JP-05: A RECOMMENDED PRACTICE FOR THE NEGOTIATION OF PROCESSING FEES

JOINT INDUSTRY TASK FORCE REPORT

prepared by

Canadian Association of Petroleum Producers
Gas Processing Association Canada
Petroleum Joint Venture Association
Small Explorers and Producers Association of Canada

October 2005

Contents

(continued)

JP-05

"We endorse or support the JP-05 Task Force Report. We encourage the industry to consider the Report's findings and use these recommended practices, as we believe they will assist the industry in the negotiation and determination of processing fees."

Endorsed By:

CAPP
CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

GPAC
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Kimi J. Rotz

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Supported By:

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COMPANY2COMPANY ADR COUNCIL

EUB

Executive Summary

The Company-to-Company (C2C) Dispute Resolution Task Force, as part of its recommendations to industry in 2004, suggested that the issue of the appropriate method for calculation of fees be readdressed. The belief of that task force and of the EUB was that fees had become a significant part of industry disputes and that the current guideline for fee determination (JP-90/95) was not being used effectively.

As a result, a new task force was formed with representatives from CAPP, GPAC, PJVA, and SEPAC, along with participation from the EUB. This task force decided to create an entirely new document rather than a revision or addendum to JP-90/95. The goal of this recommended practice is to improve the negotiating process and so result in more outcomes that are mutually acceptable to the parties with fewer disputes. However, the practices recommended remain suggestions.

A primary recommendation of JP-05 is that the basis of any fee be disclosed to the parties, as is relevant to the negotiation. The task force believes this recommendation is more practical than under JP-90/95 due to the simpler nature of the fee calculation and the reduced breadth of the range between the upper and lower limit proposed.

The recommended fee formula is

20% * Rate Base + Operating Costs + Lost GCA

where

- the rate base is a negotiated number from original cost to replacement cost,
- operating costs are the same as for facility owners, and
- lost GCA reflects the reduced royalty credits on *unused* capacity capital.

There are a number of situations for which the application of JP-05 is not appropriate:

- any case where the fee is partially a financing arrangement
- existing contracts
- new midstream facilities
- regulated facilities

The JP-05 report recommends appropriate dispute resolution practices and describes how tools for dispute resolution can be sourced from industry. There are sections in the report on regulatory issues and the linkages between JP-05 and Alberta oil and gas regulatory guides.

1 Introduction

This report (hereinafter referred to as “JP-05”) is a continuation of the work begun with JP-90 and JP-95. The context for JP-90 was a concern of the regulators for processing plant fee practices by the industry. With government encouragement, industry developed JP-90 (and later on its own initiative, JP-95) to improve the process of negotiation by providing guidelines on a number of factors affecting processing fees recognizing a range of potential considerations and outcomes as well as to make dispute resolution more effective. These goals remain the focus of the industry work on this matter and the practices recommended in this report remain guidelines for use in the event the parties fail to reach successful conclusion of negotiations. In that regard, negotiations operate freely in a competitive marketplace where successful negotiations are a result of freely reached agreement and where failure of negotiations may lead to regulatory proceedings.

This JP-05 report was prepared in response to recommendations made to the upstream petroleum industry by the Company-to-Company (C2C) Task Force on dispute resolution and recognition by the upstream industry of a need to update and revamp the JP-90/95 guidelines. The C2C Task Force was a voluntary energy industry initiative driven by landmen, engineers, accountants, lawyers, and joint venture, administration, regulatory, and dispute resolution professionals, with over 70 individuals participating. The C2C Task Force has evolved into the C2C ADR (Appropriate Dispute Resolution) Council. The Task Force report and recommendations were endorsed by eight industry associations and two regulators by their signatures.

In its report, the C2C Task Force recognized that fees are an integral part of many industry disputes and that there is a lack of clarity and consistency in the industry’s application of fee calculation methodology. Specifically, the C2C Task Force recommended that the upstream petroleum industry address

1) effective use of JP-95 to promote negotiation of fair processing fees;
2) those protocols which can be applied to resolve fee disputes;
3) recommended ways of ensuring that the industry is acting properly in the application and use of JP-95;
4) the development of a users’ guide to assist in the application of JP-95;
5) means of building industry awareness of the requirements for the use of JP-95;
6) strengthening the requirements for the application of JP-95, both through the regulatory process and through industry association stewardship; and
7) any other industry issues around the use of JP-90/95, specifically issues not adequately dealt with in either the JP-90 or JP-95 reports.

The mandate of the JP-05 Task Force (based on the above recommendations) is to

1) provide clarity on content and process in fee determination and negotiation; and
2) incorporate the C2C principles and processes for resolving fee disputes.

This new Recommended Practice was deemed necessary because, although the industry generally adopted the fee calculation methodology of JP-90/95, most of the other principles of JP-90/95 have not been ingrained as industry practice. Perhaps the two biggest areas of concern were

1) failure to follow the practice of relevant disclosure (see chapter 4 for more information on disclosure) between negotiating parties, and

2) lack of an effective dispute resolution mechanism.

The JP-05 Task Force decided at an early stage of the review that an explanation or addendum to JP-95 was not the best alternative available. A new standalone report has consequently been created. This Recommended Practice supersedes JP-90 and JP-95.

For a more detailed historical perspective, refer to the summaries from both the JP-90 and JP-95 reports, reproduced as Appendix A attached.

The term "processing fee" as used in this report also includes other facility fees, such as transportation and compression. The principles of this report also apply to any fluid handling facility fee in the petroleum industry.

Although the word "partner" has been used to describe joint venture participants in various places in this report, it should be noted that we are not implying legal partnerships.

1.1 APPLICATION, SUPPORT AND DISCLOSURE

1.1.1 Application

Experience suggests that in the majority of situations, the fee quoted would be regarded as reasonable and the parties would execute an agreement. If processing arrangements can be agreed upon without using the methodology of JP-05, then it is not necessary to use the Recommended Practice or disclose cost recovery information to test these negotiated fees.

Where initial discussions have failed, the parties are encouraged to apply effective negotiation techniques (see later chapters) that include disclosure and justification of the relevant information used to derive the fee.

JP-05 applies to fee derivations in the following circumstances:

- fees negotiated between producing (E&P) companies needing or holding unused facility capacity, where such capacity was originally constructed for a producer's own use rather than for custom processing;
- fees developed by companies that offer midstream processing services;
- fees required by CAPL Joint Operating Agreement partners that elect non-participation in a production facility and elect the fee option under a CAPL operating agreement;
- fees required by freehold mineral rights owners where the fees have not been specified in the lease agreements; and
- fees required by parties that elect non-participation in a new facility development to be the subject of a CO&O Agreement.

1.1.2 Sanctity of Existing Contracts

The fee structure guidelines are intended to be applied on a go-forward basis, since the Task Force acknowledges that there is sanctity of existing contracts. However, in situations where disagreements exist within existing contracts, such as to the methodology of fee determination or ambiguity in terms, the fee guideline described in this report could be used as an objective benchmark for comparative purposes.

1.1.3 Support

This Recommended Practice was endorsed by the following organizations, who were represented on the JP-05 Task Force by the following individuals:

1) Canadian Association of Petroleum Producers - CAPP
   - Jerry Harvey – CNRL
   - Rob Kerr – Anadarko
   - Rick Steffensen – Petro-Canada
2) Gas Processing Association Canada – GPAC
   - Paul Nelson – Taylor Gas Liquids
   - Frank Serpico – ATCO Midstream
3) Petroleum Joint Venture Association – PJVA
   - Kevin Gilliham – Burlington Resources
   - Tim Reimer – Conoco Phillips
   - Noel Smyth – Keyera Energy
   - Mike Taylor – Devon Canada
4) Small Explorers and Producers Association of Canada - SEPAC
   - John Kingsbury – GPMi

As well, advice and support was provided from the Alberta Energy and Utilities Board (EUB) by

- Georgette Habib
- Bill Remmer

1.1.4 Disclosure

For negotiations or other forms of ADR (see chapters 2 and 9), the parties should engage in collaborative discussions and disclose all relevant information so that full understanding of each other's objectives and interests can be achieved. The parties can develop privacy and confidentiality agreements where necessary.

Disclosure can be an iterative process where each party should understand the need for the information and why it has been requested. This iterative process and the provision of appropriate information with a demonstrated need as part of the negotiations is defined as "relevant disclosure" throughout this document. As a minimum, parties should disclose the input data used in the JP-05 calculations.

The concept of relevant disclosure is integral to fee negotiations conducted under the JP-90 and JP-95 guidelines. However, the practice has never gained complete acceptance or been rigorously applied. The JP-05 Task Force believes one reason for this is that in any situation where facilities exist as a natural monopoly, it has always been easier and quicker for the facility operator to state a fee with a "take-it-or-leave-it" implication. In practice, most facilities are in this position due to the impracticality of building new facilities. This is due to the lack of economically viable options caused by the time delay required to build versus using existing infrastructure, or occasionally due to regulatory constraints.

