

(2) Exemptions

(a) RGT RPO:

In the event the failure by Westcoast to provide RGT service can be directly attributed to the quality of commingled gas delivered by an RGT RPO, Westcoast will retain the right to recover the payment of CDC's paid from the shipper(s) receiving the gas at that receipt point. The burden of proof lies with Westcoast in proving the linkage between the actions of an RPO and Westcoast's failure to provide RGT service. Westcoast will provide a complete record of the incident to the shippers affected by the failure.

(b) Hydrates:

If the failure to provide RGT service by Westcoast can be directly attributed to hydrates in the RGT system this will be considered an EO. Westcoast will not include this failure to provide service in the calculation of reliability for the purposes of paying CDC's in the RGT system. Interruptions of this type will be identified by way of an incident notification from Westcoast to shippers affected, declaring the time period, nature of the incident, and pipeline(s) affected. Recurring incidents such as hydrates and liquid loading will be investigated by the AOC's to find a solution which reduces or eliminates further occurrences.

(c) Downstream Interconnect or Transportation Service:

If the failure to provide RGT service by Westcoast can be directly attributed to the actions of a downstream interconnecting pipeline or other facility (eg., storage facility) or the actions of the TN (Transportation Service - Northern) or TS (Transportation Service - Southern) systems, this will be considered an EO. Evidence that the problem was caused by a downstream event will be provided in the form of plant inlet and outlet pressure data confirming pressures above the levels specified in Appendix III accompanied where appropriate by an incident report or formal notification of a problem issued by a downstream interconnect. Westcoast will not include this failure to provide service in the calculation of reliability for the purpose of paying CDC's in the RGT system.

(d) Westcoast will resolve intra-day reliability problems by equitably allocating available capacity upstream of a constraint, within the practical limits of the physical facilities and computer management systems.

B. Treatment Reliability Measurement

(1) Treatment service reliability will be measured on a daily basis by the lesser of:

(a) announced facility CD restriction, and

(b) the combination of inlet pressure, outlet pressure and allocated volume. (In the event that the inlet pressure to the plant is greater than the daily average pressure specified in Appendix III and the plant outlet pressure is less than or equal to the daily average pressure specified in Appendix III, the reliability not received will be the CD minus the volume received. Notwithstanding the preceding, in the event the plant outlet pressure is greater than the daily average pressure specified in Appendix III or any of

the shipper's CD limits of raw, residue, H₂S, and CO₂ is provided in full, the service will be considered to have been fully available.)

(2) **Service limits:**

Determination of whether Westcoast has provided Treatment service will include evaluation of performance with respect to CD limits of raw gas, H₂S, CO₂ and residue gas.

(3) **Exemptions:**

If the failure to provide Treatment service by Westcoast can be directly attributed to the actions of a downstream interconnecting pipeline or other facility (eg., storage facility) or the actions of the TN or TS systems, this will be considered an EO. Westcoast will not include this failure to provide service in the calculation of reliability for the purpose of calculating CDC's for Treatment service. Westcoast will provide a complete record of the incident to the shippers affected by the failure.

C. Transportation Reliability Measurement

Transportation system reliability will be measured as described in the GT&C.

D. Linkage of Service

Westcoast will provide linkage from firm primary or assigned Treatment service to matched firm primary or assigned RGT service in respect of a Treatment outage for the determination of Treatment CDC's as outlined in the CDC calculation section of this document. There will be no other linkages between service zones. In particular, if an RGT outage is caused by a Treatment failure the RGT outage will be exempt from the RGT reliability calculation despite the linkage with respect to the determination of the amount of Treatment CDC to be credited. Westcoast will provide a complete record of the incident to the shippers affected by the failure.

IV. CALCULATION OF CDC'S

A. RGT and Treatment

1. After the end of each year Westcoast will calculate, based on actual metered or allocated gas flows, pressure measurements, CD restrictions and contracted gas volumes, the annual UPO reliability level for each shipper firm service.
2. Westcoast will use the average CD level held over the year to calculate CDC's. CDC's will be paid out to the "primary service holder" on an annual basis. Distribution of these CDC's between parties involved in assignments of capacity will be between assignor and assignee as per their commercial arrangement. Westcoast will pay CDC's on short term firm contracts that are held for only a portion of the year and do not have renewal rights associated with the contract. In the event Westcoast does not meet it's annual UPO reliability target shippers will be given CDC's for the base toll and applicable demand toll adjustment on the difference between their actual reliability level and the target reliability level.
 - **Primary Service Holder:** The primary service holder will, in most cases, be the party who Westcoast holds the contract with and /or has the renewal rights for the service. In some instances it may be necessary to have some parties elect to become the primary service holder.

- **Assignments:** For the purposes of this calculation, any service assigned to an acquiring shipper will be deemed to have remained in the hands of the primary service holder in the calendar year. The assigned block of firm service CD and related UPO volumes and UDCC's (Underutilized Demand Charge Credits) will be included in the determination of the primary service holder's reliability and CDC's. Acquiring parties will not receive CDC's from Westcoast.
- **Primary, Alternate and Secondary Receipt Points:** Primary receipt points are those which are identified in Schedule B of the firm service agreements held with Westcoast. Alternate primary receipt points are permanent service relocations during the calendar year. Secondary receipt points are receipt points which Westcoast has authorized a temporary relocation. For the purposes of calculating reliability shortfalls CD, UPO and UDCC volumes relating to service at alternate and secondary receipt points will be combined with service at primary receipt points.
- **Service Grouping at Receipt Points and Partial Assignments:** UPO and UDCC volumes will be combined for primary and secondary service holders and primary and secondary receipt points on specific days in order to calculate an annual reliability level.

The calculation of CDC's for the primary holder will be:

- (A) Full Volume = Shipper's Average CD in year times number of days in year (usually 365)
- (B) Net Volume Loss = Total Volume Loss – volume loss due to PO's (must qualify under PO rules) – volume loss due to EO's (e.g., hydrates) (must qualify under EO rules)
- (C) Net Volume Loss After UDCC Adjustment = B - UDCC's received in the year
- (D) Reliability = $(A - C)/A \times 100\%$
- (E) Target UPO Reliability = $100\% - \text{UPO}\%$. Westcoast will credit CD charges if D is less than E (actual reliability is below target)
- (F) Reliability shortfall = $E - D \%$
- (G) CDC volume = $F \times A$
- (H) Tolls on which CDC are based will be the shipper's volume weighted average daily demand tolls (i.e., volume weighted for shipper's mix of 1, 3, 5 year and negotiated tolls) for the shipper's service in effect, at the facility, on the days on which the reliability shortfall is deemed to occur. Deeming will be done by prorating the shortfall over the volumes and days of net volume loss (i.e., excludes qualified PO and EO volumes and days). Linkages between Treatment and RGT will also be determined for each day on which the reliability shortfall is deemed to occur based on the service in effect on those days.
- (I) CDC's = $G \times H$ (calculated for multiple days and tolls)

A sample calculation of the above has been included as Appendix V

B. Transportation

Westcoast will pay CDC's to individual TN and TS firm shippers as specified in the GT&C with the exception of the following change. CDC's will be calculated using the volume weighted average toll paid by the shipper for all equivalent service (same receipt point and delivery point for both option A and option B services) in the service zone affected.

C. Linkage of Service

Linkages between zones for the purpose of calculating CDC's are based on the following principles. In the RGT and Transportation service zones, Westcoast will issue CDC's for the affected firm services in the zone in which the facility where the reliability target has not been met is located. In the Treatment zone, Westcoast will issue CDC's payable to the primary service holder for the affected firm primary or assigned Treatment services and that shipper's linked firm primary, alternate or secondary RGT services. Where the facility is within the RGT service zone, no CDC's will be issued for Treatment or Transportation services; where the facility is within the Treatment service zone, no CDC's will be issued for Transportation services; and where the facility is within a Transportation zone, no CDC's will be issued for RGT and Treatment services and Transportation services in other zones.

With the exception of Treatment service, CDC's will be calculated using only the volume weighted average toll for the affected services in the zone in which the reliability target was not met. Treatment CDC's will be calculated using the tolls for the shipper's affected Treatment and matched RGT services when Treatment does not meet its reliability target. Westcoast will continue to allow the contracting practice of having unmatched firm RGT and Treatment service. For the purpose of calculating Treatment CDC's for matched service, RGT will be linked to Treatment by calculating the volume weighted average toll for the shipper's affected Treatment service and the related RGT service. Only Treatment tolls will be used to calculate CDC's for Treatment service not matched to RGT. In the event of unmatched RGT and Treatment services where Treatment exceeds RGT, the first block of Treatment service deemed to be affected will be the unmatched service. In no event will CDC's be paid more than once for the same RGT service (i.e., payment of RGT CDC's under both the RGT portion of this paragraph and under the RGT linked to Treatment in the Treatment portion of this paragraph is not contemplated).

V. PROCEDURAL CHANGES

Westcoast's reliability commitments are conditional upon termination of the following operational and billing practices that encourage or condone poor operational control or that are at odds with the current Westcoast contracting and facility design practices. This will result in the loss of some of the system flexibility that shippers on the Westcoast system currently enjoy. The new policies and procedures support the philosophy that both Westcoast, shippers and interconnects accept responsibility and accountability for those things within their control.

A. Nominations '97

The current GMS authorization process has served the pipeline division and its customers well over the past five years in providing gas management services. The changes in the gas industry over the past years have created a demand for new services. The customers' business transactions have also become more complicated over time in response to the changes in the way the industry does business. The current authorization process does not allow for these new services to be offered in a timely and efficient manner and places the burden of processing the complex transactions on Westcoast instead of on the shippers. As a result, the current authorization process has become slow, unreliable, and complex. Our shippers have stated they would like to see Westcoast adopt industry wide standards (i.e., GISB {Gas Industry Standards Board}) so that Westcoast can offer new services and make it

easier for them to complete their business. Therefore, an authorization process that is simple, flexible, and reliable is required. Specific objectives of the new authorization process are as follows:

- develop a baseline authorization process which provides the flexibility to develop new services in a manner which is timely and consistent with the principles and procedures of the settlement agreement
 - adopt industry standard (GISB) transaction sets thereby providing flexibility to the shippers to nominate using the application of their choice (NrG, their own GMS)
 - create an authorization process which is simpler to use so that the shippers have more control over their business and the business process can be authorized in a shorter time cycle
 - a simpler process should also be more reliable in that the shippers' business will be authorized as expected and it will be easy to operate and maintain the business process from Westcoast's standpoint
 - provide a structure that will allow for tighter control of the RGT system by delinking the RGT and Treatment business processes from TN, thereby allowing the RGT and Treatment business processes to stand alone
 - adopt a receipt point operator (RPO) approach with third party dry gas points
- (1) As a minimum, Westcoast will conform with the GISB industry standard nomination cycle. Renominations to upstream and downstream interconnects will be limited by the renomination times of the interconnecting party. The standard nomination cycle is as follows:
- Westcoast will provide all information that the shippers require to set up business for the next day, including allowable business levels based on current supply, cumulative imbalance position and agreed pack and draft rates by 9:30 Central Clock Time (8:30 a.m. Calgary Clock Time) for the next gas day
 - shippers will nominate to Westcoast their business for the next day by 11:30 Central Clock Time (10:30 am Calgary Clock Time)
 - Westcoast will authorize business back to shippers by 4:30 p.m. Central Clock Time (3:30 Calgary Clock Time) for the next gas day. No business will knowingly be authorized if it will put the shipper out of tolerance. Westcoast will provide shippers with a GISB Type II Intra-day nomination opportunity. A GISB Type II Intra-day nomination is defined as a renomination placed a day prior to the gas day. Shippers electing to use this option must nominate by 5:30 p.m. Central Clock time (4:30 p.m. Calgary Clock Time) and Westcoast will authorize back to shippers at 8:00 p.m. Central Clock Time (7:00 p.m. Calgary Clock Time).
- (2) Westcoast will provide shippers with a GISB Type I Intra-day nomination opportunity. A GISB Type I Intra-day nomination is defined as a renomination placed for the current gas day. Shippers electing to utilize this opportunity will renominate business to Westcoast for the current gas day by 1:00 p.m. Central Clock Time (12:00 p.m. Calgary Clock Time). Westcoast will authorize by 5:00 p.m. Central Clock Time (4:00 p.m. Calgary Clock Time) for the current gas day.
- (3) Westcoast will retain the authority to reauthorize the RGT and Treatment system separately from the Transportation system.

- (4) If, after Westcoast confirms authorizations related to the nomination cycle, Westcoast determines it is unable to meet its delivery obligations due to an event of force majeure in either of the Transportation zones, Westcoast will declare force majeure and curtail service in the affected service zone. In curtailing service, Westcoast will curtail or interrupt service in the following priority and sequence:
 - (a) Westcoast will first curtail or interrupt Interruptible Service in the reverse order to that in which it was authorized (where authorized at the same priority, service will be curtailed pro rata on the basis of the volumes of Interruptible Service previously authorized for that day); and
 - (b) Westcoast will curtail or interrupt Firm Service last, pro rata on the basis of CD.
- (5) Westcoast will have the capability to reauthorize the RGT and Treatment zones separately and on a more frequent basis than the TN and TS zones. Westcoast will use reasonable efforts to provide shippers with the capability at standardized intervals to change RGT and Treatment service nominations in response to changing system conditions.
- (6) Westcoast will require shippers to nominate fuel gas utilization with the implementation of Nominations 97. Westcoast will set weekly fuel gas ratios during periods of large fuel utilization swings.

B. RGT and Treatment Nomination Detail

- (1) Westcoast will authorize shippers firm entitlements from specific receipt points to specific delivery points in the RGT system as specified in the contract. Westcoast will give firm entitlements for specific raw, residue, H₂S and CO₂ volumes as specified in the contract.
- (2) Shippers must nominate their specific RGT and Treatment contract services. Nominations must include all aspects of raw, residue, H₂S and CO₂. RGT nominations will be communicated as a raw volume. Residue volume, H₂S and CO₂ nominations will be determined based upon the commingled stream composition as communicated to Westcoast by the RPO.
- (3) With the implementation of Nom's 97 and park and loan or similar services Westcoast will recognize different market types such as swing or balancing markets to allow gas to flow under firm contracts in the RGT and Treatment areas without a direct linkage to a downstream market.
- (4) If, after Westcoast confirms authorizations related to the nomination cycle, Westcoast determines it is unable to meet its delivery obligations due to an event of force majeure in the RGT or Treatment zones, Westcoast will declare force majeure and reduce the service capacity of the affected service zone and unilaterally reallocate capacity through the intra-day nomination process utilizing the authorization priorities outlined in the GT&C.

C. Elimination of RGT and Treatment UDCC's

Westcoast's RGT and Treatment reliability commitments require the removal of flexibility that allows firm shippers to effectively move service between RGT receipt points and between plants for billing purposes. The focus will be to encourage shippers to contract for the correct firm service levels and locations to meet their production requirements. Westcoast's reliability commitment will require the

elimination of all inter-plant UDCC's related to Treatment Service effective November 1, 1997 and the elimination of all inter-receipt point UDCC's related to RGT Service effective the later of December 1, 1997 or the implementation of TLC (Temporary Location Commitment system).

- (1) Westcoast will offer to shippers capacity which is currently uncontracted on a timely basis to facilitate the movement of existing RGT, Treatment and TN contracts to better match the production needs of shippers. The service relocation program will include an individual review of shipper contracts with a long term commitment to an individual location where the shipper needs to move the location. Westcoast may, at its sole discretion, allow these movements. This does not constitute an offer to build facilities or to give firm contract entitlements to shippers where no capacity is currently available.
- (2) Westcoast will develop a TLC system to allow shippers to confirm short term temporary movements of firm contract receipt points within the same RGT system to areas where excess RGT capacity is known to exist. The TLC system will give existing firm shippers, on a first come first served basis, firm rights at the new (secondary) authorized receipt points and reduced firm rights at the prior receipt points (primary) for the duration of the TLC if they have received an authorization for a TLC. For a request made by 9:00am Calgary Clock Time, Westcoast will provide, by 10:00am Calgary Clock Time, a Temporary Location Commitment for the next gas day (green zone - wide open) or 10:00 am two business days later for gas day three business days out (yellow zone - hydraulic run required to determine availability). Westcoast will give at least 3 months notice to shippers on the expected implementation date of the TLC system.
- (3) Once the service relocation program, referred to in section C-1, is complete and the TLC system RGT Phase I reliability is in place, Westcoast will discontinue the practice of crediting inter-area and inter-receipt point UDC's to interruptible movements in the RGT systems. The practice of crediting inter-plant UDC's to interruptible treatment service will be discontinued on November 1, 1997. Credit for inter-day UDC's within a month (i.e., monthly determination of interruptible charges) will be continued on a volume basis. Any UDCC's will be included in the evaluation of reliability and the calculation of CDC's as a deduction from UPO's.
- (4) Acid gas over utilization charges will continue to be determined using the current methodology, however, like interruptible movements, they will be determined on a monthly basis and the use of inter-plant UDCC's to reduce them will be eliminated.

D. Elimination of Transportation UDCC's

All UDCC's related to TN and TS will be eliminated effective November 1, 1997 (i.e., daily determination of interruptible charges with no inter-day UDCC's and no inter-receipt point or delivery point UDCC's). Delivery point diversions in TN will continue to be authorized on an interruptible basis with daily tolling to be determined in consultation with the Toll and Tariff Task Force as part of the discussions to finalize biddable interruptible service. Downstream and upstream delivery point diversions in TS will continue to utilize the current crediting mechanism on a daily basis with necessary changes to be determined in consultation with the Toll and Tariff Task Force as part of the discussions to finalize biddable interruptible service.

E. RPO's

Westcoast's commitment to service reliability for RGT and Treatment as outlined above is conditional on Westcoast obtaining greater control over and information on the receipt of gas at each receipt point into its RGT facilities. In addition, Westcoast will be removing itself from activities related to production behind the receipt point and will deal with a commingled gas stream at the receipt point. To achieve this, certain amendments will be made to the GT&C including the following:

- (1) Shippers will be required to make daily nominations for RGT service at each receipt point.
- (2) Each shipper will be required to provide Westcoast with the following information in respect of each receipt point at which a shipper is entitled to RGT service:
 - (a) confirmation of shipper's gas supply to meet each daily nomination for RGT service;
 - (b) estimates of shipper's gas deliveries for each day;
 - (c) shipper's actual gas deliveries at the receipt point or its allocated share of actual gas deliveries where more than one shipper is delivering gas at the receipt point, for each day;
 - (d) gas composition of the commingled stream for each day (e.g., H₂S and CO₂ percentages, heating value and liquids);
 - (e) receipt point average pressures for each day.
- (3) Where a shipper is not the RPO of the metering and interconnecting facilities immediately upstream of the receipt point then, as a condition of service, the shipper will provide the information referred to in (2) above to Westcoast through the RPO as its agent and Westcoast will be entitled to rely on the information received from the RPO for the purposes of (2) above as if it were provided directly by the shipper.
- (4) Nominations outlined in (2) above will remain in effect until new nominations are submitted to Westcoast by the shipper or its agent.
- (5) The information provided to Westcoast in (2) above by the shipper or by the RPO where the shipper is not the RPO, will be used by Westcoast to effect the shipper's daily business and to ensure that the shipper is complying with the GT&C. In addition, the assessment of balancing/overproduction charges referred to below will also be based upon the information provided to Westcoast in (2) above. Where the shipper's gas delivered at a receipt point or the commingled gas stream delivered at a receipt point by more than one shipper does not comply with Westcoast's gas quality or receipt point pressure specifications, Westcoast will have the right to take reasonable steps to enforce compliance, including the right to suspend all receipts at the receipt point (e.g., the shutting-in of the receipt point). Westcoast will not unreasonably suspend receipts from the RPO. If Westcoast suspends receipts, Westcoast will work with the RPO to resolve the situation expeditiously.
- (6) Westcoast will implement new liquid allocation procedures as previously voted on and approved by the JIOC. The new allocation procedure would be based on a recovery efficiency methodology which recognizes that not all streams processed in the gas plant get the same

product recovery efficiency. Westcoast will encourage receipt point operators to install liquid meters at receipt points so that volume data from gas and liquid flow meters is used to calculate the receipt point volumes. Westcoast will require that RPO's increase the frequency of liquid and gas sampling for the commingled stream. Theoretical liquids produced at receipt points equipped with liquid meters will be calculated based on measured gas and liquid volumes. Theoretical liquids produced at receipt points without liquid meters will be calculated on a pro rata basis on the remaining liquids after the allocation to those with liquid meters. Westcoast will proceed with modifications to its GMS and DVS systems to accommodate the new liquid allocation methodology and the data from liquid meters. The implementation of the new liquid allocation procedures would take effect on January 1, 1998.

F. Balancing Procedures and Charges

Westcoast's ability to provide reliable operation is dependent on the ability to control and match system deliveries with system receipts. The current aggregate balancing policies and procedures, while offering shippers flexibility, directly impact Westcoast's ability to offer reliability. To enable improved reliability, Westcoast must implement daily balancing on an account by account basis, eliminating the current practice of aggregate balancing. Daily balancing will be enforced through a system of imbalance tolerances and charges. The charges are not intended to generate revenue but are intended to assist Westcoast in taking control of its system. This system of imbalance tolerances and charges will be implemented once the GT&C changes are approved by the Board as part of the approval for the negotiated settlement.

- (1) Daily balancing rules will be applied to all shipper accounts at receipt points onto the transportation system. Aggregate system balancing by shippers will be eliminated.
- (2) The concept of FVE's (Facility Variance Event) will be eliminated coincidentally with the implementation of Phase I reliability commitments. FVE's related to Treatment facilities will be eliminated upon implementation of Phase I Treatment reliability commitments and FVE's related to RGT facilities will be eliminated upon implementation of Phase I RGT reliability commitments. Thereafter, suspense accounts will only be used for dealing with month end adjustments related to estimate/actual adjustments or prior period adjustments.
- (3) Each shipper holding an account at a location where gas is physically delivered into the transportation system from a Westcoast plant or a dry gas source (receipt account), will be obligated to balance supply and deliveries out of that account on a daily basis so as to stay within an account imbalance tolerance. Westcoast will each day identify a system balancing tolerance range which is the greater of a percentage of business and a minimum volume. The range will not exceed 0/+20% or -20/0% or 0/ +3000 GJ or -3000/0 GJ. Individual account tolerances will be calculated by multiplying the shipper's average daily business out of that account by the system balancing tolerance range. The system balancing tolerance range at target line pack is anticipated to be the greater of +/-10% and +/- 1500 GJ on a daily basis. Inventory transfers do not qualify as business for the purposes of calculating the average business out of an account.
- (4) Shippers may inventory transfer volume into or out of their accounts using inventory transfer services to maintain their cumulative account imbalance within account imbalance tolerances. Shippers wishing to move inventory to an account at another location must be authorized to transport the inventory to the new location and pay a fee equivalent to the avoided tolls to physically move gas between the two account locations.

- (5) Westcoast may from time to time adjust the system balancing tolerance range in pre-defined levels (see Appendix IV) based upon changes or as a precaution against expected changes in system line pack. Changes or expected changes may be related to supply onto the Westcoast system, downstream demand or Westcoast facility operations. System balancing tolerances identified during the course of the nomination cycle may be changed at any point in the gas day in reaction to changes in line pack conditions. Shipper account tolerances will reflect any changes in the system balancing tolerances. Westcoast will make reasonable efforts to provide shippers with a renomination opportunity which they may use to renominate authorized business to stay within balancing tolerance.
- (6) At each receipt account, shippers will have a free zone which is 20% of the account imbalance tolerance range (e.g., -4/0% when the tolerance is -20/0%). As long as the cumulative outstanding imbalance in the account is within the free zone no action is required. Outside of this tolerance shippers must demonstrate, in a form satisfactory to Westcoast, their intention to trend the cumulative outstanding account imbalance to zero at a minimum daily rate of 30% of the outstanding cumulative account imbalance. Where the shipper is not able to satisfy Westcoast as to their intention to trend their outstanding cumulative account balance appropriately, Westcoast will have the right but not the obligation to direct such correction.
- (7) Westcoast will develop interruptible balancing services which shippers may nominate to avoid balancing charges. Westcoast will provide such services by the second quarter of 1998. Balancing services must be self-funding, that is, services may not be provided to certain shippers at the expense of shippers at large.
- (8) In the event a downstream interconnect revises its own requirements the interconnect will have the unilateral right within the gas day to downward nominate supply from a delivery shipper (this may impact supply at a plant outlet or dry gas source) or redirect a supply to another downstream interconnect (assumes the interconnect holds the appropriate Westcoast service) or make arrangement with Westcoast to park the gas supply on the transportation system.
- (9) Shippers who lose market as a result of a change in delivery nomination on the intra-day nomination will be expected to stay within balancing tolerance by nominating for balancing services if available, by locating another delivery market coincidental to the loss in market, by locating another delivery market where a further intra-day nomination capability exists, or by shutting in production. Where the shipper does not stay within balancing tolerances, balancing charges will apply.
- (10) Westcoast will seek to enter into annual RGT swing arrangements which compensate the involved RPO(s) appropriately. The terms of these annual agreements will be reviewed and approved by the AOC's. These swing arrangements will be utilized to provide balancing services to shippers and to provide more equitable access to the system.
- (11) If after Westcoast confirms authorization related to the last intra-day nomination cycle, a Westcoast facility problem prevents Westcoast from accepting all scheduled receipts, therefore creating an imbalance between system deliveries and receipts, Westcoast will retain the right to change the system balancing tolerance range or to reauthorize receipt nominations to ensure all shippers holding firm service upstream of the constrained facility are treated equitably. To stay within balancing tolerances, shippers may provide Westcoast with a predetermined list of balancing services they wish Westcoast to use to keep their account in balance.

- (12) In the event of a supply failure after the last intra-day nomination Westcoast will use reasonable efforts to keep the market whole until the next available nomination cycle.
- (13) In the event of a failure by Westcoast to provide TN or TS service the shipper will be responsible to:
 - (a) Renominate at the next available nomination cycle to bring its imbalance account back within tolerance, and
 - (b) Pay Westcoast for any balancing service such as park and loan requested by the shipper and provided by Westcoast to keep the shipper's imbalance account within tolerance within the current nomination cycle.
- (14) In the event of a failure of a Westcoast gas treatment plant or a dry gas source to provide gas supply to the Transportation system the shipper will be responsible to:
 - (a) Renominate at the next available nomination cycle to bring its imbalance account back within tolerance, and
 - (b) Pay Westcoast for any balancing service such as park and loan service requested by the shipper and provided by Westcoast to keep the shipper's imbalance account within tolerance within the current nomination cycle.
- (15) Imbalance charges will be applied when a shipper's cumulative outstanding account imbalance is outside of the imbalance tolerance. Once triggered, charges will be based on the difference between the cumulative account imbalance and account imbalance tolerance. Account imbalances are not authorized and will be billed based on daily estimates reported or on EFM numbers compared to authorized volumes.
- (16) Charges will be 1.1 times the average of the Canadian Enerdata "weighted average" and the Gas Daily "high common" price for Station 2.

