Tolls, Tariff, Facilities & Procedures Committee

Resolution T2004-04: NGL Extraction Convention

Resolution

The Tolls, Tariff, Facilities & Procedures Committee (TTFP) agrees to submit the Natural Gas Liquids (NGL) Extraction Convention report to the Alberta Energy & Utilities Board (EUB). The TTFP recommends an explanatory presentation on the report also be made to the EUB.

Background

In Decision 2004-006, in respect of Solex Gas Processing Corp.'s (Solex) Application to amend a Gas Processing Scheme, the EUB noted that the current convention for NGL extraction on the Alberta System created perceived inequities. The EUB requested that the affected parties work with NOVA Gas Transmission Ltd. (NGTL) to initiate a review of the current convention for extraction of NGL's off of the Alberta System.

The TransCanada PipeLines Limited (TCPL) Alberta Customer Advisory Council (CAC) met and described five perceived inequities identified in the Solex decision. The CAC also identified several extraction alternatives beyond the current convention. In June 2004, NGTL's TTFP adopted Issue T2004-04 and formed an industry task force. The NGL Extraction Convention Task Force (NECTF) took over the review of the NGL extraction convention from the CAC. The objective for the NECTF was to create a balanced and unbiased report for the EUB regarding the current convention and any identified alternatives.

The NECTF met weekly from June 2004 to September 2005, bringing together people with diverse industry backgrounds and experience to review the Solex Decision, industry history and current NGL contracting convention. Also, the NECTF developed descriptions of five alternatives to the current convention and reviewed the associated benefits and concerns for each alternative. The report does not resolve any issues related to the perceived inequities, but rather has improved industry understanding of how the current NGL extraction convention works and how the identified NGL alternatives could work.

The report reviews the identified alternatives using a common set of descriptors. These descriptors attempt to capture the benefits and concerns for each alternative, including status quo, across a broad range of relevant industry categories without being evaluative or comparative. These categories included ownership, contracting, market, value, administration and operations. Common themes emerged such as NGL extraction rights, NGL ownership, component tracking, challenges with the current infrastructure, gas quality in the common stream, impact to the market place and transitional issues.

Being a collaborative effort, it is recommended there be a group, rather than individual, explanation of the report. The NECTF suggests the best first step with this report would be to hold a facilitated explanation by NECTF representatives with EUB staff and Board members. The value in the report is the sharing of expertise rather than the precise words in the report.

The ongoing level of participation, breadth of knowledge and experience of the members, and the willingness to share ideas, explore concepts and learn contributed greatly to the ability of the NECTF to complete the task. This report constitutes a consolidation of many views and alternatives regarding the extraction contracting convention. Since this report represents the culmination of a wide ranging and often contentious discussion, members do not necessarily agree on all aspects of the report.

Next Steps

TransCanada will file the NGL Extraction Convention report with the EUB for information and recommend a facilitated explanation of the report. This report is a first step in any further discussion on this issue and would expect additional industry consultation if further dialogue on these alternatives is sought.

NGL Extraction:
Current Convention and Alternatives

NGL Extraction Convention Task Force

September 2005

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EXECUTIVE SUMMARY

The Natural Gas Liquid (NGL) Extraction Convention Task Force (NECTF) was established in response to an Alberta Energy and Utilities Board (Board) request in January 2004. In Decision 2004-006 in respect of Solex Gas Processing Corp.'s (Solex) Application to amend a gas processing scheme, the Board noted that the current convention for NGL extraction on the Nova Gas Transmission Ltd. (NGTL) system created perceived inequities. The Board requested that the affected parties resolve the issues through a "collaborative process afforded to all NGTL shippers through the TTP (now TTFP) committee."

Before the task force was formed, TransCanada Pipelines Limited's Customer Advisory Council (CAC) met several times. The CAC discussions resulted in the description of five perceived industry inequities and four alternatives to the current convention with a recommendation to the TTFP that this content form the basis of a review process.

In June 2004, the TTFP established the task force and adopted a set of criteria to guide NECTF members' discussions. The goal was for NECTF to provide a balanced and unbiased report for the Board.

Early in its process, the Task Force agreed that due to the divergent views of its members it could not resolve the contentious issues surrounding the perceived inequities. Instead, the Task Force has developed a detailed report that discusses the current convention and a variety of alternative conventions. There was no attempt to assess the value or costs of any perceived inequities. The Task Force further elected not to determine exactly what any current inequities might be. It would, instead, focus on reviewing the alternatives using a method members could apply across all of them.

This report constitutes a consolidation of many views and alternatives regarding the extraction contracting convention. Since this report represents the culmination of a wide ranging and often contentious discussion, members do not necessarily agree on all aspects of the report. Furthermore, the Task Force considers this report a first step in any further discussion on this issue and would expect additional industry consultation if further dialogue on these alternatives is sought.

Task Force members representing a broad cross-section of industry met weekly over the course of a year. To increase their understanding about all the issues involved with the current convention, they reviewed industry history and listened to a number of presentations. In seeking a way to approach the current convention and the alternatives to it, they also developed a set of descriptors which they could potentially apply across all of the alternatives. Descriptors fell into six broad categories:

- ownership/royalty
- contracting
- proceeds/value
- market
- operations/administration
- other.

Throughout the many weeks of discussion and debate about the Status Quo (current convention) and the proposed alternatives, several major themes emerged:

- NGL extraction rights
- Ownership of NGL
- Measurement and component tracking
- Challenges with the existing infrastructure
- Issues regarding lean and rich gas in the common stream
- Marketplace impact
- Transitional issues
- Significance of the historical evolution of the current convention.

The four alternatives to the current convention, including a fifth alternative brought forward by a NECTF member, are listed below:

<u>Equalization</u>

The Equalization alternative would mirror the existing equalization process used for crude oil and condensate in Alberta and would not alter the current commercial processes between extraction plants and holders of the extraction rights at the delivery point. The alternative would expect to reduce the inequality between producers of rich versus lean gas and have minimal impact on current industry practices.

<u>Single Value Bucket</u>

The Single Value Bucket would have extraction plants aggregate all of the extraction premiums into a ‘bucket’. Producers would receive a share of the overall bucket based on the heat value each producer placed on the pipeline. The goal of this alternative is to minimize the need for major administration while providing a share of the extraction value to producers.

<u>Receipt Contracting</u>

The Receipt Contracting alternative would move value from the export shipper to the receipt shipper which could align more closely with the provincial royalty payee. Receipt shippers would receive a pro rated share of the common stream and would be able to contract for extraction. Although the alternative does not address the lean/rich gas inequality, it lays the foundation for a future solution to the problem.

Producer Directed

The Producer Directed alternative sought a way to maintain the flexibility of the current system and the efficiency of the NIT market through a method that would allow producers to contract for NGL extraction. Ownership of the liquids entrained in the NGTL common stream and the associated extraction rights would be represented by extraction rights credits (ERCs). ERCs could be traded independently from the gas market and owned by producers until such ownership is transferred.

Regulated Business

The Regulated Business alternative is intended to provide a balance between maintaining the viability of the extraction plant system and the rights of owners to capture the in-stream components of their natural gas in kind. The extraction plants on the NGTL system would be actively regulated under the Gas Utilities Act on a cost-of-service basis, and in-stream components would be taken in kind. All extraction plants would be aggregated into a single composite plant including costs and yields. All owners of the gas would be required to process their component-tracked gas stream through the extraction plant and responsible for their share of the cost of service.

1 INTRODUCTION

The Natural Gas Liquid (NGL) Extraction Convention Task Force (NECTF) was established in response to a request from the Alberta Energy and Utilities Board (Board) arising from the Solex Gas Processing Corporation's Application No. 1283973. In its January 27, 2004 Decision No. 2004-006, the Board noted that parties to the hearing had stated there are inequities within the present system. The Board further stated it expected the matter to be resolved through an industry review process.

The suggested venue for the industry review was Nova Gas Transmission Ltd.'s (NGTL) Tolls, Tariff & Procedures (TTP) committee, now known as the Tolls, Tariff, Facilities & Procedures committee (TTFP).

1.1 Background

In the Solex Decision, the Board concluded that the rights of producers to extract liquid from the common stream must be balanced against the objectives of preserving the viability of the straddle plant system and maintaining the competitive natural gas market structure that has been developed in Alberta.

In the Board's view, producers should have a fair opportunity to realize the value of their NGL content, and although "joint ownership exists among shippers in the NGTL common stream, an individual producer should be able to reprocess its share of the common stream, provided that is not an exclusive privilege and the producer does not recover more than its appropriate share of the NGL content."

The Board believes that maintaining a viable straddle plant industry is in the public interest. "When the petrochemical industry was developed, it relied on the straddle plants to provide the needed feedstock in economic quantities, thus creating added value for Alberta." The Board noted, "The producers also benefited from having additional markets for NGL recovery and additional gas markets in the form of shrinkage gas."

1.2 Task Force Mandate from the TTFP and Customer Advisory Council

The TransCanada Pipelines Limited's (TCPL) Customer Advisory Council (CAC) met and described five perceived inequities identified in the Solex Decision. The CAC also provided several extraction alternatives to be considered beyond the current convention.

The CAC's perceived inequities were:

1. Receipt shippers who place dry gas with no NGL content on the system, and who also hold export delivery service, get a share of the common stream and access to NGL entrained in that stream.

2. Double Dipping:
    - Producer-shippers who extract in the field get a share of the NGL in the common stream if they are also export shippers.

- Producer-shippers with production that enters the NGTL system downstream of extraction plants can obtain value for NGL in the common stream, even though their gas cannot be processed physically, if they hold export delivery service.

3. Producers who do not hold export delivery service cannot get direct access to the NGL which they put into the gas stream once the NGL are on the NGTL system.

4. The EUB decision confirms producer rights to NGL; however, the current convention prevents the exercising of those rights if the producer doesn't also hold export delivery service.

5. Producers are responsible for NGL royalty payments without access to benefits of the NGL value.

In June 2004, NGTL's TTFP committee chose the industry task force name, the NGL Extraction Convention Task Force (NECTF) and adopted a set of criteria to guide committee members' discussions. The TTFP committee's objective for the Task Force was the production of a balanced and unbiased report for the Board. In its issue statement, the committee said the problem required:

- Identification of perceived inequities, if any;
- Determination of the value of any perceived inequities;
- Identification of options that could address perceived inequities;
- Assessment of the options including cost/benefit and impact on the balance of stakeholder interests.

Early in its process, the Task Force agreed that due to the divergent views of its members it could not resolve the contentious issues surrounding the perceived inequities. Instead, the Task Force has developed a detailed report that discusses the current convention and a variety of alternative conventions. There was no attempt to assess the value or costs of any perceived inequities. The Task Force further elected not to determine exactly what any current inequities might be. It would, instead, focus on reviewing the alternatives using a method members could apply across all of them.

Task Force members also determined fairly early that although they would discuss and prepare a report about alternatives to the current convention, they would not make recommendations, apply a value or undertake a cost-benefit review of the alternatives discussed.

'Status Quo' and five alternative approaches to the management of NGL extraction rights that were reviewed, discussed and documented include:

- Status Quo (Current Convention)
- Equalization
- Single Value Bucket

- Producer Directed
- Receipt Contracting
- Regulated Business.

1.3 NGL Extraction Convention Task Force Membership

TransCanada, through the TTFP, invited all interested parties to participate in the Task Force. Members represented a cross-section of the industry.

Organizations Represented
Alberta Department of Energy
AltaGas Ltd.
Anadarko Canada Corporation
Apache Canada Ltd.
ATCO Midstream
BP Canada Energy Company
Burlington Resources Canada Ltd.
Canadian Association of Petroleum Producers
ConocoPhillips Canada
Devon Canada Corporation
EnCana Corporation
ExxonMobil Canada
Imperial Oil Resources Ltd.
Industrial Gas Consumers Association of Alberta
Inter Pipeline Fund
Keyera Energy Canada
MGV Energy Inc.
Nexen Marketing
NOVA Chemicals Corporation
Pacific Gas & Electric Company
Shell Canada Limited
Solex Gas Processing Corporation
Talisman Energy Canada
Taylor Gas Liquids
Terasen Gas Inc.
TransCanada PipeLines Ltd.

2 PROCESS

The NECTF set the initial task of investigating and describing how the current NGL extraction convention works and how it evolved. Task Force members then searched the depths of their knowledge and experience to consider how alternatives to that convention might work and the implications of these alternatives for various industry stakeholders. Finding a common method for reviewing the current convention (Status Quo) and all of the alternatives was an early priority.

2.1 Identifying Descriptors

A set of descriptors and questions developed by Task Force members provided the tool for reviewing the various alternatives and perceived inequities with consistency. After the descriptors and questions were developed, descriptors were then grouped into six broad categories. This tool allowed the Task Force to examine and to define the Status Quo, before applying the same tool to the other alternatives. (For a detailed listing of the descriptors and questions used see Appendix C.)

Descriptors and questions were grouped under these headings:

- Ownership/Royalty
- Contracting
- Proceeds/Value
- Market
- Operations/Administration
- Other.

2.2 NECTF Meetings

Task Force members have met weekly since June 30, 2004, bringing together people with diverse industry backgrounds and experience. Reviewing the Solex Decision, industry history, and listening to a number of presentations assisted members' understanding about the benefits, issues and potential inequities involved. Presentations about proposed alternatives by members of the industry offered insights into potential new directions. Further ideas were obtained throughout the weeks of discussion and debate which followed.

The ongoing level of participation, breadth of knowledge and experience of the members and their willingness to share ideas, explore concepts and learn, contributed greatly to the ability of the Task Force to complete this report.

2.3 Industry Stakeholders, their Roles and Interests

In undertaking its work, the Task Force noted the various stakeholders involved with the natural gas industry in Alberta:

- Producers
- Field plant operators and common stream operators (CSO)
- Province of Alberta
- Receipt shippers
- NIT buyers and sellers
- Storage operators and participants
- Export delivery shippers
- NGTL
- Extraction plant owners
- Petrochemical industry (ethane buyers)

- NGL industry
- Intra-Alberta and Ex-Alberta Consumers
- Alberta Energy and Utilities Board.

It was acknowledged that, for a number of reasons, companies may occupy more than one stakeholder position as a result of the following:

- Economic drivers and viable markets;
- Proximity of production to transmission lines;
- Amount of production;
- Richness of the gas;
- Third party processing availability;
- Taxation structure;
- Individual corporate business lines.

Although not exhaustive, the list highlights the many dimensions companies' consider when assessing their stakeholder interests. In addition, ownership and commercial interests of a number of participants were changing as the discussion proceeded. Also, some members did not participate in all the discussions. This report is a result of extensive and often contentious discussion and debate among task force members and it represents a broad cross-section of information. As a result not all members can agree with all aspects of this report. In addition, since this report contain no recommendations as to an alternative, this report is meant to be a first step towards further discussions on the contracting convention. Additional industry consultation would be required on any further process regarding this issue.

3 HISTORICAL BACKGROUND

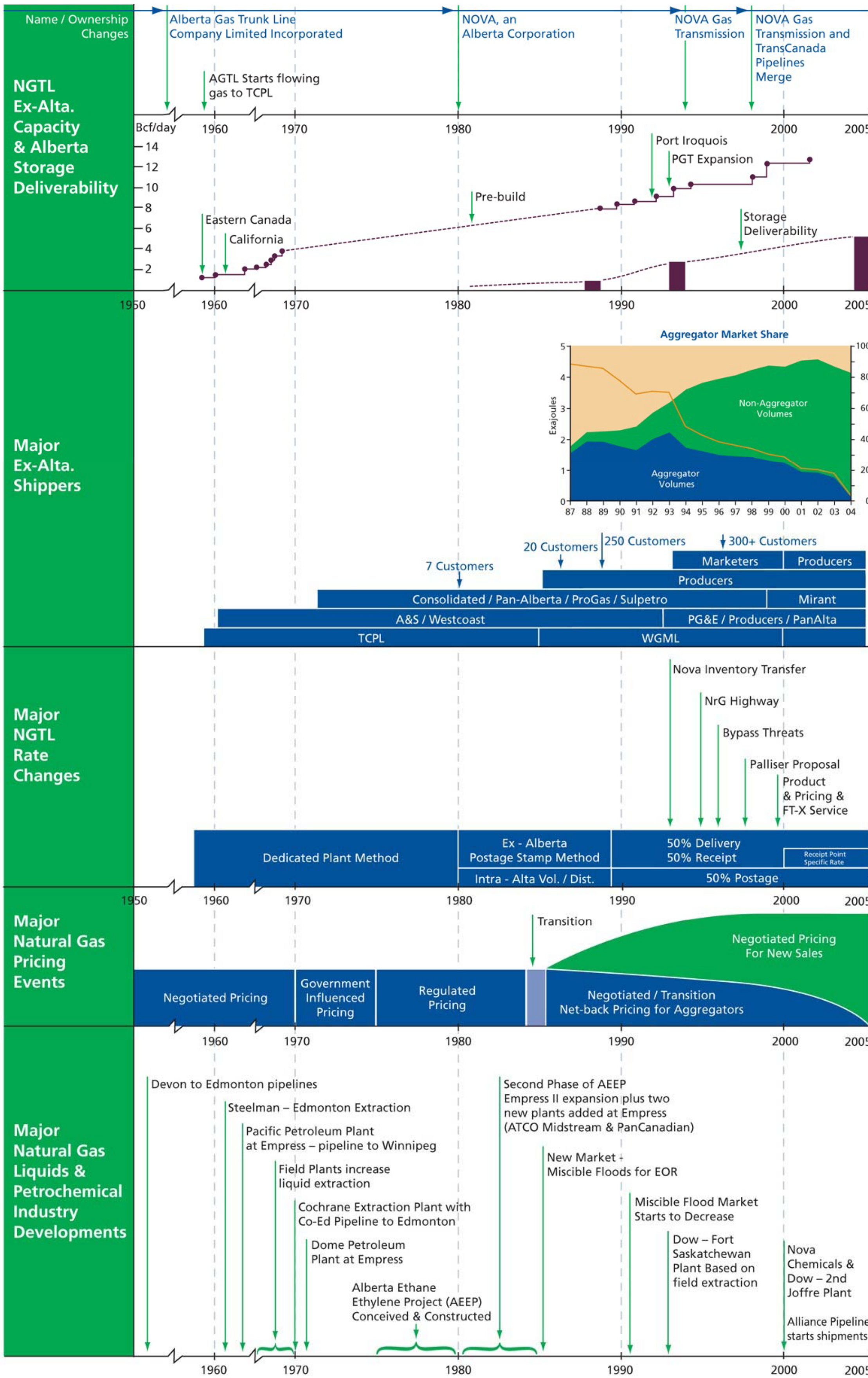
The purpose of this section is to first, attempt to determine when aspects of the current NGL contracting convention of extraction plants contracting with NGTL delivery shippers arose. Second, to identify some of the relevant historical events which lead to this contracting convention coming into practice. And finally, to identify those historical events and factors which lead some participants in the industry to conclude that the current contracting convention is now potentially inequitable.