Another reason for the historical lack of disclosure may be an excessively large range between upper and lower limit fees derived from the calculations suggested in JP-95. The concern of parties with capacity to rent appears to be that disclosure would weaken their bargaining position and always drive the fee to the lower limit. It is the opinion of the JP-05 Task Force that the probability of relevant disclosure is inversely proportional to the breadth of the range between the upper and lower limit fees. It is the intention of the Task Force to reduce the breadth of such range, thereby encouraging disclosure between negotiating parties.

Further, where "use of capacity" fees will have a material dollar impact on the processor and the producer (significant volumes and high per unit cost), it remains the recommendation of this Task Force that those parameters used in the calculation of the fee be disclosed. These parameters would include, but are not necessarily limited to

1) rate of return
2) facility life
3) facility capacity
4) capital base
5) the basis of derivation of the capital base
6) the basis for determination of operating costs

Fee disputes that proceed to some form of dispute resolution or come before the EUB for settlement will have, as part of the process, the requirement to disclose all such parameters. The EUB has stated that failure to disclose will result in disputes being sent to ADR for the parties to resume negotiation, or the EUB may factor such lack of disclosure into its hearing deliberations.

2 Keys to Successful Fee Negotiations

The cost of fee disputes between companies in the oil and gas industry is measured in time and money wasted, relationships damaged and opportunities missed. The implied message for those involved is plan and prepare for negotiations, engage in effective and collaborative communications, avoid conflict in the first instance, and reach agreement in a timely and effective manner.

The focus of this document is to assist those directly involved in fee negotiations by providing a methodology and tools to calculate fees, which can be used as a guide or standard as the parties continue with their direct negotiations. The JP-05 Recommended Practice should bring the parties closer to agreement by providing industry-endorsed guidelines for fee determinations.

However, regardless of the numbers, parties will limit their chances to reach agreement if they will not communicate face to face, will not take the time to understand the needs and concerns of the other party, or will not disclose even how they calculated the fees they desire. The need to improve negotiations has been recognized by the industry associations and their regulators in a number of recent initiatives, including the C2C ADR Council's *Let's Talk Handbook* and the inclusion of new ADR clauses in the CAPL operating procedures, PJVA model agreements, and EUB ADR guidelines. All these initiatives have a number of common themes:

1) to encourage the right people to communicate in the right way at the right time;
2) to encourage parties to solve their own disputes more effectively; and
3) to mitigate the potential for disputes to impact long-term business relationships adversely.

To ensure that negotiations are effective, parties must prepare for the negotiations and be willing to engage in a genuine problem-solving process. Accordingly, representatives of the parties should

1) conduct themselves in an honest and forthright manner, i.e.,
    - be willing to meet early and face-to-face,
    - not withdraw from the communications, and
    - not use "power plays" or coercion to win agreement;
2) have the necessary authority to deal with issues that must be resolved and be willing to bring in senior individuals to assist where required;
3) disclose all relevant information required for a complete, frank discussion of options;
4) be willing to listen to the other party's representatives, understand their concerns and interests, make accommodations, and consider alternative solutions;
5) be able to separate the people from the issues to be resolved; and
6) be willing to jointly design a process to resolve fee issues and not let concerns escalate into a dispute.

Readers will find in the C2C ADR Council's *Let's Talk Handbook* useful and practical suggestions why and how to manage conflict and improve the likelihood of successful processing fee negotiations. Pages 81-94 of the handbook are devoted to proven ways and means to achieve a successful resolution of processing fee issues. You will find the Cost-Benefit Analysis and Problem Solving Planner particularly suited to identifying and selecting the most appropriate approaches to resolving processing fee disputes. No two disputes are alike, and each may need a different approach or plan to achieve a successful resolution.

These pages of the *Let’s Talk Handbook* will help you plan your approach. Two useful tools included in the handbook are

1) Cost-Benefit Analysis Tool—a worksheet used to assess the full cost associated with a range of options to deal with the dispute, including
   - internal and external resources;
   - lost opportunity;
   - time value of money; and
   - chances of success
2) Problem Solving Planner—a set of forms that assists the negotiators by asking a number of key questions, including
   - where are we in the negotiation and what got us here?
   - what are my needs, expectations, and concerns; and those of the other parties?
   - what are the challenges and barriers?
   - what are resolution processes and procedural options?
   - how can we quantify risk and present values of outcomes?
   - how do we measure success?

Information on the C2C ADR Council and the *Let’s Talk Handbook* can be obtained on the C2C ADR Council web site at www.webstart.ca/c2c

3 Special Circumstances Not Addressed by JP-05

The JP-05 report addresses most issues that require consideration when negotiating gathering and processing fees. However, in a business as complex as the energy industry, there are always situations that occur that may affect fee negotiations and cannot be addressed in the framework of a negotiated-fee-for-service methodology. Examples of some of these circumstances follow to help participants in potential fee negotiations where unique situations may require resolutions not anticipated in this report.

3.1 Working Interest Owner (WIO) Financing

One exception from a JP-05 derived fee must necessarily be the situation whereby one working interest owner (WIO) in a well, gathering system or other facility proposes to expend capital that would increase the flow of gas from such well or through such gathering system or facility and where all gas must flow through the equipment proposed.

If one or more WIOs do not participate for their proportionate share of the capital expense but share in the benefit of that expense, then the fee that the funding WIO may charge is not subject to JP-05. Fee determination in such a situation is ideally addressed in the applicable joint operating agreement; however, if not, it is up to the parties to decide an appropriate methodology based on applicable risks and rewards.

3.2 Transaction-Based Fees

When an owner sells its interest in a facility to another party and continues to produce to that facility under a proprietary arrangement included as part of the transaction, the fee in that agreement is not subject to JP-05 during the term of such an agreement. For example, a plant owner may willingly sell its interest in a facility at a price and in return pay processing fees that are lower or higher than JP-05 would suggest. The new plant owner could not subsequently revise the fees to align them with JP-05 during the term of the applicable agreement.

3.3 New Mid-Stream Facility

If a facility is built by a third party to handle a producer’s production, the fee structure for the “anchor” producer need not be according to JP-05 for the initial production stream.

3.4 Production Back-out

In some circumstances, it is possible that the addition of new production into existing facilities will change the operating conditions in the facilities, thereby reducing existing production, and causing production back-out. This is likely to occur on gathering systems or compression, where the addition of new production will raise compression suction pressure or increase gathering system pressure drop.

In most cases, the fundamental issue is whether or not capacity is available. If new production causes a production back-out, then there is insufficient capacity available to gather, compress or process additional volumes. In this event, the party requiring capacity must recognize not only the value of the service, but also the impact on existing production.

Where capacity is not available, owners and users of infrastructure could consider

a) third parties adding their own facilities at their own cost to access the existing facilities, thereby minimizing the back-out of existing production;

b) third parties requesting the processor to add facilities to accommodate additional volumes, with recovery of costs through fees to the third parties;

c) waiting for capacity to become available; and

d) negotiating a back-out fee.

Processors are encouraged to assess the benefits of having the additional volumes in any of the facilities that will be used, particularly the benefit on their total facility operating costs.

The goal in any solution should be to assess all options that allow for the additional production to access the facilities and the removal of constraints to that access.

The JP-05 Task Force has determined that it is not within the scope of JP-05 to prescribe the methodology for the determination of costs or fees that might be applicable due to deferral of existing production, as these costs entail timing of deferral, product pricing, production burdens, and degree of production back-out. Any attempt to do so would require extensive identification of all the potential circumstances and potential variables that might impact the displacement of existing production.

4 The Basis for Development of a Capital Fee

4.1 Recommendation

The JP-05 Task Force recommends that the following practices be established for the determination of the capital fees for both producer-owned facilities and midstreamer-owned facilities:

1) The rate of return on capital be fixed at 20%.
2) The depreciation component of the capital charge be eliminated.
3) The recommended lower limit rate base be the as-spent capital, including any capital additions during the life of the facility, with the provision that the lower limit not be less than 50% of the upper limit.
4) The upper limit rate base be the replacement cost of the facility.
5) The relevant range for calculating a capital fee for non-involved third parties upon recapitalization or a market-based transaction of a facility be between the lower limit and the upper limit on the same basis as if the recapitalization had not taken place.

