UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended DECEMBER 31, 1998

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______

Commission File Number: 1-10934

LAKEHEAD PIPE LINE PARTNERS, L.P.
(Exact name of Registrant as specified in its charter)

DELAWARE	39-1715850
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

LAKE SUPERIOR PLACE
21 WEST SUPERIOR STREET
DULUTH, MINNESOTA 55802-2067
(Address of principal executive offices and zip code)

(218) 725-0100
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
CLASS A COMMON UNITS	NEW YORK STOCK EXCHANGE

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

As of March 1, 1999, the aggregate market value of the Registrant's Class A Common Units held by non affiliates of the Registrant was $965,384,000 based on the reported closing sale price of such units on the New York Stock Exchange on that date.

As of March 1, 1999, there were 22,290,000 of the Registrant's Class A Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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This Annual Report on Form 10-K contains forward-looking statements. These statements are based on the Partnership's beliefs as well as assumptions made by and information currently available to the Partnership. When used in this document, the words "anticipate," "believe," "expect," "estimate," "forecast," "project," and similar expressions identify forward-looking statements. These statements reflect the Partnership's current views with respect to future events and are subject to various risks, uncertainties and assumptions including:

- the Partnership's dependence upon adequate supplies of and demand for western Canadian crude oil,

- the price of crude oil and the willingness of shippers to ship crude oil when prices are low,

- regulation of the Partnership's tariffs by the Federal Energy Regulatory Commission and the possibility of unfavorable outcomes of future tariff proceedings,

- the Partnership's ability to complete Year 2000 readiness activities, and

- the effects of competition, in particular, by other pipeline systems.

If one or more of these risks or uncertainties materialize, or if the underlying assumptions prove incorrect, actual results may vary materially from those described in this Form 10-K. Except as required by applicable securities laws, the Partnership does not intend to update these forward-looking statements. For additional discussion of such risks, uncertainties and assumptions, see "Items 1 & 2. Business and Properties -- Business Risks" included elsewhere in this Form 10-K.

PART I

ITEMS 1 & 2. BUSINESS AND PROPERTIES

OVERVIEW

Lakehead Pipe Line Partners, L.P. is a publicly traded Delaware limited partnership ("Registrant" or "Partnership"), which owns a 99% limited partner interest in Lakehead Pipe Line Company, Limited Partnership ("Operating Partnership"), also a Delaware limited partnership. Unless the context otherwise requires, references in this Form 10-K to the Partnership include the Registrant and the Operating Partnership.

The Partnership was formed in 1991 to acquire, own and operate the regulated crude oil and natural gas liquids pipeline business of Lakehead Pipe Line Company, Inc. (the "General Partner"), a wholly-owned subsidiary of Enbridge Pipelines Inc. ("Enbridge Pipelines" formerly Interprovincial Pipe Line Inc.). Enbridge Pipelines is a Canadian company owned by Enbridge Inc. ("Enbridge" formerly IPL Energy Inc.) of Calgary, Alberta, Canada. The General Partner owns a 14.8% limited partner interest (in the form of 3,912,750 Class B Common Units) and a 1% general partner interest in the Registrant, as well as a 1% general partner interest in the Operating Partnership (an effective 16.6% combined interest in the Partnership). The remaining 83.4% limited partner interest in the Partnership is represented by 22,290,000 publicly traded Class A Common Units.

The Partnership and Enbridge Pipelines transport crude oil and other liquid hydrocarbons for others through the world's longest liquid petroleum pipeline system ("System"). The System is the primary transporter of crude oil from western Canada to the United States and is the only pipeline that transports crude oil from western Canada to eastern Canada. The System serves all the major refining centers in the Great Lakes region of the United States, as well as the province of Ontario, Canada and the Patoka/Wood River refinery and pipeline hub in southern Illinois. Various subsidiaries of Enbridge own the Canadian portion of the System ("Enbridge Pipelines System") and the Partnership owns the U.S. portion of the System ("Lakehead System").

The System extends from Edmonton, Alberta, across the Canadian prairies to the U.S. border near Neche, North Dakota. From Neche the System continues on to Superior, Wisconsin, where it splits into two branches with one branch travelling through the upper Great Lakes region and the other through the lower Great Lakes region of the United States. Both branches reenter Canada near Marysville, Michigan. From Marysville the System continues on to Toronto, Ontario and Montreal, Quebec, with lateral lines to Nanticoke, Ontario and the Buffalo, New York area. The System is approximately 3,000 miles long, of which, approximately 1,750 are in the United States.

Shipments tendered to the System primarily originate in oil fields in the western Canadian provinces of Alberta, Saskatchewan, Manitoba and British Columbia and in the Northwest Territories of Canada and reach the System through facilities owned and operated by third parties or affiliates of Enbridge Pipelines. Deliveries from the System are currently made in the prairie provinces of Canada, in the Great Lakes and Midwest regions of the United States and the province of Ontario, principally to refineries, either directly or through connecting pipelines of other companies.

All scheduling of shipments (including routes and storage) is handled by Enbridge Pipelines in coordination with the Partnership. The Lakehead System includes 16 connections to pipelines and refineries at various locations in the United States, including the refining areas in and around Chicago, Illinois, Minneapolis-St. Paul, Minnesota, Detroit, Michigan, Toledo, Ohio, Buffalo and Patoka/Wood River. The Lakehead System has three main terminals at Clearbrook, Minnesota, Superior, and Griffith, Indiana. The terminals are used to gather crude oil prior to injection into the Lakehead System and to provide tankage in order to allow for more flexible scheduling of oil movements.

PROPERTIES

The Lakehead System consists of approximately 3,200 miles of pipe with diameters ranging from 12 inches to 48 inches, 60 main line pump station locations with a total of approximately 663,000 installed horsepower and 54 crude oil storage tanks with an aggregate working capacity of approximately nine million barrels. The volume of liquid hydrocarbons in the Lakehead System required at all times for operation is approximately 13 million barrels, all of which is owned by the shippers on the Lakehead System. The Lakehead System regularly transports up to 45 different types of liquid hydrocarbons including light, medium and heavy crude oil (including bitumen), condensate, synthetic crudes and natural gas liquids ("NGL").

The Lakehead System is comprised of a number of separate segments as follows:

- Canadian border to Clearbrook segment including portions of four pipelines consisting of 18-, 20-, 26-, and 34-inch diameter pipe with a total annual capacity of 1,571,000 barrels per day. This segment includes approximately 40 miles of 48-inch pipeline looping that increases the annual capacity of this segment;

- Clearbrook to Superior segment including portions of three pipelines consisting of 18-, 26-, and 34-inch diameter pipe, respectively, with a total annual capacity of 1,337,000 barrels per day. This segment also includes approximately 80 miles of 48-inch pipeline looping;

- Superior to Marysville segment consisting of 30-inch diameter pipe with an annual capacity of 509,000 barrels per day;

- Superior to Chicago area segment including two pipelines of 24- and 34-inch diameter pipe with a total annual capacity of 889,000 barrels per day;

- Chicago area to Marysville segment that is a 30-inch diameter pipe with an annual capacity of 333,000 barrels per day;

- Canadian border to Buffalo segment consisting of 12-inch diameter pipe with an annual capacity of 74,000 barrels per day.

Estimated annual capacities noted above take into account receipt and delivery patterns and ongoing pipeline maintenance, and reflect achievable pipeline capacity over long periods of time. Lakehead System capacities set forth above do not include the estimate of annual capacity upon completion of Phase I of the Terrace Expansion Program ("Terrace") which is expected to be completed in two stages during 1999. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, -- Terrace Expansion Program." Terrace will add an additional 170,000 barrels per day annual capacity to the Lakehead System from the Canadian border to Superior. The properties described above include facilities added during the System Expansion Program II ("SEP II") of the Lakehead System, consisting primarily of a new 24-inch diameter pipeline from Superior to the Chicago area (approximately 450 miles). This new pipeline, together with other pipeline system modifications, is projected to provide approximately 170,000 barrels per day of additional delivery capacity to the Midwest U.S. markets served by the Partnership. The new pipeline has an ultimate potential capacity of 350,000 barrels per day through the installation of additional pumping units. SEP II complements a Cdn. $160 million expansion of the Enbridge Pipelines System.

The Partnership believes that the Lakehead System has been constructed and is maintained in accordance with applicable federal, state and local laws and regulations, standards prescribed by the American Petroleum Institute and accepted industry practice. The Partnership attempts to control corrosion of the pipeline through the use of pipe coatings and cathodic protection systems and monitors the integrity of the Lakehead System through a program of periodic internal inspections using electronic instruments. On a bi-weekly basis, the entire pipeline right of way is inspected from the air. In addition, trained and skilled operators use computerized monitoring systems to identify pressure drops that might indicate potential disruptions in flow, and operate remote controlled valves and pumps that allow the Lakehead System to be shut down quickly if required.

TITLE TO PROPERTIES

The Partnership conducts business and owns properties located in seven states. In general, the Lakehead System is located on land owned by others and is operated under perpetual easements and rights of way, licenses or permits that have been granted by private land owners, public authorities, railways or public utilities.

The pumping stations, tanks, terminals and certain other facilities of the Lakehead System are located on land that is owned by the Partnership, except for five pumping stations that are situated on land owned by others pursuant to easements or permits. An affiliate of the General Partner has acquired properties for the benefit of the Partnership in connection with SEP II. See "Item 13. Certain Relationships and Related Transactions." Substantially all of the Lakehead System assets are subject to a first mortgage securing indebtedness of the Operating Partnership.

BUSINESS RISKS

The Lakehead System is dependent upon the level of supply of crude oil and other liquid hydrocarbons from western Canada. Supply, in turn, is dependent upon a number of variables, one of which is the price of crude oil. In recent months, the price of crude oil has reached a twenty year low, resulting in reduced throughput on the System. For a discussion of the forecast of the future supply of crude oil produced in western Canada, see "-- Supply and Demand for Western Canadian Crude Oil."

Demand for western Canadian crude oil and NGL in the geographic areas served by the Lakehead System is affected by the delivery of other crude oil and refined products into the same areas. Existing pipeline capacity for the delivery of crude oil to the Midwest U.S., the primary destination market served by the Lakehead System, exceeds current refining capacity. The Partnership believes that the System has certain advantages over other transporters of crude oil with which it competes and the System is among the lowest cost transporters of crude oil and NGL in North America based on costs per barrel mile transported. See "-- Competition."

Enbridge Pipelines is in the process of modifying a pipeline segment from Sarnia, Ontario to Montreal, involving a reversal of a line to bring crude oil from Montreal to Sarnia ("Montreal Extension" or "Line 9"). The line reversal will result in Enbridge Pipelines becoming a competitor of the Partnership for supplying crude oil to the Ontario market which is anticipated to decrease the level of deliveries into the Ontario market. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, - -- Montreal Extension Reversal."

The Partnership cannot predict the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce the demand for crude oil and other liquid hydrocarbons in the areas in which deliveries are made by the Lakehead System. In addition, reduced throughput on the System could result from testing, line repair, reduced operating pressures, reduced crude oil supply or other causes.

The operations of the Partnership are subject to federal and state laws and regulations relating to environmental protection and operational safety. Although the Partnership believes that the operations of the Lakehead System are in substantial compliance with applicable environmental and safety regulations, risks of substantial costs and liabilities are inherent in pipeline operations, and there can be no assurance that such costs and liabilities will not be incurred, see "-- Environmental and Safety Regulation."

The Partnership filed a rate increase with the Federal Energy Regulatory Commission ("FERC") in late 1998 to reflect the projected incremental costs and throughput resulting from SEP II. A Tariff Agreement previously reached between the Partnership and customer representatives sets forth parameters governing the tariff increase associated with SEP II, Terrace, and other expansion projects, although individual customers who are not parties to the agreement could potentially challenge any existing or future rate filing. Any challenge, if successful, could have a material adverse effect on the Partnership. For a discussion of FERC regulation, Partnership tariff rates, and the Tariff Agreement, see "-- Regulation" and "-- Tariffs."

REGULATION

FERC Regulation

The Partnership's interstate common carrier pipeline operations are subject to rate regulation by the FERC under the version of the Interstate Commerce Act ("ICA") applicable to oil pipelines. The ICA requires that petroleum products and crude oil pipeline rates be just, reasonable and non-discriminatory. The ICA permits challenges to new, changed and existing rates through either a "protest" or "complaint." At the FERC, a protest normally applies only to a proposed change in a pipeline's rates or practices and subjects the pipeline to a forward-looking investigation and possible refund obligation if the FERC chooses to suspend the proposed change as it is empowered to do for up to seven months from the proposed date of the change. A complaint, by comparison, typically applies to an existing rate or practice and subjects the pipeline, in certain circumstances, to possible retroactive liability for past rates or practices found to be unlawful.

The FERC utilizes a simplified ratemaking methodology for oil pipelines that prescribes an indexing methodology for setting rate ceilings. As described in FERC Orders No. 561 and No. 561-A, the index used is the Producer Price Index for Finished Goods minus 1% ("PPIFG-1"). Rate ceiling levels are increased or decreased each July 1. The PPIFG-1 for use on July 1, 1998, was approximately negative 0.6%. Inflationary rate increases allowed under the FERC's indexing methodology may be different than increases in the Partnership's costs. Indexed rates are subject both to protests and to complaints, but in either case the FERC's existing regulations specify that the party challenging a rate must show reasonable grounds for asserting that the amount of any rate increase resulting from application of the index is so substantially in excess of the pipeline's increase in costs as to be unjust and unreasonable (or that the amount of any rate decrease is so substantially less than the actual cost decrease incurred by the pipeline that the rate is unjust and unreasonable).

The FERC has stated that, as a general rule, pipelines must utilize the indexing methodology to change rates. However, the FERC has retained cost-based ratemaking, market-based rates and settlements as alternatives to the indexing approach. A pipeline can follow a cost-based approach when it can demonstrate that there is a substantial divergence between the actual costs experienced by the carrier and the rates resulting from application of the index. Under FERC's cost-based methodology, crude oil pipeline rates are permitted to generate operating revenues, based on projected volumes, not greater than the total of the following components:

- operating expenses,

- depreciation and amortization,

- federal and state income taxes and

- an overall allowed rate of return on the pipeline's rate base.

During the period 1992 to 1995, the Partnership implemented several rate filings in accordance with this methodology, see "-- Tariffs, -- Rate Cases." In addition, a pipeline can charge market-based rates if it first establishes that it lacks significant market power in a particular relevant market, and a pipeline can establish rates pursuant to a settlement if agreed upon by all current shippers. Initial rates for new services can be established through a cost-based filing or through an uncontested agreement between the pipeline and at least one shipper not affiliated with the pipeline.

Other Regulation

The governments of the United States and Canada have, by treaty, agreed to ensure nondiscriminatory treatment with respect to the passage of oil and gas through the pipelines of one country across the territory of the other. Individual border crossing points require U.S. government permits that may be terminated or amended at the will of the U.S. government. These permits provide that pipelines may be inspected by or subject to orders issued by federal or state government agencies.

TARIFFS

Rate Cases

The Partnership had several rate cases pending before the FERC during the period from 1992 to 1996. The primary issue included the applicability of the FERC's Opinion 154-B/C trended original cost methodology. The FERC issued decisions on the Partnership's 1992 tariff rate increase that determined the Partnership was entitled to use the FERC's Opinion No. 154-B/C rate methodology, although it was not entitled to recover in its cost of service a tax allowance with respect to income attributable to individual limited partners.

In 1996, the FERC approved a settlement agreement ("Settlement Agreement") between the Partnership, the Canadian Association of Petroleum Producers ("CAPP") and the Alberta Department of Energy ("ADOE") on all then-outstanding contested tariff rates. The Settlement Agreement provided for a tariff rate reduction of approximately 6% and total rate refunds and interest of $120.0 million through the effective date of October 1, 1996, with interest accruing thereafter on the unpaid balance. The Partnership made rate refunds of $41.8 million in the fourth quarter of 1996, with the balance being paid through a 10% reduction of tariff rates until all refunds have been made, which is expected to occur sometime late in the second half of 1999. At December 31, 1998, the remaining liability for rate refunds was $28.7 million.

The Settlement Agreement also provided for the terms of an incremental tariff rate surcharge for a period of 15 years to recover the cost of, and allow a rate of return on the Partnership's investment in, SEP II. The rate of return on this investment will be based, in part, on the utilization level of the additional capacity constructed. As specified in the Settlement Agreement, higher utilization will result in a greater rate of return, subject to a minimum and maximum rate of return of 7.5% and 15.0%, respectively. The tariff rate surcharge will be recomputed on a cost of service basis and filed with FERC each year. The Settlement Agreement provided that the agreed underlying tariff rates will be subject to indexing as prescribed by FERC regulation and that CAPP and ADOE will not challenge any rates within the indexed ceiling for a period of five years, expiring October 2001.

Tariff Agreement

In 1998, the Partnership filed an offer of settlement ("Tariff Agreement") with the FERC to facilitate the filing of tariff rate surcharges in late 1998 and early 1999. This filing consolidated the 1996 Settlement Agreement with respect to SEP II and other significant agreements with customers concerning Terrace and the transportation of heavy crude oil. The FERC found the Tariff Agreement a reasonable compromise and approved it on the grounds that it is fair, reasonable, and in the public interest.

With respect to Terrace, the Tariff Agreement included terms governing a tariff surcharge associated with the project. A fixed toll increase of Cdn. $0.05 per barrel for the movement of light crude oil from Edmonton to the Chicago area will be allocated approximately Cdn. $0.02 ($0.013 U.S.) to the Partnership and Cdn. $0.03 to Enbridge Pipelines. The toll increase is also subject to increase or decrease based on changes in certain defined circumstances. The portion of the agreement associated with Terrace also establishes in-service and notice dates for future phases of the expansion program. Should CAPP not provide notice to construct later phases of Terrace by July 1, 2001, the toll increment will revert to a cost of service recovery, including collection of both prospective and past variances between revenue generated by the Cdn. $0.05 toll increment and the Terrace cost of service.

Other Pipeline Rate Cases

On January 13, 1999, the FERC issued an opinion and order in the Santa Fe Pacific Pipeline, L.P. ("SFPP") case that addressed various issues of interest to FERC-regulated publicly traded partnerships and other oil pipelines including application of FERC's Opinion No. 154-B/C rate methodology and income tax allowances for publicly traded partnerships. The SFPP opinion is anticipated to have no impact on the Partnership's current rates due to the Tariff Agreement with customers. If the SFPP opinion were applied to

the Partnership in some future rate proceedings, the impact to the Partnership, positive or negative, would be dependent upon the specific application of the rulings in that opinion to the Partnership.

Many of the ratemaking issues contested in the Partnership's rate cases, in particular the FERC's own oil pipeline ratemaking methodology, have not previously been reviewed by a federal appellate court. Any decision ultimately rendered by the FERC on any rate case involving its oil pipeline ratemaking methodology, including the recent SFPP decision, may be subject to judicial review. Any such judicial review could ultimately result in alternative ratemaking methodologies that could have a material adverse effect on the Partnership.

Tariffs

Under published tariffs for transportation by the Lakehead System, the rates for light crude oil from the Canadian border near Neche to principal delivery points at January 1, 1999 (including a tariff surcharge related to SEP II) are set forth below. As previously discussed, the Partnership's published tariffs are subject to a 10% reduction; the tariffs less this 10% reduction are also set forth below.

	PUBLISHED TARIFF PER BARREL	PUBLISHED TARIFF PER BARREL LESS 10% REDUCTION
Clearbrook, Minnesota	$0.165	$0.149
Superior, Wisconsin	$0.318	$0.286
Chicago, Illinois area	$0.647	$0.582

Canadian border near Marysville, Michigan..........	$0.747	$0.672
Buffalo, New York area............................	$0.792	$0.713

The rates at January 1, 1999, for medium and heavy crude oils are higher, while those for NGL are lower, than the rates set forth in the table to compensate for differences in costs for shipping different types and grades of liquid hydrocarbons. The Partnership periodically adjusts its tariff rates as allowed under FERC's indexing methodology and the Tariff Agreement and will file a tariff surcharge for Terrace during the first half of 1999 of an estimated $0.013 per barrel for light crude oil to the Chicago market. See "-- Tariffs, - -- Tariff Agreement."

DELIVERIES FROM THE LAKEHEAD SYSTEM

Deliveries from the Lakehead System are made in the Great Lakes and Midwest regions of the United States and in Ontario, principally to refineries, either directly or through connecting pipelines of other companies. Major refining centers within these regions are located near Sarnia, Nanticoke, Toronto, Minneapolis-St. Paul, Superior, Chicago, the Patoka/Wood River area, Detroit, Toledo, and Buffalo areas. Crude oils and NGL transported by the Lakehead System are feedstock for refineries and petrochemical plants.

The U.S. government segregates the United States into five districts, Petroleum Administration for Defense Districts ("PADD"), for purposes of its strategic planning to ensure crude oil supply to key refining areas in the event of a national emergency. The oil industry utilizes these districts in reporting statistics regarding oil supply and demand. The Lakehead System services the northern tier of PADD 2. U.S. governmental publications project that crude oil demand in this area will remain relatively constant. In addition, these publications project the total supply of crude oil from producing areas in the U.S. southwest, Rocky Mountains and Midwest that currently serve the entire PADD 2 market to decline in the near term as reserves are depleted, resulting in a need for additional supplies of crude oil to replace the continuing demand. As a result of these factors, the Partnership believes that the Lakehead System will be able to maintain or exceed its current level of deliveries into PADD 2.

The following table sets forth Lakehead System average deliveries per day and barrel miles for each of the years in the five-year period ending December 31, 1998.

	DELIVERIES				
	1998	1997	1996	1995	1994
	(THOUSANDS OF BARRELS PER DAY)				
UNITED STATES					
Light crude oil.......................................	338	282	309	345	335
Medium and heavy crude oil............................	627	652	569	513	452
NGL...	27	26	23	18	8
Total United States...................................	992	960	901	876	795
EASTERN CANADA					
Light crude oil.......................................	366	355	348	332	321
Medium and heavy crude oil............................	97	98	102	96	108
NGL...	107	99	100	105	102
Total Eastern Canada..................................	570	552	550	533	531
TOTAL DELIVERIES......................................	1,562	1,512	1,451	1,409	1,326
BARREL MILES (billions per year).......................	391	389	384	385	366

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, -- Montreal Extension Reversal."

SUPPLY AND DEMAND FOR WESTERN CANADIAN CRUDE OIL

Supply

Substantially all of the shipments delivered through the Lakehead System originate in oilfields in western Canada. The Lakehead System also receives U.S. and Canadian production at Clearbrook through a connection with a pipeline owned by a subsidiary of Enbridge, U.S. production at Stockbridge and Lewiston, Michigan, and both U.S. and offshore production in the Chicago area. Changes in supply from western Canada would directly affect movements through the Enbridge Pipelines System and, therefore, the supply available for transportation through the Lakehead System.

Enbridge Pipelines applied to the National Energy Board of Canada ("NEB") in December 1997 to construct its Terrace Phase I facilities in Canada which would complement the Terrace Phase I facilities to be constructed by the Partnership in the United States. As part of that application, Enbridge Pipelines submitted a forecast of supply of western Canadian crude oil and a projection of the markets in which it could be reasonably expected to be consumed. Forecasts by their nature are based upon numerous assumptions, including estimates provided by industry, many of which are beyond the control of Enbridge Pipelines or the Partnership. The forecast submitted to the NEB in 1997 showed the supply of western Canadian crude oil in the year 2003 at over 2,550,000 barrels per day, approximately 500,000 barrels per day above 1997 average daily production of western Canadian crude oil. The supply of western Canadian crude oil was expected to remain at over 2,500,000 barrels per day through 2010. While acknowledging the uncertainty associated with forecasts of the supply of crude oil and other commodities shipped on the Enbridge Pipelines System, the NEB accepted as reasonable the forecasts of the supply of crude oil and other commodities submitted by Enbridge Pipelines and recommended that a certificate for construction be issued. The forecast quantity of crude oil was made subject to numerous uncertainties and assumptions, including a crude oil price of $17.50 per barrel in 1998 rising to $22.25 in 2010.

At December 31, 1998, the benchmark West Texas Intermediate ("WTI") crude oil price closed at $12.05 per barrel, up from the 1998 low of $10.73 per barrel. This lower crude oil price, compared to that assumed in the 1997 forecast, has impacted the crude oil supply available in western Canada. Enbridge Pipelines has recently completed its updated forecast of western Canadian crude oil supply and markets for western Canadian crude oil. This long-term outlook is partially based on supply projections from the oil sands

projects currently operating, being expanded or proposed in western Canada. The Partnership believes that production from these projects is less sensitive to the price of crude oil due to the size and committed capital expenditures involved. The updated forecast projects the supply of western Canadian crude oil to be lower during the period 1999 through 2002 than the Terrace forecast by approximately 120,000 to 190,000 barrels per day. The forecast supply of western Canadian crude oil is projected to recover to 2,500,000 barrels per day in 2003, rising to over 2,600,000 barrels per day from 2004 through 2010. The updated forecast assumes a WTI crude oil price of $14.50 per barrel in 1999, $19.50 in 2003, and $23.00 in 2010.

As a result of the decline in crude oil prices, it is anticipated that 1999 deliveries on the Lakehead System could be approximately 50,000 to 75,000 barrels per day (on average) less than 1998 delivery levels of 1,562,000 barrels per day, a trend which could continue into the year 2000.

Despite the downturn in crude oil prices and deliveries, the Partnership believes that the outlook regarding future growth prospects continues to be positive and that the potential for increased crude oil production in western Canada remains substantial. The timing of growth in supply of western Canadian crude oil, however, will be dependent upon recovery of crude oil prices.

Demand

Rising crude oil demand and declining inland U.S. domestic production are contributing to an increasing need for importing crude oil into the PADD 2 market. The Partnership believes that PADD 2 will continue to provide an excellent market for western Canadian shippers as returns to crude oil producers are expected to remain attractive. Moreover, the Partnership believes that PADD 2 will remain the most attractive market for western Canadian supply since it is currently the largest North American processor of western Canadian heavy crude oil and has the greatest potential for converting refining capacity from light to heavy crude.

Although western Canadian producers experience competition from Venezuelan and Mexican heavy crude oil in PADD 2, western Canadian heavy crude oil is expected to remain the dominant supply source for the region. Latin American heavy crude oil will continue to provide the swing supply to the PADD 2 region. In the short-term, Latin American deliveries to PADD 2 are expected to increase due to reduced supply of western Canadian crude oil resulting from low crude oil prices and producer returns. However, over the long-term, it is expected that producers of Latin American heavy crude oil will concentrate on PADD 3 and PADD 5 markets, where they receive a higher return than compared to PADD 2.

Based on the recent forecast completed by Enbridge Pipelines, exports from western Canada to the United States are forecast to increase to approximately 1,800,000 barrels per day in 2005 and remain at that level or above through 2010. This is approximately 700,000 barrels per day higher than 1997 exports. Of the exports to the United States, PADD 2 would receive approximately 1,470,000 barrels per day in 2005, approximately 600,000 barrels per day higher than 1997. Exports to PADD 2 would rise to approximately 1,540,000 barrels per day in 2007 and decline to approximately 1,430,000 barrels per day by 2010. Although in 1999 exports on the System to PADD 2 are anticipated to be marginally lower than 1998, recovery is expected in 2001 with long-term exports surpassing Terrace forecast levels by 2005. Current low crude oil prices are expected to delay supply and market growth for western Canadian crude oil by approximately one to two years.

Deliveries to eastern Canada averaged approximately 570,000 barrels per day in 1998. Demand in eastern Canada is expected to grow to approximately 640,000 barrels per day over the next several years. Partnership deliveries to eastern Canada are, however, expected to decline due to the reversal of Enbridge's Line 9 from Montreal to Sarnia. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, -- Montreal Extension Reversal."

Crude oil refineries in eastern Canada are generally configured to process light sweet and light sour crude oil. While Canadian crude oil supplies have increased over the last several years, the supply of conventional light sweet and light sour crude oil in western Canada is expected to decline. Eastern Canadian refiners cannot process significantly greater amounts of western Canadian heavy crude oil without substantial reconfiguration of their refineries. To the extent eastern Canadian refiners have found it difficult to obtain light crude oil supply from western Canada at an economic price, refiners have been recently accessing U.S. and imported

light crude volumes through Lakehead System pipeline connections in the Chicago area. Light crude oil movements originating in the Chicago area for delivery to eastern Canada have increased from approximately 70,000 barrels per day in 1997 to approximately 110,000 barrels per day in 1998. These movements are expected to decline following the reversal of the Enbridge's Line 9 in 1999.

CUSTOMERS

The Lakehead System operates under month-to-month transportation arrangements with its shippers. During 1998, 48 shippers tendered crude oil and NGL for delivery through the Lakehead System. These customers included integrated oil companies with production facilities in western Canada and refineries in eastern Canada, major oil companies, refiners and marketers. Shipments by the top ten shippers during 1998 accounted for approximately 80% of total revenues during that period. Revenue from Amoco (through affiliated companies), Mobil Oil Company of Canada Ltd. and Imperial Oil Limited accounted for approximately 20%, 14% and 12%, respectively, of total operating revenue generated by the Lakehead System during 1998. The remaining shippers each accounted for less than 10% of total revenues.

CAPITAL EXPENDITURES

In 1998, the Partnership made capital expenditures of $487.3 million, of which $470.7 million was for its two expansion programs SEP II and Terrace and $16.6 million was for other projects including core maintenance of $7.2 million. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, -- SEP II, -- Terrace Expansion Program."

TAXATION

For federal and state income tax purposes, the Partnership and Operating Partnership are not taxable entities. Federal and state income taxes on Partnership taxable income are borne by the individual partners through the allocation of Partnership taxable income. Such taxable income may vary substantially from net income reported in the statement of income.

COMPETITION

Because pipelines are the lowest cost method for intermediate and long haul movement of crude oil over land, the System's most significant existing competitors for the transportation of western Canadian crude oil are other pipelines. In 1998 the Enbridge Pipelines System transported approximately 65% of total western Canadian crude oil production, of which more than 90% was transported by the Lakehead System. The remainder of 1998 western Canadian crude oil production was refined in Alberta or Saskatchewan or transported through other pipelines. Of the pipelines transporting western Canadian crude oil out of Canada, the System provides approximately 70% of the total pipeline design capacity. The remaining 30% of design capacity is shared by five other pipelines transporting crude oil to British Columbia, Washington, Montana and other states in the Northwest U.S.

Competition among common carrier pipelines is based primarily on transportation charges, access to producing areas and proximity to end users. The Partnership believes that high capital requirements, environmental considerations and the difficulty in acquiring rights of way and related permits make it difficult for a competing pipeline system comparable in size and scope to the System to be built in the foreseeable future.

Express Pipeline Ltd. ("Express Pipeline"), a joint venture between Alberta Energy Company, Ltd. and TransCanada PipeLines Limited, owns and operates a 170,000 barrel per day capacity pipeline that carries western Canadian crude oil to the U.S. Rocky Mountain region, where it connects to a 150,000 barrels per day capacity pipeline system. This connecting pipeline serves the Patoka/Wood River market area. Express Pipeline began service in early 1997. The General Partner believes, however, that the System is more attractive to western Canadian producers shipping to the Chicago or Patoka/Wood River market area as it offers lower tolls and shorter transit times than Express Pipeline and does not require shipper volume commitments as currently required by Express Pipeline.

The System encounters competition in serving shippers to the extent that shippers have alternate opportunities for transporting liquid hydrocarbons from their sources to customers. In selecting the destination for their supplies of crude oil, sellers generally desire to use the alternative that results in the highest return to them. Generally, it is expected that sellers will receive the highest return from markets served by the System, but alternate markets may, for periods of time, offer equal or better returns for the seller. Such markets could potentially include the U.S. Rocky Mountain region for sweet crude oil and the Washington State market for light sour crude oil.

In the United States, the Lakehead System encounters competition from other crude oil and refined product pipelines and other modes of transportation delivering crude oil and refined products to the refining centers of Minneapolis-St. Paul, Chicago, Detroit and Toledo and the refinery market and pipeline hub located in the Patoka/Wood River area. The Lakehead System transports approximately 45% of all crude oil deliveries into the Chicago area, approximately 75% of all crude oil deliveries into the Minneapolis-St. Paul area and virtually all deliveries of crude oil to Ontario.

Please refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, -- Montreal Extension Reversal," for discussion of a planned reversal of the Montreal Extension that will result in Enbridge Pipelines becoming a competitor of the Lakehead System for supplying crude oil to the Ontario market.

ENVIRONMENTAL AND SAFETY REGULATION

General

The operations of the Partnership are subject to federal, state and local laws and regulations relating to protection of the environment and safety. Although the Partnership believes that the operations of the Lakehead System are in substantial compliance with applicable environmental and safety laws and regulations, the risk of substantial liabilities are inherent in pipeline operations, and there can be no assurance that substantial liabilities will not be incurred. To the extent that the Partnership is unable to recover environmental costs in its rates or through insurance, the Partnership could be subject to material costs.

In general, the Partnership expects to incur future ongoing expenditures to comply with industry and regulatory environment and safety standards. Such expenditures cannot be accurately estimated at this time, although the Partnership does not expect that they will have a material adverse effect on the Partnership.

Air

The operations of the Partnership are subject to the federal Clean Air Act and comparable state statutes.

Water

The federal Water Pollution Control Act, as amended by the Oil Pollution Act of 1990 ("WPCA"), imposes strict controls on the discharge of oil into navigable waters. The WPCA provides penalties for any discharges of petroleum products in reportable quantities, imposes liability for clean-up costs and natural resource damage, and allows for third party lawsuits. State laws also provide varying civil and criminal penalties and liabilities in the case of a release of petroleum into surface water or groundwater. Spill prevention control and countermeasure requirements of federal laws require diking and similar structures to help prevent contamination of navigable waters in the event of a petroleum overflow, rupture or leak. In response to regulations mandated by the WPCA, the Partnership has submitted to the Office of Pipeline Safety ("OPS") of the U.S. Department of Transportation ("DOT") oil spill emergency response plans, which have been approved, and a certification that it has the resources to respond to a worst case spill. Expenses of routine compliance with these and other similar regulations are not expected to have a material adverse impact on the Partnership.

Remediation Matters

Contamination resulting from spills of crude oil and petroleum products is not unusual within the petroleum pipeline industry. Historic spills along the Lakehead System as a result of past operations may have resulted in soil or groundwater contamination. The Partnership is addressing known sites through monitoring and remediation programs.

Superfund

The Comprehensive Environmental Response, Compensation and Liability Act of 1989, as amended, also known as "Superfund," and comparable state laws impose liability, without regard to fault or the legality of the original act, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. In the course of its ordinary operations, the Lakehead System generates wastes, some of which fall within the federal and state statutory definitions of a "hazardous substance" and some of which were historically disposed of at sites that may require cleanup under Superfund and related state statutes.

Waste

The Partnership generates hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act and comparable state statutes. The Partnership believes that operations of the Lakehead System are in substantial compliance with such statutes in all states in which it operates. The Environmental Protection Agency ("EPA") is currently in the process of developing stricter disposal standards for nonhazardous waste.

Safety Regulation

The Partnership's operations are subject to construction, operating and safety regulation by the DOT and various other federal, state and local agencies. The Pipeline Safety Act of 1992, as amended by the Accountable Pipeline Safety and Partnership Act of 1996, requires the OPS to consider environmental impacts and do a risk assessment, as well as satisfy its traditional public safety mandate, when developing pipeline safety regulations. The Act also mandates the OPS to establish pipeline operator qualification rules, requires pipeline operators to provide maps and records to the OPS, and authorizes the OPS to require pipelines to be modified to accommodate internal inspection devices. Regulations issued pursuant to the Act require pipeline operators to implement drug and alcohol testing programs for employees and contractors that are engaged in safety-sensitive activities. Additional legislation or regulations have been proposed requiring remotely controlled shutoff valves in populated or environmentally sensitive areas, increased public education of pipeline safety and accident prevention and periodic integrity testing of pipelines by internal inspection or hydrostatic testing. The Partnership currently has an integrity testing program utilizing internal inspection devices and has conducted additional hydrostatic testing for selected segments of the Lakehead System. The Partnership is also subject to the requirements of federal and state Occupational Safety and Health Acts.

EMPLOYEES

Neither the General Partner nor the Partnership has any employees. The General Partner is responsible for the management and operation of the Partnership and to fulfill these obligations, it has entered into agreements with Enbridge and certain of its subsidiaries to provide the required services. The Partnership reimburses the General Partner or its affiliates for expenses incurred in performing these services at cost.

ITEM 3. LEGAL PROCEEDINGS

The Partnership is a defendant in various lawsuits and a party to various legal proceedings arising in the ordinary course of business. Some of these lawsuits and proceedings are covered, in whole or in part, by insurance. The Partnership believes that the outcome of all these lawsuits and proceedings will not, individually or in the aggregate, have a material adverse effect on the financial condition of the Partnership. In connection with the transfer of its pipeline business to the Partnership, the General Partner agreed to indemnify the Partnership from and against substantially all liabilities, including liabilities relating to

environmental matters, arising from operations prior to the transfer. This indemnification does not apply to amounts that the Partnership would be able to recover in its tariffs, through insurance, or to any liabilities relating to a change in laws after December 27, 1991.

In late July 1998, the Partnership's directional drilling operations for SEP II construction caused a discharge of non-hazardous bentonite drilling mud in a wetlands area. The Partnership does not believe that any penalties that might be assessed by the EPA will have a material impact on the financial condition of the Partnership. The State of Illinois is pursuing an action relating to this discharge under Natural Resource Damage Assessment regulations of the Clean Water Act to seek compensation for damage to the wetlands area. It is expected that a settlement will be reached with the State to resolve the matter and that it will not have a material impact on the financial condition of the Partnership.

In a letter dated August 19, 1998, the Illinois Attorney General informed the Partnership that it is seeking a penalty of $135,000 for a May 28, 1998, release of crude oil caused by a third party in Orland Park, Illinois. The Partnership and the Attorney General are in negotiations on this matter.

The Partnership received a Notice of Violation, dated October 29, 1998, from the Wisconsin Department of Natural Resources ("Wisconsin DNR") that alleges the Partnership failed to monitor discharges of water from SEP II construction trenches on certain occasions and exceeded the effluent limitations set forth in a permit The Partnership has submitted its reply to the notice and intends to cooperate with the Wisconsin DNR in an effort to resolve the issue and any penalties that may ensue. It is not anticipated that any penalty will have a material impact on the financial condition of the Partnership.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the fourth quarter of 1998.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Partnership's Class A Common Units are listed and traded on the New York Stock Exchange, the principal market for the Class A Common Units, under the symbol LHP. The quarterly price range per Class A Common Unit and cash distributions paid per unit for 1998 and 1997 are summarized below:

	FIRST	SECOND	THIRD	FOURTH
1998 QUARTERS				
High	$ 46 3/4	$ 49 15/16	$ 52 7/16	$ 54
Low	$ 43	$ 44 5/16	$ 46 11/16	$ 46 3/4
Cash distributions paid	$0.78	$0.86	$0.86	$0.86

	FIRST	SECOND	THIRD	FOURTH
1997 QUARTERS				
High	$ 38 3/4	$ 39	$ 47 3/4	$ 47 7/8
Low	$ 33	$ 33 7/8	$ 38	$ 38 3/8
Cash distributions paid	$0.68	$0.68	$0.78	$0.78

On March 1, 1999, the last reported sales price of the Class A Common Units on the New York Stock Exchange was $43 5/16. At March 1, 1999, there were approximately 39,000 Class A Common Unitholders of which there were approximately 3,600 registered Class A Common Unitholders of record. There is no established public trading market for the Partnership's Class B Common Units, all of which are held by the General Partner.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth, for the periods and at the dates indicated, summary historical financial and operating data for the Partnership. The table is derived from the consolidated financial statements of the Partnership and notes thereto, and should be read in conjunction with those audited financial statements.

	YEAR ENDED DECEMBER 31,				
	1998	1997	1996(1)	1995(1)	1994
	(DOLLARS IN MILLIONS, EXCEPT PER UNIT AMOUNTS)				
INCOME STATEMENT DATA:					
Operating revenue	$ 287.7	$ 282.1	$ 274.5	$ 268.5	$ 246.0
Operating expenses(2)	182.3	174.0	187.1	195.2	159.7
Operating income	105.4	108.1	87.4	73.3	86.3
Interest and other income	6.0	9.7	9.6	7.1	4.1
Interest expense	(21.9)	(38.6)	(43.9)	(40.3)	(29.8)
Minority interest	(1.0)	(0.9)	(0.7)	(0.5)	(0.7)
Net income	$ 88.5	$ 78.3	$ 52.4	$ 39.6	$ 59.9
Net income per unit(3)	$ 3.07	$ 3.02	$ 2.11	$ 1.60	$ 2.61
Cash distributions paid per unit	$ 3.36	$ 2.92	$ 2.60	$ 2.56	$ 2.51
FINANCIAL POSITION DATA (AT YEAR END):					
Property, plant and equipment, net	$1,296.2	$ 850.3	$ 763.5	$ 725.1	$ 727.6
Total assets	$1,414.4	$1,063.2	$ 975.9	$ 915.2	$ 868.6

Long-term debt	$ 814.5	$ 463.0	$ 463.0	$ 395.0	$ 364.0
Partners' capital					
Class A Common Unitholder	$ 453.4	$ 461.6	$ 376.3	$ 387.9	$ 409.3
Class B Common Unitholder	37.3	36.7	21.7	21.7	23.5
General Partner	4.3	3.5	1.6	1.5	1.6
	$ 495.0	$ 501.8	$ 399.6	$ 411.1	$ 434.4
CASH FLOW DATA:					
Cash provided from operating activities	$ 103.6	$ 106.6	$ 93.9	$ 121.5	$ 108.1
Cash used in investing activities	$ (427.9)	$ (101.7)	$ (84.7)	$ (54.0)	$ (102.7)
Cash provided from (used in) financing activities	$ 252.7	$ 24.1	$ 3.4	$ (32.5)	$ 27.7
Capital expenditures included in investing activities	$ (487.3)	$ (126.9)	$ (76.7)	$ (35.5)	$ (136.9)
OPERATING DATA:					
Barrel miles (billions)	391	389	384	385	366
Deliveries (thousands of barrels per day)					
United States	992	960	901	876	795
Eastern Canada	570	552	550	533	531
	1,562	1,512	1,451	1,409	1,326

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(1) 1996 results reflect the impact of the Settlement Agreement between the Partnership and customer representatives on all outstanding contested tariff rates. 1995 results reflect the impact of a June 1995 FERC decision.

(2) Operating expenses include provisions for prior years' rate refunds of $20.1 million and $22.9 million in 1996 and 1995, respectively.

(3) The General Partner's allocation of net income has been deducted before calculating net income per unit as follows: 1998, $8.0 million; 1997, $4.4 million; 1996, $1.6 million; 1995, $1.2 million; and 1994, $1.4 million.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

1998 was a successful year for the Partnership as record net income and crude oil deliveries were achieved despite a decline in world crude oil prices. The strong performance of the Partnership during 1998, coupled with expectations for strong long-term performance, influenced the Board of Directors of the General Partner to increase the quarterly cash distribution on April 16, 1998 to $0.86 per unit ($3.44 on an annualized basis) from $0.78 per unit. This most recent increase in the distribution is primarily the result of earnings growth from capacity expansions.

Challenges encountered by the Partnership during construction of the $450 million System Expansion Program II ("SEP II") were overcome and the targeted completion date of first quarter 1999 was met. During December 1998, the process of filling the new pipeline with crude oil was begun and deliveries from the new line will commence in March 1999. A tariff increase associated with the new line was filed with the Federal Energy Regulatory Commission ("FERC") in late December and became effective on January 1, 1999. See "-- SEP II".

The Partnership, together with Enbridge Pipelines Inc., of Edmonton, Alberta, ("Enbridge Pipelines" formerly Interprovincial Pipe Line Inc.), began construction of the first phase of the Terrace Expansion Program ("Terrace") in 1998. Terrace is a multi-phase program that will eventually add approximately 350,000 barrels per day of pipeline system delivery capability with the first phase of 170,000 barrels per day expected to be operational by September 1999. The remaining capacity may be added at customer request in stages over the next several years. See "-- Terrace Expansion Program".

Deliveries by the Partnership of crude oil and natural gas liquids ("NGL") increased 3% over the previous record levels attained in 1997. In late 1998, the Partnership began experiencing a decline in the level of crude oil deliveries compared with the first half of 1998. Producers of crude oil throughout North America began reducing production of less profitable crude oil due to the significant drop in world crude oil prices. At December 31, 1997, the benchmark

West Texas Intermediate ("WTI") crude oil price was $17.83 per barrel. At December 31, 1998 the reference WTI price closed at $12.05 per barrel, up from the 1998 low of $10.73.

While utilization of the Partnership's pipeline system historically has been fairly insensitive to modest changes in the price of crude oil, the current world crude oil price situation is anticipated to impact the supply of available crude oil and the Partnership's short-term results. Despite this forecast decrease in crude oil deliveries, the Partnership anticipates generating more than sufficient cash from operating activities to continue its current level of distribution through 1999. See "-- Future Prospects."

RESULTS OF OPERATIONS

Net income for 1998 was $88.5 million ($3.07 per unit) compared with $78.3 million ($3.02 per unit) for 1997 and $52.4 million ($2.11 per unit) for 1996. Net income for 1996 was impacted by rate refunds ($20.1 million) and related interest expense ($3.2 million) attributable to prior years recorded in response to a settlement agreement (the "Settlement Agreement") between the Partnership and certain customer representatives that concluded a dispute that began in 1992 concerning the Partnership's tariff rates. See "Items 1 & 2. Business and Properties, -- Tariffs, -- Rate Cases."

Crude oil and NGL deliveries averaged a record 1,562,000 barrels per day in 1998, up from the 1,512,000 barrels per day averaged during 1997, a 3% growth in Lakehead System deliveries. Crude oil and NGL deliveries increased 4% during 1997 when compared with 1996 results. Over the three-year period, increased deliveries resulted from greater crude oil production in western Canada, increased transportation of foreign and U.S. crude received in the Chicago area, combined with increased pipeline capacity from the Partnership's expansion programs. System utilization measured in barrel miles was relatively unchanged over the three year period due to shorter average length of haul.

Net income for 1998 was $10.2 million higher than net income in 1997 primarily due to increased operating revenue and lower interest expense partially offset by higher operating expenses and lower interest and other income. Net income per unit increased $0.05 due to the increase in net income despite a greater number of weighted average units outstanding during 1998 compared with 1997 and additional incentive

income allocations to the General Partner related to the achievement of certain target cash distribution levels. See Note 3 to the Partnership's consolidated financial statements. Weighted average units outstanding increased in 1998 due to the full year impact of the October 1997 Class A Common Unit offering.

Net income in 1997 improved $25.9 million in comparison with 1996. A 1996 non-recurring charge of $20.1 million related to prior years' rate refunds required under the Settlement Agreement together with a related interest accrual of $3.2 million accounts for a majority of the increase. In addition, a combination of higher operating revenue and lower interest expense, partially offset by higher operating expenses, led to the increase in net income. Per unit amounts increased significantly primarily due to increased net income.

Operating revenue for 1998 was $287.7 million, or $5.6 million greater than operating revenue for 1997. The increase was primarily due to increased deliveries and the full year impact of a July 1, 1997, tariff increase of 1.6%, partially offset by a 0.6% tariff decrease on July 1, 1998, as required under the FERC's indexing methodology and an increase in the proportion of heavy crude oil deliveries (up 9% to 625,000 barrels per day). The Partnership's current tariff rate for medium and heavy crude oil deliveries to the Chicago area is approximately 7% and 20% higher, respectively, than that for lighter crude oils. The positive impact of increased deliveries and heavier crude oil mix were somewhat offset by a decreased average length of haul (686 miles in 1998 versus 704 miles in 1997). Average length of haul decreased due to increased receipt of crude oil in the Chicago area from U.S. and foreign sources for delivery to markets east of Chicago including eastern Canada.

Operating revenue for 1997 was $282.1 million, or $7.6 million greater than 1996 primarily due to increased deliveries and the transportation of a greater proportion of heavy crude oil (up 22% to 573,000 barrels per day). Operating revenue was also favorably impacted by the full year impact of a July 1996 tariff rate increase of 0.9%, and an additional 1.6% on July 1, 1997. Operating revenue for 1996 reflects tariff rates implied in the Settlement Agreement.

Total operating expenses of $182.3 million in 1998 were $8.3 million greater than 1997 primarily due to higher power costs associated with increased deliveries, and a heavier crude oil mix. Operating and administrative costs increased $3.9 million primarily due to increased rents for rights-of-way as a result of the renewal of certain lease agreements that expired during the year, and higher maintenance costs associated with an increased level of internal pipeline inspection. Depreciation expense increased due to the growth in property, plant and equipment.

Total 1997 operating expenses were $13.1 million less than 1996 primarily due to the absence of a $20.1 million provision for prior years' rate refunds recorded in 1996. The decrease in total operating expenses was somewhat offset by higher power costs associated with a heavier crude oil mix and increased deliveries. Operating and administrative expenses increased largely due to higher property taxes. Depreciation expense for 1997 increased due to growth in property, plant and equipment, somewhat offset by the impact of revised depreciation rates that became effective on July 1, 1996. The depreciation rates were revised to better represent the expected service life of the pipeline system.