3.1 Methodology

A Task Force team researched historical events along the following dimensions in its search for answers:

1) increases in NGTL ex-Alberta delivery capacity;
2) major NGTL transportation holders;
3) major NGTL rate structure changes;
4) major natural gas pricing events;
5) major natural gas liquids and petrochemical industry developments.

Based on this research, the composite chart on the next page summarizes what were felt to be some of the most relevant events behind the current convention. The proximity of the events which occurred has resulted in some hypothesized preliminary cause-and-effect conclusions. A more detailed written chronology of these dimensions, drawn from several public sources, is provided in Appendix B.



Name / Ownership Changes
Alberta Gas Trunk Line Company Limited Incorporated
NOVA, an Alberta Corporation
NOVA Gas Transmission
NOVA Gas Transmission and TransCanada Pipelines Merge
NGTL Ex-Alta. Capacity & Alberta Storage Deliverability
AGTL Starts flowing gas to TCPL
Bcf/day
Eastern Canada
California
Pre-build
Port Iroquois
PGT Expansion
Storage Deliverability
Major Ex-Alta. Shippers
Aggregator Market Share
Exajoules
Non-Aggregator Volumes
Aggregator Volumes
7 Customers
20 Customers
250 Customers
300+ Customers
Marketers
Producers
Consolidated / Pan-Alberta / ProGas / Sulpetro
Mirant
A&S / Westcoast
PG&E / Producers / PanAlta
TCPL
WGML
Major NGTL Rate Changes
Nova Inventory Transfer
NrG Highway
Bypass Threats
Palliser Proposal
Product & Pricing & FT-X Service
Dedicated Plant Method
Ex - Alberta Postage Stamp Method
Intra - Alta Vol. / Dist.
50% Delivery 50% Receipt
Receipt Point Specific Rate
50% Postage
Major Natural Gas Pricing Events
Transition
Negotiated Pricing For New Sales
Negotiated Pricing
Government Influenced Pricing
Regulated Pricing
Negotiated / Transition Net-back Pricing for Aggregators
Major Natural Gas Liquids & Petrochemical Industry Developments
Devon to Edmonton pipelines
Steelman – Edmonton Extraction
Pacific Petroleum Plant at Empress – pipeline to Winnipeg
Field Plants increase liquid extraction
Cochrane Extraction Plant with Co-Ed Pipeline to Edmonton
Dome Petroleum Plant at Empress
Alberta Ethane Ethylene Project (AEEP) Conceived & Constructed
Second Phase of AEEP Empress II expansion plus two new plants added at Empress (ATCO Midstream & PanCanadian)
New Market - Miscible Floods for EOR
Miscible Flood Market Starts to Decrease
Dow – Fort Saskatchewan Plant Based on field extraction
Nova Chemicals & Dow – 2nd Joffre Plant
Alliance Pipeline starts shipments
1950
1960
1970
1980
1990
2000
2005

3.2 Timing

The research indicates that the current convention of extraction plants contracting with NGTL ex-Alberta delivery shippers was built upon the commercial arrangements that were in effect during the late 1960s, 1970s and first half of the 1980s. With the start of price deregulation in 1984, the ex-Alberta shipper's role was no longer solely filled by aggregators. The next major evolution of the convention happened in approximately 1993, coincidentally or potentially in response to the following critical events:

- increased incidence in separate contracting of the receipt and delivery components of NGTL transportation;
- development of increased intra-Alberta storage capacity and use by industry of storage for the deliverability management, price enhancement, and title transfer of the gas;
- implementation of the NOVA Inventory Transfer (NIT) service in 1993;
- development of electronic clearing houses providing title transfer and price discovery associated with NIT transactions;
- decreased dominance by major aggregators of both sales and contracting of NGTL transportation, and the emergence of many new shippers.

3.3 Events which Lead to Current Contracting Convention

Throughout the 1950s, 60s and 70s and most of the 1980s, the same corporate entities, predominately the major aggregators, held both the receipt and delivery transportation service on NGTL and took title to the natural gas and NGL components in the common gas stream as the gas was received onto the NGTL system. Beyond 1984 and into the 1990s, the major aggregators continued to hold both receipt and delivery capacity and most of the export permit approvals and licenses. In addition, new shippers contracting for transportation on NGTL after 1984 also held both receipt and delivery service until approximately 1989. There was no need to distinguish between receipt and delivery shippers during this time.

Extraction plant locations were another factor. Since the majority of these extraction facilities were constructed at the two major Alberta export delivery points, and because the flow of gas past the plants approximately matched ex-Alberta delivery nominations, it was these quantities and locations that were used as a reference in the NGL extraction contracts. A transporter's receipt volumes were not the primary consideration.

Some industry participants suggest that liquids extraction contracting practices have not changed since they began in the late 1960s. There have always been contracts between extraction plants and NGTL transporters based on ex-Alberta delivery volumes. Other industry participants argue that the process has changed fundamentally because contracts today are with delivery shippers, rather than with NGTL transporters holding both receipt and delivery service. Receipt shipping and delivery shipping are now two distinct procedures often involving different parties.

Beginning in 1993, both the expansion of natural gas storage facilities within Alberta, and the creation and evolution of NIT, caused market dynamics and practices to change. These developments made it practical for market participants to choose whether to:

- sell their gas at the field plant;
- contract for NGTL receipt capacity only and then sell the gas at NIT;
- hold both receipt and delivery NGTL capacity with the opportunity to sell at the Alberta border;
- hold delivery capacity only and purchase gas at NIT.

The increased flexibility of NIT, and the development of electronically-based clearing houses fundamentally changed the dynamics of title transfer activity on NGTL. Now, title transfer and price discovery services shifted from one where title between receipt onto, and delivery off, the NGTL system did not change, as a general rule, to one where such transfers could and did change multiple times.

In 1984, when the process of price deregulation started, major aggregators accounted for more than 90 per cent of the ex-Alberta gas market and transportation on NGTL. Between 1984 and 1993, because of long-term contract and ongoing take-or-pay* recovery obligations, aggregators' total volumes remained strong diminishing to 70 per cent of ex-Alberta volumes by 1993. In 1993, as most of the take-or-pay obligations had expired, aggregators' volumes began to decline just as the total market was embarking on a period of growth. Now non-aggregators such as producers, marketers and end users were moving into the new incremental market and, by 2004, the traditional aggregators accounted for less than five per cent of the total ex-Alberta market.

Several major events and trends contributed to the decline in traditional aggregator dominance in the early 1990s.

1) Alberta and Southern (A&S) ceased operations in 1993, de-contracting its gas supplies and arranging for its former producers to take assignment of A&S' NGTL receipt capacity; and Pacific Gas and Electric (PG&E), the A&S parent company, former producers for A&S and Pan-Alberta took assignment of the majority of A&S delivery capacity at the Alberta-B.C. border.

2) TCPL/Western Gas Marketing Limited's (WGML) take-or-pay obligations were almost recovered and, as most producers wanted to market their gas directly, WGML saw their contracted volumes decline.

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*'Take or pay' was a common contract feature of reserve-based natural gas supply contracts that A&S and TCPL had with producers This contract feature included a minimum quantity the buyer was obliged to 'take' and if that quantity was not taken then the buyer was required to 'pay' for the shortfall. An additional contract item associated with 'take or pay' gave the buyer a recovery provision whereby the buyer could purchase gas in future periods in excess of the minimum quantity. Both TCPL and Alberta and Southern (A&S) negotiated recovery settlements which allowed them to recover take-or-pay pre-paid gas over a 10 to 15 year period.

3) The early 1990s was a period of significant pipeline construction and expansion beyond Alberta associated with Pacific Gas Transmission East Leg/Northern Border, and Iroquois. As indicated above, these new incremental markets were captured predominately by non-aggregators - producers, marketers and, in some cases, end-use buyers - who contracted for NGTL delivery capacity and purchased gas at NIT.

3.4 Events and Trends Leading to Perceptions of Inequity

Three events or trends have led predominately to the perception that the current contracting practices are potentially inequitable. They include:

1) the period of natural gas price regulation the industry experienced from 1975 through 1986 and the transition regime that was implemented to revert to negotiated pricing;
2) the trend by the producing industry to contract for receipt capacity only and to sell gas through NIT with the result that the corporate entities placing natural gas onto the NGTL system now differed from those removing gas off the system; and
3) Alberta's implementation of its explicit royalty assessment on NGL left in the NGTL gas stream.

The period during which the natural gas industry moved from negotiated pricing to price regulation and then back to negotiated pricing, casts further light onto the differences of opinion about who should have the right to contract for liquids extraction. At the outset in the 1960s, the major aggregators (TCPL and A&S) operated under explicit negotiated prices with their system producers and took title to the gas as it was delivered onto the AGTL (now NGTL) system. The pricing practice in effect during this period was an add-forward system: in order to arrive at a bundled delivery price, aggregators added all the transportation and administration costs incurred to deliver the gas to the various markets onto the negotiated costs of the natural gas. During this early period under the title transfer and add-forward pricing system, and when the Alberta natural gas liquids extraction plant extraction and associated petrochemical industry initially developed, there was no disagreement about who held the right to contract for NGL extraction. The title transfer point was clear.

Regulated government pricing marked a turning point for the natural gas industry. Beginning in the early 1970s and definitely from 1975 through 1986, government price regulations were in effect. The regulation scheme allowed for continued negotiation of prices for gas that would serve Alberta markets, but set different regulated prices for both the ex-Alberta Canadian domestic market and for the international export market. Because the international export prices were set higher than domestic prices, the Alberta Government put a price adjustment mechanism in place. This mechanism was an attempt to equalize the benefits of higher priced export sales on a netback basis to all producers. Regulated pricing effectively changed the pricing system from the former add-forward basis to regulated netback pricing and included sales revenue from shrinkages sales associated with liquids extraction. The aggregators contracted for extraction rights and retained all of the value from those rights. The only benefit to producers was the extra market that shrinkage sales represented.

Although the shift back to deregulated pricing is said to have occurred from 1984-86, the transition regime associated with long-term aggregator gas supplies lasted well into the 1990s. During these years of transition, aggregators were required to obtain majority producer approval of all renegotiated sales prices and to continue to flow the benefit of those sales, on a netback basis, to producers. Producers did not receive any value for liquids but did receive the advantage of the extra sale of gas which contributed to the average weighted field price. Historically, under the aggregators, the producers received no value for NGL extraction rights. As the aggregators' market share diminished, some producers began holding both receipt and delivery contracts that allowed them to contract directly with extraction plants for NGL extraction. The regulated price period and its extended transition have created a perception that there is no value in liquids extraction rights except for an additional shrinkage gas sale.

One final event may also have contributed to the perceptions of inequity which exist today. In October 2002, the Alberta government implemented explicit royalty assessments on the natural gas liquids contained in the NGTL common stream. Some industry participants must pay these royalty charges, but if those same participants then sell their gas at NIT or intra-Alberta on the NGTL system, they do not see an explicit return from liquids extraction. Other industry participants are of the view that the NIT price includes a premium for liquids extraction.

3.5 Summary

A number of events have lead us to where we are today, but the year 1993 marks the beginning of some key changes. The major aggregators' volumes began to decrease in 1993 and continued to decline significantly thereafter. At the same time, NIT's evolution resulted in the new practice of different parties holding receipt capacity but not, necessarily, export delivery capacity on NGTL, with gas now being traded predominately through NIT transactions. Multiple NIT transactions have lead to less transparency surrounding the benefits from liquids extraction flowing back to the producers that placed liquids into the NGTL common stream. Diminished transparency has fostered the perception of inequities and differences of opinion about who should have the right to contract for liquids extraction; and the combination of NIT transactions and separate receipt and delivery contracting has obscured the title transfer point of the gas.

4 CURRENT CONVENTION SUMMARY

Under the current convention, the right to extract NGL from natural gas transported on the NGTL system is held by shippers with delivery service at the export point downstream of an extraction plant. The one exception is at the Joffre Ethane Extraction Plant (JEEP) where the right to extract NGL is held by shippers who hold delivery service within Alberta at a point immediately downstream of that extraction plant.

Ownership of NGL is deemed to be with the party holding title to the natural gas. Producers hold title and control of the gas as it leaves the ground. Meanwhile, a transfer of gas ownership can occur at numerous points before an export delivery shipper contracts with an extraction plant on the NGTL system. Such ownership transfers can take place at the wellhead, the gathering system, the plant gate, at the field deep-cut plant, at the receipt point onto NGTL, at NIT and at the delivery point off NGTL. However, once the gas is on the NGTL system, ownership transfers are only facilitated through NIT. Shippers nominating gas at the receipt and delivery points are deemed by NGTL to be the owners of the gas at those points.

Because of the differential between gas prices and NGL prices, there have been times, historically, when the extraction of in-stream components was a money-losing proposition. As a result, greater amounts of gas would bypass extraction plants. This aspect of extraction plant risk exposure was not addressed by the Task Force.

The majority of gas produced in Alberta is available to be processed at extraction plants on the NGTL system with the exception of:

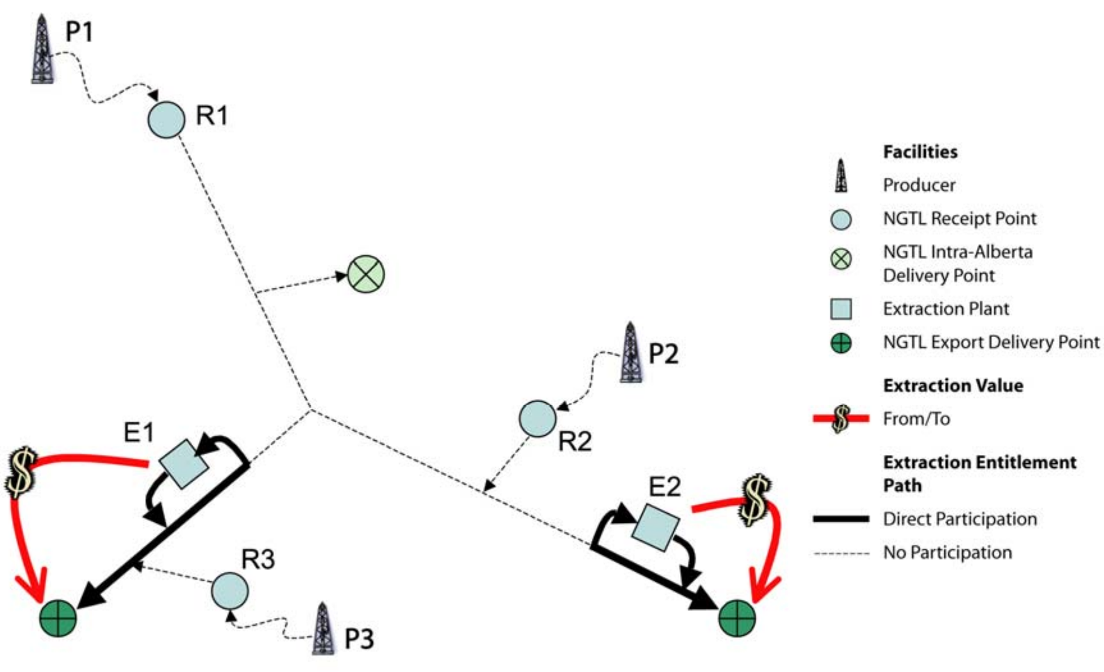
- gas consumed within the province of Alberta including pipeline fuel;
- gas that is received onto the NGTL system downstream of extraction plants;
- gas delivered to connecting pipelines upstream of extraction plants (Alliance, ATCO, Duke Energy, TransGas pipeline systems).