4.2 JP-05 Foundation

JP-90 and JP-95 reports developed guidelines to determine fair value gathering and processing fees within a relevant range to promote negotiation of fees between owners of facilities and custom users. In doing so, the reports recognized that certain key economic principles were important to the methodology used by the processing business:

1) Processing fees should involve rates of return on capital reflecting the expected industry rates of return used by facility owners to make the investment decision and reflect the risks taken by those owners in constructing the facilities.
2) Each negotiation for custom processing is unique. There is not one “correct” capital fee for any given negotiation. The capital rate base, and thus the capital fee, will lie within a “relevant range” depending upon the specific economics, the risks and benefits of the type of service, and the availability of capacity.
3) The risk of unused capacity remains with the facility owners. A fee structure must, therefore, reflect the benefit of accessing the unused capacity and properly compensate facility owners for renting it out.

To provide a fee methodology consistent with these principles, the JP-90 and JP-95 reports recommended a basis for fee determination consisting of three components:

- a capital fee to realize a return on a facility;
- an operating fee to recover the actual costs of operation; and
- a fee to recover the lost Gas Cost Allowance (GCA) to plant owners for additional Crown royalties arising from reduced GCA claims.

The determination of the fee for negotiation was contained within the capital fee methodology.

The capital fee determination contained several parameters:

1) A return on capital to be used to provide appropriate returns to a plant owner for use of his asset, while not unduly restricting the development economics of the custom user.

2) Depreciation charges to reflect the useful facility life, with the recommendation that the facility value be depreciated to not less than 50% of historical cost including additions. This recognized that an operating plant has value to its owner, as well as to a custom user.

3) JP-90 and JP-95 introduced the idea of upper and lower limits or a relevant range using the capital rate base as a parameter in recognition of the need to define the playing field for negotiating processing arrangements in which producers had originally developed the facilities for their own purposes. JP-90 also envisioned that the circumstances and risks characteristic to the custom processing situation would determine where within the relevant range the appropriate answer should be sought. The lower limit of the relevant range is the depreciated as-spent capital to a limit of 50% of the as-spent capital. The upper limit of the relevant range is the undepreciated replacement cost of the facility or of that portion of the facility (i.e., functional unit) being accessed. Processing fees developed at the upper limit should reflect situations where the risk to the owners of being unable to access their capacity is high, such as providing firm custom processing capacity in a facility with limited available capacity. By establishing the capital rate base as the single degree of freedom to negotiate a fee, the methodology sought to simplify the basis for which an owner and user could reach a negotiated agreement on a fee.

With the increase in companies that are purchasing or building facilities solely for the purpose of custom processing (midstream companies), JP-95 recognized that establishing a relevant range based only on the capital rate base may not be an effective means to develop a fee structure for these situations. As a consequence, JP-95 also provided a basis for the determination of fees at a facility owned by a midstream company by recommending that the return on capital be the negotiated variable for fee determination, rather than the capital rate base.

4.3 JP-05 Capital Fee Determination Issues

In its deliberations, the Task Force recognized that the concept of using the as-spent capital versus replacement cost as the single degree of freedom for negotiating a fee has led to several outcomes:

1) For older facilities, the relevant range has widened to the point that the variation between the upper and lower limit for negotiation is excessive. This inhibits disclosure and hampers negotiation.

2) To generate more favourable positions within the relevant range, owners and users of facilities are modifying the JP-95 recommended depreciation and rate of return methodology to enhance their positions on fees. This inhibits disclosure and hampers negotiation.

3) Rather than disclose the relevant information required to determine the appropriate position in the relevant range for the specific processing circumstance, companies are resorting to tendering a fee on a “take-it-or-leave-it” basis, citing reasons of confidentiality or inability to provide data as the basis for their fee negotiation. This inhibits disclosure and hampers negotiation.

4) Non-specific guidelines in JP-95 for dealing with the determination of capacity or capability in compressors and pipelines has led owners to employ whichever methodology generates the greatest benefit for them. This inhibits disclosure and hampers negotiation.

5) Producers of gas accessing plants that had more processing functions than the producer required to treat their gas were being charged fees as if they used the entire plant. The

concept of paying functional unit fees for only those services required in a facility was not applied appropriately. This inhibits disclosure and hampers negotiation.

The Task Force recognized that these issues had to be addressed to promote the use of the JP-05 Recommended Practice as a fair method for the determination of fees and to encourage relevant disclosure and negotiation.

4.4 JP-05 Recommended Capital Fee Determination

The first issues the Task Force recognized a need to address were the widening relevant range and the need to simplify the methodology while taking into account the interests of facility owners and custom users. To this end, the Task Force recognized the following concepts:

1) The fundamental economic premises embodied in JP-90 and JP-95 are still valid. Therefore, the concept of negotiating a fee within the relevant range must be maintained for the guideline to work effectively and to establish fair and representative fees.
2) Midstream facility owners and producer facility owners are commonly
   - partners in facilities,
   - own facilities that provide equivalent services, or
   - are competing to purchase facilities.

Therefore it does not make sense to specify different fee methodologies for each. The guidelines established should be common for both types of facility owners.

3) For older facilities, having the as-spent capital rate base depreciated to 50% was not a fair value of the services provided by that facility. The capital cost base in older facilities determined using JP-90 and JP-95 was severely discounted against newer facilities, even though the older facilities provide equivalent service.
4) Depreciation of the capital rate base may not be an appropriate means to compensate facility owners for gathering and processing services, especially when custom processing services occur over the facility's life and serve to extend its life.
5) The addition of the depreciation component in the capital charge was used in the early years of a facility life in the JP-90/95 calculation to maximize the capital fee. This element of the fee was seldom adjusted downwards in subsequent years to reflect the depreciation of the capital.
6) Although JP-90 and JP-95 specified the means to calculate the return on capital, the variability of the long-term bond rate and the marginal tax rate meant the rate of return calculation changed from year to year. In many instances, higher returns that were calculated in accordance with JP-90 and JP-95 were not adjusted downwards when bond rates or tax rates decreased. In other cases, rates of return were held at levels clearly out of bounds of JP-90 and JP-95. The JP-05 Recommended Practice, for simplicity, needed to fix the rate of return.

4.5 Recommendations for the Derivation of Capital Fees

1) **The rate of return on capital be fixed at 20%.** JP-90 and JP-95 recommended the rate of return on capital be pegged to the long-term bond rate, including a fixed equity premium and uplifted for the marginal tax rate. This calculation, in effect, fixed the return on capital with the purpose of eliminating this parameter as a degree of freedom in a negotiation. In reality, companies have tended to use the return on capital as another means of broadening the fee negotiations. This was never the intent of the guidelines.

The return on capital from 1990 to the present has ranged from 15.5% to 23.5%. This range is generally a reasonable indication of what investors in the oil and gas business demand for a return on their investments. Given the long-term life of gathering and processing infrastructure, an average return on capital of 20% is a fair return that recognizes the inherent value in facility infrastructure and fairly compensates facility owners for renting out their capacity.

2) **The depreciation component of the capital charge be eliminated.** The capital charge employed would be the undepreciated capital rate base times the rate of return in a year, and therefore no depreciation is to be included.

   The Task Force recognizes that gas processing facilities rarely provide services only for the reserves that they were originally constructed for. Over time, as reserves decline, owners will seek to contract third-party gas to provide an additional source of cash flow and to defray rising unit operating costs. As a result, facilities will continue to provide useful services beyond the life of the original reserves. To depreciate these facilities down to a low value for low-risk custom processing circumstances is not a fair reflection of their inherent value to a custom user. Similarly, it is not appropriate to add a depreciation component to a fee based on the cost of a replacement facility. When the value for the lower limit calculations has been reduced by depreciation to 50%, the difference in value for the lower limit fees and the upper limit fees was unreasonably large and not an appropriate negotiation range. The Task Force believes the range of values for processing services should be much narrower than those defined by JP-90 and JP-95.

3) **The recommended lower limit rate base be the as-spent capital, including any capital additions during the life of the facility, with the provision the lower limit not be less than 50% of the upper limit.** This will ensure that older facilities, over time, will not develop a large spread in the relevant range and will fairly set the lower limit of older facilities to recognize fair value for gathering and processing services.

4) **The recommended upper limit rate base be the (undepreciated) replacement cost of the facility.** The replacement cost may be determined, in the earlier years, as the as-spent capital inflated each year with the long-term inflation rate. The Task Force recommends that in absence of specific cost data, a value of 3% per annum be used, as this represents the average inflation rate for the last 20 years for both Alberta (3%) and Canada (2.9%). In later years, an engineering study may be required to provide a replacement cost estimate for the processes required. A table of inflationary factors (Consumer Price Index) from 1948 to 2004 is attached as Appendix B.

5) **The relevant range for calculating a capital fee for third parties upon recapitalization or a market-based transaction of a facility lies between the lower limit and the upper limit, as described above, on the same basis as if the recapitalization had not taken place.** This protects third parties that had no influence or decision involvement in the transaction from being subjected to a commercial arrangement structured for different purposes.

