiatives, was determined by assuming an equivalent gas/steam ratio varying from 92 in 1972 to 90 in 1978 and then remaining constant to 1989. On this basis the fuel requirements are as shown on the following table;

Yearly Fuel Requirements for Crude Bitumen

Year	1972	1973	1974	1975	1976	1977	1978
Fuel Requirement ksm3/d	80	69	64	230	251	197	214
Year	1979	1980	1981	1982	1983	1984	1985
Fuel Requirement ksm3/d	278	301	480	458	584	747	1489
Year	1986	1987	1988	1989			
Fuel Requirement ksm3/d	3053	3233	3695	3747			

3) Calculate Percent Fuel Requirements

For each sector, the fuel energy requirement, both as a percent of the energy processed and as total energy (i.e. PJ per year) was calculated using an energy factor of 40.48 MJ/s m3 for the fuel used in conventional oil or natural gas processing and a factor of 37.4 MJ/s m3 for the fuel gas used in the processing of crude bitumen.

4) Calculate CO2 Emissions

The CO2 emissions for each sector were calculated using a factor of 49.7 kilotonnes of CO2 per PJ of energy consumed.

5) Determine Energy Utilization Improvements Due to Energy Conservation Initiatives

The percentage reduction in energy requirements between the case with no energy conservation initiatives and the actual performance was calculated for 1989. The overall improvement in energy utilization and the reduction of CO2 emissions was also calculated as the difference between the summation of the requirements without energy conservation initiatives and the actual performance.

Baseline CO2 Calculations: Future Energy Requirements

The future energy requirements were estimated by using EMR's 2020 Vision (Canadas Long Term Energy Outlook) as the basis for oil and gas production volumes. Assumptions were then made for increased energy required to produce conventional oil as more water is produced, and an estimated increase in energy required to produce natural gas as reservoir pressures deplete. Crude bitumen energy requirements were assumed to be very cyclic and were estimated with assumptions as to when additional production might be commissioned. The following steps 1 - 8 illustrate methodology and assumptions used.

1) Production Volume Forecast

Internal ERCL volume forecasts (expressed as oil equivalent meter cubed per day) for conventional oil, crude bitumen, natural gas liquids and natural gas were adjusted to reflect conditions outlined in EMR's 2020 vision (eg frontier gas development starting in 1999 or 2000).

2) Estimate Volumes of Conventional Oil and Gas Processed

For purposes of the forecast, the volumes of NGL and conventional oil were assumed to be equivalent on an oil equivalent basis and were summed to give the total volume of conventional oil produced. The gas was assumed to have an oil equivalence of 1000 meter cubed/meter cubed of oil. Crude bitumen volumes were taken to be equivalent to conventional oil volumes.

3) Estimate Volume of Oil and Gas Actually Processed

It was assumed that the conventional oil processed would be 85% of the conventional oil produced to Esso Resource's account. For natural gas it was assumed that the gas processed in Esso Resource's facilities would be 150% of the gas produced by Esso Resources.

4) Calculate Total Energy Processed

The energy values for conventional oil, crude bitumen and natural gas were taken to be 42.53 GJ/m3, 41.40 GJ/m3, 40.48 MJ/s m3 respectively.

5) Estimate Percent Energy Required for Fuel

To compensate for the anticipated increased water handling in the processing of conventional oil, the 1989 fuel requirement of 3.5 percent was escalated at 3% per year through 2005. To compensate for the expected increased compression required for processing natural gas, and recognizing that some compression would be electrically driven, the fuel gas requirements were escalated at 1% per year from the base of 4.99 percent in 1989. Crude bitumen fuel requirements were taken from internal company projections.

6) Calculate Fuel Requirements and CO2 Emitted

The fuel requirement for each sector was calculated using the percent fuel energy and the total energy processed. From this energy requirement the carbon dioxide emitted was calculated using the factor of 49.7 kilo tonnes per C02 per PJ of energy consumed.

7) Calculate Electric Requirements and CO2 Emitted.

Future electrical end use energy needs were estimated by escalating conventional oil and gas 1989 load requirement by 2% per year. Adjustments were then made for major project additions in the crude bitumen sector. CO2 emissions were calculated by assuming that all future incremental power was supplied with CO2 emissions of 0.983 kt/GWhr.

8) Calculate Baseline CO2 Emissions

Baseline emissions were determined by summation of emissions from electrical, fuel, and process CO2 emissions. Process CO2 emissions were estimated at 480 kt/yr of CO2 from sour gas recovery processes.

Calculation Procedures: Impact of Acquisitions

Acquisitions of Sulpetro Limited in 1986, of Ocelot, United Canso and JCIP in 1987 and of Texaco Canada Limited in 1989 had significant impacts on the total energy requirements of Esso Resources Canada Limited. To make an estimate of this impact,

the volumes of oil and gas produced by these companies and reported in their last annual reports was used as the basis for assuming the energy requirement and CO_2 emission from this production.