4.1 How the NGTL system works

After leaving the wellhead, natural gas and any accompanying in-stream components may require conditioning plant processing or compressing before they enter the NGTL system at a receipt point. A producer has the option to extract in-stream liquid components before the gas reaches such a receipt point. Knowledge about the content of the gas as it flows from the wellhead to the NGTL receipt meter is a combination of estimates for the current month, actual data from the month-end gas plant allocation process, and prior period adjustments. A common stream operator (CSO) at the NGTL receipt point manages the gas flows and allocates ownership of the gas to NGTL shippers who have transportation contracts at that receipt location. Once the gas is measured for heat content and volume, NGTL takes custody and control of the gas. The gas is then commingled into the pipeline's common stream.

There are approximately 700 gas plants, 900 receipt points, 160 intra-Alberta delivery points and eight export/import points on the NGTL system. The common stream reflects the commingling of gas to and from all of these points. Rich gas contains more NGL components than lean gas placed on the pipeline, and the gas composition of the common stream varies depending on the point at which the composition is measured. The gas composition at any given point also varies from day to day.

Figure 4-1 Status Quo
NGL extraction rights and revenues go to export shippers.



Extraction plants reprocess gas from the NGTL common stream at the two major Alberta export points. On the western leg, a single extraction plant is located approximately 150 kilometers north of the Alberta/British Columbia border point. At the Saskatchewan/ Alberta border to the east, (Empress and McNeill) four extraction plants are in operation. In addition, JEEP is located at the Joffre intra-Alberta delivery location.

Gas flows destined for delivery points downstream of the extraction plants are available to these extraction plants for processing based on instructions to NGTL from export delivery shippers. Export delivery shippers also have the option to bypass extraction plants entirely. An export delivery shipper's extraction entitlement is limited to the volume of gas for which he or she has delivery contracts on a given gas day. Export delivery shippers contract with the extraction plants for the removal of NGL based on the content at the extraction plant. NGTL is not a participant in these contractual arrangements but provides a service to facilitate the processing of common stream gas at extraction plants.

NGTL's Extraction Service (FT-X) provides for an 'on/off' service for gas that is processed at an extraction plant. Extraction plants measure the shrinkage associated with the extraction of NGL from the common stream and report the shipper allocation of the shrinkage to NGTL. A shipper must hold FT-X service to receive an allocation of shrinkage delivery. The practice of custody transfers off the pipeline into and out of extraction plants predates the existence of NGTL's actual FT-X service. The practice has evolved over time and is not specifically outlined in NGTL's Tariff.

The export delivery shipper must inform NGTL which upstream extraction plant will process his or her gas. This instruction is called a banding instruction. In the case where several plants will be used, shippers must also tell NGTL the quantity of their gas assigned to each plant. Volumes of gas, rather than energy content, govern these transactions. At Empress/McNeill, export delivery shippers have the option to assign their extraction rights/entitlement to another party, known as pooling. Despite widespread perceptions, NGTL does not measure the gas in or out of extraction plants but relies on extraction plant measurements.

Automated administrative processes at NGTL support activities for extraction at the extraction plants based on the banding and pooling instructions provided from export delivery shippers. Shippers may change these instructions at any time. NGTL informs the extraction plants of the quantity of gas they have been authorized to process, based on the gas cycles on which gas is nominated and confirmed at the downstream delivery points. The process begins with NGTL confirming a shipper's nomination requests at the downstream delivery points. The banding and pooling instructions are then applied to these confirmed nominations and the results are forwarded to each of the extraction plants. At the end of the gas day, the final banding and pooling results from all the nomination cycles are provided by NGTL to the extraction plants. The extraction plants provide final shrinkage allocations to NGTL based on these results. Shippers' transportation accounts are updated based on these shrinkage allocations and must be balanced with supply onto the pipeline.

Approximately 100 nominations are confirmed daily at Empress/McNeill and another 20 nomination changes occur at the intra-day nomination cycles. About 50 nominations per day occur at the Alberta/British Columbia border with another 15 confirmed at the Joffre Interconnect.

Automated FT-X administrative processes are in place to support extraction activities and are relatively simple. They require less than one full-time position to handle any changes to the standing instructions from shippers and to inform the extraction plants.

The major advantages of the current convention are:

- easy and cost effective to administer with costs borne by the extraction plant;
- matches the physical gas flow and gas content in the common stream with the commercial arrangement;
- provides added liquidity for the NIT market since extraction plant owners are significant volume buyers at NIT;
- extraction plant owners and NGL buyers take the risk when the price of shrinkage exceeds the value of the liquids produced;
- extraction plant owners and NGL buyers bear all volume and capital risks.

4.2 Concerns about the Current Convention

4.2.1 Extraction Rights - Value

Under the current convention, only export delivery shippers are able to contract with extraction plant operators. Consequently, only those receipt shippers/producers holding export delivery capacity may contract with extraction plant operators and obtain value for the in-stream components in the common stream. If they do not hold export delivery, producers and receipt shippers relinquish their rights to the in-stream components, once their gas is on the pipeline, by selling their gas within Alberta. In both cases, receipt shippers receive NIT-based value for their gas and in-stream components. Some parties believe this NIT value recognizes the extraction value while other parties do not. The fact that no transparent value for the right to extract liquids at a downstream extraction plant exists today, applies to both sides of the argument. Whether or not improved market transparency will occur under other alternatives is debatable, as well.

4.2.2 Royalty Payments – Value

Effective October 2002, the provincial royalty program changed so that separate reference prices are calculated for each in-stream component (ISC). Each component in the gas stream is now assigned a differentiated transportation cost based on the premise that it costs less to transport NGL entrained in the gas stream, as compared to methane, because NGL are higher in heat content. The royalty program values ISC sold for gas consumption at gas value, and ISC sold for shrinkage gas at mainline extraction plants at the shrinkage gas value. Any implicit ‘uplift’ or ‘premium’ in the value of the shrinkage gas above the gas value is included in the calculation of the ISC reference prices. It is important to recognize that the value of this ‘uplift’ or ‘premium’ is not always positive, but the royalty program captures whatever value is realized.

4.2.3 Common Stream Issues

A major concern with the current convention for some parties is that it does not recognize the leanness or richness of an individual producer’s components and only deals with common stream composition. It should also be noted that sidestreaming affects the common stream at the inlets to extraction plants.

5 MAJOR THEMES

5.1 Introduction

Throughout the discussions, certain topics frequently arose and had significant impact on members’ understanding about extraction rights contracting. This section outlines what the Task Force learned about these issues. Knowledge about this subject matter is crucial if one is to understand and evaluate the alternatives presented in the report.

5.2 NGL Extraction Rights

Extraction rights are defined as the right to process a specific volume of gas upstream of a delivery point to recover the entrained NGL content. Extraction rights are currently conferred upon certain parties through a contracting convention and are created at points on the NGTL system where gas can access an extraction plant. The convention is rooted in the industry's history. When the original extraction plants were built, aggregators were the only Alberta export shippers on the NGTL system; they held both the receipt and delivery transportation. Since the extraction plants were physically located near export delivery points, administering extraction based on export nominations was operationally efficient. The contracting convention continues to confer extraction rights on export shippers who do not need a direct contractual link to gas producers.

NIT emerged in 1993 and evolved into a market that provides shippers the opportunity to transact business and exchange volumes without the requirement to hold both receipt and delivery capacity on NGTL. The predominant use of the NIT market has resulted in the emergence of the current NGL extraction right issues. The NIT market is a 'natural gas' market and does not explicitly address the disposition of any natural gas liquids entrained in the common stream.

One side of the debate says that if there is not an explicit disposition by the original owner (the producer) of the entrained liquids or the right to extract those liquids, then those liquids or rights should remain in the possession of the producer until expressly relinquished. The premise is that the price of gas in the NIT market is determined by the price of gas in the North American market adjusted for transportation costs and local market conditions. The NIT value is considered to be indifferent to the issue of extraction rights value. Therefore, it is argued that extraction rights do not have an impact on the NIT price. Proponents of the explicit disposition concept argue that the current extraction contracting convention bestows value to the export shippers rather than to the producer. The proponents maintain the convention should be changed to allow the original owner to control the entrained liquids further downstream or, at least explicitly, to get the value for the 'right' to extract the in-stream liquids.

The other side of the debate says that under the current convention, those liquids or rights are practically, but not explicitly, dealt with as an integral part of the natural gas when it is sold on the NGTL system in the NIT market. Therefore, shippers of natural gas on the NGTL system implicitly agree to surrender their 'right' to extract the in-stream liquids by putting their gas on the system and are, in fact, compensated for the 'right' to extract in-stream liquids through the price paid for the natural gas in the NIT market. Once a sales transaction has occurred, including transactions at NIT, complete title to the gas, including the in-stream components, are transferred to the buyer. Therefore, it is argued that the value associated with liquids extraction has the effect of increasing the NIT price. Proponents of this side of the debate also argue that the current contracting convention should be retained at least for operational efficiencies.

5.3 Ownership of NGL

Currently, gas entering the NGTL system becomes part of a common stream and has operated on the basis that shippers have rights to a certain quantity of energy (gigajoules) in the common stream but they do not have explicit rights to the components or to a certain volume of gas at a specific heat value. This practice of allocating a proportionate share of the common stream simplifies and enables NGTL operations, east and west flows of the gas, intra-Alberta deliveries, contracting, and extraction plant operations. The Board has concluded that once a shipper enters into a transportation contract with NGTL, it gives up any and all specific rights to NGL in that gas in exchange for an appropriate share of the common stream. (Reference: Solex Decision 2004-006, item 4.4.)

At certain points on the NGTL system upstream of delivery points where there are extraction plants, the current convention confers the right to extract NGL from the gas stream to shippers holding delivery capacity provided they own gas at those points.

5.4 Measurement and Component Tracking

NGTL uses the following tracking methods within its business operations:

- energy and gas volume are measured as the gas is received onto the system;
- energy balances are determined for each of its shippers;
- energy and gas volume delivered off the system are measured at both intra-Alberta and ex-Alberta delivery points;
- energy and volume of entrained liquids removed at extraction plants are measured by the plants and reported to NGTL;
- the frequency and quality of measurement data are not uniform across the entire NGTL system.

A number of the alternatives examined in this report would require NGTL to track either heat content or components by shipper. NGTL's existing tracking methods involve variability in the types of equipment used and variable measurement frequency. These factors and the need for some form of tracking that is different from current methods raises questions regarding the testing requirements, methods and cost of such procedures and who would have responsibility for their management and administration.

Upstream of NGTL, accurately determining a producer's share is difficult. First, the term 'producer' can indicate different parties at the wellhead, gathering system, processing plant or field extraction plant. None of these parties is yet on the NGTL system. For practical derivation purposes, most of the alternatives use either average heat content (MJ/m^3) or energy. Many ownership details upstream of an NGTL receipt meter are maintained in the Petroleum Registry but this information is confidential and not totally comprehensive. For these reasons, the alternatives have been very cautious in assuming a precise determination of 'producers' share'.

Several of the alternatives initially contemplated full in-stream component tracking and it was recognized that such tracking was complex, possibly expensive and administratively burdensome. However, where full component tracking was considered necessary for the alternative to fulfill its objectives, the need was noted. In most cases, though, the Task Force considered that the intended impact of each alternative could be achieved using a proxy of heat content (MJ/m^3) for component tracking. The transition to full component tracking could occur once industry gained more understanding about the issue, and/or component tracking became more reasonable or achievable through changes in technology.

5.5 Challenges with Existing Infrastructure

The current gas transportation and marketing infrastructure is affected by:

- physical pipeline assets;
- operational practices employed by NGTL;
- the contractual arrangements for transportation;
- commercial arrangements;
- NGTL rate design.

Changes to the current contracting convention could have implications for each of the above elements. For example, gas balancing between east and west flows and the various extraction plants at Empress would be much more challenging without a linkage to ensure a connection of the right to contract for extraction and the physical flow of the gas to export points.

When addressing each alternative, it has been challenging to recognize how an alternative would fit into the existing infrastructure. For example, potential benefits that could be derived from the proposed alternatives need to be weighed against the efficient operation of the existing gas transmission system. Also, various alternatives could have an impact on both upstream and downstream infrastructure. The current combined infrastructure has been instrumental in maintaining the NIT market, the extraction plant system and the petrochemical industry in Alberta. Other models, however, that accomplish the same could be considered as an alternative convention.

5.6 Rich and Lean Gas in the Common Stream

The composition and heat content of the natural gas put into the common stream on NGTL differs at each receipt point. Gas that has more NGL components has higher heat content and is referred to as ‘rich’ gas while gas that has less NGL components has lower heat content and is referred to as ‘lean’ gas. Under the current practice, a shipper is only entitled to a share of the common stream equal to the total energy supplied by the shipper.

When exercising extraction rights under the current convention, an ex-Alberta shipper has access to the common gas stream at an export point regardless of whether the shipper acquired the gas as a common stream (purchased it at NIT) or acquired the gas at extraction plants by virtue of being able to access the common stream. Conversely, another shipper holding both receipt and ex-Alberta delivery service who puts rich gas onto the system, loses value by not being able to access the equivalent liquids content that shipper put onto the system. The situation is similar for a receipt shipper who sells gas at NIT or for intra-Alberta deliveries.

This rich versus lean gas issue may become more important as decisions are made concerning transportation alternatives for the relatively rich gas from Alaska, and as very lean gas sources such as natural gas from coal become a greater part of the gas supply mix.

5.7 Marketplace Impact

When discussing the various alternatives, the Task Force considered the impact that different alternatives would have on two distinct market places: the Alberta Market Hub (or NIT market) and the potential emergence of a market for extraction rights. The Task Force did not consider the impact alternatives may have on the NGL markets downstream of either field processing plants or extraction plants.

The viability of the NIT market was also taken into account. Viability was assumed to have two dimensions: transparency and liquidity. None of the alternatives was considered to be detrimental to the viability of the NIT market (Appendix D). The Task Force, however, did not look beyond transparency and liquidity or evaluate any alternative to the current convention for its possible impact on the price of gas in the NIT market.

Finally, as a general comment, the Task Force noted some instances where the alternatives would have an impact on the current commercial arrangements between the extraction plants and the current extraction rights holders. Some of the current commercial contracts between these two parties are long term and, hence, might pose a barrier to transition from the Status Quo to any alternative.

5.8 Significance of the Historical Evolution of the Current Convention

The Historical Background (Section 2) and supporting Historical Timelines (Appendix B), helped to provide all parties with a better perspective regarding the ways in which the current convention has evolved over many years. The illustrated chart directionally documents the major industry milestones that have influenced the convention’s evolution. The purpose of the historical context is not to avoid change but to ensure that parties considering amendments to the current convention recognize the impact future decisions may have on all stakeholders within the gas, liquid and petrochemical industries.

5.9 Transitional Issues

Transitional issues are inevitable when changes to the current convention are considered. These could include creating a new marketplace for NGL extraction rights, and changing existing commercial agreements, both resulting in increased overhead and administration costs. Export shippers, for example, have existing commercial agreements with extraction plant owners which would require some type of process to move to a new alternative. A vehicle to handle extraction rights transactions would also be required for some of the alternatives discussed.

All of the proposed alternatives would create an incremental administrative burden. The allocation of transition costs across stakeholders is another matter for consideration. These additional costs would have to be considered relative to the benefits provided by each alternative while also considering any inequities created by the alternative. The Task Force made no attempt to quantify any of the costs or benefits of either the current system or any of the alternatives, or to develop cost-benefit analyses.

6.0 ALTERNATIVE OVERVIEWS

The following are brief descriptions of the alternatives which the Task Force considered and debated. All of them apply to NGTL connected gas volumes and not to other pipelines. For more detail about these alternatives, see Appendix D.

6.1 Equalization Alternative

Overview

Under this alternative, NGL extraction value is presumed to be included in the intra-Alberta sales (NIT) price. Equalization would require shippers of lean gas to transfer a portion of their revenues from the sale of that gas to shippers of richer gas. This alternative builds on the Status Quo and adjusts the price of the gas behind the receipt points so that the producers receive their proportionate share of value based on the quality of their gas.

The equalization alternative would mirror the existing equalization processes used for crude oil and condensate in Alberta. This alternative does not alter the current commercial processes between extraction plants and holders of the extraction rights at the delivery point. Also, it seeks to ensure the protection of the Alberta public interest with respect to the extraction and petrochemical plants through a fair and equitable business model.