6) **Where appropriate, Functional Unit fees be established. In some cases, a facility will be divided into functional or processing units.** This may be for accounting purposes or for recognizing that different inlet streams access different parts of the process within that facility. The intent of using functional units, or deemed functional units, in setting processing fees is to establish fees that reflect the actual costs of processing for an inlet stream based on composition.

In a number of larger, more diverse processing facilities, facility owners have implemented fees based on the characteristics of the gas being processed by charging fees only for the plant processes required. For example, raw gas containing hydrogen sulfide would pay for use of gas treating, sulfur recovery and sulphur handling functional units. Sweet gas would not pay these costs and would only be charged for the processes used (e.g., dehydration, compression, liquids recovery). The basis for the functional unit fees could be a JP-05 type of calculation, using a split of the total facility capital and operating costs into allocable functional units. This is only feasible (and accurate) if the facility operator's records of capital and operating costs are easily allocable to various functional units.

Functional unit fees are appropriate for facilities developed to process wide ranges of gas compositions. Breaking the fees into functional units for both the capital and operating portions provides a fair cost allocation to the various types of gas being processed and avoids burdening any one gas stream with costs of processing that are not required. An important consideration for functional unit fees is that the unit capacity and throughput be on a basis (e.g., H_2S, C_3+) that fairly reflects the functional unit process and the services be paid for by the owners of the raw gas.

The Task Force recommends that the upper and lower limits of the capital fee be calculated as follows:

Upper Limit Fee:

Upper Limit Capital Fee = 20% rate of return multiplied by Replacement Cost divided by Annual Capacity

Lower Limit Fee:

Lower Limit Capital Fee = 20% rate of return multiplied by Original Cost (as spent) divided by Annual Capacity (provided that the minimum value is 50% of the Upper Limit Fee)

FORMULAS

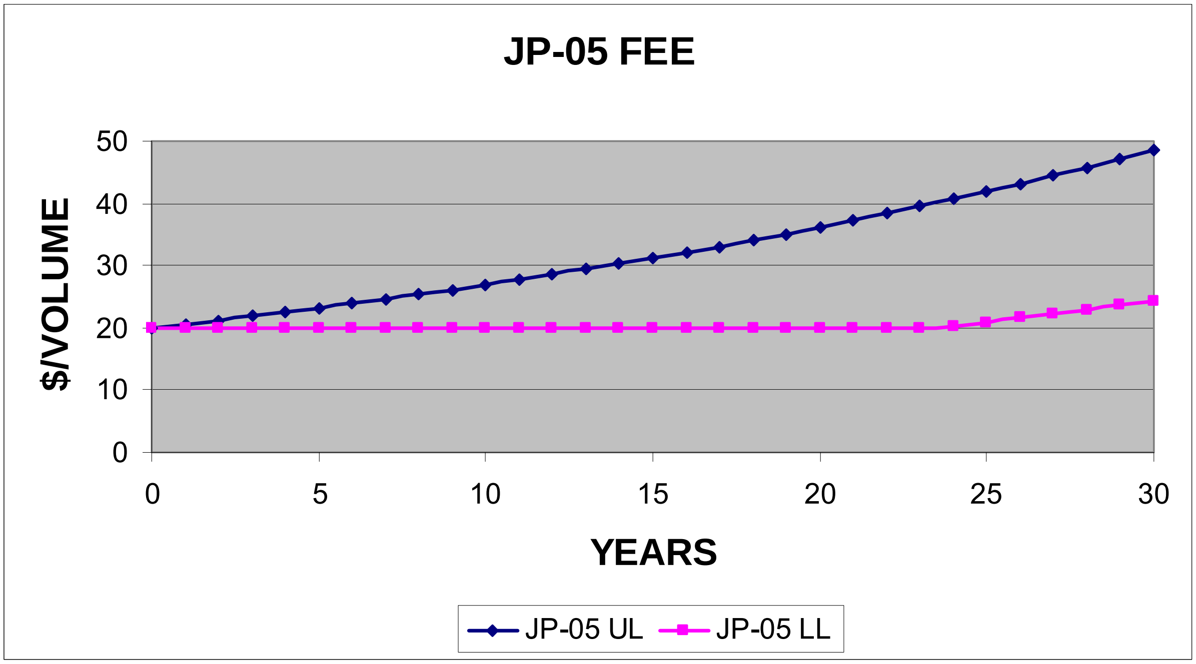
$$ULF = \frac{0.2 * OC * (1.03^n)}{CAP * 350}$$

$$LLF = \frac{0.2 * OC}{CAP * 350} \quad \text{(minimum of 50\% of ULF)}$$

Where

ULF = upper limit fee
LLF = lower limit fee
OC = original capital cost
CAP = facility daily capacity
n = number of years since facility was built
350 = number of operating days in a year (normally about 350)
1.03 = assumed 3% inflation rate on facility replacement cost (see Section 4.5 (4))

Graphically the capital fee formula is represented as follows (per $100 investment per unit capacity):



The appropriate positioning of the fee within the range between the upper and lower limits is based on the degree of risk borne by the respective parties. This is discussed in greater detail in Section 4.7.

4.6 The Purpose of Relevant Range of Fees

The Task Force continues to support the idea of upper and lower limits or a relevant range using the capital rate base in recognition of the need to define the playing field to negotiate processing arrangements. The circumstances and risk characteristics of the custom processing situation would determine where within the relevant range the appropriate answer should be sought. This is an area that continues to be improperly applied by the industry. There have been instances where processors have been pushing the upper limit, instead of assessing the appropriate position within the relevant range for the particular processing arrangement that fairly reflects the risk of the arrangement to the parties.

Fees at the lower limit should be developed for situations where there are no capacity constraints. For example, if a facility is underutilized and the owners wish to have an incentive to attract additional throughput to the facility, the fees should trend to the lower limit.

Processing fees developed at the upper limit should reflect situations with higher risk to the owners of the facility. Producer-owners of a facility that is operating near full capacity that contract for the processing of third-party gas on a firm basis are at risk of not being able to access their own capacity, so the fee should trend to the upper limit.

4.7 Positioning Within the Relevant Range: Capacity Availability and Level of Service

Once a relevant range is established, the parties must narrow down the appropriate position within the range. As previously described, positioning is a function of the degree of risk borne by the processor and producer. The greater the degree of risk to the processor, the higher in the range the fee should be.

Elements of Risk

1) Availability of Capacity: As a facility becomes more utilized, there is greater opportunity cost to the owner and fees should tend towards the upper limit of the relevant range. The fuller a facility becomes, the greater the risk to the facility owner of either having its own gas backed out or of missing an opportunity to contract for gas processing at higher value. From the gas producer’s point of view, the closer to capacity an existing facility operates, the greater the likelihood it may have to build its own capacity, and therefore fee negotiations in the existing facility should reflect the competitive alternative of building new capacity.
2) Level of Reserves Commitment: If the producer commits to deliver specified reserves for processing, the processor’s risk is decreased, and fees should trend downwards in the relevant range. If there is no commitment by the producer, the processor’s risk is increased, and fees should trend upwards in the relevant range. In between these two extremes would be cases where the producer dedicates wells, groups of wells, or future gas in a geographic area. Generally, the more assurance the producer provides to a facility owner of a future revenue stream, the less risk the processor bears and the lower in the relevant range the fee should be.
3) Term: The term of a processing agreement can influence the degree of risk borne by the parties. A producer owning a plant may view a long-term contract to process firm volumes as high risk if there is a possibility that processing of third-party gas may cause curtailing of its own volumes in the future. However, a long-term delivery commitment from a customer provides more assurance of future revenue than a short-term one. It is up to the parties to decide how the contract term should influence determination of where in the relevant range a capital fee should lie.
4) Level of Service: A firm service commitment is of higher risk to the processor and of greater value to the producer; therefore the fee should trend towards the upper limit. If the firm service includes a “use-or-pay” provision, the risk is higher for the producer and the fee should trend lower.

All of these factors should be tabled in the negotiation. It is up to the parties to discuss which factors play a role in the particular situation under discussion and assign appropriate weightings to the factors that apply.

JP-05 – Positioning within the Relevant Range (Examples)

Criteria	Risk	Position in Range	Description
1. Availability of Capacity	Ability of producer owners to access capacity	High ↑ ↓ Low	Near full capacity Underutilized facility
2. Level of Reserves Commitment	Degree of commitment a custom user has to a midstreamer owned facility	High ↑ ↓ Low	None Well or area dedication
3. Term	Ability of producer owners to access future capacity. Security for a custom user of future capacity needs	High ↑ ↓ Low	Long term, near capacity facility Short term
4. Level of Service	Ability of owners to access capacity. Risk to custom users of not having capacity available	High ↑ ↓ Low	Firm Interruptible

4.8 Capacity Versus Throughput Considerations – Determination of Unit Capital Cost

The issue of the determination of facility capability (capacity or throughput) was also assessed by the Task Force, and the following is the JP-05 recommended practice.