Interest expense of $21.9 million in 1998 decreased $16.7 million from 1997 largely due to the capitalization of interest costs associated with SEP II and Terrace as part of the costs of constructing the assets. Capitalized interest reflects the Partnership's average cost of debt, of approximately 7.8%, and the average level of funds invested in construction. Capitalized interest increased due to the significant construction projects ongoing during 1998. Interest expense is further decreased due to the utilization of the Partnership's cash balances to finance a portion of the capital expenditures rather than issuing additional debt or equity. Interest capitalization generally ceases once a capital project is complete and ready for service. Interest paid increased to $44.4 million in 1998 from $39.9 million paid in 1997 primarily due to greater borrowing on the Partnership's revolving credit facility.

Interest expense for 1997 decreased $5.3 million from 1996 due to lower balances and interest rates with respect to rate refunds payable, and increased capitalized interest attributable to greater construction work in process during 1997. These changes were partially offset by additional interest on greater average borrowings in 1997 under the Partnership's credit facility.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 1998, cash, cash equivalents and short-term investments totaled $47.0 million, down $125.5 million since December 31, 1997. In keeping with the Partnership's financing plans for SEP II and Terrace, existing cash balances were used to partially finance the expansion programs. Of this $47.0 million, $24.7 million ($0.86 per unit) was set aside for the cash distribution paid on February 12, 1999, with the remaining $22.3 million available for capital expenditures and other business needs.

Cash generated from operating activities in 1998 decreased marginally by $3.0 million from 1997 to $103.6 million, as the impact of higher net income was offset by changes in working capital requirements. Cash generated from operating activities in 1997 increased $12.7 million from 1996 to $106.6 million primarily due to higher net income, partially offset by the reduction in liability for accrued rate refunds.

In response to the October 1996 Settlement Agreement, the Partnership made rate refunds of $28.5 million in 1998 and $27.7 million in 1997 with the remaining balance continuing to be repaid through a 10% reduction of tariff rates. This reduction will continue until all refunds have been made. Based on the $28.7 million remaining balance at December 31, 1998, and projected pipeline system deliveries, the 10% reduction is expected to remain effective until sometime late in the second half of 1999.

In 1998, the Partnership made capital expenditures of $487.3 million, of which $358.0 million were for SEP II, $112.7 million were for Terrace, and $16.6 million were for other projects. With $450.0 million of capital expenditures having been incurred or committed on SEP II through December 31, 1998, the project is largely complete except for minor restoration and clean-up work and the finalization of rights-of-way costs in 1999. In 1997, the Partnership made capital expenditures of $126.9 million, including $84.9 million for SEP II and $42.0 million for other projects.

The first phase of the Terrace expansion is largely complete and capital expenditures are anticipated to total approximately $138.0 million. In addition to Terrace, the Partnership anticipates spending approximately $8.2 million for pipeline system enhancements and $13.5 million for core maintenance activities in 1999. See "-- Future Prospects, -- Lakehead System Expansion Projects."

Excluding future phases of Terrace, ongoing capital expenditures are expected to average $10 to $20 million on an annual basis (approximately 50% for enhancement and 50% for core maintenance of the pipeline system). Core maintenance activities, such as the replacement of equipment and preventive maintenance programs, are expected to be undertaken to enable the Partnership's pipeline system to continue to operate at its maximum operating capacity. Enhancements to the pipeline system, such as renewal and replacement of pipe, are expected to extend the life of the Lakehead System and permit the Partnership to respond to developing industry and government standards and the changing service expectations of its customers.

On an annual basis the Partnership makes expenditures of a capital and operating nature related to maintaining compliance of the Lakehead System with applicable environmental and safety regulations. Capital expenditures for safety and environmental purposes comprise a portion of the routine core maintenance and enhancement capital expenditures annually incurred by the Partnership. Amounts are not readily segregated since individual projects may be undertaken for a variety of reasons in addition to environment and safety considerations. Future environment and safety expenditures are not anticipated to be material in relation to the Partnership's results of operations.

At December 31, 1998, the Partnership had $310.0 million aggregate principal amount of First Mortgage Notes outstanding that bear interest at the rate of 9.15% per annum, payable semi-annually. The notes are due and payable in ten equal annual installments beginning in the year 2002. During 1998, the Partnership increased the size of its $205.0 million Revolving Credit Facility to $350 million. Total borrowings under the facility of $305.0 million were outstanding at December 31, 1998. Interest rates on this facility are variable and currently approximate 6%.

During the third quarter of 1998, the Board of Directors of the General Partner approved a $200 million uncommitted lending facility from the General Partner to the Partnership. This uncommitted facility provided

an alternative source of funds at market interest rates in the event that a disruption in the capital markets delayed anticipated debt and equity issuances. In late September 1998, the Partnership borrowed, and subsequently repaid in early October, $37.0 million under this arrangement.

In October 1998, pursuant to a $400 million shelf registration statement filed with the Securities and Exchange Commission ("SEC"), $200 million face amount of senior unsecured notes were issued to retire borrowings under the Revolving Credit Facility and to repay the loan of $37 million issued by the General Partner. The Partnership issued the senior unsecured notes in two tranches of $100 million, each, with maturities of 2018 (with an interest rate of 7%) and 2028 (with an interest rate of 7.125%), respectively. For additional details relating to the Partnership's debt, see Note 6 to the Partnership's Consolidated Financial Statements.

In October 1997, the Partnership issued 2.2 million Class A Common Units. Net proceeds from the offering, including the General Partner's contribution, were $99.2 million. This offering increased the number of Class A Common Units outstanding to 22,290,000. Proceeds from this offering were used to finance a portion of SEP II. For additional information regarding the 1997 equity offering and Partnership organization, see Note 1 to the Partnership's Consolidated Financial Statements. During the fourth quarter of 1998, the Partnership filed a $200 million shelf registration statement with the SEC for the issuance of additional Class A Common Units. As of December 31, 1998, no Class A Common Units have been issued under this registration statement.

Distributions paid to partners during 1998 increased $20.0 million to $95.3

million ($3.36 per unit). Distributions increased as a result of the increase in the quarterly distribution to $0.86 per unit from $0.78 per unit declared in April 1998, the issuance of 2.2 million Class A Common Units in 1997, and increased incentive distributions paid to the General Partner as a result of higher levels of cash distributions per unit. Distributions paid to partners for 1997 increased $11.4 million to $75.3 million ($2.92 per unit) compared to 1996.

The Partnership distributes quarterly all of its Available Cash, which is generally defined to mean, with respect to any calendar quarter, the sum of all of the cash receipts of the Partnership plus net reductions to reserves less all of its cash disbursements and net additions to reserves. These reserves are retained to provide for the proper conduct of the Partnership's business, to stabilize distributions of cash to Unitholders and the General Partner and as necessary to comply with the terms of any agreement or obligation of the Partnership. On February 12, 1999, the Partnership paid a $0.86 per unit distribution related to the fourth quarter of 1998.

The Partnership anticipates that it will continue to have adequate liquidity to fund future recurring operating, investing and financing activities. The Partnership intends to fund Terrace, remaining SEP II expenditures, and ongoing capital expenditures with the proceeds from future debt and equity offerings, other borrowings, cash generated from operating activities, and existing cash, cash equivalents and short-term investments. Cash distributions are expected to be funded with internally generated cash. The Partnership's ability to make future debt and equity offerings will depend on prevailing market conditions and interest rates and the then-existing financial condition of the Partnership.

FUTURE PROSPECTS

Income and cash flows of the Partnership are sensitive to oil industry supply and demand in Canada and the United States, and the regulatory environment. As the Partnership's pipeline system is operationally integrated with the Enbridge Pipelines System in western Canada, the Partnership's revenues are dependent upon the utilization of the Enbridge Pipelines System by producers of western Canadian crude oil. The Partnership believes long-term demand for its pipeline system will continue in light of industry's increasing production forecasts for western Canadian crude oil and anticipated increased demand for crude oil in the Midwest U.S. See "Items 1 & 2. Business and Properties, -- Supply and Demand for Western Canadian Crude Oil."

In late 1998, representatives of the Canadian Association of Petroleum Producers ("CAPP") and the Partnership concluded informal discussions concerning the projected supply of western Canadian crude oil and

NGL available for delivery during 1999. Based on these discussions, and as a result of the general decline in crude oil prices, it is anticipated that deliveries on the Partnership's pipeline system could be approximately 50,000 to 75,000 barrels per day (on average) less than 1998 delivery levels of 1,562,000 barrels per day. At this potential level of utilization, the Partnership will earn a 7.5% nominal rate of return on its SEP II equity investment during 1999, the minimum prescribed in tariff agreements reached with a majority of the Partnership's customers. See "Items 1 & 2. Business and Properties, -- Regulation, -- Tariffs."

The collective impact of reduced deliveries and a 7.5% rate of return on SEP II equity is anticipated to result in net income for 1999 of approximately $80 to $90 million. Based on current projections, the Partnership anticipates generating sufficient cash from operating activities to continue its current level of cash distribution through 1999. Despite the recent weakness in crude oil prices, the Partnership's outlook regarding future growth prospects remains positive. While the availability of western Canadian crude oil is sensitive to the long-term outlook for crude oil prices, the Partnership believes that recent announcements by major Canadian oil producers affirming oil sands development and other long-term expansion projects is encouraging and illustrative of long-term supply growth from the western Canadian sedimentary basin.

The Lakehead and Enbridge Pipelines Systems (the "System") serve as a strategic link between the western Canadian oil fields and the markets of the Midwest U.S. and eastern Canada and have for the last several years operated at or near capacity. In response to a long-term trend of increasing supply of crude oil from western Canada and the growth of demand in the markets of the Midwest U.S., the Partnership plans not only to maintain the service capability of the existing Lakehead System but also to expand its capacity where appropriate. This is consistent with the Partnership's principal business objective to increase cash generated from its operations to enhance cash distributions. This strategy has enabled the Partnership to increase quarterly cash distributions to Common Unitholders from $0.59 per unit in 1992 to $0.86 per unit currently.

Lakehead System Expansion Projects

Key current and future expansion projects of the Partnership are summarized below:

- SEP II -- This expansion was largely completed in early 1999. SEP II involved the construction of a new pipeline from the Partnership's pipeline terminal at Superior, Wisconsin, to its Chicago, Illinois, market area. The pipeline is expected to provide an additional 170,000 barrels per day of delivery capacity on the Lakehead System. Under a tariff agreement with its customers ("Tariff Agreement"), a tariff surcharge has been implemented that recovers the costs of, and return on, the SEP II facilities. The Tariff Agreement allows the Partnership to earn a return on its SEP II equity investment based on the benchmark National Energy Board of Canada ("NEB") multi-pipeline rate of return. Under the Tariff Agreement, return on SEP II equity can range from a minimum equivalent to the NEB multi-pipeline rate of return less 3% (subject to a 7.5% floor) to a maximum of the multi-pipeline rate of return plus 3% (subject to a 15% ceiling). Rate of return on equity within the range is determined by measuring SEP II capacity utilization on the Enbridge Pipelines System in Canada. See "Items 1 & 2. Business and Properties, -- Regulation, -- Tariffs."

- Terrace Expansion Program -- This expansion program, which is being undertaken by the Partnership in conjunction with Enbridge Pipelines, is a phased expansion that is expected to ultimately provide an additional 520,000 barrels per day of heavy crude oil capacity for western Canadian producers seeking greater access to Midwest U.S. markets. Subject to continued industry support, customer requirements and receipt of regulatory approvals, the General Partner and Enbridge Pipelines anticipate that this expansion program will be completed in stages beginning in 1999. Phase I of Terrace includes construction of new 36-inch diameter pipeline facilities from Kerrobert, Saskatchewan, to Clearbrook, Minnesota. The new pipeline will join existing 48-inch diameter pipeline loops between Kerrobert and Clearbrook, creating another separate pipeline joining those locations. Phase I is expected to provide an initial 95,000 barrels per day increase in capacity in the first half of 1999, rising to 170,000 barrels per day by September 1999. Phase I construction is expected to cost the Partnership approximately $138 million for construction of facilities in the U.S., and Enbridge Pipelines Cdn. $610 million for construction of facilities in Canada. Subsequent phases of Terrace are dependent upon customer

requirements and, if completed, are expected to provide up to 350,000 barrels per day of added heavy crude oil capacity in addition to the 170,000 barrels per day to be provided by Phase I. Subject to completion of all phases, and after allowing for anticipated declines in light crude oil production, total System delivery capability is expected to increase by 350,000 barrels per day. A tariff surcharge for Terrace of approximately $0.013 per barrel (for light crude oil to Chicago) is anticipated to be filed in the first half of 1999. This tariff surcharge is premised on the completion of Phase 2 and Phase 3 of Terrace. Should these later phases not proceed, the Partnership will be allowed to increase its tariff surcharge on a cost of service basis to allow recovery of, and return on, its Phase I Terrace investment including any revenue variances between the application of the toll increment and annual Terrace cost of service. See "Items 1 & 2. Business and Properties, -- Regulation, -- Tariffs."

The Partnership is subject to a rate regulatory methodology that prescribes rate ceilings that are adjusted each July 1. The rate ceilings are adjusted by reference to annual changes in the Producer Price Index for Finished Goods minus one percent ("PPIFG-1"). The General Partner expects the PPIFG-1 to decrease approximately 1.9% for 1998. This decrease in the PPIFG-1 should not have a material effect on 1999 operating revenue since the decrease does not apply to SEP II or Terrace tariff surcharges and will be effective mid-year 1999. To date, the Partnership has been able to manage its pipeline system to ensure inflationary cost pressures in excess of the PPIFG-1 have not materially impacted net income. The FERC is scheduled to review the appropriateness of the indexing methodology, and specifically the PPIFG-1 index, in year 2000.

The indexed rate environment, the Settlement Agreement, and other negotiated settlements with customers for SEP II and Terrace are benefiting the Partnership and its customers by restoring stability and providing predictable tariff rates. Customer representatives who are a party to the various agreements have agreed not to challenge any rates within the indexed ceiling until October 2001. In addition, to the extent allowed under FERC orders or by agreement with customers, the Partnership has filed, and will continue to file, for additional tariff increases from time to time to reflect ongoing expansion programs.

Enbridge Inc. Projects

Enbridge Inc. ("Enbridge" formerly IPL Energy Inc.) the ultimate parent of the General Partner, is also engaged in North American crude oil pipeline projects which are related to the Enbridge Pipelines and Lakehead Systems. The General Partner believes that certain of these projects are complementary to ongoing and future expansion projects even though they are not owned by the Partnership, since the projects may result in increased deliveries on the Lakehead System. Such projects are summarized below:

- Mustang -- In 1996, a U.S. subsidiary of Enbridge entered into a partnership ("Mustang Pipe Line Partners") with Mobil Illinois Pipe Line Company, a subsidiary of Mobil Oil Corporation, to own and operate a crude oil pipeline that connects the Lakehead System to the Patoka/Wood River refinery area and pipeline hub south of Chicago. The Partnership has entered into a joint tariff agreement with Mustang Pipe Line Partners that became effective January 1, 1999. The agreement covers shipments of western Canadian crude oil over the Lakehead System and the Mustang pipeline. The joint tariff agreement provides lower transportation costs to shippers desiring access to the Patoka/Wood River market area. Prior to the joint tariff agreement, this market area was not competitively accessible to Partnership customers. The joint tariff agreement results in a reduction in the Partnership's light crude oil rate for deliveries destined for the Patoka/Wood River market area. The Mustang system has a capacity of approximately 100,000 barrels per day.

- Enbridge Toledo -- Enbridge has completed construction of a new pipeline, which connects the Partnership's facilities at Stockbridge, Michigan, to two refineries in the Toledo, Ohio, area. This pipeline is anticipated to have an approximate capacity in excess of 80,000 barrels per day in heavy crude oil service and became available for service in early February 1999.

- Enbridge Athabasca (formerly Wild Rose)-- Enbridge is scheduled to complete construction of a new 30-inch diameter pipeline for the delivery of heavy crude oil from the Athabasca oil sands region near Fort McMurray, Alberta, to Hardisty, Alberta, by March 31, 1999. At Hardisty, the Athabasca pipeline would access other pipeline systems including the Enbridge Pipelines System in western

Canada. This project would provide new pipeline capacity to accommodate anticipated growth in production in the Athabasca oil sands region. When fully powered, the Athabasca pipeline is anticipated to have an ultimate capacity of 570,000 barrels per day. Enbridge has entered into a 30-year transportation arrangement with Suncor Energy Inc., the initial shipper on the pipeline.

Montreal Extension Reversal

The Enbridge Pipelines System includes a section which extends from Sarnia, Ontario, to Montreal, Quebec (the "Montreal Extension" or "Line 9"). The portion of the Montreal Extension from Sarnia to North Westover, Ontario, is currently in west-to-east service and the portion of the Montreal Extension from North Westover to Montreal has been purged with nitrogen and remains available for service. Enbridge Pipelines and a group of refiners have developed the Line 9 reversal project to enable crude oil imported into eastern Canada through facilities of Portland Pipe Line Corporation and Montreal Pipe Line Limited to be transported on Line 9 in an east-to-west direction from Montreal to the major refining centers in Ontario. The reversal of the Montreal Extension will result in Enbridge Pipelines becoming a competitor of the Lakehead System for supplying crude oil to the Ontario market. This reversal is expressly permitted by the agreements entered into at the time of formation of the Partnership. The NEB approved construction of facilities as well as the tolling methodology for the Line 9 project on December 18, 1997. Enbridge received notice in July 1998 from the group of sponsoring refiners to proceed with construction of facilities necessary for reversal. Construction to allow for full reversal is expected to be completed late in the third quarter or early in the fourth quarter of 1999 at which time the reversed Line 9 is anticipated to have a capacity of approximately 240,000 barrels per day from Montreal to Sarnia. Due to upstream capacity constraints, the Montreal extension is anticipated to be reversed in two stages, with the first stage entering service in May 1999 with a capacity of 120,000 barrels per day from Montreal to North Westover.

The Partnership anticipates that the reversal of Line 9 will result in a decline in deliveries over the Lakehead System to eastern Canada. Displaced volumes originating in western Canada are anticipated to be diverted to other markets in the Midwest U.S. U.S. domestic and foreign crude oil volumes that enter the Lakehead System in Chicago are also anticipated to decline from recent historical levels due to the reversal of Line 9. The level of decline in deliveries over the Lakehead System to eastern Canada will be dependent upon the global crude oil market dynamics and the level of utilization of Line 9.

Year 2000 Issue

The Partnership's pipeline system is operationally dependent on the ability of Enbridge Pipelines to transport crude oil and other liquid hydrocarbons from western Canada to reach markets in the United States and eastern Canada. Due to the integrated nature of these two pipeline systems, the Partnership's Year 2000 Readiness Program is being conducted in conjunction with Enbridge Pipelines.

The Partnership's Year 2000 Readiness Program continues on schedule, with several milestone points being reached by December 31, 1998. The Year 2000 Project Teams of Enbridge Pipelines and the Partnership have compiled a comprehensive list of all computer hardware and software, embedded chip technologies and business processes including those having significant third party interdependencies. A risk assessment and business impact analysis of each item has also been completed and the Partnership is prioritizing its efforts and resources to ensure that all critical processes and assets are made to be compliant on a timely basis. Some critical systems, such as certain accounting systems which have been replaced under a business system upgrade project, are already known to be Year 2000 compliant, thereby reducing the risk of failure.

The most critical systems are those that operate and control crude oil and NGL pipelines, as they are essential to Partnership operations. These systems are used to control the entire liquid pipeline system, including related tank farms and pumping stations. Instrumentation along the pipelines measure and control temperatures, pressures, volume flow, pump operation, valve operation control equipment and alarm states. This information is also passed to various control systems to help monitor and track flowing crude oil and NGL in the pipeline system. The control systems are expected to be compliant by mid 1999.

In addition, the Year 2000 Project Teams have identified third parties whose non compliance may have a significant effect on the ability of the Partnership to continue to conduct its business without disruption. Dialogue has been established with these entities in order to ascertain whether they will be Year 2000 compliant in advance of January 1, 2000.

The most significant third party interdependencies are reliance on electrical and telecommunication suppliers as they are essential to the ability to transport crude oil and NGL through the System. Also of significance are feeder pipeline systems that deliver much of the crude oil and NGL entering the System, as are the receiving connecting pipelines and refineries.

While the Partnership is unable to provide a current assessment of these critical suppliers' Year 2000 compliance progress, communication with these entities and monitoring of their Year 2000 readiness status will continue. In the case of critical suppliers and feeder pipelines, joint testing initiatives may also be implemented. Where timely assurance is not received, restrictions on use or replacement of vendors will be considered.

In the review of the systems potentially impacted by the Year 2000 problem, Enbridge Pipelines and the Partnership are giving consideration to the repair, replacement, workaround, outsourcing and other methods of eliminating deficiencies. Enbridge Pipelines and the Partnership are currently involved in various stages of implementing their Year 2000 compliance initiatives and expect to have all critical processes and assets compliant by mid 1999, at which point lower risk systems will be remediated.

In order to address unforeseen Year 2000 problems that could arise and in an attempt to minimize business disruptions, Enbridge Pipelines and the Partnership are developing business continuity plans for all critical processes, systems, technologies and external relationships. These plans are also expected to be completed before the end of the year.

Preliminary cost estimates for achieving Year 2000 compliance of the Partnership are approximately $6 million, including $1 million in capital costs and $5 million of operating expense, with approximately $1 million of expense having been incurred to date. A majority of the remaining costs are anticipated to be incurred in 1999. No material resource constraints have been encountered to date. Although management believes this estimate to be reasonable, due to the complexities outlined above, there can be no assurance that the actual costs of the project will not differ materially from the estimated amounts.

Despite the Partnership's best efforts, there can be no guarantees that all systems and applications will continue without interruption through January 1, 2000 and beyond. Limited testing ability on commercial software packages and the complexity of identifying all embedded microprocessors that may be used in a great variety of hardware used for process or flow control, environmental, transportation, security, communication and other systems may result in non compliant systems. Additionally, despite ongoing dialogue with interdependent third parties there can be no assurance that their systems will be fully compliant. In the event of critical system or supplier failure, crude oil and NGL deliveries could be temporarily delayed until corrective action is taken or continuity plans are implemented. Failures that result in substantial disruptions of business activities could be material to the Partnership.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Partnership's market risk is primarily impacted by changes in interest rates. The Partnership has minimal foreign exchange risk and its cash flows are not significantly impacted by changes in commodity prices as the Partnership does not own the crude oil and NGL it transports. However, commodity prices have a significant impact on the underlying supply and demand for crude oil and NGL that the Partnership transports. The Partnership does not currently hold or issue derivative instruments for trading or any other purposes.

The Partnership's market risk with respect to interest rate exposure is managed through its long-term debt ratio target, and its allocation of fixed and floating rate debt. The table below provides information about

the Partnership's financial instruments that are sensitive to changes in interest rates. For debt obligations the table presents principal cash flows and related weighted average interest rates by expected maturity date.

	EXPECTED MATURITY DATE OF DEBT INSTRUMENTS					
DECEMBER 31, 1998	1999 - 2001	2002	2003	THERE-AFTER	TOTAL	FAIR VALUE
	($U.S. IN MILLIONS)					
FIXED RATE:						
First Mortgage Notes	$0	$31.0	$ 31.0	$248.0	$310.0	$369.0
Interest Rate	--	9.15%	9.15%	9.15%		
Senior Unsecured Notes	$0	$ 0	$ 0	$200.0	$200.0	$209.0
Interest Rate	--	--	--	7.06%		
VARIABLE RATE:						

Revolving Credit Facility........	$0	$ 0	$305.0	$ 0	$305.0	$305.0
Interest Rate...................	--	--	5.8%	--		

The average interest rate of debt outstanding on the Partnership's Revolving Credit facility was 5.8% during 1998. For additional information concerning the Partnership's debt obligations, please see Note 6 to the Partnership's Consolidated Financial Statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial statements of the Partnership together with the notes thereto and the independent accountants' reports thereon, appear on pages F-2 through F-12 of this Report, and are incorporated by reference. Reference should be made to the Index to Financial Statements, Supplementary Information and Financial Statement Schedules on page F-1 of this Report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

(a) Directors and Executive Officers of the Registrant

The Registrant is a limited partnership and has no officers, directors or employees. Set forth below is certain information concerning the directors and executive officers of the General Partner. Enbridge Pipelines, the sole stockholder of the General Partner, elects the directors of the General Partner on an annual basis. All officers of the General Partner serve at the discretion of the directors of the General Partner.

NAME	AGE	POSITION WITH GENERAL PARTNER
E. C. Hambrook....................	61	Chairman and Director
P. D. Daniel......................	52	Director
S. J. Wuori.......................	41	President and Director
R. C. Sandahl.....................	48	Vice President and Director
F. W. Fitzpatrick.................	66	Director
C. A. Russell.....................	65	Director
D. P. Truswell....................	55	Director
S. R. Wilson......................	41	Vice President (since January 14, 1999) and Treasurer
M. A. Maki........................	34	Chief Accountant
S. D. Lenczewski..................	38	Secretary

Mr. Hambrook was elected a Director of the General Partner in January 1992 and has served as Chairman of the General Partner since July 1996. He also serves on the Audit Committee. Mr. Hambrook is the President of Hambrook Resources Inc.

Mr. Daniel was elected a Director of the General Partner in July 1996 and served as its President from July 1996 through October, 1997. Since June 1998, Mr. Daniel has also served as President and Chief Operating Officer Energy Delivery of Enbridge. Prior thereto, Mr. Daniel served as Executive Vice President and Chief Operating Officer -- Energy Transportation Services of Enbridge from September 1997 through June 1998, as Senior Vice President of Enbridge from May 1994 to August 1997, as President and Chief Executive Officer of Enbridge Pipelines from August 1996 to August 1997, and as President and Chief Operating Officer of Enbridge Pipelines from May 1994 to August 1996. Prior to May 1994, he served as Vice President, Planning of Enbridge.

Mr. Wuori was appointed President and elected a Director of the General Partner as of November 1, 1997. He has served as President of Enbridge Pipelines since September 1997. Prior thereto, he served as Vice President, Operations of Enbridge Pipelines from May 1994 to August 1997, and, prior thereto, as District Manager of the General Partner.

Mr. Sandahl was elected a Director and appointed Vice President of the General Partner in July 1996. He served as Vice President, Operations of the General Partner from May 1994 to August 1996. Prior thereto, he was employed by Enbridge Pipelines for six years where he served in various capacities, most recently as Director of Engineering Services from June 1990 to May 1994.

Mr. Fitzpatrick was elected a Director of the General Partner in April 1993 and serves on the Audit Committee. He is also a Director of Enbridge and serves as Chairman of the Audit, Finance and Risk Committee of the Board of Enbridge.

Mr. Russell was elected a Director of the General Partner in October 1985 and serves as the Chairman of the Audit Committee. Mr. Russell served as Chairman and Chief Executive Officer of Norwest Bank Minnesota North, N.A. from January through December 1995. Prior to January 1995, he served as President of Norwest Bank Minnesota North, N.A. He also served as a Director of Minnesota Power and Light Co. until May 1996.

Mr. Truswell was elected a Director of the General Partner in May 1991 and served as a Vice President of the General Partner from October 1991 to May 1994. Mr. Truswell has served as Senior Vice President and Chief Financial Officer of Enbridge since May 1994 and prior thereto, as Vice President, Finance of Enbridge from 1992 to May 1994. He also served in various senior executive capacities with Enbridge Pipelines, including as Vice President, Finance from May 1991 to May 1994.

Mr. Wilson was appointed Treasurer of the General Partner as of November 1, 1997. He has served as Treasurer of Enbridge since September 1997 and, prior thereto, as its Assistant Treasurer from September 1995 to August 1997. Mr. Wilson has served as Treasurer of The Consumers' Gas Company Ltd., a subsidiary of Enbridge since April 1991.

Mr. Maki has served as Chief Accountant of the General Partner since June 1997. Prior thereto, he served in various supervisory and professional positions with the General Partner or Enbridge affiliates in the areas of Internal Audit, Rate Regulation and Accounting.

Ms. Lenczewski has served as Secretary of the General Partner since June 1998. Prior thereto, she served as Assistant Secretary of the General Partner, from July 1996 to June 1998.

ITEM 11. EXECUTIVE COMPENSATION

The General Partner is responsible for the management and operation of the Partnership. The Partnership does not directly employ any of the persons responsible for managing or operating the Partnership's operations, but instead reimburses the General Partner or its affiliates for the services of such persons. The General Partner, in turn, because it has no employees, has entered into services agreements with

Enbridge (U.S.) Inc., ("Enbridge U.S.") and other affiliates to provide the services required by the Partnership.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

(a) Security Ownership of Certain Beneficial Owners

TITLE OF CLASS	NAME AND ADDRESS	AMOUNT	PERCENT OF CLASS
Class A Common Units............	No person or group is known to be the beneficial owner of more than 5% of the Class A Common Units as at February 5, 1999		
Class B Common Units............	Lakehead Pipe Line Company, Inc. Lake Superior Place	3,912,750	100

21 West Superior Street
Duluth, Minnesota 55802-2067

(b) Security Ownership of Management

As of February 5, 1999, E. C. Hambrook beneficially owned 1,000 Class A Common Units and R. C. Sandahl beneficially owned 200 Class A Common Units. Class A Common Units beneficially held by all directors and officers as a group represented less than 1% of the Partnership's outstanding Class A Common Units.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The Partnership is managed by the General Partner pursuant to the Amended and Restated Agreements of Limited Partnership of the Partnership and the Operating Partnership, as amended ("Partnership Agreements"). The General Partner has entered into a services agreement with Enbridge U.S. whereby the General Partner will utilize the resources of Enbridge U.S. to operate the Partnership. Under this agreement, Enbridge U.S. will be reimbursed for all direct and indirect expenses it incurs or payments it makes on behalf of the Partnership. The General Partner also receives certain administrative, engineering, treasury and computer services from Enbridge and Enbridge Pipelines for the benefit of the Partnership. The Partnership reimburses the General Partner for the cost of these services. For information about reimbursements to the General Partner, see Note 7 to the Partnership's Consolidated Financial Statements.

The Partnership has entered into an easement acquisition agreement with Enbridge Holdings (Mustang) Inc. ("Enbridge Mustang" formerly IPL Patoka Pipeline Holdings (U.S.A.) Inc.), a subsidiary of Enbridge U.S. For the benefit of the Partnership, Enbridge Mustang has acquired certain real property for purposes of granting a pipeline easement to the Partnership. Enbridge Mustang is reimbursed for all net costs associated with this process at cost by the Partnership and will be indemnified by the Partnership from and against all liabilities that may arise in connection with this process. This agreement was entered into to facilitate easement acquisitions for SEP II. Enbridge Mustang will begin to dispose of real property acquired in 1997 and 1998 and repay advances from the Partnership as properties are sold beginning in 1999.

The Partnership has implemented an agreement with Mustang Pipe Line Partners to provide for a joint tariff covering shipments of western Canadian crude oil to the Patoka/Wood River market area south of Chicago. These shipments travel on the Lakehead System to Chicago and on the Patoka/Wood River market area through the Mustang pipeline system. The joint tariff agreement provides for lower transportation costs to shippers desiring access to the Patoka/Wood River market area, an incentive which the Partnership believes complements its expansion programs. Mustang Pipe Line Partners is a Delaware general partnership owned by Mobil Illinois Pipe Line Company and a wholly owned subsidiary of Enbridge U.S.

Under the terms of the Revolving Credit Facility Agreement, the Partnership, Lakehead Services, Limited Partnership ("Services Partnership") and the General Partner may draw down funds up to a combined maximum of $350.0 million. The Partnership has a 1% general partner interest in the Services

Partnership, with the General Partner having a 99% limited partner interest. For additional details, see Note 6 to the Partnership's Consolidated Financial Statements.

The Partnership has entered into a $200 million uncommitted lending facility with the General Partner. This uncommitted facility provided an alternative source of funds at market interest rates in the event that a disruption in the capital markets delayed access to debt and equity markets. In late September 1998, the Partnership borrowed, and subsequently repaid in early October, $37.0 million under this arrangement.

For discussion of distribution restrictions and incentive distributions payable to the General Partner, see Note 3 to the Partnership's Consolidated Financial Statements.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) As to financial statements, supplementary information and financial statement schedules, reference is made to "Index to Financial Statements, Supplementary Information and Financial Statement Schedules" on page F-1 of this Report.

(b) The Registrant filed the following reports on Form 8-K during the fourth quarter of 1998: A report on Form 8-K was filed on December 28, 1998, submitting a press release of the Registrant dated December 21, 1998, announcing a tariff filing and net income expectations for 1999.

(c) The following Exhibits (numbered in accordance with Item 601 of Regulation S-K) are filed or incorporated herein by reference as part of this Report.

EXHIBIT NUMBER	DESCRIPTION
3.1	Certificate of Limited Partnership of the Partnership. (Partnership's Registration Statement No. 33-43425 -- Exhibit 3.1)
4.1	Form of Certificate representing Class A Common Units. (Registrant's Form 8-A/A, dated May 2, 1997)
4.2	Amended and Restated Agreement of Limited Partnership of the Partnership, dated April 15, 1997. (Registrant's Form 8-A/A, dated May 2, 1997)
10.1	Note Agreement and Mortgage, dated December 12, 1991. (1991 Form 10-K -- Exhibit 10.1)
10.2	[Intentionally Omitted].
10.3	Distribution Support Agreement, dated December 27, 1991, among the Partnership, Lakehead Pipe Line Company, Inc. and Interprovincial Pipe Line Inc. (1991 Form 10-K -- Exhibit 10.3)
10.4	Assumption and Indemnity Agreement, dated December 18, 1992, between Interprovincial Pipe Line Inc. and Interprovincial Pipe Line System Inc. (1992 Form 10-K -- Exhibit 10.4)
10.5	Amended Services Agreement, dated February 29, 1988, between Interprovincial Pipe Line Inc. and Lakehead Pipe Line Company, Inc. (1991 Form 10-K -- Exhibit 10.4)
10.6	Amended Services Agreement, dated January 1, 1992, between Interprovincial Pipe Line Inc. and Lakehead Pipe Line Company, Inc. (1992 Form 10-K -- Exhibit 10.6)
10.7	Certificate of Limited Partnership of the Operating Partnership. (Partnership's Registration Statement No. 33-43425 -- Exhibit 10.1)
10.8	Amended and Restated Agreement of Limited Partnership of the Operating Partnership, dated December 27, 1991. (1991 Form 10-K -- Exhibit 10.6)
10.9	Certificate of Limited Partnership of Lakehead Services, Limited Partnership. (Partnership's Registration Statement No. 33-43425 -- Exhibit 10.4)
10.10	Amendment No. 1 to the Certificate of Limited Partnership of Lakehead Services, Limited Partnership. (Partnership's Registration Statement No. 33-43425 -- Exhibit 10.16)

EXHIBIT NUMBER	DESCRIPTION
10.11	Amended and Restated Agreement of Limited Partnership of Lakehead Services, Limited Partnership, dated December 27, 1991. (1991 Form 10-K -- Exhibit 10.9)
10.12	Contribution, Conveyance and Assumption Agreement, dated

	December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership. (1991 Form 10-K -- Exhibit 10.10)
10.13	LPL Contribution and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership and Lakehead Services, Limited Partnership. (1991 Form 10-K -- Exhibit 10.11)
10.14	Services Agreement, dated January 1, 1996, between IPL Energy (U.S.A.) Inc. and Lakehead Pipe Line Company, Inc. (1995 Form 10-K -- Exhibit 10.14)
10.15	Amended and Restated Revolving Credit Agreement, dated September 6, 1996, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P., Lakehead Services, Limited Partnership, Lakehead Pipe Line Company, Limited Partnership and the Bank of Montreal and Harris Trust and Savings Bank. (1996 Form 10-K -- Exhibit 10.15)
10.16	First Amendment to Amended and Restated Revolving Credit Agreement, dated September 6, 1996, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P., Lakehead Services, Limited Partnership, Lakehead Pipe Line Company, Limited Partnership and the Bank of Montreal. (1996 Form 10-K -- Exhibit 10.16)
10.17	Second Amendment to Amended and Restated Revolving Credit Agreement, dated June 16, 1998, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P., Lakehead Services Limited Partnership, Lakehead Pipe Line Company, Limited Partnership and Bank of Montreal, The Toronto Dominion Bank, Canadian Imperial Bank of Commerce, ABN AMRO Bank, N.V. Cayman Islands Branch and Bank of Montreal, as agent. (Form 10-Q/A, filed September 14, 1998 -- Exhibit 10.1)
10.18	Settlement Agreement, dated August 28, 1996, between Lakehead Pipe Line Company, Limited Partnership and the Canadian Association of Petroleum Producers and the Alberta Department of Energy. (1996 Form 10-K -- Exhibit 10.17)
10.19	Promissory Note, dated as of September 30, 1998, among Lakehead Pipe Line Company, Inc. as lender and Lakehead Pipe Line Company, Limited Partnership as borrower.
10.20	Treasury Services Agreement, dated January 1, 1996, between IPL Energy Inc. and Lakehead Pipe Line Company, Inc. (1996 Form 10-K -- Exhibit 10.18)
10.21	Tariff Agreement as filed with the Federal Energy Regulatory Commission for the System Expansion Program II, and Terrace Expansion Project.
10.22	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (1998 Form 8-K of Lakehead Pipe Line Company, Limited Partnership -- Exhibit 4.1, dated October 20, 1998)
10.23	First Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (1998 Form 8-K of Lakehead Pipe Line Company, Limited Partnership -- Exhibit 4.2, dated October 20, 1998)
10.24	Second Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (1998 Form 8-K of Lakehead Pipe Line Company, Limited Partnership -- Exhibit 4.3, dated October 20, 1998)
10.25	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (1998 Form 8-K of Lakehead Pipe Line Company, Limited Partnership -- Exhibit 4.4, dated October 20, 1998)

EXHIBIT NUMBER	DESCRIPTION

21 Subsidiaries of the Registrant.
27 Financial Data Schedule as of and for the year ended December 31, 1998.

All Exhibits listed above, with the exception of Exhibits 10.19, 10.21, 21, and 27 are incorporated herein by reference to the documents identified in parentheses.

Copies of Exhibits may be obtained upon written request of any Unitholder to Investor Relations, Lakehead Pipe Line Company, Inc., Lake Superior Place, 21 West Superior Street, Duluth, Minnesota 55802-2067.

(d) As to financial statement schedules, reference is made to "Financial Statement Schedules" on page F-1 of this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

Lakehead Pipe Line Partners, L.P.
(Registrant)

By: Lakehead Pipe Line Company, Inc.,
as General Partner

Date: March 9, 1999

By: /s/ S.J. WUORI

S.J. Wuori
(President)

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on March 9, 1999 by the following persons on behalf of the Registrant and in the capacities indicated with Lakehead Pipe Line Company, Inc., General Partner.

/s/ S.J. WUORI S.J. Wuori President and Director (Principal Executive Officer)	/s/ E.C. HAMBROOK E.C. Hambrook Chairman and Director
/s/ R.C. SANDAHL R.C. Sandahl Vice President and Director	/s/ M.A. MAKI M.A. Maki Chief Accountant (Principal Financial and Accounting Officer)
/s/ F.W. FITZPATRICK F.W. Fitzpatrick Director	/s/ P.D. DANIEL P.D. Daniel Director
/s/ C.A. RUSSELL C.A. Russell Director	/s/ D.P. TRUSWELL D.P. Truswell Director

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LAKEHEAD PIPE LINE PARTNERS, L.P.

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FINANCIAL STATEMENT SCHEDULES

Financial statement schedules not included in this Report have been omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Partners of
Lakehead Pipe Line Partners, L.P.

In our opinion, the accompanying consolidated statements of financial position and the related consolidated statements of income, of partners' capital and of cash flows present fairly, in all material respects, the financial position of Lakehead Pipe Line Partners, L.P. and its subsidiary (the "Partnership") at December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998 in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

PRICEWATERHOUSECOOPERS LLP

Minneapolis, Minnesota
January 8, 1999

LAKEHEAD PIPE LINE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF INCOME

YEAR ENDED DECEMBER 31,

	1998	1997	1996
	(DOLLARS IN MILLIONS, EXCEPT PER UNIT AMOUNTS)		
Operating Revenue (Note 9)	$ 287.7	$ 282.1	$ 274.5
Expenses			
Power	69.0	65.9	62.0
Operating and administrative	71.9	68.0	66.7
Depreciation	41.4	40.1	38.3
Provision for prior years' rate refunds (Note 9)	--	--	20.1
	182.3	174.0	187.1
Operating Income	105.4	108.1	87.4
Interest and Other Income	6.0	9.7	9.6
Interest Expense (Note 6)	(21.9)	(38.6)	(43.9)
Minority Interest	(1.0)	(0.9)	(0.7)
Net Income	$ 88.5	$ 78.3	$ 52.4
Net Income Per Unit (Note 4)	$ 3.07	$ 3.02	$ 2.11
Weighted Average Units Outstanding (millions)	26.2	24.4	24.0

The accompanying notes to the consolidated financial statements are an integral part of these statements.

LAKEHEAD PIPE LINE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF CASH FLOWS

	YEAR ENDED DECEMBER 31,		
	1998	1997	1996
	(DOLLARS IN MILLIONS)		
Cash Provided from Operating Activities			
Net income	$ 88.5	$ 78.3	$ 52.4
Adjustments to reconcile net income to cash provided from operating activities:			
Depreciation	41.4	40.1	38.3
Accrued rate refunds and related interest (Note 9)	2.1	3.5	42.6
Minority interest	1.0	0.9	0.7
Other	0.1	0.5	0.6
Changes in operating assets and liabilities:			
Accounts receivable and other	(2.8)	4.8	(0.7)
Materials and supplies	--	(0.1)	(1.6)
General Partner and affiliates	(1.0)	2.4	0.2
Accounts payable and other	2.1	1.5	3.6
Interest payable	0.2	2.1	0.7
Property and other taxes	0.5	0.3	(1.1)
Payment of rate refunds and related interest (Note 9)	(28.5)	(27.7)	(41.8)
	103.6	106.6	93.9
Investing Activities			
Short-term investments, net	53.9	29.8	(8.0)
Advances to affiliate (Note 7)	(25.5)	(6.5)	--
Additions to property, plant and equipment	(487.3)	(126.9)	(76.7)
Changes in construction payables	31.0	1.9	--
	(427.9)	(101.7)	(84.7)
Financing Activities			
Variable rate financing, net (Note 6)	152.0	--	68.0
Fixed rate financing, net (Note 6)	196.9	--	--
Proceeds from unit issuance, net (Note 1)	--	99.2	--

Distributions to partners (Note 3)	(95.3)	(75.3)	(63.9)
Minority interest	(0.9)	0.2	(0.7)
	252.7	24.1	3.4
Increase (Decrease) in Cash and Cash Equivalents	(71.6)	29.0	12.6
Cash and Cash Equivalents at Beginning of Year	118.6	89.6	77.0
Cash and Cash Equivalents at End of Year	$ 47.0	$ 118.6	$ 89.6

The accompanying notes to the consolidated financial statements are an integral part of these statements.

LAKEHEAD PIPE LINE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

	DECEMBER 31, 1998	DECEMBER 31, 1997
	(DOLLARS IN MILLIONS)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 47.0	$ 118.6
Short-term investments	--	53.9
Advances to affiliate (Note 7)	32.0	6.5
Accounts receivable and other	25.2	22.4
Materials and supplies	7.1	7.1
	111.3	208.5
Deferred Charges and Other	6.9	4.4
Property, Plant and Equipment, Net (Note 5)	1,296.2	850.3
	$ 1,414.4	$ 1,063.2
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities		
Due to General Partner and affiliates	$ 2.9	$ 3.9
Accounts payable and other	53.3	20.2
Interest payable	5.5	5.3
Property and other taxes	11.9	11.4
Current portion of accrued rate refunds and related interest (Note 9)	28.7	29.0
	102.3	69.8
Long-Term Debt (Note 6)	814.5	463.0
Accrued Rate Refunds and Related Interest (Note 9)	--	26.1
Minority Interest	2.6	2.5
Contingencies (Note 10)		
	919.4	561.4
Partners' Capital		
Class A Common Unitholders (Units authorized and issued -- 22,290,000)	453.4	461.6
Class B Common Unitholder (Units authorized and issued -- 3,912,750)	37.3	36.7
General Partner	4.3	3.5
	495.0	501.8
	$ 1,414.4	$ 1,063.2

The accompanying notes to the consolidated financial statements are an integral part of these statements.

LAKEHEAD PIPE LINE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

	CLASS A COMMON UNITHOLDERS	CLASS B COMMON UNITHOLDER	GENERAL PARTNER	TOTAL
	(DOLLARS IN MILLIONS)			
Partners' capital at December 31, 1995	$ 387.9	$ 21.7	$ 1.5	$ 411.1
Net income allocation	40.6	10.2	1.6	52.4
Distributions to partners	(52.2)	(10.2)	(1.5)	(63.9)
Partners' capital at December 31, 1996	376.3	21.7	1.6	399.6
Allocation of net proceeds from unit issuance (Note 1)	85.6	12.6	1.0	99.2
Net income allocation	60.1	13.8	4.4	78.3
Distributions to partners	(60.4)	(11.4)	(3.5)	(75.3)
Partners' capital at December 31, 1997	461.6	36.7	3.5	501.8
Net income allocation	66.7	13.8	8.0	88.5
Distributions to partners	(74.9)	(13.2)	(7.2)	(95.3)
Partners' capital at December 31, 1998	$ 453.4	$ 37.3	$ 4.3	$ 495.0

The accompanying notes to the consolidated financial statements are an integral part of these statements.

LAKEHEAD PIPE LINE PARTNERS, L.P.

NOTES TO THE 1998 CONSOLIDATED FINANCIAL STATEMENTS
(DOLLARS IN MILLIONS, EXCEPT PER UNIT AMOUNTS)

1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS

Lakehead Pipe Line Partners, L.P. ("Lakehead Partnership") is a publicly traded limited partnership that owns a 99% limited partner interest in Lakehead Pipe Line Company, Limited Partnership ("Operating Partnership"), both Delaware limited partnerships, and collectively known as the "Partnership". The Partnership was formed in 1991 to acquire, own and operate the crude oil and natural gas liquids pipeline business of Lakehead Pipe Line Company, Inc. (the sole "General Partner"). The General Partner is a wholly-owned subsidiary of Enbridge Pipelines Inc. ("Enbridge Pipelines") (formerly Interprovincial Pipe Line Inc.), a Canadian company owned by Enbridge Inc. (formerly IPL Energy Inc.) of Calgary, Alberta, Canada.

In October 1997, the Lakehead Partnership issued an additional 2,200,000 Class A Common Units for total net proceeds of $99.2 million, including the General Partner's contribution, bringing the total number of Class A Common Units issued to 22,290,000. Class A Common Units are publicly traded and represent an 83.4% limited partner interest in the Partnership. The General Partner has a 14.8% limited partner (in the form of 3,912,750 Class B Common Units) and 1.0% general partner interest in the Lakehead Partnership, as well as a 1.0% general partner interest in the Operating Partnership (an effective 16.6% combined interest in the Partnership).

The Lakehead Partnership holds a 1% general partner interest in Lakehead Services, Limited Partnership ("Services Partnership"), a Delaware limited partnership, originally formed to facilitate the financing of the Operating Partnership.

The Operating Partnership is engaged in the transportation of crude oil and natural gas liquids through a common carrier pipeline system. Substantially all of the shipments delivered originate in western Canadian oil fields. The majority of the shipments reach the Operating Partnership at the Canada/United States border in North Dakota, through a Canadian pipeline system owned by Enbridge Pipelines. Deliveries are made in the Great Lakes region of the United States and to the Canadian Province of Ontario, principally to refineries, either directly or through the connecting pipelines of other companies.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Partnership are prepared in accordance with generally accepted accounting principles in the United States and conform in all material respects with the historical cost accounting standards of the International Accounting Standards Committee. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures.

PRINCIPLES OF CONSOLIDATION

The financial statements of the Partnership include the accounts of the Lakehead Partnership and the Operating Partnership on a consolidated basis. The equity method is used to account for the Partnership's 1% general partner interest in the Services Partnership. The General Partner's 1% interest in the Operating Partnership is accounted for by the Partnership as a minority interest.

REGULATION OF PIPELINE SYSTEM

As an interstate common carrier oil pipeline, rates and accounting practices are under the regulatory authority of the Federal Energy Regulatory Commission ("FERC").

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

REVENUE RECOGNITION

Substantially all pipeline system revenues are derived from transportation of crude oil and natural gas liquids and are recognized in income upon delivery. Amounts provided for accrued rate refunds are recognized as a direct reduction from revenues except for amounts related to prior years (Note 9), which are separately stated as a provision for prior years' rate refunds.

CASH EQUIVALENTS AND SHORT-TERM INVESTMENTS

Cash equivalents are defined as all highly marketable securities with a maturity of three months or less when purchased. Short-term investments are marketable securities with a maturity of more than three months when purchased. Both are accounted for as held-to-maturity securities and valued at amortized cost.

MATERIALS AND SUPPLIES

Materials and supplies are stated at the lower of cost or market value.

DEFERRED FINANCING CHARGES

Deferred financing charges are amortized on the straight-line basis over the life of the related debt which is comparable to results using the effective interest method.

PROPERTY, PLANT AND EQUIPMENT

Expenditures for system expansion and major renewals and betterments are capitalized; maintenance and repair costs are expensed as incurred. An allowance for interest incurred on external borrowings during construction is capitalized. Depreciation of property, plant and equipment is provided on the straight line basis over their estimated service lives. When property, plant and equipment are retired or otherwise disposed of, the cost less net proceeds is normally charged to accumulated depreciation and no gain or loss is recognized.