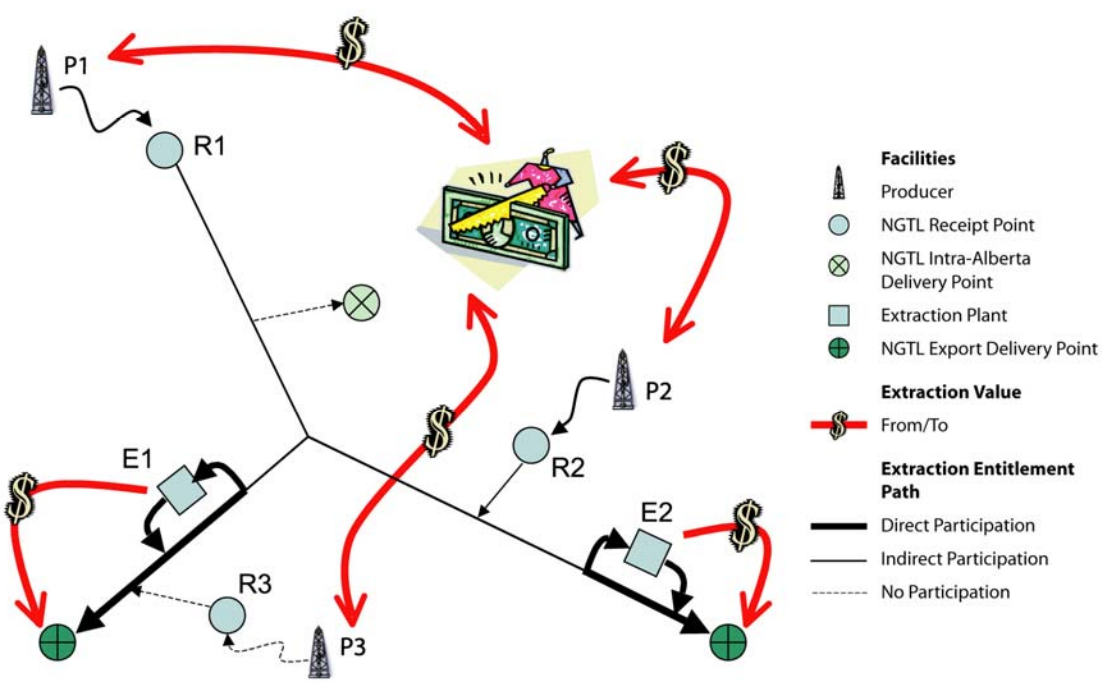
The goal of the equalization process is to transfer an appropriate amount of value among producers based on the component content of individual streams using scaled factors for those components that add or subtract from the overall value of the realized common stream price. This would result in leveling the playing field among producers contributing to the common stream. Producers who extract liquid in the field or produce very lean gas streams would compensate producers who deliver richer streams thereby equalizing the content value of the common stream.

The Equalization Alternative model would provide for equalization factors and scales for natural gas that would be developed and maintained in the same manner as the crude and condensate program is administered today. Heating value, as the primary driver of value for extraction rights, is the obvious factor to use in the equalization of natural gas. As an option, detailed equalization scales could also be developed using the components of residue gas that affect the gross heating value:

- Ethane-plus hydrocarbon component content;
- CO_2 content or total non-hydrocarbon gas content.

Figure 6-1 Equalization Alternative

NGL extraction rights and revenues go to export shippers. NIT value reallocated among producers, based on gas quality.



Benefits of the Equalization Alternative are considered to be:

- rich gas would receive higher value than lean gas;
- extraction contracts would continue to follow the physical flow of the gas;
- no identified impact on the viability of the NIT market;
- receipt shippers would notice an impact on their revenues but producer revenues may not be affected;
- the incentive for field extraction may lessen because producers of rich gas would be compensated for the value they contribute to the common stream;
- contractual arrangements would remain between export shippers and extraction plants.

Some potential issues include:

- difficulty in establishing the equalization scales;
- the potential exists for sidestream plant participants to receive equalization twice;
- administration and data collection.

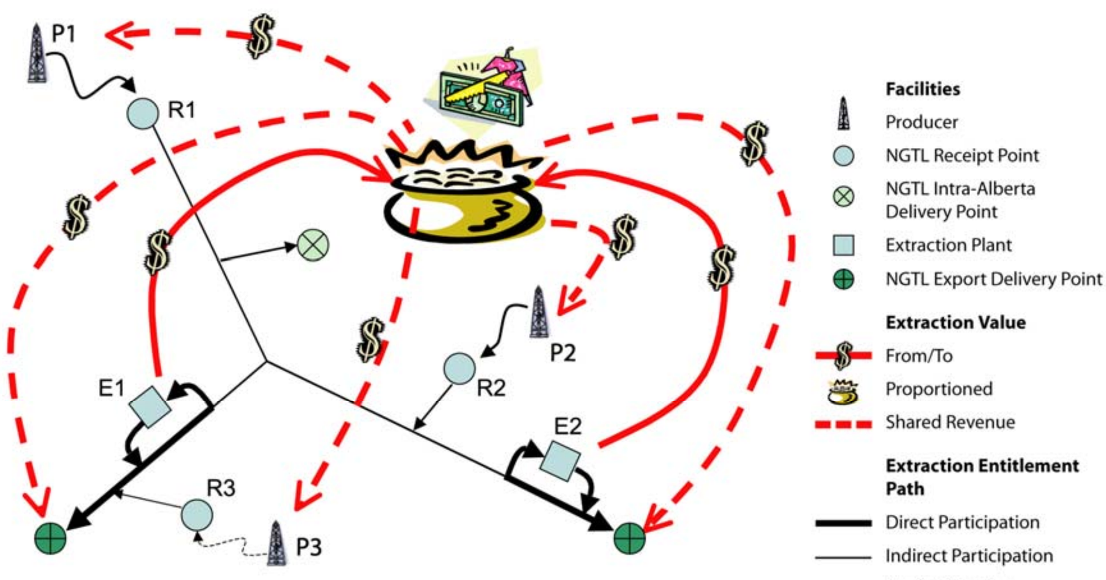
6.2 Single Value Bucket Alternative

Overview

The Single Value Bucket alternative builds on the Status Quo in that the extraction plant would continue to contract with the delivery shipper. The extraction plant would aggregate all of the extraction premiums into a 'bucket'. Producers would receive a share of the overall bucket based on the heat value each producer had placed on the pipeline. Delivery shippers would also receive a share of the bucket as an incentive to negotiate the best deal for extraction.

The goal of this alternative is to create more equity within the NGL extraction system and to reduce the need for major administrative changes while sharing the extraction premium between the delivery shipper and the producer. The advantage of this alternative is that it

Figure 6-2 Single Value Bucket Alternative
NGL extraction revenues are aggregated into a single bucket and shared between export shippers and producers.



is relatively easy to administer because it builds on the Status Quo and requires little, or no, capital costs. Volume growth at extraction plants may result from lower discretionary field recovery leading to higher extraction plant efficiencies and lower capital and operating costs at field processing plants and the extraction plants. In addition, the alternative would ensure the protection of the Alberta public interest with respect to the extraction and petrochemical plants through a fair and equitable business model.

Some benefits from the Single Value Bucket are considered to be:

- rich gas would receive higher payment from the bucket than lean gas;
- extraction contracts would still follow the physical flow of the gas, eliminating a need to track intra-Alberta deliveries,
- no identified impact on the viability of the NIT market;
- a portion of the extraction premium would flow to the producer;
- possibility of less incentive for field extraction.

Some potential issues are:

- determining producer/delivery shipper split of the value in the ‘bucket’;
- administration and data collection;
- issues with existing extraction contracts between delivery shippers and extraction plant owners;
- increased risk of gas bypassing extraction plants;
- redistribution of extraction premium value.

6.3 Receipt Contracting Alternative

Overview

The Receipt Contracting alternative shifts the right to NGL extraction entitlement from the export delivery shipper to the receipt shipper. The assumption is that producers are either receipt shippers themselves or they have agreements with receipt shippers that would allow value derived from receipt-based extraction entitlement to flow through to the producers.

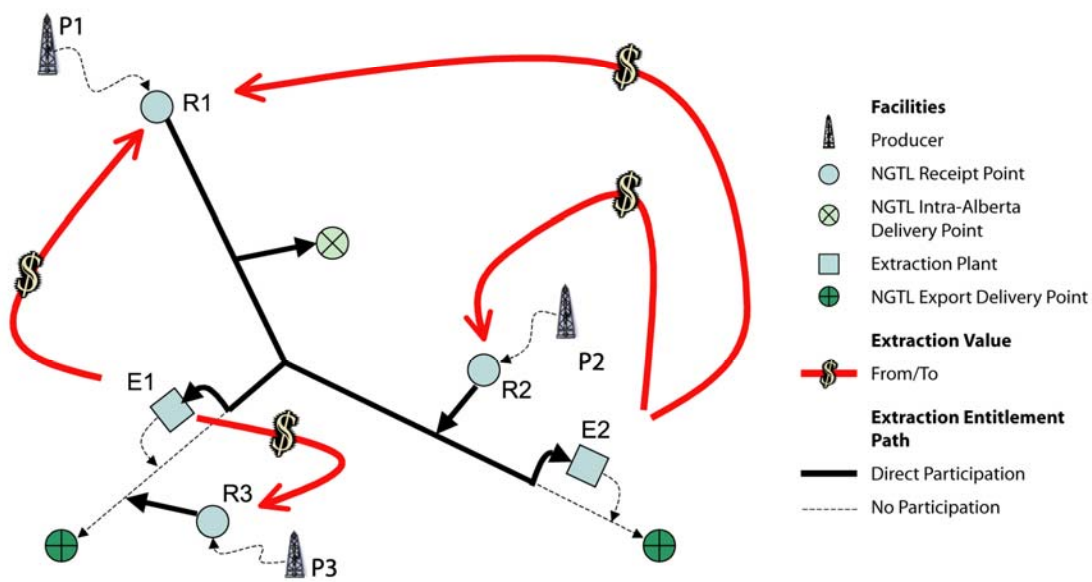
The goal of Receipt Contracting is to move value from the export shipper to the receipt shipper which could align more closely with the provincial royalty payee. Receipt Contracting would see receipt shippers receiving extraction rights for their allocated pro rated share of the common stream. Receipt shippers could choose to:

- contract directly with single or multiple extraction plants;
- default their entitlement to a pool managed by NGTL or other third party;
- bypass the extraction plants;
- name an agent to manage their entitlement.

Although this alternative does not address the lean gas/rich gas inequity, it has a goal to lay the foundation for a future solution to the problem. In addition, it would ensure the protection of the Alberta public interest with respect to the extraction and petrochemical plants through a fair and equitable business model.

In order to match the physical flow of the gas to what is actually available to the extraction plants for extraction, an east and west extraction factor would be assigned at each receipt location. The extraction factor would also include a reduction factor applied pro rata across all receipt locations for gas not available for extraction (such as intra-provincial deliveries and fuel). NGTL would need to publish these extraction factors.

Figure 6-3 Receipt Contracting Alternative
NGL extraction entitlement and revenues go to receipt shippers.



Some benefits from Receipt Contracting are considered to be:

- the extraction premium flows to the receipt shipper (but not necessarily to the producer);
- could attract richer gas to the NGTL system;
- no identified impact on the viability of the NIT market.

Some potential issues are:

- does not address lean gas/rich gas issue;
- impact on existing extraction contracts between delivery shippers and extraction plant owners;
- redistribution of extraction premium value;

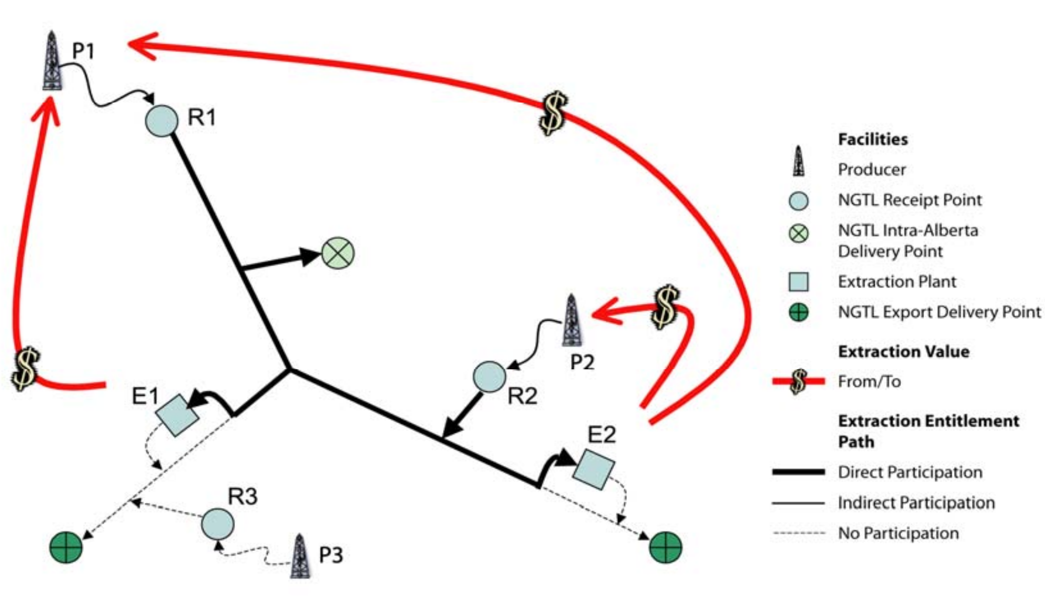
- administration and data collection;
- because there are many more receipt shippers than there are delivery shippers, extraction plants would have to deal contractually with greater numbers of players than is currently the case.

6.4 Producer Directed Alternative

Overview

The original goal of the Producer Directed alternative was to ensure that producers are provided a fair opportunity to realize the value of the in-stream components and that a producer is able to negotiate a commercial arrangement to reprocess its share of the common stream. However, in order to create an alternative that maintains the flexibility of the system as it stands today, and the efficiency of the NIT market, this alternative has changed to allow producers to contract for the right to extract liquids only. Only the gas that is physically available for processing would receive credit. In addition, this alternative would ensure the protection of the Alberta public interest with respect to the extraction and petrochemical plants through a fair and equitable business model. Practically, a producer's right to extract NGL in the common stream would be defined by the producer's residue gas and corresponding heat content upstream of the NGTL receipt point. Extraction could occur at any extraction plant on the NGTL system. The rights to extraction could be sold to other parties at any point on the NGTL system, at the receipt point, or exercised at an extraction plant. Extraction right holders would be free to make their own commercial contracts with extraction plants or to transfer their ownership rights to another party at any point in the transportation route. The extraction rights holder at the time of processing would be responsible for shrinkage makeup.

Figure 6-4 Producer Directed Alternative
NGL extraction rights and revenues go to producers.



Ownership of the liquids entrained in the NGTL common stream and the associated extraction rights would be represented by extraction rights credits (ERCs). An ERC is a volumetric unit of the common stream gas available for processing to recover NGL. The number of ERCs available on a given day would equal the gas volume available for extraction. ERCs would be allocated at the receipt point onto NGTL and tracked back to the residue gas owner upstream of the NGTL receipt point. NGTL would advise the CSO of the number of ERCs available at a specific receipt point. In lieu of full component balancing, ERCs could be allocated based on an energy content in excess of some predetermined threshold (e.g. 36 MJ/m^3). Extraction of NGL at a specific extraction plant would be limited to the number of ERCs the processor holds.

ERCs could be traded independently from the gas market and would be owned by producers until such ownership is transferred. The ERC holder would enter into an extraction service contract with an extraction plant. Any ERC holder who did not transfer his ERCs to an extraction plant on any given day would not receive any value for them and the associated volume of gas would be bypassed.

Benefits of the Producer Directed alternative include:

- producers receive value for the extraction rights;
- no impact is anticipated on the viability of the NIT market;
- it could attract rich gas to the NGTL system;
- richer gas would receive more credits than leaner gas for the same volume because ERCs would be allocated based on heat rate at the receipt points.

Some potential issues are:

- impact on existing extraction contracts between delivery shippers and extraction plants;
- redistribution of extraction premium value;
- administration and data collection.