G. Estimate to Actual Charges

Estimate to Actual charges will be implemented to encourage shippers to provide Westcoast with flow data accurate enough that Westcoast can utilize that data to make system operational decisions and run the above balancing system.

- (1) Westcoast will implement an estimate to actual variance charge that will apply to non-EFM locations. The estimate to actual variance charge for RGT receipt points will be implemented at the same time as the implementation of the Phase I RGT reliability commitment; for TN receipt points, it will be implemented at the same time as the Phase I Treatment reliability commitment.
- (2) Estimate to Actual Variance is defined as the absolute value of the difference between estimate and actual volumes on a daily basis, which are outside the greater of a $\pm 5\%$ or $\pm 7 \times 10^3 \text{ m}^3$ tolerance based on receipt point volumes (raw on the RGT system or residue on the TN system as the case may be). Estimate to actual variance charges will be in place to encourage accurate reporting of estimated volumes at non-EFM locations.
- (3) Variances will be calculated with a one day lag to allow for corrections by shippers of estimation errors.

- (4) Charges will be 1.15 times the average of the Canadian Enerdata "weighted average" and the Gas Daily "high common" price for Station 2.
- (5) For raw gas variances, charges will be billed on a residue equivalent basis using the shrinkage ratio from the month end plant statement.

H. Overproduction Charges

Westcoast will implement Residue, Raw and Acid Gas overproduction charges to motivate minimal overproduction on the part of shippers thereby minimizing the related impact on other shippers. The charges will apply to overproduction above authorized volumes on a daily basis in the RGT, Treatment or Transportation systems. Westcoast will provide a tolerance at each receipt point and will only apply overproduction charges where the actual daily volumes are outside of the tolerance as follows:

- (1) A daily raw overproduction charge will be applied on actual raw volumes which exceed that day's authorized receipt point volume (including the plant inlet where Westcoast does not provide RGT service) plus the greater of 5% or $7 \times 10^3 \text{m}^3$. This charge will be implemented at an aggregate inlet to plant level at the same time as Westcoast's Phase I Treatment reliability commitment takes effect. It will be implemented at an individual RGT receipt point level at the same time as Westcoast's Phase I RGT reliability commitment takes effect.
- (2) A daily acid gas overproduction charge will be applied on the sum of the volumes that each of actual H_2S and CO_2 volumes exceed each of that day's authorized H_2S and CO_2 volumes at the plant plus 5%. Acid gas overproduction tolerances may be reduced to 2% at an individual plant if Westcoast deems it necessary to deliver reliable service to all shippers. Reduction of acid gas overproduction tolerances will be announced to shippers at the affected facility. This charge will be implemented at an aggregate inlet to plant level at the same time as Westcoast's Phase I Treatment reliability commitment takes effect. Westcoast will not utilize an overproduction tolerance which is tighter than the accuracy of the reconciliation between the aggregate theoretical acid gas at the plant inlet and actual acid gas recovered.
- (3) A daily residue overproduction charge will be applied on actual residue volumes which exceed that day's authorized receipt point volume plus the greater of 5% or $7 \times 10^3 \text{m}^3$. These tolerances will apply to overproduction above authorized volumes on a daily basis at dry gas sources in the TN system and will be implemented when Westcoast's Phase I Treatment reliability commitment takes effect.
- (4) Charges will be 1.25 times the average of the Canadian Enerdata "weighted average" and the Gas Daily "high common" price for Station 2. Raw and acid gas overproduction charges will be billed on a residue equivalent basis using the shrinkage ratio from the month end plant statement.
- (5) All charges will be billed as part of the monthly billing cycle.

I. Two Step Overproduction Charge Evaluation

Westcoast will develop a two step overproduction charge evaluation methodology for use during Treatment Service upsets within the current gas day. Overproduction behind the plant will be evaluated on an aggregate level when the plant is constrained. A shipper may produce up to the pro-

constraint authorized volume at any one or number of receipt points so long as total production into the plant from that shipper does not exceed the post-constraint volume authorized by Westcoast for that same shipper for the current gas day.

J. Electronic Flow Measurement

To provide reliable operation in the RGT system, Westcoast must have access to real time data. This will allow Westcoast to manage the system to avoid pressures above those specified in the GT&C. EFM will also provide Westcoast and shippers the opportunity to monitor shipper imbalances on a real time basis and eliminate much of the delay and uncertainty when evaluating shipper status and shipper performance. While originally committed to 100% EFM on receipts, Westcoast recognizes that substantially all of our requirements can be met through installation of EFM at those receipt points that account for 90% of the RGT receipts behind Westcoast treatment facilities. EFM at RGT receipt points will therefore be implemented as follows:

- (1) All RGT system shippers will cause RPO's to install EFM devices in the RGT system on receipt points where the greater of the contracted service or demonstrated capability to deliver is:
 - Five mmscfd or more in the Fort Nelson RGT system
 - Five mmscfd or more in the Grizzly Valley RGT system
 - Two mmscfd or more in the Fort St. John RGT system
- (2) Installation of compulsory EFM devices will be completed by April 1, 1998. Any location which is above the minimum volume required for EFM implementation set out above, and does not have EFM installed and operating by April 1, 1998, will have physical receipts reduced to the minimum volume for EFM specified in paragraph (1) above. This will be accomplished either by using receipt point availabilities and overproduction charges or by physically shutting in the receipt point at Westcoast's sole discretion.
- (3) On receipt points below the volumes specified above for the respective RGT systems, RPO's will have the option to install EFM devices. All shippers will be subject to estimate to actual charges at any locations that do not have EFM devices.
- (4) Westcoast will not warrant Phase I RGT and Treatment reliability levels to shippers receiving gas in RGT areas where EFM has not been fully implemented until estimate to actual charge systems and other necessary aspects of Phase I are implemented. Westcoast will warrant Phase II RGT and Treatment reliability levels commencing on the later of January 1, 1998 and EFM fully installed in a RGT area. RGT areas may be broken into sub-areas for the purpose of determining if EFM is fully implemented and Phase II reliability targets will apply if, in Westcoast's sole judgment, the reliability of full EFM sub-areas are not affected by other sub-areas.
- (5) EFM devices must be of a type and kind acceptable for custody transfer service and must meet Westcoast's Electronic Flow Measurement Policy specifications.
- (6) RPO's will supply EFM field devices and electronic signals to land line locations in accordance with Westcoast Electronic Flow Measurement Policy.

- (7) Westcoast will provide landline data collection and data processing into the Gas Management System. Gas management reports will be available to shippers.
- (8) Westcoast will provide an EFM coordinator in Calgary until May 1, 1998 to coordinate the implementation of this program. The coordinator will ensure the most efficient implementation of EFM, resolve standards issues, ensure minimal duplication of facilities and efforts, and act as an industry EFM consultant and coordinator.
- (9) In the event of EFM device failure Westcoast will advise the RPO of a timeframe to correct failure. In the event correction does not take place in the specified time frame or the EFM device suffers chronic failures Westcoast will give the RPO notice that the RPO must show cause within 5 business days why Westcoast should not take action. If the RPO has not shown cause within the 5 business day period set out by Westcoast, Westcoast may, at its sole discretion, reduce the receipt point to the minimum volume for EFM specified in paragraph 1 above. This will be accomplished either by limiting authorized receipts, re-instituting estimate to actual charges or by physically restricting volumes received from the receipt point.

K. OBA's with Interconnects

Westcoast will pursue OBA's (Operational Balancing Agreements) with downstream interconnecting pipeline operators. Westcoast will develop a pro forma OBA which includes an imbalance discipline on the interconnecting pipelines similar but not identical to the discipline imposed on upstream operations.

- (1) Although no opinion has yet been offered by operators of interconnecting pipelines, Westcoast's proposal for OBA's will include the following:
 - (a) Imbalance tolerances based upon the size of the imbalance measured as a percentage of the daily average authorized deliveries at the interconnect.
 - (b) A balancing free zone within the tolerances where no balancing activity would be required.
 - (c) A requirement that imbalances outside of tolerance be corrected at the first nomination opportunity at a rate of 30% of the outstanding imbalance per day. This obligation will include intra-day nominations where that capability exists.
 - (d) Interconnect imbalance correction to have higher priority than firm service.
 - (e) Magnitude of interconnect imbalance and daily makeup to be identified to industry.
 - (f) For BC Gas, a 6:00pm Calgary Clock Time renomination (or equivalent procedure) which allows redirection of gas to Aitken Creek Storage, NOVA or other downstream interconnecting pipelines or facilities (eg., storage) as available.
- (2) Westcoast will have the right to constrain shippers' TN and TS firm service to specific delivery points or groupings, on a pro rata basis, to enforce correction of a positive interconnect imbalance. Service cuts related to interconnect balancing would not be included in reliability calculations and would not be eligible for CDC's.

- (3) Westcoast will commit to work with interconnecting pipeline operators to work out a correction plan on outstanding imbalances which will bring imbalances back to within tolerance for November 1, 1997. Full interconnect balancing to be implemented on that date.
- (4) Prior period adjustments and estimate to actual revisions to imbalances will be performed monthly and handled through daily pro rata payback over a one month interval. Westcoast may elect to decrease the adjustment and payback cycle if technically feasible.
- (5) If Westcoast is unable to successfully negotiate appropriate OBA's with a interconnecting pipeline operator by November 1, 1997, Westcoast will revert to allocation of delivery imbalances back to delivery shippers at the affected locations. Should this occur, Westcoast would require the interconnecting pipeline operator to allocate daily imbalances to its nominated shippers.
- (6) If an interconnecting pipeline operator is not fulfilling the terms of the OBA to the satisfaction of Westcoast, and the two parties are not able to reach a satisfactory resolution to the performance issue, Westcoast may terminate the OBA agreement according to the terms therein and request that the interconnect allocate daily imbalances to delivery shippers.
- (7) Should imbalances be allocated to Westcoast delivery shippers, the balancing tolerances and procedures specified in section V, F with necessary changes will be applied to delivery shippers. Balancing charges for account imbalances at the delivery point will be 1.10 times the indices selected by Westcoast in consultation with the Toll and Tariff Task Force as being the most representative of the price paid for gas delivered at that delivery point.

L. Pay on Production

Westcoast and CAPP (Canadian Association of Petroleum Producers) have discussed the concept of invoicing RGT and Treatment services on daily receipts into a shipper's account rather than on authorized daily deliveries out of the account. While no changes are contemplated at this time, it is Westcoast's intent to work with shippers toward a January 1, 1999 implementation of this concept.

VI. IMPLEMENTATION

Westcoast will require the control tools in place as outlined in this document in order to assure higher levels of reliability. Phase I and Phase II reliability target commitments have been established in Appendix II.

A. RGT and Treatment

- (1) Implementation of all reliability commitments and procedural changes will be subject to NEB (National Energy Board) approval of the multi year negotiated settlement and applicable GT&C changes before the dates specified.
- (2) Phase I reliability will be implemented first for Treatment Service including the one way linkage of Treatment to RGT service contingent on implementation of overproduction charges, evaluated on aggregate production into Westcoast Treatment facilities. The target implementation date will be pilot phase July 1, 1997 and implementation September 1, 1997.

- (3) The second implementation of Phase I will be for RGT service with a pilot phase targeted for October 1, 1997 and an implementation date of December 1, 1997. Receipt point specific overproduction charges will be implemented effective the same date. Reliability warranties for both RGT and Treatment Service will be in effect by December 1, 1997 regardless of the status of system changes.
- (4) The critical changes required for the implementation of each phase are outlined below:

Phase I

Nominations '97 implementation

Imbalance charges

Estimate to Actual charges

Overproduction charges

Receipt Point Common Stream Operator

Renomination capability

Elimination of RGT and Treatment Inter-plant and Inter-receipt point crediting

Phase II

In place with the implementation of the Electronic Flow Measurement program. Each of Fort Nelson, Pine River and Ft St. John RGT systems could have a different implementation date. Implementation could be as soon as January 1, 1998 and will not be later than April 1, 1998. The EFM program will include systems to gather EFM data and make it available to shippers. Data will be provided to shippers at a frequency and format suitable for imbalance management.

VII. MISCELLANEOUS MATTERS

- (1) Parties to this agreement recognize that the mechanics and procedures related to reliability have been developed in good faith and that the stated intention is to provide optimum reliability for Westcoast facilities for the shipper at large during the term of this agreement. All parties agree that, if it is later determined that, despite the reasonable efforts of all parties, the mechanics and procedures negotiated are not meeting the intention of optimum reliability, the parties will revisit the procedures which are not achieving the desired intention and will reach consensus on what further changes are to be made to enable the goal to be met and a schedule for their implementation.

Grouping of receipt points for the purpose of determining overproduction is an example of a procedure which may be considered once all of the other procedures in this document are implemented.

- (2) Westcoast will provide a procedure manual which outlines the responsibilities of receipt point operators under the various procedures. This procedure manual will be provided to all shippers and RPO's prior to the implementation of phase I reliability targets.

APPENDIX I **ANNUAL RGT AND TREATMENT OUTAGE PLANNING SCHEDULE**

Date	Milestone
July - September	Westcoast Field Services areas to develop first draft of PO and UPO maintenance requirements for coming year. Each line item to include estimating assumptions.
October	AOC to review Westcoast's draft requirements and agree to annualized PO level based upon plant characteristics, maintenance history, level of contracts, etc.
October	AOC to review Westcoast report on UPO requirements. As above, UPO allowances to take into account plant and RGT system characteristics, maintenance history, agreed upon PO, benchmark studies, level of contracts, etc. AOC to agree on an annualized UPO level. ASEC to review and approve.
November	Westcoast to develop PO advisory schedule which breaks annual PO plan into monthly PO. Advisory schedule to be based upon planning guidelines established by the AOC, consultation with Pipeline Division re coordinating opportunities which minimize shipper impact and consultation with area producers.
December 15	Westcoast to publish PO advisory schedule for rest of year on NrG.
6 th business day prior to 1 st of month	Westcoast to publish PO schedule by day for coming month. Estimated YTD totals for PO and UPO at beginning of planning period and PO at end of planning period to be announced. Westcoast to provide timely notice of subsequent changes to the maintenance schedule for the month which are anticipated to affect shippers ability to utilize service.

APPENDIX II

1997 RGT AND TREATMENT UPO AND PO RELIABILITY TARGETS

1997 UPO and PO reliability targets for each area are set out below. Monthly PO reliability targets and annual UPO targets in last three columns.

	1997 PO Reliability Targets (%)									Annual UPO (%)		
	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Present	Phase I	Phase II
FT. Nelson RGT	100	100	100	100	100	100	100	100	99.0*	1.5	1.0	1.0
Ft Nelson Treatment	99.8	62.8	100	100	100	100	100	100	96.4	2.0	1.5	1.5
Ft. St. John RGT	100	100	90	100	100	100	100	100	98.8*	6.5	3.8	2.0
McMahon Treatment	89.8	98.5	89.3	100	100	100	100	100	98.1	6.1	4.6	3.5
Grizzly Valley RGT	100	100	100	100	100	100	100	100	100*	10.0	3.5	2.0
Pine River Treatment	100	100	100	72.3	89.5	100	100	100	96.8	2.6	2.3	2.0
Sikanni Treatment	100	100	100	91.6	100	100	100	100	99.3	1.5	1.5	1.5

Any additional PO components of PO reliability targets required for the RGT system sub areas will be listed by exception and will form an attachment to this table.

*** Exceptions:**

Fort Nelson RGT	July	RP's Beaver River Pipe Line	85%
Fort St. John RGT	May	RP's Behind Laprise B.S.	30%
		RP's Behind Rigel B.S.	90%
	June	RP's Behind Nig B.S.	95%
	Sept.	RP's Behind Bluehills B.S.	95%
Grizzly Valley RGT	June	RP's on 20" Grizzly Pipe Line	90%
		RP's on 8" Bull Moose Pipe Line	97%

APPENDIX III

RGT AND TREATMENT PRESSURE MEASUREMENT CRITERIA

RGT system and Treatment reliability will be measured on a daily basis by the lesser of:

1) announced facility CD restriction, and 2) the combination of pressure measurement, at specific locations, and flow.

A. RGT System

RGT system pressure will be measured at receipt points. In the event the meter used to record the pressure to determine the daily average pressure is not immediately adjacent to Westcoast's RGT system a reasonable proxy will be used for pressure at the receipt point. The AOC will review prospectively the methodology used to determine the daily average pressure for the receipt point to ensure the use of a reasonable proxy.

The daily average receipt point pressure targets were selected to maximize the contractible capacity of the system and at the same time be a reasonable trigger for the payment of CDC's. To maximize the contractible capacity of the RGT system, the targets were kept at or near the current GT&C operating pressures, which are the pressures used by Westcoast in the design and modeling of the systems. In the Fort Nelson and Pine River RGT systems, GT&C pressure and maximum operating pressure (MOP) of the pipelines are the same. In these instances the pressure target was reduced below the GT&C pressure to take into account that many producer owned facilities begin to turn down prior to reaching MOP of the pipeline.

<u>RGT System</u>	<u>Daily Average Receipt Point Pressure Target¹¹</u>	
McMahon	800 psig ¹	5520kpa
Fort Nelson	1160 psig ²	8000kpa
Pine River	1160 psig	8000kpa

In the event that the daily average pressure at any receipt point is over the daily average receipt point pressure target, the reliability not received will be the CD minus the volume received.

B. Treatment

Treatment (Gas Process Plant) pressure will be measured at both the plant inlet meter and the plant outlet meter. At each of Westcoast's gas treatment facilities the inlet and outlet meter location has been identified and the pressure is available on Westcoast's current SCADA system.

The daily average inlet and outlet pressure targets were selected with regard to maximizing the contractible capacity of the facility, matching to the design pressures used by Westcoast and being reasonable triggers for the payment of CDC's. To maximize the contractible capacity of the gas process plants, the targets were kept at or near the current GT&C outlet operating pressures, which are the pressures used by Westcoast in the design and modeling of the systems. At the Pine River gas process plant, the outlet pressure was selected based on the required pressure to move the full design residue volume from the facility to the discharge side of Compressor Station 2. The inlet pressures were selected based on pressure drops experienced across the facilities. Sikanni gas process plant inlet and outlet pressures were taken from the current GT&C. In all cases the measurement of the pressures is currently available on Westcoast's SCADA system and the locations and the pressures recorded are representative of system operating conditions.

McMahon Plant:

Inlet Daily Average Pressure Target	650 psig ³	4485kpa
Outlet Daily Average Pressure Target	930 psig ⁴	6624kpa

Note: If inlet pressure is greater than 650 psig and all compressors at BS1 are available to run but are not being run, then plant identified as unable to receive gas. If inlet pressure is greater than 650 psig and all compressors at BS1 are not available to run, then RGT identified as unable to deliver all gas to plant and plant is identified as fully available.

Fort Nelson:

Inlet Daily Average Pressure Target	1000 psig ⁵	6900kpa
Outlet Daily Average Pressure Target	930 psig ⁶	6624kpa

Pine River:

Inlet Daily Average Pressure Target	1035 psig ⁷	7142kpa
Outlet Daily Average Pressure Target	975 psig ⁸	6555kpa

Sikanni:

Inlet Daily Average Pressure Target	1232 psig ⁹	8500kpa
Outlet Daily Average Pressure Target	1170 psig ¹⁰	8070kpa

Notes:

- ¹ Except on segments of pipelines in the gathering system with a tariff MOP pressure identified in the GT&C greater than 800 psig. In these instances, the daily average pressure target will equal the GT&C pressure.
- ² Except on segments of pipelines in the RGT system with a tariff MOP pressure identified in the GT&C greater than 1170 psig. In these instances, the daily average pressure target will equal the GT&C pressure.
- ³ Measured at the suction to Booster Station #1
- ⁴ Measured at the discharge to Taurus Unit #15
- ⁵ Measured at "plant mixing T"
- ⁶ Measured at plant outlet meter
- ⁷ Measured at plant inlet meter upstream of the flow control valve
- ⁸ Measured at plant outlet meter
- ⁹ Measured at plant inlet meter
- ¹⁰ Measured at plant outlet meter
- ¹¹ Metric conversions are approximate only.

APPENDIX IV IMBALANCE TOLERANCE RANGE

1. Standard Tolerance Levels and Approximate Linepack Triggers

Tolerance Range*	Free Zone	Linepack**
0/+20%	0/+4%	2650 MMcfd
-2.5%/+17.5%	-0.5%/+3.5%	2700 MMcfd
-5%/+15%	-1%/+3%	2750 MMcfd
-7.5%/+12.5%	-1.5%/2.5%	2800 MMcfd
-10%/+10%	-2%/+2%	2850 MMcfd
-12.5%/+7.5%	-2.5%/+1.5%	2900 MMcfd
-15%/+5%	-3%/+1%	2950 MMcfd
-17.5%/+2.5%	-3.5%/+0.5%	3000 MMcfd
-20%/0	-4%/0	3050 MMcfd

* Westcoast may change the tolerance range more than one level in the event of sudden changes or expected changes in linepack. Westcoast is under no obligation to move in one level increments.

** Triggers are approximate only. As stated in Schedule D, Westcoast may adjust the tolerance range based upon changes or expected changes in the system line pack.

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Tolerance Range*	Free Zone	Linepack**
0/+20%	0/+4%	2650 MMcfd
-2.5%/+17.5%	-0.5%/+3.5%	2700 MMcfd
-5%/+15%	-1%/+3%	2750 MMcfd
-7.5%/+12.5%	-1.5%/2.5%	2800 MMcfd
-10%/+10%	-2%/+2%	2850 MMcfd
-12.5%/+7.5%	-2.5%/+1.5	2900 MMcfd
-15%/+5%	-3%/+1%	2950 MMcfd
-17.5%/+2.5%	-3.5%/+0.5%	3000 MMcfd
-20%/0	-4%/0	3050 MMcfd

* Westcoast may change the tolerance range more than one level in the event of sudden changes or expected changes in linepack. Westcoast is under no obligation to move in one level increments.

** Triggers are approximate only. As stated in Schedule D, Westcoast may adjust the tolerance range based upon changes or expected changes in the system line pack.

APPENDIX V SAMPLE CDC CALCULATION

1 Period	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Average
2 CD (MMcf/d)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	12.0	12.0		10.3
3 Days in Month	31.0	28.0	31.0	30.0	31.0	30.0	31.0	31.0	30.0	31.0	30.0	31.0	365.0	
4 Max Volume (MMcf)	310.0	280.0	310.0	0	310.0	300.0	310.0	310.0	300.0	310.0	360.0	372.0	3772.0	
5 Total Volume Loss (MMcf)	0.0	0.0	3.1	15.0	3.1	12.0	109.3	21.7	15.0	12.4	7.2	0.0	198.8	
6 PO Volume Loss (MMcf)	0.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0	0.0	0.0	100.0	
7 EO Volume Loss (MMcf)	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	
8 UPO Volume Loss (MMcf)	0.0	0.0	3.1	12.0	3.1	12.0	9.3	21.7	15.0	12.4	7.2	0.0	95.8	
9 UDCC Volume (MMcf)	0.0	2.0	0.0	0.0	0.0	1.0	0.0	0.0	1.0	0.0	0.0	0.0	4.0	91.80.3
10 UPO Volume Net of UDCC														
11 UPO Reliability Adjusted for UDCC														
12 UPO Reliability Target														97.6%
13 UPO Reliability Variance														98.0%
														-0.4%
14 UPO Reliability Variance (MMcf)	0.0	0.0	-0.5	-2.0	-0.5	-2.0	-1.6	-3.7	-2.6	-2.1	-1.2	0.0	-16.4	
15 Base Toll (\$/mcf)	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0		
16 Adjustment Toll (\$/mcf)	10.0	10.0	5.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	5.0		
17 Total Toll (\$/mcf)	56.0	56.0	51.0	51.0	46.0	46.0	46.0	46.0	46.0	46.0	51.0	51.0		
18 Demand Charge (\$000)	170.3	170.3	155.1	155.1	139.9	139.9	139.9	139.9	139.9	139.9	186.2	186.2	1862.7	
19 CDC's (\$000)	0.0	0.0	-0.3	-1.0	-0.2	-0.9	-0.7	-1.7	-1.2	-1.0	-0.6	0.0	-7.7	
20 Net Demand Charge (\$000)	170.3	170.3	154.9	154.1	139.7	139.0	139.2	138.2	138.7	138.9	185.5	186.2	1855.0	-0.4%

APPENDIX VI

SAMPLE CDC CALCULATION FORMULA SHEET

Monthly Line 4 = Monthly Line 2 x Monthly Line 3

Average Line 2 = Total Line 4 / Total Line 3

Line 8 = Line 5 - Line 6 - Line 7

Total Line 10 = Total Line 8 - Total Line 9

Line 11 = 1 - Total Line 10 / Total Line 4

Line 13 = Line 12 - Line 11

Total Line 14 = Line 13 x Total Line 4

Monthly Line 14 = Total Line 14 x Monthly Line 8 / Total Line 8

Line 17 = Line 15 + Line 16

Line 18 = Line Line 10 x Line 17 x 365 / 12

Line 19 = Line 14 x Line 17

Line 20 = Line 18 - Line 19

Line 21 = Total Line 19 / Total Line 18



ORDER TO-1-95

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") for Orders under Part IV of the Act approving a negotiated settlement respecting an incentive toll methodology and associated tolls and tariffs;

Before the Board on 22 March 1995.