1) Processing Facilities

The Task Force recommends maintaining the status quo, i.e., the annual capital charge be calculated based on total plant or functional unit capacity. The capacity is the capability of the facility or functional unit as determined by the plant owner. By calculating capital charges on the basis of capacity, this method avoids transferring the financial risks of the owners' decisions, or market factors, to the custom users. Firm capacity should be calculated for capital recovery on maximum capacity requested, while interruptible contracts should be calculated on actual capacity used.

Capacity that is different from nameplate capacity would occur if the operator could demonstrate that the actual capability is different. For example, if a plant is actually processing at sustained rates above nominal capacity, the capacity should be the current throughput level. Or if some equipment has been removed or feedstock changes have occurred, resulting in decreased capacity from license, a new reduced capacity should be used.

2) Compressors

The Task Force recommends that this should be the maximum throughput capability of the compressor at the current operating conditions (which include the new gas throughput) based on compressor performance curves.

If a compressor is lightly loaded or is recycling gas and the volumes of new gas are small enough that recycling continues after their addition, then addition of the new gas should not raise the suction pressure and would not reduce the compressor capacity. In this case the capacity used in the fee formula should be the compressor **capability** at current operating conditions.

If the addition of new gas results in the compressor suction pressure increasing, the capacity to handle the existing volumes will decrease. Therefore, in this case the capacity used in the fee formula should be the compressor **throughput** at current operating conditions.

This application is not intended to address back-out issues, which are discussed in Chapter 3.

3) Gathering Lines

Transmission capability of pipelines varies as a function of operating conditions of the pipeline. Changes in line operating pressures will generate significant variations in pipeline capacity, especially as the pressure fluctuates, such as in gathering lines upstream of compression. This creates a situation where pipeline capacity may not be fixed and varies with conditions.

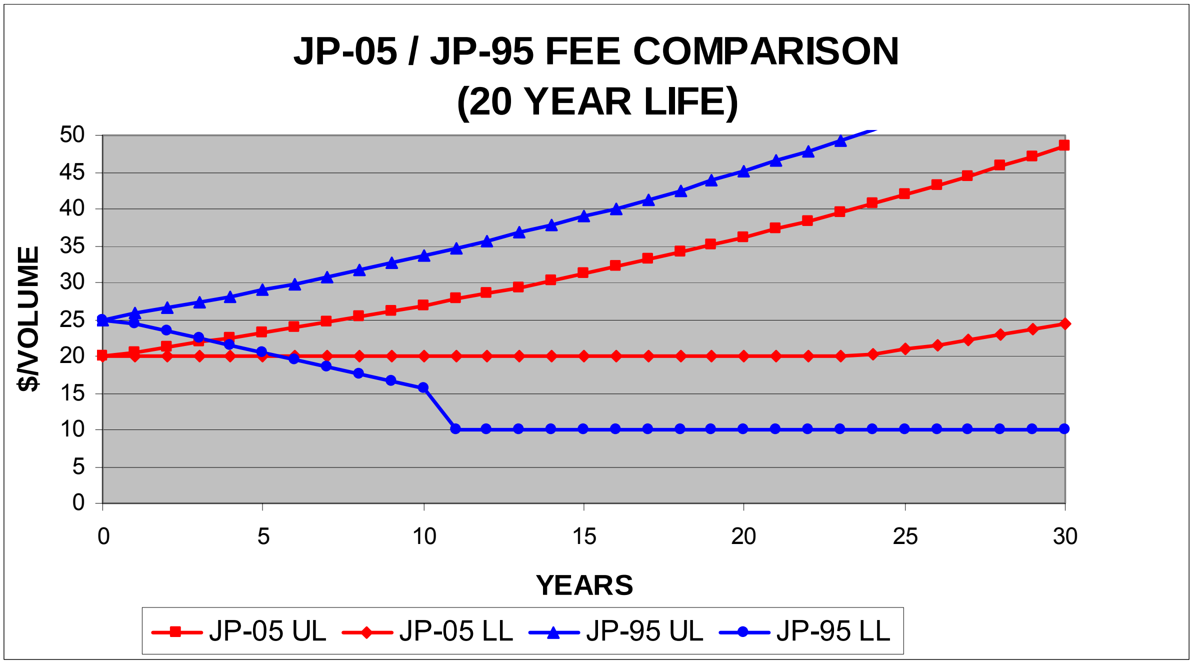
The Task Force recommends that for gathering lines where specific design parameters, including system capacity and pipeline cost, are well established, the JP-05 determination of capital fees should be based on capacity of the pipeline.

In situations where costs are known but the design parameters are not known or the use of the pipeline has changed from the original intent, the parties should try to determine if the pipeline used is at capacity under current operating conditions. If so, capacity equals throughput and the determination of capital fees should be based on throughput.

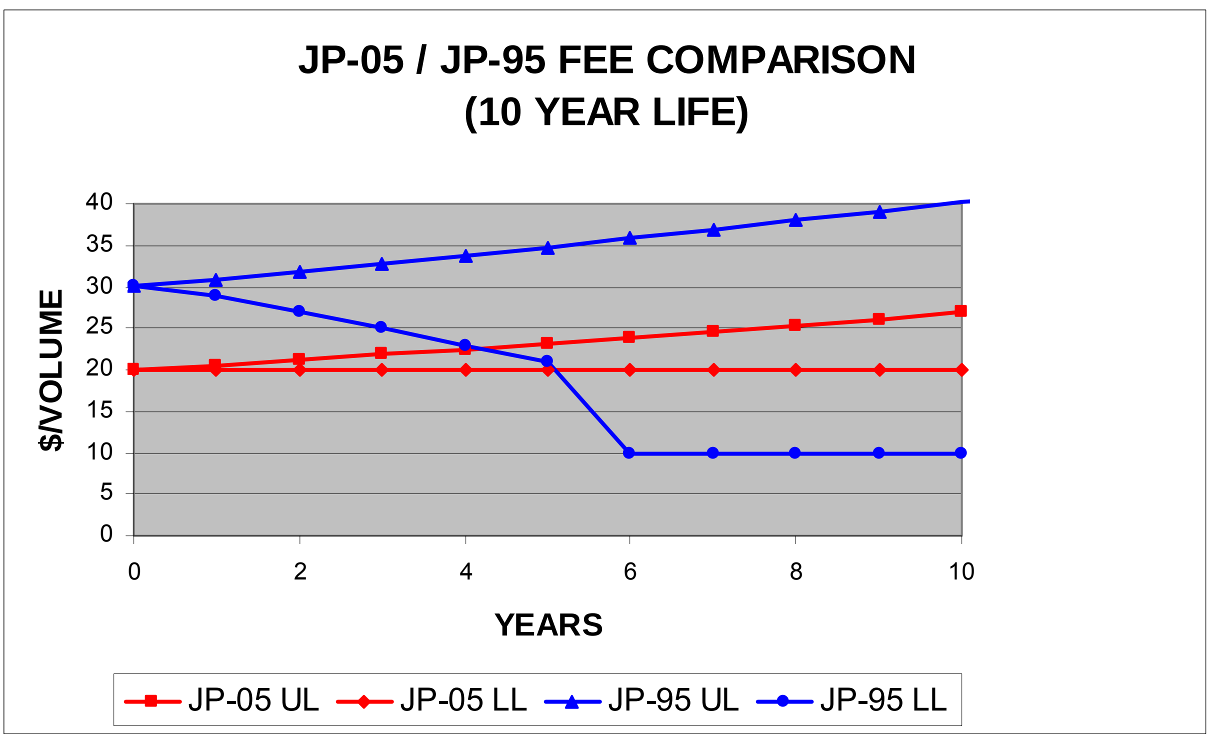
If agreement cannot be reached using either of the above methodologies or if the prospective fee dollars are relatively trivial, the Task Force recommends that a transportation capital fee of between $\$0.20/e^3\ m^3$ and $\$0.35/e^3\ m^3$ per kilometre in use or affected ($0.01 to $0.015/mcf/mile) be negotiated. The Task Force views this as a default method for the determination of gathering fees.