6.5 Regulated Business Alternative

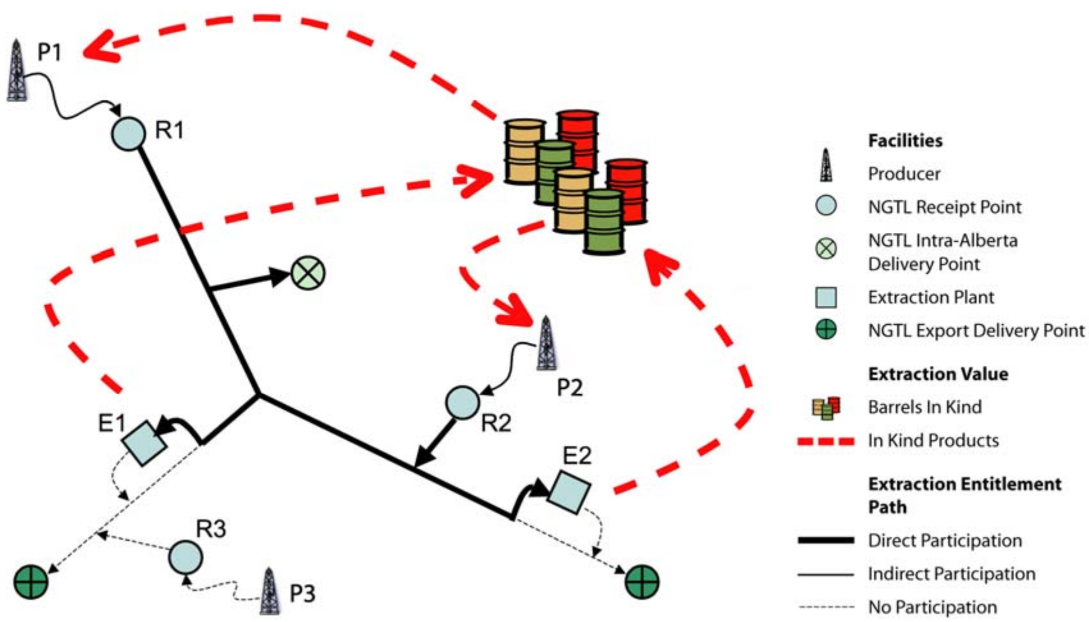
Overview

This alternative proposes that the extraction plants on the NGTL system would be actively regulated, on a cost-of-service basis, by the Alberta Energy and Utilities Board under the legislation of the Gas Utilities Act. With this alternative, the costs and yields of all extraction plants on the NGTL system would be aggregated or ‘pooled’ to represent a single composite Alberta Extraction Plant. All in-stream component owners would be required to process their component-tracked gas stream through the extraction plant and be responsible for their share of the cost of service. Each owner would be entitled to a product allocation, in kind, based on its pro rata share of entitlements, which would be derived from each owner’s specific pro rata share of components delivered to the Alberta Extraction Plant and based on its component composition at the originating receipt point.

The goal of this alternative is twofold: to ensure each owner has the opportunity to obtain the full market value of his in-stream components; and to ensure the protection of the Alberta public interest, particularly with respect to the extraction and petrochemical plants, is accomplished through a fair and equitable business model.

Ownership of the natural gas and its in-stream components would remain with producers until such rights are relinquished by commercial arrangements. Subject to the public interest, this would include the commercial right to extract the components, take them in-kind and sell them into the most profitable market.

Figure 6-5 Regulated Business Alternative
NGL extraction rights and product (barrels of NGL) go to owners. Owners pay extraction cost of service.



Under the current common stream format, owners have the right to their respective share of the common stream (natural gas and its in-stream components). In this proposed model, the common stream format would be replaced with a component-tracked model: the value available to each owner would be their respective pro rata share of the components going into the NGTL system relative to those removed by the Alberta Extraction Plant.

Benefits of the Regulated Business alternative include:

- owners would receive access to their NGL in kind (no rich/lean gas issues);
- no identified impact on the viability of the NIT market;
- extraction contracts would continue to follow the flow of the gas;

- diminished incentive for field extraction;
- no risk of gas by-passing extraction plants;
- no double-dipping with component tracking;
- more aligned with NGL royalty payments
- incremental extraction capacity or sidestreaming requires regulatory oversight;
- could assist in attracting rich gas to the NGTL system;
- provides transparency of extraction costs;
- ensures viability of extraction plants and ethane supply.

Some potential issues are:

- impact on existing extraction contracts between delivery shippers and extraction plants;
- redistribution of extraction premium value;
- increased administration and data collection;
- introduction of economic regulation of extraction plants;
- amending the Gas Utilities Act.

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Appendices

APPENDIX A

Glossary of Terms/Acronyms

For purposes of this report, the following definitions apply

Term	Meaning
CSO	Common stream operator
Component-tracked gas stream	The natural gas stream on the NGTL system upstream of any extraction plant or at any delivery point. The parties with entitlement to the gas (based on an agreed methodology) would be entitled to a prorated share of individual components contained in the gas.
Common stream	The natural gas stream on the NGTL system upstream of any extraction plant or at any delivery point that is currently accepted by all parties (receipt shippers, buyers, sellers, delivery shippers). The composition of the gas at those points where it is delivered from the NGTL system is what parties with entitlement to the gas will receive.
ERC	Extraction rights credit. Applies to Producer Directed alternative only.
Extraction plant	Any gas processing plant which has the capability to reprocess the natural gas stream on the NGTL system for recovery of NGL components and to redeliver the processed gas back onto NGTL.
Field deep-cut plant	A field plant upstream of a NGTL receipt point that has been designed specifically to process gas streams for the recovery of NGL components that do not need to be recovered to meet the hydrocarbon dew point requirement of the NGTL system as defined by the specification requirement of the NGTL Tariff.
Field processing plant	A field plant upstream of a NGTL receipt point that has been designed specifically to process gas streams for the recovery of NGL components to meet the hydrocarbon dew point requirement of the NGTL system as defined by the specification requirement of the NGTL Tariff.
FT	Pipeline transportation term for Firm Transportation service.

FT-A	NGTL term meaning Firm Transportation service for Intra-Alberta deliveries.
FT-D	NGTL term for Firm Transportation Delivery service for Alberta export border deliveries.
FT-R	NGTL term for Firm Transportation Receipt service for NGTL receipts onto the pipeline.
FT-X	NGTL term for Firm Transportation – Extraction indicating Firm transportation service for extraction shrinkage deliveries.
FT-P	NGTL term for Firm Transportation – Alberta Points to Point. Firm transportation service from one or more receipt points to a single intra-Alberta delivery point.
IT	Pipeline transportation term for ‘interruptible’ transportation service
IT-R	NGTL term for Interruptible Receipt transportation service.
IT-D	NGTL term for Interruptible Delivery. Interruptible transportation service for Alberta export border deliveries.
IT-S	NGTL term for Interruptible – Access to Storage. Interruptible transportation service for both delivery of gas to a storage facility and receipt of gas from that storage facility.
Natural gas stream	The volume of gas at any point on the NGTL system which meets the specification requirements of the NGTL Tariff.
NIT	NGTL inventory transfer.
NGL	Natural gas liquids.
Producer	An entity that produces natural gas.
Receipt shipper	A shipper putting gas onto the pipeline at a receipt point; may also be a producer providing gas from a wellhead; a purchaser at a gathering system; the buyer at a field processing plant; the buyer at a field deep-cut plant; or the buyer at a receipt point.

APPENDIX B

Historical Timelines

1. NGTL Ex-Alberta Delivery Capacity & Alberta Storage Deliverability
2. Major NGTL Transportation Holders
3. Major NGTL Rate Structure Changes
4. Major Natural Gas Pricing Events
5. Major Natural Gas Liquids & Petrochemical Industry Developments

1. NGTL Ex-Alberta Delivery Capacity & Alberta Storage Deliverability

Year Event

1958 Alberta Gas Transmission Ltd.(AGTL) Plains (eastern) gathering and transmission system completed and connected to the TransCanada Pipeline (TCPL) system at Empress to serve Eastern Canadian markets.[1]

1961 AGTL Foothills (western) gathering and transmission system completed and connected to the Alberta Natural Gas Ltd. (ANG) pipeline at the Alberta-British Columbia (ABC) border. ANG connected to Pacific Gas Transmission (PGT) at the Kingsgate international border which in turn interconnected with the Pacific Gas and Electric Co. (PG&E) serving the northern California market.[2]

1961-70 Capacity at ABC expands to serve California and Pacific Northwest markets. Service to PG&E begins at a certified level of 415 MMcf/day. During the decade, the authorized volume increases to 615 MMcf/day, then to 815 MMcf/day and finally to 1 Bcf/day.[3]

1963-1970s Capacity at Empress expands to service Eastern Canadian and U.S. export markets.[4]

1971 Capacity at Empress expands to serve Consolidated Natural Gas U.S. market.[5]

1972 National Energy Board approves a big expansion of TCPL's pipeline mainly in western Canada and Ontario.[6]

1972 Capacity at Empress expands to accommodate Pan-Alberta direct sales to Gas Metropolitain Inc.[7]

1981 Capacity at ABC expands to accommodate Pan-Alberta western leg pre-build volume on Foothills Pipeline.[8]

1981 Capacity at McNeill (near Empress) expands to accommodate Pan-Alberta eastern leg prebuild volume on Foothills Pipeline which interconnects with the Northern Border Pipeline Company in the U.S. Northern Border is either expanded or extended in 1991, 1992, 1998 and 2001.[9]

pre-
1988 Storage used primarily for gas utility management and peak shaving.[10]

1988 Alberta gas storage deliverability approximately 1 Bcf/day with working gas in storage of 50 Bcf/day.[11]

late
1980s Alberta gas storage begins to be used by producers for deliverability management. [12]

early
1990s Alberta gas storage starting to be used for export price enhancement, title transfer and outage protection.[13]

1992 Capacity at Empress expands to accommodate connection of Iroquois Pipeline.[14]

1992 Foothills Pipeline which connects to NGTL at Caroline, exists Alberta at McNeill near Empress to the Northern Border system at Monchy, Saskatchewan, is expanded from 1.075 Bcf/day to 1.480 Bcf/day.[15]

1993 Capacity at ABC expands to accommodate 1993 PGT Expansion. The expansion increases ANG/Foothills and PGT system capacity from 1.520 Bcf/day to 2.455 Bcf/day of firm transportation.[16]

mid-
1990s Alberta gas storage used to enhance pipeline balancing, capture price volatility and hub services.[17]

1994 Alberta gas storage deliverability is approximately 2.8 Bcf/day with working gas storage of 150 Bcf.[18]

1999 The Portland Natural Gas Transmission System is connected to the TransQuebec and Maritimes Pipeline. It currently has 235 MMcf/day of capacity at the international border.[19]

2005 Alberta gas storage deliverability is approximately 5.2 Bcf/day with working gas storage at 250 Bcf.[20]

2. Major NGTL Transportation Holders

<u>Year</u> <u>Event</u>

1958 TCPL major transportation holder on AGTL Plains system (NGTL's former name) removes gas from Alberta to eastern markets and takes title to gas at receipt points.[1]

1961 Alberta & Southern Gas Co. major transportation holder on AGTL Foothills system removes gas from Alberta to California market and takes title of gas at receipt points. Westcoast Transmission also starts removing small volume of gas at ABC border.[2]

1968 Consolidate Natural Gas Ltd. starts contracting for gas to export to U.S.[3]

1970 Seven ex-Alberta transportation customers at Empress and ABC including TransCanada Pipeline, A&S, Westcoast Transmission, British Columbia (Gulf), Mic Mac Group (Petro Canada Group)[4]

1971 Consolidated Natural Gas Ltd. starts shipping gas at Empress for export to U.S.[5]

1972 Pan-Alberta Gas Ltd. begins making gas purchases with U.S. export objective.[6]

1974 Alberta Petroleum Marketing Commission (APMC) is created to reinforce province's control over petroleum resources.[7] AMPC starts operations in March 1974. In November the APMC implements an administrative system that requires all natural gas produced in Alberta to be delivered to the Minister and resold to domestic and exports markets, with differential price adjustment distributed to all producers.[8]

1974 Pan-Alberta commences direct sales to Gas Metropolitain Inc. and TCPL acts as contract carrier.[9]

1979 ProGas Consortium, Pan-Alberta and TCPL apply to Alberta Energy Resources Conservation Board (ERCB) and receive approval for gas removal permits all aimed at export markets.[10]

1981 Deliveries by Pan-Alberta Gas Ltd. begin on western leg to pre-build segment of Alaska Highway pipeline.[11]

1981 Pro Gas commences sales at Empress.[12]

1982 Deliveries by Pan-Alberta Gas Ltd. begin on eastern leg to pre-build segment of Alaska Highway pipeline.[13]

1983 National Energy Board (NEB) approves Omnibus Export applications, the first such long-terms approvals given since 1970. The bulk of these additional exports planned for the period 1984-1994.[14]

1986 Major aggregators account for 90 per cent of market.[15]

1993 Number of delivery shippers on NGTL increases significantly.[16]

1993 A&S ends gas supply contracts and former producers take assignment of A&S' receipt capacity. Pacific Gas & Electric, former major producers for A&S and Pan-Alberta take assignment of the majority of A&S delivery capacity at the Alberta-B.C. border.[17]

1999 Major aggregators account for 30 per cent of market.[18]

1999 ProGas is purchased by BP.

3. Major NGTL Rate Structure Changes

Year	Event
1958	Dedicated Plant Method: specific units of plants or allocated percentages of common plant assigned to shippers requesting service under cost-of-service agreements.[1]
1980	Postage Stamp with Commodity Charge Only: all costs rolled-in and recovered through 100 per cent commodity-based charge for Alberta export shippers, based on volumes shipped to the Alberta borders. Intra-Alberta delivery rates reflected volume distance.[2]
1986	Postage Stamp with Demand and Commodity Charges: 100 per cent commodity postage stamp rate for Alberta export deliveries changes to a two-part demand/commodity rate design with NGTL fixed costs recovered in a demand charge and variable costs recovered in a commodity charge.[3]
1989	Intra-Alberta deliveries changed to demand/commodity design based on receipt point contract demands and an intra-Alberta postage stamp rate of approximately 50 per cent of the postage stamp rate applicable to Alberta export shippers.[4]
1993	One-time rationalization of contract receipt volumes to more closely match actual deliverability and needs. "… in early 1993, participants chose to focus on other issues, i.e. Contract Demand Relief …"[5]
1993	In November, NIT expands to allow bi-directional daily transfers 24/7, with a four hour notice period.
1994	In conjunction with Alberta and Southern Gas (A&S) pipeline de-contracting gas supply, the firm also de-contracts NGTL transportation. Former A&S producers or their agents assume receipt capacity rights and obligations while the A&S parent company, Pacific Gas and Electric, and certain major producers assume the majority of delivery capacity. The remaining capacity is sold either on a short-term basis or brokered away over time by AltaGas Services on behalf of PG&E.
1995	Daily inventory transfers are included in an electronic bulletin board, NrG Highway.
1996	NGTL and industry recognize that continuation of the postage stamp rate design for receipt service is unsustainable in view of numerous pipeline projects that can bypass the Alberta System at the border. A lengthy and extensive process of stakeholder consultation is undertaken with the goal of developing a new service and rate design framework.[6]
1999	NGTL files a Products and Pricing (P&P) application seeking approval of a receipt point specific rate design.[7]

2000 Energy and Utilities Board (EUB) approves the P&P application in Decision 2000-6. Natural gas for the export market is subject to a distance-and-diameter sensitive receipt charge and a postage stamp delivery charge. Intra-Alberta volumes continue to be subject to receipt charges only.[8]

4. Major Natural Gas Pricing Events

Year Event

1958 TCPL, Westcoast and A&S, the major ex-Alberta shippers of Alberta natural gas, sign reserve-based contracts with producers that generally include a fixed initial price with periodic price escalator provisions. "For the first 28 years or so of its existence, TCPL will act as a buy/sell pipeline: it will buy gas from western Canadian producers and sell it to Eastern Canadian distributors. During that period, most of the gas transported by TCPL will thus become its property."[1]

1967 NEB decision sets three-part export price criteria: (1) export price must recover costs incurred; (2) should not be less than comparable price to customers in Canada; and (3) should not be less than the least-cost alternative energy source in the relevant export market.[2]

1969 In response to inflation concerns, federal government establishes Prices and Income Commission, subjecting domestic prices to guidelines; ceases activities in June 1972.[3]

1971 U.S. President Nixon imposes comprehensive price controls extending to crude oil and natural gas and petroleum products. Effect more pronounced on oil than natural gas because interstate gas had already been subject to field price regulation.[4]

1972 Alberta ERCB releases "Report on Field Pricing of Gas in Alberta" finding that field price of natural gas is too low and have been for some time.[5]

1973 TCPL makes uniform 26 cent/mcf price redetermination offer, after ERCB freezes gas removals due to reluctance to renegotiate prices.[6]

1974 Through a decision under the modified Alberta Arbitration Act, TCPL's gas purchase price for a number of contracts is set at 60 cents/mcf effective November 1 with 13 cent/mcf increase effective November 1975 and annual redeterminations thereafter.[7]

1975 Jan. 1: export price is set at $Cdn 1.00/Mcf.

1975 April: An Alberta Arbitration Board award increases Alberta natural gas field price from 60 cents to 1.15 cents/mcf effective Nov. 1.[8]
May: Federal and provincial governments agree natural gas export prices increase, should rise to $1 to $1.40/mcf effective Aug. 1 and then to $1.60/mcf effective Nov.1, with additional revenue flowed to producers.[9]

1975 Regulated prices implemented, with differential prices in domestic versus export markets, and export flowback system to equalize return to all producers.[10]