WHEREAS on 29 September 1994, IPL filed a Class 2 toll Adjustment Application and Review of Depreciation Rates with the National Energy Board ("the Board") in respect of tolls under Part IV of the Act effective 1 January 1995;

AND WHEREAS on 14 October 1994, the Board advised that it would set down IPL's Toll Application as a Class 3 Hearing;

AND WHEREAS on 10 November, the Board issued Hearing Order RH-4-94 setting out the Directions on Procedure to govern the hearing;

AND WHEREAS on 16 February 1995, IPL filed an application for Board approval of a toll settlement between itself and the Canadian Association of Petroleum Producers, which is comprised of the information under the tabs, Application, Explanatory, 1995 Tolls, Principles of Settlement, Public Consultation and Letters of Support;

AND WHEREAS on 22 February 1995, the Board adjourned the RH-4-94 Hearing procedure *sine die*, pending its decision on the toll settlement;

AND WHEREAS on 3 March 1995 the Board discharged IPL from any further participation in the RH-2-94 proceeding and declared that all cost of capital issues would thereafter be considered by the RH-4-94 Hearing panel;

AND WHEREAS the Board has reviewed the comments of interested parties on the toll settlement as well as reply comments by IPL;

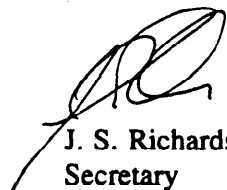
AND WHEREAS the Board considers that the tolls incorporated in draft NEB tariff 186 are just and reasonable:

IT IS ORDERED THAT:

1. the Draft NEB Tariff 186 which, *inter alia*, permits the collection by IPL of Allowance Oil as more particularly described in section 6 of the Explanatory and Article 4.3 of the Principles of Settlement is approved;
2. IPL shall forthwith file with the Board, and serve on all interested parties, a final tariff and tolls conforming with draft tariff 186;
3. the tolls incorporated in the final tariff filed, pursuant to paragraph 2 above, shall come into effect 1 April 1995;
4. the methodology for calculating the revenue requirement for the years 1995 - 1999 inclusive (as described in the Application, Explanatory, and Principles of Settlement) is approved ;
5. the following deferral accounts and carrying charge rate to record variations described in section 5 of the Explanatory and article 4.0 of the Principles of Settlement shall be established:
 - (i) Cost Performance Benefit Sharing;
 - (ii) Capacity Sharing;
 - (iii) Transportation Revenue Variance;
 - (iv) Starting Point Inflation Adjustment;
 - (v) Tax Allowance Variance;
 - (vi) Non Routine Adjustment Variance;
 - (vii) Deferred Amount Adjustment; and
 - (viii) Allowance Oil Revenue Adjustment;
6. the tolls filed with the Board on an annual basis for each of the years 1995 - 1999 are declared interim effective 1 January in each subsequent year, pending an annual tariff filing pursuant to section 60 (1) (a) of the Act which shall be made on or before 1 April in each year for tolls to be effective 1 April of that year;
7. leave to calculate the Montreal Extension credit included in each transmission, receipt and delivery charge on the basis of actual deliveries in the years as more particularly described in the Explanatory for Toll Calculation is granted;
8. Approval on an interim basis is granted for the filing on an annual basis of the calculation of Net Revenue Requirement for the year and Annual Results in the form set out in Schedule D of the Principles of Settlement, pending a final determination by the Board which will not be made until all interested parties have had the opportunity to express their views on this issue;
9. IPL is relieved of the requirement to comply with all reporting and filing requirements of NEB Order TO-7-90;

10. IPL is relieved of the requirement to file continuous improvement reports in accordance with the direction of the NEB post-audit letter dated 30 July 1993;
11. IPL is granted leave to withdraw the Toll Application dated 29 September 1994 and the September, 1994 Review of Depreciation Rates filed with the Board;
12. Order TOI-5-94, which authorized the tolls to be charged on an interim basis pending a final decision on both the RH-2-94 and RH-4-94 proceedings, is revoked and the tolls that were authorized to be charged thereunder are disallowed as of the end of the day on 31 March 1995;
13. Those provisions of IPL's tariffs and tolls, or any portion thereof, that are contrary to any provision of the Act, to the Board's decision contained in the attached letter, or to any Order of the Board including this Order, are hereby disallowed.

NATIONAL ENERGY BOARD



J. S. Richardson
Secretary

ALBERTA ENERGY AND UTILITIES BOARD

Calgary, Alberta

NOVA GAS TRANSMISSION LTD. COST EFFICIENCY INCENTIVE SETTLEMENT

Order U96119

File 1601-2

1. INTRODUCTION

NOVA Gas Transmission Ltd. (NGTL) filed an application (the Application) with the Alberta Energy and Utilities Board (the Board) on 2 August 1996 for approval of 1996 rates, tolls and charges and for approval of a Cost Efficiency Incentive Settlement (the Settlement). NGTL filed its application pursuant to Section 28(a) of the *Gas Utilities Act* (the GU Act) noting that "arising out of the uncertainty that exists as to the Board's power to approve rates as determined in accordance with a multi-year settlement, amendments are being made to the *Gas Utilities Act* to clarify the Board's powers. In these circumstances, NGTL is making this application". On 31 August 1996, the GU Act was amended by the addition of Section 36.1 and the amendment was proclaimed 3 September 1996. On 13 September 1996, NGTL amended the Application to seek approval of the Settlement under Section 36.1 of the GU Act, as amended.

Public Notice of the Settlement was given on 27 September 1996. The Public Notice requested that parties notify the Board and NGTL by 4 October 1996 of their interest in any proceedings related to the Settlement, as well as set out their interest and the manner in which they were affected by the Settlement. NGTL conducted a technical workshop for interested parties in order to discuss details of the Settlement. Registered intervenors provided comments on 25 October 1996. NGTL provided comments in reply to those of intervenors on 1 November 1996.

2. BACKGROUND

The Board last set the revenue requirement of NGTL for the test year 1995 in Decision U96001, dated 4 January 1996, as amended by Order U96020, dated 6 February 1996. The 1995 rates, tolls and charges of NGTL were set in Decision U96055, dated 12 June 1996. On 27 March 1996, NGTL informed the Board that it was preparing a general rate application for 1996 and requested an annualized interim rate increase of 9.8% to lessen the rate shock to shippers in 1996. Based on the remaining 9 months of transportation service, this resulted in a firm service rate of 131.41/10³m³/month or an increase of 13.2%. The Board approved these interim rates effective 1 April 1996 in Decision U96047, dated 8 May 1996. In April 1996, NGTL also advised the Board and the Tolls, Tariff and Procedures Committee (TTP), a pipeline/shipper collaborative body, that it would not be filing a general rate application for 1996 at that time as it had begun discussions with the Canadian Association of Petroleum Producers (CAPP) on the possibility of an incentive

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settlement for 1996 and beyond. In these discussions, CAPP and NGTL determined that there were sufficient grounds for and agreement on draft terms of a five-year settlement. Accordingly, NGTL and CAPP, in May 1996, informed the TTP of the progress of discussions and provided a summary of the issues under consideration. In June 1996, the TTP formed a Task Force to review and participate in developing the details of a settlement. In July 1996, the TTP received a draft copy of the Settlement which was subsequently approved on 31 July 1996 by an unopposed resolution. NGTL applied to the Board for approval of the Settlement on 2 August 1996.

3. PARTICULARS OF THE APPLICATION AND THE SETTLEMENT

NGTL requested approval of 1996 rates, tolls and charges and for 1997-2000 rates, tolls and charges to be determined in accordance with the terms of the Settlement. NGTL's total revenue requirement for 1996, as negotiated, is \$1,150,000,000, which represents an 8% increase over the 1995 revenue requirement approved in Order U96020. Based on forecast 1996 volumes, NGTL proposed final firm service rates consisting of a demand charge of \$130.27/10³m³/Month and a commodity charge of \$0.25/10³m³ for 1996. Other rates were derived from the firm service rates. These rates are 12.1% higher than those approved in Decision U96055 but less than the interim rates approved in Order U96047.

NGTL also applied for the Board to declare in abeyance all deferral and reserve accounts approved in Decision U96001, except the Firm Service Demand Revenue and Throughput Volume Deferral Accounts. Under the terms of the Settlement these deferral accounts would be reinstated on 1 January 2001 or sooner in the event the Settlement is terminated before that date. NGTL then applied for approval of deferral and adjustment accounts required for rate-making purposes under the Settlement. Finally, NGTL requested that certain Board Directives in Decision U96001 be placed in abeyance during the term of the Settlement.

For years beyond 1996, rates would be set according to the following formula:

$$\text{TRR} = \text{BRR} + \text{DCCRR} + \text{CCCRR} + \text{FT} \pm \text{Z}$$

Where TRR	= Total Revenue Requirement
BRR	= Base Revenue Requirement
DCCRR	= Deferred Capacity Capital Revenue Requirement
CCCRR	= Cumulative Capacity Capital Revenue Requirement
FT	= Forecast income and capital Taxes
Z	= the sum of the following items related to the previous year

- a) Customers' share of threshold earnings variance
- b) Income and capital tax variance
- c) Throughput volume deferral account
- d) Firm service demand revenue deferral account
- e) Rates variance deferral account
- f) Non-routine adjustments
- g) Customers' share of the deferred capacity capital revenue variance
- h) Customers' share of the cumulative capital revenue variance

Variances would be shared equally and symmetrically by NGTL and its customers on a pre-tax basis. For the years beyond 1996, the base revenue requirement would be adjusted according to the following formula:

$$\text{BRR} = (\text{PBRR} \pm \text{RA} \pm \text{BRNRA}) \times \text{EF}$$

Where BRR = Base Revenue Requirement
 PBRR = Previous year's Base Revenue Requirement
 RA = Rebasing Adjustment
 BRNRA = Base Revenue Non-Routine Adjustments
 EF = Escalation Factor

Base revenue requirement is composed of the operating and capital costs, depreciation charges and taxes (municipal, income and capital) associated with the pipeline system. Depreciation charges would be based on the following composite depreciation rates:

1996 -	3.0%
1997 -	3.1%
1998 -	3.2%
1999 -	3.3%
2000 -	3.5%

The 1996 Employment Transition and Continuity Program costs and 1996 Inventory Management costs (Transitional Costs) would be amortized at the rate of \$7,000,000 per year over three years beginning with the first year of the settlement. The escalation factor for each year is to be 2% per year to account for cost increases. The rebasing adjustment is the difference between the previous year's base revenue requirement and actual base revenue requirement. NGTL identified certain unanticipated costs and/or events which would result in a non-routine adjustment to the following year's revenue requirement.

Also included in the Settlement is a Receipt Facilities Incentive Mechanism which would provide customers the option of building receipt facilities themselves if they could be satisfactorily built at less cost than NGTL could. NGTL also undertook to solicit bids on at least 25% of its projects. A Future Capital and System Utilization Incentive Mechanism which would provide incentives to ensure efficient use of facilities in rate base and efficient construction of new facilities was also contemplated under the Settlement. However, at the time of the Application, this mechanism was still being negotiated by NGTL and the TTP with a target date of 31 December 1996 for completion.

The term of the Settlement called for NGTL to provide on or before 1 March 1996 a report "containing information related to the terms of this Settlement". At the time of the Application, the form and content of this report were still being negotiated by NGTL and the TTP with a target of 31 December 1996 for completion.

The Settlement would require NGTL to file interim rates with the Board and its customers on or before 15 December each year to take effect on 1 January of the following year. NGTL would file final rates with customers and the Board on or before 1 March each year. If the difference between interim and final rates is less than 5% any surplus or deficiencies would be held in the Rates Variance Deferral Account if requested by the TTP. NGTL agreed to calculate rates according to whatever rate design would be in effect at the time. Rate design matters were not addressed in the Settlement.

NGTL or any customer acting in good faith could terminate the Settlement in certain circumstances such as the CPI falling below 1% or rising above 4%, a downgrade of NGTL below A-low by any rating agency, the building of a competitive export pipeline of greater than 100 mmf/day capacity or geopolitical changes having significant effects on financial markets. Finally, the Settlement contained provisions for a compliance audit of NGTL, if necessary, and for settling disputes under the terms of the Settlement. In the event a dispute is not resolved, an application to the Board regarding the matter in dispute may be made. Any such application must also contain a request that the Board deal with the disputed matter on an expedited basis.

By letter dated 15 November 1996, NGTL provided pro-forma Reporting Requirements for the financial information required by the Settlement. NGTL noted that the TTP had adopted the reporting requirements document as a starting point on the report which would ultimately be filed with the Board.

By letter dated 28 November 1996, NGTL informed the Board that, despite the 1996 rates being lower than the interim rates approved by Order U96047, a 1996 revenue deficiency of approximately \$25.4 million exists due to carrying charges and because interim rates came into

force as of 1 April 1996. NGTL proposed rolling the 1996 deficiency into 1997 rates in order that shippers not experience the significant rate spike that collecting the deficiencies in 1996 would cause.

4. COMMENTS OF INTERESTED PARTIES

The following parties submitted comments on the Application and the Settlement.

Amoco

Amoco Canada Petroleum Company Ltd. (Amoco) fully supported the efforts of CAPP with respect to incentive regulation. Amoco submitted that this style of regulation encouraged pipelines to become more efficient, reducing costs and increasing earnings. This, in the opinion of Amoco, would benefit both the pipeline and shippers.

Although Amoco concurred with the process of negotiation and the decisions which were made, Amoco considered that the Settlement in its final form would not provide the full benefits that incentive regulation could bring. Amoco considered that the various elements of the Settlement, such as the base revenue escalation, annual rebasing, constant earnings threshold relative to a declining rate base, symmetrical sharing, negotiated depreciation rate, flow-through treatment of capital additions and non-routine adjustments and the various off-ramps, worked to preserve the status quo for NGTL. In the opinion of Amoco, NGTL had not put anything at risk if it did not change the way it did business. Amoco also noted that the Settlement, as filed, was incomplete as some issues had not been settled. Amoco considered that, since capital additions were a flow-through item, the Future Capital and System Utilization Incentive Mechanisms portion of the Settlement should be completed before the Board accepted the Settlement.

On the other hand, Amoco considered that the 1996 rates which the Settlement produced were approximately the same as would have resulted from a public hearing on the matter. Furthermore, shippers had gained some certainty as to future rates on NGTL's system. Amoco concluded that it would not be hurt financially if the Settlement were implemented. On balance, Amoco stated that it would not oppose the Settlement in order to gain some of the immediate benefits.

CAPP

CAPP stated that the objective of the Settlement had been to improve the competitiveness of Alberta natural gas in the North American market through a reduction in transportation costs. CAPP considered the Settlement would accomplish this by encouraging NGTL to lower operating costs while providing the current levels of service and by reducing the regulatory costs over the

term of the Settlement. For these reasons, CAPP submitted that the Settlement met the intent of the GU Act, as amended, and was in the public interest.

CAPP requested the Board to direct NGTL to identify in a report to the Board and its shippers the starting 1996 rate base, financing and associated interest costs that were in place at the commencement of the Settlement and to explain any differences from the 1995 year end.

CCA

The Consumers' Coalition of Alberta (CCA) was not opposed to the Settlement as it represented a balancing of the interests of all stakeholders.

PanEnergy/Mobil

PanEnergy Marketing on behalf of itself and Mobil Oil Canada (PanEnergy/Mobil) requested that the Board require a formal vote on the merits of the Settlement at the completion of the public process. PanEnergy/Mobil submitted that the Board could only be satisfied with the Settlement if a majority of shippers, by both volume and number, supported NGTL's initiative. Subsequently, PanEnergy/Mobil advised, by letter to NGTL, that it had no further comments on the Settlement.

SEPAC

The Small Explorers and Producers Association of Canada (SEPAC) submitted a letter which it had placed before the TTP's meeting on 31 July 1996, outlining its reasons for opposing the settlement. SEPAC considered that the Settlement did not set specific performance targets for NGTL nor did it put NGTL at risk if it failed to reduce costs. SEPAC also objected to the process by which CAPP and NGTL negotiated the principal Settlement terms and then presented them as a package to the TTP, which both parties considered was not subject to any further negotiation. In the opinion of SEPAC, the Settlement suffered from the short time frame in which it was negotiated. SEPAC considered that the five-year term of the Settlement was too long and would have preferred a shorter term of two or three years. Finally, SEPAC considered that accepting the Settlement would require acceptance of Transportation by Others (TBO) as it now existed with the roll-in of Foothills Zone 7 costs. SEPAC noted that both the 1994 and 1995 TBO including Foothills Zone 7 costs were the subject of current review and variance applications.

The Utilities

Northwestern Utilities Limited on behalf of itself and Canadian Western Natural Gas Company Limited (the Utilities) made no objection to the Settlement, predicated on progress made by

NGTL and the Utilities with respect to the Utilities' concern with NGTL's Economic Criteria for System Expansion. The Utilities expected to resolve this concern "very shortly".

5. NGTL's REPLY COMMENTS

NGTL noted that the objectives of the Settlement were to improve the competitive position of Alberta-sourced natural gas, achieve the lowest possible transportation cost and highest possible system utilization and to reduce the resources used in the traditional regulatory process. All parties to the Settlement were clear on these objectives at the beginning of the process. NGTL submitted that the Settlement aligned the interests of all parties concerned with the competitive position of Alberta gas. NGTL submitted that the Settlement was balanced and focussed on the needs of customers while providing mutual safeguards and mechanisms to handle contingencies and newly emerging issues.

NGTL considered that most submissions confirmed that the process used to arrive at the Settlement was sound. Although SEPAC had stated that it was in opposition to the Settlement, it had not proposed any alternatives nor had it put forward evidence. NGTL stated that it would incorporate the additional reporting requests proposed by CAPP in its submission.

NGTL stated that the issues discussed in Article 12.3, Future Capital and System Utilization Incentive Mechanisms, and Article 16, Reporting Requirements, continued to be worked on by NGTL and the TTP in order to meet the target dates for resolving those issues established in the Settlement.

6. BOARD FINDINGS

Negotiated settlements have a role in the regulatory process. They provide applicants and interested parties an opportunity, through discussion unconstrained by the legal procedures inherent in a hearing, to develop a better understanding of the issues; to achieve mutually satisfactory outcomes; and to obtain greater certainty of results. They may also result in savings in hearing time and costs. In the Board's view, a settlement process should, among other things, be open and fair to all parties who may be affected by the possible outcomes and who wish to participate and contribute to the process. While the procedures which guided this particular settlement generally met this standard, the Board notes the concerns expressed by SEPAC and recommends that in future settlement proceedings the procedures be reviewed in two respects: (1) to provide parties who may not be directly engaged in the negotiations with an opportunity to participate in the establishment of the terms of reference for the negotiations, and (2) to provide

information on the status of the negotiations and an opportunity for input to the negotiations to such parties earlier in the settlement process than was the case in this instance.

The Board is satisfied that all parties affected by the rates charged by NGTL have had an adequate opportunity to inform themselves as to the provisions of the Settlement and to comment on the Application and the Settlement. The Board notes that, with the exception of SEPAC, parties who submitted comments supported or did not oppose the Settlement. The Board also notes that SEPAC did not request a hearing to deal with its objections to the application nor did it make recommendations regarding the disposition of the application. Therefore, the Board does not consider it necessary to require a formal poll of NGTL's shippers to determine the level of acceptance of the Settlement before rendering its decision.

The Board has considered the reservations expressed about the Settlement by Amoco and SEPAC and is not persuaded that the concerns raised outweigh the benefits of the Settlement.

Regarding the absence of specific performance targets, the Board is satisfied that the incentive measures contained in the Settlement and its length offer sufficient opportunity for NGTL to realize efficiency gains which will benefit all parties. The Board will monitor the results achieved under the Settlement.

Regarding the matters outstanding under the Settlement, the Board recognizes the importance of providing incentive mechanisms for future capital and system utilization on NGTL. The Board is also of the view that performance measures are an important component of the reporting requirements under the Settlement. However, the Board is not persuaded that these matters need be completed before it renders a decision on the Settlement. To ensure that they are addressed in a timely fashion, the Board will direct NGTL to complete them by 31 December 1996 as stipulated in the Settlement and to file details with the Board and interested parties on the first day of business 1997.

Regarding the matter of the roll-in of the costs charged by Foothills Pipe Lines Ltd. for transportation service on Zone 7, the Board is in the process of examining applications for review of the Board's findings in Decisions E95079 and U96001 and will advise parties in due course on this matter.

The Board is satisfied overall that the Settlement reflects an appropriate balance of the interests of affected parties, that it will result in just and reasonable rates, and that it is in the public interest. Therefore, the Board approves the Settlement as filed.

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The Board also approves, for the term of the Settlement, NGTL's request to continue the Firm Service Demand Revenue Deferral Account and the Throughput Volume Deferral Account approved in Decision U96001, to hold all other deferral and reserve accounts approved in Decision U96001 in abeyance, and to hold in abeyance the Board's directives in Decision U96001 listed in Schedule "C" of this Decision. Finally, the Board approves NGTL's proposal to recover revenue deficiencies in 1996 by rolling the deficiencies into 1997 rates.

7. ORDER

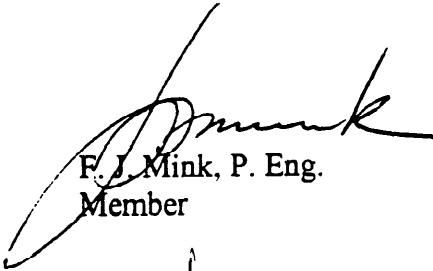
THEREFORE, it is ordered that:

- (1) The interim rates, tolls and charges contained in Schedule "A" of Order U96047 are terminated as of 31 December 1996.
- (2) The rates, tolls and charges contained in Schedule "A" of this Decision are final for 1996 and are in effect for all transportation service rendered on and after 1 January 1997.
- (3) The outstanding directions from Decision U96001 listed in Schedule "B" of this Decision are to be held in abeyance for the term of the Settlement.
- (4) The reserve and deferral accounts approved in Decision U96001 listed in Schedule "C" of this Decision are to be held in abeyance for the term of the Settlement.
- (5) The Cost Efficiency Incentive Settlement is hereby approved and shall apply to all rates, tolls and charges of NOVA Gas Transportation Ltd. for the term of the Settlement or until 31 December 2000.

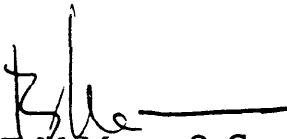
Dated in Calgary, Alberta on 12 December 1996.



C. Bélanger
Chair



F. J. Mink, P. Eng.
Member



B. T. McManus, Q. C.
Member

12 December 1996

SCHEDULE "A"

TABLE OF PROPOSED 1996 RATES, TOLLS AND CHARGES

<u>Service</u>	<u>Rates, Tolls and Charges</u>
1. Rate Schedule FS	FS Demand Rate \$130.27/10³m³/Month FS Commodity Rate \$0.25/10³m³ FS Surcharge: Applicable to all FS contracts at meter station no. 2143, Bay Tree Schedule No. 94-09410-0 \$3.53/10³m³ 95-01886-0 \$3.53/10³m³
2. Rate Schedule IT-2	IT-2 Commodity Rate \$4.53/10³m³ (Jan 1 - Jun 30) IT-2 Commodity Rate \$4.98/10³m³ (Jul 1 - Dec 31) IT-2 Surcharge: Applicable to all IT-2 contracts at meter station no. 2143, Bay Tree Service Identification No. 95-89161-2 \$3.53/10³m³ (expires Oct. 31/96) 95-78025-0 \$3.53/10³m³ (expires Oct. 31/96) 95-73551-0 \$3.53/10³m³ (expires Oct. 31/96) 95-69246-0 \$3.53/10³m³ (expires Oct. 31/96) 95-71269-0 \$3.53/10³m³ (expires Oct. 31/96) 95-84697-0 \$3.53/10³m³ (expires Oct. 31/96) 96-85242-0 \$3.53/10³m³ (commences Nov. 1/96)
3. Rate Schedule T-4	T-4 Customer Charge: Schedule No. 93-01682-3 \$1,482.00/month 93-45103-2 \$2,308.00/month (expires Sept. 30/96) 93-34765-3 \$376.00/month 93-43358-3 \$941.00/month 94-85429-2 \$187.00/month 94-85430-2 \$2,257.00/month 94-08377-2 \$6,208.00/month 93-01680-2 \$213.00/month

SCHEDULE "A"

Table of Proposed 1996 Rates, Tolls and Charges (Cont'd)

4. Rate Schedule OS	OS Charge: Schedule No. 93-01685-2 \$988.00/month 90-02911-1 \$17,800.00/month 91-01535-1 \$4,085.00/month 93-21461-1 \$7,807.00/month 86-02922-1 \$0.25/10³m³ (expires Oct. 31/96) 86-03110-1 \$0.25/10³m³ (expires Oct. 31/96) The OS Charge applicable to measurement Service is determined in accordance with the provisions of Appendix 1 attached to the applicable Schedule of Service, a copy of which is set forth on page 99 of the Tariff.
5. Rate Schedule TS	TS Commodity Rate \$4.53/10 ³ m ³
6. Other rates, tolls and charges	Rates, tolls and charges calculated in accordance with Operating Agreement dated April 23, 1980 between Foothills Pipe Lines (Alta.) Ltd. and The Alberta Gas Trunk Line Company Limited. Rates, tolls and charges calculated in accordance with Agreement for Operation and Maintenance Service dated November 1, 1992 between Her Majesty the Queen and NOVA Corporation of Alberta.

SCHEDULE "B"

**EUB DIRECTIVES IN DECISION U96001
TO BE PLACED IN ABEYANCE**

1. Depreciation Expense

"The Board directs NGTL to carry out a detailed depreciation study of its operations and to file it with the Board as part of its next general rate application." (p. 67)

2. Necessary Working Capital - Lead/Lag Study

NGTL is directed to perform a lead-lag study on actual cash flows and to file the results of that study with its next general rate application. (p. 49)

3. Foreign Exchange Practice

"The Board wishes to consider this issue fully and, therefore, directs NGTL to address it in its next general rate application." (p. 130)

4. Deferral and Reserve Accounts

"The Board directs NGTL to provide, in future general rate applications, a reconciliation of the balances in the Insurance Reserve, including a description of the charges made against the Insurance Reserve and justification for the charges made against the Insurance Reserve." (p. 171)

5. Construction Work in Progress

"... The Board directs NGTL to demonstrate the continued efficiency of its scheduling in its general rate applications." (p. 43)

6. Existing Property, Plant and Equipment

"... NGTL is directed to provide, in its next general rate application, evidence to support 1972 rate base additions and evidence to demonstrate that the amount of the additions consistent with the opening and closing rate base balances for that year." (p. 23)

SCHEDULE "B"

7. Reporting Requirements

"The Board encourages NGTL to consult its shippers and to provide recommendations in this regard to the Board in its next general rate application. The Board will require NGTL to file quarterly reports on its finances with the Board on a timely basis, commencing with year-end 1995, and to provide copies to interested parties who request them. ... The Board will also require NGTL to file annually supplementary performance information commencing with year-end 1995. ... For the time being, NGTL's supplementary performance information should consist of the measures identified by McKinsey & Co. to NGTL as useful for evaluating the performance of pipelines." (p. 174)

8. Technical Audit/Outsourcing

"NGTL should keep the Board and its shippers apprised of the results of [a resource analysis study of its Pipeline Services Group], with a particular focus on cost reduction measures which have been identified and implemented. In this regard, the Board directs NGTL to report on the progress it has achieved. (p. 28)

SCHEDULE "C"

NOVA GAS TRANSMISSION LTD.