4.9 Comparison to JP-95 Theory

Graphs of JP-95 and JP-05 capital fees for both 20-year-life and 10-year-life facilities follow:



UL = upper limit, LL = lower limit



The significant differences between JP-05 and JP-95 are as follows:

1) JP-95 assumed a depreciation component of the rate base that resulted in a higher upper limit than JP-05 by the amount of the depreciation. Assuming straight-line depreciation over 20 years, the depreciation component had the effect of raising the capital component of any fee by 25% (5% points on 20%). Using a 10-year life, the capital component would be 50% higher (10% points on 20%).
2) The JP-95 lower limit depreciated to the extent of depreciation each year until the facility was 50% depreciated. This resulted in a different (lower) rate base each year. JP-05 does not depreciate the lower limit rate base and, consequently, does not add a depreciation component to the rate base. The result is that the average fee for a 20-year-life facility is the same for the first 10 years under JP-95 and JP-05. After year 10, the JP-05 lower limit is double the JP-95 lower limit, due to the cumulative effects of depreciation and the elimination of the depreciation term after year 10.
3) JP-95 and JP-05 both allowed the upper limit rate base to be inflated. JP-05 has recommended 3% as the long-term average, rather than leaving an estimate of inflation open to interpretation or abuse. This recommendation would have to be reconsidered if a period of extreme inflation occurred. If required, an engineering study may be more appropriate than a calculated inflation rate.
4) JP-95 calculated a return on capital based on current bond and tax rates. JP-05 fixes the return on capital based on a longer term average that is a reasonable return on capital for the industry.
5) JP-95 had a much broader range between upper and lower limit fees. The relative size of the range was exacerbated for older facilities.

The following table provides a comparison of the parameters of JP-90/95 with the equivalent parameters in JP-05.

COMPARISON OF JP-05 WITH JP-90/95		
	JP-90/95	**JP-05**
Capital Recovery Fees:		
Return on Capital	Calculated from current bond rates, income tax rates, and risk premiums	20% fixed
Capital Base		
- Upper Limit Basis	Replacement cost (actual)	Replacement cost (original, inflated at 3%)
- Lower Limit Basis	Depreciating original cost	Original cost (subject to lower limit ≥50% of replacement)
Depreciation Component	Yes, to 50% of original cost	No
Plant Capacity	Licensed, or Effective if different	Licensed, or effective if different
Compressor Capacity	Throughput	Throughput or based on technical data
Pipeline Capacity	Throughput or capacity	Based on technical data, or if inconclusive, \$0.20 to \$0.35/e^3 m^3 per km
Operating Costs	Flow-through, based on usage	Flow-through, based on usage
Lost Gas Cost Allowance	Yes	Yes (unchanged)
Working Capital Recapture	Capital/operating component	Operating component

4.10 Comparison to Actual JP-95 Practice

1) Under JP-95 there was a tendency to set a fee in the first few years of a facility life and keep the capital component fixed indefinitely. This was partially due to the excessive administrative load that would be involved in revising fees annually. JP-05 removes the need to revise lower limit (capital) fees annually until late in the life of a facility.
2) JP-95 had a step function reduction in the lower limit once the facility was 50% depreciated that was not generally followed by the industry. This was caused by the elimination of the depreciation component at this point. JP-05 eliminates any fee discontinuities.
3) JP-95 assumed that rate base was the only degree of freedom in a fee negotiation, but industry practice was to vary rate of return as well. This was perhaps partially driven by the need to generate a “reasonable” fee for facilities that were installed years ago at a much lower cost than current replacement value.

5 The Basis for Development of an Operating Fee

The Jumping Pound fee calculation methodology incorporates a capital cost and an operating cost component. The purpose of this chapter is to recommend the most common methods of charging the operating cost component.

5.1 Components of Operating Cost

It is recommended that the operating cost component be made up of

- operating costs, often referred to as direct costs, plus
- overhead, plus
- working capital allowance.

Operating costs are those expenditures incurred to maintain facility operation, so the facility can achieve the purpose for which it was designed and constructed. Operating costs may include, but are not limited to, such things as surface lease expense, property taxes, access maintenance, vegetation control, security, fencing, electrical, fuel, operation and maintenance of equipment, tools, lubricants, chemicals, consumables, labour, supervision, fire detection and control, water, sewage, ongoing environmental monitoring and cleanup costs, and many others, depending on facility size, complexity and process type.

Unless otherwise specified by the governing documents of a facility, the JP-05 Task Force recommends use of the definition of operating costs as set forth in the 1999 PJVA Construction, Ownership and Operating Agreement (CO&O) model, which defines operating costs as "… all costs and expenses, except Capital Costs, incurred in connection with the testing, operation, maintenance and repair of the Facility".

In addition to the aforementioned "direct" costs, the facility operator also incurs indirect costs (maintaining a central office, phone system, technical and administrative staff, etc.), a portion of which must be allocated to the facility. Indirect costs are covered by overhead, which is added to the direct costs of operation and maintenance. Overhead is generally an amount equal to 10% of direct costs, unless facility governing documents specify a different value.

The remaining item of the operating cost component is "working capital allowance", a premium paid to compensate the facility operator for the cost of its capital used in carrying all facility costs at its own expense for the time period between billing for and receiving payment of fees (normally two months). Working capital allowance is calculated by dividing the sum of operating costs plus overhead by 6 and multiplying the result by the rate of return:

[(operating cost + overhead)/6] x 20%

5.2 Allowable Operating Costs

The JP-05 Task Force recommends that the operating cost component be the sum of the actual direct operating costs plus overhead, as specified by the facility governing documents, plus working capital allowance, divided by total throughput volume:

[(operating costs)+(overhead)+(working capital allowance)]/total throughput volume

This calculated value is the per-unit operating cost component of the fee.

The facility operator must be prepared to disclose pertinent information relating to direct costs and overhead during fee negotiations.

5.3 Turnaround Costs

A point of contention in the development of operating cost components of third-party fees is the method in which facility turnaround costs are handled. Typically, a facility is "turned around" once every two to five years, at a significant addition to normal operating and maintenance expenses.

The Task Force recognizes that recovery of turnaround costs can be handled by various methods. As a default, the JP-05 Task Force suggests that turnaround costs be fully charged in the year incurred, subject to anything to the contrary in the facility governing agreement and accounting procedure.

5.4 13th Month Adjustments

In some agreements, the operating cost component is charged based on the facility operator's best estimate of operating expenses to be incurred in a period (usually one year), divided by the operator's best estimate of volume throughputs during such period. At the end of the year, when actual expenses and volumes are known, the operating charges levied against any production stream during the year are adjusted, resulting in a credit or additional charge to the producer.

Benefits of this method are

- no risk to the processor of insufficient operating cost recoveries;
- producer pays only those operating costs for which it is obligated; and
- producer generally has audit rights.

Disadvantages to this method include

- producer cannot accurately budget for processing fees, as large year-end adjustments are possible;
- the times to prepare 13th month billings or credits are necessarily lengthy, in order to allow for gathering actual data; thus an additional charge or credit may not be seen by the producer for 180 days or longer following year-end;
- 13th month adjustments are time and manpower intensive and can lead to errors; and
- processors are not generally receptive to third parties auditing facility books and records, which may result in a producer having access to information it has no right to.

Flow-through operating costs and 13th month adjustments are generally used in cases where the facility operator is risk averse, has the necessary staff to perform the adjustments in a timely manner, is able to provide space for auditors, and can provide timely response to audit queries.

5.5 "Fixed" Fees

Another method of charging the operating cost component in a fee structure is to "fix" the operating cost component for a given period, usually one year. In this method, the processor uses its best estimate of the year's operating costs (including overhead and working capital allowance) and its best estimate of throughput volumes to arrive at the estimated per-unit operating cost component for the year, which is then fixed for the period. Note that in this method there are no provisions for after-the-fact adjustments for unforeseen expenses or for volume throughputs that vary significantly from the original estimates.

Fixed fees require the processor to maintain excellent records of operating expense and throughput volume trends in order to establish per-unit costs on a go-forward basis. Trend analysis of both cost and production data allows for some confidence in forecasting for the year; however, this method is best employed by those processors with a reasonable degree of risk tolerance. Use of a two- to five-year rolling average of operating costs will capture turnaround costs for most facilities.

The fixed fee concept is risk-reward, in that a facility may operate more efficiently than forecast or may be able to add new throughput volumes during the year. Such happenings would result in the per-unit operating cost being less than forecast, providing the processor with enhanced economics.

Benefits of the fixed fee concept are

- elimination of 13th month adjustments;
- better cost/revenue forecasting for both producer and processor; and
- elimination of the need to audit operating costs.

In a fee negotiation, any processor adopting a fixed fee must be willing to disclose both its projected operating costs for the facility for the fee period and its estimates of throughput volumes used in the development of the operating cost portion.

The JP-05 Task Force does not preferentially recommend either the fixed or 13th month adjusted operating cost methodology—both are acceptable. The method used must be determined by the facility operator subject to the facility governing agreements and in conjunction with the non-operating owners of the facility.

6 Lost Gas Cost Allowance

6.1 What Is Gas Cost Allowance?

To be marketable, natural gas must be essentially free of all impurities (e.g., water, liquid hydrocarbons, carbon dioxide, hydrogen sulphide, helium) and must be at a pressure adequate to be pipelined. To compensate processors for processing of the Crown's share of gas, certain deductions, called Allowable Costs, are permitted when computing their reduction in royalty payable. The Allowable Costs, referred to as Gas Cost Allowance (GCA) for consistency with JP-90 and JP-95, comprise an operating cost component and a capital cost component.