1976 Export price increases to $Cdn 1.80/MMBu.[11]

1977 Export price increases to $Cdn 2.30/MMBu, effective Jan 1, and to $US 2.16/Mcf effective Sept. 21.[12]

1979 Export price increases to US$ 2.145/Gj effective May 1; to US$ 2.61/Mcf effective Aug. 11; and US$ 3.22/Gj effective Nov. 3.[13]

1980 Export price increases to US$ 4.17/Gj, effective Feb. 17.[14]

1981 Export increases to US$ 4.94/Mcf, effective Apr. 1.[15]

1983 Export price decreases to US$ 4.40/Mcf, effective Apr. 11.[16]

1983 Export price set at US$ 4.40/Mcf and US$ 3.4/Mcf (VRIP), effective July 6.[17]

1984 Price deregulation process starts in response to decreasing U.S. demand, with directed and limited renegotiations allowed. Major aggregators who account for more than 90 per cent of market are allowed to renegotiate prices with customers provided aggregators can get agreement from majority of netback producers.[18]

1986 Federal government replaces border price test for gas exports with price monitoring to ensure export prices do not remain below prices paid by Canadians for extended periods.[19]

5. Major Natural Gas Liquids & Petrochemical Industry Developments

Year Event

1950s Liquids extracted from gas stream to get down to pipeline specification; three small product pipelines built to move propane, butane and condensate from Imperial Oil's Devon plant to Edmonton; salt caverns in Saskatchewan and Alberta and loading facilities for propane.[1]

1951 Shell's Jumping Pound plant is built as a deep-cut facility.[2]

1960s First extraction plant constructed in Edmonton by Steelman Gas Ltd. (Dome Petroleum subsidiary) for gas processed once at upstream plants. Key markets for liquids extracted by Steelman are originally in Northern Manitoba and Minnesota. (Note: Dome is taken over by Amoco; Amoco and BP merge to form BP Amoco – name subsequently changed to BP Canada Energy Company.)[3]

1962 Shell's Waterton plant is built as a deep-cut facility.[4]

1962 First extraction plant constructed at Empress by Pacific Petroleum with initial capacity 1 Bcf/day, which expands to 1.5 Bcf/day shortly after start-up. A 6-inch liquids petroleum pipeline, the Petroleum Transmission Company, is built from Empress to Fort Whyte, Manitoba in conjunction with the plant.[5]

1965+ Field plants are constructed at Judy Creek, Harmattan, Edson, Caroline and Kaybob, and have higher propane and butane extraction capabilities. Existing plants also increase LPG extraction capabilities.[6]

1970 Extraction plant built and in operation at Cochrane on western AGTL system with pipeline from Cochrane to Edmonton (Co-Ed).[7]

1971 First shipments from Edmonton delivered on Interprovincial Pipeline to Sarnia where fractionation facilities are located. [8]

1971 Second extraction plant commissioned at Empress by Dome Petroleum (called Empress I), with ethane extraction capability.[9]

1976 Alberta Ethane Ethylene Project (AEEP) construction starts based on conception by Dome Petroleum, Dow Chemical and AGTL.[10]

1979 AEEP commences full operation and includes:

- four extraction plants (original Edmonton plant, Cochrane plant, and two Empress plants);
- an ethylene plant located at Joffre;
- and ethylene pipeline connecting Joffre plant to derivative plants at Fort Saskatchewan;
- an ethane pipeline (the Alberta Ethane Gathering System (AEGS)) connecting extraction plants to storage and ethylene plant;
- four ethylene derivatives plants; and,
- the Cochin pipeline system for deliveries of propane, propane plus, ethane and ethylene out of Fort Saskatchewan to U.S. Midwest and Sarnia.[11]

Note: The AEEP was based on an inexpensive and plentiful ethane supply. The extraction plants secured the right to extract liquids from the two major gas aggregators, TCPL and Alberta and Southern. First contracts between the ethylene and extraction plants owners were 20-year cost of service agreements. Prices paid for ethane were based on heat equivalent, or shrinkage price of gas leaving Alberta, which were regulated at that time.[12]

1983 Empress II extraction plant is commissioned.[13]

1984 Second phase of Alberta's ethylene industry begins operation and includes:

- second Alberta Gas Ethylene plant at Joffre;
- addition of two new extraction plants at Empress;
- expansion of Cochrane extraction plant;
- Shell Jumping Pound field plant as source of ethane;
- Three new ethylene derivative plants (Shell styrene plant at Scotford; Nova's linear low density polyethylene (LLDPE) plant at Joffre, and Union Carbide ethylene oxide/ethylene glycol facility at Prentiss);
- Dow's LLDPE plant in Fort Saskatchewan is added shortly, thereafter.[14]

Note: Similar to the first phase, ethane prices for the second ethylene plant were cost-of-service based using shrinkage prices. However, since natural gas prices were being deregulated, ex-Alberta natural gas and shrinkage costs were no longer determined by governments; they were now subject to negotiation.[15]

1985 New market for NGL emerges as miscible agent in enhance oil recover (EOR) leads to the addition of a substantial deep-cut extraction capability at Alberta field plants.[16]

1986 As substantial quantities of ethane are being removed at field plants, concern develops about an insufficient ethane supply for the ethylene industry.[17]

1987 Ethane supply concern prompts the Alberta government to adopt an ethane policy which assures ethane availability to satisfy existing industry requirements for period of time covered by existing ethane supply agreements. ERCB holds hearing into implementation.[18]

1990 Gas production increases while miscible flood demand wanes. Ethane supply shortage concerns dissipate.[19]

1994 Dow Chemical constructs world-scale ethylene unit at Fort Saskatchewan based on supply from field plants, in particular a new discovery at Caroline. Dow and Shell build new de-ethanizer/fractionator facilities at Fort Saskatchewan. Ethylene from Dow's plant results in commitment to expand existing Dow facilities.[20]

1999 Alberta government announces changes to natural gas and natural gas liquids royalties. [21] After extensive industry/government consultation process, new system is implemented in October 2002.

2000 Nova Chemicals and Union Carbide/Dow complete construction of another world-class ethylene plant at Joffre.[22]

2000 Alliance Pipeline starts delivering natural gas and gas liquids from Alberta and British Columbia to the Aux Sable processing plant at Joliet, near Chicago.[23]

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APPENDIX C – Reference Questions and Descriptors Tool

NGL Extraction Convention Task Force
Questions and Descriptors (by Category)

Ownership/Royalty

Lean/Rich Gas: Does the alternative differentiate between lean gas and rich gas contributions to the common stream?

Rights to NGL: Does the alternative reflect the EUB view that producers have rights to their NGL in the common stream?

Double Dipping: Does the alternative contractually extract NGL from the common stream twice?

Sidestreaming: NGL extraction from common stream then returning residue gas to common stream upstream of extraction plants

Extraction Rights Allocation: methodologies for allocating extraction rights to appropriate parties

Alignment with the Provincial Royalty Program: Does the alternative have a result whereby the party paying the royalty receive the value for the NGL?

Holder of Extraction Value: There may be differences between who contracts to have liquids extraction and the parties who initially hold the extraction rights. If there is a trail of transferred extraction rights, it may be necessary to list who holds the rights at which point in the alternative.

What Tracking is Required/Possible? Does the allocation of volume between the parties recovering liquids require that all of the liquids put onto the system in the gas be defined by volume and by component (e.g. component tracking)?
Does the amount of liquid removed at all delivery points in the system (including intra-Alberta delivery points) need to be defined to properly allocate the liquids recovered at the straddles?

Does the alternative under consideration reflect the party who owns the extraction rights until such time as the extraction rights are sold or transferred?

- Does the alternative give the receipt shipper, extraction rights to
  - Actual components put on the system
  - Proportional Components in the common stream?
- Are extraction rights bundled with the gas?
- Can either receipt or delivery shippers access extraction rights?

Common stream: How do the alternatives impact the common stream?

Contracting

Contracting Parties with Straddles: depending on the alternative, different industry parties may need to be identified at each stage or step of extraction.

Bypass of Extraction plants: When gas flows deliberately pass all liquids extraction either because the stream is too lean to contain economic liquids recovery or the extraction rights holder has not entered into an extraction contract, due to operational upsets or the shipper providing no processing instructions or a bypass instructions to NGTL.

Unavailable for Extraction: Gas that cannot flow to the extraction plants

Linkage to FT-X Service: Does the alternative impact FT-X service?

Alignment with NGTL Tariff

- Does the alternative require additional contractual processes and administration with or by NGTL?
- Does the alternative create new restrictions with respect to an individual shipper's ability to contract for receipt and delivery anywhere on the system?
- Does the alternative physically fix the location of NIT transactions?
- Is the alternative consistent with the existing tolling structure? Does it imply or require a full or partial change to point-to-point tolling or other tolling structure?
- Does the alternative have implications on the balance of the split between FT-R and FT-D tolls?

Is there an impact on existing commercial arrangements? Does the alternative impact existing commercial arrangements?

Proceeds/Value

Incremental Value & Efficiency: Does the alternative provide opportunity to reduce upstream capital and operating costs?

Value: Value is a measure of benefit determined by a party to a transaction, directly or indirectly, as a result of that transaction

- Does the alternative under consideration assist in attracting gas to the NGTL system?

Market

Transparency: Does the alternative provide an open visible market for extraction rights?

Extraction plant Viability: How does the alternative impact extraction plant economic sustainability or viability?

Non-Alberta Gas: Will parties owning gas outside of Alberta consider the convention equitable?

What is the impact on NIT viability: To be 'viable' the NIT market needs a minimum volume, a minimum number of active buyers and a minimum number of active sellers plus a price discovery mechanism.

- Will there be sufficient quantities to maintain liquidity in the intra-Alberta gas market?
- Will there need to be a liquids (*LIT*) market and will that market have liquidity?

Can Assign Or Sell Extraction Rights: Does the alternative provide the flexibility to assign or sell extraction rights?

Impact on NGL Market Efficiency, Transparency and Liquidity This descriptor was discussed at the September 14th NECTF meeting and it was decided that it was out of scope.

Residue Gas: Refers to gas which has been processed by an extraction plant and returned to the pipeline.

<u>Operations/Administration</u>

Account Balancing: Is there any impact to NGTL account balancing?

Ease of Administration: What is the relative ease of administration for each alternative with consideration for:

- number of nominations from extraction plant for NGTL to process;
- number of contracts by shippers for NGTL to implement;
- number of counterparties to allocate shrinkage and makeup gas to;
- number of staff required for NGTL to manage extraction contracts

Simplicity: Easily understood and performed by all parties

Can it be Implemented: What are the barriers to implementation?

Intermediary Extraction Value Holder: Does the alternative create an intermediate holder of the extraction rights?

How to Track Bypass Gas: This refers to any procedure or process to track NGTL gas flows which bypass liquids extraction.

Content Equalization: Sometimes NGTL has modified the delivery flows in an attempt to achieve a similar content access by extraction plants.

Flow Splitting: Allocation of flows between extraction plants. If an alternative assumes flow splitting or balancing, the process needs to be transparent and well understood.

Does it align with NGTL System?

Physical:

- Does the alternative create a contractual arrangement that would require NGTL to alter physical gas flow operations?
- Does the alternative require NGTL to track individual shipper's heating value, components or volume?
- Does the alternative recognize commingled nature of the NGTL common stream?

NGTL Administered Variation: there may be an alternative that assumes an administrator role for NGTL or some other third party.

Component Balancing: Component balancing in its strictest sense refers to ensuring that whatever volume of individual components brought onto the system matches with the volume of individual components taken off of the system. Practically speaking, component balancing would have to be pro-rated in some manner as not all of the components brought onto the system are available to be taken off of the system (e.g. Intra-Alberta deliveries, NGTL usage, extraction plant usage etc.).

Physical Balancing: measurement and allocation of energy and volume.

<u>Other</u>

Does the alternative create new issues, perceived inequities, considerations and flaws and challenges?

APPENDIX D - ALTERNATIVES

Notes to Appendix D:

1. The information from Appendix C as it applied during discussion of the various alternatives has been consolidated here for easier review of the material.
2. Some alternatives' discussions used only those descriptors and questions that could be applied reasonably to the alternative under review.
3. The category 'Other' was added later and was only applied to the Receipt Contracting and Producer Directed alternatives.

NATURAL GAS EQUALIZATION ALTERNATIVE

Overview

This alternative builds on the Status Quo and is based on the premise that the market price for natural gas includes value for NGL extraction rights that could be exercised at extraction plants. This alternative adjusts the price of the gas behind the receipt points so that producers receive their proportionate share of value based on the quality of their gas.

The equalization alternative would mirror the existing equalization processes used for crude oil and condensate in Alberta. This alternative does not alter the current commercial processes between extraction plants and holders of the extraction rights at the delivery point. In addition, it seeks to ensure the protection of the Alberta public interest with respect to extraction and petrochemical plants through a fair and equitable business model.

The goal of the equalization process is to transfer an appropriate amount of value among producers based on the component content of individual streams using scaled factors for those components that add or subtract from the overall value of the realized common stream price. This would result in leveling the playing field among producers contributing to the common stream. Producers who extract liquid in the field or produce very lean gas streams would compensate producers who deliver richer streams thereby equalizing the content value of the common stream.

The quality of individual crude oil or condensate streams entering large gathering systems differs from the aggregate quality when it exits the system as a common stream blend. Unit pricing for these crude/condensate blends is generally established at the outlet of these large gathering systems. The producers use equalization procedures to make up for the product quality differences entering a common stream pipeline and the common product price at the pipeline outlet. The equalization calculation is based on factors that have a direct impact on the quality that affects the value of the common stream to downstream buyers such as density, sulphur content and, in the case of condensate, butane.

CAPP co-ordinates the crude and condensate program, an industry committee maintains the financial scales for the program and the various pipeline operators administer the program.

The Equalization Alternative model would provide for equalization factors and scales for natural gas that would be developed and maintained in the same manner as the crude and condensate program is administered today. Heating value, as the primary driver of value for extraction rights, is the obvious factor to use in the equalization of natural gas. As an alternative, detailed equalization scales could also be developed using the components of residue gas that affect the gross heating value:

- Ethane-plus hydrocarbon component content;
- CO_2 content or total non-hydrocarbon gas content.

As with the oil/condensate process, natural gas equalization would transfer value to producers who positively contribute to the common stream price by producing rich gas from producers who negatively impact the price by producing lean gas. In simple terms, the greater the variance in heat content in a given receipt stream from the system weighted average heat content, the greater the impact equalization would have on that receipt stream.

Correctly developed and administered, the equalization process would:

1. Reduce the inequality between producers of rich gas versus those who sell lean gas either by choice through field extraction or by default through naturally dry gas reserves.
2. Give producers value for their extraction rights proportionally, based on contribution to the 'richness' of the common stream.
3. Provide value, on a proportional basis, to those producers who pay the most in ISC royalties.
4. Use industry accepted procedures, existing data and allocation systems that are already in place.
5. Preserve the simplicity and liquidity of NIT market.
6. Preserve the balance of NGTL revenue requirements between FT-D and FT-R, and maintain NGTL's operating flexibility to move gas in the Alberta system without being constrained by a connection between physical and commercial obligations.
7. Continue to allow for the administratively simple, proven convention of having the FT-D shippers exercise extraction rights on the NGTL system.

Equalization Alternative - Ownership/Royalty

<u>Rights to NGL</u>

- The delivery shipper would continue to hold the extraction rights. Equalization would help producers offset the differences in the quality of gas going into the common stream.
- Incentive for double dipping would decrease based on the equalization process since value would be transferred to richer gas producers. However, double dipping remains an issue unless disallowed by the EUB.
- May reduce producers' desire to sidestream if equalization payments are considered to be satisfactory.

- No change to product/NGL extraction rights allocation. Extraction rights would continue to be sold by producers to FT-R shippers who would, in turn, sell them to FT-D shippers directly, or through NIT transactions.

Common stream
- Rich gas producers would be compensated for increasing the value of the common stream.

Tracking
- A weighted average heat value system is required for the equalization process. Heat value would be determined from receipt points and from extraction plant inlets which would take intra-Alberta delivery into account.

Alignment with Provincial Royalty
- This equalization process aligns better with royalty payments. Producers with richest gas pay the most in In-Stream Components (ISC) royalties and would receive the greatest benefit from the implementation of equalization.

Equalization Alternative - Contracting

Extraction plants
- No change. FT-D shippers remain contracting parties.

NGTL
- No change to transportation value.

Equalization Alternative - Proceeds/Value

Value/Efficiency
- The alternative would redistribute value to those who contribute most to the common stream value.
- Producers, individually, would evaluate the benefits of equalization versus field plant recovery. Producers that have made the economic decision to invest capital in field recovery, liquefaction, transportation, fractionation and marketing systems to capture the full NGL value are not likely to abandon this investment for simple extraction rights value.
- Producers would receive market value for common stream gas including extraction rights as determined by the buyers and sellers in the open natural gas market.

NGTL
- The alternative under consideration could directionally attract additional rich upstream gas. The value to the producer may not be material enough, however, to make a material change from the Status Quo.