INCOME TAXES

The Partnership is not a taxable entity for federal and state income tax purposes. Accordingly, no recognition has been given to income taxes for financial reporting purposes. The tax on Partnership net income is borne by the individual partners through the allocation of taxable income. Such taxable income reportable to Unitholders may vary substantially from financial income as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under the Partnership Agreement. The aggregate difference in the basis of the Partnership's net assets for financial and tax reporting purposes cannot be readily determined due to inaccessible information regarding each partner's tax attributes in the Partnership.

COMPARATIVE AMOUNTS

Certain comparative amounts are reclassified to conform with the current year's financial statement presentation.

3. CASH DISTRIBUTIONS

The Partnership distributes quarterly all of its "Available Cash", which is generally defined in the Partnership Agreement as cash receipts less cash disbursements and net additions to reserves for future requirements. These reserves are retained to provide for the proper conduct of the Partnership business and as necessary to comply with the terms of any agreement or obligation of the Partnership. Distributions by the

3. CASH DISTRIBUTIONS (CONTINUED)

Partnership of its Available Cash generally are made 98% to the Class A and B Common Unitholders and 2% to the General Partner, subject to the payment of incentive distributions to the General Partner to the extent that certain target levels of cash distributions to the Unitholders are achieved. The incremental incentive distributions payable to the General Partner are 15%, 25% and 50% of all quarterly distributions of Available Cash that exceed target levels of $0.59, $0.70, and $0.99 per Class A and B Common Units, respectively.

In 1998, the Partnership paid cash distributions of $3.36 per unit consisting of $0.78 per unit paid in February and $0.86 per unit paid in May, August and November. In 1997, the Partnership paid cash distributions of $2.92 per unit consisting of $0.68 per unit paid in February and May, and $0.78 per unit paid in August and November. In 1996, distributions of $2.60 per unit consisted of $0.64 per unit paid in February, May and August, and $0.68 per unit paid in November.

The cash distribution in respect of the fourth quarter 1996 was the last distribution subject to certain preferential rights of the Class A Common Units and certain support obligations of the General Partner. These rights terminated with the distribution paid in February 1997 and, with respect to subsequent cash distributions, Class A and B Common Units are treated as one class of units.

4. NET INCOME PER UNIT

Net income per unit is computed by dividing net income, after deduction of the General Partner's allocation, by the weighted average number of Class A and Class B Common Units outstanding. The General Partner's allocation is equal to an amount based upon its 1% general partner interest, adjusted to reflect an amount equal to incentive distributions and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. Net income per unit was determined as follows:

	YEAR ENDED DECEMBER 31,		
	1998	1997	1996

Net income	$ 88.5	$ 78.3	$ 52.4
Net income allocated to General Partner	(0.9)	(0.8)	(0.5)
Adjusted to reflect:			
Incentive distributions	(7.0)	(3.5)	(1.0)
Historical cost basis depreciation	(0.1)	(0.1)	(0.1)
	(8.0)	(4.4)	(1.6)
Net income allocable to Common Units	$ 80.5	$ 73.9	$ 50.8
Weighted average units outstanding (millions)	26.2	24.4	24.0
Net income per unit	$ 3.07	$ 3.02	$ 2.11

5. PROPERTY, PLANT AND EQUIPMENT, NET

	AVERAGE DEPRECIATION RATES	DECEMBER 31, 1998	DECEMBER 31, 1997
Land	--	$ 6.2	$ 6.1
Rights-of-way	3.6%	126.4	12.6
Pipeline	4.1%	783.0	519.6
Pumping equipment, buildings and tanks	4.6%	427.1	355.4
Vehicles, office and communications equipment	13.9%	28.8	27.4
Construction in progress	--	115.8	87.4
		1,487.3	1,008.5
Accumulated depreciation		(191.1)	(158.2)
		$1,296.2	$ 850.3

6. DEBT

	DECEMBER 31, 1998	DECEMBER 31, 1997
First Mortgage Notes	$ 310.0	$ 310.0
Revolving Credit Facility Agreement	305.0	153.0
Senior Unsecured Notes, Net	199.5	--
	$ 814.5	$ 463.0

FIRST MORTGAGE NOTES

The First Mortgage Notes ("Notes") are secured by a first mortgage on substantially all of the property, plant and equipment of the Partnership and are due and payable in ten equal annual installments beginning 2002. The interest rate on the Notes is 9.15% per annum, payable semi-annually. The Notes contain various restrictive covenants applicable to the Partnership, and restrictions on the incurrence of additional indebtedness including compliance with certain issuance tests. The General Partner believes these issuance tests will not negatively impact the Partnership's ability to finance current expansion projects. Under the Note Agreements, the Partnership is permitted to make cash distributions not more frequently than quarterly in an amount not to exceed Available Cash (Note 3) for the immediately preceding calendar quarter.

REVOLVING CREDIT FACILITY AGREEMENT

The Partnership has a $350.0 million ($205.0 million prior to June 18, 1998) Revolving Credit Facility Agreement scheduled to mature during September 2003, but is subject to extension. Each year, on the anniversary date of the facility, the current maturity date may be extended by one year subject to the approval of the lending banks. Upon drawdown, the loans are secured by a first lien on the mortgaged property that ranks equally with the Notes or may be fully collateralized with U.S. or Canadian government securities. The facility contains restrictive covenants substantially identical to those in the Note Agreements, provides for borrowing at variable interest rates and currently attracts a facility fee of 0.075% (1997 - 0.075%, 1996 - 0.085%) per annum on the entire $350.0 million ($205.0 million prior to June 18, 1998). At December 31, 1998, $305.0 million of the facility was utilized and is classified as long-term debt (1997 - $153.0 million). The interest rate on loans averaged 5.8% (1997 - 6.2%; 1996 - 6.8%) and was 5.5% at the end of 1998 (1997 - 6.2%).

6. DEBT (CONTINUED)
SENIOR UNSECURED NOTES

On October 1, 1998, the Operating Partnership issued a total of $200.0 million Senior Unsecured Notes in two tranches of $100.0 million. The first tranche of $100 million carries an interest rate of 7.00% and matures in 2018. The second tranche carries an interest rate of 7.125% and matures in 2028. Interest on both tranches is payable semi-annually. The Senior Unsecured Notes do not contain any financial tests restricting the issuance of additional indebtedness.

INTEREST

Interest expense includes $2.1 million related to accrued rate refunds (1997 -$3.5 million; 1996 - $9.7 million) and is net of amounts capitalized of $25.5 million (1997 - $3.3 million; 1996 - $2.4 million). Interest paid amounted to $44.4 million (1997 - $39.9 million; 1996 - $44.8 million).

7. RELATED PARTY TRANSACTIONS

The Partnership, which does not have any employees, uses the services of the General Partner and its affiliates for managing and operating its pipeline business. These services, which are reimbursed at cost in accordance with service agreements, amounted to $34.9 million (1997 - $33.2 million; 1996 -$33.9 million) and are included in operating and administrative expenses. At December 31, 1998, the Partnership has accounts payable to the General Partner and affiliates of $2.9 million (1997 - $3.9 million).

Under the terms of the Revolving Credit Facility Agreement, the Services Partnership and the Partnership may draw down funds up to a combined maximum of $350.0 million ($205.0 million prior to June 18, 1998). The Partnership is entitled to require the Services Partnership to repay any amounts owed by the Services Partnership in order to allow the Partnership to borrow thereunder. During 1996, the Partnership paid the Services Partnership a standby fee of $0.4 million for this entitlement. Effective September 1996, the standby fee was eliminated and replaced with a facility fee, which the Partnership pays directly to the lenders. The Partnership will continue to have borrowing priority over the Services Partnership. At December 31, 1998, the Services Partnership had no borrowings under the facility.

The Partnership has entered into an easement acquisition agreement with Enbridge Holdings (Mustang) Inc. ("Enbridge Mustang") (formerly IPL Patoka Pipeline Holdings (U.S.A.) Inc.), an affiliate of the General Partner. Enbridge Mustang has acquired certain real property for the purpose of granting pipeline easements to the Partnership for a new pipeline constructed by the Partnership from Superior, Wisconsin to Chicago, Illinois. The Partnership has made non-interest bearing cash advances to Enbridge Mustang in order to provide for these real property acquisitions by Enbridge Mustang. These advances amounted to $32.0 million at December 31, 1998 (1997 - $6.5 million).

During the third quarter of 1998, the Board of Directors of the General Partner approved a $200.0 million lending facility from the General Partner to the Partnership to provide an alternative backup source of funds in the event that a temporary disruption in the capital markets delays anticipated debt and equity issuances. Under this facility, in late September 1998, the Partnership borrowed $37.0 million from the General Partner at an interest rate of 8.75%. This loan was repaid in early October upon completion of the Operating Partnership's Senior Unsecured Note offering. No amounts were outstanding at December 31, 1998.

8. MAJOR CUSTOMERS

Operating revenue received from major customers was as follows:

	YEAR ENDED DECEMBER 31,		
	1998	1997	1996
Amoco Oil Company..	$57.9	$60.7	$63.2
Mobil Oil Company of Canada Ltd............................	$40.0	$42.5	$37.2
Imperial Oil Limited.......................................	$33.6	$33.2	$35.4

The Partnership has a concentration of trade receivables from companies operating in the oil and gas industry. These receivables are collateralized by the crude oil and other products contained in the Partnership's pipeline and storage facilities.

9. ACCRUED RATE REFUNDS AND RELATED INTEREST

In October 1996, the FERC approved a July 1996 agreement ("Settlement Agreement") between the Partnership and customer representatives on all outstanding contested tariff rates. The Settlement Agreement resulted in an approximate tariff rate reduction of 6% and total rate refunds and related interest of $120.0 million through the effective date of October 1, 1996.

The Partnership provided for $42.6 million of rate refunds and related interest in 1996 to reflect the Settlement Agreement. Of the amount provided, rate refunds related to 1996 of $12.8 million have reduced operating revenue, with prior years' portion, $20.1 million, separately stated as a provision for prior years' rate refunds. Rate refund interest expense for 1996 and prior year amounts totaling $9.7 million were recorded in interest expense. The balance of the $120.0 million of accrued rate refunds and related interest required under the Settlement Agreement was provided for prior to 1996.

Refunds required under the Settlement Agreement began in 1996 with $41.8 million repaid during the fourth quarter of 1996, with the remaining balance being repaid through a 10% reduction on future rates. This reduction will continue until all refunds have been made, which is expected to remain effective until sometime during the second half of 1999. During 1998, refunds of $28.5 million (1997 - $27.7 million) were made to customers and interest expense of $2.1 million (1997 - $3.5 million) was recorded by the Partnership. Interest will continue to accrue on the unpaid balance based on the 90-day Treasury bill rate.

10. CONTINGENCIES

ENVIRONMENT

The Partnership is subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid pipeline operations and the Partnership could, at times, be subject to environmental cleanup and enforcement actions. The General Partner manages this environmental risk through appropriate environmental policies and practices to minimize the impact to the Partnership. To the extent that the Partnership is unable to recover environmental costs in its rates (if not covered through insurance), the General Partner has agreed to indemnify the Partnership from and against any costs relating to environmental liabilities associated with the pipeline system prior to its transfer to the Partnership in 1991. This excludes any liabilities resulting from a change in laws after such transfer. The Partnership continues to voluntarily investigate past leak sites for the purpose of assessing whether any remediation is required in light of current regulations, and to date no material environmental risks have been identified.

10. CONTINGENCIES (CONTINUED)

OIL IN CUSTODY

The Partnership transports crude oil and natural gas liquids ("NGL") owned by its customers for a fee. The volume of liquid hydrocarbons in the Partnership's pipeline system at any one time approximates 12 million barrels, virtually all of which is owned by the Partnership's customers. Under terms of the Partnership's tariffs, losses of crude oil not resulting from direct negligence of the Partnership may be apportioned among its customers. In addition, the Partnership maintains adequate property insurance coverage with respect to crude oil and NGL in the Partnership's custody.

11. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts of cash equivalents and short-term investments approximate fair value. The short-term investments consist of high quality commercial paper.

Based on the borrowing rates currently available for instruments with similar terms and remaining maturities, the carrying value of borrowings under the Revolving Credit Facility approximate fair value, the fair value of the First Mortgage Notes approximates $369 million (1997 - $363 million) and the fair value of the Senior Unsecured Notes approximates $209 million. Due to defined contractual arrangements, refinancing of the First Mortgage Notes and Senior Unsecured Notes would not result in any financial benefit to the Partnership.

SUPPLEMENTARY INFORMATION (UNAUDITED)
SELECTED QUARTERLY FINANCIAL DATA
(DOLLARS IN MILLIONS, EXCEPT PER UNIT AMOUNTS)

	FIRST	SECOND	THIRD	FOURTH	TOTAL
1998 QUARTERS					
Operating revenue....................	$ 72.9	$ 74.4	$ 70.2	$ 70.2	$ 287.7
Operating income.....................	$ 28.0	$ 28.6	$ 27.2	$ 21.6	$ 105.4
Net income...........................	$ 22.9	$ 24.2	$ 22.6	$ 18.8	$ 88.5
Net income per unit(1)...............	$ 0.80	$ 0.85	$ 0.78	$ 0.64	$ 3.07

	FIRST	SECOND	THIRD	FOURTH	TOTAL
1997 QUARTERS					
Operating revenue....................	$ 68.7	$ 66.9	$ 72.3	$ 74.2	$ 282.1

Operating income....................	$ 25.7	$ 26.9	$ 27.1	$ 28.4	$ 108.1
Net income...........................	$ 17.7	$ 19.2	$ 19.4	$ 22.0	$ 78.3
Net income per unit(1)..............	$ 0.71	$ 0.75	$ 0.76	$ 0.80	$ 3.02

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(1) The General Partner's allocation of net income has been deducted before calculating net income per unit.

EXHIBIT 10.19

PROMISSORY NOTE

$37,000,000.00 Dated: September 30, 1998

FOR VALUE RECEIVED, the undersigned, LAKEHEAD PIPE LINE COMPANY, LIMITED PARTNERSHIP, a Delaware limited partnership (the "Borrower"), HEREBY PROMISES TO PAY to the order of LAKEHEAD PIPE LINE COMPANY, INC., a Delaware corporation (the "Lender") at its offices in Duluth, Minnesota or as otherwise directed, in lawful money of the United States of America and in immediately available funds, the principal sum of THIRTY SEVEN MILLION AND NO/100 DOLLARS ($37,000,000.00), together with interest on the outstanding principal balance from day to day remaining unpaid as herein specified in monthly installments as follows:

(a) On October 1, 1998, and continuing monthly and regularly thereafter on the first day of each and every month until September 1, 2013, interest only at the Loan Interest Rate on the outstanding principal, with the interest rate being adjusted on each Interest Rate Adjustment Date, shall be due and payable; and

(b) A final installment in the amount of all outstanding principal, plus accrued and unpaid interest, shall be due and payable on the Maturity Date.

INTEREST

Each change in the rate of interest charged hereunder shall become effective, without notice to Borrower, on each Interest Rate Adjustment Date. Without limiting the foregoing, Lender shall use its best efforts to notify Borrower of any change in the interest rate hereunder, and until Borrower is notified by Lender of such change, Borrower may continue to make payments hereunder at the prior interest rate; provided, however, nothing contained herein shall be construed as limiting Lender's right to collect interest at the rates described in this Note and Borrower will promptly pay any shortfall occasioned by Borrower's underpayment of interest on demand. In the event of overpayment, Lender will apply the overpayment against the next accruing payment of interest.

It is the intention of the parties hereto that the Lender shall conform strictly to usury laws applicable to it. Accordingly, if the transactions contemplated hereby would be usurious as to the Lender under laws applicable to it (including the laws of the United States of America or any other jurisdiction whose laws may be mandatorily applicable to the Lender notwithstanding the other provisions of this Note) then, in that event, notwithstanding anything to the contrary herein, it is agreed as follows:

(a) the aggregate of all consideration which constitutes interest under applicable law that is contracted for, taken, reserved, charged or received by the Lender shall under no circumstances exceed the maximum amount allowed by such applicable law, and any excess shall be canceled automatically, and if theretofore paid, shall be credited by the Lender on the principal amount outstanding hereunder (or, to the extent that the principal amount outstanding hereunder shall have been or would thereby be paid in full, refunded by Lender to Borrower); and

(b) in the event that the Maturity Date is accelerated by reason of any Event of Default, or in the event of any prepayment, then such consideration that constitutes interest under applicable law may never include more than the maximum amount allowed by such applicable law, and excess interest, if any, provided for herein shall be canceled automatically by the Lender as of the date of such acceleration or prepayment and, if theretofore paid, shall be credited by the Lender on the principal amount outstanding hereunder (or, to the extent that the principal amount shall have been or would thereby be paid in full, refunded by Lender to the Borrower).

All sums paid or agreed to be paid to the Lender for the use, forbearance or detention of sums due hereunder shall, to the extent permitted by applicable law, be amortized, prorated, allocated and spread in equal parts throughout the full term hereof until payment in full so that the rate or amount of interest on account of the principal outstanding hereunder does not exceed the maximum amount and rate of interest allowed by such applicable law. If at any time and from time to time (i) the amount of interest payable to the Lender on any date shall be computed at the Highest Lawful Rate, and (ii) in respect of any subsequent interest computation period the amount of interest otherwise payable to the Lender would be less than the amount of interest payable to the Lender computed at the Highest Lawful Rate, then the amount of interest payable to the Lender in respect of such subsequent interest computation period shall continue to be computed at the Highest Lawful Rate until the total amount of interest payable hereunder shall equal the total amount of interest which would have been payable if the total amount of interest had been computed without giving effect to this paragraph.

DEFINITIONS

As used in this Note, the following terms shall have the respective meanings indicated below:

"Acquired Assets" shall mean, at any date of determination, any assets other than Newly Constructed Assets acquired by the Borrower or any of its Subsidiaries from any Person at any time during the four consecutive calendar quarter period used to determine Consolidated Cash Flow as at such date of determination.

"Applicable Margin" means the following percentages for the specified levels, which shall be determined on each Quarterly Reporting Date for the following calendar quarter:

PRICING CHART

LEVELS	APPLICABLE MARGIN
I	.50%
II	.625%
III	.8125%
IV	1.25%
V	2.50%

For purposes of the foregoing Pricing Chart, the applicable levels shall be determined as set forth below. The Cash Flow/Interest Coverage Pricing Ratio will be determined by the stated ratio on each Quarterly Certificate. In the event that Borrower does not deliver a Quarterly Certificate on any Quarterly Reporting Date, Level V shall apply during the following quarter until such Quarterly Certificate is delivered.

Level I shall be applicable, as at any date of determination, if the Cash Flow/Interest Coverage Pricing Ratio as at such date shall be equal to or greater than 3.75;

Level II shall be applicable, as at any date of determination, if the Cash Flow/Interest Coverage Pricing Ratio as at such date shall be equal to or greater than 3.00 but less than 3.75;

Level III shall be applicable, as at any date of determination, if the Cash Flow/Interest Coverage Pricing Ratio as at such date shall be equal to or greater than 2.50 but less than 3.00;

Level IV shall be applicable, as at any date of determination, if the Cash Flow/Interest Coverage Pricing Ratio as at such date shall be equal to or greater than 2.25 but less than 2.50; and

Level V shall be applicable, as at any date of determination, if the Cash Flow/Interest Coverage Pricing Ratio as at such date shall be less than 2.25.

"Business Day" shall mean any day excluding Saturday, Sunday, and any other day on which banks are required or authorized to close in New York City, New

York or Chicago, Illinois and, if the applicable day relates to LIBOR Rate Loans, on which trading is carried on by and between banks in Dollar deposits in the interbank eurodollar market.

"Capital Lease" shall mean, as applied to any Person, any lease of any property (whether real, personal or mixed) by such Person (as lessee or guarantor or other surety) which would, in accordance with GAAP, be required to be classified and accounted for as a capital lease on a balance sheet of such Person.

"Cash Flow/Interest Coverage Pricing Ratio" means, as of the end of each calendar quarter, the quotient obtained by dividing (A) the sum of (a) EBITDA plus (b) to the extent not included in EBITDA, EBITDA with respect to Acquired Assets, excluding, however, (c) any nonrecurring amounts (including, without limitation, amounts paid to shippers (or accrued) pursuant to decisions of regulatory bodies or negotiated settlement agreements) to the extent included in the foregoing clauses (a) and (b), less (d) the amount of investment income generated by such Person and its Subsidiaries on a consolidated basis from the investment of cash and cash equivalents, in each case for the period of four consecutive calendar quarters ending on such calendar quarter ending date by (B) the sum of (x) the Consolidated Gross Interest Expense less (y) the amount of investment income generated by such Person and its Subsidiaries on a consolidated basis from the investment of cash and cash equivalents for the same four consecutive calendar quarter period.

"Consolidated Cash Flow" shall mean, at any date of determination, (a) all cash receipts of the Borrower and its Subsidiaries from operations (except in respect of Acquired Assets or Newly Constructed Assets which are treated below in this definition) during the period of four consecutive calendar quarters most recently ended prior to such date of determination, but excluding (A) cash proceeds from Interim Capital Transactions and (B) net cash receipts from operations in respect of assets sold pursuant to Section 8.07(c), less (b) the amount of investment income received by such Person and its Subsidiaries on a consolidated basis during such period from the investment of cash and cash equivalents, less (c) the sum of:

(i) all cash operating expenditures of the Borrower and its Subsidiaries during such period (including, without limitation, cash operating expenditures of Subsidiaries prior to the acquisition thereof by the Borrower and taxes paid by the Borrower as an entity and by its Subsidiaries during such period),

(ii) an amount equal to the actual reserves, if any, established by the general partner of the Borrower during such period for the incremental revenues collected by the Borrower and its Subsidiaries during such period pursuant to a rate increase which revenues are, at such date of determination, subject to possible refund,

(iii) the amount, if any, by which cash reserves outstanding as of the end of the period that the general partner of the Borrower determines in its reasonable discretion to be necessary or appropriate to provide for the future cash payment of expenditures of the type referred to in clause (i) above exceeds such cash reserves outstanding at the beginning of such period, plus

(iv) the amount, if any, by which cash reserves outstanding at the end of the period that the general partner of the Borrower determines in its reasonable discretion to be necessary or appropriate to provide funds for distributions with respect to the four calendar quarters following the end of such period exceeds such cash reserves outstanding at the beginning of such period,

plus (d) with respect to Acquired Assets, an amount equal to the cash receipts generated by such Acquired Assets (less actual cash operating expenditures paid with respect to such Acquired Assets) during the four consecutive calendar quarters ending on the date of determination (regardless of the ownership thereof during such period), plus (e) with respect to Newly Constructed Assets, an amount equal to the product obtained by multiplying (i) the cost thereof by (ii) the interest rate applicable to United States Treasury Bonds with a maturity of 30 years (which interest rate shall be determined as of the applicable date of determination) plus 1%, all as determined on a consolidated basis and after elimination of intercompany items.

"Consolidated Gross Interest Expense" means, as of the end of any calendar quarter, Consolidated Interest Expense plus the amount of capitalized interest (as determined in accordance with GAAP) of the Borrower and its consolidated Subsidiaries during the same four calendar quarters used to determine Consolidated Interest Expense as of such calendar quarter-end.

"Consolidated Interest Expense" means, as of the end of any calendar quarter, the interest expense of the Borrower and its consolidated Subsidiaries incurred for the financing of the ordinary course of business

operations of the Borrower and its consolidated Subsidiaries during the period of the four most recently completed calendar quarters ending on such calendar quarter ending date (as determined in accordance with GAAP).

"EBITDA" shall mean, for any period, (a) Net Income for such period plus (b) depreciation, amortization, interest expense, and income taxes for such period, in each case to the extent deducted in determining Net Income for such period, all as determined on a consolidated basis for the Borrower and its Subsidiaries.

"GAAP" shall mean generally accepted accounting principles in effect in the United States from time to time.

"Highest Lawful Rate" means the maximum nonusurious interest rate that may under applicable law be contracted for, charged, received, taken or reserved by Lender in connection with loans made by Lender.

"Indebtedness" of any Person shall mean (without duplication):

(a) any indebtedness for borrowed money which such Person has directly or indirectly created, incurred or assumed;

(b) any indebtedness, whether or not for borrowed money, secured by any Lien in respect of property owned by such Person, whether or not such Person has assumed or become liable for the payment of such indebtedness, provided that the amount of such Indebtedness if not so assumed shall in no event be deemed to be greater than the fair market value from time to time (as determined in good faith by such Person) of the property subject to such Lien;

(c) any indebtedness, whether or not for borrowed money, with respect to which such Person has become directly or indirectly liable and which represents the deferred purchase price (or a portion thereof) or has been incurred to finance the purchase price (or a portion thereof) of any property, service or business acquired by such Person, whether by purchase, consolidation, merger or otherwise, excluding, however, trade accounts payable incurred in the ordinary course of business by the Person whose Indebtedness is being determined;

(d) any obligations under Capital Leases to the extent such obligations would, in accordance with GAAP, appear on a balance sheet of such Person;

(e) any indebtedness of the character referred to in clause (a), (b), or (d) of this definition deemed to be extinguished under GAAP but for which such Person remains legally liable; and

(f) any indebtedness of any other Person of the character referred to in clause (a), (b), (c), (d) or (e) of this definition with respect to which the Person whose Indebtedness is being determined has become liable by way of a Guaranty.

"Interest Rate Adjustment Date" means the date hereof and the first day of each and every month thereafter prior to the Maturity Date.

"Interim Capital Transactions" shall mean (a) borrowings and sales of debt securities (other than for working capital purposes and other than for items purchased on open account in the ordinary course of business) by the Borrower, (b) sales of equity interests by the Borrower or capital contributions to the Borrower, and (c) sales or other voluntary or involuntary dispositions of any assets of the Borrower (other than (i) sales or other dispositions of inventory in the ordinary course of business, (ii) sales or other dispositions of other current assets including accounts receivable or (iii) sales or other dispositions of assets as a part of normal retirements or replacements), in each case prior to the commencement of the dissolution and liquidation of the Borrower.

"Lien" shall mean, as to any Person, any mortgage, lien (statutory or otherwise), pledge, reservation, right of entry, encroachment, easement, right-of-way, restrictive covenant, license, charge, security interest or other encumbrance in or on, or any interest or title of any vendor, lessor, lender or other secured party to or of such Person under any conditional sale or other title retention agreement or Capital Lease with respect to, any

property or asset owned or held by such Person, or the signing or filing of a financing statement with respect to any of the foregoing which names such Person as debtor, or the signing of any security agreement with respect to any of the foregoing authorizing any other party as the secured party thereunder to file any financing statement or any other agreement to give or grant any of the foregoing. For the purposes of this Note, a Person shall be deemed to be the owner of any asset which it has placed in trust for the benefit of the holders of Indebtedness of such Person and such trust shall be deemed to be a Lien if such Indebtedness is deemed to be extinguished under GAAP and such Person remains legally liable therefor.

"Loan Interest Rate" means from the date hereof until the next Interest Rate Adjustment Date 8.75% per annum and thereafter means the lesser of (i) the Highest Lawful Rate, or (ii) the sum of the LIBOR Rate plus the Applicable Margin.

"LIBOR Rate" means the rate per annum (rounded to 1/16 of 1%) at which dollar deposits approximately equal in principal amount to the entire principal amount of this Note and for a period of one (1) month are offered, as quoted on the display designated as page 4136 on the Telerate Service (or such other display as may replace Page 4136 on the Telerate Service), or such other nationally-recognized rate quoting service selected by Lender.

"Maturity Date" means September 30, 2013.

"Net Income" shall mean, for any period, the net earnings income (or loss) after taxes for such period taken as a single accounting period on a consolidated basis for the Borrower and its Subsidiaries determined in accordance with GAAP.

"Newly Constructed Assets" shall mean, at any date of determination, any pipeline assets and facilities related thereto which are intended to be included in the common carrier rate base of the Borrower and which are then being either constructed by or on behalf of the Borrower or any of its Subsidiaries or if already owned by the Borrower or its Subsidiaries, substantially rehabilitated or enhanced.

"Person" means any individual, partnership, firm, corporation, association, joint venture, trust or other entity or enterprise, or any governmental or political subdivision or agency, department or instrumentality thereof.

"Quarterly Certificate" means a certificate signed by an officer of the general partner of Borrower, stating (i) what the Cash Flow/Interest Coverage Pricing Ratio is for the immediately preceding calendar quarter and (ii) that there exists no Event of Default hereunder.

"Quarterly Reporting Date" means the first day of each January, April, July and November during the term hereof.

"Subsidiary" shall mean any corporation, association, partnership, joint venture or other business entity at least a majority (by number of votes) of the stock of any class or classes (or equivalent interests) of which is at the time owned by a Person or by one or more Subsidiaries of such Person or by a Person and one or more Subsidiaries of such Person, if the holders of the stock of such class or classes (or equivalent interests) (a) are ordinarily, in the absence of contingencies, entitled to vote for the election of a majority of the directors (or Persons performing similar functions) of such business entity, even though the right so to vote has been suspended by the happening of such a contingency, or (b) are at the time entitled, as such holders, to vote for the election of the majority of the directors (or Persons performing similar functions) of such business entity, whether or not the right so to vote exists by reason of the happening of a contingency.

COVENANTS

During the term hereof, Borrower shall comply with the following covenants:

(a) Borrower shall deliver to Lender a Quarterly Certificate on each Quarterly Reporting Date.

(b) Borrower will at all times preserve and keep in full force and effect its partnership existence.

(c) Borrower will at all times comply with all laws and regulations applicable to it, the failure with which to comply, individually or in the aggregate, would materially adversely affect its business or its operations.

(d) Borrower will, and will cause each Subsidiary to, pay all taxes, assessments and other governmental charges imposed upon it or any of its properties or assets or in respect of any of its franchises, business, income or profits when the same become due and payable, but in any event before any penalty or interest accrues thereon, and all claims (including, without limitation, claims for labor, materials and supplies) for sums which have become due and payable and which by law have or might become a Lien upon any of its properties or assets; provided that no such tax, assessment, charge or claim need be paid or reimbursed if being contested in good faith by appropriate proceedings properly initiated and diligently conducted and if such reserves or other appropriate provision, if any, as shall be required by GAAP shall have been made therefor and be adequate in its good faith judgment.

(e) Borrower will maintain or cause to be maintained in good repair, working order and condition all properties used or useful in its business and that of its Subsidiaries and from time to time will make or cause to be made all appropriate repairs, renewals and replacements thereof. Borrower will maintain or cause to be maintained, with financially sound and reputable insurance companies, on commercially reasonable terms, insurance with respect to its properties and business and the properties and business of its Subsidiaries of the types and in the amounts generally carried by similar businesses in the same industry.

DEFAULT; REMEDIES

It shall be a default hereunder upon the occurrence of any of the following (each an "Event of Default"):

(a) Borrower shall default in the payment of any amount due hereunder, and such default shall continue for more than five (5) Business Days; or

(b) Borrower shall fail to comply with any covenant contained herein, and such default shall not have been remedied within thirty (30) days after written notice thereof is received by Borrower; or

(c) Borrower or any Subsidiary of Borrower (as principal or guarantor or other surety) shall default in the payment of any amount of principal of, or premium or interest on Indebtedness which is outstanding in a principal amount of at least $15,000,000 (other than the Indebtedness governed by this Note); or any event shall occur or condition shall exist in respect of any Indebtedness which is outstanding in a principal amount of at least $15,000,000 (other than the Indebtedness governed by this Note) or of any mortgage, indenture or other agreement relating thereto, the effect of which is to cause (or to permit one or more Persons to cause) such Indebtedness to become due and payable before its stated maturity or before its regularly scheduled dates of payment, and such default, event or condition shall continue for more than the period of grace, if any, specified therein and shall not have been waived; or

(d) The filing by or behalf of Borrower or its general partner of a voluntary petition or an answer seeking reorganization, arrangement, readjustment of its debts or for any other relief under any bankruptcy, reorganization, compromise, arrangement, insolvency, readjustment of debt, or dissolution, liquidation, or similar act or law, state or federal, now or hereafter existing ("Bankruptcy Law"), or any action by Borrower or its general partner for, or consent or acquiescence to, the appointment of a receiver, trustee or other custodian of Borrower or its general partner or of all or a substantial part of its property; or the making by Borrower or its general partner of any assignment for the benefit of creditors; or the admission by Borrower or its general partner in writing of its inability to pay its debts as they become due; or

(e) Any of the following: (i) the filing of any involuntary petition against Borrower or its general partner in bankruptcy or seeking reorganization, arrangement, readjustment of its debts or for any other relief under any Bankruptcy Law and an order for relief by a court having jurisdiction in the premises

shall have been issued or entered therein; (ii) any other similar relief shall be granted under any applicable federal or state law; (iii) a decree or order of a court having jurisdiction in the premises for the appointment of a receiver, liquidator, sequestrator, trustee or other officer having similar powers over Borrower or its general partner or over all or a part of its property shall have been entered; (iv) the involuntary appointment of an interim receiver, trustee or other custodian of Borrower or its general partner or of all or a substantial part of its property; or (v) the issuance of a warrant of attachment, execution or similar process against any substantial part of the property of Borrower or its general partner, and the continuance of any such event described in the foregoing clauses (i) -- (v), both inclusive, for 60 consecutive days unless dismissed, bonded to the satisfaction of the court having jurisdiction in the premises or discharged; or

(f) A final judgment or judgments (which is or are non-appealable or which has not or have not been stayed pending appeal or as to which all rights to appeal have expired or been exhausted) shall be rendered against Borrower for the payment of money in excess of $15,000,000 and the same shall not be discharged or execution thereon stayed pending appeal within 60 days after entry thereof, or, in the event of such a stay, such judgment shall not be discharged within 30 days after such stay expires.

Upon an Event of Default, the principal of this Note and any accrued interest shall become, forthwith, due and payable without presentment, demand, protest or other notice of any kind (including, without limitation, notice of intent to accelerate), all of which are hereby waived by Borrower.

MISCELLANEOUS

The principal balance under this Note and any accrued interest thereon may be prepaid in whole or in part at any time without premium or penalty.

The Borrower and any and all endorsers, guarantors and sureties hereof severally waive grace, demand, presentment for payment, notice of dishonor or default or intent to accelerate, protest and notice of protest and diligence in collecting and bringing of suit against any party hereto, and agree to all renewals, extensions or partial payments hereon and to any release or substitution of security herefor, in whole or in part, with or without notice, before or after maturity.

This Note shall be governed by, and construed and interpreted in accordance with, the laws of the State of Texas and any applicable laws of the United States of America.

LAKEHEAD PIPE LINE COMPANY, LIMITED PARTNERSHIP

By: Lakehead Pipe Line Company, Inc., its general partner

By:

Name: Mark A. Maki
Title: Chief Accountant

By:

Name: Scott R. Wilson

Title: Treasurer

EXHIBIT 10.21

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Lakehead Pipe Line Company, Limited Partnership	))	Docket No. OR99-______

OFFER OF SETTLEMENT

Pursuant to 18 C.F.R. Section 385.602 (1998), Lakehead Pipe Line Company, Limited Partnership ("Lakehead"), a common carrier oil pipeline regulated by this Commission, hereby submits this Offer of Settlement. By this offer, Lakehead seeks Commission approval for a comprehensive settlement agreement (hereafter the "1998 Settlement Agreement"), which was entered into on October 21, 1998 by Lakehead and the Canadian Association of Petroleum Producers ("CAPP"), the principal representative of the producers Lakehead serves. The 1998 Settlement Agreement is intended to govern the rate recovery by Lakehead of the costs of three projects for the expansion of Lakehead's capacity and the broadening of its capability to transport heavier crude oil. Its primary features are:

(1) a cost-of-service based surcharge, for 15 years, on terms included as part of the settlement of Lakehead's most recent rate case, for recovery of costs associated with Lakehead's portion of the System Expansion Program Phase II ("SEP II");

(2) an agreed-upon flat-rate surcharge for 15 years for recovery of costs associated with Lakehead's portion of the so-called Terrace Expansion Project ("Terrace"); and

(3) an increase in the existing heavy oil surcharge from 20 percent of the standard rate to as much as 22 percent to reflect a planned operational change permitting shippers to transport heavier grades of crude through the Lakehead system.

In the case of the two expansion-related surcharges, the terms of those surcharges have been extensively negotiated between CAPP and Lakehead's Canadian affiliate Enbridge Pipelines, Inc. ("Enbridge"),[1] on behalf of itself and Lakehead. The resulting agreements have been formally approved by the National Energy Board of Canada ("NEB"), and the terms of the SEP II surcharge were included in the Lakehead rate settlement approved by this Commission on October 18, 1996. The proposed change to the heavy oil surcharge has also been agreed to by CAPP and the affected heavy oil producers, and has been approved in principle by the NEB. This change is conditional on CAPP giving notice to Enbridge and Lakehead of CAPP's intent to have the higher viscosity limit implemented, and on Lakehead's operations being altered to permit movement of much heavier crudes than could be accommodated in the past.

This Offer of Settlement is being filed now, in advance of any rate filing or litigated proceeding, to facilitate public notice of the proposed changes and to permit timely Commission consideration of those changes before they are scheduled to take effect in January 1999. Following the procedures in Rule 602, the Commission should approve the 1998 Settlement Agreement as being fair, reasonable and in the public interest, and should grant a

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1 Enbridge was formerly known as Interprovincial Pipe Line Inc. ("IPL"). The

name was changed to Enbridge effective October 7, 1998. For simplicity and clarity, "Enbridge" will be used throughout this pleading to refer to the former IPL, even in historical references.

limited waiver of the tariff filing rules to permit implementation of the resulting surcharges and longer-term rate provisions.

EXECUTIVE SUMMARY

Lakehead and Enbridge each operate separate portions of a single oil pipeline system connecting Western Canadian oil fields to major U.S. Midwest and Eastern Canadian refining centers. Due largely to sharply increased oil production in Western Canada and the attractiveness of the U.S. market in and around Chicago, the existing capacity of the Enbridge/Lakehead system has been consistently oversubscribed in recent years. This bottleneck, in turn, has had a negative effect on Canadian oil producers' revenues from sale of their oil, as well as a deleterious effect on U.S. refiners seeking access to Western Canadian sources of supply.

In an attempt to relieve this capacity shortfall, and in consultation with the producers, Enbridge and Lakehead embarked on a series of major, staged expansions designed to add capacity in increments over a period of years. SEP II was in its formative stages at the time of the settlement of Lakehead's most recent FERC rate case in 1996 ("1996 FERC Settlement").2 General provision was made in the 1996 FERC Settlement for the future rate treatment of the SEP II expansion costs through an incremental cost-based surcharge. After that settlement, Lakehead and Enbridge, in consultation with CAPP, undertook a further series of expansions known as the Terrace project. The Terrace project, in conjunction with the additional capacity made available through SEP II, is expected to facilitate increased production as well as enhanced

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2 The 1996 FERC Settlement is Attachment A to the 1998 Settlement Agreement (Ex. 1 hereto).

net sales revenues (i.e., "netbacks") to the producers. These projects are also expected to increase the availability of Canadian crude oil for U.S. Midwest refiners. The total cost of these expansions, however, is daunting - more than $1 billion (U.S.) over a period of ten years, much of it concentrated in the early period. While the expanded capacity will yield increased throughput - and thus increased revenue - for Enbridge and Lakehead even at existing rates, that increased revenue is insufficient by itself to cover the entire cost of these massive projects.

Accordingly, Enbridge and Lakehead have worked with the producers, represented by CAPP, to develop cost recovery mechanisms that are fair, reasonable, consistent and flexible enough to accommodate even unexpected contingencies without provoking a renewal of the burdensome tariff litigation that both sides have previously endured. As noted above, Enbridge, Lakehead and CAPP initially reached agreement on a rate surcharge for SEP II costs, the terms of which were included in the 1996 FERC Settlement. In anticipation of the Terrace project, the parties sought to negotiate an even more innovative agreement. The result is the Terrace Toll Agreement (Attachment B to the 1998 Settlement Agreement (Ex. 1)), which embodies a set of principles for recovery of the Terrace costs during the next 15 years. The centerpiece of this agreement is a fixed-rate surcharge on Enbridge and Lakehead's rates to remain in effect through 2013, with only limited adjustments pursuant to the agreement.

The Terrace Toll Agreement has already been reviewed and approved by the NEB under its guidelines for negotiated settlements and the just and reasonable rate standard.3 By this

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3 The NEB approved the draft of the Terrace Toll Agreement as it existed in June 1998. The details of the agreement have been further refined since that time, resulting in the definitive statement, dated October 21, 1998, which appears as Attachment B to the 1998 Settlement Agreement (Ex. 1). None of the essential substantive terms has been altered in the definitive agreement, which will be resubmitted to the NEB for review in the very near future.

Offer of Settlement, Lakehead seeks similar approval from this Commission for the Terrace surcharge, and confirmation of the terms of the SEP II surcharge, so that these innovative agreements can be implemented unconditionally as expeditiously as possible. As described below, Lakehead also seeks a limited waiver of the technical tariff regulations to the extent necessary to permit the surcharges to be put in place in Lakehead's FERC tariffs. This limited waiver should also extend to the proposed increase in Lakehead's heavy oil surcharge to reflect the ability of Lakehead to accept heavier crude oil once the SEP II facilities are in service.4

BACKGROUND

Lakehead and Enbridge collectively own and operate the longest crude oil pipeline system in North America. The system stretches from Western Canada through the Great Lakes region of the United States, to Eastern Canada and upstate New York. All portions of the system north of the international border are owned and operated by Enbridge, while all portions of the system in the United States are owned and operated by Lakehead. Approximately 90 percent of the throughput transported by Lakehead originates on the Enbridge system in Canada. About two-thirds of that volume is delivered in the United States and the remainder is delivered in Eastern Canada. The rates charged by Enbridge for the portion of the transportation service

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4 The specific provisions from which a waiver is sought are 18 C.F.R. Section Section 342.1, 342.3(a) and 342.4 (1998).

that occurs in Canada are regulated by the NEB. This Commission regulates the rates charged by Lakehead for its service within the United States.5

Since 1995, Enbridge's rates in Canada have been governed by an Incentive Toll Settlement Agreement that was negotiated between Enbridge and CAPP. CAPP represents Canadian oil producers that collectively account for more than 95 percent of the throughput transported on the Enbridge/Lakehead system. The Incentive Toll Settlement Agreement was approved by the NEB on March 24, 1995. In general, it provides a methodology for setting rates in Canada based on an incentive ratemaking approach designed to align the interests of Enbridge and its shippers.6

1996 FERC Settlement

Lakehead's rates are currently governed by the 1996 FERC Settlement, which resolved Lakehead's most recent major rate proceeding before this Commission. That proceeding originated with a rate filing by Lakehead on April 1, 1992 that was protested by CAPP and other parties, leading to a series of phased hearings before a FERC administrative law judge. The judge issued an initial decision in Phase I of the proceeding on December 7, 1993, Lakehead Pipe Line Co., Limited Partnership, 65 FERC Paragraph 63,021 (1993), and a Phase II initial decision on October 31, 1994. Lakehead Pipe Line Co., Limited Partnership, 69 FERC Paragraph 63,006 (1994).

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5 Lakehead is a master limited partnership whose units are traded on the New York Stock Exchange. Approximately 84 percent of its partnership interests are held by public unitholders (including other corporations), with the remaining approximately 16 percent being held by Lakehead Pipe Line Company, Inc., the general partner of the Lakehead partnership and a wholly owned subsidiary of Enbridge.

6 Although the incentive methodology is intended to continue indefinitely, specific parameters for setting rates have been established only through 1999. Enbridge and CAPP have commenced negotiations regarding continuation of the agreement beyond 1999.

The Commission issued its decision in Phase I on June 15, 1995. Opinion No. 397, Lakehead Pipe Line Co., Limited Partnership, 71 FERC Paragraph 61,338 (1995). The Commission largely reaffirmed that decision on rehearing in Opinion No. 397-A, Lakehead Pipe Line Co., Limited Partnership, 75 FERC Paragraph 61,181 (1996), which was issued on May 1, 1996.

While the Commission's Phase I decision was pending on petitions for review filed by Lakehead and CAPP in the U.S. Court of Appeals for the District of Columbia Circuit, the parties reached a settlement of the entire dispute, including both Phase I and Phase II rates, as well as future rates for at least five years. That settlement provided that Lakehead would provide monetary relief totaling $120 million for past rates found not to be just and reasonable, with the relief divided between direct refunds and a 10 percent surcredit applicable to future rates.7 1996 FERC Settlement (Ex. 1, Att. A) Paragraph 7. Lakehead also instituted an immediate 6 percent decrease in its filed rates for the future, providing an aggregate annual revenue decrease of approximately $17 million. In return, CAPP and the Alberta Department of Energy agreed not to challenge Lakehead's rates for five years, provided those rates do not (other than as permitted in the settlement) exceed the amount allowed under the Commission's indexing regulations. Id. Paragraphs 12, 13.

Under the 1996 FERC Settlement, the limitation of Lakehead's rates to the indexed ceilings has two specific exceptions. First, to the extent Lakehead undertakes system capacity expansions during the five-year period, including specifically SEP II, the costs of such expansions can be recovered through an incremental surcharge to Lakehead's rates calculated in

accordance with Appendix D to the 1996 FERC Settlement. Id. Paragraph 13.A. Appendix D, in turn, is an excerpt from the Enbridge Incentive Toll Settlement Agreement. The general effect of paragraph 13.A. and Appendix D is to permit Lakehead to calculate a separate cost of service for the SEP II expansion facilities, using the agreed-upon terms, and to add the resulting tariff increment onto the existing rates as a tariff surcharge. The second exception is that Lakehead is permitted to increase its indexed rates to reflect so-called "non-routine adjustments" to the extent reflected in Appendix E to the FERC 1996 Settlement, which is an excerpt from paragraph 7.0 of the Enbridge Incentive Toll Settlement Agreement. 1996 FERC Settlement (Ex. 1, Att. A) Paragraph 13.B.

SEP II

The SEP II expansion project commenced in January 1996 with Enbridge's filing of an application with the NEB for a certificate of public convenience and necessity for the portion of the SEP II facilities in Canada. As reflected in the NEB order approving SEP II, the goal at that time was to increase the delivery capacity from Western Canada into Chicago by approximately 120,000 barrels per day (b/d).8 This increase was expected to result from two primary sources - (1) construction of a new Enbridge line and associated facilities from

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7 The 10 percent surcredit is scheduled to remain in effect until such time as the remainder of the $120 million, plus interest, has been returned to Lakehead's shippers. Under current projections, the surcredit will expire in the second half of 1999.

8 See Reasons for Decision, Interprovincial Pipe Line Inc., Docket OH-1-96 (NEB, July 1996) (hereafter "NEB SEP II Decision"). A copy of the NEB SEP II Decision is attached hereto as Exhibit 2.

Edmonton to Hardisty, Alberta and (2) construction of a new Lakehead line (Line 14) from Superior, Wisconsin, to Chicago.9

While the SEP II project was pending before the NEB, Enbridge, Lakehead and CAPP concluded an agreement regarding the future rate treatment of the SEP II costs (the so-called "Risk Sharing Agreement" or "RSA").10 The Risk Sharing Agreement provides, in general, that the SEP II costs will be recovered during a 15-year period through a cost-of-service calculation based on terms outlined in the agreement. Included in those terms are variations in the return on equity to reflect the degree of utilization of the facilities. In essence, at higher utilization rates, Enbridge and Lakehead can recover a higher return on equity, whereas at lower utilization rates, the return on equity falls below the level normally allowed. The RSA also provides that the rates will be calculated "in a manner and amount consistent with existing toll [i.e., rate] design for Lakehead and [Enbridge]." 1996 FERC Settlement (Ex. 1, Att. A), Appendix D.11

The RSA was submitted to the NEB for approval on May 31, 1996. In approving the agreement, the NEB noted that no party had opposed it and that the so-called "Shippers Group" had characterized the agreement as "an innovative and appropriate method of ensuring that some of the risk associated with potential under-utilization of expansion capacity would be

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9 SEP II also involved other modifications and upgrades to various Enbridge and Lakehead facilities that increase both the overall capacity of the system and its capability to handle heavier grades of crude oil.

10 A copy of the Risk Sharing Agreement is attached to the FERC Settlement (Ex. 1, Att. A) as Appendix D.

11 Exhibit 3 hereto is an Explanatory Statement describing in more detail the terms of the Risk Sharing Agreement as it applies to Lakehead.

borne by the pipeline, rather than by shippers." NEB SEP II Decision (Ex. 2) at 13. The Board therefore concluded that the Risk Sharing Agreement "has broad shipper support" and "the settlement represented by the RSA is just and reasonable in the circumstances." Id. at 14.

As noted earlier, the RSA was also incorporated into the 1996 FERC Settlement, which was then being negotiated between Lakehead and CAPP. Paragraph 13.A. of the 1996 FERC Settlement provides that the SEP II surcharge is an exception to the general requirement that Lakehead's settlement rates not be increased by more than the amount allowed by the FERC index. That paragraph also specifies that the terms of the surcharge are to be governed by the RSA (which was attached as Appendix D), and that, in calculating the surcharge, Lakehead will utilize a tax allowance "equal to 30 percent of the tax allowance that would apply if Lakehead were a corporation," reflecting the fact that under Opinion Nos. 397 and 297-A Lakehead is not entitled to a tax allowance on the portion of its net income attributable to individual unitholders. The 1996 FERC Settlement was submitted to the Commission on September 5, 1996, and was not opposed by any shipper or other party. It was approved by the Commission by letter order on October 18, 1996. 77 FERC Paragraph 61,051 (1996).