Under the Alberta Gas Royalty Regulations, plant owners are allowed a GCA deduction when calculating royalties payable. The GCA is calculated using a modified Jumping Pound formula that includes operating costs, depreciation based on the remaining useful life of the facility not to exceed 20 years, and a 15% return on average remaining capital rate base.

In 1994, the Alberta Crown Royalty Regulations were changed to allow facility owners to claim their portion of the capital GCA as a part of their "capital pool." The allowance claimed is then based on each owner's corporate average Crown royalty rate. This has the effect of allowing owners who have no facility throughput to use their capital GCA as a deduction for their corporate Crown royalties payable. However, the capital GCA for a facility is reduced by a Custom Processing Adjustment Factor (CPAF) prior to being allocated to the owners. The custom processing factor is unique to each facility cost centre. It is calculated as the ratio of the custom processed volumes to the total facility throughput. The balance of the capital portion of the GCA would then be allocated to the owners based on percent ownership, or using some other equitable method which recognizes the relative custom processing income allocated to each owner.

In addition in 1994, the operating component of the GCA was determined on a facility-specific basis for designated facilities having an EUB-approved design capacity over 3,000 10^3 m^3/day (covering the largest 38 gas processing facilities in Alberta). Each of these 38 plants had a unique "postage stamp" operating GCA value, regardless of the type of gas being processed. This postage stamp rate included all gathering, compression and processing costs, and was called the Unit Operating Cost Rate (UOCR). All other facilities were assigned one of five postage stamp operating GCA values, based on the plant type and the nature of gas being processed. The amount of operating cost allowance that the facility owners could claim was the UOCR, which meant that their operating cost allowance was no longer affected by custom processed volumes. The UOCR was applied to all plant owner volumes regardless of the share of operating cost borne by custom volumes.

In 2004, the regulations related to GCA were further modified. Non-designated EUB facilities currently classified in one of the five plant types have a new UOCR calculation: the processing component UOCR is based on the actual operating costs of the facility, and the gathering and compression components are based on surveyed operating costs. An operating cost survey will be conducted, whereby a representative sample of gathering and compression from each plant class (sweet, sour, dry gas) will be selected to file actual operating costs for two selected production years to determine the base gathering and compression survey rates for each plant class. These survey rates will then be indexed to the current year, taking into consideration the rate of change of similar costs in the designated EUB facilities.

6.2 Lost Gas Cost Allowance

As mentioned above, GCA is an allowable deduction from Alberta Crown royalties for the facility owners. Should owners desire to have outside gas processed in their facility, a custom fee is charged for processing of the gas. This custom processing charge, in most circumstances, becomes the non-owner's allowable deduction for Crown royalties. However, since the Crown allows the deduction of the custom processing charges for the non-owner, the GCA that is allowed for the owners of the facility is reduced. As noted above, this reduction is determined by the custom processing factor, which is the ratio of the custom volumes processed to the total throughput.

Under current regulations, the allocation of capital GCA to facility owners can be expressed as

GCA * OV/TV

Where

GCA = Total Capital GCA associated with the specific facility from AC2
OV = Owner's Throughput Volume
TV = Total Throughput Volume

or

$$\text{GCA allocated to Facility Owners} = \text{Total Capital Gas Cost Allowance} * \left(\frac{\text{Total Owners Facility Throughput}}{\text{Total Facility Throughput}}\right)$$

Since the capital GCA reduction for owners is based on throughput, facility owners will be faced with a situation where their allowable GCA deduction for Crown royalty purposes is less than the deductions would have been had the facility owners not provided capacity for third-party processing.

There are two aspects to this reduction in GCA:

4) the portion of GCA that was legitimately reduced because part of the facility capacity is now being used for the custom processing business, and
5) a further portion (assuming the plant remains below capacity) related to the Alberta Crown's policy of disallowing capital devoted to custom processing on the basis of the ratio of custom throughput to total throughput rather than the ratio of custom throughput to full capacity. This latter portion can be termed as lost GCA.

The owners of the facility can recoup the lost GCA, which otherwise could have been claimed had no third-party gas been processed. Both JP-90 and JP-95 recognized and recommended that a lost GCA charge be applied as a processing fee component to recover the portion of the GCA for which the processor is not compensated. The JP-05 Task Force acknowledges that a component to the processing fee, recovering a portion of this reduction can still be a legitimate charge in a processing fee determination. Also consistent with JP-90 and JP-95, the Task Force further recommends that there be no operating component in the lost GCA charge. This is in recognition of the benefits of reduced per-unit operating cost resulting from processing third-party gas.

Given the above, the lost GCA (LGCA) can be expressed as

LGCA = GCA*(1-CV/TC)-GCA*OV/TV

Where

CV = Custom Volume
TC = Total Plant Capacity
OV = Owner's Throughput Volume
TV = Total Throughput Volume

Since processing income is taxable, whereas GCA savings at the time of writing are only partially federally taxable, the charge to account for the LGCA can be expressed as

LGCA Charge= LGCA*LGCA Factor

$$\text{LGCA Factor} = \frac{\text{CERR} * [1- (\text{PTR} + \text{FTR*DPCR})]}{(1-\text{EITR})}$$

Where

CERR = Crown Effective Royalty Rate
PTR = Provincial Tax Rate
FTR = Federal Tax Rate
EITR = Effective Combined Federal and Provincial Income Tax Rate

DPCR = Deductible percentage of Crown royalties

With the elimination of the existing 25 per cent resource allowance and full deduction of actual provincial Crown royalties for federal income tax purposes by year 2007, Lost Gas Cost Allowance Factor from then onward can be expressed as:

LGCA Factor = CERR

Meanwhile for the year 2006 LGCA Factor can be illustrated as:

.25(1-.115-.23*.65)/(1-EITR) = 0.2724

Where:

CERR = 25%

PTR (for Alberta) =11.5%

FTR = 23%

EITR=PTR+FTR *1-(.35*deductible percentage of existing 25% resource allowance as per federal budget),

and

DPCR = 65%

6.3 Illustration

Below is an illustration of a determination of a capital fee based on both unit of capacity and throughput, as well as the LGCA charge. For purposes of the illustration, we assume that the following parameters have been used:

Facility has $4,000,000 capital base
ROR on the capital base is 20%
Capacity 200 e^3 m^3/d
Throughput 100 e^3 m^3/d

Owner(s) throughput 60 $e^3\ m^3/d$
Non-owner throughput 40 $e^3\ m^3/d$

Capital GCA of $1,000,000 (derived from the submission by operator of the AC2)

Capital Fee based on Unit of Capacity	Capital Fee based on Throughput
$\frac{20\% \times (4{,}000{,}000)}{200\ e^3\ m^3/d \times 350}$	$\frac{20\% \times (4{,}000{,}000)}{100\ e^3\ m^3/d \times 350}$
$=\$11.43/e^3\ m^3$	$=\$22.86/e^3\ m^3$

Given the premise that the capital charge component of the processing fee is based on a per unit of capacity, the owners/producers believe the allocation of GCA has to be determined on the same basis, i.e., on their share of volume as a percentage of total capacity. In this specific example and from an owner's perspective, the allowed GCA deduction associated with non-owner's volumes should be calculated as

$$\text{Capital GCA} - \text{Capital GCA} * \frac{\text{(Custom User Volume)}}{\text{Total Capacity}}$$

$$\text{or} \quad \$1{,}000{,}000-(\$1{,}000{,}000 * 40\ e^3\ m^3/d\ /\ 200\ e^3\ m^3/d)$$

$$= \quad \$1{,}000{,}000-(\$1{,}000{,}000 * 0.2)$$

$$= \quad \$800{,}000$$

However, under current regulation, the amount of capital GCA available to facility owners is

$$\text{Capital GCA} * \frac{\text{(Total Throughput-Non-Owner throughput)}}{\text{Total throughput}}$$

$$\text{or} \quad \$1{,}000{,}000 \times \frac{(100\ e^3\ m^3/d - 40\ e^3\ m^3/d)}{100\ e^3\ m^3/d}$$

$$= \quad \$600{,}000$$

The $600,000 represents the amount of capital GCA that is available to the facility owners.

Lost GCA Recovery Component Portion of Fee

- In the illustration above, from the owner's perspective the $800,000 minus $600,000, or $200,000, is the amount that would have been allocated had the allocation been capacity based rather than throughput based. The missing $200,000 is the amount that should be recovered from the non-owners by means of a supplement to the fee charged by the owners to the non-owners. This supplement would then be further adjusted on an after-royalty after-tax basis.
- By applying the formula, the resulting Lost Gas Allowance charge is approximately one-third of the LGCA. Refer to chapter 12 for examples of the calculations.
- Why is this adjustment not the difference between the total facility GCA of $1,000,000 minus the actual allocation of $600,000? Again, the premise is that the owner's/producer's allocation should be based on their share of volume as a percentage

of total capacity.