COST EFFICIENCY INCENTIVE SETTLEMENT

DEFERRAL/RESERVE ACCOUNTS

The deferral accounts which NGTL applied to be held in abeyance are:

- Capital Additions to the Pipeline
- Foreign Exchange Gains/Losses
- Future Legislation Changes and Reassessment of Income and Capital Taxes
- Transportation by Others
- Municipal and Property Taxes
- Interest and Property Taxes
- Interest Expense
- ET&C and Resource Analysis

The reserve accounts which NGTL applied to be held in abeyance are:

- Hearing Costs
- Uninsured Losses

JULY 31, 1996

COST EFFICIENCY INCENTIVE SETTLEMENT

FOR

NOVA GAS TRANSMISSION LTD.

**(This Settlement represents a proposal adopted by
the Tolls, Tariff and Procedures Committee ("TTP"))**

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- (g) **"Base Revenue Long Term Debt"** at any given time, means the aggregate of NGTL's long term debt (being debt repayable over a period of greater than one year) as follows:
 - (i) outstanding as at January 1, 1996 as demonstrated in Schedule "E";
 - (ii) entered into during the Term up until such time that may be required for purposes of refinancing maturing long term debt or short term debt (being debt repayable over a period shorter than one year) related to Base Revenue Rate Base that was outstanding as at January 1, 1996; and
 - (iii) entered into during the Term up until such time for the purposes of financing Maintenance Capital and General Plant Capital;less:
 - (iv) long term debt repayments made over the Term up until such time.
- (h) **"Base Revenue Requirement"** shall have the meaning ascribed thereto in Article 5;
- (i) **"Base Revenue Short Term Debt"** shall have the meaning ascribed thereto in Section 5.6(v);
- (j) **"Capacity Capital"** means the costs of all prudently incurred facility additions or modifications required to meet throughput capital requirements added to the Pipeline System after January 1, 1996, including without limitation, additional pipeline, measurement, and compression facilities;
- (k) **"Capitalization Amount"** means the indirect capital labour and overhead costs allocated to capital projects;
- (l) **"Capitalization Amount Variance"** shall have the meaning ascribed thereto in Section 10.1;
- (m) **"Carrying Charges"** means the cost of financing related to amounts subject to recovery or payment in future periods calculated at a rate that is equivalent to one-twelfth of the

Operating Return in any particular Year applied to the monthly balances of such recoveries or payments;

- (n) **"Composite Depreciation Rates"** means the rates of depreciation negotiated by the Parties for use in this Settlement in determining depreciation expense in accordance with the provisions of this Settlement during the Term;
- (o) **"Cumulative Capacity Capital Revenue Requirement"** shall have the meaning ascribed thereto in Article 8;
- (p) **"Cumulative Capacity Capital Revenue Variance"** shall have the meaning ascribed thereto in Section 8.2;
- (q) **Customer"** means any Person named as Customer in an Index of Service or Schedule of Service as such terms are defined in the Tariff;
- (r) **"Debt Interest Expense on Base Revenue Debt"** shall have the meaning ascribed thereto in Section 5.6(v);
- (s) **"Deemed Common Equity"** means 32%;
- (t) **"Deferred Capacity Capital"** means Capacity Capital in service additions in a given Year;
- (u) **"Deferred Capacity Capital Revenue Requirement"** shall have the meaning ascribed thereto in Article 7;
- (v) **"Deferred Capacity Capital Revenue Variance"** shall have the meaning ascribed thereto in Section 7.3;
- (w) **"Employment Transition and Continuity Program" or ("ET&C")** means NGTL's program designed to enable workforce reductions and transitions;
- (x) **"Escalation Factor"** shall have the meaning described thereto in Section 5.7;
- (y) **"EUB"** means the Alberta Energy and Utilities Board;
- (z) **"Firm Service Demand Revenue"** means the revenue received by NGTL in the application of the "FS Demand Rate" as identified in the Tariff;

- (aa) **"Forecast Income and Capital Taxes"** in a given Year means NGTL's forecast of the aggregate of all federal and provincial income taxes and large corporation capital taxes calculated for such Year in a manner consistent with the methodology approved by the EUB in Decision U96001;
- (ab) **"Foreign Exchange Gains or Losses on Interest Payments"** in respect of any particular Year, means the net positive or negative amount determined by aggregating for all U.S. dollar debt interest payment made by NGTL in a Year, the difference between the historical Cdn./U.S. dollar exchange rate for the debt and the actual exchange rate at the time of each interest payment on such debt multiplied by the U.S. dollar interest payment amount;
- (ac) **"Gas Plant-In-Service"** means the original cost of fixed assets required to provide utility service to Customers before the deduction of accumulated depreciation;
- (ad) **"Gas Utilities Act"** means the Gas Utilities Act, R.S. A 1980 c. G-4, as amended;
- (ae) **"General Plant Capital"** means the aggregate of all amounts in respect of capital additions for assets such as vehicles, buildings (including leasehold improvements), heavy and other work equipment, office equipment, computer and telecommunication equipment, and technology assets transferred by NGTL into service in a given Year;
- (af) **"Income and Capital Tax Variance"** shall have the meaning ascribed thereto in Section 9.2;
- (ag) **"Insurance Costs"** means the portion of insurance premiums for property and liability coverage related to Capacity Capital additions;
- (ah) **"Inventory Management Program"** means a process of optimizing NGTL's inventory levels;
- (ai) **"Long Term Interest Expense on Base Revenue Long Term Debt"** for any period of time means the actual interest calculated on NGTL's Base Revenue Long Term Debt for such period, including debt issue costs which are amortized over the life of the related debt issues;

- (aj) **"Maintenance Capital"** means the aggregate of all amounts in respect of capital additions for assets which enhance the operational efficiency, safety and/or reliability of the Pipeline System transferred into service in a given Year;
- (ak) **"NGTL"** means NOVA Gas Transmission Ltd.;
- (al) **"Non-Routine Adjustments"** shall have the meaning ascribed thereto in Section 13.1;
- (am) **"Operating Return"** means the following rate of return:
 - (a) for the 1996 Year, the rate is 9.64%; and
 - (b) for the 1997 to 2000 Years, the rate in any given Year will be the aggregate of:
 - (i) the Deemed Common Equity multiplied by the rate of return on common equity determined each year in accordance with the methodology established in the National Energy Board RH-2-94 Decision; and
 - (ii) the rate of return on debt which is fixed over the Term at a rate of 5.96% determined by multiplying a cost factor of 8.765% for the cost of debt by the debt component of 68%.
- (an) **"Pipeline System"** means the gas gathering, transportation facilities and general plant owned and operated by NGTL from time to time in the Province of Alberta under the jurisdiction of the EUB;
- (ao) **"Rebasing Adjustment"** shall have the meaning ascribed thereto in Section 5.5;
- (ap) **"Receipt Facilities Incentive Mechanism"** shall have the meaning ascribed thereto in Section 12.1;
- (aq) **"Short Term Interest Expense on Base Revenue Short Term Debt"** for a period of time means the actual average interest rate incurred by NGTL for debt, consisting of bank loans, commercial paper or bankers' acceptances, which is payable within one year for such period, multiplied by the weighted average Base Revenue Short Term Debt during such period;

- (ar) **"Tariff"** means NGTL's Gas Transportation Tariff effective January 1, 1995, as amended by the EUB from time to time;
- (as) **"Term"** shall have the meaning ascribed thereto in Section 3.1;
- (at) **"Threshold Earnings"** means the negotiated NGTL annual earnings of \$173,000,000 on the Base Revenue Requirement on an after-tax basis;
- (au) **"Throughput Volume Revenue"** means revenue received by NGTL in the application of the "IT Commodity Rate", the "FS Commodity Rate" and the "TS Commodity Rate", as identified in the Tariff;
- (av) **"TTP"** means the Tolls, Tariff and Procedures Committee being that group of interested parties which qualify for and which have registered with NGTL in any year to address and attempt to resolve issues relating to NGTL's tolls, Tariff and services in such year as part of NGTL's Collaborative Process;
- (aw) **"Total Revenue Requirement"** shall have the meaning ascribed thereto in Article 4;
- (ax) **"Transitional Costs"** means the forecast 1996 ET&C costs and the 1996 costs of NGTL's Inventory Management Program;
- (ay) **"Uninsured Losses"** means the deductible portion of property or liability losses and the portions of an insured claim not paid by the insurer including expenses;
- (az) **"Weighted Average Cumulative Capacity Capital GPIS"** in any given Year means the thirteen month weighted average of the Capacity Capital in-service additions to the Pipeline System since January 1, 1996 excluding the Deferred Capacity Capital for the Year such determination is made;
- (ba) **"Weighted Average Cumulative Capacity Capital Net GPIS"** in any given Year means the thirteen month weighted average Capacity Capital in-service additions, net of accumulated depreciation, to the Pipeline System since January 1, 1996 excluding the Deferred Capital Capacity for the Year such determination is made;

- (bb) **"Weighted Average Deferred Capacity Capital GPIS"** in any given Year means the thirteen month weighted average of Capacity Capital in-service additions to the Pipeline System in that Year;
- (bc) **"Weighted Average Deferred Capacity Capital Net GPIS"** in any given Year means the thirteen month weighted average of Capacity Capital in-service additions, net of accumulated depreciation, to the Pipeline System in that Year; and
- (bd) **"Year"** means a period of time commencing on January 1 and ending on December 31.

2.2 Application

This Settlement shall only apply to the Pipeline System.

2.3 Negotiated Settlement

This Settlement is the result of negotiations and it is agreed that no single component of the Settlement is to be construed as representing the position of the Parties on the appropriate Total Revenue Requirement and the resulting transportation rates that would be obtained in the absence of a Settlement. The Parties intend that this Settlement be viewed as a whole, and that no element of this Settlement should be considered as acceptable to any of the Parties in isolation from all other aspects of the Settlement. All elements of the Settlement are inextricably linked. This Settlement and the terms and provisions hereof shall not prejudice the position of any of the Parties subsequent to the expiration or termination of this Settlement.

2.4 Compliance with 1995 EUB Directives

The Parties will support an application by NGTL to the EUB for an Order placing those directives listed in Schedule "G" as ordered by the EUB in Decision U96001 in abeyance during the Term.

2.5 EUB Implementation

The implementation and enforceability of this Settlement is subject to EUB approval. The Gas Utilities Act currently does not provide the EUB with the authority to fix and approve just and reasonable transportation rates in the manner and for the Term contemplated by this Settlement. During the Term, and for so long as the EUB remains unable to approve the terms of this Settlement in total and the transportation rates that will result therefrom, the Parties agree to support an annual application to the EUB for an order(s) fixing and approving

just and reasonable transportation rates based on the provisions of this Settlement for the services performed by NGTL. If, at any time during the Term, the EUB is able to approve an application to approve just and reasonable rates in the manner and for the Term herein contemplated, the Parties agree to support any such application based on the provisions of this Settlement. In the event that the EUB fails during the Term to approve and fix just and reasonable transportation rates based on the Total Revenue Requirements, as determined pursuant to this Settlement, the provisions of Section 15.1(a) shall apply.

2.6 Headings

The headings of the Articles and Sections and the Table of Contents of this Settlement are inserted for convenience of reference only and shall not affect the meaning or construction of this Settlement.

2.7 References

Unless otherwise expressly stated:

- a) all references to Articles and Sections in this Settlement refer to articles or sections of this Settlement;
- b) whenever the singular is used in this Settlement, the same shall be construed as meaning plural or vice versa, as the context so requires;
- c) all references to "dollars" or "\$" in the Settlement shall mean the lawful currency of Canada; and
- d) all references to "annual", "annual basis" or "annually" shall be referenced to a Year.

2.8 Schedules

- (a) Schedule "G" hereto forms part of and is incorporated fully into this Settlement.
- (b) Schedules "A" to "F" to this Settlement are provided only for the purposes of demonstrating the application of the calculation methodologies defined herein. The data contained in these Schedules shall not be construed to represent NGTL's Total Revenue Requirement. If there is any conflict between any such Schedule, or anything contained in such Schedule and any provision of the body of this Settlement, the provisions of the body of this Settlement shall prevail.

ARTICLE 3
TERM

3.1 Term

The effective date of this Settlement is January 1, 1996 and this Settlement will continue in effect until December 31, 2000 inclusive, unless otherwise terminated pursuant to Article 15.

3.2 Survival

For any period beyond December 31, 2000, the Parties will enter into good faith negotiations prior to December 31, 1999 in an effort to extend or modify the provisions of this Settlement to be effective January 1, 2001. These negotiations would include a review of the results of the Settlement over the first three years in attaining the objectives set out in Section 1.2

ARTICLE 4
TOTAL REVENUE REQUIREMENT

4.1 1996 Total Revenue Requirement

The Total Revenue Requirement for the 1996 Year shall be deemed to be \$1,150,000,000, being the sum of the following amounts:

- (a) Base Revenue Requirement of \$1,094,000,000; and
- (b) Forecast Income and Capital Tax of \$56,000,000.

4.2 1997 - 2000 Total Revenue Requirement

In respect of the 1997 to 2000 Years, the Total Revenue Requirement for each Year shall be an amount calculated annually based on the following formula:

$$\text{TRR} = \text{BRR} + \text{DCCRR} + \text{CCCRR} + \text{FT} +/- \text{Z}$$

- Where:
- | | |
|-------|--|
| TRR | = Total Revenue Requirement; |
| BRR | = Base Revenue Requirement; |
| DCCRR | = Deferred Capacity Capital Revenue Requirement; |
| CCCRR | = Cumulative Capacity Capital Revenue Requirement; |
| FT | = Forecast Income and Capital Taxes; and |
| Z | = the sum of the following items related to the previous Year: |
- (a) Customers' share of Threshold Earnings Variance determined in accordance with Article 6;
 - (b) Income and Capital Tax Variance determined in accordance with Article 9;
 - (c) Throughput Volume Revenue Deferral Account determined in accordance with Section 11.3;
 - (d) Firm Service Demand Revenue Deferral Account determined in accordance with Section 11.2;
 - (e) Rates Variance Deferral Account determined in accordance with Section 14.4;
 - (f) Non-Routine Adjustments determined in accordance with Section 13.2;
 - (g) Customers' share of Deferred Capacity Capital Revenue Variance determined in accordance with Section 7.3; and
 - (h) Customers' share of Cumulative Capacity Capital Revenue Variance determined in accordance with Section 8.2.

The method of calculating the Total Revenue Requirement for the 1997 to 2000 Years is demonstrated in Schedule "A".

ARTICLE 5

BASE REVENUE REQUIREMENT

5.1 Costs Included in Base Revenue Requirement

In respect of any particular Year, the Base Revenue Requirement shall be an amount which includes the aggregate of the following amounts:

- (a) costs and expenses associated with the Base Revenue Rate Base including:
 - operating costs
 - depreciation expense
 - municipal and property tax
 - Foreign Exchange Gains or Losses on Interest Payments on Base Revenue Long Term Debt
 - Debt Interest Expense on Base Revenue Debt
- (b) costs and expenses associated with the Pipeline System including:
 - transportation by others costs
 - regulatory hearing costs
 - Uninsured Losses
 - Transitional costs
 - ET&C costs
- (c) Threshold Earnings;
- (d) costs and expenses related to Maintenance Capital and General Plant Capital expenditures; and
- (e) operating costs related to Capacity Capital.

5.2 Base Revenue Rate Base

At any given time, Base Revenue Rate Base means an amount determined as the aggregate of the following amounts:

- (i) the gross Gas Plant-In-Service calculated for NGTL as at January 1, 1996;
- (ii) the accumulated depreciation on Gas Plant-In-Service calculated for NGTL as at January 1, 1996;
- (iii) Maintenance Capital in-service transfers to such time over the Term;
- (iv) General Plant Capital in-service transfers to such time over the Term;
- (v) necessary cash working capital for the Pipeline System;
- (vi) linepack cost for the Pipeline System;
- (vii) cost of materials and supplies required to such time over the Term to operate the Pipeline System;
- (viii) unamortized capital assets; and
- (ix) unamortized Transitional Costs.

less:

- (x) cumulative asset retirements to such time over the Term;
and
- (xi) cumulative depreciation expense to such time over the Term.

The method of calculating the Base Revenue Rate Base is demonstrated in Schedule "F".

5.3 1996 Base Revenue Requirement

The Base Revenue Requirement for the 1996 Year shall be \$1,094,000,000.

5.4 Determination of 1997 to 2000 Base Revenue Requirement

The Base Revenue Requirement for each of the 1997 to 2000 Years shall be calculated annually based on the following formula:

$$BRR = (PBRR +/- RA +/- BRNRA) \times EF$$

Where:

- BRR = Base Revenue Requirement
- PBRR = previous Year's Base Revenue Requirement
- RA = Rebasing Adjustment calculated in accordance with Section 5.5;
- BRNRA = Base Revenue Non-Routine Adjustments determined in accordance with Section 13.3.; and
- EF = Escalation Factor determined in accordance with Section 5.7.

The method of calculating the Base Revenue Requirement is demonstrated in Schedule "B".

5.5 Rebasing Adjustment

The Rebasing Adjustment in any given Year is an amount equal to the difference between the previous Year's Actual Base Revenue Requirement and the previous Year's Base Revenue Requirement.

5.6 Actual Base Revenue Requirement

In respect of any particular Year, the Actual Base Revenue Requirement for each Year shall be an amount calculated as the aggregate of:

(a) the actual costs incurred by NGTL in such Year in respect of each of the components referred to in Section 5.1, subject to the following:

(i) operating costs will exclude a Capitalization Amount that will not exceed \$57,000,000 per Year. This amount does not include the ET&C costs which are capitalized;

(ii) depreciation expense shall be calculated on the basis of the following Composite Depreciation Rates:

1996 -	3.0%
1997 -	3.1% -
1998 -	3.2% -
1999 -	3.3%
2000 -	3.5%

(iii) For the 1997 to 2000 Years, ET&C costs in a given Year will be allocated to Base Revenue Requirement and to Capacity Capital in a manner consistent with the practice for 1996 Year. The portion allocated to Base Revenue Requirement in a given Year will be amortized in equal amounts over three Years commencing - in the Year the cost is incurred;

(iv) Transitional Costs will be amortized at the rate of \$7,000,000 per Year over three Years commencing in the 1996 Year; and

(v) Debt Interest Expense on Base Revenue Debt shall be the aggregate of the Long Term Interest Expense on Base Revenue Long Term Debt and Short Term Interest Expense on Base Revenue Short Term Debt. Base Revenue Short Term Debt at any given time means NGTL's outstanding short term debt consisting of bank loans, commercial paper and bankers' acceptances, (being debt repayable over a period shorter than one year) which is incurred to partially finance the Base Revenue Rate Base and is calculated as follows:

Base Revenue Short Term Debt = thirteen month weighted average of the Base Revenue Rate Base - (Deemed Common Equity x the thirteen month weighted average Base Revenue Rate Base) - Base Revenue Long Term Debt.

(b) the Capitalization Amount Variance determined in accordance with Article 10.

5.7 Escalation Factor

The Escalation Factor for each Year shall be 2% to provide for cost increases in the previous Year's Base Revenue Requirement including the escalating Composite Depreciation Rate, the revenue requirement for Maintenance Capital and General Plant Capital expenditures and the effect of inflation. It also takes into account cost decreases as a result of a declining Base Revenue Rate Base over the Term.

ARTICLE 6
THRESHOLD EARNINGS VARIANCE

6.1 Threshold Earnings Variance

In respect of any particular Year, the Threshold Earnings Variance in a given Year shall be an after tax amount calculated as follows:

$$\text{Threshold Earnings Variance} = (\text{Base Revenue Requirement} - \text{Actual Base Revenue Requirement}) \times (1 - \text{income tax rate})$$

The Threshold Earnings Variance shall be shared equally by NGTL and its Customers on a pre-tax basis. The Total Revenue Requirement in the following Year shall be reduced or increased by the Customers' share of such variance on a pre-tax basis. The Parties are responsible for any income taxes associated with their share of the Threshold Earnings Variance.

ARTICLE 7
DEFERRED CAPACITY CAPITAL REVENUE REQUIREMENT

7.1 Deferred Capacity Capital

In respect of any particular Year, the revenue requirement related to Capacity Capital in service transfers in a given Year will be recorded in a deferral account and included in the determination of the following Year's Total Revenue Requirement.

7.2 Determination

In respect of any particular Year, the Deferred Capacity Capital Revenue Requirement shall be an amount calculated as the aggregate of the following amounts:

- (a) the Weighted Average Deferred Capacity Capital Net GPIS multiplied by the Operating Return;
- (b) depreciation expense calculated by multiplying the Weighted Average Deferred Capacity Capital GPIS by the applicable Composite Depreciation Rate as follows:

1996	-	3.0%
1997	-	3.1%
1998	-	3.2%
1999	-	3.3%
2000	-	3.5%
- (c) municipal and property taxes, if applicable;
- (d) Insurance Costs;
- (e) Actual Income and Capital Taxes; and
- (f) Carrying Charges calculated based on the aggregate monthly balance of items (a) to (e) above.

7.3 Deferred Capacity Capital Revenue Variance

In respect of any particular Year, the Deferred Capacity Capital Revenue Variance shall be an amount calculated as the difference between the Actual Rate of Return on Debt incurred in such Year and the negotiated rate of return on debt of 5.96% multiplied by the Weighted Average Deferred Capacity Capital Net GPIS. The Deferred Capacity Capital Revenue Variance shall be shared equally by NGTL and its Customers on a pre-tax basis. The Total Revenue Requirement for the following Year will be increased or reduced by the Customer's share of such variance.

The method of calculating Deferred Capacity Capital Revenue Requirement is demonstrated in Schedule "C".

ARTICLE 8
CUMULATIVE CAPACITY CAPITAL REVENUE REQUIREMENT

8.1 Determination

In respect of any particular Year, the Cumulative Capacity Capital Revenue Requirement shall be an amount calculated as the aggregate of the following amounts:

- (a) Weighted Average Cumulative Capacity Capital Net GPIS multiplied by the Operating Return;
- (b) depreciation expense calculated by multiplying the Weighted Average Cumulative Capacity Capital GPIS by the applicable Composite Depreciation Rate as follows:

1996	-	3.0%
1997	-	3.1%
1998	-	3.2%
1999	-	3.3%
2000	-	3.5%

- (c) forecast municipal and property taxes calculated at a fixed rate of 1.2% times the amount of the Weighted Average Cumulative Capacity Capital GPIS;
- (d) forecast Insurance Costs;
- (e) forecast Foreign Exchange Gains or Losses on Interest Payments; and
- (f) Forecast Income and Capital Taxes.

8.2 Cumulative Capacity Capital Revenue Variance

In respect of any particular Year, the Cumulative Capacity Capital Revenue Variance shall be an amount calculated as the aggregate of the following variances:

- (a) the difference between the Actual Rate of Return on Debt incurred in such Year and the negotiated rate of return on debt of 5.96% multiplied by the Weighted Average Cumulative Capacity Capital Net GPIS; and

- (b) the difference between the actual and forecast costs for items (c), (d) and (e) of Section 8.1.

The Cumulative Capacity Capital Revenue Variance shall be shared equally by NGTL and its Customers on a pre-tax basis. The Total Revenue Requirement for the following Year will be increased or reduced by the Customer's share of such variance.

The method of calculating Cumulative Capacity Capital Revenue Requirement is demonstrated in Schedule "D".

ARTICLE 9

INCOME AND CAPITAL TAXES

9.1 Forecast Income and Capital Taxes

In respect of any particular Year, in a given Year NGTL will prepare Forecast Income and Capital Taxes based on each Year's Base Revenue Requirement and Cumulative Capacity Capital Revenue Requirement.

9.2 Income and Capital Tax Variance

In respect of any particular Year, the Income and Capital Tax Variance shall be an amount calculated as the variance between the Forecast Income and Capital Taxes and the Actual Income and Capital Taxes based on each Year's Base Revenue Requirement and Cumulative Capacity Revenue Requirement for such Year. The following Year's Total Revenue Requirement will be increased or reduced by the amount of such variance plus Carrying Charges.

The method of calculating such income and capital taxes is illustrated on Schedules "B" and "D".

9.3 Deferred Income Tax Drawdown

The drawdown of the remaining balance in the deferred income tax account as at December 31, 1995, and the income tax effect thereon are excluded from the 1996 Forecasted Income and Capital Taxes and will be excluded from the 1996 Actual Income and Capital Taxes. For the purposes of this Settlement, it is deemed that this amount is equal to and is offset by the 1995 deferral accounts approved by the EUB Decision U96001 as described in Section 19.4(a).

ARTICLE 10
CAPITALIZATION AMOUNT VARIANCE

10.1 1996 Capitalization Amount Variance

For the 1996 Year, the Capitalization Amount Variance shall be an amount calculated as the difference between the actual Capitalization Amount for such Year and the negotiated Capitalization Amount of \$57,000,000. If this Capitalization Amount Variance is negative, the negative amount will be included in the determination of Actual Base Revenue Requirement. If the Capitalization Amount Variance is positive NGTL will treat the variance as a shareholder expense.

10.2 1997 to 2000 Capitalization Amount Variance

For each of the 1997 to 2000 Years, the Capitalization Amount Variance shall be an amount calculated as the difference between the actual Capitalization Amount for each Year and the lesser of the previous Year's actual Capitalization Amount or \$57,000,000. If this Capitalization Amount Variance is negative, the negative amount will be included in the determination of Actual Base Revenue Requirement. If the Capitalization Amount Variance is positive, the portion of the positive amount that will be included in the determination of Actual Base Revenue Requirement is limited to the aggregate of the Capitalization Amount Variance applied to the Actual Base Revenue Requirement in the prior Years. The portion of the positive amount that is in excess of the aggregate applied for Capitalization Amount Variance of prior years will be recorded as a shareholder expense by NGTL.

10.3 ET&C Costs

For the purpose of Sections 10.1 and 10.2, the benefits from current or prior Year's ET&C costs will be taken into account in the determination of the Capitalization Amount Variance.

ARTICLE 11
REVENUE DEFERRAL ACCOUNTS

11.1 Continuation of Deferral Accounts

The Firm Service Demand Revenue and Throughput Volume Revenue Deferral Accounts approved by the EUB in Decision U96001 shall be continued by NGTL.

11.2 Firm Service Demand Revenue Deferral Account

Each Year, NGTL shall forecast the Firm Service Demand Revenue for such Year. Any positive or negative variance between the forecast and actual Firm Service Demand Revenue for such Year shall be recorded in the Firm Service Demand Revenue Deferral Account and included in the following Year's Total Revenue Requirement with Carrying Charges.