Terrace

The Terrace project originated out of the realization that SEP II would not, by itself, be sufficient to eliminate the capacity constraints on the Enbridge/Lakehead system, in light of the projected growth in the volume of Western Canadian production available for transportation to Chicago and beyond. The importance of Terrace is highlighted in the NEB order approving construction by Enbridge of the Phase I facilities for the project. Reasons for

Decision, Interprovincial Pipe Line Inc., Docket OH-1-98 (NEB, June 9, 1998) (hereafter "NEB Terrace Decision").12 In that decision, the NEB accepted as reasonable Enbridge's supply forecasts indicating that production of Western Canadian crude oil is expected to increase from 1,980,000 barrels per day (b/d) in 1996 to 2,580,000 b/d in 2009. NEB Terrace Decision (Ex. 4) at 12. The NEB also accepted Enbridge's forecast that its system would remain capacity-constrained for the foreseeable future if it is not expanded significantly. Id. at 16. Noting Enbridge's projection that the expanded capacity would increase the revenues of Western Canadian producers by $5.6 billion on a net present value basis over the period 2000 to 2010, id. at 17, the NEB concluded:

> some of the benefits of this expansion would include the production of crude oil that would otherwise be shut in or sold to less attractive markets due to apportionment [i.e., prorationing] on [Enbridge], as well as a potential improvement in the competitive position of western Canadian crude oil deliveries in [the U.S. Midwest] as a result of increased reliability of these deliveries.

Id.

In the course of planning and executing the Terrace project, Lakehead and Enbridge have consulted and coordinated closely with CAPP as the representative of the interests of the Western Canadian producers seeking expanded access to the markets served by Lakehead. This coordination has involved the scope and timing of the various expansion stages, as well as the proposed rate treatment of the expansion costs. Having been through extensive rate litigation both at this agency (for Lakehead) and at the NEB (for Enbridge), the pipelines and CAPP were interested in avoiding a tariff dispute over the expansion costs if at all possible. Both sides also

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12 For the Commission's convenience, a copy of the NEB Terrace Decision is attached as Exhibit 4.

saw opportunities to put in place innovative tariff structures that would appropriately balance the risks between the shippers and the carrier.

The provision in the 1996 FERC Settlement relating to the SEP II expansion was an early example of this forward-thinking attempt to anticipate and resolve potential disputes before they arise. The parties took an even more innovative approach in structuring an agreement regarding the treatment of costs associated with Terrace. The Terrace Toll Agreement (Ex. 1, Att. B) is a statement of principles intended to govern the recovery of costs for all phases of the Terrace expansion. The agreement was submitted to the NEB and approved by the Board in the NEB Terrace Decision. Unlike the SEP II Risk Sharing Agreement, which contemplates a cost-of-service based surcharge added to the existing Lakehead rates, the Terrace Toll Agreement provides for a flat cents-per-barrel surcharge to be kept in place through December 31, 2013, subject to adjustment only as provided in the agreement.

The provisions of the Terrace Toll Agreement are described in detail in an Explanatory Statement that is attached as Exhibit 5 to this Offer of Settlement. In broad summary, the agreement provides that the costs of all phases of the Terrace expansion project will be recovered by Enbridge and Lakehead collectively through an incremental surcharge of five cents Canadian (Cdn) per barrel. Terrace Toll Agreement (Ex. 1, Att. B) Paragraph 7.[13] Consistent with the terms of the Agreement, id. Paragraph 9, Enbridge and Lakehead have agreed to an initial division in which three cents (Cdn) per barrel will be recovered by Enbridge and two cents (Cdn)

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13 The base surcharge of five cents (Cdn) applies to transportation of one barrel of light crude oil from Edmonton, Alberta, to Griffith, Indiana. The agreement provides that the base surcharge "shall be adjusted on a distance basis and for commodity credits or surcharges, consistent with [Enbridge] and [Lakehead]'s then existing [rate] design." Terrace Toll Agreement (Ex. 1, Att. B) Paragraph 7.

per barrel will be recovered by Lakehead.[14] Using the currency conversion formula specified in the agreement, this results in a base surcharge of approximately 1.3 cents (U.S.) per barrel on Lakehead's rates.

Subject only to adjustments specified in the agreement, this 1.3 cent (U.S.) per barrel surcharge will remain unchanged for the life of the agreement (through 2013). It is the parties' intent that the surcharge - unlike Lakehead's underlying rates - will not be subject to indexing, either upwards or downwards, since the anticipated impact of inflation has already been taken into account in the negotiation of the surcharge amount and the various adjustments to it. Thus, barring variances contemplated in the Terrace Toll Agreement, Lakehead's surcharge would remain at the 1.3 cent (U.S.) per barrel level no matter what happens with general inflation rates. This means that Lakehead and Enbridge are absorbing 100 percent of the operating cost risk on this project, excluding changes to property tax expenses exceeding the forecast amount by 20 percent or more. Id. Paragraph 12. As explained in more detail in the Explanatory Statement (Ex. 5), with respect to the capital costs of constructing the expansion facilities, Lakehead and Enbridge bear all of the risk for the first 5 percent of any cost variation, and 50 percent of the risk after the first 5 percent. Id. Paragraph 13.[15]

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14 Those proportions correspond generally to the relative levels of investment in the expansion facilities by Enbridge and Lakehead.

15 The agreement also permits future adjustment of the 1.3-cent surcharge for such items as agreed-upon scope and timing changes to the project, capital cost and construction cost variances, and variations in bond rates or equity rates of return by more than two percentage points from stipulated 1998 levels. Id. Paragraph 17. In addition, Lakehead may receive an additional increment as specified in the agreement if the constructed facilities are underutilized due to lack of total throughput at designated levels. Id. Paragraph 19.

The Terrace Toll Agreement assumes that all phases of the planned expansion will go forward at CAPP's request. Id. Paragraph 3. It is essentially designed to recover the costs of all phases - including both capital and operating costs - - on a levelized basis through the fixed per-barrel surcharge. In the event CAPP were to elect not to go forward with future phases of the expansion, Enbridge and Lakehead would substitute a cost-of-service based surcharge (similar to the one agreed upon for SEP II) in place of the fixed rate surcharge set forth in the agreement. Id. Paragraph 14. This cost-of-service surcharge would take account not only of Lakehead's future unrecovered costs, but also of revenues foregone by Lakehead during the period the 1.3 cent (U.S.) surcharge was in place instead of a higher cost-of-service based surcharge. Id. If Lakehead and Enbridge fail to achieve the capacity increases forecast for the various phases of the Terrace project, they are required to refund one cent (Cdn) per barrel for each 5,500 cubic meters per day (m3/d) (approximately 34,600 barrels per day) by which capacity falls short. Id. Paragraph 17.

350 Centistoke Project

The third component of the 1998 Settlement Agreement involves the surcharge for heavy crude oil. Lakehead's existing rates provide, for each point-to-point movement, a standard rate for light petroleum, and associated surcharges and surcredits for varying categories of petroleum such as heavy and medium (both of which are more viscous and thus more costly to transport) and gasolines/condensates and natural gas liquids ("NGL") (both of which are less

viscous and thus less costly to transport). The existing surcharges and surcredits range from a 20 percent surcharge for heavy crude to a 10 percent surcredit for NGL.

Historically, as a result of operational limitations, Enbridge and Lakehead have defined "Heavy Crude Petroleum" as a commodity having a density of 904 kg/m3 to 927 kg/m3 and a viscosity of 100 to 250 centistokes.16 As a result, heavy oil shippers seeking to transport crude with a higher density or viscosity have been required to blend their crude with a diluent (usually condensate) to lower its viscosity to an acceptable level. This blending requirement raises the cost of transporting heavy crude and has at times strained supplies of condensate in Western Canada.

In response to industry concern over this issue, Enbridge and Lakehead developed the so-called "350 Centistoke Project." This project involves certain modifications to the Enbridge/Lakehead system, principally in the form of added capability to heat the heavier crudes prior to transportation, that will permit the shipment of heavy crudes up to a viscosity of 350 centistokes. As part of the development of this project, Enbridge and Lakehead also reached agreement with industry on the rate implications of transporting these heavier crudes. In essence, it was agreed that the heavy crude surcharge would be increased from 20 percent to up to 22 percent at such time as the heavier grades of crude begin to be accepted on the system. This increase reflects the additional cost on average to move the heavier grades of crude relative

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16 A "centistoke" is a unit of kinematic viscosity which is commonly used as measure of the viscosity of crude petroleum.

to the standard rate, as determined through the same computer modeling process that produced the existing surcharges and surcredits.17

The 350 Centistoke Project was presented to the NEB for approval of both the new facilities and the proposed rate treatment on April 22, 1997. The Board issued its approval of the project on August 21, 1997.[18] The approval order states:

> The Board notes that the 350 Centistoke Project was developed between [Enbridge] and an industry task force represented by heavy oil interests and has received the formal support of [CAPP]. The Alberta Department of Energy and Pan Canadian Petroleum Limited have filed letters in support of the project. The Board further notes that no party has expressed any concerns with [Enbridge's] application.

NEB 350 Centistoke Decision (Ex. 7) at 1. The Board thus "approved in principle a two percentage point surcharge (to 22 percent) for heavy crude petroleum. . . . " Id. at 2.

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17 A copy of Enbridge's application to the NEB for approval of the 350 Centistoke Project, and CAPP's letter of agreement to the terms of the project (hereafter collectively the "350 Centistoke Agreement") is Attachment C to the 1998 Settlement Agreement (Ex. 1). An Explanatory Statement describing the 350 Centistoke Agreement is attached hereto as Exhibit 6.

18 A copy of the NEB 350 Centistoke Decision is attached hereto as Exhibit 7.

DISCUSSION

The public interest and the Commission's policies encouraging settlements strongly favor implementation in Lakehead's tariffs of the SEP II, Terrace and 350 Centistoke agreements, all of which are consolidated in the 1998 Settlement Agreement. Because of the long-term nature of these agreements, Commission approval will facilitate their implementation both now and in future Lakehead rate filings.[19]

I. THE COMMISSION'S PRO-SETTLEMENT POLICIES SUPPORT IMPLEMENTATION OF THE 1998 SETTLEMENT AGREEMENT

The Commission has long maintained a policy favoring the voluntary resolution of controversies involving regulated companies.[20] In particular, the Commission has consistently recognized that the parties directly involved in a matter can often structure a solution better adapted to their particular circumstances than the general rules that necessarily are designed to cover a wide variety of cases.[21] The Commission thus generally approves

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19 The Commission has broad discretion to waive its regulations as necessary to achieve its statutory mandate to serve the broader public interest. See, e.g., 18 C.F.R. Section 385.101(e). That discretion is more than sufficient in this case to justify the limited waiver of the indexing rules necessary to permit Lakehead to go forward with the innovative agreements negotiated with CAPP and approved by the NEB.

20 E.g., Northern Wasco County People's Utility District, 60 FERC Paragraph 61,087, at 61,280-81 (1992) ("The Commission encourages voluntary settlements as beneficial to the orderly and expeditious conduct of its business, and gives substantial deference to consensual resolutions that are consistent with the Commission's statutory responsibilities."); Order No. 561, FERC Stats. & Regs. Paragraph 30,985, at 30,941 (The final rule "retains the Commission's current policy of encouraging settlements of rate issues at any

stage in our proceedings.").

21 See Tennessee Gas Pipeline Company, 20 FERC Paragraph 61,096, at 61,206-07 (1982); Order No. 561, FERC Stats. & Regs. Paragraph 30,985, at 30,959 ("The Commission . . . finds that allowing rate changes to reflect the agreement of shippers and the pipeline would further its policy of favoring settlements as a means for parties to avoid litigation and thereby lessen the regulatory burdens of all concerned.").

uncontested settlement agreements when they are shown to be "fair, reasonable and in the public interest." 18 C.F.R. Section 385.602(g)(3) (1998).

Here, of course, no rate dispute presently exists between Lakehead and any of its shippers. Nonetheless, Lakehead has looked ahead and attempted to steer away from a potential future rate dispute by reaching a negotiated agreement on the manner in which the costs of the SEP II, Terrace and 350 Centistoke projects will be handled. This negotiated agreement includes provisions benefiting both sides, and represents a reasonable accommodation of all of the relevant interests. In fact, as noted above, each of the underlying agreements has been approved by the NEB as ones "that will result in just and reasonable tolls." E.g., NEB Terrace Decision (Ex. 4) at 18. The SEP II provisions were also included in the previously approved 1996 FERC Settlement. Taken as a whole, therefore, it is clear that the SEP II, Terrace and 350 Centistoke agreements are a fair and reasonable resolution of the various interests involved, and that approval of the 1998 Settlement Agreement is strongly in the public interest.

The SEP II and Terrace expansions are expected to add hundreds of thousands of barrels of daily capacity to the Enbridge and Lakehead systems. The incremental capacity added by these expansions standing alone would dwarf many other pipeline systems in the lower 48 states. In that sense, the expansions more closely resemble the addition of new service than the continuation of existing service. On the other hand, none of the projects will allow Lakehead to serve any additional destinations after the expansions that it could not previously serve. It will simply be able to deliver substantially larger quantities of oil to the existing destinations on its system, with essentially all of the increase coming from shippers that are already utilizing

Lakehead's existing transportation services. Technically, therefore, there is no "new service" to which a separate cost-of-service or other new rate can be applied.22

The solution embodied in the SEP II and Terrace agreements is to impose a separate surcharge on top of the underlying indexed settlement rates. Those surcharges are based on the incremental cost of adding the new capacity, measured over a period of years, and are not intended to affect the indexed rates for pre-existing service levels (which were already set by the 1996 FERC Settlement). All system shippers will benefit from the substantial increase in capacity (and consequent avoidance of prorationing of volumes), and these surcharges consequently are distributed across Lakehead's rates, in accordance with its pre-existing rate design. As described above, in the case of Terrace, the surcharge will essentially take the form of a flat rate for 15 years. In the case of SEP II, since the surcharge is based on the facilities costs incurred by Lakehead, the surcharge will be recalculated each year to incorporate such changes as depreciation of the rate base, throughput increases or decreases, and modifications to the return on equity permitted under the agreement.23

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22 Similarly, the 350 Centistoke project will broaden the category of heavy crude that can be transported on the Enbridge/Lakehead system, but will not result in "new" service to any additional destinations or customers.

23 Lakehead will provide an incremental cost of service calculation with its initial SEP II surcharge filing to be effective upon completion of the SEP II facilities (currently projected for January 1999), and will update that cost of service showing for each subsequent year's rate filings. Those filings will, of course, be subject to challenge by the Commission or any shipper based on the specific costs included in that year's surcharge. By this Offer of Settlement, however, Lakehead is seeking confirmation that the basic concepts set forth in paragraph 13.A. and Appendix D to the 1996 FERC Settlement will apply to any evaluation of the SEP II surcharge, including specifically the exemption of that surcharge from indexing and the adjustment of the equity rate of return in accordance with system utilization.

The exemption of the SEP II and Terrace surcharges from indexing is supported by two major considerations. First, the principal representative of the producers of the vast majority of Lakehead's shipments by volume (CAPP) has expressly agreed to the surcharge mechanism, indicating that the producers that effectively bear Lakehead's rates expect the surcharge approach to be more beneficial than alternative regulatory approaches.24 This Commission and the NEB previously approved settlements incorporating the SEP II mechanism, and, after thorough consideration, the NEB approved the Terrace agreement as one that "has broad shipper support" and that "will result in just and reasonable tolls." NEB Terrace Decision (Ex. 4) at 18. The Terrace Toll Agreement also includes a number of innovative provisions that are designed to benefit shippers. These include:

- the amount of the Terrace surcharge is fixed (subject only to adjustments specified in the agreement) through December 31, 2013;

- because the surcharge is levelized over a 15-year period (1999-2013), the shippers avoid a "front-end shock" from the costs of the expansion project;

- Enbridge and Lakehead are absorbing 100 percent of the operating cost risk over 15 years, subject only to a narrow exception for property taxes;

- Enbridge and Lakehead are absorbing the bulk of the capital cost risks;

- Enbridge and Lakehead are obligated to make refunds if the expansion facilities do not yield the amount of additional capacity specified in the agreement; and

- shippers avoid the need to undertake lengthy and expensive regulatory proceedings regarding Lakehead's recovery of the Terrace costs.

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24 Like Enbridge, Lakehead is an independent pipeline system, unaffiliated with any of the shippers or producers on the system.

Similarly, Lakehead is benefited by the avoidance of unnecessary regulatory litigation, as well as the relative certainty and stability of cost recovery for an expansion which is being undertaken largely for the benefit of the shippers.

A second major consideration favoring these settlements is that it is important both to Lakehead and to shippers that the SEP II and Terrace surcharges be administered under the terms of the relevant agreements, and not under the generic indexing rules As noted above, one of the key benefits to shippers from the Terrace settlement is that Lakehead and Enbridge are absorbing virtually all of the operating cost risk (i.e., the risk that operating costs for the expansion facilities will exceed projections), as well as the majority of the capital cost risks. Subjecting the agreed-upon surcharge to possible upward adjustments for general inflation, as measured by the PPI-1 index, would deprive the shippers of this benefit, at least in part, and would defeat the purpose of imposing a fixed-rate charge in place of a year-by-year cost of service increment. Similarly, from Lakehead's point of view, it would be unfair to require a reduction in the Terrace surcharge in a year when the PPI-1 index is negative, since Lakehead would not be able to avail itself of upward changes in the index. With respect to SEP II, since the surcharge is designed to track the costs of the expansion year by year, adding (or subtracting) an indexing adjustment would likewise undermine the central purpose of the mechanism.

In short, Lakehead and CAPP have fashioned an overall, long-term settlement to govern recovery of the costs of the SEP II, Terrace and 350 Centistoke projects in a balanced, reasonable manner. The Commission's pro-settlement policies strongly favor approval of this agreement.

II. THE COMMISSION SHOULD WAIVE ITS TARIFF REGULATIONS AS NECESSARY TO PERMIT LAKEHEAD TO IMPLEMENT THE SEP II, TERRACE AND 350 CENTISTOKE SURCHARGES

By this Offer of Settlement, Lakehead seeks confirmation that the indexing rules will not preclude it from filing the SEP II and Terrace surcharges as an increment on top of its existing indexed settlement rates. Plainly, while the PPI-1 index was intended to take account of normal variations in operating and capital costs over time,25 it was never meant to cover the sudden substantial increase in costs attributable to major expansion programs such as SEP II and Terrace.26 If Lakehead were constrained to charge only its indexed rates, it would have no economic incentive to undertake expansions such as these, where the incremental revenue at the existing rate level would not cover its increased capital and operating expenses. Yet, given the potential benefit to the producers (on a net present value basis, $5.6 billion from Terrace alone according to Enbridge's estimate, see NEB Terrace Decision (Ex. 4) at 17), the public interest would plainly be harmed by discouraging Lakehead (or other pipelines in similar situations) from proceeding with needed expansions that the parties who bear the rates overwhelmingly favor.

With respect to the 350 Centistoke surcharge, similar reasoning applies. The affected heavy oil producers in Canada supported this surcharge increase before the NEB, and CAPP, which represents those producers, has agreed to its implementation by Lakehead.

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25 Order No. 561, Revisions to Oil Pipeline Regulations Pursuant to the Energy Policy Act of 1992, FERC Stats. & Regs. Paragraph 30,985, at 30,951-52 (1993), on reh'g, Order No. 561-A, FERC Stats. & Regs. Paragraph 31,000, at 31,093-98 (1994); petitions for review denied sub nom. Association of Oil Pipe Lines v. FERC, 83 F.3d 1424, 1433-36 (D.C. Cir. 1996) ("AOPL").

26 Order No. 561-A, FERC Stats. & Regs. Paragraph 31,000, at 31,107; AOPL, 83 F.3d at 1437 n.27.

Although this change is nominally a rate increase above the indexed ceiling, it is not in fact an increase when measured against the increased facilities utilization required to transport 350 centistoke crude oil. In other words, the heavier crude will be more costly to transport because it is more viscous, and thus, among other things, will tend to displace greater volumes of less heavy crudes. The increase of up to two percentage points in the heavy crude surcharge will merely reflect that additional cost burden in a way that is consistent with Lakehead's existing rate design and that the affected producers have agreed in advance is fair and reasonable. It will also maintain parity between the heavy oil surcharge structure for Enbridge and Lakehead.

In sum, the public interest supports approval of the SEP II, Terrace and 350 Centistoke agreements and waiver of the Commission's regulations to the extent necessary to permit the periodic filing of the appropriate surcharges and exemption of those surcharges from indexing.

PROPOSED PROCEDURE

Although there is no pending proceeding in which the 1998 Settlement Agreement can be submitted, Lakehead proposes that the Commission follow its Rule 602 procedures for processing this Offer of Settlement. In particular, parties seeking to comment on any aspect of the proposed settlement would be required to do so within 20 days of the date of the filing of this Offer of Settlement (Rule 602(f)(2)). Reply comments would then be due 10 days later. Following receipt of the comments and reply comments (if any), the Commission could proceed expeditiously to consideration of the Offer of Settlement.

From a timing standpoint, Lakehead intends to file the various surcharges to be effective upon completion of the various facilities, which may be as early as January 1999. In order to provide the 30 days notice required by statute, Lakehead may need to make its tariff

filing as early as December 1998. Lakehead therefore respectfully requests that the Commission act on this Offer of Settlement as expeditiously as possible (ideally by no later than December 1, 1998), so that Lakehead will have an adequate opportunity to prepare the necessary tariff materials for filing with the Commission on a timely basis.

CONCLUSION

For the reasons set forth above, Lakehead seeks Commission approval of the 1998 Settlement Agreement with CAPP (Ex. 1), and a waiver of the tariff filing regulations to the extent necessary to permit implementation of the surcharges as described in that agreement.

Respectfully submitted,

/s/ S. Reed

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Counsel for Lakehead Pipe Line Company,
Limited Partnership

October 27, 1998

Exhibit No. 1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Lakehead Pipe Line Company,)
Limited Partnership)

Docket No. OR 99-____

SETTLEMENT AGREEMENT

This Settlement Agreement is executed as of this 21st day of October, 1998, between Lakehead Pipe Line Company, Limited Partnership ("Lakehead") and the Canadian Association of Petroleum Producers ("CAPP"). The purpose of this Settlement Agreement is to govern the rate recovery by Lakehead of the costs of three projects for the expansion of Lakehead's capacity and the broadening of its capability to transport heavier crude oil. Those three projects are designated as System Expansion Program Phase II ("SEP II"), the Terrace Expansion Program ("Terrace") and the 350 Centistoke Project. In consideration of the provisions set forth in this Settlement Agreement, Lakehead and CAPP (hereafter the "Settling Parties") agree as follows:

1. Following the execution of this Settlement Agreement, Lakehead will submit it to the Federal Energy Regulatory Commission ("FERC") for approval as an offer of settlement under 18 C.F.R. Section 385.602 (1998). The Settling Parties shall cooperate fully, each at its own expense, in seeking and supporting such approval.

2. The Settling Parties intend this Settlement Agreement to be an integrated package, no part of which is separable from the whole. Each side

has made compromises on various positions in order to reach a voluntary agreement on the proposed rate recovery of the SEP II, Terrace and 350 Centistoke project costs. Accordingly, this Settlement Agreement shall be deemed withdrawn, and shall no longer be of any force or effect, in the event the FERC or a reviewing court orders any modification of its terms.

3. The Settling Parties hereby acknowledge and reaffirm their prior agreement that the costs of Lakehead's portion of the SEP II facilities, which are now expected to go into service in January 1999, will be recovered by Lakehead for 15 years through a cost-of-service surcharge in the Lakehead tariffs to be determined as set forth in paragraph 13.A and Appendix D of the Settlement Agreement of August 28, 1996 ("1996 Settlement"), which was approved by the FERC on October 18, 1996. 77 FERC Paragraph 61,051 (1996). A copy of the 1996 Settlement is attached hereto as Attachment A. The intent of the Settling Parties is that the initial SEP II surcharge be filed to be effective

at the time the Lakehead SEP II facilities go into service.

4. The Settling Parties further agree that the costs of Lakehead's portion of the Terrace project will be recovered by Lakehead for 15 years through a specified surcharge in the Lakehead tariffs on the terms set forth in the "Terrace Toll Agreement Statement of Principles," executed on October ___, 1998 ("Terrace Agreement"). A copy of the Terrace Agreement is attached hereto as Attachment B. The intent of the Settling Parties is that the initial Terrace surcharge be filed to be effective at the time the Lakehead Terrace Phase I facilities go into service.

5. The Settling Parties also agree that, at such time as Lakehead begins to offer transportation service for heavy crude petroleum having a viscosity of up to 350 centistokes, the surcharge in the Lakehead tariffs for the heaviest grade of crude petroleum will increase from 20 percent of the standard rate to up to 22 percent of the standard rate on the terms set forth in Attachment C hereto ("350 Centistoke Agreement"), which constitutes the Settling Parties' agreement on the rate treatment of the 350 Centistoke Project.

6. This Settlement Agreement is not intended to supersede, replace, limit or modify the 1996 Settlement previously approved by the FERC.

7. The intent of the Settling Parties is that approval by the FERC of this Settlement Agreement shall also constitute a waiver of the FERC's technical tariff filing regulations, specifically including 18 C.F.R. Section 342.1, 342.3(a) and 342.4, to the extent necessary to put the tariff surcharges provided for in this Settlement Agreement into effect.

8. The Term of this Settlement Agreement shall be for 15 years from the later of the date when the SEP II surcharge or the Terrace surcharge becomes effective as provided herein.

9. Approval of this Settlement Agreement by the FERC does not constitute approval of, or precedent regarding, any principle or issue settled herein.

10. The language of this Settlement Agreement shall, in all cases, be construed according to its fair meaning and not strictly for or against

any of the Settling Parties. This Settlement Agreement may be modified, amended or supplemented only by a written instrument executed by the Settling Parties.

WHEREFORE, the foregoing Settlement Agreement is executed on behalf of the Settling Parties by their duly authorized representatives on the date shown below.

/s/ O. DeVries	/s/ S. R. Wilson
Name: O. Devries	Name: Scott Wilson
Title: Manager, Crude Oil & Fiscal Policy	Title: Treasurer
Canadian Association of Petroleum Producers	Lakehead Pipe Line Company, Limited Partnership

Date: October 21, 1998

29

EXHIBIT NO. 1 - ATTACHMENT A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Lakehead Pipe Line Company, Limited Partnership	)	Docket Has. IS92-27-000, IS93-4-000, 1593-33-000, IS94-20-000, 1594-24-000, IS95-5-000, 1595-26-000, IS95-27-000, and IS96-15-000

SETTLEMENT AGREEMENT

This Settlement Agreement is executed as of this 28th day of August, 1996, between Lakehead Pipe Line Company, Limited Partnership ("Lakehead"), on the one hand, and the Canadian Association of Petroleum Producers ("CAPP") and the Alberta Department of Energy ("ADOE") (collectively "CAPP/ADOE"), on the other, each of which is a party to various rate proceedings before the Federal Energy Regulatory Commission ("FERC" or "Commission") regarding Lakehead's interstate tariff rates, as well as judicial review proceedings relating thereto (the "Lakehead Proceedings"). In consideration of the provisions set forth in this Settlement Agreement, Lakehead and CAPP/ADOE (collectively the "Settling Parties") agree as follows:

1. Following the execution of this Settlement Agreement, the Settling Parties will jointly submit it to the FERC for approval as an offer of settlement under 18 C.F.R. Section 385.602 (1995). The Settling Parties shall cooperate fully, each at its own expense, in seeking and supporting such approval, including the opposition, whether written or otherwise, of all protests, interventions and comments that seek modification or rejection of the Settlement

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Agreement. Lakehead will prepare the offer of settlement documentation, including the Explanatory Statement, for submission to the FERC, subject to approval by CAPP/ADOE. The Settling Parties agree to request and support a stay of all aspects of the Lakehead Proceedings pending disposition of this Settlement Agreement.

2. The Settling Parties intend this Settlement Agreement to be an integrated package, no part of which is segregable from the whole. Each side has made compromises on various positions in order to reach a voluntary, negotiated resolution of the Lakehead Proceedings. Accordingly, as provided in paragraph 15 below, this Settlement Agreement shall be deemed withdrawn, and shall no longer be of any force or effect, in the event the Commission or a reviewing court orders a modification of its terms.

3. This Settlement Agreement is intended to resolve all outstanding rate issues in all pending phases of the Lakehead Proceedings. The FERC Dockets that are resolved by this Settlement Agreement, and that will be terminated upon approval of this Settlement Agreement, are listed in Appendix A hereto.

In addition, within 20 days after the date on which this Settlement Agreement has been approved by the FERC in an order that is no longer subject to judicial review, the Settling Parties shall withdraw their pending petitions for review at the United States Court of Appeals for the District of Columbia Circuit in Docket Nos. 96-1177 and 96-1218.

4. The purpose of this Settlement Agreement is to avoid further administrative and judicial proceedings with respect to Lakehead's interstate tariff rates. This Settlement Agreement is not intended to be inconsistent with any orders of the Commission previously entered in this proceeding, including specifically Opinion No. 397, 71 FERC (CCH) Paragraph 61,338 (1995) and Opinion No. 397-A, 75 FERC (CCH) Paragraph 61,181 (1996). This Settlement

Agreement also is not intended to affect the resolution of any issues regarding facilities for transportation of natural gas liquids on the Lakehead system.

5. Except with respect to paragraph 1 above and as otherwise specified herein, the Effective Date of this Settlement Agreement shall be the date on which a FERC order is issued approving the Settlement Agreement without modification.

6. Notwithstanding the Effective Date as specified in paragraph 5 above, no later than September 20, 1996, Lakehead shall file the rates set forth in the pro forma tariff attached as Appendix B hereto ("Appendix B rates") to take effect on October 1, 1996 pursuant to 18 C.F.R. Section 341.14 (1995), in place of the rates set forth in Lakehead FERC tariff nos. 18 and 19. The Appendix B rates constitute a rate decrease of approximately 6 percent across-the-board, and are intended to bring Lakehead's forward-looking rates into compliance with Opinion Nos. 397 and 397-A on a reasonable, compromise basis. If this Settlement Agreement has not received FERC approval prior to October 1, 1996, it is the intent of the Settling Parties that the Appendix B rates shall go into effect subject to investigation and refund until such time as the Settlement Agreement is acted upon by the FERC. If and when the FERC approves the Settlement Agreement, the refund condition on the Appendix B rates will be removed and any proceeding instituted with respect to those rates will be terminated. If the Settlement Agreement is disapproved, disposition of the Appendix B rates will be subject to further order of the Commission. The Appendix B rates shall be subject to indexing under 18 C.F.R. Section 342.3 (1995) commencing on July 1, 1997. If and when the Settlement Agreement is approved by the FERC, CAPP/ADOE agree that they will not thereafter challenge the Appendix B rates, including any increases or decreases to those rates permitted under the Commission's indexing regulations, 18 C.F.R. Section 342.3 (1995), in any judicial or administrative forum during the Term of this Agreement as defined in paragraph 12 below. If the Settlement Agreement is not approved without

modification, the Settling Parties shall retain all their rights with respect to the Lakehead Proceedings.

7. The Settling Parties agree that Lakehead shall fulfill its obligation to provide a remedy for the past rates found not to be just and reasonable in Opinion Nos. 397 and 397-A by providing total monetary relief of $120 million measured as of October 1, 1996. This relief shall be provided in two components: (1) a Refund Component of $37,144,124 for Phase I of Docket Nos. IS92-27-000, IS93-3-000 and IS93-33-000, which is addressed in paragraph 8 below, and (2) a Surcredit Component of $82,855,876 for Phase II and subsequent rate periods, which is addressed in paragraph 9 below.

8. No later than 30 days after the Effective Date defined in paragraph 5 above, Lakehead shall pay the sum of $37,144,124 (measured as of October 1, 1996) to its shippers of record under FERC tariff no. 2, which shall fulfill Lakehead's refund obligation in Phase I of FERC Docket Nos. IS92-27-000, IS93-4-000 and IS93-33-000. Interest shall accrue on the Phase I refund amount of $37,144,124 from October 1, 1996 through the date of payment of the refunds provided for in this paragraph at the 90-day Treasury bill rate measured for each quarter at the close of business on the last day of the previous quarter. The amount to be refunded for the period May 3, 1992 through December 31, 1992 is based upon an agreed-upon test period cost-of-service of $214,830,000, and the amount to be refunded for the period January 1, 1993 through July 5, 1993 is based upon an agreed-upon test period cost-of-service of $219,090,000. The amount to be refunded to each shipper shall be calculated by comparing the rate actually paid to the rate applicable to each service at the agreed-upon cost-of-service level using Lakehead's existing rate design and shall reflect the Commission's ruling in Opinion Nos. 397 and 397-A regarding rate floors. Within 30 days after the date of payment of the Refund Component, Lakehead shall file a refund report with the Commission showing the amounts

refunded pursuant to this provision. In the event the FERC's initial approval of the Settlement Agreement is overturned or modified through further administrative or judicial proceedings after the date of payment of the refunds as provided hereunder, such that the Lakehead Proceedings are reinstituted, Lakehead shall be entitled to credit any refunds paid under this Settlement Agreement against any refund obligation ultimately determined to apply in that litigation.

9. Within 20 days after the Effective Date as defined in paragraph 5 above, Lakehead shall file a tariff provision in the form set forth in Appendix C hereto establishing a Surcredit over a period of approximately three years. The Surcredit shall consist of a 10 percent across-the-board reduction in Lakehead's interstate tariff rates that shall remain in effect until the purpose of the Surcredit is accomplished. The purpose of the Surcredit shall be to reduce Lakehead's tariff revenues by the sum of $82,855,876 plus interest on the outstanding balance for the period from October 1, 1996 through the termination of the Surcredit (the total amount, including interest, being referred to as the Surcredit Amount). Once the Surcredit Amount has been exhausted, the Surcredit tariff provision may be cancelled by Lakehead pursuant to paragraph 10 below. The interest component of the Surcredit Amount shall be calculated monthly on the outstanding balance of the Surcredit Amount using the 90-day Treasury bill rate measured for each quarter at the close of business on the last day of the previous quarter.

10. Lakehead shall keep account of the cumulative amount of tariff reductions pursuant to the Surcredit provided under paragraph 9 above. When the total amount of tariff reductions received is expected to equal the Surcredit Amount (including interest) within 30 days, Lakehead shall file a cancellation of the Surcredit tariff provision, together with a report showing the total amount accumulated, or expected to be accumulated within 30 days, under the Surcredit. The cancellation of the Surcredit tariff provision shall be effective upon 30 days' notice. Lakehead shall have no further obligation to make the Surcredit available after it has

provided Surcredit tariff reductions equal to $82,855,876 as of October 1, 1996, plus interest calculated as set forth in paragraph 9. CAPP/ADOE agree that, if and when the Commission approves this Settlement Agreement, they will not challenge the Surcredit or the cancellation of the Surcredit, provided such cancellation conforms to the terms of this Settlement Agreement, in any administrative or judicial forum.

11. In the case of the joint tariff between Lakehead and Portal Pipe Line Company ("Portal") filed to be effective September 1, 1996 (FERC Tariff No. 94), which sets forth joint rates for transportation via Portal and Lakehead from the Canada-U.S. Border to various Lakehead destinations, Lakehead will, within 20 days after the Effective Date as defined in paragraph 5 above, file a tariff reduction applicable to FERC Tariff No. 94. That reduction will lower each joint rate by an amount at least equal to the difference between (a) Lakehead's current local tariff rate for Lakehead's portion of the joint movement and (b) the Appendix B local rate as reduced by the Surcredit. For the duration of the Surcredit, Lakehead's share of the Portal-Lakehead joint rates will be no greater than 90 percent of the Appendix B local rates for corresponding local movements, as adjusted pursuant to paragraphs 6 and 13. The Settling Parties accordingly agree that Lakehead shall be entitled to credit 10 percent of the Appendix B local rate otherwise applicable to each such movement against its Surcredit obligation.

In the event Lakehead enters into additional joint rates in the future, the Settling Parties agree to negotiate regarding the extent to which (if at all) any portion of the reduction in Lakehead's share of such joint rates below the corresponding Appendix B rates should be credited against Lakehead's Surcredit obligation.

12. The Term of this Settlement Agreement shall be for five years commencing on the Effective Date.

13. During the Term of this Settlement Agreement, Lakehead may, at its discretion, seek to file tariffs containing rates in excess of those set forth in Appendix B as adjusted pursuant to the Commission's index methodology. CAPP and the ADOE are free to pursue challenges to any such rate filings in excess of the indexed Appendix B rates, except as follows:

A. CAPP and the ADOE agree not to challenge Lakehead's filing of an incremental surcharge over and above the indexed Appendix B rates to recover the costs of a significant enhancement to the Lakehead system agreed to by CAPP, including the System Expansion Program II ("SEP II") project anticipated in 1998, provided that the incremental surcharge conforms to the terms set forth in Appendix D hereto, which were previously agreed to between CAPP, Lakehead and the Canadian pipeline to which Lakehead connects, Interprovincial Pipe Line Inc. ("IPL"), and provided further that, in calculating the surcharge, Lakehead shall utilize a tax allowance that is equal to 30 percent of the tax allowance that would apply if Lakehead were a corporation; and

B. CAPP and the ADOE agree not to challenge Lakehead's filing of an incremental surcharge over and above the indexed Appendix B rates, solely to recover non-routine cost increases limited specifically to the events set forth in sections 7.1(d) and 7.1(e) of the Incentive Toll Settlement Agreement Between IPL and CAPP dated February 16, 1995, which are attached as Appendix E hereto, to the extent events of the type described involve Lakehead.

14. Lakehead agrees that it will file with the FERC, as soon as possible but in no event later than October 1, 1996, a depreciation study incorporating a new truncation date of 2020 A.D. and corresponding revised depreciation rates for Lakehead's assets. CAPP and the ADOE agree that they will support Commission approval of Lakehead's revised depreciation

rates. CAPP and the ADOE further agree that the depreciation rates to be used in calculating the incremental surcharge for the SEP II expansion costs anticipated to be incurred in 1998 shall be determined using the same curves and economic useful lives as in the depreciation study to be filed under this paragraph.

15. If the FERC rejects this Settlement Agreement in its entirety, or if FERC or a reviewing court makes approval of this Settlement Agreement contingent upon modification of any provision of this Agreement, this Settlement Agreement shall immediately terminate and shall be deemed withdrawn as an offer of settlement or for any other purpose, and the Settling Parties shall be free to pursue all appeals or other courses of action necessary to protect their rights.

16. This Settlement Agreement is intended to supersede the Settlement Agreement filed with the Commission by Lakehead and CAPP and the ADOE on March 23, 1995 in Phase II of the Lakehead Proceedings ("March 23 Settlement"). If and when the present Settlement Agreement is approved by the FERC without modification, the March 23 Settlement shall be deemed withdrawn and shall no longer have any force or effect.

17. Unless and until this Settlement Agreement is approved by the FERC without modification in an order that is final and no longer subject to judicial review, it shall be privileged and shall not be admissible in evidence or in any way described or discussed in any proceeding, other than as necessary to secure approval by the FERC or to permit judicial review of any order of FERC approving, disapproving or modifying the Settlement Agreement. Approval of this Settlement Agreement by the FERC does not constitute approval of, or precedent regarding, any principle or issue settled herein.

18. The language of this Settlement Agreement shall, in all cases, be construed according to its fair meaning and not strictly for or against any of the Settling Parties.

This Settlement Agreement may be modified, amended or supplemented only by a written instrument executed by the Settling Parties. No obligation under this Settlement Agreement shall be for the benefit of or be enforceable by any third party.

19. This Settlement Agreement shall be governed by, and construed in accordance with, federal law to the extent applicable and otherwise by the laws of the State of Minnesota. It is the intent of the Settling Parties that the terms of this Settlement Agreement, once approved by the FERC without modification, shall be enforceable by the FERC.

20. All notices under this Settlement Agreement shall be effective when deposited in the mails, postage prepaid, certified mail, return receipt requested, or when dispatched by Federal Express or by telefacsimile, addressed to the respective Settling Parties at the addresses set forth below:

R. C. Sandahl
Vice President, Operations
Lakehead Pipe Line Company, Inc.
21 West Superior Street
Duluth, MN 55802--2067

Mark Pinney
Manager, Markets & Transportation
Canadian Association of Petroleum Producers

2100, 350 Seventh Avenue, S.W.
Calgary, Alberta T2P 3N9
Canada

Paul Kahler
Senior Regulatory Analyst
Markets and Regulatory Policy
The Alberta Department of Energy
1900, 250 Sixth Avenue, S.W.
Calgary, Alberta T2P 3E7
Canada

A Settling Party may, at any time, substitute in writing a different person or address for the one shown in this paragraph.

21. This Settlement Agreement may be executed in separate and identical counterparts.

WHEREFORE, the foregoing Settlement Agreement is executed on behalf of the Settling Parties by their duly authorized representatives on the date indicated below.

/s/ L. A. Alexander	/s/ S. Reed
Lee A. Alexander DICKSTEIN SHAPIRO MORIN & OSHINSKY LLP 2101 L Street, NW Washington, D.C. 20036-1526	Steven Reed STEPTOE & JOHNSON LLP 1330 Connecticut Avenue, NW Washington, DC 20036-1795
Counsel for Canadian Association of Petroleum Producers and the Alberta Department of Energy	Counsel for Lakehead Pipe Line Company, Limited Partnership

Dated: August 28, 1996

APPENDIX A

Below is a list of the FERC Docket Numbers associated with Lakehead's rate proceedings.

IS92-27-000
IS93-4-000
IS93-33-000
IS-94-20-000

IS94-24-000
IS95-5-000
IS95-26-000
IS95-27-000
IS96-15-000

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APPENDIX B

Attached is a proforma FERC No. 20 tariff filing reflecting the rates agreed to in the Settlement Agreement.

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FERC NO. 20
CANCELS FERC NO. 18 & 19

DRAFT

LAKEHEAD PIPE LINE COMPANY, LIMITED PARTNERSHIP

III. LOCAL TARIFF APPLYING ON CRUDE PETROLEUM AND NATURAL GAS LIQUIDS

FROM

THE INTERNATIONAL BOUNDARIES NEAR NECHE, NORTH DAKOTA, AND

GRAND ISLAND, NEW YORK, AND POINTS IN THE STATES

OF ILLINOIS, INDIANA, MICHIGAN, AND MINNESOTA

TO

POINTS IN THE STATES OF ILLINOIS, INDIANA, MICHIGAN, MINNESOTA,

NEW YORK, WISCONSIN AND

THE INTERNATIONAL BOUNDARY NEAR MARYSVILLE, MICHIGAN

THE RATES LISTED IN THIS TARIFF ARE FOR THE TRANSPORTATION OF CRUDE PETROLEUM AND NATURAL GAS LIQUIDS BY THE CARRIER. THE TRANSPORTATION RATES LISTED IN THIS TARIFF ARE SUBJECT TO THE RULES AND REGULATIONS PUBLISHED IN THE CARRIER'S TARIFFS FERC NOS. 16 AND 17, SUPPLEMENTS THERETO AND REISSUES THEREOF.

THE PROVISIONS PUBLISHED HEREIN WILL, IF EFFECTIVE, NOT RESULT IN AN EFFECT ON THE QUALITY OF THE HUMAN ENVIRONMENT.

ISSUED EFFECTIVE

ISSUED BY
P.D. DANIEL
PRESIDENT AND CHIEF OPERATING OFFICER
LAKEHEAD PIPE LINE COMPANY, INC.
GENERAL PARTNER

21 WEST SUPERIOR STREET
DULUTH, MINNESOTA 55802-2067
TEL. (218) 725-0100

DRAFT

The rates listed in this tariff are payable in United States currency and are applicable on the United States movement of Crude Petroleum and Natural Gas Liquids tendered to the Carrier at established receiving points in the United States for delivery to established delivery points in the United States.

TRANSPORTATION RATES

Commodities shall be classified on the basis of the density and viscosity of such commodities at the earlier time of receipt by the Carrier or Interprovincial Pipe Line Inc. and assessed a transportation rate as listed in the transportation rate tables below. Density shall be based on 15 degrees Celsius. Viscosity shall be based on the lower of the temperature of the commodity at the time of receipt or the Carrier's reference line temperature at the time of receipt. Where the density of a commodity falls within the density range of one commodity classification and the viscosity of the commodity falls within the viscosity range of another commodity classification, then the commodity shall be deemed to be in the commodity classification with the higher transportation rate.

NGL - A commodity having a maximum absolute vapor pressure of 1 100 kilopascals at 37.8 degrees Celsius and a density of up to but not including 600 kilograms per cubic metre (kg/m3) and a viscosity of up to but not including 0.4 square millimetres per second (mm2/s) will be classified as NATURAL GAS LIQUIDS.

LIGHT CRUDE PETROLEUM - A commodity having a density from 600 kg/m3 up to but not including 876 kg/m3 and a viscosity from 0.4 mm2/s up to but not including 20 mm2/s will be classified as LIGHT CRUDE PETROLEUM.

MEDIUM CRUDE PETROLEUM - A commodity having a density from 876 kg/m3 up to but not including 904 kg/m3 and a viscosity from 20 mm2/s up to but not including 100 mm2/s will be classified as MEDIUM CRUDE PETROLEUM.

HEAVY CRUDE PETROLEUM - A commodity having a density from 904 kg/m3 to 927 kg/m3 inclusive and a viscosity from 100 to 250 mm2/s will be classified as HEAVY CRUDE PETROLEUM.

NATURAL GAS LIQUIDS

TABLE OF TRANSPORTATION RATES FOR NGL IN DOLLARS PER CUBIC METRE

TO	FROM
	International Boundary near Neche, North Dakota
Superior, Wisconsin (c)	1.491 [D]
Rapid River, Michigan (i)	2.457 [U]
Marysville, Michigan (c), (g)	3.576 [D]
International Boundary near Marysville, Michigan(g)	3.410 [D]

ALL RATES ON THIS PAGE ARE DECREASES.

LIGHT CRUDE PETROLEUM

TABLE OF TRANSPORTATION RATES FOR LIGHT CRUDE PETROLEUM IN DOLLARS PER CUBIC METRE

FROM

TO	International Boundary near Neche, North Dakota	Clearbrook, Minnesota (a), (b)	Mokena, Illinois (b)	Griffith, Indiana (b), (h)	Stockbridge, Michigan (b)	Lewiston, Michigan (b), (f)	International Boundary near Grand Island, New York
Clearbrook, Minnesota (c)	0.908	-	-	-	-	-	-
Superior, Wisconsin (c), (d)	1.704	1.545	-	-	-	-	-
Lockport & Mokena, Illinois (c)	3.348	3.188	-	-	-	-	-
Griffith, Indiana (c), (e)	3.348	3.188	0.757	0.656	-	-	-
Bay City, Michigan (c)	3.620	3.461	-	-	-	.967	-
Stockbridge, Michigan (c)	3.986	3.825	1.346	1.346	-	-	-
Marysville, Michigan (c)	3.986	3.825	1.707	1.707	1.018	1.302	-
International Boundary near Marysville, Michigan	3.820	3.660	1.553	1.553	0.863	1.147	-
West Seneca, New York (c)	4.078	3.919	1.811	1.811	1.122	1.400	0.498

MEDIUM CRUDE PETROLEUM

TABLE OF TRANSPORTATION RATES FOR MEDIUM CRUDE PETROLEUM IN DOLLARS PER CUBIC METRE

FROM

TO	International Boundary near Neche, North Dakota	Clearbrook, Minnesota (a), (b)	Mokena, Illinois (b)	Griffith, Indiana (b), (h)	Stockbridge, Michigan (b)	Lewiston, Michigan (b), (f)	International Boundary near Grand Island, New York
Clearbrook, Minnesota (c)	948	-	-	-	-	-	-
Superior, Wisconsin (c), (d)	1.801	1.601	-	-	-	-	-
Lockport & Mokena, Illinois (c)	3.583	3.383	-	-	-	-	-
Griffith, Indiana (c), (e)	3.583	3.383	0.765	0.656	-	-	-
Bay City, Michigan (c)	3.878	3.678	-	-	-	. 993	-
Stockbridge, Michigan (c)	4.272	4.071	1.401	1.401	-	-	-
Marysville, Michigan (c)	4.272	4.071	1.791	1.791	1.047	1.354	-
International Boundary near Marysville, Michigan	4.107	3.906	1.637	1.637	0.894	1.199	-
West Seneca, New York (c)	4.372	4.172	1.904	1.904	1.159	1.460	0.505

ALL RATES ON THIS PAGE ARE DECREASES.

HEAVY CRUDE PETROLEUM

TABLE OF TRANSPORTATION RATES FOR HEAVY CRUDE PETROLEUM IN DOLLARS PER CUBIC METRE

FROM

TO	International Boundary near Neche, North Dakota	Clearbrook, Minnesota (a), (b)	Mokena, Illinois (b)	Griffith, Indiana (b), (h)	Stockbridge, Michigan (b)	Lewiston, Michigan (b), (f)	International Boundary near Grand Island, New York
Clearbrook, Minnesota (c)	1.009	-	-	-	-	-	-
Superior, Wisconsin (c), (d)	1.945	1.686	-	-	-	-	-
Lockport & Mokena, Illinois (c)	3.936	3.677	-	-	-	-	-
Griffith, Indiana (c), (e)	3.936	3.677	0.778	0.656	-	-	-
Bay City, Michigan (c)	4.263	4.004	-	-	-	1.030	-
Stockbridge, Michigan (c)	4.702	4.441	1.484	1.484	-	-	-
Marysville, Michigan (c)	4.702	4.441	1.917	1.917	1.090	1.431	-
International Boundary near Marysville, Michigan	4.537	4.275	1.765	1.765	0.938	1.278	-
West Seneca, New York (c)	4.813	4.553	2.042	2.042	1.215	1.550	0.516

(a) RECEIPT TANKAGE - The transportation rates from this receiving point include a receipt tankage charge of $0.091 per cubic metre.