Equalization Alternative - Market

Markets

- No impact to gas markets is anticipated since equalization would not affect the commercial location of NIT transactions or the FT-R/FT-D transfer. It does not arbitrarily change market balance by shifting value away from FT-D shippers.
- Transparency may decrease based on the equalization model agreed upon.

Equalization Alternative - Operations/Administration

The Equalization Alternative would mean added administration for the CSO and NGTL but processes are well known to the industry. An Equalization Committee would be required to monitor equalization scale. The equalization process is already operating effectively for crude/condensate.

Administration

- Administration would be similar to crude oil processes. CAPP could coordinate producer panel to implement scale adjustments bi-annually or as required. NGTL, as pipeline operator, could administer invoicing of equalization payments between its receipt points to the CSO who in turn would allocate payments between producers behind the receipt point.
- A third party would need to administer this program and NGTL could be the administrator.
- Data required is already being collected and used to some extent in NGTL's and CSOs' existing invoicing and allocation systems.

NGTL Operations

- No change to transport contracts or balancing procedures is expected, and the alternative would maintain the efficient and simple process of matching extraction rights to export nominations.

Implementation

- Using the precedents established with the successful crude process, it would be possible to implement the natural gas equalization process.
- It would be challenging initially to set up the equalization scale based on all the parameters and their relative accuracy, but then it should run fairly smoothly.

Other

- There could be a potential for sidestream plant participants to receive equalization twice: once at their first point of entry at NGTL, then again at the outlet of the sidestream plant.

SINGLE VALUE BUCKET ALTERNATIVE

Overview

The Single Value Bucket alternative builds on the Status Quo in that the extraction plant would continue to contract with the delivery shipper. The extraction plant would aggregate all of the extraction premiums into a 'bucket'. Producers would receive a share of the overall bucket based on the heat value each producer had placed on the pipeline. Delivery shippers would also receive a share of the bucket as an incentive to negotiate the best deal for extraction. The goal of this alternative is to reduce the need for major administration while providing a share of the extraction value to producers. Volume growth at extraction plants may result from lower discretionary field recovery leading to higher extraction plant efficiencies and lower capital and operating costs at field processing plants and the extraction plants.

The Single Value Bucket alternative seeks to create more equity within the NGL extraction system and to reduce the need for major administrative changes while sharing the extraction premium between the delivery shipper and the producer. The advantage of this alternative is that it is relatively easy to administer because it builds on the Status Quo and requires little, or no, capital costs. The Single Value Bucket alternative could encourage the creation of an enlarged overall system where growth could occur more as a result of lower extraction, capital and operating costs, than from increased amounts of NGL. Also, the alternative would ensure the protection of the Alberta Public interest with respect to extraction and petrochemical plants through a fair and equitable business model.

Benefits from the Single Value Bucket alternative are considered to be:

- Rich gas would receive higher payment from the bucket. This provides an incentive to put more NGL into the system increasing the revenue going out. The opportunity for increased revenue would create the incentive to lower the cost of extraction.
- Extraction contracts would follow the physical flow of the gas so there is no need to track intra-Alberta deliveries.
- No impact on the NIT mechanism would occur but the impact to NIT pricing is unclear.
- Tracking for producer heat content and volume using registry data would be fairly simple.

S.V. Bucket - Ownership/Royalty

<u>Rights to NGL</u>

- Double dipping remains an issue unless disallowed by the EUB.
- The alternative would not totally eliminate the economic incentive for sidestreaming but may reduce the value of sidestreaming for the producer. The same regulatory issues would apply as those in place under the Status Quo.

Ownership of extraction rights until such time as the extraction rights are sold or transferred

- This is partially achieved for extraction value only but would depend on the distribution of the bucket. The producers would have no decision-making input on where the NGL are processed nor would they have access to the liquids unless the producer would hold both receipt and delivery capacity. Therefore, the producer would have limited control over NGL unless he is able to negotiate through commercial arrangements with the receipt shipper and a delivery shipper, prior to transferring title to his gas and NGL.
- The methodology as to how the bucket would be allocated to producers is unclear. Also, there's a need to motivate the export/delivery shipper to negotiate the best deal with the extraction plant.

Common stream

- The Single Value Bucket would allow more liquids value to flow to producers commensurate with the quality of the gas they placed on the system. Rich gas would receive higher value than would lean gas. The alternative proposes to use the government registry as the basis for value allocation. The royalty already takes in-stream components into account, but the alternative may affect the royalty valuation to reflect the bucket. The alternative may also affect how the government views 'value'. As a result, the reference price may go up or down. The NGL royalty valuations would have more transparency and would be less theoretical because there would be a market price in effect. The producer would have access to the 'market price' of extraction rights value transacted between the extraction plants and delivery shippers. Today, extraction plants provide a monthly report to the Alberta Energy Board (APMC 611) which provides the Value of Gas including premium (value for liquids) for non-arms length customers.
- A portion of the bucket would be allocated to the producer. As a result, rights to the value contributed to the common stream would flow back to the producer.
- It is important to note that sidestreaming affects the common stream at the inlet of downstream extraction plants.

Tracking

- There would be a need to track heat content and volume at each NGTL receipt point. Some tracking may be required behind the receipt point to allocate the value to specific producers.

Alignment with provincial royalty program

- As this alternative attempts to allocate value among lean and rich gas shippers it more closely aligns with the royalty structure than the Status Quo.

S.V. Bucket - Contracting

Extraction plants

- Would be the same as with the Status Quo in that the delivery shipper and extraction plants would continue to contract for extraction of NGL. The extraction plant operator would provide producer value to a 'bucket administrator'. The administrator would need to be a contracting party and may need to have auditing rights. The motivation for the export shipper to contract for extraction would be provided by this party receiving a share of the extraction value. Neither the extraction plant operator nor the delivery shipper would disclose commercial deals. Both would report fairly to the EUB and to the administrator the total value of extraction rights to be distributed to the producer. No change is anticipated from the current practice of extraction plant operators entering into extraction agreements with delivery shippers.

<u>NGTL</u>

- The Single Value Bucket assumes that some liquids extraction may transfer from field to extraction plants with potentially higher recoveries. Richer gas reduces the energy per unit transportation toll on NGTL.
- FT-X service would still be required. The onus would still reside with the delivery shipper (export delivery, except Joffre).
- There would be no impact on FT-X. There could be some contractual administration with respect to administering the Single Value Bucket. With regard to the ability for an individual shipper to contract for receipt and delivery anywhere on the system, there would be no change to transportation services. Only the delivery shipper would be entitled to contract for extraction.
- There would be no change to NGTL transportation services.

<u>Impact on existing commercial arrangements</u>

- There would be more transparency to the value of extraction rights. Meanwhile, the sharing mechanism of this alternative may frustrate some existing NGL extraction contracts between parties. A percentage of long-term contracts may have to be grandfathered but this is currently unknown. Also, the actual transition steps and requirements needed to move to a new alternative are unknown.

S.V. Bucket - Proceeds/Value

<u>Value/efficiency</u>

- The alternative has the potential to reduce the number of upstream field plants. There could be some incremental value shared (the effect of greater efficiency at extraction plants) and some incremental value not shared (upstream field plant cost savings).
- Given that the share of the ‘bucket’ flowing back to producers would be diluted from the share going to export shippers and the volume of gas consumed in the intra-Alberta market, it is unclear whether or not the bucket share would materially impact the decision to build upstream extraction facilities.
- A shift in value would occur with this alternative, decreasing the value to the export shipper and increasing value to the producer.
- Other commercial arrangements such as custom processing, profit sharing measures and proprietary gas could reduce the total amount of inputs into the Single Value Bucket.
- The principles for sharing the value of the bucket are not yet determined.
- The alternative may lead to an increase of gas bypassing extraction plants. Delivery shippers may not have sufficient incentives to enter into agreements with extraction plants. Gas that is not covered by agreement would bypass the extraction plant.

<u>NGTL</u>

- The alternative under consideration could directionally attract additional rich upstream gas. The value to the producer may not be material enough, however, to make a material change from the Status Quo.

S.V. Bucket - Market

<u>Market</u>

- The aggregate dollar amount of the extraction rights value would be more visible, as would the payment to the producer, contributing to transparency.
- For gas produced outside Alberta, there would be more incentive for the rich gas shipper than under the Status Quo. For the lean gas shipper the reverse is the case.

<u>NIT viability</u>

- No impact on NIT mechanism would occur but the impact to NIT pricing is unclear.

<u>Extraction plant viability</u>

- There would be increased efficiency if the gas stream becomes richer and less efficiency if more bypass gas results.
- This alternative may lead to increased gas bypass of extraction plants. Delivery shippers may not have sufficient incentive to enter into agreements with the extraction plants. Gas not covered by agreement will bypass the extraction plants.

S.V. Bucket - Operations/Administration

<u>Administration</u>

- There would be no NGTL-administered account changes to supply and demand. However, there needs to be a revenue balancing process that would determine inputs and allocations out of the bucket by a third party administrator.
- NGTL operations would remain the same as with the Status Quo but information gathering would be complex at the outset. Information gathering could eventually become routine. Overall, the alternative is more complex when compared with the Status Quo because there is more data to manage, there are more players involved including the registry, and confidentiality and data integrity issues abound.
- Increased administration costs require consideration.
- An extraction agreement would be based on the shipper's pro-rata share of the common stream and the bucket value would be distributed back to the producer via registry information.

<u>NGTL Operations</u>

- There would be no change to transport contracts or balancing procedures and the alternative would maintain the efficient and simple process of matching extraction rights to export nominations.

<u>Implementation</u>

- One barrier to implementation is existing long-term rights and contracts holders. These parties may resist change. The alternative could be implemented if several variables are satisfied. Would downstream rights holders buy in? There would be less extraction rights value flow to the export shipper at the border which could impact the decisions export shippers make with respect to liquids extraction. The result of those decisions could increase the amount of bypass gas. Another source for producer data could emerge (e.g. move to the receipt shipper, have a third party administer confidential data). Today, registry data is managed monthly while the Status Quo is managed daily. There would be a need to accept a change in how the data is handled. There is a need to assess the cost to administer this alternative.

RECEIPT CONTRACTING ALTERNATIVE

Overview

The Receipt Contracting alternative shifts the right to NGL extraction entitlement from the export delivery shipper to the receipt shipper. The assumption is that producers are either receipt shippers or have agreements with receipt shippers that would allow value derived from receipt-based extraction entitlement to flow through to the producers.

The goal of Receipt Contracting is to move value from the export shipper to the receipt shipper which could align more closely with the provincial royalty payee. Receipt Contracting would see receipt shippers receiving extraction rights for their allocated pro rata share of the common stream. Receipt shippers could choose to:

- contract directly with single or multiple extraction plants;
- default their entitlement to a pool managed by NGTL or other third party;
- bypass the extraction plants;
- name an agent to manage their entitlement.

Although this alternative does not address the lean/rich gas inequity, it has a goal to lay the foundation for a future solution to the problem. At the same time, the alternative would ensure the protection of the Alberta public interest with respect to the extraction and petrochemical plants through a fair and equitable business model.

The default pool would allow shippers who do not want to contract directly with extraction plants to receive value from their extraction entitlement. An administrator (possibly NGTL) would negotiate extraction agreements with all the extraction plants on behalf of the default shipper pool. The administrator would then pass back the pro rata share of extraction value to the default shippers, after deducting a service charge. This is similar to arrangements made on the Westcoast (Duke Energy) pipeline with respect to raw gas processing.

In order to match the physical flow of the gas to what is actually available to the extraction plants for extraction, an east and west extraction factor would be assigned at each receipt location. The extraction factor would also include a reduction factor applied pro rata across all receipt locations for gas not available for extraction (such as intra-provincial deliveries and fuel). NGTL would need to publish these extraction factors.

Because extraction plants would contract with receipt shippers, sidestreaming projects may become less attractive to producers. The receipt shipper who contracts with the extraction plant would be responsible for the shrinkage makeup. In order to avoid development of a separate NIT market, no assignment of extraction rights at NIT would be allowed. Northern gas may be accommodated with extraction entitlement similar to gas produced within the province. Export delivery shippers without physical receipts would lose value with this alternative. Meanwhile, receipt shippers/producers would have an opportunity to realize the NGL value on which their crown royalty payments are based.

The extraction plants would enter into a larger number of processing contracts with a larger number of receipt shippers which would increase administration costs.

Receipt Contracting - Ownership/Royalty

<u>Rights to NGL</u>

- Extraction rights could be allocated by the receipt shipper at the receipt point only.

<u>Ownership of the extraction rights until such time as the extraction rights are sold or transferred</u>

- The alternative would give the receipt shipper extraction rights to a proportional share of the common stream.
- Extraction rights would be unbundled from contractual flows of the gas, but would be tied to the east-west extraction factors and the intra-Alberta deliveries. The rights would be net of the volumes of gas flowing to intra-Alberta deliveries and other gas not available for extraction.

<u>Common Stream</u>

- The issue of lean/rich gas is not addressed at stage one where gas is measured by volume. A perceived inequity for lean versus rich gas exists in the Status Quo alternative. In stage one of this alternative, the treatment of lean versus rich gas would be the same as exists within the Status Quo.

<u>Tracking</u>

- Extraction rights would be held by the receipt shipper rather than the delivery shipper
- All receipt shippers would be allocated a pro rata share of extraction rights at extraction plants. There would be a need to track a pro rata share of intra-Alberta deliveries and other gas not available for extraction but no tracking of in-stream components would be required. This alternative introduces a two-step process: step one – establish extraction rights; step two – endow extraction rights to volume extracted. Daily versus monthly allocation would be trued-up the following month.
- Net storage delivery or receipt would be considered in the intra-Alberta factor.

<u>Alignment with the provincial royalty program</u>

- Increased alignment with provincial royalty program.

Receipt Contracting – Contracting

<u>Extraction plants</u>

- Extraction contracts would be with receipt shippers or their agents.

Bypass of extraction plants

- All receipt shippers would have the right to contract at extraction plants or to bypass.
- Receipt gas physically unavailable for extraction downstream of extraction plants would receive extraction rights under the proposed alternative but these could be allocated a zero factor in the future.

NGTL

- The receipt shipper or their agents would hold FT-X service.
- The alternative would require contractual processes for the default pool to be administration by NGTL. No material impact on the NGTL tolling structure would occur.

Impact on existing commercial arrangements

- There would be an impact on existing commercial arrangements.

Receipt Contracting - Proceeds/Value

Value/Efficiency

- The alternative may reduce upstream processing. However, the Receipt Contracting alternative may lead to extraction rights aggregators or trading which could restore efficiency. The impact on key industry players would be as follows: the export shipper would lose value; the receipt shipper would gain value; extraction plants would remain relatively neutral and may even benefit from competition as a result of more parties holding extraction rights bidding for service.
- Receipt extraction aggregators may be desired and evolve, except in the case of the default pool where NGTL would provide this service.
- Visible value would be shifted away from ex-Alberta delivery service holders.

Receipt Contracting – Market

Market

- No change with respect to transparency.
- Control of the downstream NGL infrastructure limits participation in the NGL market. Although the potential exists for more participants in NGL markets through custom processing, infrastructure barriers are still a factor.
- The gas supply would remain the same, but there would be more participants with extraction rights under this alternative, and no change in the number of buyers of the liquids. It is unclear whether the alternative would lead to more competition in the NGL market.
- This alternative might attract more gas and thus more NGL for recovery.

NIT viability

- No impact on NIT mechanism would occur but the impact to NIT pricing is unclear.

Extraction plant viability

- A potential still exists for sidestreaming which decreases the viability of the extraction plants.

- This alternative could create more competition for extraction plants due to more players contracting for extraction service.

Receipt Contracting - Operations/Administration

Administration

- No impact on supply/demand account balancing.
- Receipt allocations on NGTL often change at month end when CSOs finalize production. This could trigger a re-allocation of extraction which may not be reflective of daily entitlement volumes and would need to be corrected. A mechanism to correct this prior period revision could be handled in the same manner as revision for gas volumes by rolling forward, and adjustments made the following month.
- The number of parties nominating to extraction plants would increase. The number of contracts to manage would also change due to a drive for different types of contracts and commercial arrangements. Overall, the numbers of contracting parties would increase and the result would be more competition and more administration for extraction plants.
- The alternative would be more complex than the Status Quo. Different contractual arrangements for extraction rights could exist. Most receipt shippers would hold at least two extraction agreements to accommodate the east extraction and west extraction factor. It is unclear how the east gate extraction plants would be differentiated by receipt shippers and balances. Different contractual arrangements could be made between producer and receipt shipper. The decision to bypass must be exercised by the receipt shipper or the gas would go to the default pool.
- Component balancing is not required when there is no recognition for rich versus lean gas.

NGTL Operations

- NGTL would need to post an extraction factor for east and west border delivery.
- Intra-Alberta deliveries would need to be tracked.
- NGTL would need to provide an extraction rights balancing mechanism.
- Bypass volumes would need to be tracked.
- NGTL would need to handle default pool service.
- Today there are about 200 receipt shippers and about 80 delivery shippers. The number of shippers NGTL would be required to manage would remain the same but the number of FT-X contract holders would increase.