11.3 Throughput Volume Revenue Deferral Account

Each Year, NGTL shall forecast the Throughput Volume Revenue for such Year. Any positive or negative variance between the forecast and actual Throughput Volume Revenue for such Year shall be recorded in the Throughput Volume Revenue Deferral Account and included in the following Year's Total Revenue Requirement with Carrying Charges.

ARTICLE 12 OTHER INCENTIVE MECHANISMS

12.1 Receipt Facilities Incentive Mechanism

During the 1997 Year, each time that NGTL receives a Customer's request for service under Rate Schedule FS as identified in the NGTL's Gas Transportation Tariff and that request requires the engineering, procurement and construction ("EP&C") of any receipt facilities, the following procedures shall apply:

- (a) NGTL will determine the size of the receipt facilities to meet the prospected flow requirements;
- (b) NGTL will consult with the Customer on the most appropriate manner to conduct the EP&C of the receipt facilities referred to in Section 12.1(a). This consultative process will consider the various alternatives available in carrying out the required EP&C, including the possibility that the Customer could provide for the EP&C of such facilities. In deciding on the appropriate party to conduct the EP&C of the receipt facilities, NGTL and the Customer shall have due regard to the criteria provided for in Section 12.1(d) and (f) and any such party shall meet the requirements of Section 12.1(g) below;
- (c) In the event that NGTL and the Customer agree that the Customer is the appropriate party to conduct the EP&C of the receipt facilities and NGTL and the Customer are able to agree on the estimated cost and

timing of such facilities, NGTL will contract with the Customer for the Customer to conduct the EP&C thereof at the agreed upon estimated cost;

(d) In the event that Customer and NGTL select NGTL to conduct the EP&C of such facilities or Customer and NGTL are unable to agree on the appropriate party, NGTL will conduct the EP&C of such facilities at NGTL's estimated cost;

(e) NGTL will utilize a bid process for or at least 25% of all EP&C services (determined on the basis of the number of construction projects) to be performed by NGTL in connection with the construction of receipt facilities in the 1997 Year, soliciting bids from third-party EP&C management firms as selected by NGTL. In deciding on the appropriate firm, NGTL shall have due regard to the criteria provided for in Section 12.1(f) and any such firm must meet the requirements of Section 12.1(g); provided however that NGTL reserves the right to reject all bids if none of the bids are found, in NGTL's sole discretion, to offer the lowest cost alternative;

(f) In determining the appropriate party to conduct the EP&C of the receipt facilities in accordance with the provisions of this Section 12.1, the following criteria shall be considered:

(i) lowest cost estimate, including applicable overhead costs;

(ii) required connection schedule and the ability of each party to conduct the EP&C of the receipt facilities in accordance with such schedule; and

(iii) all regulatory requirements.

(g) Any party selected to conduct the EP&C of any such facilities shall build such facilities to NGTL's specifications and standards including the safety, health, environmental and risk standards of NGTL.

12.2 Review of Receipt Facilities Incentive Mechanism

Following the 1997 Year, NGTL will review with the TTP the results of the 1997 receipt facilities construction program with the intention of either extending or modifying this program for the remainder of the Term.

12.3 Future Capital and System Utilization Incentive Mechanisms

(a) The Parties shall use reasonable efforts to negotiate a mutually acceptable arrangement in respect of a NGTL capital efficiency incentive program by December 1, 1996. This program will identify incentives and implement plans to ensure:

- efficient use of those facilities included in Base Revenue Rate Base;
- determination of efficient Capacity Capital; and
- efficient construction of Capacity Capital.

(b) Prior to the construction of any new facilities at an export delivery point, NGTL will provide those Customers who have contracted for service under Rate Schedule FS at such point, notice of the proposed expansion and requesting that the Customer provide NGTL with notice of the Customer request for relief in accordance with the Tariff. NGTL will use reasonable efforts to accommodate such requests.

(c) NGTL will work diligently with the TTP to review, and if necessary, modify, NGTL's design and contracting practices at the export delivery points to ensure:

- contract levels and services align with pipelines located downstream of the Pipeline System;
- NGTL meets Customer requirements with minimal facility additions to its Pipeline System; and
- Customer has an opportunity for maximum year round contract utilization

(d) Upon review of the implications of a "summer contract level" at Empress export delivery point and agreement by the Parties, NGTL will revise its contracting practices at Empress to a summer contract level by January 1, 1997.

ARTICLE 13
NON-ROUTINE ADJUSTMENTS

13.1 Non-Routine Adjustments

Non-Routine Adjustments shall be the amount of any additional or unanticipated costs or expenses or reductions in costs or expenses incurred by NGTL in any particular Year as a result of any of the following circumstances:

- (a) changes in legislation, regulations or ordinances or the issuance of orders or directives which result in changes to safety, health, or environmental requirements, practices or procedures for NGTL;
- (b) changes in revenues or expenses resulting from changes in applicable accounting standards of the Canadian Institute of Chartered Accountants;
- (c) where NGTL is subject to an EUB order which would have an impact on elements of cost to NGTL;
- (d) Uninsured Losses which aggregate more than \$10,000,000;
- (e) decreases to Base Revenue Requirement as a result of the costs of NrG Highway being billed directly to the users of the service;
- (f) the cost of distinct and new programs necessary to address existing, new or unanticipated Pipeline System failure mechanisms which significantly impact upon the integrity of the Pipeline System, such as cracking and/or corrosion in the Pipeline System;
- (g) changes in transportation by others costs due to orders or directives issued by a regulatory agency having jurisdiction or due to the cost of distinct and new programs necessary to address existing, new or unanticipated failure mechanisms which significantly impact upon the integrity of the pipeline, such as cracking and/or corrosion in the pipeline;
- (h) prudent foreign exchange gains or losses that are realized on the redemption of U.S. dollar debt that is not refinanced or is refinanced in Canadian dollar debt as a result of a more favourable interest rate differential, that result in a lower cost for the Customers; or
- (i) an audit requested pursuant to Article 18.

13.2 Reimbursement for Non-Routine Adjustments

All Non-Routine Adjustments that occur in a given Year shall be included, subject to the review contained in Sections 14.2 and 14.3 and the dispute resolution procedure contained in Section 17.1, in the following Year's Total Revenue Requirement with Carrying Charges.

13.3 Base Revenue Non-Routine Adjustments

All Non-Routine Adjustments that are determined by NGTL, acting reasonably, to likely reoccur in any future Year, shall be applied, subject to review contained in Sections 14.2 and 14.3 and dispute resolution contained in Section 17.1, in the determination of the Base Revenue Requirement for each Year in which such revenue or costs are incurred pursuant to Section 5.3.

ARTICLE 14 RATE CALCULATION

14.1 Calculation of Transportation Rates

During the Term, transportation rates for each Year, calculated in accordance with the rate design approved by the EUB from time to time, shall be based on the Total Revenue Requirement, firm service demand quantity and throughput forecast prepared by NGTL.

14.2 Interim Rates

On or before December 15 of each Year during the Term, NGTL shall provide the EUB, its Customers and the TTP with interim transportation rates to take effect January 1 of the following Year. The interim transportation rates will be based on the forecast of the following Year's Total Revenue Requirement, firm service demand quantity and throughput forecasts prepared by NGTL.

14.3 Final Rates

On or before March 1 of each Year during the Term, NGTL will inform the EUB, its Customers and the TTP of the Total Revenue Requirement for each Year calculated in accordance with the terms of this Settlement and the rates calculated therefrom, along with any necessary supporting information.

14.4 Rates Variances Deferral Account

For each Year, if the variance between the final transportation rates and the interim transportation rates for each year is greater than 5%, NGTL shall adjust its rates effective April 1 of such Year for the balance of such Year to reflect the impact of the variance resulting from the use of the interim transportation rates. If the variance is less than 5%, TTP will have the option to request that NGTL adjust its rates by April 1, otherwise the variance shall be recorded in the Rates Variance Deferral Account and be included in the following Year's Total Revenue Requirement with Carrying Charges.

ARTICLE 15 TERMINATION

15.1 Right to Terminate

Any Party, any member of the TTP or any Customer acting in good faith shall have the option to terminate this Settlement in accordance with Section 15.2 in any of the following circumstances:

- (a) if this Settlement is not approved in its entirety by the EUB, or if it is subsequently materially varied by an EUB Order;
- (b) if, over a 12 month period, the rate of change in either the Consumer Price Index for Canada All Items (Not Seasonally Adjusted) as reported in the Consumer Prices and Price Index as publication number [62-001] published by Statistics Canada, or the Consumer Price Index for Alberta All Items (Not Seasonally Adjusted) as reported in the Canadian Statistical Review, Publication published by Statistics Canada is less than 1% or greater than 4%;
- (c) NGTL is downgraded below A-low or equivalent credit rating by any Canadian or United States bond rating agency. NGTL must reasonably demonstrate that the downgrade is related to the Pipeline System;
- (d) regulatory approval is obtained for the construction and operation of a natural gas pipeline with a capacity of greater than 100 mmcf/day which will have the effect of providing a significant alternative to the Pipeline System for transportation service to, or across the Alberta border;

ARTICLE 17
DISPUTE RESOLUTION PROCESS

17.1 Dispute Resolution

In the event of any dispute under this Settlement, including, but not limited to, a dispute respecting the determination of the Total Revenue Requirement and the transportation rates calculated therefrom, the Parties or any member of the TTP or any Customer will in good faith attempt to resolve the dispute. If a satisfactory resolution cannot be obtained within 45 days, NGTL, the TTP, any member of the TTP or any Customer may severally or jointly file an application with the EUB regarding the matter in dispute. Any application must also contain a request that the EUB deal with the disputed matter on an expedited basis.

ARTICLE 18
AUDIT

18.1 Right to Audit

Subject to Section 18.3, at any time prior to December 31, 2001, and upon prior reasonable notice being given to NGTL, the TTP, any member of the TTP or any Customer may conduct one independent audit per Year in order to determine compliance by NGTL with the terms of this Settlement. Any such audit must be conducted by a qualified firm of independent chartered accountants having offices in the Province of Alberta.

18.2 Confidentiality of Information

Subject to Section 18.3, NGTL shall provide the auditors selected by the TTP, any member of the TTP, or any Customer pursuant to Article 18.1 with reasonable access to source data necessary for the conduct of the audit; provided always that, the auditor will execute a confidentiality agreement in a form satisfactory to NGTL requiring the auditor to maintain confidentiality in respect of source data identified by NGTL as confidential.

18.3 Audit of Shared Services

An audit of the services provided by NOVA Corporation to NGTL will be conducted by NGTL's external auditor and a report respecting compliance by NGTL with the terms of this Settlement will be provided to the party requesting such audit.

18.4 Audit Costs

The full cost of the audits referred to in Sections 18.1, and 18.3, inclusive of NGTL employee person-hours, will be borne by the party requesting the audit, unless the TTP by an unopposed resolution agree that these costs are recoverable as a Non-Routine Adjustment pursuant to Section 13.1(i).

ARTICLE 19
MISCELLANEOUS PROVISIONS

19.1 Toll Design

Toll design and Tariff issues are not addressed by this Agreement.

19.2 Negotiated Composite Depreciation Rates

The Composite Depreciation Rates provided for in this Agreement are negotiated rates and are not to be construed as representing the position of the Parties on the appropriate rate to be used by NGTL in determining depreciation expense during the Term or thereafter. The use of such rates shall not be construed so as to prejudice NGTL's ability to recover full depreciation on all prudently incurred capital investments.

19.3 Accounting Policies and Procedures

During the Term, NGTL will continue to apply accounting policies and procedures that have been used in the determination of the 1996 Base Revenue Requirement. More specifically,

- (a) NGTL will maintain its current policy of only recognizing foreign exchange gains or losses on the redemption of U.S. dollar debt when the U.S. dollar debt is refinanced with Canadian dollar debt, except as noted in Section 13.1(h);
- (b) calculation of amounts charged to NGTL by NOVA Corporation for shared services and amounts charged by NGTL to NOVA Corporation and affiliates for services performed by NGTL; and
- (c) calculation of the Capitalization Amount.

19.4 1995 Deferral Accounts

(a) The Parties acknowledge that the Base Revenue Requirement for the 1996 Year excludes the amounts existing in the deferral accounts approved by the EUB in Decision U96001 as at December 31, 1995. The balances recorded in these deferral accounts will not be included in the determination of the Actual Base Revenue Requirement for the 1996 Year. For the purposes of this Settlement, it is deemed that the balances recorded therein are equal and offset by the amount of the deferred income tax drawdown at January 1, 1996, and the income tax effect thereon as described in Section 9.3.

(b) All deferral accounts approved by the EUB in Decision U96001 shall be placed in abeyance and will not accumulate balances, with the exception of the deferral accounts described in Article 11.

(c) All deferral accounts which existed as at December 31, 1995 will be re-instated effective the earlier of January 1, 2001, and the termination of this Settlement, to be disposed of in accordance with a renewed or modified Incentive Settlement or pursuant to a decision from the EUB in a General Rate Application for the Year immediately following the expiration or termination of this Settlement.

19.5 Disposition at Termination

(a) Any of the revenue requirement balances existing at the Termination of the Agreement that are associated with Non-Routine Adjustments, Deferred Capacity Capital, and variances and deferral account balances included in component 'Z' of Section 4.2 will be included in the calculation of the following Year's rates.

(b) At the time of termination or expiration of this Settlement, the Deferred Capacity Capital, the Cumulative Capacity Capital, and the Base Revenue Rate Base will be consolidated.

**ARTICLE 20
TERMS AND CONDITIONS OF SERVICE**

20.1 Service

During the Term, NGTL will continue to provide service in accordance with the Tariff.

SCHEDULE A

Illustrative Example of Calculating Total Revenue Requirement
(\$ millions)

<u>Line</u>	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>
1 Base Revenue Requirement (Schedule B)	1,115.9	1,131.3	1,151.7	1,181.4
2 Deferred Capacity Capital Revenue Requirement (Schedule C)	19.6	19.9	20.7	21.0
3 Cumulative Capacity Capital Revenue Requirement (Schedule D)	41.0	82.7	123.4	162.1
4	<u>1,176.5</u>	<u>1,233.8</u>	<u>1,295.8</u>	<u>1,364.5</u>
Other Total Revenue Requirement adjustments				
5 - Customers' share of Threshold Earnings Variance (Schedule B)	-	(3.4)	(1.1)	3.2
6 - Customers' share of Deferred Capacity Capital Revenue Variance (Schedule C)	(0.1)	(0.1)	0.2	0.3
7 - Customers' share of Cumulative Capacity Capital Revenue Variance (Schedule D)	-	(0.3)	0.2	0.6
8 - Non-Routine Adjustments	-	-	-	-
9 - Firm Service Demand Revenue Deferral Account	-	-	-	-
10 - Throughput Volume Revenue Deferral Account	-	-	-	-
11 - Rates Variance Deferral Account	-	-	-	-
12 - Income and Capital Tax Variance	-	-	-	-
13	<u>(0.1)</u>	<u>(3.8)</u>	<u>(0.7)</u>	<u>4.1</u>
14 Forecast Income and Capital Taxes				
15 - Base Revenue Requirement (Schedule B)	77.3	101.5	123.8	142.2
16 - Cumulative Capacity Capital Revenue Requirement (Schedule D)	(1.3)	6.0	6.3	9.5
17	<u>76.0</u>	<u>107.4</u>	<u>130.2</u>	<u>151.7</u>
18 Total Revenue Requirement	<u>1,252.4</u>	<u>1,337.4</u>	<u>1,425.3</u>	<u>1,520.3</u>

SCHEDULE B

Illustrative Example of Calculating Base Revenue Requirement
(5 millions)

Line		1996	1997	1998	1999	2000
BASE REVENUE REQUIREMENT						
1	Opening Base Revenue Requirement	1,094.0	1,094.0	1,115.9	1,131.3	1,151.7
2	Rebasing Adjustment (Line 9)	-	-	(6.8)	(2.1)	6.5
3	Base Revenue Non-Routine Adjustments	-	-	-	-	-
4		<u>1,094.0</u>	<u>1,094.0</u>	<u>1,109.1</u>	<u>1,129.2</u>	<u>1,158.2</u>
5	Escalation Factor (2% x Line 4)	-	21.9	22.2	22.6	23.2
6	Base Revenue Requirement	<u>1,094.0</u>	<u>1,115.9</u>	<u>1,131.3</u>	<u>1,151.7</u>	<u>1,181.4</u>
REBASING ADJUSTMENT						
7	Base Revenue Requirement (Line 6)	1,094.0	1,115.9	1,131.3	1,151.7	1,181.4
8	Actual Base Revenue Requirement ⁽¹⁾	<u>1,094.0</u>	<u>1,109.1</u>	<u>1,129.2</u>	<u>1,158.2</u>	<u>1,185.4</u>
9	Rebasing Adjustment	-	(6.8)	(2.1)	6.5	4.0
THRESHOLD EARNINGS VARIANCE						
10	Pre-tax earnings ⁽²⁾	229.0	257.1	276.6	290.4	311.2
11	Income and capital taxes (Line 31)	(56.0)	(80.3)	(102.4)	(120.9)	(140.4)
12	Net earnings	<u>173.0</u>	<u>176.8</u>	<u>174.2</u>	<u>169.5</u>	<u>170.8</u>
13	Threshold Earnings	<u>173.0</u>	<u>173.0</u>	<u>173.0</u>	<u>173.0</u>	<u>173.0</u>
14	Threshold Earnings variance	-	3.8	1.2	(3.5)	(2.2)
15	Customers' share of Threshold Earnings Variance (50% x Line 14)	-	1.9	0.6	(1.8)	(1.1)
16	Reduction (addition) to Total Revenue Requirement in following year (grossed-up: Line 15/(1-.4462))	-	<u>3.4</u>	<u>1.1</u>	<u>(3.2)</u>	<u>(2.0)</u>
NGTL EARNINGS ON BASE REVENUE REQUIREMENT						
17	Threshold Earnings (Line 13)	173.0	173.0	173.0	173.0	173.0
18	NGTL's share of Threshold Earnings Variance (Line 14 - Line 15)	-	1.9	0.6	(1.8)	(1.1)
19	NGTL earnings on Base Revenue Requirement	<u>173.0</u>	<u>174.9</u>	<u>173.6</u>	<u>171.3</u>	<u>171.9</u>
FORECAST INCOME AND CAPITAL TAXES - BASE REVENUE REQUIREMENT						
20	Threshold Earnings (Line 13)	173.0	173.0	173.0	173.0	173.0
21	Depreciation	180.9	185.0	185.0	205.0	220.0
22	Capital cost allowance	(269.1)	(270.0)	(250.0)	(230.0)	(220.0)
23	Capitalized interest component of AFUDC	(7.0)	(7.0)	(7.0)	(7.0)	(7.0)
24	Other adjustments, net	(9.8)	(3.0)	(3.0)	(3.0)	(3.0)
25	Large corporation capital tax	9.6	8.0	8.0	7.0	6.0
26	Taxable income	<u>56.6</u>	<u>86.0</u>	<u>116.0</u>	<u>145.0</u>	<u>169.0</u>
27	Income taxes (Line 26 x 44.62%(1-44.62%))	46.4	68.3	83.5	116.8	136.2
28	Large corporation capital tax	9.6	8.0	8.0	7.0	6.0
29	Forecast Income and Capital Taxes on Base Revenue Requirement	<u>56.0</u>	<u>77.3</u>	<u>101.5</u>	<u>122.8</u>	<u>142.2</u>
30	Income tax on Rebasing Adjustment (Line 9 x 44.62%)	-	3.0	0.9	(2.9)	(1.8)
31	Income and Capital Taxes ⁽³⁾	<u>56.0</u>	<u>80.3</u>	<u>102.4</u>	<u>120.9</u>	<u>140.4</u>

(1) Actual Base Revenue Requirement is equal to negotiated 1996 Base Revenue Requirement for purposes of this illustration. Actual Base Revenue Requirements shown for 1997 to 2000 are for illustrative purposes only.

(2) Capitalization Amount Variance is included in pre-tax earnings calculation for purposes of determining the Threshold Earnings Variance.

(3) Income and Capital Tax calculation required to determine NGTL net earnings for purposes of comparison to the Threshold Earnings which is an after tax amount.

SCHEDULE E

Base Revenue Long Term Debt as at January 1, 1996
(\$ thousands)

	<u>Effective Interest Rate</u>	<u>Maturity Date</u>	<u>Principal Outstanding</u>
UNSECURED DEBENTURES			
17-3/4% Series 8	17.75%	1997	15,000
10% Series 8	10.00%	1998	100,000
11.95% Series 13	11.95%	2007	103,748
Series 14	9.11% (1)	1999	100,000
11.70% Series 15	11.70%	2008	130,500
11.20% Series 18	11.20%	2014	140,250
12-5/8% Series 19	12.19% (1)	2010	95,667
11-7/8% Series 20	11.34% (1)	2001	100,000
12.20% Series 21	11.32% (1)	2016	125,000
8-1/2% - \$175 MM U.S.	8.50%	2012	223,046
8.30% Series 22	8.30%	2003	150,000
7-7/8 % \$200 MM U.S.	7.88%	2023	248,544
8.5% \$125 MM U.S.	8.50%	2004	163,024
9.90% Series 23	9.90%	2024	100,000
U.S. UNSECURED NOTES			
9.75% - \$130 MM U.S.	9.60% (1)	1997	76,804
8.95% - \$150 MM U.S.	8.95%	2000	173,258
7-7/8% - \$125 MM U.S.	7.88%	2002	159,319
7.25% - \$150 MM U.S.	7.25%	1999	181,708
U.S. Medium Term Notes (1995)	6.33%	2001 - 2025	128,650
CDN. UNSECURED NOTES			
Medium term notes (1994)	(2)	1998 - 2002	200,000
Medium term notes (1995)	8.65%	2006 - 2026	334,900
			<u>3,049,418</u>

(1) Effective rate after reduction as per E92086.

(2) A portion of this issue carries floating rate interest, therefore effective rate will vary over the term of the agreement.

SCHEDULE F**Illustrative Example of Calculating Base Revenue Rate Base
(\$ millions)**

<u>Line</u>		
1	Opening Gas Plant-In Service	5,500
2	GPIS transfers - Maintenance and General Plant Capital	20
3	Retirements	<u>(2)</u>
4	Gas Plant-In Service	<u>5,518</u>
5	Opening accumulated depreciation	(1,500)
6	Depreciation expense	(15)
7	Retirements	<u>2</u>
8	Accumulated depreciation	<u>(1,513)</u>
9	Net gas plant in service	4,005
10	Necessary working capital	2
11	Materials and supplies	30
12	Linepack	15
13	Unamortized capital assets and Transitional Costs	<u>25</u>
14	Base Revenue Rate Base	<u><u>4,077</u></u>

Note: The weighted average Base Revenue Rate Base in a Year will be the thirteen month average of the month-end balances as calculated above.

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ARTICLE 1

INTRODUCTION

1.1 Purpose of Settlement

NOVA Gas Transmission Ltd. ("NGTL") and its stakeholders as represented by the TTP (collectively, the "Parties") propose the implementation of this Cost Efficiency Incentive Settlement (the "Settlement") which provides incentives for NGTL to operate in a manner consistent with a competitive market and which is expected to deliver benefits to NGTL's Customers and shareholders alike. It will be applied, subject to the approval by the EUB, in determining the Total Revenue Requirement for each Year during the Term and the transportation rates for service on the Pipeline System calculated therefrom in accordance with NGTL's current rate design and pursuant to the Tariff. The Parties intend this Settlement to be interpreted and applied in good faith and in a manner consistent with the spirit of the objectives set out in Section 1.2 hereof.

1.2 Objectives

The objectives of this Settlement are as follows:

- (a) to improve the competitive position of Alberta-sourced natural gas by aligning more closely the interests of the Parties through the provision of a framework which encourages operating and capital costs reductions and the minimization of transportation rates, relative to the rates that would have existed under the traditional regulatory process. If NGTL reduces such costs, it has an opportunity to improve shareholder earnings;
- (b) to provide the lowest possible costs and the highest possible system utilization, without compromising pipeline efficiency and reliability or adversely impacting safety or the environment;
- (c) to maintain or improve the safe, efficient, reliable and flexible operations of the Pipeline System;
- (d) to maintain the financial integrity of NGTL;
- (e) to provide for timely and cost effective expansions of the Pipeline System in order to meet Customer's requirements;
- (f) to reduce the resources consumed by all interested or affected parties in the traditional regulatory process; and

- (g) to ensure that NGTL maintains adequate levels of maintenance and operating practices.

ARTICLE 2

INTERPRETATION

2.1 Definitions

In this Settlement and in the Schedules attached hereto:

- (a) **"Actual Base Revenue Requirement"** shall have the meaning ascribed thereto in Section 5.6;
- (b) **"Actual Income and Capital Taxes"** in a given Year, means the aggregate of all actual federal and provincial income taxes and large corporation capital taxes, calculated in a manner consistent with the methodology approved by the EUB in Decision U96001 together with any payments or credits for reassessments related to prior Years that have not previously been accounted for;
- (c) **"Actual Rate of Return on Debt"** in any given Year means the actual interest rate on debt related to the Capacity Capital incurred in such Year multiplied by the debt component of 68%;
- (d) **"AFUDC"** means an allowance for funds used during construction set at a rate that is equivalent to the Operating Return and which will be applied to the gas plant under construction balances of Maintenance Capital, General Plant Capital and Capacity Capital. The debt portion of AFUDC will be provided as a deduction in the income tax calculation in any particular Year as demonstrated in Schedule "B";
- (e) **"Base Revenue Rate Base"** shall have the meaning ascribed thereto in Section 5.2;
- (f) **"Base Revenue Debt"** means the aggregate of Base Revenue Long Term Debt and Base Revenue Short Term Debt incurred by NGTL from time to time in financing the Base Revenue Rate Base using a debt to common equity ratio of 68:32;

DECISIONS

RE:

**FORMULISTIC APPROACHES
TO RETURN ON COMMON EQUITY**



TCPL

National Energy Board

Reasons for Decision

TransCanada PipeLines Limited

Westcoast Energy Inc.

Foothills Pipe Lines Ltd.

Alberta Natural Gas Company Ltd

Trans Québec & Maritimes Pipeline Inc.

Interprovincial Pipe Line Inc.

Trans Mountain Pipe Line Company Ltd.

Trans-Northern Pipeline Inc.

RH-2-94

March 1995

Cost of Capital

National Energy Board

Reasons for Decision

In the Matter of

TransCanada PipeLines Limited, Westcoast Energy Inc., Foothills Pipe Lines Ltd., Alberta Natural Gas Company Ltd, Trans Québec & Maritimes Pipeline Inc., Interprovincial Pipe Line Inc., Trans Mountain Pipe Line Company Ltd. and Trans-Northern Pipeline Inc.