(b) RECEIPT TERMINALLING - The transportation rates from this receiving point include a receipt terminalling charge of $0.251 per cubic metre.

(c) DELIVERY TERMINALLING - The transportation rates to this delivery point include a delivery terminalling charge of $0.165 per cubic metre.

(d) DELIVERY TANKAGE - The transportation rates to this delivery point include a delivery tankage charge of $0.091 per cubic metre.

(e) In addition to the transportation rate shown, a delivery tankage charge of $0.091 per cubic metre will be assessed if the Carrier's delivery tankage at Griffith, Indiana is used by the Shipper.

(f) BREAK-OUT TANKAGE CREDIT - The transportation rates from this receiving point include a break-out tankage credit of 1.992 cents per hundred cubic metre miles for light crude petroleum, 2.151 cents per hundred cubic metre miles for medium crude petroleum, and 2.390 cents per hundred cubic metre miles for heavy crude petroleum.

(g) BREAK-OUT TANKAGE CREDIT - The transportation rate to this delivery point includes a break-out tankage credit of 0.541 cents per hundred cubic metre miles.

(h) In addition to the transportation rate shown, a receipt tankage charge of $0.091 per cubic metre will be assessed if the Carrier's receipt tankage at Griffith, Indiana is used by the Shipper.

(i) The toll includes a delivery terminalling charge of $0.182 per cubic metre and a break-out tankage credit of 0.594 cents per hundred cubic metre miles.

[D] - Denotes decrease in rate.

[U] - Denotes unchanged rate.

APPENDIX C

Attached is a proforma supplement to FERC No. 20 reflecting the 10% surcredit.

SUPPLEMENT

SUPPLEMENT NO. 1
TO FERC NO. 20

DRAFT
LAKEHEAD PIPE LINE COMPANY, LIMITED PARTNERSHIP

LOCAL TARIFF APPLYING ON CRUDE PETROLEUM AND NATURAL GAS LIQUIDS

From

THE INTERNATIONAL BOUNDARIES NEAR NECHE, NORTH DAKOTA, AND

GRAND ISLAND, NEW YORK, AND POINTS IN THE STATES

OF ILLINOIS, INDIANA, MICHIGAN, AND MINNESOTA

to

POINTS IN THE STATES OF ILLINOIS, INDIANA, MICHIGAN, MINNESOTA,

NEW YORK, WISCONSIN AND

THE INTERNATIONAL BOUNDARY NEAR MARYSVILLE, MICHIGAN

ISSUED UNDER AUTHORITY OF 18 CFR 341.4(A). THIS SUPPLEMENT IS ISSUED PURSUANT TO F.E.R.C. ORDER NO. APPROVING THE SETTLEMENT AGREEMENT BETWEEN LAKEHEAD PIPE LINE COMPANY, LIMITED PARTNERSHIP, ON THE ONE HAND, AND THE CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS AND THE ALBERTA DEPARTMENT OF ENERGY ON THE OTHER. AS PROVIDED IN F.E.R.C. ORDER NO. , ALL RATES IN FERC NO. 20, SUPPLEMENTS THERETO AND REISSUES THEREOF ARE SUBJECT TO A 10% SURCREDIT REDUCTION UNTIL SUCH TIME AS THE TOTAL SURCREDIT AMOUNT PLUS INTEREST IS EXHAUSTED, AT WHICH TIME THE SURCREDIT WILL BE SUBJECT TO CANCELLATION AS PROVIDED IN THE SETTLEMENT AGREEMENT.

THIS SUPPLEMENT IS ISSUED ON DAYS NOTICE UNDER AUTHORITY OF 18 CFR 341.14. THIS PUBLICATION IS CONDITIONALLY ACCEPTED SUBJECT TO REFUND PENDING A 30 DAY REVIEW PERIOD.

THE PROVISIONS PUBLISHED HEREIN WILL, IF EFFECTIVE, NOT RESULT IN AN EFFECT ON THE QUALITY OF THE HUMAN ENVIRONMENT.

ISSUED EFFECTIVE

ISSUED BY
P.D. DANIEL
PRESIDENT AND CHIEF OPERATING OFFICER
LAKEHEAD PIPE LINE COMPANY, INC.
GENERAL PARTNER

21 WEST SUPERIOR STREET
DULUTH, MINNESOTA 55802-2067
TEL. (218) 725-0100

Schedule of Calculating the Remaining Refund Surcredit
to be Applied to Transportation Revenue invoices in
Accordance with the Negotiated Settlement with CAPP

	Assuming Interest Compounded Monthly
Negotiated Settlement Contingent Rate Refund and Interest Amount as of October 1,1996	$ 120,000,000
Less the Payment of Phase I of the Contingent Rate Refund and Interest Amount on October 1, 1996	($37,144,124)
Remaining Balance of the Contingent Rate Refund and Interest to be Repaid by a Surcredit Over the Next Three Years	$ 82,855,876
Plus Estimated Interest Calculated on the Remaining Balances of the Rate Refund over the 3 Year Pay Back Period (See Attached Schedule)	$ 7,702,581
Total Amount of Rate Refund and Estimated Interest to be Paid Over the Next Three Years	$ 90,558,457
Divided by the Long Range Plan Planned Case Total Transportation Revenue Over the Next Three Years From January 1, 1997 Through December 31, 1999 (See Attached Schedule)	$ 899,780,028
Surcredit as a Percentage of Invoiced Revenue to be Applied to Each Transportation Revenue Invoice	10%

N:\Fercdec\Repayment Summary of Refund over next three years monthly compounding

Lakehead Pipe Line Company, Limited Partnership
Example of Calculation of Interest on Refund Balance Going Forward
(Compounded Monthly)

Included as Part of the Settlement Agreement

DESCRIPTION	BEGINNING BALANCE (a)	90 Day T-BILL RATE (b)	Interest Accrued on Remaining BALANCE (c)	REFUND PAYMENT (d)	ENDING BALANCE (e)	Longe Range Plan PERIOD (f)	Longe Range Plan Estimated REVENUE (g)
10/1/96	120,000,000			(37,144,124)	82,855,876	Jan - 97	24,994
12/31/96	82,855,876	5%	1,035,698		83,891,574	Feb - 97	24,994
1/31/97	83,891,574	5%	349,548	(2,499,400)	81,741,722	Mar - 97	24,994
2/28/97	81,741,722	5%	340,591	(2,499,400)	79,582,913	Apr - 97	24,994
3/31/97	79,582,913	5%	331,595	(2,499,400)	77,415,108	May - 97	24,994
4/30/97	77,415,108	5%	322,563	(2,499,400)	75,238,271	Jun - 97	24,994
5/31/97	75,238,271	5%	313,493	(2,499,400)	73,052,364	Jul - 97	24,994

6/30/97	73,052,364	5%	304,385	(2,499.400)	70,857,349	Aug - 97	24,994
7/31/97	70,857,349	5%	295,239	(2,499,400)	68,653,188	Sep - 97	24,994
8/31/97	68,653,188	5%	286,055	(2,499,400)	66,439,843	Oct - 97	24,994
9/30/97	66,439,843	5%	276,833	(2,499,400)	64,217,277	Nov - 97	24,994
10/31/97	64,217,277	5%	267,572	(2,499,400)	61,985,449	Dec - 97	24,994
11/30/97	61,985,449	5%	258,273	(2,499,400)	59,744,322	Jan - 98	24,994
12/31/97	59,744,322	5%	248,935	(2,499,400)	57,493,857	Feb - 98	24,994
1/31/98	57,493,857	5%	239,558	(2,499,400)	55,234,015	Mar - 98	24,994
2/28/98	55,234,015	5%	230,142	(2,499,400)	52,964,757	Apr - 98	24,994
3/31/98	52,964,757	5%	220,686	(2,499,400)	50,686,043	May - 98	24,994
4/30/98	50,686,043	5%	211,192	(2,499,400)	48,397,835	Jun - 98	24,994
5/31/98	48,397,835	5%	201,658	(2,499,400)	46,100,093	Jul - 98	24,994

Lakehead Pipe Line Company, Limited Partnership
Example of Calculation of Interest on Refund Balance Going Forward
(Compounded Monthly)

Included as Part of the Settlement Agreement

						Longe Range Plan	
DESCRIPTION	BEGINNING BALANCE (a)	90 Day T-BILL RATE (b)	Interest Accrued on Remaining BALANCE (c)	REFUND PAYMENT (d)	ENDING BALANCE (e)	PERIOD (f)	Estimated REVENUE (g)
6/30/98	46,100,093	5%	192,084	(2,499,400)	43,792,777	Aug - 98	24,994
7/31/98	43,792,777	5%	182,470	(2,499,400)	41,475,847	Sep - 98	24,994
8/31/98	41,475,847	5%	172,816	(2,499,400)	39,149,263	Oct - 98	24,994
9/30/98	39,149,263	5%	163,122	(2,499,400)	36,812,985	Nov - 98	24,994
10/31/98	36,812,985	5%	153,387	(2,499,400)	34,466,972	Dec - 98	24,994
11/30/98	34,466,972	5%	143,612	(2,499,400)	32,111,184	Jan - 99	24,994
12/31/98	32,111,184	5%	133,797	(2,499,400)	29,745,581	Feb - 99	24,994
1/31/99	29,745,581	5%	123,940	(2,499,400)	27,370,121	Mar - 99	24,994
2/28/99	27,370,121	5%	114,042	(2,499,400)	24,984,763	Apr - 99	24,994
3/31/99	24,984,763	5%	104,103	(2,499,400)	22,589,466	May - 99	24,994
4/30/99	22,589,466	5%	94,123	(2,499,400)	20,184,189	Jun - 99	24,994
5/31/99	20,184,189	5%	84,101	(2,499,400)	17,768,890	Jul - 99	24,994
6/30/99	17,768,890	5%	74,037	(2,499,400)	15,343,528	Aug - 99	24,994
7/31/99	15,343,528	5%	63,931	(2,499,400)	12,908,059	Sep - 99	24,994
8/31/99	12,908,059	5%	53,784	(2,499,400)	10,462,443	Oct - 99	24,994
9/30/99	10,462,443	5%	43,594	(2,499,400)	8,006,637	Nov - 99	24,994
10/31/99	8,006,637	5%	33,361	(2,499,400)	5,540,598	Dec - 99	24,994

Lakehead Pipe Line Company, Limited Partnership
Example of Calculation of Interest on Refund Balance Going Forward
(Compounded Monthly)

Included as Part of the Settlement Agreement

						Longe Range Plan	
DESCRIPTION	BEGINNING BALANCE (a)	90 Day T-BILL RATE (b)	Interest Accrued on Remaining BALANCE (c)	REFUND PAYMENT (d)	ENDING BALANCE (e)	PERIOD (f)	Estimated REVENUE (g)
11/30/99	5,540,598	5%	23,086	(2,499,400)	3,064,284		
12/31/99	3,064,284	5%	12,768	(2,499,400)	577,652		
1/31/00	577,652	5%	2,407	(580,059)	(0)		
			7,702,581				
			===============				

(a) = Previous Ending Balance Carried Forward
(b) = 90 Day T-Bill Rater per Settlement Agreement
(c) = Beginning Balance x (b) x 1/12

(d) = Monthly Estimated Revenue x 10%
(e) = Beginning Balance + Interest Accrued - Refund Payments
(f) = Long Range Plan Estimated Revenue

N:\Rates\Refund Interest Calculation Going Forward 2

APPENDIX D

Attached is a copy of the terms and conditions of the Risk Sharing Agreement which were previously agreed upon by CAPP, Lakehead and IPL.

IPL/LPL and CAPP
SEP Il
Risk Sharing Agreement

- Agreement relates to both IPL and Lakehead in respect to the System Expansion Program Phase II facilities and is subject to National Energy Board and Federal Energy Regulatory Commission approvals.
- At 75% utilization of facilities or 90,000 b/d, the return on deemed expansion equity will be the annual multi-pipeline rate as determined by the National Energy Board.
- Up to 50% facilities utilization or 60,000 b/d, the return on deemed expansion equity capital would be the multi-pipeline rate less 3.00%, subject to a minimum rate of return of 7.50% in years 1 through 10 and 8.50% in years 11 through 15.
- Rate of return on deemed expansion equity increases with facilities utilization on a straight line basis, to multi-pipeline rate plus 3.00% at 100% utilization, subject to a maximum rate of return of 15% during the term of the agreement
- Drag reducing agent costs flow through as a surcharge if appropriate.
- All costs including operating, interest and depreciation costs flow through to tariffs.
- Volume "at risk" would have incremental capacity expansions "stacked" on top.
- Total tolls will be charged in a manner and amount consistent with existing toll design for Lakehead and IPL. Point to point tolls will reflect a volume-distance allocation of costs. Distribution of revenue and costs between IPL and Lakehead will be at IPI/LPL's discretion, subject to regulatory approval.
- The agreement is subject to approval of IPL and LPL Boards of Directors.
- The term of the agreement is for 15 years commencing on the date of completion.
- This agreement is without prejudice to any other discussions or negotiations, and does not necessarily reflect the views of any of the parties as to appropriate costs of capital in either Canada or the United States.

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APPENDIX E

Attached is the applicable section of the Incentive Toll Settlement Agreement dated February 16, 1995, between Interprovincial Pipe Line Company and the Canadian Association of Petroleum Producers.

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INCENTIVE TOLL PRINCIPLES OF SETTLEMENT

Between

Interprovincial Pipe Line Inc.

And

Canadian Association of Petroleum Producers

7.0 NON-ROUTINE ADJUSTMENTS TO ANNUAL REVENUE REQUIREMENTS

7.1 Circumstances may arise which necessitate adjustments to the annual Revenue Requirement and resulting tolls. Evens resulting in Non-Routine Adjustments shall be:

(d) Changes in costs resulting from legislation, regulations, orders or directions by any government authority which result in changes to safety or environmental requirements, practices, or procedures for IPL.

(e) The cost of distinct and new programs necessary to address new or unanticipated failure mechanisms and significant increases in the rates of cracking and/or corrosion in the pipeline or other existing failure mechanisms experienced by IPL.

55

Exhibit No. 1 - Attachment B

TERRACE TOLL AGREEMENT
STATEMENT OF PRINCIPLES

Enbridge Pipelines Inc. (Enbridge) and the Canadian Association of Petroleum Producers (CAPP) have agreed that they wish to implement a negotiated toll structure for the Terrace expansion project.

The Statement of Principles which follows sets forth the principles which the parties intend to govern the establishment of tolls for all phases of the Terrace expansion.

Enbridge and CAPP have entered into the negotiated settlement in respect of

Terrace with an appreciation that the Incentive Toll Settlement (ITS) entered into and approved in 1995 is the subject of renegotiations in respect of extending the term of the ITS beyond 1999. CAPP and Enbridge have entered into the Terrace toll agreement on the understanding that the ITS will be renegotiated consistent with the ITS, and will exclude the matters set out in Article 8 of the ITS.

The following Schedules are appended to and form a part of these Principles of Settlement:

- "A" Description of Terrace Facilities
- "B" Adjustments to the 5 Cents Per Barrel Increment
- "C" Adjustments for LPL Phase III Trigger
- "D" Fluid Properties Of Liquid Hydrocarbons in Enbridge System: Terrace Phase I
- "E" Forecast Deliveries at Base Capacity (259,100 m3/day)
- "F" Forecast Property Taxes
- "G" Arbitration Process
- "H" Power Calculation
- "I" Forecast Operating Costs

1 Negotiated tolls for the Enbridge/LPL Terrace program will recover costs associated with all facilities associated with all phases of Terrace Expansion Program. The Terrace Expansion Program is expected to be a phased capacity addition program intended to add capacity in the years 1999 and following.

2 The Terrace facilities, the expected capacity increases associated with the facilities, and the in-service timing are appended as Schedule A. Enbridge and LPL commit to deliver the additional annual capacity on or before the dates set out in these Principles. The dates upon which the facilities are expected to come into service are:

   i) January 15, 1999 first in-service of Phase I facilities, providing 15,100 m3/d of incremental capacity from a base system capacity (which is defined as including SEP II and SEP III 350 Centistoke facilities) of 259,100 m3/d. The incremental capacity to be provided includes incremental heavy crude oil capacity on the 24 inch line.

   ii) September 30, 1999 second tranche of Phase I capacity in-service, totaling 26,500 m3/d of incremental from the base.

   iii) Hardisty to Kerrobert extension in service September 30,2000 [Phase II] providing 33,400 m3/d of incremental capacity from the base.

   iv) Clearbrook to Superior extension and associated pumping in service September 30, 2001 [Phase III] providing 56,900 m3/d of incremental capacity from the base.

   v) Mokena to Griffith extension, Line 14 stations in service, Line 14 heater in service between 2002 and 2007 [Future Terrace Phase(s)].

   Under the Terrace design, it is anticipated that all Enbridge Western Canadian pipelines will operate with an annual capacity at ninety percent of design capacity. Throughput losses due to regular internal inspections are reflected in the ten percent operating margin. Historically, the reduction in throughput capacity in months of internal inspections has been 10 percent on a system basis and 20 percent for heavy crude. Additional throughput losses have been experienced in the 1990-1996 period due to increased internal inspection activities. As a consequence of the Terrace design, the extraordinary throughput losses associated with increased internal inspections of approximately 1,600 m3/day are expected to be eliminated.

3. The in service commitments made by Enbridge/LPL are subject to CAPP providing written notice to Enbridge/LPL requesting construction in advance of the proposed in-service dates. The notice periods in respect of Phase II, III, and Future Terrace Phases described above are 18 months, 24 months and 36 months respectively; provided that notice given prior to March 31, 1999 in respect of Phase II may be deemed by Enbridge/LPL to have been given on March 31, 1999. Upon Enbridge giving notice to CAPP of a requirement by Enbridge/LPL to undertake material commitments in order to meet in-service

dates, CAPP will confirm its continuing service request prior to Enbridge/LPL being required to make those commitments.

4. For the purpose of determining "in service" the date which shall be used for Enbridge is the date upon which the last leave to open order is granted by the National Energy Board for the completion of pipeline facilities in Phase I (excluding pump stations) and for LPL, the availability of the facilities for service.

5. The delivery by Enbridge/LPL of the capacities associated with Phase I is subject to shipper approval for commingling crude in the 24 inch line to be transported in laminar flow.

6. Cost recovery on the Terrace facilities and related operating costs will be effected by application of a fixed toll increment applicable to all base (259,100 m3/d) and Terrace volume transported on the Enbridge/LPL systems.

7 The toll increment shall be five cents (Cdn) per barrel for light crude transportation from the Edmonton, Alberta receipt point to the Griffith, Indiana delivery point and shall be adjusted on a distance basis and for commodity credits or surcharges, consistent with Enbridge and LPL's then existing toll design.

8 The fixed toll increment charge will become effective upon the in-service of the first of the Terrace facilities, as "in service" is defined in paragraph 4, and shall terminate December 31, 2013.

9 The fixed toll increment shall be allocated between Enbridge and LPL as determined by Enbridge and LPL, provided that no less than one cent shall ever be allocated to either of the Enbridge or LPL systems. The exchange rate which shall apply to the LPL component of the fixed toll increment for all purposes in these Principles unless otherwise stated shall be the average exchange rate for the period commencing October 1, 1998 and ending December 31, 1998 as published in the Bank of Canada Review, Statistical Supplement.

10 The fixed toll increment shall be subject to a transportation revenue variance (TRV) in Enbridge which operates in the same fashion as the then-existing TRV in Enbridge. In the event there is no TRV mechanism in place for IPL, the fixed toll increment shall be subject to a TRV which operates in the same fashion as the TRV operated in Enbridge in 1997.

11 The base toll upon which the fixed increment will be added assumes the filling of the Enbridge/LPL systems at the quoted SEP II capacity of 259,100 m3/day, in accordance with the receipt and delivery schedule attached as Schedule E.

12 Enbridge and LPL will assume one hundred percent of operating cost variance risk, excluding changes to property tax expense which exceeds or falls below the forecast by twenty percent or more. The forecast operating costs are appended as Schedule I, and the audit rights in respect of those costs are set out in Paragraph 25. The forecast property taxes are attached as Schedule F. Property tax variances exceeding twenty percent from forecast shall result in an increase or decrease to the fixed toll increment by way of a surcharge or surcredit in accordance with Schedule B.

13 Enbridge and LPL will assume five percent of the capital cost variance risk and fifty percent of the capital cost variance risk thereafter on quoted target costs, as inflated, set out below. Capital cost variance for Terrace will be calculated on a cumulative basis and variances will be carried from one phase to the next. Target costs for the purpose of capital cost variance for facilities to be constructed after 1999 will be inflated from December 31, 1997 using the Canadian and US Gross Domestic Product deflators Published by Statistics Canada (Publication Number D15162) and the Bureau of Economic Analysis (U.S. Department of Commerce Publication Number P1D GDP) for facilities in Enbridge and LPL respectively.

ENBRIDGE Cdn $	LPL US$	
$575mm	$117mm	Jan 1999 Phase I
$35mm	$17mm	Sept. 1999 Phase I
$227mm	$178mm	Phases II & III 2000 and 2001
	$70mm	Other Phases 2002-2007

14 In the event CAPP does not provide notice to Enbridge on or before July 1, 2001 requesting Enbridge/LPL to proceed with both Phases II and III, costs for the Terrace project, including revenue variance between the application of the fixed toll increment and the cost of service model, will be calculated, and prospective tolls will be collected on a cost of service basis. In respect of LPL, the Terrace related costs will be collected via a cost of service surcharge layered onto the indexed base. Capital and operating cost sharing risk will revert to cost of service recovery.

15 In the event of a reversion to a cost of service model in accordance with the preceding paragraphs, and in the event the parties are unable to agree upon the appropriate cost of service parameters which shall be applied, the parties agree that the matters of capital structure, return on equity and tax allowance in respect of the LPL portion of the Terrace investment will be resolved through an arbitration process, the details of which are set forth in Schedule G. The cost of service parameters which will apply in respect of the Enbridge portion of the Terrace investment will be determined under then-existing Incentive Toll arrangement if agreed to by the parties or the then prevailing NEB methodology.

16 Until such time as both Phases II and III are placed into service, Phase I will be considered to be a Non Routine Adjustment (NRA) in both Enbridge and LPL as NRA is defined and treated in the 1995 Enbridge Incentive Toll Settlement. However, tolls will continued to be charged at the five cent negotiated rate subject to the TRV in Enbridge. Any revenue variance will be amortized and collected over the remaining term of the Principles (effective January 1, 2002) plus carrying costs based on the year average Bank of Canada rate plus 50 basis points if Phases II and III are not committed to by July 1, 2001.

17 a) Subject to the following paragraphs, Enbridge/LPL have committed to deliver the agreed capacity set out in Schedule A. If quoted forecast capacities are not achieved as scheduled, Enbridge/LPL will be subject

to a capacity shortfall penalty whereby for each 5,500 m3 per day capacity shortfall Enbridge/LPL will refund to shippers an amount equal to one cent per barrel (Cdn) via a toll reduction to be made in the following year. The penalty will be calculated over the period set out in subparagraph 17 e) and will be applied in fractions pro rata for capacity shortfalls which are proportions of 5,500 m3 per day.

b) In order to determine if the capacity shortfall penalty will be in effect, CAPP has the right to request in writing that all or a portion of the Terrace facilities be placed on test. Enbridge will provide written notification to CAPP within 60 days upon completion of each Phase. CAPP will have the right at any time within the following 9 months to request that Enbridge undertake a test. Enbridge will be required to conduct the test within 2 months of receipt of notice from CAPP that it wishes to have a test undertaken or other date as mutually agreed upon.

c) Subject to the force majeure exception in subparagraph 17 d), the test will consist of flowing tests of any of Lines 2, 3 and 4, tested individually over a 72 hour period. Over the 72 hour period the line(s) subject to test must achieve 105.5% of the annual capacity in aggregate, adjusted for seasonal temperatures. If the quoted forecast capacities cannot be achieved for the test period and it has been determined that the capacities are not achievable the penalty shall be levied on Enbridge/LPL.

d) If during a test period, an event of force majeure occurs and is disruptive to the test, for the duration of the event, the test results will not be relied upon to determine the success of the test. An event of force majeure shall be an event not within the control of Enbridge/LPL and which by the exercise of due diligence it is not able to avoid or overcome, limited to: acts of God, fires, flooding, earthquakes, or other extreme weather conditions.

e) In the event Enbridge/LPL does not complete the test successfully, the penalty shall be calculated commencing the first month after the scheduled completion of the relevant Phase of the Terrace program in which Enbridge/LPL announces apportionment and shall remain in effect until such time as the quoted capacity is made available, as evidenced by a successful re test. In the event the test is successful, but Enbridge/LPL have announced apportionment in the period between giving notice that the relevant Phase is completed and undertaking the test, the penalty shall be applied for those interim months in which apportionment was announced.

f) Enbridge and CAPP will work together to plan for the test such that an adequate supply is available, pump schedules determined and third party delivery facilities are arranged to allow the 72 hour test to occur. To the extent commodities are not made available to Enbridge/LPL in sufficient quantities to permit it to achieve the quoted capacities during the duration of the test, Enbridge/LPL shall not be liable to pay the capacity penalty. The parties may agree to reduce the duration of the test should sufficient commodity supply be unavailable for the full 72 hour test period.

g) Upon 60 days notice to CAPP Enbridge/LPL have the right to re-test any or all of the lines which were the subject of an unsuccessful test at any time after such test; provided that, if commodities are not made available to Enbridge/LPL in sufficient quantities to permit it to undertake the test, the penalty shall be suspended, pending the outcome of the re-test.

18 In the event the quoted capacities are not achieved in respect of Phase I as a result of the failure to obtain timely regulatory approvals from necessary agencies including the US Corps of Engineers, the capacity penalty shall not be levied for so long as the capacity shortfall exists due to that cause. Enbridge and LPL commit to use best efforts to obtain all necessary approvals in a timely fashion.

19 The fixed toll increment of five cents shall be adjusted upward or downward as the case may be, and the increment or decrement may be allocated as between Enbridge and LPL in the discretion of Enbridge and LPL in accordance with Schedule B for the following:

i) Agreed upon scope changes to the project;

ii) Agreed upon timing changes to the project where such timing change has a cost impact;

iii) Capital cost variance;

iv) Construction cost variance due to agreed upon circumstances which are extraordinary and not within the control of Enbridge/LPL as more particularly described in Article 20;

v) Property tax variances in excess of twenty percent from forecast;

vi) In respect of Phases other than Phase I, bond rate variation by more than two percentage points from 1998 levels; and

vii) Multi-pipeline return on equity variation by more than two percentage points from 1998 level.

20 For the purposes of Article 19 iv) circumstances which are extraordinary and not within the control of Enbridge/LPL are causes which by the exercise of due diligence Enbridge/LPL have not been able to avoid or overcome, including: acts of God, acts of public enemies, wars, insurrections, riots, epidemics, landslides, earthquakes, fires, storms, floods, washouts, abnormal weather conditions affecting construction, orders, restraints or prohibitions by any competent court or Government, government department, agency or tribunal having jurisdiction over Enbridge or LPL or over parties supplying labour, material or items necessary for the Terrace expansion.

21 Subsequent to LPL completing Phase III, in the event annual actual average pumpings ex-Clearbrook are less than 215,000m3 per day, 220,000m3 per day and 225,000m3 per day from in-service to year-end 2002, 2003, and 2004 through 2013 inclusive, respectively, an adjustment to the fixed toll increment allocated to LPL shall be made in accordance with Schedule C.

22 Energy costs attributable to Terrace will be calculated using a base power costs for an agreed upon delivery forecast assuming pre-Terrace at a capacity of 259,100 m3/day. The calculation of the power allowance for the purpose of calculating the TRV will be based on the difference in the total forecast fuel and power requirements and the actual fuel and power, using the average annual cost of fuel and power for the TRV year. Illustrative samples of the power and TRV calculations and the delivery forecasts for the 259,100m3/d base and the year 1999 are appended in Schedule H.

23 The implementation of the toll method contemplated in these Principles is subject to National Energy Board and Federal Energy Regulatory Commission approval of the settlement for Enbridge and LPL respectively.

24 The parties acknowledge that the calculation of the fixed toll increment assumes the Terrace facilities are depreciated on a straight line basis using a truncation date of 2024.

25 CAPP and Enbridge/LPL agree that the operating costs allocable to the Terrace program shall be direct incremental costs of the program for the cost classified in Schedule I. Upon completion of each Phase of the Terrace program, Enbridge/LPL shall provide to CAPP an enumeration of the facilities installed and the costs thereof. Maintenance and direct operating costs associated with the enumerated facilities shall be tracked and charged separately over the term of the Statement of Principles. Any

variances from Schedule I costs shall be for Enbridge's account. CAPP has the right to audit Enbridge/LPL records and accounts to ensure Enbridge's and LPL's treatment of costs are in accordance with the Terrace Statement of Principles. Audits will be conducted by a firm of independent Chartered Accountants. An audit shall be conducted not more than once every two years and no later than the immediate twenty-four month period beyond the expiry of the Terrace Toll Agreement. All fees, costs and expenses of

the external auditors with respect to the Terrace Toll Agreement audit will be paid by CAPP, on behalf of industry. CAPP may elect to have the external audit fees and expenses paid through Enbridge as a non-routine adjustment under Clause 7 of the Incentive Toll Settlement.

In the event Enbridge seeks to recover additional revenue from shippers for additional facilities CAPP has the right to undertake an engineering audit of the facilities within six months of Enbridge notifying CAPP that such facilities are available for service. Enbridge agrees to retain, and make available for audit purposes the original Terrace hydraulic studies.

SCHEDULE A
Description of Terrace Facilities

PHASE I FACILITIES

PROPOSED FACILITIES	ITEMS CONSIDERED TO BE SCOPE CHANGES TO TERRACE	NOT IN TERRACE SCOPE
Pipe		
- - 619 km of 914 mm line pipe between Kerrobert and Gretna stations in 15 sections in Enbridge along with associated valving, tie-in piping and scraper facilities	- Changes totaling more than 5 miles of pipe combined in Enbridge & LPL - Changes in pipe diameter	
- - 100 miles of 36 inch line pipe in 4 sections between Gretna and Clearbrook stations in LPL along with associated valving and tie-in piping		
- - additional wall thickness beyond the SEP II design on discharge of five existing stations above 3.28 inches and valving at intermediate station sites for future stations		

Pump Stations		
- - Sufficient pumping equipment and power to provide 26,500 m3/d of incremental capacity assuming that the 24" pipeline between Kerrobert and Clearbrook operates in laminar flow and that crudes are pumped in the 24" pipeline in sufficient quantities for the line to operate at 25,000 m3/d at its bottleneck point. Facilities will provide 370,000 BHP pumping power to pump at annual capacity rate between Edmonton and Superior in Q4 1999. No	Additional pumping power or DRA to achieve capacities greater than 285,600 m3/d in total as follows: - Line 1 18"/20"/26" 49,500 m3/day - Line 3 21"/34" 66,000 m3/day - Line 3 24"/26"/34" 81,200 m3/day - Line 2 24" heavy line 25,000 m3/day - Line 4 36"/48" heavy line 102,100 m3/day - Line 13 16"/18"/20" 27,800 m3/day or as otherwise agreed to with industry Annual capacities noted are 90% of design	Capacity increases on Lines not affected by terrace including in Western Canada: - Changes resulting from the SEP II facilities as filed with the NEB and as agreed to with industry which impact quoted Line capacities - Changes in facilities required to accommodate crude characteristics other than as referenced in Schedule D.

more than 2 pipelines in Enbridge and LPL will handle heavy and Bow River commodities.	capacity for all pipelines capacities noted. Changes in deliveries that negatively impact Lakehead's ability to inject crude into Lines 2 and 4 at Clearbrook in Phase I

STATEMENT OF PRINCIPLES
OCTOBER 21, 1998

Breakout and Terminalling Facilities

- 2 breakout tanks at Superior	- Additional breakout tankage	- Additional tankage, receipt, delivery, terminalling or connecting facilities at any location in Canada or USA - Requested commodity segregation over and above that provided in January 1999 which result in the need for additional tankage, metering, or terminalling facilities - Changes in facilities required to accommodate crude characteristics other than referenced in Schedule D.

STATEMENT OF PRINCIPLES
OCTOBER 21, 1998

PHASE II FACILITIES

PROPOSED FACILITIES	ITEMS CONSIDERED TO BE SCOPE CHANGES TO TERRACE	NOTE IN TERRACE SCOPE
Pipe 123 km of 914 mm line pipe in 3 sections between Hardisty and Kerrobert pump stations in Enbridge with associated valving and tie-in facilities	Changes totaling more than 5 miles of pipe Changes in pipe diameter	
Pump Stations Sufficient pumping equipment and power to provide 6,900 m3/d of incremental capacity beyond Phase I facilities, assuming that the 24" pipeline between Hardisty and Clearbook operates in laminar flow and that crudes are pumped in the 24" pipeline in sufficient quantities to operate at 27,000 m3/d at its bottleneck point. Facilities will provide 384,000 BHP in pumping power to pump at annual capacity rate between Edmonton and Superior in Q4 2000. No more than 2 pipelines in Enbridge and LPL will handle heavy and Bow River commodities.	Additional pumping power or DRA to achieve capacities greater than 292,500 m3/d in total determined as follows: - Line 1 18"/20"/26" 49,500 m3/day - Line 3 24"/34" 66,000 m3/day - Line 3 24"/26"/34" 81,200 m3/day - Line 2 24" heavy line 27,000 m3/day - Line 4 36"/48" heavy line 107,000 m3/day - Line 13 16"/18"/20" 27,800 m3/day or capacities as otherwise agreed to by Enbridge/LPL and industry Annual capacities noted are 90% of design capacity for all pipeline capacities noted.	- Additional pumping power or DRA to achieve capacities greater than that quoted in Phase I facilities: - Changes in facilities required to accommodate crude characteristics other than references in Schedule D

STATEMENT OF PRINCIPLES
OCTOBER 21, 1998

Breakout and Terminating Facilities	- Breakout tankage	- additional tankage, receipt, delivery, terminalling or connecting facilities at any location in Canada or USA - Requested commodity segregation which results in additional tankage, metering, or terminating facilities over and above and not provided in January 1999.

PHASE III FACILITIES

PROPOSED FACILITIES	ITEMS CONSIDERED TO BE SCOPE CHANGES TO TERRACE	NOT IN TERRACE SCOPE
Pipe 120 miles of 36 inch line pipe in 5 sections between Clearbrook and Superior pump stations with associated valving and tie-in facilities	Changes totaling more than 5 miles of pipe Changes in pipe diameter	
Pump Stations Sufficient power to provide 23,500 m3/d of incremental capacity above Terrace Phase II facilities. Facilities will provide 409,000 BHP in pumping power to pump at annual capacity rate between Edmonton and Superior in Q4 2001. No more than 2 pipelines in Enbridge and LPL will handle heavy and Bow River commodities.		Additional pumping power or DRA to achieve capacities greater than 315,200 m3/d in total as determined as follows: - Line 1 18"/20"/25" 41,400 m3/day - Line 3 24"/34" 54,000 m3/day - Line 3 24"/26"/34" 65,000 m3/day - Line 2 heavy line 74,000 m3/day - Line 4 heavy line 107,800 m3/day - Line 13 16"/18"/20" 27,800 m3/day or as otherwise agreed to with industry Annual capacities noted are 90% of design capacity for all pipelines noted. - Changes in facilities required to accommodate crude characteristics other than referenced in Schedule D.

Breakout and Terminalling Facilities		
- - 2 breakout tanks at Superior	- additional breakout tankage	- additional tankage, receipt, delivery, terminalling or connecting facilities at any location in Canada or USA - Requested commodity segregation which results in additional tankage, metering, or terminalling facilities.

FUTURE PHASES OF TERRACE FACILITIES

PROPOSED FACILITIES	ITEMS CONSIDERED TO BE SCOPE CHANGES TO TERRACE	NOT IN TERRACE SCOPE
Pipe $US 27 million in pipeline facilities between Mokena and Griffith by the end of 2002 if needed	- Any additional pipeline extensions or connections over $US 27 million	
Pump Stations $US 40 million in station additions and modifications on Line 14 by the end of 2003 if needed	- Any incremental pump unit additions after the intermediate stations are installed over $US 40 million	
Crude Oil Heater $US 3 MM in heating facilities to increase Line 14 capacity by the end of 2007 if needed	- Any other heating facilities over $US 3 million	
Total Costs	Total costs in excess of $US 70 million	

A pipeline system schematic is shown on the following page.

PIPELINE SYSTEM CONFIGURATION
(TERRACE PHASE 1 REVISED)
(as of February 1999)

[diagram showing pipeline configuration between U.S. and Canadian cities]

Line 21

/Light Crudes

Line 1	Line 2	Line 3	Line 4	Line 5	Line 6	Line 7
/NGL /Light Crudes /Synthetics	/Heavy Crudes	/Light Crudes /Medium Crudes /Synthetics /Condensates	/Heavy Crudes /Medium Crudes	/NGL /Light Crudes /Synthetics /Condensate	/Light Crudes /Medium Crudes /Heavy Crudes /Synthetics	/Light Crudes /Medium Crudes /Heavy Crudes /Synthetics

Line 8	Line 9	Line 10	Line 11	Line 12	Line 13	Line 14
/Refined products	/Light Crudes /Medium Crudes /Condensate	/Light Crudes /Medium Crudes /Heavy Crudes /Condensate /Synthetics	/Light Crudes /Condensate /Synthetics	/Light Crudes /Medium Crudes /Heavy Crudes /Synthetics	/Synthetics /Refined products	/Light Crudes /Condensates /Synthetics /Medium Crudes /Heavy Crudes

SCHEDULE B
ADJUSTMENTS TO THE 5 CENTS PER BARREL INCREMENT*
(CDN DOLLARS)

	Adjusting Event	Adjustment Phase I	Adjustment Phase II
1	Aggregate Scope Changes resulting in Capital cost changes greater than +/-$10 million from original estimate provided in Paragraph 13 of the Principles of Settlement	0.18 cents per barrel per $10 million change in capital costs	0.14 cents per barrel per $10 million change in capital costs
2	Capital Cost Variance outside +/-5% of estimate provided in Schedule A and construction cost variance agreed upon as falling under Paragraph 19 iv) of the Statement of Principles	0.09 cents per barrel per $10 million change in capital costs	0.07 cents per barrel per $10 million change in capital costs
3	Changes in Multi-pipeline cost of equity beyond current rate plus 200 basis points	For 1999-2007 and for 2008-2013 .3 cents per barrel and .15 cents per barrel respectively for each 25 basis point change in the multi-pipeline rate of return which exceeds the 1998 multi-pipeline rate of return plus or minus 200 basis points.	
4	Variances in Cost of Debt over 200 basis points above or below current Long Canada (5.28%) and US (5.65%) 10 year bonds	For Phases II and following, .1 cent per barrel change for every 50 basis point change in debt cost above the 200 basis point variance. The toll change for debt cost variances shall apply to Enbridge and LPL independently.	
5	Property Tax variances on Terrace Facilities greater than +/-20% estimate	Treated as a surcharge or surcredit to be recovered over a period of approximately one year and applied to all volumes until such time as the applicable property tax variance plus carrying costs at the year average Bank of Canada rate plus 50 basis points has been fully recovered or refunded.	
6	Capacity Penalty	1 cent decrease per barrel per 5,500 m3 per day below stated capacity until capacity is provided	1 cent decrease per barrel per 5,500 m3 per day below stated capacity until capacity is provided

* All values in Schedule B will be applied in fractions pro rata and the exchange rate (where applicable) shall be that set out in Paragraph 9 of the Statement of Principles

STATEMENT OF PRINCIPLES
OCTOBER 21, 1998

SCHEDULE C

ADJUSTMENT FOR LPL PHASE III TRIGGER*
INCREMENT INCREASE IN YEAR FOLLOWING PUMPINGS BELOW SPECIFIED TARGET
(Cdn Currency)

PRIOR YEAR'S ACTUAL AVERAGE PUMPINGS EX-CLEARBROOK	TOLL ADJUSTMENT FOR YEAR		
	2002	2003	2004-2013
Greater than 225,000 m3/day	0 cents/barrel	0 cents/barrel	0 cents/barrel
220,000 m3/day to 224,999 m3/day	0 cents/barrel	0 cents/barrel	1 cents/barrel
215,000 m3/day to 219,999 m3/day	0 cents/barrel	1 cents/barrel	2 cents/barrel
210,000 m3/day to 214,999 m3/day	1 cents/barrel	2 cents/barrel	3 cents/barrel
205,000 m3/day to 209,000 m3/day	2 cents/barrel	3 cents/barrel	4 cents/barrel
200,000 m3/day to 204,999 m3/day	3 cents/barrel	4 cents/barrel	5 cents/barrel

- - The toll adjustment set out in Schedule C will be collected via a surcharge, based on an exchange rate fixed on the previous 12 month average and all adjustments will be applied in fractions pro rata.

- - For any year in which the Phase III facilities are in operation for a less than a full year, the actual average pumpings will be calculated on that portion of the year the facilities were available for service.

STATEMENT OF PRINCIPLES
OCTOBER 21, 1998

SCHEDULE D

FLUID PROPERTIES OF LIQUID HYDROCARBONS IN ENBRIDGE SYSTEM
TERRACE PHASE I EXPANSION PROGRAM

COMMODITY TYPE	VISCOSITY @ 15 deg C (CENTISTOKES)	DENSITY @ 15 deg C	NOTES
Synthetic Crude	5.8	864	
NGL	0.26	555	
Condensate	1.1	732	
Gasoline	0.65	722	
Distillate	3.1	839	
Mixed Blend Sweet	6.8	883	
Light Sour	21	877	
Medium	56	902	
Heavy	350 1	9401	
Bow River	225 1	9251	Increased viscosity commences January 1999

- -----------
1 Viscosity and density at Line 3 and 4 reference temperature.

SCHEDULE E

RECEIPT/DELIVERY FORECAST
Forecast Deliveries at Base Capacity
259,100m3/day

ENBRIDGE PIPELINES INC.

FORECAST DELIVERIES AT BASE CAPACITY (259 199 m3/d)
m3/d

Line No.	Delivery Location	Commodity Source	Commodity Type	Service Category(1)	Year Average
(a)	(b)	(c)	(d)	(e)	(f)
1	Edmonton	Edmonton	Cnd	1	3,000
2	Hardisty	Edmonton	Cnd	1	9,800
3		Edmonton	Lgt	1	4,400
4		Edmonton	Hvy	1	5,900
5	Subtotal				20,100
6	Kerrobert	Edmonton	Cnd	1	5,000
7	Milden	Edmonton	Dst	2	1,100
8		Edmonton	Gsl	2	1,500
9	Subtotal				2,600
10	Regina	Edmonton	Dst	2	1,700
11		Edmonton	Gsl	2	1,300
12		Edmonton	Cnd	1	300
13		Edmonton	Lgt	1	2,400
14		Edmonton	Nap	1	500
15		Edmonton	Hvy	4	700
16		Kerrobert	Hvy	1	5,100
17	Subtotal				12,000
18	Gretna	Edmonton	Dst	2	2,400
19		Edmonton	Dst	3	1,700
20		Edmonton	Gsl	2	2,900
21		Edmonton	Gsl	3	1,500
22		Regina	Dst	2	400
23		Regina	Gsl	2	500
24	Subtotal				9,400

25	U.S. Points	Edmonton	Cnd	1	100
26		Edmonton	Lgt	1	55,400
27		Edmonton	Med	1	1,700
28		Edmonton	Hvy	1	9,300
29		Edmonton	NGL	2	600
30		Hardisty	Lgt	1	8,100
31		Hardisty	Med	2	13,600
32		Hardisty	Hvy	1	15,800
33		Hardisty	Hvy	2	28,100
34		Kerrobert	Lgt	2	1,300
35		Kerrobert	Hvy	1	11,800
36		Kerrobert	Hvy	2	4,400
37		Kerrobert	NGL	2	4,900
38		Regina	Lgt	1	0
39		Regina	Hvy	1	6,700
40		Cromer	Lgt	1	9,500
41		Cromer	Med	1	2,100
42		Cromer	NGL	1	500

43	Subtotal				173,900
44	Sarnia	Edmonton	Lgt	1	16,200
45		Edmonton	Hvy	1	3,300
46		Edmonton	Cnd	1	0
47		Edmonton	NGL	2	11,600
48		Hardisty	Lgt	1	800
49		Hardisty	Hvy	2	2,900
50		Kerrobert	NGL	2	7,900
51		Regina	Lgt	1	600
52		Cromer	Lgt	1	4,500
53		Cromer	Med	1	4,100
54		U.S. Points	USL	2	700
55		Montreal	Cnd	2	1,600
56		Montreal	Lgt	2	13,600

57	Subtotal				67,800
58	Toronto	Edmonton	Lgt	1	0
59		Hardisty	Med	2	2,500
60		Hardisty	Hvy	2	800
61		Kerrobert	Hvy	1	500
62		Toronto	Med	2	500
63		Montreal	Lgt	2	10,300

64	Subtotal				14,600
65	Nanticoke	Edmonton	Lgt	1	500
66		Hardisty	Med	1	0
67		Hardisty	Lgt	1	1,800
68		Hardisty	Hvy	2	1,300
69		Regina	Lgt	1	0
70		Montreal	Lgt	2	12,700

71	Subtotal				16,300
72	Buffalo	Edmonton	Lgt	1	4,700

73	Edmonton	Hvy	1	300
74	Hardisty	Lgt	1	0
75	Hardisty	Med	2	1,400
76	Hardisty	Hvy	2	2,200

77	Kerrobert	Hvy	1	1,300
78	Cromer	Lgt	1	400
79	Cromer	Med	1	800
80	U.S. Points	Med	1	0
81	U.S. Points	USL	2	0
82	Sarnia	Cnd	1	300
				-------
83 Subtotal				11,400
84 TOTAL DELIVERIES -- Enbridge				336,100
				--------
85 Subtotal		Cdn		20,100
86		Lgt		147,200
87		Med		26,700
88		Hvy		100,400
89		NGL		25,500
90		Other		16,200
91 TOTAL DELIVERIES -- Enbridge				336,100

92	less Deliveries Upstream of Capacity Points*			36,400
93	less Receipts Downstream of Capacity Points*			40,600
94 TOTAL PUMPING AT CAPACITY POINTS*				259,100

* Capacity Points are Cromer for Line 1 and Line 2, Regina for Line 3 and Hardisty for Line 13. Capacities are 49,500 m3/d on Line 1, 79,500 m3/d on Line 2, 99,100 m3/d on Line 3 and 31,000 m3/d on Line 13.

LEGEND

Dst - Distillate	Med - Medium Crude Oil
Gsl - Gasoline	Hvy - Heavy Crude Oil
Nap - Naptha	NLG - Natural Gas Liquids
Cdn - Condensate	USL - U.S. & Offshore Light Crude Oil
Lgt - Light Crude Oil	m3/d - Cubic meters per day

NOTE (1) SERVICE CATEGORY:

(a) Use of receipt and delivery tankage is identified as follows:

1 - Uses receipt tankage but not delivery tankage.
2 - Uses neither receipt nor delivery tankage.
3 - Uses delivery tankage but not receipt tankage.
4 - Uses both receipt and delivery tankage.

(b) No receipt terminalling charge will be assessed on commodities received by Enbridge at the International Boundary near Sarnia, Ontario and no delivery terminalling charge will be assessed on the commodities delivered by Enbridge at the International Boundaries near Gretna, Manitoba and Chippewa, Ontario.

SCHEDULE F
FORECAST
PROPERTY TAXES
(000)

	1999	2000	2001	2002	2003	2004	2005	2006	2007
LPL $US	1908	2307	1996	5984	6508	7112	7332	7323	6901
Enbridge $C	2758	3069	3372	3932	4010	4090	4172	4256	4341

	2008	2009	2010	2011	2012	2013	2014
LPL $US	6705	6925	7029	7134	7241	7350	7460
Enbridge $C	4428	4516	4607	4699	4793	4888	4986

SCHEDULE G
Arbitration Procedure

1. REFERRAL TO ARBITRATION; RULES. In the event of any dispute, controversy or claim (a "Dispute") arising out of setting the parameters for or relating to the reversion to cost of service toll approach set forth in the Principles of Settlement such Dispute shall be referred to arbitration in accordance with the provisions of this Schedule. The arbitration shall be conducted under the Arbitration Act (Alberta) and any amendments thereto except to the extent that the Arbitration Act is inconsistent with or in conflict with any terms of this Schedule, in which event such terms of this Schedule shall prevail. Any other statute which applies to a Dispute shall apply only to the extent that it is not inconsistent with this Schedule.

2. THE ARBITRATORS. The Party or Parties commencing the Arbitration proceedings ("Claimant") may at any time serve a notice on the other Party or Parties ("Respondent") to the Dispute of its intention to arbitrate. Within ten (10) days (all references to "days" in this Schedule G are to business days) or Respondent's receipt of a Notice of Arbitration (as defined in subparagraph 3(a)), the Claimant and Respondent shall meet and attempt to appoint a single arbitrator. Should all of the Parties to the Dispute ("Arbitrating Parties") be unable to agree upon a single arbitrator, then either Arbitrating Party may select its own arbitrator and may serve notice upon the other Arbitrating Party to select an arbitrator. Upon receipt of such notice, the other Arbitrating Party shall have ten (10) days in which to appoint an arbitrator. The two arbitrators thus selected shall appoint a third arbitrator within ten (10) days of the appointment of the second arbitrator; and the three arbitrators shall constitute a board of arbitrators which shall determine the matter in dispute. If either Arbitrating Party shall fail to name an arbitrator within ten (10) days of receipt of a notice to do so, the second arbitrator shall be appointed by any Justice of the Court of Queen's Bench of Alberta (the "Specified Court"). If the two arbitrators shall fail to appoint the third arbitrator, then upon written application by any Arbitrating Party such third arbitrator shall be appointed by any Justice of the Specified Court. For the purposes of selection of arbitrators, the Claimants shall be treated as one Arbitrating Party, and the Respondents shall be treated as one Arbitrating Party.