1) Volumes Reported for Last Year Operation

The following table lists the production volumes reported for Sulpetro, Ocelot, United Canso and Texaco;

Production Volumes of Acquisitions

	Oil M3/d	Gas ksm3/d
Sulpetro	7827	2057
Ocelot	19	507
Canso (From ERCL 1988 Outlook)	323	765
Texaco	24469	4200

2) Estimate Energy Processed

The energy associated with the reported production was calculated using a factor of 42.53 GJ/m3 for the oil production and 40.48 MJ/s m3 for natural gas production.

3) Calculate Energy Requirements

The energy requirements were assumed to be the same as that for the overall Alberta Oil and Gas Industry and taken as 4.22% of the combined conventional oil and natural gas production.

4) Calculate C02 Emissions

The CO2 emissions were taken as being equivalent to 49.7 kilo tonnes of CO2 per PJ of energy consumed.

FUTURE CO2 REDUCTION POTENTIAL

Determination of the overall future ERCL energy efficiency (and associated CO2) reduction potential was accomplished by adding up the potential contributions (and costs) associated with the following:

* A number of generic opportunities applicable to all operations.
* Estimated site specific opportunities (with particular focus on crude bitumen's reduction potential)
* Estimated reductions from continued Operations and Maintenance improvements

Description of Generic Energy Efficiency Opportunities

An overall list of potential energy efficiency opportunities (78) was developed, by a working group mainly comprised of internal company engineering specialists, with input from previous Operations comments and opportunity lists.

This overall list was short listed by prioritizing opportunities in terms of CO2 potential and potential cost.

The resulting shot list of opportunities that have potential for company wide application in conventional oil and gas operations include:

* Installation of high efficiency burners and turbulators in field heaters and reboilers to improve overall heater efficiency.

* Optimization of artificial lift through the installation of "wellhead managers" (ie timers or pump off controllers to reduce electrical usage).

* Combustion control improvements from the use of portable O2 analyzers (and fixed units where possible), to ensure efficient combustion.

* Additional waste heat recovery from engines to supplement building heat and process heating requirements.

* Combustion air preheat for fired equipment.(both forced draft and natural draft fired equipment)

* Miscellaneous control upgrades to optimize heat utilization (particularly in reboiler systems).

* Cogeneration of steam and electricity.

* Power generation from continuous flare locations (eg oil batteries).

* Flare volume reductions thru alternate processes for low level H2S and CO2 removal.

* Flare volume reduction thru alternate flare designs.

* Alternate reservoir recovery processes.

Site Specific Items

The major impact for site specific efficiency opportunities comes from the crude bitumen sector where a list of potential items and reduction potential was developed from previous energy efficiency work. These opportunities are mainly focused on improvements to overall plant heat utilization.

For the conventional oil and gas production areas, a reduction potential and cost was applied based on feedback to date from an internal facilities review process. The total site specific improvement potential was estimated at 2.25% for 1989, with 1.75% reduction associated with minor investments (Curve C), and with 0.5% associated with major investments (Curve D). Examples of site specific opportunities include:

<u>Process changes</u>

* Solvent changes
  - lower circulation rates
  - higher absorption
* (Waste) heat recovery from aerial coolers
* Re-configuring of heat exchanger trains (Pinch technology)
* Using process heat for heat tracing needs

<u>Equipment Upgrades</u>

* Reduced electrical consumption
  - installation of high efficiency motors
  - high efficiency lighting
* Installation of unloaders on compressors
* Installation of high efficiency blades on aerial coolers
* Installation of variable speed drives
* Installation of recovery turbines/expanders
* Elimination of burn pits
* Installation of thermostatically controlled electrical heat tracing
* Use of solar power panels for power supply in remote areas (telecommunication)

* Elimination of pressure drops in piping, e.g. orifice meters
* Insulation additions or improvements
* Mass transfer pumps instead of compressors
* Heat recovery from stack gases
* Installation of better control on aerial coolers

Operations and Maintenance Reduction Potential

Additional operations and maintenance efficiency activities are estimated to result in 1 to 2 % reduction of current CO2 production. A long list of items/programs that could be implemented was developed and includes the following items:

Operations and Maintenance Surveillance

* Pay close attention to process settings
* Pay close attention/maintenance to fuel consumers
* Conduct energy conservation surveys
* Monitor electrical power consumption
* Monitor steam balances
* Set energy targets for various modes of operation
* Make better use of automated control systems
* Minimize/optimize heat flux
* Repair steam leaks/traps
* Maintain analyzers
* Monitor flue gases
* Repair leaking valves to flare

Operations Maintenance Planning

* Assign energy coordinator in each operating area
* Minimize shutdowns
* Reduce causes/effects of unscheduled shutdowns
* Monitor heat exchanger fouling (schedule cleaning)
* Promote networking between areas

Operations and Maintenance Conservation Measures

* Shut off steam tracing in the summer
* Shut off electric tracing in the summer
* Shut off steam utilities not needed
* Shut down glycol heating boilers when not needed
* Shut down glycol pumps when not needed
* Shut down pumps on recycle
* Recover steam condensate