Submissions dated 20 June 1994, 17 June 1994, 20 June 1994, 20 June 1994, 20 June 1994, 17 June 1994, 20 June 1994 and 20 June 1994 respectively, as amended, for 1995

In respect of Cost of Capital

RH-2-94

March 1995

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Abbreviations

A&S	Alberta & Southern Gas Company
Act	<i>National Energy Board Act</i> (the)
ADOE	Alberta Department of Energy
ANG	Alberta Natural Gas Company Ltd
ANS	Alaska North Slope
BC Gas	BC Gas Utility Ltd.
Board	National Energy Board (the)
CAPP	Canadian Association of Petroleum Producers
CBRS	Canadian Bond Rating Service Limited
COFI/Methanex/Cominco	Council of Forest Industries of British Columbia, Methanex Corporation and Cominco Ltd.
CPUC	California Public Utilities Commission
DBRS	Dominion Bond Rating Service Limited
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
Foothills	Foothills Pipe Lines Ltd.
FTA	Free Trade Agreement
Gaz Métropolitain	La Société en commandite Gaz Métropolitain
IGUA	Industrial Gas Users Association
IPL	Interprovincial Pipe Line Inc.
LDC	Local Distribution Company
NAFTA	North American Free Trade Agreement
NEB	National Energy Board (the)
NOVA	NOVA Gas Transmission Limited
Ontario	Ministry of Environment and Energy for Ontario
Pan-Alberta	Pan-Alberta Gas Ltd.
PG&E	Pacific Gas & Electric Company
PGT	Pacific Gas Transmission Company
PITCO	Pacific Interstate Transmission Company
Quebec	Le Procureur général du Québec

R/P Ratio

ROE

SFV

TMPL

TNPI

TQM

TransCanada

WCSB

Westcoast

Reserves/Production Ratio

Rate of Return on Common Equity

Straight Fixed Variable

Trans Mountain Pipe Line Company Ltd.

Trans-Northern Pipeline Inc.

Trans Québec & Maritimes Pipeline Inc.

TransCanada PipeLines Limited

Western Canada Sedimentary Basin

Westcoast Energy Inc.

Glossary of Terms

Class 1 Toll Adjustment Application	Class 1 applications permit adjustments to the tolls for an oil pipeline, which are required because of significant changes in throughput and specific throughput-related costs from those approved in the most recent Board Decision.
Class 2 Toll Adjustment Application	Class 2 applications permit adjustments to the revenue requirement and tolls for an oil pipeline, which are required because of any significant changes in the cost of service from that approved in the most recent Board Decision, with the exception of those changes identified as requiring a Class 3 application.
Class 3 Toll Adjustment Application	Class 3 applications are required when an oil pipeline company is applying to change the rate of return on rate base authorized by the Board, the method of calculation of income taxes or the policies or principles approved by the Board at any previous hearing.
Eastern Zone (TransCanada)	This refers to the Eastern toll zone for purposes of determining the toll applicable to any point on the TransCanada system. It includes all points in the Central Delivery area, the Southwestern Delivery area and the Eastern Delivery area.
Eastern Leg (Foothills)	The portion of Foothills from Caroline, Alberta to Monchy, Saskatchewan, consisting of Zone 6 in Alberta and Zone 9 in Saskatchewan.
Western Leg (Foothills)	The portion of Foothills from Caroline, Alberta to Kingsgate, B.C., consisting of Zone 7 in Alberta and Zone 9 in B.C.
full-cycle supply costs	Total cost associated with resource exploitation typically expressed as an average cost per unit of production over the project life. By contrast to half-cycle cost, it includes capital expenditures associated with exploration.
Group 1 Pipelines	Group 1 pipelines consist of the ten major pipelines which are audited by the Board on a regular basis and whose operating results are continuously monitored by the Board.
load factor	The percentage utilization of capacity.

NEB Rules of Practice and Procedure (1987)	NEB Rules which set out the procedures for making applications, representations and complaints to the Board, the conduct of hearings and generally the manner of conducting any business before the Board.
negative salvage	The amount by which the cost of removing an asset from service exceeds the salvage proceeds.
Part IV	The section of the NEB Act which deals with Traffic, Tolls and Tariffs.
Prebuild Section (Foothills)	The portions of the Alaska Natural Gas Transportation System ("ANGTS") which have been prebuilt to transmit natural gas of Canadian origin before the pipeline is placed in service for the transmission of natural gas of Alaskan origin, being all or part of facilities in Zones 6 to 9.
R/P ratio	A ratio which divides the remaining reserves of a basin by the annual production.
Retail Wheeling	The transmission of electricity from a wholesale supplier to a retail customer by a third party.
SFV Toll Design	A toll design whereby all fixed costs are assigned to the monthly demand charge based on contracted capacity and all variable costs are assigned to actual throughput. The equivalent Canadian term is FFV or Full Fixed Variable.
trigger mechanism	The requirement for oil pipelines to file an application for new tolls when it is forecast that ROE for the calendar year will exceed that approved by the Board at the most recent toll hearing by more than two percentage points.
Zones (Westcoast)	For toll calculation purposes, the Westcoast system is divided into five zones (i.e. Raw Gas Transmission Zone, Processing Zone, Transportation North Zone, Transportation South Zone and Alberta Zone).

Recital and Appearances

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

IN THE MATTER OF Directions on Procedure respecting a Public Hearing concerning the Cost of Capital of TransCanada PipeLines Limited, Westcoast Energy Inc., Foothills Pipe Lines Ltd., Alberta Natural Gas Company Ltd, Trans Québec & Maritimes Pipeline Inc., Interprovincial Pipe Line Inc., Trans Mountain Pipe Line Company Ltd. and Trans-Northern Pipeline Inc.; and

IN THE MATTER OF the National Energy Board Hearing Order No. RH-2-94;

HEARD in Calgary, Alberta on 24, 25, 26, 27, 28 and 31 October 1994; 1, 2, 3, 14, 15, 16, 17, 18, 28, 29 and 30 November 1994; and 1, 2, 5, 6, 7, 8, 9, 12, 13, 14, 15 and 20 December 1994.

BEFORE:

R. Priddle	Presiding Member
A. Côté-Verhaaf	Member
C. Bélanger ¹	Member
K.W. Vollman	Member
R.L. Andrew	Member

APPEARANCES:

C.B. Johnson	TransCanada PipeLines Limited
J.M. Murray	
C.B. Ledingham	
J. Lutes	Westcoast Energy Inc.
R. Sirett	
J. Lutes	Foothills Pipe Lines Limited
B. Pierce	
D.G. Davies	Alberta Natural Gas Company Ltd
R. Graw	
L.-A. LeClerc	Trans Québec & Maritimes Pipeline Inc.
R. Heider	
W.M. Moreland	Interprovincial Pipe Line Inc.
M.H. Patterson	
C.B. Johnson	Trans Mountain Pipe Line Company Ltd.
M.W.P. Boyle	
C.B. Ledingham	
J.A. Campion	Trans-Northern Pipeline Inc.

¹ Effective 2 February 1995, C. Bélanger ceased to participate in the RH-2-94 proceeding

L.G. Keough
N.J. Schultz

R.B. Wallace

P.C.P. Thompson, Q.C.

S. Trueman
A. Kerr

E.C. Eddy

I.A. Blue, Q.C.
D. Parcell

R. Moore

C.B. Woods

N. Mills

C. Hart

S.R. Miller

M.A.K. Muir

E.S. Decter

J.S. Bulger

J.T. Horte

P. McCunn-Miller

J. Turchin

J. Brisson

P. Noonan
C. Beauchemin

Canadian Association of Petroleum Producers

Council of Forest Industries of British Columbia, Methanex
Corporation and Cominco Ltd.

Industrial Gas Users Association

Amoco Canada Petroleum Company Ltd.

BC Gas Utility Ltd.

C.W. Amos

Imperial Oil Resources Limited

Mobil Oil Canada

NOVA Gas Transmission Limited

PanCanadian Petroleum Limited

Petro-Canada Inc.

ProGas Limited

Shell Canada Limited

La société en commandite Gaz Métropolitain

Wascana Energy Inc.

Alberta Department of Energy

Ministry of Environment and Energy for Ontario

Le Procureur général du Québec

Board Counsel

Overview

(Note: This overview is provided for the convenience of the reader and does not constitute part of the Reasons for Decision. For details, the reader is referred to the relevant sections of the Reasons for Decision.)

Rate of Return on Common Equity for the Benchmark Pipeline for the 1995 Test Year

The Board concluded that, for the 1995 test year, a rate of return on common equity of 12.25% is appropriate for the benchmark pipeline. In making this determination, the Board gave primary weight to the equity risk premium technique. The 12.25% determination was based on a finding that 9.25% is a reasonable estimate of the yield on long-term Government of Canada bonds in 1995 and that a reasonable all-inclusive equity risk premium for the benchmark pipeline is 300 basis points.

The Board determined that it is appropriate to apply the benchmark rate of return on common equity to each of the submitting pipelines who have not been otherwise discharged or exempted from this proceeding.

Capital Structure effective 1 January 1995

The Board found that a 30% deemed common equity ratio is appropriate for TransCanada, Foothills, ANG and TQM effective 1 January 1995.

The Board determined that a 35% deemed common equity ratio is appropriate for Westcoast.

The Board concluded that a 45% deemed common equity ratio is appropriate for TMPL.

Adjustment Mechanism and Re-examination of Cost of Capital Beyond 1995

The Board determined that an automatic mechanism to make yearly adjustments to the approved rate of return on common equity is appropriate. The Board's adjustment mechanism, to apply from 1996 onwards, has the following characteristics:

- the test-year bond yield forecast will be the average of the 3-months-out and 12-months-out 10-year Government of Canada forecast published in the previous year's November issue of Consensus Forecasts (Consensus Economics Inc., London, England) plus the actual 10-year to 30-year bond yield spread in October of that year;
- the change in forecast bond yields will be multiplied by a factor of 0.75 to arrive at the adjustment to the rate of return on common equity; and
- the adjusted rate of return on common equity will be rounded to the nearest 25 basis points.

The Board did not set any time limits or interest rate boundaries on the adjustment mechanism or the capital structures determined in this decision.

Chapter 1

Introduction

The Board began setting the cost of capital for the pipelines under its jurisdiction in 1973. Since that time, some pipelines have had their cost of capital reviewed regularly in the context of pipeline-specific toll proceedings. Other pipelines have only occasionally appeared before the Board for a cost of capital examination. This process has given rise to two concerns. Firstly, the Board has noted that evidence submitted by expert financial witnesses has tended to be much the same from one proceeding to the next. While the financial parameters change from year to year, the techniques and interpretations used in making rate of return on common equity recommendations typically do not. This led the Board to consider what potential economies could be realized from the implementation of a formulaic adjustment mechanism for rate of return on common equity.

Secondly, fluctuations in financial markets continue during and between hearings. Rates of return for one toll-making period, which rely on financial market data, can therefore vary across companies simply because different companies' rates of return are set at different times. In order to address this concern, the Board was attracted by the concept of a generic hearing where all pipeline companies would make their cases simultaneously using a consistent set of financial parameters.

On 17 March 1994, the Board issued Hearing Order RH-2-94 setting out its intention to hold a multi-pipeline cost of capital hearing. The Hearing Order directed eight of the Group 1 pipelines, [these pipelines were: Alberta Natural Gas Company Ltd ("ANG"), Foothills Pipe Lines Ltd. ("Foothills"), Interprovincial Pipe Line Inc. ("IPL"), TransCanada PipeLines Limited ("TransCanada"), Trans Mountain Pipe Line Company Ltd. ("TMPL"), Trans-Northern Pipeline Inc. ("TNPI"), Trans Québec & Maritimes Pipeline Inc. ("TQM"), and Westcoast Energy Inc. ("Westcoast")], to file submissions in respect of their cost of capital to be included in tolls commencing 1 January 1995. The Hearing Order indicated that the issues to be considered were, *inter alia*, the following:

- a) What is the appropriate capital structure for each of the pipelines being considered in this proceeding?
- b) What is the appropriate rate of return on common equity for each of the pipelines being considered in this proceeding? Should the same rate of return on common equity be awarded for all the pipelines?
- c) How often should the pipelines' cost of capital be reviewed? What are the specific factors that would trigger a subsequent review of the pipelines' cost of capital?
- d) Subsequent to these proceedings, what simplified procedure should be implemented to effect an annual adjustment to the rate of return applicable to the pipelines between cost of capital proceedings?

In setting this matter down for hearing, it was the Board's intention to put in place means of improving the efficacy of the toll setting process for the year 1995 and beyond. The Board expressed the desire to avoid annual hearings on the cost of capital and was of the view that some automatic mechanism to adjust the return on common equity could be the most appropriate way to ensure that this return continued to be fair to all parties, while avoiding the expense of litigating annual or

biennial changes in the rate of return. The Board therefore included as an issue in the RH-2-94 proceeding, the design and implementation of a predetermined adjustment mechanism to the rate of return on the common equity component. The Board's objective in this regard was to conduct detailed examinations of the pipelines' cost of capital only when significant changes had occurred in financial markets, business circumstances, or in general economic conditions. The Hearing Order also indicated that matters other than cost of capital would be addressed in the pipelines' individual toll proceedings.

The Hearing Order indicated that pipelines which presented an uncontested settlement acceptable to the Board two weeks prior to the commencement of the hearing, on either their capital structure or their rate of return on equity, would be exempted from having to deal with these matters in the proceeding. Pipelines exempted by virtue of a settlement could still participate as interested parties. On 17 May 1994, the Board held a Pre-Hearing Conference to address procedural matters relating to the oral portion of the hearing.

Prior to the beginning of the hearing, TNPI submitted a settlement which was set down to be spoken to at the commencement of the hearing. After hearing all parties who wished to be heard, the Board accepted the settlement and TNPI was exempted from further participation in the oral phase of the hearing as a pipeline subject to this proceeding. TNPI elected to retain intervenor status for the remainder of the proceeding.

The oral portion of this proceeding was divided into two phases. The first phase addressed the issue of the appropriate rate of return on equity for a benchmark pipeline as well as the matter of a simplified procedure to be implemented to effect an annual adjustment to the rate of return on equity applicable to the pipelines between cost of capital proceedings. The second phase addressed the pipeline-specific cost of capital issues including capital structure and rate of return on equity where a pipeline or intervenor asked for a rate of return on equity that was different from that of a benchmark pipeline. The oral portion of the hearing commenced in Calgary on 24 October 1994 and closed on 20 December 1994, a total of 29 hearing days.

On 1 February 1995, IPL and the Canadian Association of Petroleum Producers ("CAPP") jointly filed a letter requesting that the Board reserve its decision regarding IPL-specific issues pending the Board's review of a proposed multi-year toll settlement between IPL and its shippers. On 17 February, IPL submitted a multi-year toll settlement for approval by the Board.

On 3 March 1995, the Board discharged IPL from the RH-2-94 proceeding. As a result, cost of capital issues related to IPL were delegated to the RH-4-94 Hearing Panel.

Parties should note that, while the Board has evaluated all of the relevant evidence presented in this proceeding, it has chosen in this Decision to summarize the evidence and positions of the parties only to the extent necessary to explain how specific issues were addressed in the decision-making process.

Chapter 2

Rate of Return on Common Equity for the Benchmark Pipeline

2.1 Introduction

The concept of using a benchmark pipeline to determine the rate of return on common equity originated in the RH-2-94 Pre-Hearing Conference. In the context of this proceeding, a benchmark pipeline refers to a hypothetical utility whose overall investment risks are characteristic of a low-risk, high-grade regulated pipeline. The Board's objective was to determine an appropriate rate of return on common equity for a benchmark pipeline and use this as the standard for determining the rate of return on common equity for all of the pipelines subject to this proceeding.

The Board received evidence from six expert witness panels regarding the appropriate rate of return on common equity for a benchmark pipeline. Although the evidence on some aspects of this issue was more extensive than in the past, and some techniques were presented with greater sophistication, no new techniques beyond the comparable earnings, discounted cash flow ("DCF") and equity risk premium methods were advanced for the Board's consideration. A summary of the recommendations put forward by each of the expert witnesses is provided in Table 2-1. Further details on the key parameters used in arriving at each determination are set out in Appendix II.

Table 2-1
Summary of Recommendations on Fair Rate of Return on Common Equity
(%)

	TransCanada, Westcoast, Foothills & ANG	IPL & TMPL	TQM	CAPP	Ontario & IGUA	COFI/Methanex/ Cominco
Comparable Earnings						
Test Results	11.50-12.00	12.25-12.75	11.53	NA	10.65-11.15	NA
Weight	15	25	equal	NA	40	NA
Discounted Cash Flow						
Fair Rate of Return	12.25	12.50-12.90	10.81-12.56	10.33	9.40-10.75	NA
Weight	10	5	equal	50	20	NA
Equity Risk Premium						
Fair Rate of Return	13.10-13.70	13.30-14.00	13.35-13.98	10.28-10.39	10.20-11.65	11.00-11.50
Weight	75	70	equal	50	40	exclusive
Recommendation	13.00	13.00-13.50	13.00	10.50-11.00	10.75-11.25	11.00-11.50

2.2 Comparable Earnings Technique

Four of the six expert witness panels gave some weight to the comparable earnings technique. Dr. Sherwin and Ms. McShane, on behalf of TransCanada, Westcoast, Foothills and ANG, Dr. Morin, on behalf of TQM, and Dr. Evans, on behalf of IPL and TMPL, all supported the comparable earnings test in principle. Each of these panels, however, noted some shortcomings of this technique and, consequently, gave this test relatively less weight. The shortcomings included inherent weaknesses in the use of this technique, such as reliance on accounting rather than market data. Another shortcoming was the fact that the economic recession and continuing corporate restructuring have caused, and are likely to continue to cause Canadian industrial companies to experience depressed earnings, making the test's results unreliable. Dr. Cannon, on behalf of the Ministry of Environment and Energy for Ontario ("Ontario") and the Industrial Gas Users Association ("IGUA"), relied heavily on the results of the comparable earnings test since he viewed it as less susceptible to interest rate volatility.

The two remaining expert witness panels did not support or rely upon the comparable earnings methodology. Drs. Booth and Berkowitz, on behalf of CAPP, did not rely on the comparable earnings test since they viewed it as useful in providing only a broad macroeconomic check on the fair rate of return on common equity. They also suggested that the comparable earnings test is very sensitive to the sample selection screens. Dr. Waters, on behalf of Council of Forest Industries of British Columbia, Methanex Corporation and Cominco Ltd. ("COFI/Methanex/Cominco"), opposed the use of the comparable earnings test because he viewed accounting returns as an unsuitable basis for calculating investors' required rate of return on common equity.

2.3 Discounted Cash Flow Technique

The DCF test was given some weight by all witnesses except Dr. Waters. Dr. Morin and Drs. Booth and Berkowitz relied on the DCF test to a greater extent than other witnesses. In justifying the weight given to his DCF test, Dr. Morin stated that no one individual method provided an exclusive foolproof formula for determining a fair rate of return but each method provided useful evidence and facilitated the formulation of an informed judgment. Although Dr. Sherwin and Ms. McShane gave relatively little weight to their DCF test results, they utilized the DCF framework in one of their two equity risk premium tests.

While not questioning the theoretical underpinnings of the DCF model, several parties drew the Board's attention to practical limitations of applying the test to industry and utility data. For example, Dr. Sherwin and Ms. McShane pointed to the difficulty of estimating investors' expectations for dividend growth rates. Their concern was echoed by Dr. Waters who stated that it was doubtful that historical growth rates, as applied by most rate of return analysts, could play a meaningful role in cost of capital estimation at this time. Dr. Cannon expressed his concern over the DCF test's reliance on share price information. He stated that sometimes a utility's share price may be elevated or depressed by unreasonable expectations or fears, making the DCF test, in his view, an inappropriate guide for establishing a regulated rate of return.

2.4 Equity Risk Premium Technique

Most expert witnesses gave primary weight to the results of the equity risk premium test in recommending a fair rate of return on common equity for 1995. In forecasting long-term Government of Canada bond yields for 1995, witnesses had regard to the published forecasts of short and long-term interest rates for 1995, spot interest rates in Canada and the U.S., the state of the Canadian and U.S.

economies, the Canadian political situation, expected inflation and economic growth for 1995 and beyond and their own professional judgment. Based on these considerations, witnesses put forward long-term Government of Canada bond yield forecasts for 1995 ranging between 8.00 and 9.25%.

With the exception of Dr. Cannon, all witnesses revised their long-term bond yield forecasts upwards by 25 to 75 basis points, at the beginning of the hearing, as spot and forecast interest rates had moved higher. Dr. Cannon's forecasted long-term bond yield of 8.0 to 8.5% for 1995 was the lowest, while Dr. Morin's forecast of 9.25% was the highest. During the proceeding, Dr. Cannon was challenged about the appropriateness of relying on a long-term bond yield forecast of 8.0 to 8.5% given that, in the months preceding the hearing, spot and forecast interest rates had materially increased. Dr. Cannon took the view that nothing had changed in the financial markets to warrant an upward revision to his long-term bond yield forecast since the filing of his evidence. Dr. Sherwin and Ms. McShane and Dr. Evans relied on a forecasted long-term bond yield of 8.5 to 9.0% for 1995 (mid-point of 8.75%), while Dr. Waters and Drs. Booth and Berkowitz relied on a range of 8.25 to 8.75% (mid-point of 8.50%).

Risk premium estimates for the market as a whole varied in the range of 3.50 to 6.90%. The market risk premiums estimated by the intervenors' witnesses were lower than those of the pipelines' witnesses. One factor contributing to this variance was the fact that Dr. Cannon and Drs. Booth and Berkowitz reduced their historical market risk premiums by 80 to 125 basis points to account for a "purchasing power" or "maturity risk" premium which, in their view, is currently incorporated in the nominal long-term Canada bond yields. In their view, this premium is required by bond investors to account for unanticipated inflation which may affect their ultimate rate of return. Dr. Waters agreed with the concept in principle but did not explicitly make such an adjustment. The pipelines' witnesses did not share the view that such an adjustment was necessary. On the other hand, the pipelines' witnesses gave weight to U.S. market data which tend to increase their market risk premium.

There was little consensus amongst the parties on the relative risk of the benchmark pipeline vis-à-vis the market as a whole. Along with other risk factors, some experts relied on their own calculated betas. Others made use of published betas to estimate the relative risk of the benchmark utility. Some of the experts applied qualitative factors to adjust the market risk premium for the lower risk of utilities. As a result, the relative risk of the benchmark pipeline to the market as a whole was estimated in the range of 45 to 70%.

Some parties presented evidence to justify a financing flexibility allowance adjustment to the "bare-bones" cost of equity. The reasons given for the allowance included out-of-pocket issuance expenses, market pressure and market breaks. The recommended financing flexibility allowance adjustment ranged between 20 and 125 basis points. On the other hand, some of the witnesses argued that there was no need for an explicit adjustment for financing flexibility.

2.5 Views of the Board

The Board is persuaded that the 1990/1991 economic recession and continuing corporate restructuring in Canada may be adversely affecting corporate profitability. As a result, the comparable earnings test may be currently producing results which do not provide an appropriate basis for estimating a fair rate of return for the benchmark pipeline for 1995. The Board is of the view that, under different economic circumstances, the results of this test may be more useful but it assigns little weight to its results in this proceeding.

The Board agrees with the majority of expert witnesses that the DCF test is theoretically sound, but that its usefulness is limited because of certain practical difficulties. The Board shares the views of those who pointed out the difficulty of estimating investors' expected dividend growth rate under the recent and prevailing financial market conditions. The Board notes that Drs. Booth and Berkowitz appear to have taken the greatest amount of care in addressing the practical problems of the DCF test. Notwithstanding their diligence and the comprehensiveness of their DCF analysis, the Board has assigned little weight to the DCF test results in this proceeding primarily because of concerns relating to the lack of objective measurements of investor dividend growth expectations.

Given the problems associated with the application of the comparable earnings and DCF tests at this time, the Board has decided to give primary weight to the results of the equity risk premium test. In arriving at an appropriate long-term Government of Canada bond rate for 1995, the Board took into account short- and long-term spot interest rates and interest rate forecasts for 1995 published in the fall of 1994. In addition, the Board is of the view that inflationary expectations in the U.S. are likely to put upward pressure on U.S. interest rates. This, in turn, is likely to exert upward pressure on Canadian interest rates. Therefore, the Board is of the view that interest rates in Canada during 1995 may not come down to levels forecast by some parties in this proceeding. These considerations have led the Board to rely on the upper end of the recommended long-term Government of Canada bond yield forecast range, namely, 9.25% for 1995.

The Board is of the view that the equity risk premium for the market as a whole is 450 to 500 basis points. In arriving at this conclusion, the Board gives some weight to the concept of "purchasing power risk" or "maturity risk", but acknowledges that specific quantification of this factor is lacking. The Board gave relatively less weight to the U.S. equity risk premium data than to the equivalent Canadian data. After adjusting for the relatively lower risk of the benchmark pipeline and adding a modest allowance for financial flexibility (which includes flotation costs), the Board is of the view that a reasonable all-inclusive equity risk premium for the benchmark pipeline would be 300 basis points. When added to a long-term bond rate of 9.25%, the Board finds that the appropriate rate of return on common equity for the benchmark pipeline is 12.25%.

The Board is of the view that the rate of return on common equity for the benchmark pipeline is appropriate for all of the pipelines subject to this proceeding. The Board is cognizant of the linkage between the rate of return on common equity and the pipelines' capital structures and has determined that any risk differentials between the pipelines can best be accounted for through adjustments to the common equity ratios rather than by making company-specific adjustments to the benchmark pipeline's rate of return on common equity.

Decision

The Board approves a rate of return on common equity of 12.25% for each of the submitting pipelines who have not been otherwise discharged or exempted from this proceeding for the 1995 test year.

Chapter 3

Capital Structure

3.1 Introduction

A summary of existing, applied-for and recommended capital structures is shown in Table 3.1.