3. COMMENCEMENT OF ARBITRATION PROCEDURES.

    (a) The Party commencing arbitration proceedings (the "Claimant") shall serve upon the other party (the "Respondent") a notice of arbitration (the "Notice of Arbitration"). No more than five (5) days after the selection of the Arbitrator, the Claimant shall serve the Notice of Arbitration upon the Arbitrator. Arbitration proceedings are deemed to commence on the date on which the Notice of Arbitration is served upon the Respondent.

(b) Notice of Arbitration shall include the following, set out in plain, concise and summary language:

(i) a demand that the Dispute be referred to arbitration;

(ii) the names and addresses of the Arbitrating Parties;

(iii) a reference to the provisions of the Agreement out of or in relation to which the Dispute arises;

(iv) the general nature of the claim;

(v) a statement of the facts supporting the claim;

(vi) the points at issue;

(vii) the name and address of the Claimant's counsel;

(viii) the relief or remedy sought; and

(ix) a proposal as to the identity of the Arbitrator and three alternative proposals;

Within fifteen (15) days of service of the Notice of Arbitration, the Respondent shall also make a proposal of the type provided for in Section 3(b)(ix) above.

(c) Within thirty (30) days of receiving the Notice of Arbitration or such longer period of time as the Arbitrating Parties may agree or the Arbitrator may permit the Respondent shall serve as its response (the "Response") in writing upon the Claimant. Within five (5) days of the selection of the Arbitrator, the Respondent shall serve its Response upon the Arbitrator.

(d) A Response shall reply in plain, concise and summary language to the particulars in subparagraphs 3(b)(v), 3(b)(vi) and 3(b)(viii) above and shall specify information of the type provided for in subparagraph 3(b)(vii) above.

(e) The documents filed pursuant to this paragraph 3 shall be referred to as the "Written Evidence" and may only be supplemented with leave of the Arbitrator.

(f) Both the Claimant and the Respondent shall each fully disclose and completely append to its Notice of Arbitration Response a summary of all material facts and evidence upon which it intends to rely, including the following:

(i) a copy of the agreements and all amendments thereto out of which the Dispute arises including the Agreement and all Schedules thereto;

(ii) a list of all relevant documents, including adverse documents, identified by the parties thereto, the date and subject matter thereof;

(iii) copies of any expert reports intended to be relied upon; and

(iv) a list of any and all witnesses intended to be relied upon, including names, addresses, employment, a summary of the material testimony of each such witness and, where appropriate, the qualifications of the witnesses.

4. FAILURE TO DELIVER A RESPONSE. If an Arbitrating Party does not deliver a response within five days of written notice by the Arbitrator to do so and the Arbitrator determines that there is no sufficient explanation for such failure to deliver, the Arbitrator may make such an Award as is considered appropriate in the circumstances, including an Award terminating the arbitration.

5. CHALLENGES OF ARBITRATOR.

   (a) An Arbitrating Party who intends to challenge the Arbitrator shall send a written statement of the reasons for the challenge to the other Arbitrating Parties and to the Arbitrator.

   (b) Any challenge of the Arbitrator shall be based upon the actual or potential bias of the Arbitrator, the Arbitrator's conflict of interest or other ground that is related to the impartiality of the Arbitrator. The challenge shall be made to the Specified Court.

   (c) Where the mandate of an Arbitrator terminates for any reason, a substitute Arbitrator shall be appointed pursuant to the rules and procedures set forth in paragraph 2 above.

6. PRELIMINARY CONFERENCE. No later than seven (10) days after the last item of Written Evidence has been filed, the Arbitrating Parties and their counsel shall meet, either in person or by telephone conference call with the Arbitrator for a preliminary conference that determines the issues upon which the Arbitrating Parties are truly in disagreement, the granting of any interim orders of relief that may have been applied for in the Written Evidence and the scheduling of the balance of the arbitration including any oral hearing. The Arbitrating Parties shall use their best efforts to reach agreement on as many matters as possible in order to reduce the amount of time required to resolve the matters in dispute. The Arbitrating Parties shall also provide the Arbitrator with an agreed statement of facts and an agreed list of exhibits to be filed within ten (10) days after the conclusion of the conference provided in this paragraph 6, to the extent that the Arbitrating Parties have been able to agree upon such matters.

7. EVIDENCE GATHERING.

   (a) Where an Arbitrating Party on notice to the Arbitrator and the Arbitrating Parties alleges that relevant evidence is or may be in the possession of another Arbitrating Party, and can satisfy the Arbitrator that there is a conflict, disagreement or uncertainty on important evidentiary matters, such Arbitrating Party may demand (a "Demand") that the Arbitrator require the other Arbitrating Parties to do any or all of the following:

      (i) respond in writing to information requests under oath or affirmation;

      (ii) produce further documents (including documents that are either adverse in interest to the producing party or confidential) but not documents in respect of which such Arbitrating Party may validly claim privilege or confidentiality pursuant to paragraph 14 below); and

      (iii) produce witnesses including experts for attendance at a pre-hearing oral examination under oath or affirmation.

   (b) Where an Arbitrating Party on notice to the Arbitrator and the other Arbitrating Parties alleges that a third party has relevant and important evidence, the Arbitrator may demand production of that evidence in such form and on such terms as the Arbitrator may prescribe which shall fairly protect the interests of the Arbitrating Parties.

(c) All procedures commenced pursuant to subparagraphs 7(a) and (b) shall be completed within thirty (30) days of the initial Demand.

(d) Any evidence obtained by an Arbitrating Party adverse in interest in response to a Demand or request under this paragraph 7 may be submitted to and relied upon by the Arbitrator as prima facie proof of the truth of its contents, unless the opposing party raises a reasonable doubt about the reliability of such evidence, in which case the Arbitrator may determine the admissibility, relevance and materiality of such evidence.

(e) Only if there is a conflict in the expert reports or in the evidence on an important matter in the Dispute may the Arbitrator retain a neutral, independent and impartial expert (the "Expert") qualified in the subject matter provided the Arbitrating Parties agree to such an appointment. The Expert shall be appointed after the Arbitrator has had due regard to the submissions of the Arbitrating Parties on the selection of, qualifications of, and issues to be submitted to the Expert. The Arbitrating Parties shall receive all documents submitted to the Arbitrator by the Expert, and shall have an opportunity to examine, and to offer written or oral rebuttal of any evidence presented to the Arbitrator by the Expert. Costs associated with the Expert are payable by the Arbitrating Parties, and the Arbitrating Parties shall be entitled to stipulate that the Expert's fees shall not exceed an amount agreed to by the Arbitrating Parties.

(f) The Arbitrator may determine the admissibility, relevancy and materiality of any evidence. Unless otherwise provided in this Schedule, the Arbitrator's decision on all procedural matters is final and binding upon the Arbitrating Parties.

8. HEARINGS

(a) Where there is a conflict, disagreement or uncertainty on evidentiary matters an Arbitrating Party may demand, or the Arbitrator upon its own initiative may order, a hearing at which oral evidence on the evidentiary matters so identified will be tendered with each other Arbitrating Party entitled to call rebuttal evidence (if previously disclosed to the other party) and to cross-examine. The Arbitrator must advise the Arbitrating Parties of the date, time and place of the arbitration hearing, and must decide such matters after consulting the Arbitrating Parties.

(b) Any oral hearing shall be held in camera and unless otherwise agreed by all Arbitrating Parties, only their representatives, their counsel, the Arbitrator and those persons called as witnesses may attend. Each witness must be excluded from the hearing until that person is called to give evidence, unless all Arbitrating Parties agree that the witness need not be excluded.

(c) A hearing shall proceed in the following manner:

(i) each Arbitrating Party may make an introductory statement;

(ii) each Arbitrating Party may present its evidence through a panel or panels of witnesses or otherwise as it sees fit;

(iii) the testimony of any and all witnesses shall be under oath, declaration of affirmation and the Arbitrator may administer such oaths, declarations and affirmations;

(iv) the order of presentation of evidence shall be: Claimant; Respondent and Claimant (rebuttal evidence only);

(v) surrebuttal evidence may be presented only with leave of the Arbitrator;

(vi) the order of examination of witnesses shall be: examination-in-chief by counsel for the Arbitrating Party presenting such evidence; cross-examination by counsel for each other Arbitrating Party; re-examination by the first Arbitrating Party's own counsel; and, if the Arbitrator chooses, examination by the Arbitrator; and

(vii) the Arbitrator may require any person to give evidence and attend an oral hearing and such orders are enforceable in the same manner as and have the same effect as a notice to attend in court proceedings, and shall be served in the same manner.

(d) Following conclusion of the procedures specified in subparagraph 8(c) above, the Claimant shall present its oral argument, followed by the oral

argument of the Respondent, the Claimant's replies and the Respondent's replies to the Claimant's replies. If the Arbitrator deems it advisable to do so, it may order the Arbitrating Parties to submit written briefs of argument, prior to and in addition to or in lieu of their oral arguments. In no event may such briefs exceed 10 pages.

9. THE AWARD. Not later than 10 days following the conclusion of the hearing, the Arbitrator shall furnish to each Arbitrating Party a written statement of the Award. The Award shall be final and binding on the Arbitrating Parties as to the questions submitted to arbitration in the Notice of Arbitration. There shall be no appeal from or judicial review of the Award.

10. APPLICABLE LAW. The Arbitrator shall apply the laws of the Province of Alberta. All matters of procedure shall be resolved in accordance with the laws of the Province of Alberta.

11. CLAIMS GIVING RISE TO OTHER PROCEEDINGS. Unless the Arbitrating Parties agree otherwise, the application of the arbitration provisions of this Schedule to the Dispute shall terminate if an Arbitrating Party advances or is required to respond to any other legitimate claim not covered by this Schedule, providing that such other claim arises out of substantially the same facts or subject matter as the Dispute governed by this Schedule and could reasonably give rise to contribution, indemnity, duplicative or inconsistent remedies or relief. The Arbitrator shall be empowered to determine whether any such claim falls within the contemplation of this paragraph 11.

12. NON-ARBITRABLE MATTERS. Any matter expressed in the Agreement to be a matter for agreement by the Arbitrating Parties shall not constitute a Dispute to be referred to or settled by arbitration proceedings pursuant to this Schedule or otherwise.

13. ATTORNMENT; ENFORCEMENT. The Arbitrating Parties hereby submit to the exclusive jurisdiction of the Specified Court in any action, suit or proceedings with respect to the enforcement of the provisions of this Schedule and the non-exclusive jurisdiction of the Specified Court with respect to the enforcement of any Award. For greater certainty, the Parties confirm that the agreement to submit matters to arbitration is intended solely to bind the parties hereto and is not intended in a any way to fetter or restrict the exercise of jurisdiction of any regulatory authority having jurisdiction over the matters which are subject to arbitration. The Arbitrating Parties agree to take any and all action as may be necessary to

designate and maintain such designation of agents for service of notices under this Schedule for the duration of the Agreement and to promptly advise the other Parties in writing of any unavoidable change of agent or address of agent along with the identity and address of its new agent as required.

14. CONFIDENTIALITY OF INFORMATION.

(a) Each Arbitrating Party and the Arbitrator shall retain in confidence the reasons for decision for the Award, all documents and other materials and all information obtained from any of the Arbitrating Parties in the arbitration and further, shall not use the same, or allow the same to be used, for any purpose collateral to the arbitration. The Arbitrating Parties shall be responsible for ensuring that their officers, employees, witnesses, representatives and consultants comply with the obligation of confidentiality herein.

(b) No Arbitrating Party shall refuse to produce any relevant documents on grounds of confidentiality alone, provided that a party may withhold documents if the conditions set forth in Section 16.1 of the National Energy Board Act apply, or if the rules of privilege applied by the laws of the Province of Alberta would result in such document being privileged in legal proceedings conducted in the Province of Alberta.

15. COSTS. Each Arbitrating Party shall bear its own costs associated with the Arbitration and shall bear 50 percent of all third party costs

16 PLACE OF ARBITRATION. The arbitration shall be conducted in Calgary, Alberta, Canada.

SCHEDULE H
Power Calculation

Following is an explanatory of the allocation of power costs and benefits to the Terrace Project and the calculation of the TRV power.

PROCEDURE FOR ALLOCATION OF POWER COST/BENEFITS TO TERRACE AND TRV

A. Calculate the energy requirements to transport the post SEP II base capacity at 259,000 m3/d using the crude slate and receipt and delivery schedule found in Schedule E.

B. Multiply the power requirements determined in (A) by the previous year's average unit cost of energy plus fuel and DRA.

C. Forecast the energy requirements annually to transport the post Terrace volumes at annual capacity using the forecast of crude type mix for each year as found in the example for 1999 in Table H below.

D. Multiply the power requirements determined in (C) by the previous year's average unit cost of energy plus fuel and DRA.

E. The Difference between Power at base capacity (B) less the power associated with the current forecast at annual capacity (D) will be deemed Terrace Power attributable to Enbridge. In the example shown below, Terrace Power is shown as \$122 million - \$98 million = \$24 million.

F. The difference between the Actual Power Cost and the Terrace Power at capacity determined in (D) will represent the TRV power allowance, which will be deducted from the TRV revenue.

Below is a graphical illustration of the treatment of power costs.

[Graph]

POWER CALCULATION EXAMPLE

	LINE NO.	DESCRIPTION	GWh	$97 AVG	$ TOTAL MILLIONS
A,B		ENERGY REQUIREMENTS FOR BASE CAPACITY (259 100 m3/d):			
	1	Power	2800	40.55	114
	2	Fuel			1
	3	DRA			6

	4	Total Energy Requirements for Base Capacity			122
C,D		ENERGY REQUIREMENTS AT CAPACITY (259 100 m3/d) JANUARY 1999			
	5	Power	233	40.55	9
	6	Fuel			0
	7	DRA			1

	8	Total Energy Requirements at Capacity Jan 1999			10
C,D		ENERGY REQUIREMENTS AT CAPACITY (274 200 m3/d) FEBRUARY - SEPTEMBER 1999			
	9	Power	1459	40.55	59
	10	Fuel			1
	11	DRA			3

	12	Total Energy Requirements at Capacity Feb - Sept 1999			63
C,D		ENERGY REQUIREMENTS AT CAPACITY (285 600 m3/d) OCTOBER - DECEMBER 1999			
	13	Power	583	40.55	24
	14	Fuel			0
	15	DRA			1

	16	Total Energy Requirements at Capacity Oct - Dec 1999			25
C,D		ENERGY REQUIREMENTS FOR 1999 CAPACITY			
	17	Power	2275	40.55	92
	18	Fuel			1
	19	DRA			5

	20	Total Energy Requirements for 1999 at Capacity			98

* The energy requirements shown in the table above are for the partial year

period with its corresponding aggregate system capacity forecast for that period.

ENBRIDGE PIPELINES INC.
TABLE H
FORECAST DELIVERIES FOR 1999 AT CAPACITY
m3/d

Line No.	Delivery Location	Commodity Source	Commodity Type	Service Category(1)	Year Average
(a)	(b)	(c)	(d)	(e)	(f)
1	Edmonton	Edmonton	Cnd	1	1,200
2	Hardisty	Edmonton	Cnd	1	10,400
3		Edmonton	Lgt	1	8,400
4		Edmonton	Hvy	1	1,000
5	Subtotal				19,800
6	Kerrobert	Edmonton	Cnd	1	4,900
7	Milden	Edmonton	Dst	2	1,000
8		Edmonton	Gsl	2	1,400
9	Subtotal				2,400
10	Regina	Edmonton	Dst	2	1,700
11		Edmonton	Gsl	2	1,400
12		Edmonton	Cnd	1	300
13		Edmonton	Lgt	1	800
14		Edmonton	Nap	1	500
15		Edmonton	Hvy	4	600
16		Kerrobert	Hvy	1	5,000
17	Subtotal				10,300
18	Gretna	Edmonton	Dst	2	2,300
19		Edmonton	Dst	3	1,700
20		Edmonton	Gsl	2	2,900
21		Edmonton	Gsl	3	1,500
22		Regina	Dst	2	400
23		Regina	Gsl	2	500
24	Subtotal				9,300
25	U.S. Points	Edmonton	Cnd	1	2,400
26		Edmonton	Lgt	1	57,300
27		Edmonton	Med	1	2,300
28		Edmonton	Hvy	1	33,300
29		Edmonton	NGL	2	600
30		Hardisty	Lgt	1	1,800
31		Hardisty	Med	2	14,500
32		Hardisty	Hvy	1	7,200
33		Hardisty	Hvy	2	38,700
34		Kerrobert	Lgt	2	1,500
35		Kerrobert	Hvy	1	5,600
36		Kerrobert	Hvy	2	5,500
37		Kerrobert	NGL	2	4,900
38		Regina	Lgt	1	900
39		Regina	Hvy	1	7,100

40		Cromer	Lgt	1	11,900

41		Cromer	Med	1	1,500
42		Cromer	NGL	2	500

43	Subtotal				197,500
44	Sarnia	Edmonton	Lgt	1	16,000
45		Edmonton	Hvy	1	5,900
46		Edmonton	Cnd	1	700
47		Edmonton	NGL	2	11,500
48		Hardisty	Lgt	1	900
49		Hardisty	Hvy	2	0
50		Kerrobert	NGL	2	7,600
51		Regina	Lgt	1	900
52		Cromer	Lgt	1	3,600
53		Cromer	Med	1	3,900
54		U.S. Points	USL	2	1,100
55		Montreal	Cnd	2	1,300
56		Montreal	Lgt	2	13,900

57	Subtotal				67,300
58	Toronto	Edmonton	Lgt	1	300
59		Hardisty	Med	2	1,600
60		Hardisty	Hvy	2	300
61		Kerrobert	Hvy	1	500
62		Toronto	Med	2	500
63		Montreal	Lgt	2	10,300

64	Subtotal				13,500
65	Nanticoke	Edmonton	Lgt	1	0
66		Hardisty	Med	1	300
67		Hardisty	Lgt	1	1,500
68		Hardisty	Hvy	2	1,000
69		Regina	Lgt	1	400
70		Montreal	Lgt	2	12,700

71	Subtotal				15,900
72	Buffalo	Edmonton	Lgt	1	2,700
73		Edmonton	Hvy	1	300
74		Hardisty	Lgt	1	1,400
75		Hardisty	Med	2	2,000
76		Hardisty	Hvy	2	2,000
77		Kerrobert	Hvy	1	1,300
78		Cromer	Lgt	1	400
79		Cromer	Med	1	0
80		U.S. Points	Med	1	800
81		U.S. Points	USL	2	200
82		Sarnia	Cnd	1	300

83	Subtotal				11,400
84	TOTAL DELIVERIES -- ENBRIDGE				353,500

85	Subtotal		Cnd		21,500
86			Lgt		147,600
87			Med		27,400
88			Hvy		115,300
89			NGL		25,100
90			Other		16,600

91	TOTAL DELIVERIES -- ENBRIDGE	353,500

LEGEND

Dst - Distillate	Med - Medium Crude Oil
Gsl - Gasoline	Hvy - Heavy Crude Oil
Nap - Naptha	NLG - Natural Gas Liquids
Cdn - Condensate	USL - U.S. & Offshore Light Crude Oil
Lgt - Light Crude Oil	m3/d - Cubic meters per day

NOTE (1) SERVICE CATEGORY:

(a) Use of receipt and delivery tankage is identified as follows:
   1 - Uses receipt tankage but not delivery tankage.
   2 - Uses neither receipt nor delivery tankage.
   3 - Uses delivery tankage but not receipt tankage.
   4 - Uses both receipt and delivery tankage.

(b) No receipt terminalling charge will be assessed on commodities received by Enbridge at the International Boundary near Sarnia, Ontario and no delivery terminalling charge will be assessed on the commodities delivered by Enbridge at the International Boundaries near Gretna, Manitoba and Chippewa, Ontario.

Enbridge and CAPP agree that twelve months after the completion of Terrace, Phase I Enbridge will conduct a recalibration of the model used to calculate power consumption based on the actual twelve month operating experience.

In the event of recalibration demonstrates a forecast to actual variance which exceeds two percent, Enbridge/LPL will reset both the base power consumption and the forecast Terrace power consumption pro rata to reflect the results of the recalibration, and shall refund or collect the revenue variance associated with the recalibration via a surcharge or surcredit to be collected or refunded in the subsequent year.

SCHEDULE I
Operating Costs

	ENBRIDGE C$			
	PHASE I	PHASE II	PHASE III	2009
Personnel	0	930	930	930
Pump Maintenance	0	230	330	330
Mainline Maintenance	0	90	110	110

Mainline Inhibitor	1 320	330	330	330
In-Line Inspection				2 450
Tank Maintenance				
Insurance	70	100	100	100
Total	1 390	1 680	1 800	4 250
Inflation @ 2%	56	103	148	1 140
Revised Estimate	1 446	1 783	1 948	5 390

	LPL US$ 000			
	PHASE I	PHASE II	PHASE III	2009
Personnel	0	0	250	250
Pump Maintenance	100	100	170	170
Mainline Maintenance	30	30	100	100
Mainline Inhibitor	225	225	225	225
In-Line Inspection				204
Tank Maintenance	30	30	130	130
Insurance	21	21	70	70
Total	406	406	945	1 149
Inflation @ 2%	12	19	58	225
Revised Estimate	418	425	1 003	1 374

Exhibit No. 1 - Attachment C

IPL

Interprovincial Pipe Line Inc.

IPL Tower 10201 Jasper Avenue
P.O. Box 398
Edmonton, Alberta T5J 2J9

Robert L. Nichols
Vice-President, Accounting & Regulatory Affairs

Office: (403) 420-5210
Direct: (403) 420-8274
Fax: (403) 420-5389

File No DDP96-08-07

April 22,1997

Mr. Michel L. Mantha
Acting Secretary
The National Energy Board
9th Floor, 311 - 6 Avenue S. W.
Calgary, AB T2P 3H2

Dear Mr. Mantha:

RE: 350 Centistoke Project
Application of Interprovincial Pipe Line Inc. for Orders
Pursuant to Section 58 and Part IV of the National Energy Board Act

Please find enclosed for filing twenty (20) copies of an Application made by Interprovincial Pipe Line Inc. ("IPL") pursuant to Section 58 and Part IV of the National Energy Board Act.

The program is intended to provide facilities necessary to allow IPL to raise the density and viscosity limits of heavy crude accepted for transportation on the IPL system and reduce the amount of condensate required for blending, while maintaining current system capacity. The Application seeks an order authorizing construction of line heaters and associated pump facilities and modifications on the IPL system as well as associated toll orders implementing an increase to the heavy crude oil surcharge to reflect the provision of service for more viscous and dense commodities.

The capital cost of the facilities is approximately $9 million, and the planned in service date is December 31, 1997.

The 350 Centistoke Program was developed between IPL and an industry task force represented by heavy oil interests.[1] The two objectives of the task force were to provide service for more viscous and dense material while leaving other classes of shippers unaffected. The project was developed in close cooperation with the task force and IPL is unaware of any opposition among shippers to either the construction or the 2 percentage point heavy crude surcharge increase associated with the acceptance of 350 centistoke material. The program has received the formal support of the Canadian

- ----------

1 The task force included Amoco Canada Petroleum Company Ltd., CAPP, Gibson Petroleum Company Inc., Husky Oil Operations Ltd., Imperial Oil Resources Limited, Murphy Oil Company Ltd., PanCanadian Petroleum Limited, Renaissance Energy Ltd., Shell Canada Limited, Koch Oil Co. Ltd. and Talisman Energy Inc.

Association of Petroleum Producers ("CAPP"). CAPP's letter supporting the program is attached as Appendix I to this transmittal letter.

In the light of the cooperative efforts between IPL, the heavy crude producing and shipping interests, and CAPP, IPL is of the view that there are no unresolved industry issues surrounding the 350 Centistoke Project and notes that the implementation of this program will have minimal toll impact on other than heavy crude shippers when SEP II facilities are in-service.

The 350 Centistoke heater facilities will be ready for service before SEP II facilities are in-service and IPL proposes constructing the 350 Centistoke facilities but implementing the higher density and viscosity limits only upon a request being made by CAPP. The 350 Centistoke facilities will provide a benefit to IPL shippers prior to the implementation of increased density and viscosity limits as their operation will have the effect of increasing capacity, assuming the existing viscosity and density limits remain in place until the Line 14 portion of the SEP II program is in-service

The facilities for which approval is sought pursuant to Section 58 are wholly situated on IPL property, and there has been minimal landowner or other stakeholder concerns identified through IPL's Early Public Notification process. The Environmental Impact Assessment ("EIA") which forms part of the Application has identified potential adverse environmental and socio-economic effects and mitigative measures in respect of those potential effects. IPL has undertaken to implement the recommended mitigative measures.

Based on the nature of the facilities applied for, the level of support in respect of toll and facilities issues associated with the project, and no identification of landowner or environmental or socio-economic concerns which IPL believes cannot be mitigated, IPL requests that the Board consider this Application by means of a written proceeding. In the light of the nature of the issues raised by the Application, IPL is of the view that a written process will allow a full and fair consideration of the issues while providing the most efficient means of considering the project.

A copy of this Application is concurrently being served upon IPL's Interested Parties list.

Yours very truly,

INTERPROVINCIAL PIPE LlNE INC.

R.L. Nichols
Vice-President,
Accounting & Regulatory Affairs

Enclosure

cc: Interested Parties

April 22, 1997

Canadian Association of Petroleum Producers

Appendix I
CAPP Letter of Support

CAPP

April 22, 1997

Mr. Robert L. Nichols
Vice President, Accounting & Regulatory Affairs
Interprovincial Pipe Line Inc.
10201 Jasper Avenue
Edmonton, Alberta T5J 2J9

Dear Mr. Nichols:

RE: INTERPROVINCIAL PIPE LINE INC. - 350 CENTISTOKE PROJECT APPLICATION

With respect to the above-noted application by Interprovincial Pipe Line (IPL) to the National Energy Board, the Canadian Association of Petroleum Producers (CAPP) supports the changes presented in the application.

On behalf of its members, CAPP has worked with IPL and the industry task force to review the project and has concluded that the requested changes provide overall benefit to the industry. The proposed changes will reduce the requirement for diluent blending of heavy crude oils for shipment on the Interprovincial pipeline system, which represents a significant saving to producers. In addition, shortages in the supply of condensate used as diluent have hampered producers' ability to bring their products to market. Consequently, any reduction in the reliance on diluent will impact positively on producers.

Prior to the completion of SEP 11, in 1998, there is uncertainty as to the ability to implement the proposed changes without a negative impact on non-heavy shippers. In the period before the completion of SEP II, the surplus capacity needed on the Lakehead system to implement the 350 centistoke project will be dependent on supply growth, market development and the utilization of alternative pipelines. Interprovincial has committed to implementing the proposed service changes in a timely manner, consistent with the needs of the market place. Thus, implementation will be responsive to signals from the market. As agreed, the necessary signal for IPL to proceed with the implementation of the 350 centistoke change will be provided by CAPP, as a representative of industry.

Yours truly,

Onno DeVries
Manager, Crude Oil and Fiscal Policy

2100, 350-7 Avenue S.W. Calgary, Alberta, Canada T2P 3N9
telephone (403) 267-1100 facsimile (403) 261-4622

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Exhibit No. 2

{LOGO}

NATIONAL ENERGY BOARD

Reasons for Decision

INTERPROVINCIAL PIPE LINE INC.

OH-1-96

July 1996

Facilities and Toll Methodology

98

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Recital and Appearances

IN THE MATTER OF the National Energy Board Act and the regulations made thereunder;

AND IN THE MATTER OF an application dated 12 January 1996 by Interprovincial Pipe Line Inc. for a Certificate of public convenience and necessity under Part Ill of the Act, authorizing a capacity expansion of its pipeline system, and for an Order under Part IV of the Act, respecting toll design and tariffs;

AND IN THE MATTER OF Hearing Order OH-l-96;

HEARD at Calgary, Alberta on 3, 4, 5 and 7 June 1996.

BEFORE:

R.L. Andrew	Presiding Member
A. Cote-Verhaaf	Member
J.A. Snider	Member

APPEARANCES:

C.K. Yates R.A. Neufeld	Interprovincial Pipe Line Inc.
N.J. Schultz	Canadian Association of Petroleum Producers
R.W. Laidlaw	Alberta Energy Company Ltd.
F.R. Foran	Amoco Canada Petroleum Company Ltd.
L.G. Keough	Express Pipeline Ltd.
H.R. Huber	Imperial Oil Limited, Mobil Natural Gas Canada Ltd., Petro-Canada, Shell Canada Limited
K.F. Miller	Koch Oil Co. Ltd.
H.R. Huber	Murphy Oil Company Ltd.
A. Reid	Alberta Department of Energy
B. de Jonge	National Energy Board Counsel

Chapter 1

INTRODUCTION

1.1 The Application

On 12 January 1996, Interprovincial Pipe Line Inc. ("IPL" or "the Company") applied pursuant to Part III of the National Energy Board Act ("the Act") for a certificate of public convenience and necessity to authorize the construction of additional facilities on its pipeline system in western Canada and, pursuant to Part IV of the Act, for an Order respecting toll design and tariffs.

The applied-for System Expansion Program Phase II ("SEP II") would consist of pipeline, pump unit additions, pump modifications, pump replacements, motor replacements, and drag reducing agent ("DRA") injection connections. The proposed facilities, at an estimated cost of $140 million, would increase delivery capability of the existing IPL system to Chicago by 19 600 m3/d

(120,000 b/d). A map of the IPL system is shown in Figure 1-1.

In a letter dated 31 May 1996, IPL filed with the National Energy Board ("the Board") details of a Risk Sharing Agreement ("RSA") which it, together with Lakehead Pipe Line Company ("Lakehead"), had negotiated with the Canadian Association of Petroleum Producers ("CAPP"). The RSA modified the applied-for toll treatment of the SEP II facilities to share the risk of underutilization of these facilities. IPL sought to have the RSA approved as a Non-Routine Adjustment pursuant to its Incentive Tolling Agreement.

1.2 Environmental Screening

The National Energy Board ("the Board") conducted an environmental screening of the applied-for facilities in compliance with the Canadian Environmental Assessment Act ("CEAA"). The Board ensured there was no duplication in requirements under the CEAA and the Board's own regulatory process.

The Board determined that, taking into account the implementation of IPL's proposed mitigative measures and those set out in the attached conditions, the project is not likely to cause significant adverse environmental effects. This represents a decision pursuant to paragraph 20(1)(a) of the CEAA.

{MAP - Figure 1-1 - IPL System Expansion Program Phase II}

Chapter 2

FACILITIES

2.1 Expansion Facilities

IPL' s applied-for expansion includes the following:

Line 1 & construction of 148 km of 508 mm outside diameter ("O.D.") pipeline from kilometre post ("kp") 22.1 near Edmonton to kp 170 near Hardisty, Alberta;

- replacement of four pipeline sections totaling 12 km of 508 mm O.D. pipeline between Hardisty and Herschel stations;
- replacement of 30 motors, replacement of 30 pumps, modification of 11 pumps, addition of 11 pumping units and the construction of 12 DRA injection skids at various stations between Edmonton, Alberta and Gretna, Manitoba; and
- construction of a new pump station, NGL prover, booster pumps and associated piping at the Edmonton Terminal.

Line 2B & construction of a 21 600 MJ (6 000 kWh) line heater at Cromer station;

- replacement of 4 pump units; and

- the addition of 3 pump units.

Line 13 & reactivation of 22.1 km of 508 mm O.D. pipeline between the Edmonton Terminal and kp 22.1;

- connection of five pump stations at Edmonton, Kingman, Metiskow, Herschel and Craik from Line 1 to Line 13 service;

- connection of the refined products manifold, booster pumps and associated piping at the Edmonton Terminal to accommodate injections of refined products into Line 13;

- construction of eight mainline connections between kp 22.1 and kp 687.4 (near Regina) to accommodate the transfer of 501.2 km of 508 mm pipeline from Line 1 to Line 13 service; and

- construction of five DRA injection skids.

The proposed expansion will increase the capacity of Line 1 from 36 600 m3/d (230,000 b/d) to 49 500 m3/d (311,000 b/d) and of Line 2B from 76 300 m3/d (480,000 b/d) to 79 500 m3/d (500,000 b/d). The capacity of Line 13 of 31 000 m3/d (195,000 b/d) will not change. Upon completion of the SEP II expansion, Line 1 will be used to transport crudes such as lube light, sweet light, Synthetic and NGLs; Line 2 will transport condensate, Caroline Condensate, and crudes such as sweet light, sour light, Synthetic, Sarnia Special, and OSE; Line 3 will ship Bow River, heavy and sour light crudes and Line 13 will ship Synthetic crude and refined products.

The proposed Line 13 facilities are intended to facilitate the reallocation of refined products from Line 1. A schedule summarizing the applied-for facilities is included as Appendix 1.

2.1.1 Pipeline

IPL applied to construct a new 508 mm O.D. pipeline between kp 22.1 and Hardisty, Alberta. This line would be used as a new Line 1 segment, and the existing Line 1 pipeline between the Edmonton Terminal and Hardisty (including the reactivated segment described below) would be transferred to Line 13 service. This would allow Line 13 to be operated as a continuous line from Edmonton to Clearbrook, Minnesota. IPL submitted that the new pipeline would be needed to facilitate the transfer of refined products from Line 1 to Line 13, as Line 1 is expected to become oversubscribed due to the forecast increase in NGL shipments on Line 1 of 3 200 m3/d (20,000 b/d). IPL further explained that in order to accommodate the increase in NGL shipments, either Line 1 had to be expanded or refined products had to be moved into a different line. IPL chose to move refined products into Line 13. IPL noted that the existing capacity on Lines 2 and 3 between the Edmonton Terminal and Hardisty could not be effectively utilized for refined products shipments without building a tank farm at Hardisty and moving the refined products through this tankage to be re-injected into Line 13 at Hardisty.

IPL also applied to reactivate a section of pipeline between Edmonton and kp 22.1. This segment was originally part of Line 1, but was taken out of service in 1987 as the result of a capacity expansion program. In its application, IPL requested exemption from retesting this section, pursuant to the requirements of Part V of the Onshore Pipeline Regulations ("the Regulations"). The pipe section was hydrotested in 1993 in preparation for IPL's 1994 capacity expansion program but subsequently was not returned to service. Although this section was internally inspected in 1972, 1980, and 1987, and corrosion excavations of select locations were conducted between 1985 and 1989, no inspection or further maintenance, beyond IPL's annual cathodic protection survey, has been conducted on this line segment since 1993.

No parties expressed concerns with IPL's proposed pipeline construction.

2.1.2 Pumps

SEP II includes the construction of a new pump station (including four pumps) on Line 1 at the Edmonton Terminal, the addition of pump units at Strome, Hardisty, Cactus Lake, Loreburn (2 units), Bethune, Odessa, Cromer, West Souris, Glenboro, and Manitou stations, and the replacement of 30 motors and pumps and the modification of 11 pumps at various locations on Line 1. On Line 2B, new pump units would be installed at Souris, Glenboro, and Gretna stations, while one pump and motor replacement would occur at Glenboro and three at Manitou station.

No parties commented on IPL's proposed addition of pumping capacity.

2.1.3 Line 2B Heater

IPL proposed the installation of a line heater on Line 2B at Cromer, Manitoba. Heating the oil at Cromer would have the effect of reducing the viscosity of the oil, thereby increasing the throughput at that location. IPL had not undertaken the detailed design of the line heater prior to the start of the OH-1-96 hearing. However, IPL indicated that detailed design information would be provided to the board when it became available.

Express Pipeline Ltd. ("Express") questioned the estimated operating costs of the proposed line heater, as compared to the line heater currently used by Lakehead on Line 6 at Superior, Wisconsin. IPL agreed that the annual fuel costs for the line heater would be in the range of $750,000 to $1,000,000, although fuel contracts had not yet been obtained.

2.1.4 Drag Reducing Agent

IPL applied to install 12 Drag Reducing Agent ("DRA") injection skids at Edmonton, Hardisty, Kerrobert, Milden, Loreburn, Bethune, Glenavon, Langbank, Cromer, West Souris, Glenboro, and Manitou stations on Line 1, and five DRA injection skids on Line 13 at Edmonton, Kingman, Metiskow, Herschel, and Craik stations. DRA is a chemical additive that reduces the pressure gradient in the section of pipe in which it has been injected. As part of the System Expansion Program Phase I (approved by the Board under Order XO-J1-1-96). IPL installed 14 DRA skids on Line 2A and 6 skids on Line 13. Together, the SEP I and SEP II applications represent a significant increase in the use of DRA on the IPL system. In response to a question by the Board, IPL confirmed that it may now be close to reaching the maximum economic limit for the use of DRA on Lines 1 and 2, although the exact economic limit had not been determined. IPL also noted that while current DRA technology does not work effectively with heavy oil, different products are being developed that may increase the application of DRA. In addition, decreases in the cost of the drag reducing material could change the economic cut-off point for its use.

VIEWS OF THE BOARD

With respect to the construction of 148 km of new 508 mm O.D. pipeline between kp 22.1 and Hardisty, the Board agrees that IPL's proposed construction is an appropriate method of accommodating the forecast increase in natural gas liquids ("NGL") shipments from Edmonton.

With respect to the 22.1 km section of pipeline for which IPL requested an exemption from pressure testing prior to reactivation, the Board notes that section 54(I) of the Regulations requires that a pipeline be retested in accordance with Part V of the Regulations prior to reactivation, if the pipeline has been deactivated for 12 months or more. In addition, the Board notes that IPL did not apply for a deactivation of this line section as required by section 53(1) of the Regulations and that the line section has been out of service for nine years. Absent a retesting of the pipe section, the Board is not persuaded that the reactivation would provide for a level of safety at least equivalent to

that generally provided for by Canadian Standards Association ("CSA") standards. Therefore, the Board will not exempt IPL from the requirement to retest this line section prior to reactivation.

DECISION

IPL is directed to retest the line section between Edmonton and kp 22.1 in accordance with the requirements of Part V of the Regulations. Upon successful completion of the retesting, IPL is further directed to notify the Board of the results of the test (including the test pressures) and the desired maximum operating pressure of the line.

2.2 Alternatives to the Proposed Expansion

As part of its application, IPL provided an evaluation of three alternatives to its proposed design. Briefly, the alternatives consisted of: the addition of 84 km of 1219 mm O.D. looping on Line 3; increasing the operating pressure of Line 1; or expanding the Westspur and Portal pipeline systems (including extending Line 13 from Clearbrook to Superior). IPL noted that none of these alternatives provided the required capacity increase of 19 600 m3/d (120,000 b/d). The alternatives were compared on the basis of capital expenditure per unit of capacity increase.

At the request of the Board, IPL provided an assessment of the incremental annual operating costs associated with each of the design alternatives, plus the annual operating costs of its proposed expansion. IPL also provided an assessment of an additional expansion alternative, consisting of sufficient 1219 mm O.D. looping on Line 3 to achieve the desired capacity increase. The incremental toll impact of each option at 100% capacity utilization (no risk sharing), and of Alternatives 4 (the sum of Alternatives 2 and 3) and 5 (the Line 3 looping) at various utilization levels with the risk sharing agreement were also provided. These comparisons are illustrated in Table 2.1.

IPL submitted that the principal drive for expanded pipeline capacity from western Canada is the forecast increase in Canadian heavy crude oil production, underpinned by a slower than anticipated decline in conventional light crude oil production. IPL noted that its design intent was to create additional space on Line 3 for the forecast heavy crude growth by moving sour and lighter crudes off Line 3 and onto other lines. Although IPL's application originally indicated that SEP Il would eliminate apportionment, IPL subsequently suggested that the removal of market constraints for heavy crude (as described in section 5.2.1) would result in SEP II not being able to supply sufficient take away capacity and that further expansions of the IPL system would be necessary.

TABLE 2-1
COMPARISON OF SELECTED EXPANSION ALTERNATIVES

	SEP II Design	Alternatives 2&3	Line 3 Looping
Capital Cost (C$)	140,000,000	340,000,000	490,000,000
Capacity increase (m3/d)	19600	18600	19600
Incremental Annual Power Cost	19,400,000	18,500,000	8,400,000
Incremental Annual DRA Cost	3,700,000	2,600,000	0
Unit Cost ($/m3/d increase)	7,143	18,300	25,000
Toll Increase (No Risk Sharing)	2c.	5c.	5c.
Toll Increase @ 100% Utilization (Risk Sharing)	3c.	6c.	6c.
Toll Increase @ 75% Utilization (Risk Sharing)	2c.	4c.	5c.

Express argued that the applied-for facilities would not do the job that they were intended to do. It noted that IPL's evidence suggested that by 1999 there would be almost no spare capacity on Line 3 to accommodate the forecast increase in heavy oil supply and that an additional expansion of IPL's system would be necessary to address the apportionment issue. Express also argued that IPL had failed to provide any meaningful comparison of alternatives which would address the true demand for additional capacity on its system.

VIEWS OF THE BOARD

The Board finds a comparison of viable alternatives to be germane to its assessment of the appropriateness of a proposed design. The Board notes that the proposed design is the most cost-effective of the various alternatives presented, and that the design provides some flexibility to minimize the cost of transportation if throughput were to fluctuate in the future. The Board also notes that IPL's proposed design does not appear to fully resolve the issue of capacity constraint for heavy crude shipments. However, the Board appreciates the high level of support accorded to the proposed expansion and, therefore, the Board accepts IPL's applied-for design.

Chapter 3

LAND AND ENVIRONMENTAL MATTERS

3.1 Route and Site Selection and Land Requirements

IPL stated that its proposed expansion was designed to follow its existing pipeline corridor while at the same time avoiding or minimizing new surface disturbance and attendant negative impacts to the biophysical and socio-economic environments. IPL determined that these needs could best be met by constructing additional pipeline parallel to its pipeline corridor, by modifying its existing pipeline tie-ins, and by increasing pumping capacity at several IPL stations between Edmonton, Alberta and Gretna, Manitoba.

Two alternative pipeline routes were considered by IPL. The first alternative involved paralleling their pipelines between Edmonton and Hardisty along the north side of their existing pipeline corridor. The second alternative involved crossing over their pipeline from the north side near Kingman Pump station (kp 51.1), paralleling the corridor along the south side to kp 152.1 near Lougheed, Alberta and then crossing back to the north side for the remainder of the segment to kp 170.0 near Hardisty, Alberta. IPL chose the second alternative as it would involve acquisition of less new permanent easement than the first alternative.

With respect to the location of new facilities, other than line pipe, consideration was not given to new sites as existing sites offered the following advantages:

- the existing facilities have been in service for up to 40 years and are well known to all parties;
- no significant environmental or socio-economic constraints are associated with the existing facilities sites;
- impacts associated with new facilities on new sites would increase the amount of land disturbed by IPL operations; and
- terminal and pump station operations can be completed more efficiently from existing facilities rather than from additional facilities that are geographically separated.

IPL indicated that it would require 18.3 m of new permanent right-of-way and between 5 and 17 m of temporary working rights. IPL provided six different configurations for the various loop segments proposed as well as a summary of the new land requirements on a station by station

basis.

No parties objected to the proposed routing/siting or the requirements for new land rights.

VIEWS OF THE BOARD

The Board agrees with IPL's rationale for installing the proposed pipeline facilities

either within existing easements or adjacent to its existing easement. The Board further finds that the general routes proposed are acceptable and that IPL's anticipated requirements for permanent easements and temporary work space are reasonable.

3.2 Environmental Matters

The Board completed an Environmental Screening Report pursuant to the CEAA and the Board's own regulatory process. In accordance with Hearing Order OH-1-96, the Environmental Screening Report was released to IPL, those parties who requested a copy from the Board, and federal agencies that had provided specialist advice on the proposed facilities.

The comments received, and the Board's views, have been added to the Environmental Screening Report as Appendices I and II respectively. Copies of the Board's Environmental Screening Report are available upon request from the Board's Regulatory Support Office.

VIEWS OF THE BOARD

The Board has considered the Environmental Screening Report, and the comments received on the report, and is of the view that the SEP II project is not likely to cause significant adverse environmental effects, when considered with the implementation of IPL's proposed mitigative measures and those set out in the attached conditions. This represents a decision pursuant to paragraph 20(l)(a) of the CEAA.

The Board is satisfied with the environmental and socio-economic information provided by IPL with regard to the potential adverse environmental effects which may result from the construction and operation of the proposed facilities and with IPL's proposed monitoring and mitigation measures.

Chapter 4

FINANCIAL MATTERS AND TOLLING TREATMENT

- --

4.1 Financial Matters

4.1.1 Tolling Methodology

IPL applied for approval of an integrated toll design methodology for the SEP 11 facilities. The Company considered the SEP II facilities to be a capital program related to an extension of the existing services it provides to shippers.

No parties expressed concerns regarding IPL's applied-for tolling methodology.

4.1.2 Treatment of Costs

IPL requested that the Board find the costs of SEP 11 to be a Non-Routine Adjustment in accordance with the Principles of Settlement, filed in support of its February 1995 Incentive Toll Application.

No parties were opposed to IPL's proposed treatment of the costs of SEP II as a Non-Routine Adjustment.

VIEWS OF THE BOARD

Since SEP II is an extension of the existing services that IPL provides to its shippers, the Board considers it appropriate that the costs of the program be rolled-in. Furthermore, the Board agrees that these costs constitute a Non-Routine Adjustment under the terms of IPL's February 1995 Incentive Toll Agreement.

4.2 Requested Exemption from the Guidelines for Filing Requirements

In its application, IPL requested exemption from filing proforma statements of rate base and cost of service as well as proposed method and rates of depreciation by plant account contemplated in the February 1995 Guidelines for Filing Requirements ("the Guidelines"). IPL submitted that this information was not relevant under IPL's incentive method of financial regulation approved by the Board under Order TO-1-95.

IPL also requested exemption from filing five years of average unit transportation costs (tolls)

beyond the first year after the SEP II facilities are expected to be in service. IPL stated its view that in light of the incentive method of regulation which governs IPL's operations, it is not possible to forecast tolls with reasonable reliability over a five year term. IPL further submitted that tolls would vary from year to year based on operating results, and that providing five year tolls based on a series of assumptions may not be meaningful to the Board.

IPL further sought exemption from filing proforma balance sheets, proforma financial statements, and supporting details on the proposed return on rate base and provision for income taxes because, in IPL's view, the magnitude of the debt component of the financing was not material to IPL's financial position.

No parties opposed IPL's request for exemption from the Guidelines.

VIEWS OF THE BOARD

The Board considers the reasons given by IPL for not filing the above information to be acceptable and, therefore, grants the requested exemptions from the Guidelines.

4.3 Risk Sharing Agreement

By letter dated 31 May 1996, IPL filed the updated evidence of Brian T. Vaasjo. In this evidence, Mr. Vaasjo stated that IPL was approached by CAPP to discuss the possibility of reaching an agreement to share the risks relating to the potential under-utilization of the SEP II facilities. The first meeting was held on 17 May 1996 and an agreement was reached on 31 May 1996.

The Risk Sharing Agreement ("RSA") relates to both IPL and Lakehead in respect of the SEP II facilities and would be subject to approval by the National Energy Board and the Federal Energy Regulatory Commission.

Under the RSA, the rate of return on the deemed equity portion of the SEP II facilities would vary based upon the level of utilization of the facilities. At 75% utilization of the facilities, or 14 700 m3/d (90,000 b/d), the return on the deemed equity component of the SEP II facilities would be the annual multi-pipeline rate as determined by the Board. If the SEP II facilities are utilized at between 0% and 50%, or up to 9 800 m3/d (60,000 b/d), the return on the deemed equity of SEP II would be the multi-pipeline rate less 3.0%, subject to a minimum rate of return of 7.5% in years 1 through 10 and 8.5% in years 11 through 15. The rate of return on SEP II deemed equity increases with facilities utilization on a straight line basis, from the multi-pipeline rate less 3.0% at 50% utilization to the multi-pipeline rate plus 3.0% at 100% utilization, subject to a maximum rate of return of 15.0% during the term of the agreement. The toll impact of the SEP II facilities is shown in Table 4-1.

The utilization level of the SEP II facilities would be calculated on a full system basis. That is, IPL would determine the total system capacity by adding the 19 600 m3/d (120,000 b/d) throughput related to the SEP II expansion to the annual capacity under the Incentive Toll Agreement. The actual throughput would then be measured and compared to this total system

capacity to determine the utilization level. The percentage of the SEP II facilities utilized would determine the return level to be received by IPL for these facilities. To the extent that actual throughput was less than the total system capacity there would be a volume shortfall. For example, if that shortfall was 4 900 m3/d (30,000 b/d), the SEP II facilities would be 75% utilized and IPL would earn the annual multi-pipeline rate.