Implementation

- There are barriers that would have to be overcome before implementation. The alternative would require transition and solutions for commercial arrangements shifted to receipt shippers. Key decisions regarding administration would have to be made. Existing extraction rights holders' contracts may be frustrated. The number of extraction contracts would increase. The administration costs would increase. Additional mechanisms would be required in order to approximately balance physical gas flow into the extraction plants.

Receipt Contracting – Other

New issues/inequities

- The alternative would shift extraction value from export delivery shippers to receipt shippers. Reallocations (prior period adjustment process) would need to be applied in the following month.

Flaws/Challenges

- Entitlement contracts require an extraction factor which may not match extraction plants' physical flow and would require greater complexity to administer.
- There may be a need to move heat-value-based extraction rights at the receipt point.

PRODUCER DIRECTED ALTERNATIVE

Overview

The original goal of the Producer Directed alternative was to ensure that producers are provided a fair opportunity to realize the value of the in-stream components and that a producer is able to negotiate a commercial arrangement to reprocess its share of the common stream. However, in order to create an alternative that maintains the flexibility of the system as it stands today, and the efficiency of the NIT market, this alternative has changed to allow producers to contract for the right to extract liquids only. In addition, the alternative would ensure the protection of the Alberta public interest with respect to the extraction and petrochemical plants through a fair and equitable business model. Practically, a producer’s right to extract NGL in the common stream would be defined by the producer’s residue gas and corresponding heat content upstream of the NGTL receipt point. Extraction could occur at any extraction plant on the NGTL system. The rights to extraction could be sold to other parties at any point on the NGTL system, at the receipt point, or exercised at an extraction plant. Extraction right holders would be free to make their own commercial contracts with extraction plants or to transfer their ownership rights to another party at any point in the transportation route. The extraction rights holder at the time of processing would be responsible for shrinkage makeup.
Ownership of the liquids entrained in the NGTL common stream and the associated extraction rights would be represented by extraction rights credits (ERCs). An ERC is a volumetric unit of the common stream gas available for processing to recover NGL. The number of ERCs available on a given day would equal the gas volume available for extraction. ERCs would be allocated at the receipt point onto NGTL and tracked back to the residue gas owner upstream of the NGTL receipt point. NGTL would advise the CSO of the number of ERCs available at a specific receipt point. In lieu of full component balancing, ERCs could be allocated based on an energy content in excess of some predetermined threshold (e.g. 36 MJ/m^3). Extraction of NGL at a specific extraction plant would be limited to the number of ERCs the processor holds.

ERCs would be tradable independently from the gas market and would be owned by producers until such ownership is transferred. The ERC holder would enter into an extraction service contract with an extraction plant.

Gas produced downstream of an extraction plant would not be eligible to receive ERCs. Any ERC holder who did not transfer his ERCs to an extraction plant on any given day would not receive any value for them and the associated volume of gas would be bypassed.

The rationale behind this alternative is that producers would benefit directly from the value of their in-stream components. A potential refinement would have ERCs based on components, a change that could evolve over time.

The ERC marketplace would require commercial negotiations between significant numbers of buyers and sellers. The ERC marketplace would require sufficient liquidity to operate effectively in setting a value for ERCs.

Producer Directed - Ownership/Royalty

Rights to NGL

- The producer would hold extraction rights initially, and the holder of extraction value could trade that value forward from the wellhead. Producers would be allocated a pro rata share of extraction right credits (ERC). Any ERCs not exercised on a given day would have no value and an equivalent volume of natural gas would bypass the extraction plants.
- ERCs would only be allocated to owners of natural gas when the gas exceeded a specific threshold yet to be determined (e.g. 36 MJ/m^3).
- Production downstream of extraction plants would not be eligible for ERC allocation.
- ERCs would be separate from the natural gas stream although ERCs match the physical flow of natural gas available at the inlets to extraction plants.
- Double dipping would be prevented. No ERC holder could exercise more ERCs than allocated and an extraction plant could not process more volume than that covered by ERCs in the plant's possession.
- The alternative promotes competition which may, or may not, encourage sidestreaming.

Ownership of the extraction rights until such time as the extraction rights are sold or transferred

- This alternative reflects the party owning the extraction rights which would be unbundled from the gas.

Common stream

- The Producer Directed alternative differentiates lean/rich gas upstream of the NGTL receipt point at the producer level in the form of ERCs. The CSO would be required to allocate ERCs upstream of the NGTL receipt point daily.

Tracking

- Heat value is currently tracked upstream and downstream of field plants. ERCs would be based on tracking heat value back to producers.

Alignment with provincial royalty program

- The alternative is more aligned with gas royalty costs and responsibilities than the Status Quo because the producer has the explicit opportunity to obtain value for ERCs.

Producer Directed – Contracting

Extraction plants

- Extraction plants would contract with holders of ERCs. ERCs may be held and traded by extraction plants to achieve a daily balance among these plants.

Bypass of extraction plants

- Holders of ERCs would have to right to contract at extraction plants. The natural gas stream associated with ERCs that are not contracted to any extraction plant would be bypassed.

Unavailable for extraction

- Natural gas production downstream of all extraction plants would not be eligible for ERCs.

FT-X Service

- FT-X service would not be affected. Holders of FT-X service may not be both the ERC owner and the physical gas flow owner.

NGTL

- NGTL would allocate daily ERCs to receipt points. CSOs would allocate ERCs back to producers.
- The alternative would have no other impact on NGTL rates or rate design.

Impact on existing commercial arrangements

- There would be an impact on existing commercial arrangements.

Producer Directed - Proceeds/Value

Value/Efficiency

- The alternative may reduce upstream capital requirements.
- The alternative would require CSO/third party administration and reporting.
- This alternative provides a mechanism that makes the value of extraction rights for in-stream components explicit and visible to the owners of these components.
- The lack of a connection between ERCs and the physical flow of gas may add risk for balancing across the system which could lower the value of the extraction rights.
- Visible value would be shifted from ex-Alberta delivery service holders. Value would be shifted to producers of gas above a heating value threshold. In the case of gas entering NGTL from outside the province, the shippers on upstream pipelines who have gas above a threshold would also gain this value.

Producer Directed – Market

Market

- The ERC market would be more open and transparent than the market for extraction rights under the Status Quo.
- There would be a specific market place for ERCs with, probably, a greater number of players: producers, marketers, aggregators, extractors and export shippers might all participate. Initially, market power may be skewed in favour of the relatively small number ERC buyers (i.e. the extractors) which might reduce the value of extraction rights.
- ERCs would represent the extraction rights of the original owners or the in-stream components. ERCs could be traded at any point up to an extraction plant inlet.

- This alternative might attract more gas and more NGL for recovery.

Extraction plant viability
- A potential still exists for sidestreaming which would decrease the viability of extraction plants.
- The alternative could create more competition for extraction plants due to more players contracting for extraction services.
- Potential exists for greater bypass since there would be no default provision for ERCs that are not contracted.

NIT viability
- There would be no impact on the quantities of gas (commingled stream or methane) to maintain an adequately liquid intra-Alberta gas market. No change is expected regarding the numbers of NIT buyers and sellers. No impact is anticipated on gas/methane or existing liquids market price discovery mechanisms.
- The alternative could result in an increase in the number of shrinkage suppliers because there would be many more ERC holders than there are ex-Alberta shippers. The market place might encourage the development of ERC aggregators with fewer shrinkage suppliers as a result.

Producer Directed - Operations/Administration

Administration
- The ERC holder at the inlet of extraction plants would be responsible for shrinkage make-up and, therefore, would require an NGTL account. A mechanism for allocating shrinkage make-up would be required that would include daily and monthly processes, likely based on how the ERCs were exercised.
- Administration needs and costs would increase, beyond those in effect under the Status Quo, for the ERC administrator, NGTL, the CSO and the extraction plant operator. This alternative would require two levels of administration – one for the current gas and one for ERCs.
- An ERC administrator would be required to manage the entire ERC program.
- Producers with gas below the threshold may be at a disadvantage if they had to pay administrative costs.
- Component balancing could be a further refinement of this alternative.
- An intermediary extraction value holder would not be required but aggregators may evolve.
- An administrator/NGTL would need to get the ERC allocations back to extraction plants.

NGTL Operations
- NGTL would allocate volumes to extraction plants based on the physical flow of gas and the ERCs contracted by extraction plants each day. ERCs allocated on any given day would be made equal to the volumes of gas available to the extraction plants.
- Physical Alignment: This alternative does not create an NGL-driven contractual arrangement that would require NGTL to alter physical flow operations. There would

be a need to track heat value at the producer level. The alternative does recognize the commingled nature of the common stream.

Implementation

- Barriers would have to be overcome before implementation, and contractual ‘grandfathering’ may compound these barriers. Existing extraction rights holders’ contracts may be frustrated. The alternative would require transition and solutions for commercial arrangements that would be different than under the Status Quo. Key decisions would have to be made about administration. A mechanism for administering ERCs would have to be developed. A discussion model suggests a daily estimate for determining gross ERCs at NGTL meter stations is possible that would meet requirements for receipt production and east/west physical swings on the pipeline.
- This alternative would require considerable lead time because of the complexity for developing an ERC market and contractually separating physical flows and ERCs.

Producer Directed – Other

New issues/inequities

- Export shippers would lose the value of their extraction rights.
- Industry would need a mechanism for tracking and balancing/allocating ERCs with the physical flows to extraction plants.
- The alternative would likely cause the evolution of an ERC market.
- Timing issues relate to the month end process and the reallocation process.
- It is unclear who would set thresholds; how thresholds would be set; and how often.
- NGTL would be responsible for the data at the receipt point, and the CSO would be responsible for the data behind the receipt point.

Flaws/challenges

- Gas produced outside Alberta could be accommodated with this model by having the connecting pipeline operator allocate ERCs.

REGULATED BUSINESS ALTERNATIVE

Overview

This alternative proposes that the extraction plants on the NGTL system would be actively regulated, on a cost-of-service basis, by the Alberta Energy and Utilities Board under the legislation of the Gas Utilities Act. With this alternative, the costs and yields of all extraction plants on the NGTL system would be aggregated or ‘pooled’ to represent a single composite Alberta Extraction Plant. All in-stream component owners would be required to process their component-tracked gas stream through the extraction plant and be responsible for their share of the cost of service. Each owner would be entitled to a product allocation in kind, which would be derived from each owner’s specific pro rata share of components delivered to the Alberta Extraction Plant and based on its component composition at the originating receipt point.

The goal of this alternative is twofold: to ensure each owner has the opportunity to obtain the full market value of his in-stream components; and to ensure the protection of the Alberta public interest particularly with respect to the extraction and petrochemical plants, is accomplished through a fair and equitable business model.

Ownership of the natural gas and its in-stream components would remain with producers until such rights are relinquished by commercial arrangements. Subject to the public interest, this would include the commercial right to extract the components, take them in kind and sell them into the most profitable market.

Under the current common stream format, owners have the right to their respective share of the common stream (natural gas and its in-stream components). In this proposed model, the common stream format would be replaced with a component-tracked stream model: the value available to each owner would be their respective pro rata share of the components going into the NGTL system relative to those removed by the Alberta Extraction Plant.

In brief, this alternative is intended to provide a balance between maintaining the viability of the extraction plant system and the rights of owners to capture the in-stream components of their natural gas in-kind.

Further key components of this alternative include the following:

- All owners of the natural gas stream, subject to a threshold, that can physically have their liquids extracted, would be required to contract with the Alberta Extraction Plant with the exception of purchases for intra-Alberta consumption. Owners of the natural gas stream would be responsible for their share of the cost of service and for disposition of the products recovered. There would be no requirement for shrinkage make-up with this alternative as each owner would take his product in kind.
- Each owner of the common stream who contracted for processing with the administrator for the Alberta Extraction Plant would receive his share of in-stream components based on a pro rata yield at the extraction plant outlet.

- The mechanism by which this would take place would involve aggregating the costs and allocating the in-stream components from each of the existing extraction plants. The revenue requirement would be compiled by each of the extraction plants and aggregated into a single common rate, and subject to an AEUB hearing.
- Extraction plant yield would be aggregated in order to ensure efficient utilization of existing extraction plant infrastructure. An administrator would dispatch the owner's gas to the extraction plants based on physical constraints and plant efficiency (most to least). Yield would then be allocated to the owners based on a pro-rata share of each plant inlet.
- A tariff-based contractual relationship would exist between the Alberta Extraction Plant and the owners of the natural gas and its in-stream components.

Regulated Business - Ownership/Royalty

Under this model, the extraction plants are owned by the respective investors. The natural gas and in-stream components are owned by the respective producers until such ownership is transferred by way of commercial agreement to another party. The model would be based on full component tracking as the in-stream component owner has the obligation to take product in kind. Another proxy may be used if it satisfied the needs of this model.

<u>Rights to NGL</u>

- Double-Dipping would be impossible with component tracking. An owner can only make transactions until the account reaches zero.
- Sidestreaming would only occur as a regulated entity and be subject to need and necessity to serve the public interest.
- The alternative confirms ownership of extraction rights until such time as they are sold or transferred by way of commercial agreement.

<u>Common stream</u>

- The concept of a common stream is replaced by the concept of a component-tracked gas stream as this alternative assumes full component balancing.
- Rights to the in-stream components in the component-tracked gas stream would be owned by producers until such ownership is transferred by way of commercial agreement.
- The lean/rich gas issue would be resolved with the Regulated Business model because extraction rights holders would retain their respective components.

<u>Tracking</u>

- Product/NGL Allocation would require component tracking or alternate proxy.

Alignment with Provincial Royalty

- Model is more aligned with gas royalty costs and responsibilities than the Status Quo because the owner would have the opportunity to recover the in-stream components on which he has paid royalties.

Regulated Business - Contracting

The owner of a respective share of the component-tracked stream would enter into an extraction service contract with the administrator of the pooled extraction plants. The extracted products would be either delivered in kind or some other commercially agreed arrangement would apply. Each owner would then be responsible for his allocated NGL.

Extraction plants
- This alternative would require transition and solutions for existing commercial arrangements.
- Bypass would be an issue as all extraction plant capacity available to process the gas would be used.
- Owners whose gas cannot physically access an extraction plant would be ineligible to participate.

NGTL
- FT-X would still be required for custody transfer purposes but not for shrinkage make-up.
- The Regulated Business alternative aligns with the NGTL system.

Impact on existing commercial arrangements

- This alternative would require transition and solutions for existing commercial arrangements.

Regulated Business - Proceeds/Value

The extracted product would belong to the respective owner of the extracted products in the component-tracked stream.

Value/Efficiency
- Would maintain viability of current extraction plants to serve the public interest.
- Would provide the owners of the recovered in-stream components (NGL) with full market value.

NGTL
- The alternative would assist in attracting gas to the NGTL system because the value would remain with the resource owners.
- Regarding the issue of intermediary extraction value holders, these parties would be those who held the in-stream components at the extraction plant.

Regulated Business - Market

The alternative is based on extraction services provided on a cost-of-service basis which results in commercial transactions between buyers and sellers at the outlet of extraction plants.

Market

- Market transparency could increase due to owners taking their products in kind.
- Component tracking would likely produce more sellers for components which may have an impact on competitiveness, but an increase in competitiveness would require additional sellers, as well.

Extraction plant viability

- This would be maintained through cost-of-service regulation at just and reasonable rates.

NIT Viability

- Does not affect NIT viability.

Regulated Business - Operations/Administration

Administration

- No change in terms of account balancing but component holders must have NGTL accounts and would be subject to account balancing provision.
- This alternative would require an administrator and costs would increase as a result. The role of administrator is extensive under this alternative. The administrator could aggregate the nominations for the extraction plants and there would be fewer nominations than today.
- The administrator’s role:
  - calculates each owner’s in-stream components
  - handles dispatch to extraction plants
  - allocates extraction plant yield to component holders
  - administers pooled concept of costs and yields.
- This alternative uses a form of component tracking and balancing which is pro-rata share of extraction plant yield. An approved extraction plant tariff would also make it easier to understand and administer.
- An administrator/NGTL would need to get component holder allocations to the extraction plants and to component holders, as well.
- This alternative would use component balancing. All component holders would receive a pro-rata share of the pooled extraction plant yield.
- The physical balancing process is encompassed within the dispatch process.

NGTL Operations

- Content equalization would be accomplished through the administrator dispatch process (most efficient to least efficient). The operation may be modified to enhance the efficiency of the extraction plant infrastructure.

- Flow splitting would occur through dispatch by the administrator with inputs for border volume requirements and extraction plant efficiency.
- A mechanism needs to be defined to describe the dispatching process.

Implementation

- Barriers would have to be overcome before implementation, and contractual ‘grandfathering’ may compound these barriers. The alternative would require transition and solutions for commercial arrangements that would be different than under the Status Quo. Key decisions would have to be made about administration. There would be winners and losers under this alternative. Existing extraction rights holders’ contracts may be frustrated. Development of an appropriate component tracking and balancing system is required for this alternative to work.