Table 3-1
Pipeline Common Equity Ratios
Existing, Applied-for and Recommended by Intervenors

	TransCanada	Westcoast	Foothills	ANG	TQM	IPL	TMPL
Existing							
Common	30%	35%	28%	30%	25%	45%	47.5%
Preferred	9.13%	2.28%	-	-	-	-	-
Applied-for							
Common	30%	35%	30-35%	35%	35%	45-50%	50%
Preferred	9.96%	1.61%	-	-	-	-	-
Recommended by Intervenors (Common)							
CAPP	28%	30%	25%	25%	25%	32%	35%
COFI/Methanex/Cominco	NA	25-28%	NA	NA	NA	NA	NA
Ontario	27%	35%	28%	30%	24%	NA	NA
IGUA	27%	NA	NA	NA	NA	NA	NA
ADOE	28%	30%	25%	30%	25%	32%	35%
Quebec	30%	NA	NA	NA	25%	NA	NA

The evidence on the appropriate capital structure which was filed by the pipelines subject to this proceeding and intervenors reflected the Board's filing requirements. The discussion centred around the various aspects of business risk, the need for financing flexibility and the issue of cross-subsidization.

3.2 Positions of the Pipelines

3.2.1 Gas Pipelines

The evidence from the gas pipelines indicated a consensus that the Western Canada Sedimentary Basin ("WCSB") is well endowed with natural gas resources and that it will prove to be a prolific supply basin well into the next century. The gas pipelines recognized that, in recent years, supply risks have not been a significant factor. However, some pipelines offered the view that the physical existence of an abundant resource does not necessarily imply that this potential supply will become available to them. Any assessment of the risk profile, they argued, must recognize the possibility of adverse fundamental changes in the political, regulatory and pricing environment and their potentially harmful effects on gas availability and access to supply.

The gas pipelines were also in general agreement that recent reductions in reserves to production ("R/P") ratios are not indicative of an imminent supply shortfall but, rather, reflect the fact that producers are no longer required to maintain excessive inventory. In the same context, TransCanada asserted that with the decline in the reserve life index, the cost of replacing produced gas is approaching the full-cycle cost which would tend to eliminate Canadian producers' competitive edge over most U.S. producers. Westcoast added that the supply cost advantage alone does not guarantee a dominance in the market, as Canadian gas faces a transportation cost disadvantage in getting to most U.S. markets.

TransCanada

TransCanada submitted that, while currently relatively low, its market risk continues to increase. The Company argued that the factors which contribute to that increase in risk are: the growing competitive pressures facing it and its shippers; its renewal policy; the deregulation of gas prices; and open access transportation.

TransCanada submitted that Canadian and U.S. gas markets are becoming increasingly more integrated and competitive. TransCanada noted that it can no longer be viewed as a monopoly with respect to deliveries to eastern Canadian markets since it faces increased competition from alternative pipelines and supplies, including U.S.-sourced supply. TransCanada pointed out that eastern Canadian local distribution companies ("LDCs") are diversifying their gas supply portfolios to include, in some cases, up to 30% U.S.-supplied gas and are proposing new pipeline facilities to connect their franchise areas with U.S. supply and storage facilities.

TransCanada argued that, in its export markets which have increased from 22% of total deliveries in 1985 to approximately 50% in 1994, U.S. gas pipelines have lower firm service tolls which they are further able to discount. In addition, the development of a secondary market for pipeline capacity in the U.S. will mean increased competition for Canadian pipelines and Canadian gas exporters. TransCanada noted that, in the U.S. Northeast, it assumes the risk of shipping gas to an electric generation market which is facing the risks associated with surplus generating capacity, retail wheeling, and the resulting buy-out or buy-down of the power purchase contracts by electric utilities.

In addition, TransCanada noted that while U.S. LDCs have pursued supply portfolio diversification away from traditional U.S. pipeline suppliers by importing Canadian-sourced gas, those diversifications have been largely completed and there is less interest in providing competition to U.S. suppliers (i.e. less interest in Canadian gas imports).

TransCanada submitted that the competitiveness of Canadian gas exports has been put at risk by such regulatory initiatives as incremental tolling, the California Public Utilities Commission's ("CPUC") cross-over ban on the systems of Pacific Gas Transmission ("PGT") and Pacific Gas & Electric ("PG&E") and coal seam subsidies. TransCanada indicated that implementation of Federal Energy Regulatory Commission ("FERC") Order 636 has meant that, instead of contracting with creditworthy downstream U.S. pipelines, it is dealing with replacement shippers who might not be as creditworthy, thus exposing TransCanada to additional risk.

In both its domestic and export markets, TransCanada noted that it faces increased competition from alternative fuels, notably fuel oil in dual-fired boiler applications, if and as the price of those fuels falls below the price of gas on a heat-content basis.

TransCanada pointed out that its existing renewal notice policy gives its shippers the right to evergreen expiring service agreements for a minimum term of one year upon six months' notice. TransCanada argued that while this policy minimizes the shippers' financial exposure and guarantees those shippers access to long-term service, it increases TransCanada's risk of capacity underutilization and cost under-recovery, both of which could result in higher tolls to the remaining shippers and reduce TransCanada's competitive position. TransCanada is forecasting that the average term of firm transportation contracts will fall from eight years in 1994 to four years by the year 2000.

TransCanada argued that, unlike many U.S. pipelines, it has only one supply basin to draw on given that the frontier basins are expected to remain beyond economic reach. While TransCanada relies on the WCSB, the basin is not captive to TransCanada and this poses some risk. Further, the resulting perception that Canadian gas may not be reliable may represent increased risk to TransCanada.

TransCanada submitted that it views the Board's method of regulation to be a fair one, particularly the use of deferral accounts. TransCanada believes that its current regulatory risk is acceptable. TransCanada is, however, of the view that the subject proceeding increases its risk since it may result in TransCanada earning a rate of return on common equity for a number of years which it deems inappropriate. TransCanada believes that the interest in alternate forms of regulation (incentive regulation), the lack of a definitive policy on negative salvage, and the continued challenges to its use of deferral accounts, exposes it to increased regulatory risk.

TransCanada viewed the Free Trade Agreement ("FTA") and the North American Free Trade Agreement ("NAFTA") as developments which should solidify the competitive environment in the North American energy market. TransCanada argued, however, that while these Agreements should provide counter measures against protectionist forces in both Canada and in the U.S., and against federal interference with competitive pricing, constraints imposed by state regulators can negatively affect the competitiveness of Canadian exports. TransCanada submitted that while these agreements enhance assurance that U.S. markets will remain open, they also provide unlimited opportunity for U.S. pipelines to compete in Eastern Canadian markets, thus putting TransCanada at greater risk.

Mr. Lackenbauer, on behalf of TransCanada, indicated that it is of paramount importance that TransCanada maintain a rating in the A category if it is to finance its capital program on reasonable terms. The ongoing financing needs of TransCanada's transmission operations and the degree to which its securities are already largely held by virtually all the major institutions in Canada, would mean that a credit rating of less than A would immediately increase the Company's cost of capital significantly. Mr. Lackenbauer stated that many Canadian institutional investors simply cannot buy debt with a rating below the A category. Of those that can buy BBB rated debt, their capacity to do so is significantly less than that which they have to purchase in the A category or above.

TransCanada emphasized the importance of maintaining its financing flexibility through an optimal capital structure which it believes to be 60% debt, 30% common equity and 10% preferred shares. TransCanada recognized that preferred shares are a more expensive form of financing than debt. However, TransCanada suggested that the replacement of preferred shares by debt is unacceptable.

Mr. Lackenbauer stated that the perception in financial markets is that TransCanada's business risks have not decreased in recent years. Accordingly, any reduction in TransCanada's deemed common equity ratio, given the current consolidated capital structure which provides ample equity to avoid cross-subsidization, would be viewed as a negative shift in the regulatory principles that have been consistently followed by the Board. From a market perspective, it would appear to be a clear case of "entrapment" of investors if the common equity ratio were decreased at this point.

Dr. Sherwin and Ms. McShane regard TransCanada's existing capital structure as bordering on sub-optimal. In their view, 30% common equity lies at an irreducible minimum level in light of the Company's rising business risks. Further, access to capital markets would be impaired in the event of a credit downgrading.

Westcoast

Westcoast stated that the operating and physical components were the most significant negative factors in its overall risk profile. Furthermore, Westcoast stated that any evaluation of its business risks must have particular regard to the fact that over half of its rate base is invested in raw gas transmission and processing facilities. The business risks associated with the ownership and operation of such facilities, particularly the operating and physical, forecasting and supply components, are clearly greater than those associated with the ownership and operation of residue gas transmission facilities alone.

Westcoast noted that it faces increased risk associated with: more stringent environmental regulation affecting the exploration and production of gas; the construction and operation of its pipeline and processing facilities; and the consumption of hydrocarbons. Westcoast further claimed that sections of its supply areas have recently been designated by the B.C. Government as potential wilderness areas. If all these areas were designated protected wilderness areas, 5 to 15 Tcf of undiscovered marketable gas could become inaccessible.

Westcoast indicated that its most significant regulatory and political risks relate to the fact that over 50% of its throughput is shipped to the export market. Westcoast argued that U.S. federal and state governments and regulators will make decisions which are in the best interests of the U.S. and not necessarily those of Canada and Westcoast.

Westcoast indicated that its export market is inherently riskier than its domestic market due to greater gas-on-gas competition. Westcoast explained that this competition is high because the export market has access to gas from the Rocky Mountain and San Juan basins via the Northwest Pipeline system, as well as increased access to Alberta-sourced gas via the PGT system. Westcoast argued that continued excess pipeline capacity to California will result in increased competition in the U.S. Pacific Northwest. In addition, Westcoast stated that the U.S. Pacific Northwest will continue to experience significant interfuel competition, particularly from fuel oil, if current low world oil prices continue.

In its domestic market, Westcoast faces increased competition from other supply sources and from other operators providing the gathering and transmission services directly to producers. Westcoast noted that BC Gas Utility Ltd. ("BC Gas") is continuing its efforts to diversify its gas supply portfolio

by increasing its reliance on Alberta and U.S.-sourced gas, thus by-passing Westcoast's raw gas transmission and processing facilities and, in part, its mainline facilities.

Westcoast noted that approximately one-third of the currently contracted firm service to the Huntingdon export point expires in 1996, with an additional one-third expiring in 1997. Westcoast submitted that the automatic renewal rights provisions in its tariff provides shippers with a perpetual renewal option while the risk of non-renewal falls on the remaining shippers and Westcoast. Westcoast pointed out that, based on current depreciation rates, the average economic life of its assets is approximately 45 years. In the absence of long-term service agreements with creditworthy shippers, Westcoast stated that it is exposed to the longer-term risk that gas markets will not exist to enable it to recover its cost of service. Westcoast expects, however, that in the absence of adverse economic, political and regulatory events, most of its transportation service agreements will be renewed.

Westcoast stated that it faces higher total business risks than TransCanada mainly because of the operating risks arising out of the physical differences between the two systems and its lack of market diversity.

Westcoast stated that the appropriateness of the 35% common equity ratio and the resulting capital structure can be assessed by reference to the fact that it has been able to access capital on reasonable terms. Westcoast suggested that the willingness of investors to provide capital is evidence that the deemed common equity ratio and the resulting capital structure is appropriate. In Dr. Sherwin's view, Westcoast's deemed common equity ratio of 35%, which was first approved by the Board in November 1980 and confirmed by the Board in April 1994, continues to be the minimum acceptable common equity component for Westcoast's utility operations.

In the Company's view, the preferred shares should not be removed from the capital structure until such time they are redeemed or retracted. Westcoast suggested that it is unlikely that it would further allocate preferred shares to utility operations given the hybrid nature of these financial instruments and its tax position.

With respect to the issue of cross-subsidization and the actual amount of equity available to support Westcoast's non-NEB-regulated utilities, Westcoast suggested that there are no grounds for concern. Due to the nature of Westcoast's business activities and corporate structure, consolidated financial statements do not meaningfully depict the economic and financial realities underlying Westcoast's corporate activities and financial position. The non-consolidated financial statements, which reflect Westcoast's investment in its subsidiaries and the debt for which Westcoast is liable, more appropriately reflect the economic and legal obligations of Westcoast. Accordingly, Westcoast concluded that no cross-subsidization of its other investments by its NEB-regulated utility activities is taking place.

Foothills

Foothills stated that 90% of the gas shipped on its system is delivered to the highly competitive U.S. Midwest, U.S. Pacific Northwest and California export markets.

Foothills noted that its export markets are short-term or spot in nature, and are subject to competition from other gas sources, from alternative fuels and from other pipelines. Foothills also indicated that the ability of its shippers to move beyond those market areas, particularly beyond the U.S. Midwest, is constrained by Foothills' relatively high tolls and the operational complexity associated with delivering gas through a series of other pipelines.

Foothills submitted that in the U.S. Midwest market, total pipeline capacity utilization is not expected to exceed 60% over the next three to five years due to relatively weak demand growth which will, in turn, result in weaker gas prices and increased competition. With respect to the California market, Foothills suggested that its shippers will continue to be exposed to the risks associated with excess pipeline capacity and the low load factors of competing pipelines serving that market.

Foothills indicated that it is exposed to the risk associated with the fact that 82% of its transportation service contracts expire between 2001 and 2004. For its system as a whole, those firm contracts cover only 36% of Foothills' remaining investment. Under Foothills' tariff, shippers have the automatic right to renew those contracts for a one-year term upon six months' notice. Foothills argued that those contracts should not be viewed as being long term given that its assets are being depreciated over 33 years. Foothills similarly argued that, given the market's trend towards short-term arrangements, there is no assurance that its shippers will continue to serve the aforementioned markets over the medium and long terms.

Foothills asserted that, despite abundant resources in the WCSB, it faces a long-term risk related to gas supply. In a deregulated market, Foothills stated that pipelines with the highest-value markets and lowest costs will be more successful in retaining their gas supply.

Foothills stated that because of its strong reliance on export markets, it is exposed to a high degree of regulatory and political risk. Foothills cited the gas sales contract between Pan-Alberta Gas Ltd. ("Pan-Alberta") and Pacific Interstate Transmission Company ("PITCO") as an example of such risks. This contract is being restructured as a result of the intervention of the CPUC and this could result in a significant reduction in the Pan-Alberta to PITCO sales contract volumes.

Foothills submitted that it faces greater market risk than TransCanada. Specifically, Foothills noted that it has fewer long-term sales contracts supporting its transportation service contracts than TransCanada and that it is essentially an export pipeline. Foothills believes that its U.S. Midwest and California markets face greater pipeline-on-pipeline and gas-on-gas competition than TransCanada faces in its U.S. Northeast markets. Foothills noted that its relatively high transportation costs make it less competitive than other pipelines serving that market. The Company added that it is at greater risk than TransCanada because it operates as a single looped pipeline.

Foothills pointed out that various FERC orders, including FERC Order 636, have resulted in the restructuring and renegotiation of the original contractual arrangements underpinning the Prebuild financing. The result is that the significant initial credit support no longer exists.

In light of its requirements for outside financing, Foothills claimed that it requires the flexibility to finance its operations in public debt markets so that it is not limited to the requirements and restrictions of commercial bank financing. In addition, Foothills suggested that it should have the same flexibility that other pipelines have to finance its pipeline investments with long-term debt. According to Foothills, the risk profile of its business, reflected in the numerous contract restructurings, has precluded it from refinancing its bank indebtedness in the Canadian bond market.

Ms. McLeod, on behalf of Foothills, stated that credit markets impose certain standards of financial integrity on all borrowers. In Canada, the standard imposed by the credit market participants is, according to Ms. McLeod, the equivalent of a senior debt rating in at least the A rating category from the Canadian Bond Rating Service Limited ("CBRS") and the Dominion Bond Rating Service Limited ("DBRS").

ANG

ANG stated that market and regulatory factors are the two key facets of its business risk. On balance, ANG's lack of diversity of markets and the high competitive and regulatory risks of the California market render ANG's business risks higher than those of TransCanada.

ANG indicated that 5% of its throughput is shipped to the B.C. domestic market and 95% for export, notably to California (80%) and the U.S. Pacific Northwest (15%). ANG noted that while those export markets have experienced growth in recent years, exporters are facing increased gas-on-gas and inter-fuel competition and are having to deal with the consequences of new environmental legislation and the availability of hydro electricity.

Excess pipeline capacity into ANG's export markets is estimated to be 300 MMcfd in the U.S. Pacific Northwest and 1,700 MMcfd in California. ANG added that, while the combined ANG and PGT toll is competitive, U.S. gas pipelines have resorted to rate discounting in an effort to maintain throughput and high load factors.

ANG indicated that, as a result of the dismantling of the corporate affiliations and contractual relationships between Alberta & Southern Gas Company ("A&S") and PG&E, some of the ANG transportation held by A&S was assigned to others. However, most of that capacity remains either unassigned or under-utilized.

ANG noted that its transportation service agreements, which were previously supported by long-term gas sales contracts with very secure gas purchasers (90% of ANG's shipments were by A&S for sale to PG&E), are now supported by shippers and gas purchasers who are less creditworthy and who do not have long-term supply and market arrangements. ANG added that the number of shippers on its system has increased from three to 38 as a result of the A&S contract restructuring and ANG's 1993 expansion. ANG concluded that this restructuring has resulted in less certainty that its facilities will be utilized and the associated demand charges paid.

ANG argued that its other businesses are cross-subsidizing its pipeline business. It asserted that tollpayers receive the benefit of ANG's consolidated debt rating without paying the cost associated with a capital structure which would have permitted the pipeline to have achieved the same cost of debt on a stand-alone basis. ANG raised \$110 million in 10-year unsecured debentures at a spread of 105 basis points over long-term Canada bonds. On a stand-alone basis, at a 70% debt ratio and with interest coverage ratios well below two times, the interest cost to ANG would likely have been no less than that achievable by a utility with a BBB rating, or a spread over long-term Canada bonds of 125 to 150 basis points. ANG argued that its capital structure should be altered to reflect the pipeline's business risk profile, its size, its tax position and interest coverage considerations on a stand-alone basis. In ANG's view, failure to do so would be equivalent to an endorsement of reverse cross-subsidization.

ANG noted that approximately 10% of TransCanada's capital structure consists of preferred shares, which raises its total equity component over the 30% deemed by the Board.

TQM

Dr. Morin stated that the two significant factors affecting the viability of TQM are increased political risk and increased competition from alternate energy sources.

TQM noted that it serves a comparatively undiversified service territory which has: limited market growth potential; faces intense competition from fuel oil and electricity; and which includes a volatile industrial customer base. TQM estimated that approximately 28.7 Bcf of gas, or 25% of its current throughput, could be displaced by oil and electricity. TQM, which supplies more than 50% of the gas consumed in Quebec, indicated that it has recently experienced lower pipeline throughput due to a poor economic climate and an increase in the price of gas relative to oil.

TQM stated that its future revenues are largely dependent on La Société en commandite Gaz Métropolitain ("Gaz Métropolitain") sales which are concentrated among large-volume, industrial customers tied to the volatile natural resources and commodity economy, namely: metals; pulp and paper; chemical; and manufacturing. TQM noted that these industries have also been vulnerable to plant closures and downsizings and to high gas prices associated with high transportation tolls on the TransCanada and TQM systems.

TQM stated that, being located the furthest from the Alberta natural gas supply source, the Quebec market is encouraged to look at other possible gas supplies and, consequently, other gas supply routes.

TQM, while acknowledging that it generally enjoys fair and reasonable regulatory treatment and that its regulatory risk is, therefore, considered average, submitted that its regulatory risks have increased as a result of deregulation (e.g. gas price deregulation) and greater competition in gas transmission and distribution.

TQM submitted that the political and constitutional uncertainty in Quebec adds to its investment risk. TQM argued that the separation of Quebec could mean the end of the Board's jurisdiction over TQM and result in increasing pressure to set aside the Board's previous decisions regarding TQM's tolls.

Dr. Morin stated that it is important that TQM's common equity ratio be increased from its "anemic" level of 25% in order to preserve flexibility in accessing capital markets on favourable terms. Dr. Morin considers a common equity ratio of 35% to be more reflective of the Company's risk and more beneficial to both the Company and its ratepayers in the long-term.

Based on a comparison of their relative bond ratings, size, interest coverage, common equity ratio, and rate base growth, TQM stated it has higher overall risks than TransCanada.

3.2.2 Oil Pipelines

Dr. Evans indicated that the Board should not adopt CAPP's theory of business risks because the risks associated with the construction and operation of pipeline facilities fall on those who have financed the facilities and whose capital is exposed to the risk of non-recovery or non-compensatory rates of return. Dr. Evans stated that the actions of capital market participants are not consistent with acceptance of the theory that pipeline risks are either diverted or removed entirely.

Dr. Evans indicated that CAPP recommended substantial reductions in the common equity ratios of IPL and TMPL which would sharply increase the financial risks to which these pipelines are exposed and which would increase the investors' required rates of return on common equity.

The oil pipelines expressed a cautious view on oil reserves and the prospective supply outlook. TMPL claimed that crude oil pipelines face an inevitable long term decline in remaining conventional oil reserves from the WCSB. This decline, according to TMPL, will be only partially offset by increased

production of high cost synthetic oil and bitumen. In the same vein, IPL observed that its supply risks are now higher than in the 1980s mainly due to the decline in conventional oil reserves in the WCSB.

IPL

IPL identified its primary market risks as: transportation options in origin and destination markets; refinery rationalization; economic activity; conservation; and competition from alternative forms of energy and alternative sources of petroleum.

IPL stated that it faces little competition for deliveries to the Prairie provinces, which account for 13% of its total deliveries. All of the other major centres to which IPL delivers, except Ontario and Buffalo, receive crude oil from other pipelines. In most of these markets, excess incoming pipeline capacity has developed. Most notably in Montreal, Detroit and Toledo, IPL's share of deliveries has dropped significantly over the past 14 years. In Buffalo, IPL's share of the crude oil market remains unchanged at 100% but the size of the crude oil market has fallen 60% due to deliveries from refined products pipelines. In all of IPL's destination markets, the possibility of increased pipeline capacity from other sources threatens IPL's future deliveries. According to IPL, this threat translates into increased competitive risks.

IPL expressed concern that there may come a time when it will not be able to offset revenue losses from declining throughput by raising its tariffs. IPL tried to reflect this risk in its depreciation study but, according to the Company, there are other forecasts that indicate far less supply than was assumed by IPL in estimating the 2020 truncation date. IPL also disputed its alleged monopoly position by stating that it accounts for only 75% of total WCSB oil exports and that there are other pipelines (e.g. TMPL, Rangeland Pipeline Company, Wascana Pipeline Incorporated) delivering crude oil from western Canada to U.S. markets.

IPL identified three factors relating to supply risks, namely, production forecast risks, the long-term production decline, and changes in the product slate.

IPL suggested that it faces political risk due to the reliance of its shippers on export sales of crude oil to the U.S. midwest markets. This risk stems from potential political interference in the supply and demand for crude oil, both domestically and internationally.

Because of regulatory lag, IPL may over-recover or under-recover its costs and allowed rate of return. IPL stated that its ability to reset tolls, via a Class 1, 2 or 3 application or under the 2% trigger mechanism, does not eliminate all risks because the reset tolls are based on a new forecast of throughput and costs. IPL is of the view that the uncertainty it faces in forecasting throughput and costs is not significantly reduced by the method of regulation.

With respect to the issue of cross-subsidization, IPL argued that the common equity available to support the NEB-regulated pipeline reflects actual dollars of common equity invested and not an allocation of equity dollars within a consolidated enterprise.

IPL requested the Board to approve a common equity ratio range of 45 to 50% within which its actual common equity ratio would fluctuate in the years between comprehensive reviews of rate of return and capital structure. Dr. Evans stated that the 45 to 50% range is consistent with the business risks to which IPL is exposed.

TMPL

TMPL indicated that: its business risks have increased since the 1980s; are greater than natural gas pipelines' business risks; are greater than those of IPL; are less than the business risks of TNPI; and are less than those of average unregulated companies. Regarding its market risks, TMPL stated that it faces competition from other transportation modes such as tanker, barge and rail. These alternate modes may transport supplies from the same sources as TMPL or from other sources. In addition, TMPL indicated that these alternate modes do not present shippers with product quality risks.

According to TMPL, the Vancouver market is the most complex of its markets because of the number and types of commodities shipped there, each of which has its own alternative source of supply and means of transportation. This market has been transformed from a primary market for western Canadian crude oil to the swing market for western Canadian refined products. Since two of the refineries closed in 1993, total crude oil deliveries to Vancouver on TMPL have dropped by 17% and a strong export market in refined products has been replaced by increasing product imports.

TMPL stated that its short-term risks are most apparent in relation to the movement of refined products to Vancouver. If there is a refinery upset or a product supply shortfall in Edmonton, shippers will tend to divert the available supply to the landlocked markets while supplying the Vancouver market with marine imports.

The Kamloops market also faces the risks of supply disruptions at the Edmonton refineries which can lower TMPL's delivery volumes. The Kamloops terminals lack the clean-up processing facilities that are available at the Vancouver terminals and, as a result, during the past three summers, shippers transported certain products from Edmonton by rail instead of pipeline.

TMPL stated that exports via the Westridge terminal are affected by the competitiveness of the global oil market. Exports of Canadian crude oil will only be made on a spot basis when better netbacks from traditional markets are not available.

TMPL stated that the B.C. Government is considering the adoption of California's reformulated gasoline specifications. Should this occur, TMPL's risk is considerable if the Edmonton refiners are not configured to produce this quality of gasoline.

With respect to the Washington market, the primary risk relates to the continued competitiveness of Canadian crude oil in relation to Alaska North Slope ("ANS") and offshore sources of supply. The four major refineries located in Washington State which are connected to TMPL are all on tidewater and can source their crude supplies by tanker from virtually anywhere.

TMPL suggested that it faces regulatory risks through its depreciation rates and negative salvage liabilities. Although the regulatory method may be considered just and reasonable at this time, the risk exists that the regulatory regime will change before investments can be recovered. TMPL stated that it faces regulatory risks arising from this proceeding including the frequency of review of the capital structure and ROE, the possibility of a rate of return adjustment mechanism and the implications of these issues for the existing toll adjustment procedures.

According to TMPL, there is no guarantee that, under the current method of regulation, the Company will be able to recover its capital costs in the long run. If market conditions are such that products are not shipped, capital will not be recovered, regardless of the regulatory regime.

TMPL discussed relative risks between oil and gas pipelines and concluded that they are greater for oil pipelines due to such factors as: an earlier projected decline in WCSB supply; greater influence of international factors on supply and prices; vulnerability to refinery closures; greater environmental scrutiny; and the lack of long term transportation contracts or demand charges.

TMPL indicated that its equity base supports the borrowing capacity of the Company allowing the raising of funds by way of debt securities. The size of the equity base is a factor that investors and rating agencies take into account in assessing the security of a company in terms of providing interest coverages which meet the criteria of credit rating agencies. As it is, TMPL does not greatly exceed the key benchmark criteria of \$100 million in equity. Furthermore, TMPL is not a frequent issuer of long-term securities and thus does not have the name recognition of some of the larger utilities.