TABLE 4-1
SUMMARY OF SEP II TOLL IMPACT
INCREMENTAL TOLLS
(c./b Canadian)[1]

	Total	IPL	Lakehead[2]
Without Risk Sharing			
At 100% Utilization	10	2	8
At 0% Utilization	10	2	8

With Risk Sharing			
At 100% Utilization	12	3	9
At 50% Utilization	6	1	5
At 0% Utilization	6	1	5

(1) Incremental light crude tolls on Edmonton to Chicago
(2) Assuming 100% tax allowance

Further expansions of the IPL system would be "stacked on top" of the SEP II facilities. In determining the utilization rates, post-SEP II expansions would be considered to be the "top" volumes and these expansions would have to go totally unused for the utilization of the SEP II facilities to fall below 100%. The return on post-SEP II expansions would be governed by IPL's Incentive Toll Agreement.

Other stipulations of the RSA include the following:

- DRA costs would flow through as a surcharge;
- all other costs including operating, interest and depreciation costs would flow through to the tariffs;
- the agreement would be subject to approval of the IPL and Lakehead Boards of Directors;

- the term of the agreement is for 15 years, commencing on the date of completion of the facilities construction; and
- the existing toll design would not be affected and point-to-point tolls would reflect a volume-distance allocation of costs.

IPL stated that it was of the view that the RSA would result in just and reasonable tolls, and that its terms should be approved by the Board as a Non-Routine Adjustment in accordance with paragraph 7.1 (a)(i) of the Principles of Settlement filed in support of IPL' s February 1995 Incentive Toll Application approved by Board Order TO-l-95.

No parties were opposed to the RSA. The RSA was supported by parties including Amoco and the Shippers Group1, as well as Koch Oil on its own, behalf. The Shippers Group noted that the RSA is an innovative and appropriate method of ensuring that some of the risk associated with potential under-utilization of expansion capacity would be borne by the pipeline, rather than by the shippers. Koch submitted that the RSA is a highly significant benefit for shippers on IPL is consistent with the spirit, intent, and provisions of the February 1995 Incentive Toll settlement between IPL and CAPP and, therefore, should be approved by the Board.

The Board questioned whether the variable rate of return feature of the RSA could be accommodated as a Non-Routine Adjustment within the terms of the Principles of Settlement. Section 7.3 of the Principles of Settlement defines a

Non-Routine Adjustment as the sum of three components: operating cost, capital cost, and annual income taxes. The capital cost component is itself defined in subsection 7.3(b) to include depreciation expense, annual interest expense, and:

> "Annual earnings based on the common equity rate of return in effect resulting from the National Energy Board Multi-Pipeline Proceeding (RH-2-94) as adjusted from time-to-time, and applied to the applicable negotiated equity ratio set out in Article 7.3(b)(ii)."

IPL argued that this paragraph did not mean that the annual earnings component must be calculated using a rate of return equal to the multi-pipeline rate of return. Rather, it argued that the agreement provided that annual earnings would be "based on" the multi-pipeline rate of return. Since the variable rate of return provided for in the RSA is either the same as the multi-pipeline rate of return or is calculated upward or downward from the multi-pipeline rate of return, IPL argued that it was "based on" the multi-pipeline rate of return within the meaning of the Principles of Settlement. Accordingly, IPL argued that the RSA did not amount to an amendment to the Principles of Settlement, nor was an amendment to Order TO-1-95 required.

VIEWS OF THE BOARD

Without deciding whether the interpretation put forward by IPL is a correct interpretation of section 7.3 of the Principles of Settlement, the Board is of the view that it can approve the terms of the RSA in this proceeding. The public notice of the hearing,

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1 The Shippers Group was comprised at Imperial Oil Limited, Koch Oil Co. Ltd., Mobil Natural Gas Canada Ltd., Petro-Canada, Shell Canada Limited, and Murphy Oil Company Ltd.

attached as Appendix I to the Hearing Order, stated that the application sought Orders from the Board pursuant to Part IV of the Act respecting toll design and tariffs; and the preliminary list of issues attached as Appendix III to the Hearing Order included, as item #9. "The design and elements of the tolls applied for by IPL." Even though the RSA was not originally part of the application, the Board is of the view that the public notice of the hearing, together with the preliminary list of issues attached to the Hearing Order, was sufficiently broad to put interested persons on notice that toll design in respect of the applied-for facilities would be considered in this proceeding. The Board is further of the view that in disposing of that issue, it is not necessarily limited to dealing with the proposal originally made by IPL in its application. The Board therefore finds that it has jurisdiction to approve the RSA in this proceeding, even if this would effectively amount to an amendment to the Principles of Settlement or Order TO-1-95. The Board notes that the RSA has broad shipper support and is satisfied that the settlement represented by the RSA is just and reasonable in the circumstances. The terms of the RSA are therefore approved.

- ---------------

1 The Shippers Group was comprised at Imperial Oil Limited, Koch Oil Co. Ltd., Mobil Natural Gas Canada Ltd., Petro-Canada, Shell Canada Limited, and Murphy Oil Company Ltd.

Chapter 6

DISPOSITION

The foregoing constitutes our Decision and Reasons for Decision in respect of the application heard by the Board in the OH-1-96 proceeding. The Board accepts the supply and markets information provided by IPL as reasonable. In addition, the Board finds that the design of the System Expansion Program Phase II is acceptable to fulfil the demand for additional capacity on the IPL system.

With regard to Part IV matters, the Board approves a rolled-in tolling methodology for the System Expansion Program Phase II. The Board finds that the capital and operating costs relating to SEP II constitute a Non-Routine Adjustment in accordance with paragraph 7.1 (a)(i) of the principles of settlement, filed in support of IPL's February 1995 Incentive Toll Application approved by NEB order TO-1-95. The Board also approves the terms of the Risk Sharing Agreement.

The Board is satisfied that the evidence indicates a strong likelihood that the facilities will be used at a reasonable level and are required by the present and future public convenience and necessity. Therefore, the Board will recommend to the Governor-in-Council that a certificate be issued. The certificate will be subject to the conditions outlined in Appendix II.

R.L. Andrew
Presiding Member

A. Cote-Verhaaf
Member

J.A. Snider
Member

Calgary, Alberta
July, 1996

Appendix I

SCHEDULE OF FACILITIES

FIGURE A1-1

Station	Units	Description
Edmonton to Hardisty	Line 1	508 mm O.D. pipeline
Edmonton	1.1, 1.2, 1.3, 1.4	Unit addition

	Line 1	DRA skid
	13.1. 13.2, 13.3	Existing station transferred
	Line 13	DRA skid
Kingman	13.1. 13.2	Existing station transferred
	Line 13	DRA skid
Strome	1.1	Modify pump, replace motor
	1.2	Replace pump and motor
	1.3	Unit addition
Hardisty	1.1, 1.2, 1.3	Replace pump and motor
	1.4	Unit addition
	Line 1	DRA skid
Metiskow	13.1, 13.2	Existing station transferred
	Line 13	DRA skid
Cactus Lake	1.1	Modify pump, replace motor
	1.2	Replace pump and motor
	1.3	Unit addition
Kerrobert	1.1, 1.2, 1.3	Replace pump and motor
	1.4	Modify pump, replace motor
	Line 1	DRA skid
Hershel	13.1, 13.2	Existing station transferred
	Line 13	DRA skid
Milden	1.1	Replace pump and motor
	1.2, 1.3	Modify pump, replace motor DRA skid
	Line 1	

Loreburn	1.1, 1.2	Replace pump and motor
	1.3, 1.4	Unit additions
	Line 1	DRA skid
Craik	13.1., 13.2	Existing station transferred DRA skid
	Line 13	
Bethune	1.1	Modify pump, replace motor
	1.2	Replace pump and motor
	1.3	Unit addition
	Line 1	DRA skid
Regina	1 .1. 1.2	Replace pump and motor
White City	1.1	Replace pump, transfer meter
	1.2	Replace pump and motor
Odessa	1.1	Replace pump, transfer motor
	1.2	Replace pump and motor
	1.3	Unit addition
Glenavon	1.1	Replace pump, transfer motor
	1.2, 1.3	Replace pump and motor
	Line 1	DRA skid
Langbank	1.1	Replace pump, transfer motor
	1.2. 1.3	Modify pump, replace motor

	Line 1	DRA skid
Cromer	1.1	Replace pump
	1.2	Replace pump and motor
	1.3	Unit addition
	Line 1	DRA skid
	Line 2	Line heater
West Souris	1.1	Replace pump, transfer motor
	1.2	Replace pump and motor
	1.3	Unit addition
	Line 1	DRA skid
Souris	2.3	Modify pump
	2.5	Unit addition
Glenboro	1.1	Modify pump
	1.2	Modify pump, replace motor
	1.3, 2.6	Unit addition
	2,1	Replace pump and motor
	Line 1	DRA skid
Manitou	1.1	Replace pump, transfer motor
	1.2, 2.1, 2.2, 2.3	Replace pump and motor
	1.3	Unit addition
	Line 1	DRA skid

Gretna	1.1	Replace pump, trans. Motor
	1.2	Replace pump
	1.3	Modify pump
	2.4	Unit addition

Appendix II

CERTIFICATE CONDITIONS

Unless the Board otherwise directs;

1. IPL shall implement or cause to be implemented all of the policies, practices, recommendations and procedures for the protection of the environment included in or referred to in its application with the exception of minor adjustments or changes to these practices, procedures and recommendations which may be required as a result of site conditions at the time at construction. These minor amendments to practices, procedures and recommendations will be reviewed by IPL's on-site Environmental Inspector and, providing the same standard of environmental protection is achieved, may be implemented without prior Board approval, federal, provincial and/or the local authorities shall be consulted, where appropriate.

2. IPL shall, 15 days prior to the commencement to construction to the Eagle Creek crossing, advise the Board of the results of the Company's consultations with provincial authorities and with the Department of Fisheries and Oceans.

3. IPL shall, 15 days prior to the commencement of the hydrostatic test program, file with the Board copies of permits for the withdrawal and discharge of the hydrostatic test water.

4. IPL shall, 30 days after the in-service date, conduct noise emission surveys at each pump station where the addition of extra pumping units has occurred and file such reports with the Board. The noise emission surveys shall include actual noise level measurements at intervals along the station fence line and within 15 m of the nearest residence.

5. IPL shall, pursuant to section 58 of the National Energy Board Onshore Pipeline Regulations ("the Regulations"), file with the Board a post-construction environmental report within six months of the date that the construction is completed. The post-construction environmental report shall set out the environmental issues that have arisen up to the date on which the report is filed and shall:

   (a) indicate the issues resolved and those unresolved; and

   (b) describe the measures IPL proposes to take in respect of the unresolved environmental issues.

6. IPL shall, pursuant to section 58 of the Regulations, file with the Board, on or before the 31 December following each of the first two complete growing seasons after the post-construction environmental report referred to in condition 5 has been filed, a

report containing:

   (a) a list of the environmental issues indicated as unresolved in the previous report and any that have arisen since that report was filed; and

   (b) a description of the measures IPL proposes to take in respect of any unresolved environmental issues.

7. IPL shall, at least 10 days prior to the commencement of construction of the approved pipeline facilities between Edmonton and Hardisty, file with the Board the results of the heritage

resource surveys referred to in the application, including any corresponding avoidance or mitigative measures.

8. IPL shall, prior to the commencement of construction:

(a) serve the heritage resource surveys on Alberta Community Development and the Saskatchewan Heritage Branch;

(b) seek the opinion of each provincial agency described in subsection (a) above, concerning the acceptability or non-acceptance of the heritage resource surveys and

(c) advise the Board of the respective opinions of each provincial agency described in subsection (a) above, or of IPL's inability to obtain an oral or written opinion of one or more of the provincial agencies described in subsection (a) above.

9. IPL shall file with the Board detailed design information concerning the Line 2B heater at least 10 days prior to the scheduled in-service date of the heater.

10. This certificate shall expire on 1 July 1999 unless the construction and installation of the proposed facilities has commenced by that date.

EXHIBIT NO. 3

EXPLANATORY STATEMENT

SEP II RISK SHARING AGREEMENT

This Explanatory Statement briefly summarizes the primary provisions of the SEP II Risk Sharing Agreement (Exhibit 1, Attachment A, Appendix D).

1. The SEP II Risk Sharing Agreement ("RSA") applies to both Enbridge and Lakehead with respect to the System Expansion Project Phase II facilities. It was entered into subject to Commission approval, and was contained in the FERC Settlement that was approved by the Commission on October 18, 1996.

2. The general intent of the RSA as applied to Lakehead is to treat as a floor the rates established by the original FERC Settlement (subject to indexing adjustments since the date on which that settlement was approved). The costs of the SEP II project are to be recovered as a separate surcharge on top of the settlement rates, calculated on the basis of Lakehead's cost of service for the SEP II facilities viewed as a separate project.

3. For purposes of the SEP II cost-of-service calculation, Lakehead will apply the same cost-of-service model as was applied to calculate the settlement rates (i.e., one based on Opinion No. 154-B as interpreted in Opinion Nos. 397 and 397-A), with certain specified adjustments described below. The additional revenues realized as a result of the expanded throughput made possible by SEP II will be treated as a credit against the SEP II cost of service. In this

way, only the net costs of the project will be included in the surcharge.

4. The surcharge will be designed to recover the SEP II costs during a period of 15 years. Because of the impacts on the SEP II rate base from depreciation and trending, as well as changes in operating costs and projected throughput from year to year, Lakehead will

recalculate and refile the SEP II surcharge to be effective as of January 1 each year. Both the initial surcharge filing and the yearly recalculated filings will be accompanied by a cost-of-service showing based on the terms of the FERC Settlement and the RSA. The surcharge will expire automatically after 15 years.

5. The rate of return to be used each year in the surcharge calculation is to be based on the so-called multi-pipeline rate of return ("MPR") as determined annually by the National Energy Board of Canada. The MPR was initially set at 12.25% as of 1995 at the conclusion of a generic proceeding on rate of return conducted by the NEB. The MPR is adjusted annually by the NEB based on changes in interest rates. The actual rate of return in the surcharge calculation in any given year may vary upwards or downwards from the MPR depending on the degree of utilization of the SEP II facilities. If the facilities are 50 percent utilized or less, the rate of return will be the MPR less 3.00%, subject to a minimum rate of return of 7.50% in years 1 through 10 and 8.50% in years 11 through 15. If the facilities are 75 percent utilized, the rate of return will be equivalent to the MPR. If the facilities are 100% utilized, the rate of return will be the MPR plus 3.00%, subject to a maximum rate of return of no more than 15 percent at a time. At utilizations between 50 percent and 100 percent, the rate of return will vary proportionately between the levels stated above.

6. In accordance with paragraph 13.A. of the FERC Settlement, the tax allowance in the surcharge calculation is to be computed using 30 percent of the amount that would be allowed if Lakehead were a corporation rather than a master limited partnership. This agreement reflects the ruling in Opinion Nos. 397 and 397-A that master limited partnership pipelines are not entitled to a tax allowance on their net income attributable to individual unitholders. E.g., Opinion No. 397-A, 75 FERC paragraph 61,181, at 61,593-99 (1996). The 30 percent

figure takes into account the ownership of Lakehead units by Lakehead and other corporations and similar entities, as well as the attribution of book net income to Lakehead for management incentives and other purposes.

7. The surcharge will be calculated in accordance with the existing Lakehead rate design, with point-to-point rates reflecting a volume-distance allocation of costs.

8. As a settlement, the SEP II provisions regarding rate of return, tax allowance and other matters are the product of compromise and are not intended to reflect the individual views of Lakehead, Enbridge or CAPP on any substantive ratemaking issue.

Exhibit No. 4

National Energy Board

Reasons for Decision

INTERPROVINCIAL PIPE LINE INC.

OH-1-98

June 1998

- --

Facilities and Toll Methodology

125

National Energy Board

- --

REASONS FOR DECISION

In the Matter of

Interprovincial Pipe Line Inc.

Application dated 2 December 1997,
as amended, for the Terrace Phase I
Expansion Program

OH-1-98

JUNE 1998

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Cat. No. NE22-1/1998-3E
ISBN 0-662-26864-4

This report is published separately in both official languages.

COPIES ARE AVAILABLE ON REQUEST FROM:
The Publications Office
National Energy Board
311 Sixth Avenue S.W.
Calgary, Alberta, T2P 3H2
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Fax: (403) 292-5503
Phone: (403) 292-3562

No de cat. NE22-1/1998-3F
ISBN 0-662-82943-3

Ce rapport est publie separement dans les deux langues officielles.

EXEMPLAIRES DISPONIBLES SUR DEMANDE AUPRES DU:
Bureau des publications
Office national de l'energie
311, sixieme avenue s.-o.
Calgary (Alberta), T2P 3H2
Courrier electronique: orders @ neb.gc.ca
Telecopieur: (403) 292-5503
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For pick-up at the NEB office:
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Printed in Canada

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En personne, au bureau de l'Office:
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Imprime au Canada

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ABBREVIATIONS AND DEFINITIONS

Act	National Energy Board Act
apportionment	The method of allocating the difference between the total nominated volume and the available pipeline operating capacity, where the latter is smaller.
barrel	One barrel is approximately equal to 0.16 m3.
b/d	barrels per day
Board	National Energy Board
CAPP	Canadian Association of Petroleum Producers
CEAA	Canadian Environmental Assessment Act
crude oil and equivalent	A collective term used to refer to all grades of crude oil, including conventional light and heavy crude oil, pentanes and heavier hydrocarbons, synthetic crude oil and bitumen.
Express	Express Pipeline Ltd.
Guidelines for Negotiated Settlements	The Board's 1994 Guidelines for Negotiated Settlements of Traffic, Tolls and Tariffs
heavy crude oil	A collective term which includes conventional heavy crude oil and bitumen.
IPL	Interprovincial Pipe Line Inc.
km	kilometre
KP	kilometre post
Lakehead	Lakehead Pipe Line Partners, L.P.
laminar flow	A flow regime where fluid molecules in a pipe move in a parallel manner and the fluid exhibits a parabolic velocity profile (i.e., velocity at the pipe wall is zero while velocity at the centre of the pipe is the maximum).
Line 9	IPL's pipeline that extends from Sarnia, Ontario to Montreal, Quebec.

Line 14	A pipeline currently under construction by Lakehead which will extend from Superior, Wisconsin to the Chicago, Illinois area.
m3/d	cubic metres per day
mm	millimetre
netback	The per unit price received by a producer from the sale of crude oil, less applicable costs. These typically include transportation and marketing fees.
OD	outside diameter
OH-1-96	Interprovincial Pipe Line Inc., Application for System Expansion Program Phase II, Reasons for Decision dated July 1996.
OH-2-97	Interprovincial Pipe Line Inc., Application for the Line 9 Reversal Project, Reasons for Decision dated December 1997.
OSE	A light sour synthetic crude oil that is produced at the Suncor Inc. oil sands plant in

	Fort McMurray, Alberta.
PADD	U.S. Petroleum Administration for Defence Districts
SEP II	Interprovincial Pipe Line Inc.'s System Expansion Program Phase II, approved by the Board in OH-1-96.
Terrace Phase I	Interprovincial Pipe Line Inc.'s Terrace Phase I Expansion Program.
WTI	West Texas Intermediate crude oil - a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

RECITAL AND APPEARANCES

IN THE MATTER OF the National Energy Board Act ("the Act") and the regulations made thereunder;

IN THE MATTER OF an application by Interprovincial Pipe Line Inc. dated 2 December 1997, as amended on 31 March 1998, for a Certificate of Public Convenience and Necessity pursuant to section 52 of the Act; an order pursuant to section 58 of the Act for other related facilities; an order pursuant to section 21 of the Act varying Board Order XO-JI-l0-98; and an order under Part IV of the Act respecting toll design methodology; and

IN THE MATTER OF the National Energy Board Hearing Order OH-1-98.

HEARD at Calgary, Alberta, 15 and 16 April 1998.

BEFORE:

R.J. Harrison	Presiding Member
J.A. Snider	Member
D. Valiela	Member

APPEARANCES:

G.M. Nettleton	Interprovincial Pipe Line Inc.
K.F. Miller	Canadian Association of Petroleum Producers
S.H. Castonguay	Amoco Canada Petroleum Company Ltd.
L.G. Keough	Express Pipeline Ltd.
D. Armstrong	Imperial Oil Limited
P. Kahler	PanCanadian Petroleum Limited
J. Ellis	Shell Canada Limited
B. Netzel	Alberta Department of Energy
M.A. Fowke	Board Counsel
G. Delisle	

Chapter 1

INTRODUCTION

1.1 THE APPLICATION

By letter dated 2 December 1997 and as amended on 31 March 1998, Interprovincial Pipe Line Inc. ("IPL") applied to the National Energy Board ("Board"):

(a) pursuant to section 52 of the National Energy Board Act1 ("Act"), for a Certificate of Public Convenience and Necessity for new line pipe facilities;

(b) pursuant to section 58 of the Act, for an order exempting all applied-for pump unit additions, replacements and modifications and related station facilities and piping from the provisions of sections 30, 31 and 47 of the Act;

(c) pursuant to section 21 of the Act, for an amending order varying Board Order XO-J 1-10-98 to allow for the relocation of certain scraper trap facilities; and

(d) pursuant to Part IV of the Act, for an order approving a toll design methodology.

IPL' s Terrace Phase I Expansion Program ("Terrace Phase I") involves the construction of 15 new sections of 914 millimetre ("mm") (36 inch) outside diameter ("OD") pipeline to connect to existing 1219 mm (48 inch) OD pipe sections to create a fifth pipeline ("Line 4") between Kerrobert, Saskatchewan and the international border near IPL's Gretna pump station in Manitoba. The applied-for facilities include 619 kilometres ("km") (385 miles) of pipeline, 19 pumping unit additions, 15 tie-in facilities and related station facility equipment. Approximately 373 km (232 miles) of pipeline would be constructed within existing IPL easements, while 246 km (153 miles) would be constructed on new easements to be acquired adjacent to existing IPL easements.

The estimated capital cost of the Terrace Phase I facilities is $610 million. The new line pipe is expected to be in service by 31 January 1999, while all pumping facilities are expected to be in service by 1 September 1999. The applied-for facilities would increase the throughput capability of the existing IPL system by approximately 27 000 cubic metres per day ("m3 /d") (170,000 barrels per day ("b/d")).

IPL noted in its original filing that, at the request of the Canadian Association of Petroleum Producers ("CAPP"), it would be entering into discussions concerning the potential implementation of alternate tolling methodologies for Terrace Phase I. In the interim, IPL requested that Terrace Phase I be tolled on a rolled-in basis and treated as a Non-Routine Adjustment within the meaning of paragraph 7.1 (a)(i) of the Principles of Settlement filed in support of IPL's 1995 Incentive Toll Application, which was approved by the Board pursuant to Order TO- 1-95.

- ------------

1 R.S.C. 1985, C.N-7.

1 On 15 April 1998, IPL filed with the Board a tolling agreement (dated 14 April 1998) that it had negotiated with CAPP. IPL submitted that the tolling agreement would result in just and reasonable tolls and that its terms should be approved by the Board pursuant to Part IV of the Act and in accordance with the Board's 1994 Guidelines for Negotiated Settlements of Traffic, Tolls and Tariffs ("Guidelines for Negotiated Settlements"). By letter dated 15 April 1998, the Board sought comments on the agreement from parties to the hearing and shippers on the IPL system. No comments were received by the Board. A copy of the agreement is attached as Appendix II1.

1.2 ENVIRONMENTAL SCREENING

The Board conducted an environmental screening of the applied-for facilities in compliance with the Canadian Environmental Assessment Act ("CEAA"). The Board ensured that there was no duplication in the requirements under its regulatory process and the CEEA.

The Board determined that, taking into account the implementation of IPL's proposed mitigative measures and those set out in the attached conditions, the project is not likely to cause significant adverse environmental effects. This represents a decision pursuant to paragraph 20(1)(a) of the CEAA.

1 Please note that the text of the agreement as shown in Appendix II has been incorporated electronically into these Reasons from a file provided by IPL and, therefore, the Board cannot be certain that there are no discrepancies between this text and the actual text of the agreement. If any discrepancies exist, the Board directs readers to refer to the original document which constitutes the official version.

(MAP)

Chapter 2

FACILITIES

2.1 CURRENT AND PROPOSED OPERATION

The current and proposed operation of the IPL system is illustrated graphically in Appendix III and is briefly summarized below. Currently, much of the IPL system between Edmonton, Alberta and Gretna operates in a "looped" manner, where the product flow crosses over to a larger diameter pipeline upstream of each pump station, thereby increasing the capacity of each line. At the discharge side of each pump station, the product flows back into the "original" diameter pipe for that line.

Under Terrace Phase I, the present looped configuration would be replaced by straight-through operation for Lines 2, 13 and part of Line 3. This "de-looping" would result in capacity reductions on these lines. The proposed straight-through operation would allow the existing 1219 mm (48 inch) OD pipe sections currently used by Line 3 to be combined with the applied-for construction of 15 sections of 914 mm (36 inch) OD pipe to form the new Line 4. This would result in Lines 3 and 4 being operated in a partially looped manner between Edmonton and Kerrobert and in a straight-through manner downstream of Kerrobert. Line 2 would originate at the Kerrobert station.

In addition, IPL proposed that the commodities be switched between Lines 2 and 3. Line 2 would operate in heavy crude service (in laminar flow), which would have the effect of further reducing capacity on this line. Line 3 would operate in light and medium service. The proposed Line 4 would operate in heavy crude oil service. Table 2-1 lists the current and proposed post Terrace Phase I commodities that would be transported in each line.

TABLE 2-1
ALLOCATION OF COMMODITY TYPES BY LINE

LINE	WITHOUT TERRACE PHASE I	WITH TERRACE PHASE I
1	Natural gas liquids, Synthetics, Lube light, Light sweet.	Natural gas liquids, Synthetics, Lube light, Light sweet.
2	Light sweet, Light sour, Condensate,	Heavy.

	OSE, Midale, Sarnia Special, Light sour blend.	
3	Heavy, Bow River, Light sweet, Light sour.	Light sweet, Light sour, Condensate, Midale, Light synthetics, Sarnia Special, Light sour blend.
4	Not applicable.	Heavy, Bow River, Light sour, Midale, Heavy synthetics.
13	Refined products, Synthetics.	Refined products, Synthetics.

The combination of de-looping, creation of Line 4 and switching of commodities would result in system capacity changes as shown in Table 2-2.

TABLE 2-2
ANNUAL THROUGHPUT CAPACITIES
(103 m3/d)

LINE	CURRENT	POST-TERRACE PHASE I	CHANGE
1	49.5	49.5	0
13	31.0	27.8	(3.2)
2	79.5	25.0	(54.5)
3	99.1	81.2	(17.9)
4	0	102.1	102.1
TOTAL	259.1	285.6	26.5

2.2 APPLIED-FOR FACILITIES

A summary of the facility additions and modifications by line number is provided below:

- Line 1 - no changes;
- Line 2 - pump and motor additions at two stations with associated building additions, pump and motor relocations at five stations, and delivery and injection piping modifications at two stations;
- Line 3 - piping modifications at six Line 2 stations, and delivery and injection piping modifications at three stations;
- Line 4 - construction of approximately 619 km of 914 mm OD pipe sections with associated sectionalizing valves, 15 tie-in facilities, pump unit additions at three stations (three new pumps at each station) and required building additions, piping and unit modifications at 15 stations, pump and motor replacements at four stations, and delivery and injection piping modifications at two stations.

With respect to the station facilities, IPL applied pursuant to section 58 of the Act for an order exempting all applied-for pump unit additions, replacements and modifications and related facilities and station piping (as detailed in Schedule A of Appendix V) from the requirements of sections 30, 31 and 47 of the Act.

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IPL also applied for an amending order pursuant to section 21 of the Act for the relocation of previously approved[1] 1219 mm OD scraper trap facilities. IPL now intends to use these facilities as part of the Terrace Phase I program. Three receiving scraper traps will be installed as originally proposed at the Herschel, Glenboro and Glenavon stations and the remaining three sending scraper traps would be installed at the Loreburn, Craik and Odessa stations. In addition, seven existing 1219 mm OD sending traps would be dismantled and stored for future use, with the exception of one sending unit which would be relocated and used at the Souris station.

The operation of Lines 2, 13 and part of Line 3 in a straight-through manner would result in currently used crossover piping being taken out of service. IPL stated during the hearing that it intends to remove essentially all of the crossover piping and confirmed that it would file an application with the Board for the piping removal.

With respect to river crossings, IPL submitted that it is evaluating the feasibility of directionally drilling the South Saskatchewan, Qu'Appelle and Souris Rivers before making a final determination of the type of crossing methodology to be used at each of these locations. IPL stated that it would consider geotechnical feasibility, constructability, environmental concerns and cost constraints in order to determine the preferred crossing methodology for each of these rivers.

IPL submitted that the design and construction of Terrace Phase I would be in accordance with the Board's Onshore Pipeline Regulations[2] and would meet or exceed the requirements of the 1996 edition of the Canadian Standards Association standard Z662, Oil and Gas Pipeline Systems. IPL also indicated that the capital cost of the Terrace Phase I facilities, estimated to be $610 million, is based on a combination of estimated and actual material quotations and historical construction costs.

VIEWS OF THE BOARD

While the Board would be concerned about the ongoing integrity of the unused crossover piping once IPL's system is de-looped, the Board understands that IPL will apply for the removal of this piping within a reasonable time frame. If IPL chooses not to remove these crossovers, it is reminded that, pursuant to subsection 53(1) of the Onshore Pipeline Regulations, an application will be required for the deactivation of the crossover piping if IPL proposes to deactivate the piping for 12 months or more.

In the Board's view, directionally drilling the South Saskatchewan, Qu'Appelle and Souris Rivers would be the preferred crossing method from an environmental perspective. While the Board recognizes the constraints associated with this crossing methodology, such as geotechnical concerns and cost, it is not prepared to provide blanket approval for IPL's proposed alternative crossing methodologies in the absence of information on the technical feasibility of directional drilling. Therefore, the Board will require IPL to file a report on the feasibility of directionally drilling these rivers and obtain approval of the Board for the crossing methodology of each river prior to construction at each location.

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1 Board Order XO-J1-10-98.

2 SOR 89-303.

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The Board is satisfied that the proposed Terrace Phase I facilities are appropriate for the purposes of the proposed service and that all design and construction activities will meet the applicable standards and regulatory requirements. As well, the Board considers the costs associated with the facilities to be reasonable.

2.3 INTEGRITY

2.3.1 LINE 4 - INTERNAL INSPECTION CAPABILITY

To ensure that Line 4 would be 100 percent capable of internal inspection, IPL had originally intended to use separate internal inspection tools for the proposed 914 mm OD and existing 1219 mm OD pipe sections. To facilitate this, IPL applied for the installation of scraper trap facilities at each location where connections between the two pipeline diameters would occur. Subsequently, IPL determined that advances in internal inspection tool technology would allow the development of one tool to inspect line pipe of different diameters and, therefore, modified its application to make use of previously approved scraper trap facilities as described in Section 2.2.

2.3.2 LINE 13 - IDLE PIPE SECTIONS

During the hearing, the Board questioned IPL regarding the current status of the 406 mm (16 inch) OD mainline on Line 13 and the 610 mm (24 inch) OD loop sections on Line 2 between Regina, Saskatchewan and Gretna. IPL submitted that, from late 1994 to May 1997, Line 13 had operated in a parallel flow configuration using both the 406 mm OD mainline and the 610 mm OD loops. In May 1997, Line 13 was placed in a looped operation which resulted in the 406 mm OD pipe sections becoming idle. Between May 1997 and the present, the idle sections have been filled with light crude oil and have been utilized to facilitate loop swings associated with the internal inspection of adjacent pipelines. IPL submitted that, once the Terrace Phase I facilities are in service, Line 13 would be in straight-through operation using the 406 mm OD mainline and the 610 mm OD loops would be used by Line 2 in straight-through operation. IPL also indicated that a high-resolution internal inspection of Line 13 was conducted in 1995. Based on this inspection, Line 13 was subsequently examined and repaired, and a follow-up internal inspection is scheduled for 2001. Additionally, Line 13 was hydrostatically tested between Regina and Cromer, Manitoba in 1993 and between Cromer and Gretna in 1994.

2.3.3 LINE 2- LAMINAR FLOW

IPL indicated that it intends to operate Line 2 in laminar flow and that it is aware of the potential for increased internal corrosion associated with this slower flow rate. IPL submitted that it intends to increase its internal inspection frequency and to utilize inhibitors to control internal corrosion.

Views of the Board

The Board understands that an internal inspection tool capable of inspecting dual diameter pipelines of the sizes required by IPL (914 mm/1219 mm OD) does not currently exist. However, given that IPL is presently working to develop a tool for the required pipe sizes and may not need to internally inspect Line 4 for several years, the Board is reasonably confident that the required inspection equipment will be available when required.

As a result of IPL's ongoing integrity management program, including periodic in-line inspection and hydrostatic testing, the Board is of the view that IPL has adequately addressed the potential integrity issues associated with the idle 406 mm OD pipe sections on Line 13.

IPL agreed with the Board's understanding that the proposed laminar flow operation of Line 2 could increase the possibility of internal corrosion. However, the Board is of the view that the information IPL has provided to date with respect to internal corrosion mitigation on Line 2 is incomplete. Therefore, IPL is directed to re-evaluate its existing Line 2 internal corrosion control program, addressing potential corrosion issues associated with laminar flow, and to file the results with the Board.

2.4 ALTERNATIVES TO THE PROPOSED EXPANSION

As part of its application, IPL provided an evaluation of eight alternatives for the Terrace Phase I design, as outlined in Table 2-3.

TABLE 2-3
ALTERNATIVES TO THE PROPOSED EXPANSION

CANADIAN PIPELINE FACILITIES

ALTERNATIVE NO.	DESCRIPTION	REQUIRED	CONFIGURATION
1	Do nothing	None	N/A
2	914mmOD/ 1219 mm OD Phased	744km of 914mm OD pipe (619 km - Phase I)	Line 3 and new 914mm OD/1219 mm OD would provide light/medium and heavy capacity
3	660mmOD Phased	1066km of 660mm OD pipe	Line 3 and the new 660mm OD would provide heavy crude capacity
4	762mm OD/ 1219 mm OD	740km of 762mm OD pipe	Line 3 and new 762mm OD/1219mm OD would provide light/medium and heavy capacity
5	610mm OD Single Phase	1066km of 406.4mm OD pipe	Line 3 and the new 610mm OD would provide heavy crude capacity
6	Extend 1219 mm OD Loops on Line 3	743 km of 1219 mm OD pipe	No change
7	Two 508 mm OD Lines	2138 km of 508 mm OD pipe	Line 3 and the two new 508 mm OD lines would provide medium and heavy capacity
8	1067 mm OD/1219 mm OD	744 km of 1219 mm OD pipe	Line 3 and new 1067 mm OD/ 1219 mm OD line would provide light/medium and heavy capacity

IPL consulted with industry representatives and conducted quantitative and qualitative comparisons of these alternatives in order to determine the best design solution. IPL considered the following criteria in its assessment:

- ability to meet long-term and short-term capacity demands;
- expansion capability and system flexibility;
- system reliability;
- system operability; and
- economics including the present value of capital costs, operating costs and operating savings to both IPL and industry.

IPL selected Alternative No. 2 (914 mm OD/1219 mm OD) because it would meet the short-, medium- and long-term needs of IPL' s operation, it represents a flexible and reliable design, and it would result in the lowest overall cost to the industry.

VIEWS OF THE BOARD

The Board finds a comparison of viable alternatives relevant to its assessment of the appropriateness of a proposed design. The Board is of the view that IPL has satisfactorily assessed the merits of each design alternative.

2.5 ADEQUACY OF DOWNSTREAM CAPACITY

In its application, IPL noted that Lakehead Pipe Line Partners, L.P. ("Lakehead") proposes to undertake a concurrent expansion program to complement IPL' s Terrace Phase I expansion. Approximately 155 km (97 miles) of new 914 mm OD pipeline is planned to be in service by January 1999. Two additional tanks at Lakehead's Superior, Wisconsin tank farm would also be constructed with a planned in-service date of September 1999. IPL submitted that its Line 4 operations would not be affected by possible delays of the Lakehead expansion, but that Line 2 would not be available for service until the pipeline component of the Lakehead expansion is complete. A delay in the pipeline portion of the Lakehead construction could potentially cause a reduction in capacity of 25 000 m3/d (157,000 b/d) of heavy crude oil. IPL also confirmed that capacity downstream of Superior would be constrained by 36 000 m3/d (226,000 b/d) until Lakehead's Line 14 is placed in service. Line 14 is presently under construction and has a scheduled in-service date of December 1998.

VIEWS OF THE BOARD

The Board is satisfied that IPL is taking reasonable steps to ensure that the required downstream facilities will be available as required.

Chapter 3

ENVIRONMENT AND LAND MATTERS

3.1 ROUTE AND FACILITY SITE SELECTION

3.1.1 PIPELINE ROUTE SELECTION

Routing of the proposed pipeline was influenced by IPL' s desire to minimize, where feasible, the number of lands newly affected and the amount of land disturbance. Consequently, consideration was generally not given to alternative routes and the existing pipeline right of way was chosen as the preferred route because:

- the existing route has been in service for approximately 40 years and is well known to all parties;
- adequate workspace is generally available along the route;
- no environmental or socio-economic constraints are encountered along the existing right of way that cannot be effectively mitigated or compensated;
- effects associated with a widening of an existing pipeline right of way would be incremental, while a new route would affect additional lands and increase the amount of land disturbance; and
- pipeline surveillance and maintenance activities can be conducted more efficiently for pipelines located within a common right of way than for two rights of way that are geographically separated.

Where new facilities could not be located on the existing right of way due to width constraints, IPL proposed that the facilities be located adjacent to it. As a result, all proposed pipe sections would be either within or adjacent to the existing IPL right of way, with the exception of two minor deviations. The first occurs at the South Saskatchewan River between kilometre post ("KP") 504.5 and KP 506.7. This deviation was necessary because of the locations of the pipelines in the existing right of way. The second deviation occurs between KP 907.8 and KP 929.1. That deviation was made as a result of the presence of highway and railway rights of way adjacent to IPL's existing right of way. This precluded IPL from simply expanding its existing right of way. The proposed new right of way would now abut the railway right of way.

3.1.2 PERMANENT FACILITY SITE SELECTION

Siting of new facilities was also influenced by LPL's desire to limit the amount of new land disturbance, where practical, as well as to optimize maintenance activities and the use of existing infrastructure (e.g., access roads, power lines, fenced site boundaries, etc.) associated with IPL's facilities. Consequently, new permanent facilities, including pump units, scraper traps and valves, would be located within existing IPL lands.

VIEWS OF THE BOARD

The Board agrees with IPL's rationale for locating the proposed facilities and associated temporary work space either within or adjacent to the existing IPL right of way. The general route proposed by IPL for the new pipeline, including the two deviations, is accepted by the Board. The Board notes that no new fee simple lands would be acquired to accommodate the additional facilities at existing pump stations.

3.2 LAND REQUIREMENTS AND ACQUISITION

IPL has applied for a total of 619 km of line pipe between Kerrobert and the international border near IPL' s Gretna station. Approximately 373 km of pipe would be constructed within IPL's existing right of way. The remaining 246 km would be constructed in new right of way to be acquired adjacent to IPL's existing right of way. However, two exceptions, as noted in Section 3.1.1, would be required.

IPL indicated that temporary work space would also be required for such activities as:

- river, highway and road crossings;
- "shoo-flies" and temporary access roads; and
- contractor yards and pipe storage and staging areas.

VIEWS OF THE BOARD

The number of permanent easements and the amount of temporary work space required for pipeline construction is generally of concern to the Board because of the potential effects on landowners. In the present application, the Board finds that IPL' s anticipated requirements for permanent easements and temporary work space are reasonable and justified.

3.3 ENVIRONMENTAL MATTERS

The Board, pursuant to its regulatory process and the CEAA, completed an environmental screening of the proposed construction related to Terrace Phase I. The Board circulated the Environmental Screening Report to the applicant, those parties who requested a copy and federal agencies that had volunteered to provide specialist advice.

The comments received and the Board's views form Appendices I and II, respectively, to the Environmental Screening Report. Copies of the Environmental Screening Report are available upon request from the Board's Regulatory Support Office.

VIEWS OF THE BOARD

The Board has considered the Environmental Screening Report and the comments received on the report and is of the view that, taking into account the implementation of the proposed mitigative measures and those set out in the attached conditions (Appendices IV and V), IPL's Terrace Phase I is not likely to cause significant adverse environmental effects. This represents a decision pursuant to paragraph 20(1)(a) of the CEAA and Part III of the Act.

CHAPTER 4

SUPPLY, MARKETS AND ECONOMIC MATTERS

4.1 SUPPLY

IPL's crude oil production forecast for western Canada projected that supply would increase from 314 100 m3/d (1,980,000 b/d) in 1996 to a maximum of 410 200 m3/d (2,580,000 b/d) in 2009 and decrease in 2010 to 406 100 m3/d (2,550,000 b/d). The forecast was based on a composite of: a survey of western Canadian crude oil producers conducted in the fall of 1996, which was followed by extensive consultation with industry and governments; several updating adjustments to reflect light crude oil supply trends and the markets for heavy crude oil; and a number of more recent announcements regarding upgrading and synthetic oil projects. Respondents to the 1996 survey were asked to base their supply projections on a price per barrel for West Texas Intermediate ("WTI") at Cushing, Oklahoma that increased from a low of US$17.50 in 1998 to US$22.25 in 2010 and a price differential per barrel between WTI and Bow River crude oil at Chicago, Illinois that rose from US$3.00 in 1996 to US$7.00 by 2010.

IPL projected that the supply of conventional light crude oil would decline from approximately 136 700 m3/d (859,800 b/d) in 1996 to 88 400 m3/d (556,000 b/d) by 2010. Over the same period, production of pentanes plus and synthetic crude oil from mining plants was forecast to nearly double from a total of 70 000 m3/d (440,300 b/d) to an estimated 133 100 m3/d (837,200 b/d). As a result, IPL forecast that total production of light crude oil and equivalent would increase slightly from 206 700 to 218 500 m3/d (1,300,000 to 1,370,000 b/d) over the forecast period.

IPL limited the projected growth in supply of heavy crude oil as a result of its assessment of the projected market demand for heavy crude oil. As a result, its forecast of heavy crude oil production was lower than was indicated in its survey of western Canadian crude oil producers. IPL estimated that heavy crude oil production, including both bitumen and conventional heavy crude oil, would rise from an average of 107 400 m3/d (675,500 b/d) in 1996 to a high of 188 600 m3/d (1,190,000 b/d) by 2009, and then decrease to 187 600 m3/d (1,180,000 b/d) in 2010. Without market constraints, IPL forecast that heavy crude oil production could potentially increase by an additional 42 400 m3/d (266,700 b/d) by the end of the forecast period.

Express Pipeline Ltd. ("Express") questioned IPL about the effect that current oil prices and differentials could have on IPL's production forecast. IPL agreed that the price assumptions used in its 1996 survey were probably higher than current prices would indicate were appropriate. In an undertaking, IPL subsequently provided a revised crude oil price forecast with projected prices lower for the years 1998 to 2001, but otherwise unchanged for the remainder of the forecast period.

Express also questioned whether IPL had updated its production forecast in response to recent industry announcements concerning the reduction in oil-directed drilling and the deferral of heavy oil projects. IPL acknowledged that it was aware that some companies had switched from oil-directed to gas-directed drilling and that several of the announced heavy oil projects were being deferred or delayed due to low crude oil prices. However, IPL noted that it had developed its initial supply forecast with significant industry input and that it had since reconfirmed overall supply expectations through

FIGURE 4-1

LPL FORECAST OF WESTERN CANADIAN CRUDE OIL PRODUCTION

[Chart]

informal surveys and extensive consultation with industry. IPL also noted that its production forecast for heavy crude oil was lower than the supply potential due to downstream market constraints which were reflected in the forecast. While there may be some variability in the overall supply potential because of pricing, IPL believed that the overall supply available from the Western Canada Sedimentary Basin would not change appreciably.

In a letter dated 15 April 1998, CAPP confirmed that IPL had used an industry consensus forecast. No other supply forecasts were submitted.

VIEWS OF THE BOARD

The Board recognizes the uncertainties associated with forecasts of the supply of crude oil and equivalent and agrees with IPL that forecast heavy crude oil supply may be limited by market constraints. The Board notes that IPL' s initial supply forecast was developed in consultation with industry and governments and that ongoing extensive consultation, including consideration of the effect of lower than expected commodity prices in the first quarter of 1998, has supported this forecast. The forecasts of the supply of crude oil and equivalent submitted by IPL are accepted as reasonable by the Board.

4.2 MARKETS

4.2.1 DEMAND

Western Canadian crude oil supplies markets in eastern and western Canada and export markets in PADDs'1 I, II, IV and V and offshore. IPL stated that in 1996 just over half of its volumes, including natural gas liquids and refined products, were delivered to export markets in PADDs I, II and IV, while another one-third was delivered to eastern Canada and the remainder to markets in western Canada.

IPL indicated that the PADD II market provides the best netbacks for western Canadian crude oil production. Crude oil from western Canada supplies approximately one-third of this market. In 1996, IPL delivered 125 100 m3/d (786,800 b/d) of the 133 500 m3/d (840,000 b/d) of western Canadian crude oil that flowed into PADD II. IPL submitted that the capacities of refineries served by IPL in PADD II total approximately 404 800 m3/d (2,500,000 b/d). IPL also stated that it has had confidential discussions with some of these refiners, who indicated that future crude oil requirements would exceed their current capacities.

Based upon the results of its 1996 survey, IPL anticipated that total PADD II demand for western Canadian crude oil would grow to 229 500 m3/d (1,444,000 b/d) by 2002, an increase of 96 000 m3/d (604,000 b/d) or 72 percent over 1996 levels. This increase includes refinery expansions to process heavy crude oil in PADD II totaling up to 26 900 m3/d (173,000 b/d). Even with this increase in heavy demand in PADD II, IPL noted that it had limited its estimate of the growth in Canadian heavy crude oil production to anticipated demand; In IPL's view, western Canadian crude oil supply would be sufficient to accommodate increased demand in PADD II, including volumes that would be redirected into PADD II as a result of the anticipated reversal of IPL's Line 9 2.

4.2.2 WESTERN CANADIAN CRUDE OIL AVAILABLE TO LPL

IPL calculated production available to its system as the difference between western Canadian crude oil production and non-IPL disposition of western Canadian crude oil. Production volumes were adjusted for the blending of heavy crude oil with diluent, the addition of recycled and manufactured diluent and the upgrading of certain heavy blend volumes to synthetic light crude oil.

Using 1999 as a reference point, IPL expected that crude oil produced in western Canada would be distributed as follows:

- local western Canadian market (23%);
- Trans Mountain Pipe Line Company Ltd. (5%);

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1 PADD refers to the U.S. Petroleum Administration for Defense Districts. These are geographic aggregations of the 50 states and District of Columbia into five districts defined by the Petroleum Administration for Defense in 1950. These districts were originally defined during World War II for the purposes of administering oil allocation. Geographically, the five districts are East Coast (I), Midwest (II), Gulf Coast (III). Rocky Mountain (IV) and West Coast (V).

2 Interprovincial Pipe Line Inc.. OH-2-97, Reasons for Decision dated December 1997.

- Rangeland Pipe Line Company and Wascana Pipe Line Ltd.'s Milk River pipeline (6%);
- Express (6%); and
- IPL (60%).

Express challenged IPL's estimate of non-IPL disposition. In its letter of 2 December 1997. Express asserted that IPL had underestimated throughput on the Express system. Although it did not oppose IPL's proposed expansion, Express argued that IPL had underestimated growth in demand for western Canadian crude oil in markets served by Express. This growth was being created by a decline in indigenous PADD IV supply, refinery expansions and improved access to PADDs IV and II through pipelines connected to the Express pipeline. Moreover, Express was concerned that IPL had understated netbacks available in PADD II via the Express and Platte Pipeline Company ("Platte") systems, the effect of which was to make this route appear less attractive. However, Express presented no evidence to support its position.

In reply to Express, IPL agreed that if more volumes of western Canadian crude oil were delivered into PADD IV via other pipelines, then supply available to

IPL would decrease. However, IPL stated that it had considered and rejected Express' input. IPL had prepared its forecast in consultation with industry, including shippers on Express. In IPL's view, it had not understated the volumes that would move to PADD IV.

The forecast of the crude oil production available to IPL is summarized in Table 4-1 below.

TABLE 4-1
FORECAST OF WESTERN CANADIAN CRUDE OIL PRODUCTION AVAILABLE TO IPL
(10 3 m3/d)

	1996	2000	2005	2010
Western Canada Production*	334.2	389.2	441.5	441.1
Non-IPL Demand				
Western Canada	88.4	102.9	111.6	113.8
Exports				
- PADD IV**	21.1	38.8	34.9	31.3
- PADD V	17.5	7.7	7.8	5.0
Total Non-IPL Demand	127.0	149.4	154.3	150.1
Net Production Available to IPL	207.2	239.8	287.2	291.0
Other IPL Receipts	56.8	106.9	113.0	116.7
TOTAL SUPPLY AVAILABLE TO IPL	264.0	346.7	400.2	407.7

* Adjusted for blending of heavy crude oil, addition of recycled and manufactured diluent and upgrading of certain heavy blend volumes

** Includes volumes transferred onto the Platte system for delivery into PADD II.

4.2.3 THROUGHPUT

IPL prepared forecasts of its system throughput for the years 1999 to 2010, both with and without the Terrace Phase I expansion. Without the expansion, IPL expected apportionment to continue for the entire period. However, with the expansion, it is expected that apportionment would not occur between September 1999 and late 2002. In the period 1999 to 2002, IPL forecast system throughput to be 332 900 to 360 500 m3/d (2,100,000 to 2,270,000 b/d), versus 329 000 to 322 700 m3/d (2,070,000 to 2,030,000 b/d) without the expansion. With the expansion, the system is expected to be at capacity after 2002 and the additional volumes would flow primarily to PADD II.