3.3 Positions of Intervenor

3.3.1 CAPP

In formulating its position, CAPP put forth a two-pronged analysis. The first step consisted of categorizing the various business risks identified by the parties subject to this proceeding in a way which permitted, according to CAPP, a more fundamental analysis of these risks. The second prong of CAPP's dual approach focused on the evolution of the industry and the regulatory environment over time.

CAPP was of the view that the positions presented by the pipelines failed to acknowledge and address the implications and consequences of the existing regulatory and commodity market mechanisms. Based on its conceptual analytical framework, CAPP concluded that the pipelines are shielded from exposure to risks by the regulatory process. Commodity market risk is borne separately by commodity market participants. CAPP concluded that the pipelines are not subject to any meaningful degree of business risks and that, short of an unforeseen and unlikely catastrophic event, the pipelines face no serious risks with respect to the return of and on capital.

It is only for any remaining risks that the pipelines should therefore be compensated. In CAPP's view, these risks are minimal, either because of the remote likelihood of occurrence or because of the small impact they would have on the long-term ability of the pipelines to recover a rate of return of and on capital invested.

In the second part of its analysis, CAPP noted that, as the industry has moved from an administered pricing regime to a deregulated market, there have been gradual changes in many factors which, considered cumulatively, have significantly reduced pipeline business risks. CAPP stated that pipelines are considerably less risky today than they were when their present capital structures were first established. CAPP noted that these changes have yet to be acknowledged in regulatory decisions through downward adjustments to the awarded levels of common equity.

When comparing the business risks of oil pipelines and gas pipelines, CAPP noted that there are no compelling reasons for maintaining the existing significant differential between the deemed equity ratios for the two groups. CAPP suggested that the wide gap has its roots in the historical ownership and evolution of these systems.

With respect to its views on access to capital, CAPP noted that pipeline companies have some flexibility in timing projects and in timing their approach to capital markets. Pipelines have the opportunity to make shorter term financing arrangements if market conditions for the funding of long-term debt are unfavourable at any time. Further, the regulated character of the pipelines gives them the opportunity to seek regulatory relief if prevailing financial market conditions are unfavourable.

According to Drs. Booth and Berkowitz, the requirements for financing flexibility and access to capital markets essentially means that the regulated utility's debt should be rated at least at the investment grade of BBB or better. Therefore, they would recommend that the pipelines increase the use of debt since they have, in general, higher debt ratings than required to maintain their financial integrity.

CAPP suggested that adoption of its recommendations would not result in the pipelines being denied reasonable access to capital markets at reasonable cost. CAPP stated that any potential increase in debt cost will be more than offset by the decrease in the cost of equity. Mr. Cantwell, on behalf of CAPP, indicated that CAPP's recommendations may result in a minor downgrading (one notch) for each of the pipeline companies. Mr. Cantwell stated that in no case would such a downgrade result in ratings which are below investment grade or ratings which would deny the pipeline companies access to the Canadian or U.S. capital markets.

Furthermore, Drs. Booth and Berkowitz stated that, under current market conditions, it is unlikely that a change in bond rating, even should it occur, will have any impact on access to capital. In their view, the cost of debt is determined in the capital market by the normal interaction of supply and demand.

Drs. Booth and Berkowitz noted that preferred shares may have a role to play in the financing of regulated utilities. For those companies which have reached their maximum amount of debt financing, the use of preferred shares is preferable to the use of common equity.

With respect to the level of equity available to underpin the non-NEB-regulated assets of the regulated pipelines, CAPP stated that in the case of Westcoast and IPL, there appears to be explicit subsidization as the non-regulated businesses appear to have substantially lower common equity ratios than their respective regulated businesses.

Gas Pipelines

According to CAPP, no meaningful position has been put forth which challenges the availability of substantial gas reserves from the WCSB. CAPP added that the NEB's estimates of ultimate gas potential increased in each of its last six studies, while the estimates of remaining reserves have remained relatively stable. Based on the NEB's latest supply projections, CAPP concluded that the subject pipelines will be utilized at reasonable levels for their respective economic lives, and that the existing infrastructure may even be insufficient to support the level of demand forecast to the year 2010. According to CAPP, several pipelines have provided evidence on the ample supply of gas from the WCSB in support of recent facilities applications.

CAPP cited the substantial growth in Canadian gas exports and the shippers' willingness to commit to significant new pipeline expansions as evidence of the Canadian gas industry's ability and willingness to successfully compete for gas markets in a deregulated environment. In addition, CAPP stated that the pipelines' market risk has been reduced by: deregulation in Canada which has led to the adoption

of market-oriented surplus procedures; deregulation in the U.S. which has culminated in the issuance of FERC Order 636; and the FTA and the NAFTA, which have removed political barriers to trade.

CAPP submitted that the gas pipelines' risks have been reduced by: the inclusion of rate base expansions in rolled-in tolls; the use of the Straight Fixed Variable toll design ("SFV"); the use of diversions and assignments and other means to ensure higher load factors; and the advent of a secondary market for pipeline capacity.

TransCanada

CAPP argued that TransCanada's transportation services are exposed to little competition given: the lack of surplus take-away capacity; the fact that the design of the NOVA system constrains switching between pipelines; the absence of real alternatives to TransCanada's services (which suggests that its short-term service shippers will renew rather than contract with alternate pipelines); and in the diversity of shippers brought about by the new market environment (which has had the effect of reducing the risk of default and non-renewal).

Furthermore, Canadian producers are captive to the pipelines serving the WCSB. Alternative or new pipeline capacity is only available on the basis of a commitment to long-term service agreements, and TransCanada's domestic customers will continue to make only limited use of their access to U.S. transportation and supply due to foreign exchange factors, the complexity of upstream transportation arrangements and the competitiveness of Canadian supply and transportation systems serving domestic markets.

CAPP pointed out that TransCanada acknowledged in its GH-2-94 evidence that the combination of WCSB supply costs and its transportation rates would ensure that TransCanada's system will remain utilized at a reasonable level over the long term.

Westcoast

CAPP argued that Westcoast's market risks are low given its solid and secure shipper and producer base in all four zones. CAPP noted that despite Westcoast's view that it faces increased market risk, B.C. producers continue to seek market access and are willing to support significant facility expansions by executing long-term service agreements. In addition, CAPP suggested that domestic gas deliveries off the Westcoast system will be the preferred supply option over U.S. imports. It added that, while the U.S. Pacific Northwest has become somewhat more competitive, B.C. producers have a transportation advantage over deliveries off the Northwest system. CAPP was confident that B.C. producers would continue to respond to any increased competition.

CAPP quoted a report by the investment firm Smith Barney Shearson, which claimed that the most prolific discoveries in North America are taking place in B.C. where sophisticated exploration is only in the beginning stages, compared with such regions as the southwestern U.S. and Alberta. Westcoast's position as the largest processing and transmission company in B.C. makes it one of the primary beneficiaries of the prolific reserves.

CAPP contended that Westcoast benefits from projects like the Company's proposed Fort St. John and Grizzly Valley Expansion projects in that these will increase the flexibility and diversity of Westcoast's system thereby reducing operating risks.

Foothills

CAPP argued that Foothills has experienced significant transportation service cost reductions and that it is, therefore, well positioned to provide competitive transportation services. CAPP noted that Foothills' Eastern and Western Legs continue to operate at high load factors. CAPP submitted that the cost of service toll methodology continues to allow Foothills to earn its approved rate of rate of return and that the regulatory mechanisms in place shield Foothills from any significant business risks.

Drs. Booth and Berkowitz indicated that Foothills may require improved market access because of the very large amount of refinancing required to convert the syndicated bank financing to traditional bond financing. They suggested that if their proposed capital structure made accessing the bond market difficult, preferred shares could be used in place of some debt, but only on a temporary basis.

ANG

CAPP noted that ANG continues to operate on the basis of 15- and 30-year transportation service contracts with creditworthy shippers, and that the original transportation service agreements formerly held with A&S have been assumed by new shippers for the full 12 years remaining in their term. CAPP also noted that ANG's load factors have steadily improved.

CAPP disagreed with ANG's assessment of the impact of decontracting by pointing out that the Company sought NEB approval for expanded facilities on the basis of unconditional, long-term firm transportation service contracts. No mention was made at that time of any resulting increases in business risk that would warrant a higher deemed equity ratio.

TQM

With respect to TQM's political and regulatory risk, CAPP suggested that, regardless of the political outcome and who ultimately has jurisdiction over TQM, the industry will find a way to compete in Quebec given the importance of this market. However, CAPP assigned a very low probability to the Board changing TQM's regulatory treatment. CAPP submitted that Quebec's political risk is borne by the entire country and that it has existed for some time. CAPP also pointed out that expert witnesses were unanimous in their opinion that the current interest rates already reflect the perceived riskiness associated with the political uncertainty in Quebec.

Oil Pipelines

CAPP stated that access to the U.S. crude oil market is now more secure as a consequence of the FTA. The FTA has: eliminated the potential for crude oil import taxes in the future; provided security for exports; provided protection against disruption of traditional channels of supply; and constrains the United States' use of the national security power as an instrument of U.S. energy policy.

CAPP noted that both IPL and TMPL cite competition in destination markets as increasing business risks. According to CAPP, these pipelines provide the sole link to their respective markets for western Canadian crude oil. Canadian crude oil producers are price takers and have demonstrated an ability to successfully compete in these markets at international prices, adjusted for transportation costs.

CAPP submitted that both IPL and TMPL have recently completed significant expansions which would indicate that Canadian crude oil can, and does, successfully compete in the oil pipelines' respective markets.

CAPP's review of the reserves' estimates of the NEB and the Alberta Energy Resources Conservation Board as well as its own estimates, led to the conclusion that there are substantial volumes of oil reserves to support the existing pipeline infrastructure for the foreseeable future. CAPP maintained that oil supply risks are not a matter of serious dispute, and that this view is corroborated by the pipelines' evidence submitted for recent expansion hearings. These projections imply that IPL and TMPL will continue to be utilized well beyond their current truncation dates.

IPL

CAPP argued that the throughput level on IPL has been totally indifferent to the price of crude oil in spite of IPL asserting that fluctuations in crude prices determine if western Canadian crude oil would be the preferred source of crude by the market. In light of IPL's assertion that the level of crude shipped on its system was a function of refinery demand, CAPP stated that IPL's system has been at capacity notwithstanding the extensive refinery rationalization, which has occurred over a number of years.

High utilization of IPL is currently ensured because it is connected to the best markets for Canadian crude and because the capacities of other Canadian crude oil pipelines are relatively small. Furthermore, IPL bears no financial consequences of reduced supply as long as this is built into its forecast. Even if it is not, IPL can request a Class 1 adjustment when its rate of return on common equity falls more than 2% below the approved level. As for the possible change of the crude oil slate, CAPP demonstrated that it could lead to either under-earning or over-earning. IPL could ask for a toll adjustment if a heavier crude oil slate were to put its rate of return in jeopardy beyond the 2% trigger.

TMPL

CAPP disagreed with TMPL that the change in product mix, the increased reliance on Edmonton refineries and exposure to imports has increased TMPL's risks. The regulatory policies of the NEB protect against these risks by basing tolls on projected throughput, not pipeline capacity.

According to CAPP, TMPL ignored the fact that diversification has allowed the Company to achieve significant growth in rate base, one result being that it is very attractive from an investor's point of view.

CAPP indicated that TMPL has been able to respond to changing market conditions by transporting a variety of products. CAPP stated that TMPL may be exposed to some level of inter-modal competition but that TMPL is essentially a monopoly with respect to the delivery of western Canadian crude oil to the B.C. Lower Mainland and the export markets which it accesses.

CAPP presented a CBRS report which expressed an expectation that TMPL will continue expanding in view of renewed activity in the western Canadian petroleum sector and increased transportation demand from Alberta producers. With respect to TMPL's lower netbacks, CAPP argued that the price of ANS crude is expected to increase with falling Alaskan production, making the Washington State netbacks at least as attractive as those from the U.S. Midwest for Alberta shippers.

3.3.2 COFI/Methanex/Cominco

COFI/Methanex/Cominco's evidence pertained exclusively to Westcoast in the capital structure phase of this hearing. COFI/Methanex/Cominco disputed Westcoast's position that its market risks are significant and argued that whatever risks exist are borne by its shippers and customers and not by

Westcoast. COFI/Methanex/Cominco likewise disputed Westcoast's position that it is exposed to significant risk associated with the number of short-term service agreements because the economics of supply and demand underpinning those service agreements are solid, thus ensuring that the agreements will be renewed.

Dr. Waters, in discussing Westcoast's supply risk, quoted from the Company's 1993 Annual Report. The report stated that gas supply is very robust, particularly in northeastern B.C. which currently has some seven Tcf of established reserves and up to 50 Tcf of ultimate potential reserves. The area is recognized as having some of the largest reserves and highest deliverability per well on the continent. The same report also suggested that the possibility of increased gas deliveries to the east is an opportunity rather than a risk as it would allow greater diversification of Westcoast's gas processing operations and of its markets.

COFI/Methanex/Cominco stated that just and reasonable tolls are typically viewed as tolls which enable a utility to recover its costs, inclusive of a fair rate of return on invested capital. If, in fact, a utility can operate effectively with a lower proportion of common equity, which is the highest-cost form of financing, that ability should be reflected in the rates it charges and not used to enhance shareholder's rates of return. COFI/Methanex/Cominco stated that Westcoast's management must consider the investment risks resulting from a projected common equity ratio in the order of 25% to be acceptable and as not jeopardizing the financial viability of Westcoast Energy Inc., the consolidated entity. COFI/Methanex/Cominco concluded that an equivalent common equity ratio for Westcoast would not result in its investment risks exceeding those of the remainder of Westcoast Energy Inc. Accordingly, it argued that Westcoast's deemed common equity ratio should be lowered. Dr. Waters indicated that his recommended capital structure should not result in a lower debt rating than the current rating.

3.3.3 Ontario/IGUA

Ontario and IGUA co-sponsored Dr. Cannon's evidence for the capital structure phase of this proceeding. Dr. Cannon presented a financial model, described in Section 3.4, which estimated the pipelines' appropriate capital structure.

3.3.4 Other Intervenors

ADOE

The Alberta Department of Energy ("ADOE") argued that TransCanada's overall market risk has declined since deregulation and that the Company enjoys a healthy domestic and export business.

ADOE argued that Foothills' market risk has been reduced by an increase in the number of shippers since these shippers serve more diverse markets. While it concurred that the markets served by Foothills' shippers are underpinned by short-term market arrangements, ADOE argued that the markets themselves are long term and that Foothills' facilities are not at risk of underutilization. ADOE maintained that, while Foothills is subject to some risk because it is an unlooped system, the overall risks are no greater than the risks of the other pipeline systems because they are mitigated by provisions in Foothills' tariff.

ADOE indicated that, with respect to IPL, Canadian producers have no other market options with comparable netbacks and they will, therefore, accept price discounts to displace competing crude supplies and maintain market share in the premium U.S. markets, which IPL serves.

ADOE argued that other transportation services pose no meaningful risk to TMPL's long-term viability. These transportation modes do not constitute a viable economic alternative to TMPL's facilities. In reality, these alternatives are basically "relief valves" used to provide a transportation outlet when disruptions in supply or pipeline operations are encountered.

Quebec

Le Procureur général du Québec ("Quebec") argued that TransCanada's supply risk is minimal. With regard to the risk of a decline in throughput and the resulting increase in tolls, Quebec suggested that the method of regulation currently in place protects the pipelines because shippers are ultimately responsible for the tolls. Quebec added that it did not expect a change in regulation and that there was no point in speculating on alternative regulatory methods.

Quebec argued that it is still too early to draw conclusions on the evolution of TransCanada's long-term business risk given the recent structural changes in gas markets. Quebec also indicated that TransCanada's financial risk is minimal.

With regard to TQM, Quebec suggested that the competitiveness of natural gas in the province of Quebec depends on many factors, one of which is the reasonableness of TQM's tolls. Quebec doubted that an increase in the common equity ratio would translate into an increase in the competitiveness of natural gas in the province. In light of a 37% increase in throughput between 1989 and 1993 and considering the recently-approved crossing of the St. Lawrence River expansion project, Quebec did not agree with TQM's pessimistic view regarding the province's natural gas market. Quebec stated that TQM benefits from a stable regulatory environment which is likely to endure.

Finally, Quebec stated that it is not appropriate to speculate about provincial political events and asked that the Board not take this factor into account in its deliberations.

3.4 Relationship between Capital Structure and Cost of Capital

In response to a filing requirement for this proceeding, several parties submitted evidence on the relationship between capital structure and the cost of capital.

Dr. Sherwin and Ms. McShane indicated that, since Canadian regulators have mandated capital structures that are reasonably close to optimal, and since there are few publicly traded utility stocks, there is no Canadian data base for empirical quantification of the impact of changing capital structures on the cost of capital. Accordingly, this forces reliance on theoretical finance models.

Dr. Sherwin and Ms. McShane concluded that the finance models, even when adapted to the real world of Canadian utility regulation, cannot provide the basis for determining a pipeline's optimal capital structure. The models can, however, test the impact of variables such as: the use of preferred stock; alternative effective income tax rates; and degrees of leverage on the total cost of capital and, hence, the tolls. Their studies suggest that, in an increasingly competitive environment, there should be a shift in the focus of rate of return regulation towards setting an optimal capital structure within a range. For the four gas pipelines (excluding TQM), it is their view that the optimal equity range (including preferred stock) is 35 to 40%, with corresponding debt ratios in the range of 60 to 65%.

Based on the model they believe is appropriate, Drs. Booth and Berkowitz recommended that for each 1% of additional debt financing, the allowed rate of return on common equity should increase by

approximately seven basis points. They indicated that this adjustment depends on the firm's initial amount of debt financing, and ranges from a low of four basis points to a high of eight basis points.

Drs. Booth and Berkowitz concluded that these estimates are approximately the increases in ROE required by investors. However, they noted that the estimates are subject to error since they are based upon valuation formulas which are as yet unproven. Moreover, they noted that these formulas ignore the non-tax advantages of debt financing and the effects of financial distress.

Dr. Cannon presented a model to examine the relationship between utility common equity ratios and the corresponding common equity costs in the context of Canadian capital markets. The basis for the model is that the cost of equity is related to deviations in rates of return. The model made the important assumption that only short-run risks need to be considered since long-run risks are not affected by the capital structure.

The results of Dr. Cannon's simulation experiments indicated that there is a "U-shaped" relationship between the weighted average cost of capital and the degree of financial leverage employed. According to Dr. Cannon, this result is not surprising given the very low short-run risks of the pipelines. Since it is short-run risks which are magnified by the use of leverage (lower equity ratio), the very low risks result in only a small magnification of these risks by the use of more debt in place of equity. According to Dr. Cannon's standard deviation of rate of return on common equity analysis, even with a common equity ratio of 22%, TransCanada is less risky than any of his low risk, non-regulated companies.

Dr. Waters indicated that the existence of a number of "real world" factors makes these financial models weak in terms of explaining the relationship between the pipelines' ROE and their common equity ratio. To date, empirical testing to more clearly describe the relationship has not been done successfully.

Dr. Waters concluded that, whenever it is necessary to consider the reality of income taxes, unnecessarily high common equity ratios carry a high cost to the customers in the form of additional taxes. Therefore, Dr. Waters recommended that the common equity ratio be set as low as possible within a reasonable range.

3.5 Views of the Board

3.5.1 General Principles

The Board is of the view that the determination of a pipeline's capital structure starts with an analysis of its business risk. This approach takes root in financial theory and has been supported by the expert witnesses in this hearing. Other factors such as financing requirements, the pipeline's size and its ability to access various financial markets are also given some weight in order to portray, as accurately as possible, a complete picture of the risks facing a pipeline.

The Board has systematically assessed the various risk factors for each of the pipelines but has not found it possible to express, in any quantitative fashion, specific scores or weights to be given to risk factors. The determination of business risk, in our view, must necessarily involve a high degree of judgement, and the analysis is best expressed qualitatively. Under these conditions, we do not consider it realistic to refine the implications for common equity ratios to a precision of, say, one or two percent. The Board recognizes that some parties may see advantages in variations of this

magnitude. Nonetheless, the Board does not find it possible or meaningful to seek to determine the required equity ratio with such a degree of precision.

With regard to the argument that regulation shields pipelines from risk, the Board believes that its regulation provides pipelines with a degree of assurance of cost recovery which is absent for non-regulated industrials. However, the Board believes that the realities of market forces cannot be discounted when addressing pipelines' business risks.

Contrary to what some parties advocated during the hearing, the Board is of the view that it is not appropriate to over-leverage a pipeline in order to identify the minimum acceptable deemed common equity ratio acceptable.

3.5.2 Gas Pipelines

In its evaluation of the gas pipelines' business risks, the Board found certain risk factors to be more important than others. With regard to operating risks, the Board views the operation of a single high pressure line and the presence of sour gas gathering pipelines and processing plants as important risk factors. Further, the extent to which a pipeline's markets are diversified, the quality and competitiveness of those markets, and the average length of shippers' contracts were judged to be the most significant factors in the Board's evaluation of market risks. The Board also had regard for the political risk associated with export markets.

There are other risk factors which were examined in these proceedings but which the evidence suggested should be given a lesser weight. These risk factors included the method of regulation under which each pipeline operates and the adequacy of the supply available to it. The Board is of the view that these factors have, at this time, only a marginal impact on the overall risk of pipelines. It assumes the supply risk is approximately equal for all gas pipelines examined in this proceeding.

TransCanada

The Board concludes that TransCanada is a low-risk pipeline and is less risky than unregulated industrial companies. The Board is of the view that TransCanada's risks have not decreased since last evaluated in the context of a toll proceeding.

The Board is of the view that TransCanada's ability to access financial markets on the basis of a 30% deemed common equity ratio over the past 15 years, except for 1982 and 1983 when a common equity ratio of 28% was deemed, is evidence which supports the appropriateness of a 30% deemed common equity for TransCanada at this time.

With respect to preferred shares, the Board concludes that, given current cost rates, it is appropriate for TransCanada to maintain preferred shares in its capital structure at the present time.

Westcoast

Unlike other NEB-regulated pipeline systems which are exclusively residue gas transmission facilities, Westcoast's gathering lines and processing plants account for a significant portion of its overall rate base. The gas transported in Westcoast's gathering systems contains hydrogen sulphide which increases the safety risk and technical complexity of its operation. In addition, three of the five processing plants that Westcoast currently operates are large-scale plants which impose proportionate

impacts in case of outages or failures. The Board is of the view that Westcoast's operating and physical risks warrant a higher common equity ratio than that of the other gas pipelines.

The Board is aware that Westcoast's consolidated common equity ratio is projected to be considerably less than the pipeline's 35% deemed level. However, the Board is not convinced that evidence regarding a consolidated equity ratio which is different than a deemed ratio necessarily indicates the existence of cross-subsidization. The Board is of the view that the primary issue is whether or not the financing of the non-jurisdictional assets results in higher debt costs to the NEB-regulated pipeline. Based on the evidence before it, the Board cannot conclude that such cross-subsidization exists in the case of Westcoast.

With respect to preferred shares, the Board concludes that, given current cost rates, it is appropriate for Westcoast to maintain preferred shares in its capital structure at the present time.

Foothills

In reaching its conclusion on the risks facing Foothills, the Board gave weight to the fact that Foothills has a greater reliance on export markets, particularly the highly competitive U.S. Midwest, than other gas pipelines thereby increasing the Company's exposure to regulatory and political risks, and that it operates a high-pressure single-line pipeline.

Against this, the Board has considered Foothills' high degree of assurance of recovering all of its costs through its monthly cost of service method of regulation and the significant portion of its revenues included in the cost of service of other pipelines.

ANG

The Board considered the fact that about 95% of ANG's throughput is destined for export markets and that a significant portion of ANG's throughput is to the California market which is considered to be a competitive market with excess pipeline capacity. However, the Board is of the view that this is balanced by the fact that the California market has been, and is perceived to be, one of the best long-term markets for Canadian gas.

Against these market considerations, the Board took account of ANG's monthly cost of service method of regulation which provides a greater assurance than the forward test year method that the Company will recover its costs and also considered its relatively longer transportation contract terms.

The Board is of the view that the cross-subsidization issue was not of sufficient materiality to warrant a change in ANG's deemed capital structure.

TQM

The Board is of the view that TQM is characterized by its limited market growth opportunities, the intense competition from alternate energy sources and its relatively low load factors. Furthermore, the Board notes that TQM is a single pipeline which exposes it to a relatively higher risk than a pipeline with multiple lines.

On the other hand, the fact that TransCanada is the sole shipper on TQM (making TQM's tolls part of TransCanada's cost of service) dilutes TQM's high unit cost and provides the Company with a high degree of assurance that its costs will be recovered.

3.5.3 Oil Pipelines

With regard to the oil pipelines' business risks, the Board is of the view that the quality and the competitiveness of the markets served by a pipeline are the two most significant factors to be considered in its analysis.

The Board's view on crude oil supply risks is that the resource base, in terms of both the remaining established reserves as well as discovered and undiscovered resources, is sufficiently large and diversified to support the existing pipelines beyond their current truncation dates under most circumstances. In particular, the Board anticipates that a future decline in conventional oil supply from the WCSB will tend to be offset by an increased supply of unconventional oil. This view is corroborated by IPL's and TMPL's evidence contained in recent expansion applications.

The deregulation of crude oil prices and the effective removal of export controls in 1985 has allowed Canadian crude oil prices to fluctuate in accordance with events in North American and international crude oil markets and has facilitated exports to the U.S.

The Board considered that the pipelines are nearly fully utilized, that they have been expanding recently, and that the outlook for WCSB oil supply is more optimistic than when oil pipelines' business risk was previously assessed.

The Board is of the view that the risks faced by the oil pipelines are low compared to industrial companies but greater than the bottom end of the risk spectrum.

In reaching its conclusion on the risks faced by TMPL, the Board took account of risk arising from marine competition. The Board also considered the fact that TMPL is a multi-product pipeline.

Decision

The Board recognizes that the gas pipelines have some individual characteristics, described in its views above, which differentiate one from another. On balance, however, the Board is of the view that the overall business risks of TransCanada, Foothills, ANG and TQM balance out such that a similar common equity ratio can be given to these four pipelines. Accordingly, the Board approves a common equity ratio of 30% for TransCanada, Foothills, ANG and TQM. The Board is of the view that Westcoast is riskier than the other four gas pipelines, and approves a common equity ratio of 35% for Westcoast. The Board also approves the maintenance of preferred shares in TransCanada's and Westcoast's capital structures.

The Board concludes that the appropriate deemed common equity ratio for TMPL is 45%.