VIEWS OF THE BOARD

The Board agrees with IPL that PADD II could absorb the forecast additional volumes of western Canadian crude oil and accepts IPL' s evidence concerning available refinery capacity in the market and the ability of these refiners to process additional heavy crude oil.

Although Express challenged IPL' s forecasts, it provided no evidence to support its view. The Board notes that IPL reduced its supply forecast for western Canadian crude oil to accord with its assessment of the markets available for that crude. If a larger market develops via the Express system, the Board is satisfied that additional supply would be available to satisfy that demand with IPL's proposed expansion in place.

The Board recognizes that the IPL system is currently under apportionment and that it may remain so even after the SEP II(1) facilities are in service. Further, the Board notes the extensive consultation undertaken by IPL and the broad support of industry for this expansion. On balance, the Board is satisfied that IPL has provided reasonable forecasts of markets, disposition and throughput.

4.3 ECONOMIC FEASIBILITY

In its application, IPL measured the economic impact of the proposed expansion by calculating the projected increase in total producer revenue, or the projected increase in cash flow that would result due to additional volumes of crude oil reaching market via the IPL pipeline system.

For the years 2000 to 2010, the projected deliveries of crude oil through western Canadian pipeline systems were compared with the level of deliveries through those systems assuming that the Terrace Phase I facilities would be constructed. Transportation costs and resultant netbacks at Edmonton for each of the markets to which western Canadian crude oil is forecast to move from 2000 to 2010 were also considered. IPL's presentation of illustrative netbacks at Edmonton for 1997 from each of the markets that process western Canadian crude oil indicated that its system generally provides western Canadian crude oil producers with the highest netbacks, particularly with its connection to the PADD II market.

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(1) In OH-1-96, the Board approved IPL's System Expansion Program Phase II to increase delivery capability of the existing IPL system in western Canada by 19 600 m3/d (120,000 b/d).

With the expansion facilities, IPL calculated that producer sector revenues over the 2000 to 2010 period are expected to increase by $5.6 billion on a net present value basis versus the without expansion facilities case.

Express referred to IPL evidence and argued that heavy crude oil delivered via the Platte system to the southern PADD II market would provide a somewhat more attractive netback than an IPL delivery of heavy crude oil at Wood River. According to IPL, Chicago is expected to remain the most attractive netback market for western Canadian crude oil producers.

4.3.1 SUPPORT FOR PROJECT

CAPP supported the project and an accelerated timetable for obtaining regulatory approval. At the start of the hearing, IPL filed a toll agreement negotiated with CAPP whereby IPL's shippers have guaranteed IPL the recovery of the costs of the expansion over a 15-year period from 1999 to 2013 (see Chapter 5 for further details).

Further letters of support were provided by the governments of Manitoba and Saskatchewan, which particularly welcomed the positive economic benefits for their provinces.

VIEWS OF THE BOARD

The evidence indicates that industry and provincial governments are strongly supportive of the proposed expansion. In the Board's view, some of the benefits of this expansion would include the production of crude oil that would otherwise be shut in or sold to less attractive markets due to apportionment on IPL, as well as a potential improvement in the competitive position of western Canadian crude oil deliveries in PADD II as a result of increased reliability of these deliveries. The Board finds that the benefits of the IPL expansion are likely to be sufficient to justify the construction of the proposed facilities.

CHAPTER 5

TOLLS AND FINANCIAL MATTERS

In its application, IPL sought approval to have the capital and operating costs of Terrace Phase I treated as a Non-Routine Adjustment in accordance with paragraph 7.l(a)(i) of the Principles of Settlement filed in support of IPL's February 1995 Incentive Toll Application, approved by Board Order TO-l-95, and to have such costs recovered through tolls using an integrated toll design. IPL also indicated that it had been approached by CAPP to discuss the possibility of reaching a negotiated tolling agreement relating to the total Terrace Expansion Program facilities. On 15 April 1998, IPL filed with the Board a tolling agreement which had been ratified by CAPP members. A copy of the agreement is attached as Appendix II.

Upon filing the tolling agreement, IPL withdrew that portion of its application respecting the treatment of Terrace Phase I as a Non-Routine Adjustment.

A brief summary of the negotiated agreement is set out below.

- IPL and its affiliated company, Lakehead, would collect a fixed toll increment of a combined 5 cents (Canadian) per barrel that would recover costs for all phases of the Terrace Expansion Program.
- The 5 cent increment is based on the shipment of light crude oil from Edmonton to Chicago and tolls would continue to be distance based and subject to toll surcharges or credits for different commodity movements.
- The fixed toll increment would apply to all IPL/Lakehead base volumes and the Terrace incremental volume for a period commencing with the in-service date of Terrace Phase I and ending 31 December 2013.
- There would be a sharing of risks and benefits between IPL and its shippers.

IPL submitted that the toll arrangement would result in just and reasonable tolls and that its terms should be approved by the Board pursuant to Part IV of the Act and in conjunction with the Board's Guidelines for Negotiated Settlements.

On 15 April 1998, the Board issued a letter soliciting comments from parties to the hearing and shippers on the IPL system. No comments were received by the Board.

VIEWS OF THE BOARD

The Board notes that the negotiated tolling agreement has broad shipper support. The Board considers the agreement to be a negotiated settlement within the meaning of its Guidelines for Negotiated Settlements. The Board is of the view that the settlement represented by the agreement will result in just and reasonable tolls. The terms of the agreement are therefore approved.

Chapter 6

DISPOSITION

The foregoing constitutes our Reasons for Decision in respect of the applications heard by the Board in the OH- 1-98 proceeding. The Board is satisfied from the evidence that the applied-for facilities are and will be required by the present and future public convenience and necessity.

The Board approves IPL's application made pursuant to section 52 of the Act for new line pipe facilities and will recommend to the Governor in Council that a certificate be issued, subject to the conditions set out in Appendix IV.

The Board approves IPL's application made pursuant to section 58 of the Act exempting all applied-for pump unit additions, replacements and modifications and related station facilities and piping from the provisions of sections 30, 31 and 47 of the Act. Accordingly, the Board has issued Order XO-J1-16-98, as shown in Appendix V.

The Board approves IPL's application made pursuant to section 21 of the Act varying Board Order XO-J 1-10-98 to allow for the relocation of certain scraper trap facilities to new locations as described in the application. Accordingly, the Board has issued Amending Order AO-1-XO-J1- 10-98, as shown in Appendix VI.

With respect to Part IV matters, the Board approves IPL's toll arrangement.

/s/ R.J. Harrison

R.J. Harrison
Presiding Member

/s/ Judith A. Snider

J.A. Snider
Member

/s/ D. Valiela

D. Valiela
Member

Calgary, Alberta
June 1998

APPENDIX I

LIST OF ISSUES

1. The need for the expansion.

2. The economic feasibility of the proposed facilities.

3. The impact on market and supply.

4. The potential impact on existing shippers.

5. The appropriateness of the proposed method of financing the project.

6. The potentially adverse environmental and socio-economic effects of the proposed facilities, including those factors outlined in section 16(1) of the Canadian Environmental Assessment Act.

7. The safety of the design and operation of the proposed facilities.

8. The appropriate design and size of the applied-for facilities having regard to:

   (a) the costs of the facilities in relation to the additional capacity to be provided; and

   (b) the need for new capacity to transport oil and other liquid hydrocarbons.

9. The adequacy of connecting pipeline capacity to accommodate the project.

10. The appropriateness of the general route proposed.

11. The appropriate terms and conditions to be included in any approval which may be granted.

12. The determination of the appropriate toll treatment for the applied-for facilities.

APPENDIX II

TERRACE TOLL AGREEMENT[1]

STATEMENT OF PRINCIPLES

1. Negotiated tolls for the IPL/LPL Terrace program will recover costs associated with all facilities associated with all phases of Terrace Expansion Program. The Terrace Expansion Program is expected to be a phased capacity addition program intended to add capacity in the years 1999 and following.

2. The Terrace facilities, the expected capacity increases associated with the facilities, and the in-service timing are appended as Schedule A. IPL and LPL commit to deliver the additional throughput capacity on or before the dates set out in these Principles. The dates upon which the facilities are expected to come into service are:

   i) January 15, 1999 first in-service of Phase I facilities, providing 95,000 bpd of incremental capacity from a base system capacity (which includes SEP II and SEP III 350 Centistoke facilities) of 1,630,503 bpd (259,100 m3). The incremental capacity to be provided includes incremental heavy crude oil capacity on Line 3 (24 inch).
   ii) September 30, 1999 second tranche of Phase I capacity in-service, totaling 167,000 bpd of incremental capacity from the base.
   iii) Hardisty to Kerrobert extension IN service September 30, 2000 [Phase II] providing 210,000 bpd of incremental capacity from the base
   iv) Clearbrook to Superior extension and associated pumping in service September 30, 2001 [Phase III] providing 348,000 bpd of incremental capacity from the base
   v) Mokena to Griffith extension, Line 14 stations in service, Line 14 heater in service between 2002 and 2007 [later Terrace phase(s)]

3. The in service commitments made by IPL/LPL are subject to CAPP providing written notice to IPL/LPL requesting construction in advance of the proposed in-service dates. The notice periods in respect of Phase II, III and later Terrace Phases described above are 18 months, 24 months and 36 months respectively; provided that notice given prior to March 31, 1999 in respect of Phase II may be deemed by IPL/LPL to have been given on March 31, 1999. Upon IPL giving notice to CAPP of a requirement by IPL/LPL to undertake material commitments in order to meet in-service dates, CAPP will confirm its continuing service request prior to IPL/LPL being required to make those commitments.

4. For the purpose of determining "in service" the date which shall be used for IPL is the date upon which the last leave to open order is granted by the National Energy Board for the completion of pipeline facilities in Phase I (excluding pump stations) and for LPL, the availability of the facilities for service.

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1 Please note that the text of the agreement as shown in Appendix II of these Reasons is not an official version of the agreement.

5. The delivery by IPL/LPL of the capacities associated with Phase I is subject to shipper approval for commingling crude in Line 3 (24 inch) to be transported in laminar flow.

6. Cost recovery on the Terrace investment and related operating costs will be effected by application of a fixed toll increment applicable to all base (259,100 m3) and Terrace volume transported on the IPL/LPL systems.

7. The toll increment shall be five cents (Cdn) per barrel for light crude transportation from Edmonton to Chicago, and shall be adjusted on a distance basis and for commodity credits or surcharges, consistent with IPL and LPL's then existing toll design.

8. The fixed toll increment charge will become effective upon the in-service of the first of the Terrace facilities, as "in service" is defined in paragraph 4, and shall terminate December 31, 2013.

9. The fixed toll increment shall be allocated between IPL and LPL as determined by IPL and LPL, provided that no less than one cent shall ever be allocated to either of the IPL or LPL system.

10. The fixed toll increment shall be subject to a transportation revenue variance (TRV) in IPL which operates in the same fashion as the then-existing TRV in IPL. In the event there is no TRV mechanism in place for IPL, the fixed toll increment shall be subject to a TRV which operates in the same fashion as the TRV operated in IPL in 1997.

11. The base toll upon which the fixed increment will be added assumes the filling of the IPL/LPL systems at the quoted SEP II capacity of 1,630,503 bpd (259,100 m3/day).

12. IPL and LPL will assume one hundred percent of operating cost variance risk, excluding changes to property tax expense which exceeds the forecast by twenty percent or more. Property tax variances exceeding twenty percent from forecast shall result in an increase to the fixed toll increment in accordance with Schedule B.

13. IPL and LPL will assume five percent of the capital cost variance risk and fifty percent of the capital cost variance risk thereafter on quoted target costs set out below. Target costs for the purpose of capital cost variance for facilities to be constructed after 1999 will be inflated from December 31, 1997 using the Canadian and US GDP deflators for facilities in IPL and LPL respectively.

IPL Cdn $	LPL US$	
$575 mm	$117 mm	Jan. 1999 Phase I
$35 mm	$17 mm	Sept. 1999 Phase I
$227mm	$178mm	Phases II & III 2000 and 2001
	$70 mm	Other Phases 2002-2007

14. In the event CAPP does not provide notice to IPL on or before July 1, 2001 requesting IPL/LPL to proceed with both Phases II and III, costs for the project, including revenue variance between the application of the fixed toll increment and the cost of service model, will be calculated, and prospective tolls will be collected on a cost of service basis. Capital and operating cost sharing risk will revert to the traditional cost of service recovery.

15. Until such time as both Phases II and III are placed into service, Phase I will be considered to be a Non Routine Adjustment (NRA) in both IPL and LPL as NRA is defined and treated in the 1995 IPL Incentive Toll Settlement. However, tolls will continued to be charged at the five cent negotiated rate subject to the TRV in IPL. Any revenue variance will be amortized and collected over the remaining term of the Principles (effective January 1, 2002) if Phases II and III are not committed to by July 1, 2001.

16. If quoted forecast capacities are not achieved and sustained in the long term, for so long as a capacity shortfall exists, a refund of one cent per bbl for each 35,000 bbl capacity shortfall shall be effected through a reduction to the subsequent year's tolls. IPL/LPL shall not be obligated to provide a refund in respect of any capacity shortfall for which no volume is available to be nominated to and shipped on the IPL/LPL systems.

17. The fixed toll increment of five cents shall be adjusted upward or downward as the case may be in accordance with Schedule B for the following:

    i) Agreed upon scope changes to the project;

    ii) Agreed upon timing changes to the project;

    iii) Capital cost variance;

    iv) Construction cost variance due to agreed upon circumstances which are extraordinary and not within the control of IPL/LPL;

    v) Property tax variances in excess of twenty percent from forecast;

    vi) In respect of Phases other than Phase I, bond rate variation by more than two percentage points from 1998 levels; and

    vii) Multi-pipeline return on equity variation by more than two percentage points from 1998 level.

18. Subsequent to LPL completing Phase III, in the event annual actual average pumpings ex-Clearbrook are less than 215,000m3, 220,000m3 and 225,000m3 from in-service to year-end 2002, 2003, and 2004 through 2013 inclusive, respectively, an adjustment to the fixed toll increment shall be made in accordance with Schedule C.

19. Energy costs attributable to Terrace will be calculated using a base power cost for an agreed upon delivery forecast assuming pre-Terrace at a capacity of 259,100 m3/day. The calculation of the power allowance for the purpose of calculating the TRV will be based on the difference in the total forecast fuel and power requirements and the actual fuel and power, using the

average annual cost of fuel and power for the TRV year. IPL and CAPP are completing a schedule which will set out in detail the elements of the energy calculation.

20. The implementation of the toll method contemplated in these Principles is subject to IPL and LPL Board approval and National Energy Board and Federal Energy Regulatory Energy Commission approval of the settlement for IPL and LPL respectively.

20. The implementation of the toll method contemplated in these Principles is subject to IPL and LPL Board approval.

SCHEDULE A

DESCRIPTION OF TERRACE FACILITIES

PHASE 1 FACILITIES

PROPOSED FACILITIES	ITEMS CONSIDERED TO BE SCOPE CHANGES TO TERRACE	NOT IN TERRACE SCOPE
Pipe - - 619 km of 914 mm line pipe between Kerrobert and Gretna stations in Canada along with associated valving, tie-in piping and scraper facilities. - - 100 miles of 36 inch pipe line in 4 sections between Gretna and Clearbrook stations in the USA along with associated valving and tie-in piping.	- Changes totalling more than 5 miles of pipe between Canada and the USA - Changes in pipe diameter	
Pump Stations	Additional pumping power or DRA to	Capacity increases on Lines not

- - Sufficient pumping equipment and power to provide 26,500 m3/d of incremental capacity assuming that Capacity increases on Lines not Line 3 operates in laminar flow and that Hardisty crudes are pumped in Line 3 in sufficient quantities to operate at 25,000 m3/d at its bottleneck point.	Achieve capacities greater than the quoted annual capacities in the NEB application Terrace Phase 1 i.e. - Line 1, 49,500 m3/day - Line 2A, 66,000 m3/day - Line 2B, 81.200 m3/day - Line 3 24" heavy line, 25,000 m3/day - Line 4 36"/48" heavy line, 102,100 m3/day Changes in deliveries that negatively impact Lakehead's ability to inject crude into Lines 2 and 4 at Clearbrook in Phase I	affected by Terrace including in in Western Canada: - Line 13 27,800 m3/day - Changes resulting from the SEP II facilities as filed with the NEB and as agreed to with industry which impact quoted Line capacities. - Changes in facilities required to accommodate crude characteristics other than referenced in Table 3.10.1 in

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Breakout and Terminalling Facilities

- 2 breakout tanks at Superior	- Additional breakout tankage	- Additional tankage, receipt, delivery, terminalling or connecting facilities at any location in Canada or USA - Requested commodity segregation which results in additional tankage, metering, or terminalling facilities - Changes, in facilities required to accommodate crude characteristics other than referred in Appendix 3.10 in the NEB application

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PHASE 2 FACILITIES

PROPOSED FACILITIES	ITEMS CONSIDERED TO BE SCOPE CHANGES TO TERRACE	NOT IN TERRACE SCOPE
Pipe 123 km of 914 mm line pipe in 3 sections between Hardisty and Kerrobert pump stations with associated valving and tie-in facilities	Changes totalling more than 5 miles of pipe Changes in pipe diameter	
Pump Stations		
Sufficient pumping equipment and power to quoted annual power or DRA to provide 6,900 m3/d of incremental capacity beyond Phase I facilities, assuming that Line 3 operates in laminar flow and that Hardistry crudes are pumped in Line 3 in sufficient quantities to operate at 27,000 m3/day its bottleneck point.	Additional pumping power or DRA to achieve capacities greater than the quoted annual capacities in the NEB application in Terrace Phase 1 i.e. - Line 1 49,500 m3/day - Line 2A 66,000 m3/day - Line 2B 81,200 m3/day - Line 3 24" heavy line m3/day 27,000 - Line 4 36"/48" heavy line 107,000 m3/day	- Additional pumping power or DRA to achieve capacities greater than that quoted in Phase 1 facilities: - Changes in facilities required to accommodate crude characteristics other than referenced in Appendix 3.10 in the NEB application - Changes in facilities required to accommodate crude characteristics other than referenced in Table 3.10.1 in the NEB application.
Breakout and Terminalling Facilities	- breakout tankage	- additional tankage, receipt, delivery, terminalling or connecting facilities at any location in

Canada or USA

- Requested commodity segregation which results in additional tankage, metering, or terminalling facilities.

PHASE 3 FACILITIES

PROPOSED FACILITIES	ITEMS CONSIDERED TO BE SCOPE CHANGES TO TERRACE	NOT IN TERRACE SCOPE
Pipe 120 miles of 36 inch line pipe in 5 sections between Clearbrook and Superior pump stations with associated valving and tie-in facilities	Changes totalling more than 5 miles of pipe Changes in pipe diameter	
Pump Stations Sufficient power to provide 23,500 m3/d of incremental capacity above Terrace Phase II facilities.	Facility changes on Line 14 that exceed $US 70 MM and Are other than the following items: - Pump unit and station additions - Pump unit replacements or modifications - Crude oil heaters - Pipeline connections or extensions to Griffith.	Additional pumping power or DRA to achieve capacities greater than: - Line 1 41,400 m3/day - Line 2A 54,000 m3/day - Line 2B 65,000 m3/day - Line 3 heavy line 74,000 m3/day - Line 4 heavy line 107,800 m3/day - Line 13 27,800 m3/day Changes in facilities required to accommodate crude characteristics other than referenced in Appendix 3.10 in the NEB application
Breakout and Terminalling Facilities - - 2 breakout tanks at Superior	- additional breakout tankage	- additional tankage, receipt, delivery, terminalling or connecting facilities at any location in Canada or USA - Requested commodity segregation which results in additional tankage, metering, or terminalling facilities Requested commodity segregation which results in additional tankage, metering or terminalling facilities

FUTURE PHASES OF TERRACE FACILITIES

PROPOSED FACILITIES	ITEMS CONSIDERED TO BE SCOPE CHANGES TO TERRACE	NOT IN TERRACE SCOPE
Pipe $US 27 million in pipeline facilities between Mokena and Griffith by the end of 2002 if needed		- Any additional pipeline extensions or connections
Pump Stations $US 40 million in station		- Any incremental pump unit

additions and modifications on Line 14 by the end of 2003 if needed		additions after the intermediate stations are installed
Crude Oil Heater $US 3 MM in heating facilities to increase Line 14 capacity by the end of 2007 if needed	-	Any other heating facilities

SCHEDULE B

ADJUSTMENTS TO THE 5 CENTS PER BARREL INCREMENT
(CDN DOLLARS)

	ADJUSTING EVENT	ADJUSTMENT	
		PHASE I	PHASE II
1	Scope Changes resulting in Capital cost changes greater than +/- $10 million from original estimate provided in Schedule A	0.18 cents per barrel per $10 million change in capital costs	0.14 cents per barrel per $10 million change in capital costs
2	Capital Cost Variance outside +/- 5 % of estimate provided in Schedule A	0.09 cents per barrel per $10 million change in capital costs	0.07 cents per barrel per $10 million change in capital costs
3	Increases in Multi-pipeline cost of equity beyond current rate plus 200 basis points	For 1999-2007 and for 2008-2013 .3 cents per barrel and .15 cents per barrel respectively for each 25 basis point change in the multi-pipeline rate of return which exceeds the 1998 multi-pipeline rate of return plus or minus 200 basis points.	
4	Increases in Cost of Debt over 200 basis points above current Long Canada (5.28%) and US (5.65%) 10 year bonds	For Phases II and following, .1 cent per barrel change for every 50 basis point change in debt cost above the 200 basis point increase. The toll change for debt cost increases shall apply to IPL and LPL independently.	

5	Property Tax Increases on Terrace Facilities greater than +/-20 on estimate		.2 cents per barrel for each $ 1 million change in property tax greater than 20%	
6	Capacity Penalty		1 cent decrease per barrel per 35,000 barrels per day below stated capacity until capacity is provided	1 cent decrease per barrel per 35,000 barrels per day below stated capacity until capacity is provided

*the values in items 3, 4 and 5 are subject to finalization

SCHEDULE C

ADJUSTMENT FOR LPL PHASE III TRIGGER
INCREMENT INCREASE IN YEAR FOLLOWING PUMPINGS BELOW SPECIFIED TARGET
(CDN CURRENCY)

PRIOR YEAR'S ACTUAL AVERAGE PUMPINGS EX- CLEARBROOK	TOLL ADJUSTMENT FOR YEAR		
	2002	2003	2004-2013
Greater than 225,000 m3/day	0 cents/barrel	0 cents/barrel	0 cents/barrel
220 000 m3/day to 224 999 m3/day	0 cents/barrel	0 cents/barrel	1 cents/barrel
215 000 m3/day to 219 999 m3/day	0 cents/barrel	1 cents/barrel	2 cents/barrel
210 000 m3/day to 214 999 m3/day	1 cents/barrel	2 cents/barrel	3 cents/barrel
205 000 m3/day to 209 000 m3/day	2 cents/barrel	3 cents/barrel	4 cents/barrel
200 000 m3/day to 204,999 m3/day	3 cents/barrel	4 cents/barrel	5 cents/barrel

Appendix III

IPL'S SYSTEM OPERATION

[Graph]

Appendix IV

CERTIFICATE CONDITIONS

General

1. Unless the Board otherwise directs, IPL shall implement or cause to be implemented all of the policies, practices, recommendations and procedures for the protection of the environment included in or referred to in its application, in its undertakings made to other regulatory agencies or as otherwise adduced in evidence through the application process.

2. Unless the Board otherwise directs, IPL shall cause the approved facilities to be designed, manufactured, located, constructed and installed in accordance with those specifications, drawings and other information or data set forth in its application or as otherwise adduced in evidence before the Board.

Prior to the Commencement of Construction

3. Unless the Board otherwise directs, the company shall file, at least 14

days prior to the commencement of construction, a detailed construction schedule or schedules identifying major construction activities and shall notify the Board of any substantive modifications to the schedule or schedules as they occur.

4. Unless the Board otherwise directs, the company shall, at least 14 days prior to the commencement of construction, file with the Board for approval the company's field joining program.

5. Unless the Board otherwise directs, IPL shall file with the Board a report on the feasibility of directionally drilling the South Saskatchewan, Qu'Appelle and Souris Rivers and obtain approval of the Board for the crossing methodology at each of these rivers at least 14 days prior to construction at each location.

6. Unless the Board otherwise directs, IPL shall, at least 14 days prior to the commencement of construction of the pipeline crossings of Eagle Creek (KP 393.8 and KP 425.9), South Saskatchewan River (KP 505.2), Qu'Appelle River (KP 657.0), High Hill Creek (KP 667.0), Cottonwood Creek (KP 679.5), Wascana Creek (KP 689.5), Chapleau Lakes (KP 783.3), Little Pipestone Creek (KP 907.0), Black Creek (KP 1065.8), Souris River (KP 1073.5), Spring Brook (KP 1078.4 and KP 1079.0), Oak Creek (KP 1109.3 and KP 1110.3), Cypress River (KP 1120.1 and KP 1131.6), Mary Jane Creek (KP 1164.0), Thornhill Coulee (KP 1186.3) and Deadhorse Creek (KP 1196.8):

   (a) file the fish and fish habitat assessment and any new mitigative measures IPL would implement resulting from the assessment;

   (b) file the assessment of the environmental impact on fish habitat and resources at the crossing site and downstream referred to in (a) shall include, without limitation, the following:

      (i) the distribution of salmonids;
      (ii) the presence of salmonids in a tributary;
      (iii) the presence of a spawning ground within 100 m of a watercourse crossing;
      (iv) the presence of a spawning ground for warm water species within 100 m of a watercourse crossing;
      (v) the presence of an endangered or threatened species;
      (vi) the presence of a spawning migration;
      (vii) a sensitive spawning and nursery habitat downstream; and
      (viii) the risk of sediment transport;

   (c) in respect to those watercourse crossings which have been found to be sensitive, as a result of the assessment in (b) above:

      (i) the exact location and area of spawning grounds found within 100 m of the watercourse crossing;
      (ii) the percentage of the spawning grounds that would be affected by construction;
      (iii) the species spawning at these sites;
      (iv) the exact dates of construction;
      (v) a detailed description of the construction method to be used;
      (vi) sedimentation control plans;
      (vii) estimates of the habitat loss

and/or diminished productivity; and

(viii) development of a follow-up program on the productivity, of the spawning grounds after construction;

(ix) site-specific mitigative and restorative measures to be employed as a result of undertakings to regulatory agencies;

(x) evidence to demonstrate that all issues raised by regulatory agencies have been satisfactorily resolved, as well as updated environmental assessments for those areas where deficiencies were noted; and

(xi) status of authorizations, including the wording of the environmental conditions;

(d) provide copies to the Board of all correspondence from Saskatchewan Environment and Resource Management, Manitoba Natural Resources and the Department of Fisheries and Oceans - Habitat Management Division ("DFO-HMD") regarding the acceptability of the fishery resource assessment referred to in paragraph (a); and

(e) provide a description of the watercourses where DFO-HMD has required authorization pursuant to the Fisheries Act and confirmation that those authorizations have been obtained.

7. IPL shall, prior to the commencement of construction within the wetted perimeter of any watercourse deemed to be navigable pursuant to the Navigable Waters Protection Ac:, provide:

(a) confirmation that the appropriate permits have been obtained from the Canadian Coast Guard's Regional Offices; and

(b) a description of any additional procedures or measures that the Canadian Coast Guard has required IPL to implement at the watercourse crossings.

8. Unless the Board otherwise directs, IPL shall, at least 5 days prior to commencement of construction, file with the Board:

(a) copies of the preconstruction archaeology surveys conducted at the 15 pipeline loop sections between IPL's pump station at Kerrobert, Saskatchewan and the international border near its pump station at Gretna, Manitoba; and

(b) copies of all correspondence from the provincial archaeological authorities regarding the acceptability of the archaeological surveys referred to in paragraph (a).

DURING CONSTRUCTION

9. Unless the Board otherwise directs, should there be a requirement to remove excess bedrock by blasting at any work site, IPL shall:

(a) prior to the commencement of construction conduct a survey of the location of all water wells within 100 m of the proposed blasting location and sample the well water for quality, quantity and any additional parameters requested by the provincial regulatory body;

(b) during blasting and rock removal operations, monitor the quality and quantity of the water in the water wells surveyed pursuant to paragraph (a);

(c) if water quality or quantity is affected by blasting operations, provide each resident utilizing the affected well with a clear, potable water source in comparable quantity to the original source until the water in the affected well returns to its original conditions; and

(d) after construction, conduct a survey of the water wells surveyed pursuant to paragraph (a) to ensure that there has been no change to the quality and quantity of the water in the wells and report the results of those surveys to the Board.

Post Construction

10. IPL shall, prior to the commencement of hydrostatic testing of the Terrace Phase I Expansion Program facilities, provide confirmation that all necessary or required regulatory approvals have been obtained and local municipalities have been consulted.

11. IPL shall, prior to the Terrace Phase I facilities being placed in service, file with the Board updated copies of:

(a) the company's operations and maintenance manual; and

(b) the company's emergency procedures.

12. IPL shall file with the Board, prior to the Terrace Phase I facilities being placed in service, a report on the re-evaluation of its existing Line 2 internal corrosion control program, specifically addressing potential corrosion issues associated with laminar flow.

13. LPL shall, pursuant to section 58 of the Onshore Pipeline Regulations ("OPR"), file with the Board a post-construction environmental report within six months of the date that the 619 km (385 miles) of 914 runt (36 inch) outside diameter pipe segments connecting the existing 1219 mm (48 inch) outside diameter pipeline segments are placed in service. The postconstruction environmental report shall set out the environmental issues that have arisen up to the date on which the report is filed and shall:

(a) indicate the issues resolved and those unresolved; and

(b) describe the measures IPL proposes to take in respect of the unresolved issues.

14. IPL shall, pursuant to section 58 of the OPR, file with the Board, on or before the 31 December following each of the first two complete growing seasons after the post-construction environment report referred to in condition 13 has been filed, a report containing:

(a) a list of the environmental issues indicated as unresolved in the previous post-construction report and any that have arisen since that report was filed; and

(b) a description of the measures IPL proposes to take in respect of any unresolved environmental issues.

15. Unless the Board otherwise directs prior to 31 December 1999, this certificate shall expire on 31 December 1999 unless construction and installation with respect to the applied-for facilities has commenced by that date.

Appendix V

ORDER XO-J1-16-98

IN THE MATTER OF THE National Energy Board Act ("the Act") and the regulations made thereunder; and

IN THE MATTER OF an application, pursuant to section 58 of the Act, by Interprovincial Pipe Line Inc. ("IPL") filed with the Board under File No. 3200-J001-5.

BEFORE the Board on 2 June 1998.

WHEREAS the Board has received IPL's Terrace Phase I Expansion Program application, dated 2 December 1997 and as amended on 31 March 1998, at an estimated total cost of $610 million;

AND WHEREAS in its Terrace Phase I Expansion Program application, IPL applied pursuant to section 58 of the Act for the approval of all applied-for pump unit additions, replacements and modifications and related facilities and station piping as listed in Schedule A ("the station facilities");

AND WHEREAS pursuant to the Canadian Environmental Assessment Act ("CEAA"), the Board has performed an environmental screening of the station facilities and has considered the information submitted by IPL;

AND WHEREAS the Board has determined, pursuant to paragraph 20(1)(a) of the CEAA that, taking into account the implementation of IPL' s proposed mitigative measures and those set out in the attached conditions, the station facilities are not likely to cause significant adverse environmental effects;

AND WHEREAS the Board has examined the application and considers it to be in the public interest to grant the relief requested;

IT IS ORDERED that, pursuant to section 58 of the Act, the station facilities are exempt from the provisions of sections 30, 31 and 47 of the Act, upon the following conditions:

1. Unless the Board otherwise directs, IPL shall implement or cause to be implemented all of the policies, practices, recommendations and procedures for the protection of the environment included in or referred to in its application, in its undertakings made to other regulatory agencies or as otherwise adduced in evidence through the application process.

2. Unless the Board otherwise directs, IPL shall cause the approved facilities to be designed, manufactured, located, constructed and installed in accordance with those specifications, drawings and other information or data set forth in its application or as otherwise adduced in evidence before the Board.

3. Unless the Board otherwise directs, the company shall file, at least 14 days prior to the commencement of construction, a detailed construction schedule or schedules identifying major construction activities and shall notify the Board of any substantive modifications to the schedule or schedules as they occur.

4. Unless the Board otherwise directs, the company shall, at least 14 days prior to the commencement of construction, file with the Board for approval the company's field joining program.

5. IPL shall, prior to the commencement of hydrostatic testing of the station facilities, provide confirmation that all necessary or required regulatory approvals have been obtained and local municipalities have been consulted.

6. IPL shall, prior to the operation of the station facilities, file with the Board updated copies of:

   (a) the company's operations and maintenance manual; and

   (b) the company's emergency procedures.

7. IPL shall, during the first quarter of operation after start-up, conduct and file with the Board noise emission surveys to confirm that the actual noise emission levels resulting from the installation of new electrically driven pump units within or adjacent to seven existing IPL pump stations do not exceed the anticipated noise emission levels at the pump station fence line and at the nearest residence.

8. Unless the Board otherwise directs prior to 31 December 1999, this Order shall expire on 31 December 1999 unless construction and installation with respect to the applied-for facilities has commenced by that date.

NATIONAL ENERGY BOARD

Michel L. Mantha
Secretary

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(CHART)

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Appendix VI

ORDER AO-1 -XO-J1 -10-98

IN THE MATTER OF the National Energy Board Act ("the Act") and the regulations made thereunder; and

IN THE MATTER OF an application by Interprovincial Pipe Line Inc. ("IPL") filed with the Board under File No. 3200-J001-5.

BEFORE the Board on 2 June 1998.

WHEREAS the Board has previously issued Order XO-J1-10-98 approving the installation of three sending and three receiving scraper traps for use on the 904 mm (48 inch) outside diameter pipe sections upstream of IPL's Herschel, Glenavon and Glenboro stations;

AND WHEREAS the Board has received IPL's Terrace Phase I Expansion Program application, dated 2 December 1997 and as amended on 31 March 1998, in which IPL requested an amendment to Order XO-J1-10-98, allowing the previously approved three sending scraper traps to be relocated and placed in service at JPL's Loreburn, Craik and Odessa stations ("the project");

AND WHEREAS pursuant to the Canadian Environmental Assessment Act ("CEAA"), the Board has considered the information submitted by IPL and has performed an environmental screening of the proposed project;

AND WHEREAS the Board has determined, pursuant to paragraph 20(1)(a) of the CEAA that, taking into account the implementation of IPL's proposed mitigative measures, the proposed project is not likely to cause significant adverse environmental effects;

IT IS ORDERED that, pursuant to section 21 of the Act, Order XO-J1-10-98 be amended and that the project be exempted from sections 30, 31 and 47 of the Act, upon the following condition:

> Unless the Board otherwise directs prior to 31 December 1999, this Order shall expire on 31 December 1999, unless construction and installation of the proposed project has commenced by that date.

NATIONAL ENERGY BOARD

Michel L. Mantha
Secretary

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EXPLANATORY STATEMENT

TERRACE TOLL AGREEMENT

This Explanatory Statement briefly summarizes the primary provisions of the Terrace Toll Agreement (Exhibit 1, Attachment B).

1. The overall purpose of the Terrace Toll Agreement is to provide a basis for the recovery by Enbridge and Lakehead of the costs of the Terrace Expansion Program. Schedule A to the Agreement describes in detail the physical facilities to be constructed or modified in each phase of the project. Article 2 of the Agreement sets forth a schedule on which each set of new facilities is expected to be in-service, beginning with the first portion of Phase I (January 15, 1999), and continuing through Phase III (September 30, 2001), with additional phases to follow in 2002-2007 subject to further agreement of the parties as to the timing of construction.

2. At each stage, CAPP, as representative of the producers, must request in writing that Enbridge and Lakehead proceed and must give notice as provided in Article 3 of the Agreement. If CAPP elects not to request both Phases II and III by July 1, 2001, then pursuant to Article 14, the recovery of Terrace costs reverts to a cost-of-service-based surcharge rather than the fixed-rate surcharge embodied in Articles 6 and 7 of the Agreement. If the parties to the Agreement cannot agree on the terms of the cost-of-service-based surcharge, their disagreement is subject to arbitration as provided in Article 15 and Schedule G. This arbitration is solely for the purpose of determining what surcharge Lakehead would file with the Commission, and is not intended to limit or affect the FERC's jurisdiction over the filing in any way, except insofar as Lakehead and CAPP would be bound not to object to or oppose the arbitrated result.

3. The basic cost recovery mechanism under the Agreement is that Enbridge and Lakehead will collectively impose a five-cents-per-barrel Canadian (Cdn) surcharge on top of the underlying rate for transportation of light crude from Edmonton, Alberta to Griffith, Indiana (Chicago). This base surcharge is subject to adjustment "on a distance basis and for commodity credits or surcharges, consistent with Enbridge and LPL's then existing toll design." Article 7. Thus, for example, transportation of heavy crude from Edmonton to Chicago would be subject to a total surcharge of somewhat more than 5 cents (Cdn) in accordance with Enbridge and Lakehead's existing rate design, which includes a proportionately higher rate for heavier petroleum to reflect its greater viscosity. Similarly, the surcharges for shorter or longer hauls would vary in proportion to distance in the same manner as the underlying rates to which the surcharges apply.

4. As between Enbridge and Lakehead, the Agreement initially provided that the five-cent (Cdn) surcharge could be divided at Enbridge and Lakehead's discretion so long as at least one cent (Cdn) is allocated to each system. Article 9. Subsequently, Enbridge and Lakehead agreed that the five-cent (Cdn) surcharge is to be divided initially in such a way that three cents (Cdn) is incurred on the Enbridge system and two cents (Cdn) is incurred on the Lakehead system.

5. The two-cent (Cdn) increment on Lakehead is to be converted to U.S. currency on the basis of the "average exchange rate for the period commencing October [1,] 1998 and ending December 31, 1998 as published in the Bank of Canada Review, Statistical Supplement." Article 9. Based on current exchange rates, the two-cent (Cdn) surcharge would translate into approximately 1.3 cents (U.S.) per barrel. Except as noted in paragraph 14 below,

all future adjustments to the base surcharge under the Agreement will be made using the same exchange rate calculated under Article 9 of the Agreement.

6. Articles 10 and 22 provide that the three-cent (Cdn) surcharge imposed by Enbridge will be subject to a so-called Transportation Revenue Variance under the Enbridge Incentive Toll Settlement Agreement. No such provision applies to Lakehead, and these Articles are therefore irrelevant to the U.S. tariffs.

7. The two-cent (Cdn) surcharge on Lakehead's rates will remain fixed through December 31, 2013, subject only to the limited adjustments contemplated

in the Agreement. Thus, the cost recovery for the Terrace project is essentially levelized during a 15-year period, with most of the cost risks falling on Enbridge and Lakehead.

8. Under Article 12, Enbridge and Lakehead assume 100 percent of the operating cost risk (i.e., the risk that actual operating costs will exceed the costs expected at the time of the Agreement), subject only to a limited exclusion for property taxes. That exclusion is based on an agreed-upon forecast of expected future property taxes on the Terrace facilities set forth in Schedule F to the Agreement. Only if the actual experience varies from the forecast by 20 percent or more in a given year would there be an adjustment to the Terrace surcharge by way of a surcharge or surcredit as specified in Schedule B to the Agreement.

9. Under Article 13, the capital cost risks are shared between Enbridge/Lakehead and the shippers. Article 13 lists the "target costs" as of December 13, 1997 for each phase of the project (in Canadian dollars for Enbridge and U.S. dollars for Lakehead). These target costs are inflated from January 1, 1998 forward using the Canadian and U.S. Gross Domestic Product deflators. Enbridge and Lakehead absorb 100 percent of the risk of capital cost variations (i.e., the risk that costs will exceed the adjusted target costs) up to 5 percent of the

listed amounts. Above 5 percent, the five-cent (Cdn) base surcharge is adjusted upward by 0.09 cents (Cdn) per barrel per $10 million change (pro rata) for Phase I and 0.07 cents (Cdn) per barrel per $10 million change (pro rata) for Phase II. Agreement, Schedule B. This results in a split of the capital cost risk above 5 percent on a 50/50 basis. Similarly, if Enbridge and/or Lakehead can save on capital costs against the target cost, no adjustment is made for the first 5 percent of variance and any variance in excess of 5 percent is shared 50/50 under the same Schedule B formula. This provision gives Enbridge and Lakehead an incentive to pursue maximum efficiency in constructing and modifying any needed facilities and ensures that shippers will benefit from any substantial efficiencies achieved.

10. Article 17 provides a penalty for Enbridge and Lakehead if the planned facilities expansions do not yield the additional capacity projected when tested as provided in Article 17. The penalty is a one-cent (Cdn) per barrel refund for each 5,500 cubic meters per day (m3/d) (ie, approximately 34,600 barrels per day) by which capacity falls short in a given year.[1] This refund would be achieved by reducing the surcharge proportionately in the year following the capacity shortfall. No penalty is imposed, however, to the extent throughput would not have been available to fill the missing capacity on any event. In addition, pursuant to Article 18, no penalty applies if capacity is unavailable as a result of the failure to obtain timely regulatory approvals from necessary agencies.

11. If the capital costs of any phase increase by $10 million (Cdn) or more due to changes in the scope and timing of the project (as opposed to mere cost overruns), Article 19

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1 This amount is incurred on a pro rata basis, meaning, for example, that a shortfall of 550 m3/d would lead to a penalty of one-tenth of a cent (Cdn).

and Schedule B provide that the surcharge will be adjusted by 0.18 cents (Cdn) per barrel per $10 million (Cdn) change in costs for Phase I, or 0.14 cents (Cdn) per barrel per $10 million (Cdn) change in costs for Phase II. Agreement, Schedule B. The result of this provision is effectively to place the costs of any scope or timing changes requested by CAPP (above $10 million (Cdn)) on the ratepayers.

12. Article 19 further provides that the surcharge will be adjusted for construction cost variances due to "agreed upon circumstances which are extraordinary and not within the control of Enbridge/LPL as more particularly described in Article 20." This is, in effect, a force majeure clause for acts of God and similar events. If such events occur, the surcharge will be adjusted in accordance with Schedule B.

13. Article 19 and Schedule B also provide potential upward or downward adjustments of the surcharge if the cost of debt or the return on equity varies by more than two percentage points from 1998 levels. In the case of debt, if the cost of debt as measured by the current Canadian long bond rate (5.28%) and 10 year U.S. Treasury bond rate (5.65%) increases or decreases by more than 200 basis points, the surcharge is increased or decreased 0.1 cent (Cdn) per barrel for each 50 basis-point change in debt costs, applicable separately to Enbridge and Lakehead. In the case of equity, if the generic multi-pipeline cost of equity as determined by the NEB increases or decreases by more than 200 basis points from its current level, the surcharge in 1999-2007 would be increased or decreased 0.3 cents (Cdn) per barrel for each 25 basis-point change. ID. All changes are made pro rata for increases or decreases of more or less than the stated amount.

14. Article 21 is intended to provide protection to Enbridge and Lakehead if, after completion of Phase III, the anticipated increase in throughput does not materialize. Schedule C sets forth the amounts and basis for increasing the surcharge if throughput is too low in various future time periods. Any adjustments to the surcharge are to be implemented in the year following the year of the throughput shortfall. For this purpose, Canadian currency values are to be converted to U.S. currency based on the most recent 12-month average exchange rate at the time in question.

15. Article 24 provides that the calculation of the surcharge will assume that the Terrace facilities are depreciated on a straight line basis using a truncation date of 2024.

16. Article 25 provides CAPP a right to audit Enbridge and Lakehead's compliance with the Agreement upon the terms set forth in Article 25.

EXHIBIT NO. 6

EXPLANATORY STATEMENT

350 CENTISTOKE AGREEMENT

This Explanatory Statement briefly summarizes the primary provisions of the 350 Centistoke Agreement (Exhibit 1, Attachment C).

1. Lakehead will make the change to begin accepting crude with a viscosity limit of 350 centistokes when CAPP formally requests that Enbridge and Lakehead commence 350 centistoke service.

2. The 350 Centistoke Agreement provides that the surcharge in Lakehead's rates for heavy crude petroleum will be increased from 20 percent to as much as 22 percent on heavy crude petroleum deliveries made after Lakehead has commenced 350 centistoke service in accordance with the receipt of the CAPP notice.

EXHIBIT NO. 7

[LOGO]

National Energy Board Office national de l'energie

File: 3400-J001-84
21 August 1997

BY FACSIMILE (403) 420-5389

Mr. Robert L. Nichols
Vice President, Accounting and Regulatory Affairs
Interprovincial Pipe Line Inc.
IPL Tower, 10201 Jasper Avenue
P.O. Box 398
Edmonton, Alberta
T5J 2K9

Dear Mr. Nichols:

Re: Interprovincial Pipe Line Inc. ("IPL")
350 Centistoke Project Application for Orders Pursuant to
Section 58 and Part IV, Dated 22 April 1997

The Board has examined IPL's application, dated 22 April 1997, pursuant to section 58 and Part IV of the National Energy Board Act (the "Act"), for approval of facilities additions and toll orders necessary to allow IPL to increase the density and viscosity limits of heavy crude oil accepted for transportation ("350 Centistoke Project").

The Board notes that the 350 Centistoke Project was developed between IPL and an industry task force represented by heavy oil interests and has received the formal support of the Canadian Association of Petroleum Producers. The Alberta Department of Energy and PanCanadian Petroleum Limited have filed letters in support of the project. The Board further notes that no party has expressed any concerns with IPL's application.

The Board has approved the construction of the 350 Centistoke Project, as applied-for. Accordingly, the Board has issued Order OX-J1-28-97, the effect of which is to permit IPL to proceed with construction of the proposed facilities.

With regard to Part IV matters, the Board finds that the capital and operating costs relating to the proposed facilities constitute a Non-Routine Adjustment in accordance with paragraph 7.1(a)(i) of the principles of settlement, filed in support of IPL's February 1995 Incentive Toll Application approved by Order TO-1-95, issued 24 March 1995.

The Board has approved in principle a two percentage point surcharge (to 22 percent) for heavy crude petroleum with viscosity limits between 100 to 350 square millimetres per second and density limits between 904 to 940 kilograms per cubic metre, inclusive. Pursuant to subsection 19(l) of the Act, the revised heavy petroleum surcharge will not become effective until notification from CAPP and the filing of tariffs by IPL pursuant to paragraph 60(l)(a) of the Act.

The Board directs IPL to serve a copy of this letter and the attached Order on all parties identified on its interested parties list.

Yours truly,

/s/ M.L. Mantha

M. L. Mantha
Secretary

Attach.

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[LOGO]

National Energy Board   Office national de l'energie

ORDER XO JI-28-97

IN THE MATTER OF the National Energy Board Act ("the Act") and the regulations made thereunder; and

IN THE MATTER OF an application, pursuant to section 58 of the Act, by Interprovincial Pipe Line Inc. ("IPL"), filed with the Board under File 3400-J001-84.

B E F O R E the Board on 21 August 1997.

WHEREAS the Board has received an application from IPL dated 22 April 1997, respecting the construction of additional pipeline facilities to enable the transportation of crude oils at higher viscosity and density limits ("350 Centistoke Project"), estimated cost $9 million;

AND WHEREAS pursuant to the Canadian Environmental Assessment Act (CEAA), the Board has considered the information submitted by IPL and has performed an environmental screening of the proposal;

AND WHEREAS the Board has determined, pursuant to paragraph 20(1)(a) of the CEAA that, taking into account the implementation of IPL's proposed mitigative measures and those set out in the conditions to this Order, the proposal is not likely to cause significant adverse environmental effects;

IT IS ORDERED that the construction of the 350 Centistoke Project is exempt from the provisions of sections 30, 31 and 47 of the Act, upon the following conditions:

1) Unless the Board otherwise directs, IPL shall implement or cause to be implemented all of the policies, practices, recommendations and procedures for the protection of the environment included in or referred to in its application.

2) Unless the Board otherwise directs, IPL shall cause no variations to the procedures and mitigative measures for the protection of the environment

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without the prior approval of the board.

3) Unless the Board otherwise directs, IPL shall, within 14 days of the receipt of any subsequent concerns expressed by stakeholders on the IPL right-of-way, provide the Board with a report detailing the concerns and the measures IPL will implement to mitigate those

concerns.

4) Unless the Board otherwise directs, IPL shall conduct noise surveys at those terminals and pump stations where pumping unit installation and pumping unit modification are to occur and provide the Board with confirmation that noise level increases have not exceeded 3.0 decibels.

5) Unless the Board otherwise directs prior to 31 December 1998, this Order shall expire on 31 December 1998 unless the Construction and installation with respect to the additional facilities has commenced by that date.

NATIONAL ENERGY BOARD

/s/ M.L. Mantha

M. L. Mantha
Secretary

CERTIFICATE OF SERVICE

I hereby certify that I have, this 27th day of October, 1998, served copies of the foregoing Offer of Settlement and attachments via first-class mail, postage prepaid, on the Canadian Association of Petroleum Producers and on all current shippers of Lakehead Pipe Line Company, Limited Partnership.

/s/ S. Reed

Steven Reed

EXHIBIT 21

LAKEHEAD PIPE LINE PARTNERS, L.P.

PRINCIPAL SUBSIDIARIES

The Registrant's principal subsidiary is Lakehead Pipe Line Company, Limited Partnership, a Delaware limited partnership, in which the Registrant has a 99% limited partner interest.

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