- The Task Force strongly encourages operators to analyze the impact of third-party volumes on their GCA in conjunction with the benefits of additional capital fees and reduced unit operating fees. In some circumstances, the effects on the owner's GCA may be dramatic and may overwhelm the benefits from the capital and operating portions of fees. In those circumstances, operators and third parties should recognize the need to look at other alternatives to compensate the owners for that impact. However, it should be kept in mind that any component of fees may impact the competitiveness of the facility and the ability of the operator to attract additional gas.

6.4 Owner Compensation and Distribution of Gas Cost Allowance Component of fees

Owners of facilities that have an LGCA component to their fee structure should consider and formalize in their facility CO&Os or through mail ballots the means by which the LGCA component of the fee should be distributed to the facility owners.

The distribution of LGCA among facility owners could be based on

1) working interest,
2) their share of excess capacity contributed, or
3) making allowance for owners who pay excess usage fees that are claimable as custom user fees in their GCA submissions.

6.5 Non-Applicable Situations

The JP-05 Task Force also concluded that a lost GCA component to a fee should not be included in situations where the facilities were built specifically for processing additional gas. Some examples of these are the following situations:

1) A processor builds new capacity or expands existing capacity for the express purpose of custom processing gas for a producer on a "firm" or "guaranteed" basis. The fees charged to the producer would be equivalent to the producer "owning" access to that capacity it has paid for; a lost GCA component to a fee should not be a part of the custom processing fee.
2) A third-party processor who is not a producer builds a facility to provide custom processing of gas. An LGCA component to a fee is not relevant, since the third-party processor is not a producer and does not pay Crown royalties.
3) Custom processing occurs in a facility for which the GCA capital has been depreciated to zero or has been ruled inadmissible by the Crown. Since there is no GCA capital for the processor to claim, no lost GCA component to a fee is appropriate.

6.6 Conclusions

The overall impact of an LGCA component to a fee is something that the processor should consider when developing processing fees, but this consideration should be weighed with the following factors:

1) the nature of the processing arrangement being developed between the processor and the custom user (i.e., short term vs. long term);
2) the overall benefit of bringing more gas into the facility for processing;
3) the incremental cost of processing additional volumes;
4) the real value of the capital GCA lost by the facility owners; and

5) how revenues derived from custom processing are distributed to facility owners.

If all of these factors have been considered and the conclusion is still to include an LGCA component in the processing fees, then the impact of this “additional” fee on the competitive viability of the overall processing arrangement should be assessed. The LGCA component of the fee is usually largest in facilities that are much underutilized, which would benefit significantly from processing additional volumes.

The JP-05 Task Force therefore urges all processors to fully understand all of the previously stated factors prior to making a decision on whether to include or exclude a GCA component in their processing fee calculations.

7 Environmental Restoration and End-of-Life Considerations

As noted in chapter 5, ongoing environmental monitoring and cleanup costs are considered part of the operating costs of a facility for fee purposes. Monitoring costs refer to the costs of routine environmental and regulatory reporting work, and cleanup costs refer to the cost of environmental cleanup projects undertaken while the facility is still operating. The cleanup projects are usually done in order to meet current environmental regulations or to minimize future liabilities resulting from past practices or spills.

7.1 Restoration

Given that all facilities will face abandonment and reclamation in accordance with government regulations, the costs should be paid for in proportion to the benefits received by processing through the facilities. Since custom users are not owners in the facilities, and since environmental restoration costs are becoming expensive, custom user contributions to these costs should be considered.

Restoration costs refer to those costs incurred in the final decommissioning and abandonment of a facility (or portions thereof) and the ensuing reclamation work. Facility owners have recognized that abandonment and reclamation costs are a future liability that should be considered when setting custom processing fees. This trend may have started with sulphur block reclamation, as many sulphur storage facilities and blocks that serve as central deposits for sulphur from area plants are often used by parties who have no ownership in the original facilities. However, the owners of the facilities remain liable for the final cleanup of the sulphur storage facilities and blocks and the sites of the sulphur processing facilities. For that reason facility owners added a cost to the fees charged for use of the sulphur storage and the plant site to compensate them for their future liability.

PJVA published a discussion paper on environmental issues in September 1994 that discusses environmental reclamation funds for the eventual cleanup and restoration of facilities. Although the tax implications (deductibility of contributions and liability for tax on income earned within a fund) have yet to be resolved, environmental restoration funds for oil and gas facilities have been suggested similar to those in the mining industry. These funds would either be contributed to based on facility ownership by an annual assessment to owners or based on use of the facilities by an ongoing fee assessed to users. The latter method lends itself well to incorporate the fund contributions for custom users as an expense in the custom processing fees.

When restoration costs are included as a part of custom processing fees, they should be based on a legitimate estimate of the future abandonment and reclamation costs for the facilities; those costs should be prorated over all of the production expected to use the facilities over the remaining life. The total restoration cost should also be discounted to account for the present value of the future expenditure and to include the present value of any income that could be earned on fees collected prior to the funds being needed for restoration.

Proper calculation of restoration fees could be quite complex, with several variables, but the resultant fees should typically be quite small, if implemented early enough, when there is still considerable forecast facility life. If the facility is expected to be abandoned in the near future and the total restoration cost is to be recovered from the remaining production, the calculated fees could be larger. In such cases, it may be unfair to assess the total facility restoration cost to the production using the facility in the remaining operating years. Restoration fees do need to be considered when setting custom processing fees, but a rigorous calculation of this portion of the overall custom processing fee may only be warranted if the restoration costs are expected to be relatively large.

Should restoration fees be charged as part of a facility processing fee, it will be incumbent on the owners of such a facility to ensure that the associated revenue is maintained as a separate fund or other financial instrument and held for the purposes of site restoration for that particular facility. In effect, the restoration fund becomes an asset belonging to the facility, and not the owners, and must be traceable as income, as held in that fund, and as expended.

Additional discussion is included in the Environmental Matters appendix and associated annotations contained in the 1999 PJVA Model CO&O Agreement.

7.2 Other Considerations

Currently, industry and the EUB are developing the Large Facility Liability Management Program (LFP), similar to the existing Orphan Well or Licensee Liability Rating Program (LLR), for large upstream oil and gas facilities. The LFP is expected to be implemented in 2005.

The mandate of the LFP is to prevent the costs of suspending, abandoning, remediating and reclaiming a large upstream oil and gas facility from being borne by the public of Alberta if a licensee becomes defunct. Facilities to be covered under the program are

- sulphur recovery plants (currently recovering sulphur or with a history of sulphur recovery);
- oil sands in situ projects with a design capacity greater than 5,000 m^3/day; and
- straddle plants.

Under the LFP, the financial "strength" of licensees of large facilities in the program will be determined monthly and at the time of a license transfer, using a Liability Management Rating (LMR) comparing the total deemed assets of a licensee with its total deemed liabilities. If the total deemed assets of a licensee are determined to be less than its total deemed liabilities, the licensee will be required to place a deposit with the EUB equal to the difference between the deemed assets and the deemed liabilities. This is a licensee deposit and is not assigned to any facility.

The LFP also includes an option for a facility-dedicated deposit to protect the owners of a particular facility, which will be required if requested by the licensee or the majority of that facility's owners. The purpose of the facility-dedicated deposit is to ensure that there are sufficient funds available for the eventual abandonment and reclamation of that facility.

Apart from deposits required under the LFP, each facility licensee in the program will pay an annual levy for orphaned sites based on its proportional share of deemed liabilities in the LFP. The licensee will be able to allocate this levy to each of the LFP facilities it operates and the respective owners. As such, it may be appropriate to include the allocated portion of the levy in the annual operating costs of a facility for fee purposes. This levy will only be imposed if the LFP becomes responsible for the restoration of an orphaned facility.

For more information, refer to EUB Directive 024.

8 Alternative Fee Considerations

While JP-05 presents a fee structure guideline that is sufficiently flexible to promote negotiation of custom processing arrangements that are fair and reasonable to both facility owners and custom users, it is important to note there are many variations that can be used to either simplify the arrangement or allow for other benefits to both parties.

The most common use of the Jumping Pound methodology is to include the formula in the processing agreement and calculate the processing fee after each year. With the changes in the JP-05 formula that removes depreciation and fixes the return on capital, the annual changes required to a capital fee are minimal, and the only adjustments will be to operating components or changes in the processing circumstances that require a renegotiation of the fees.

The following are examples of different methods of applying the JP-05 formula. The advantages and disadvantages to both the facility owners and custom users of each method are discussed. It should be noted that this is not an exhaustive list of the possible variations; the key point is that both the facility owners and custom users should be flexible and open-minded in negotiations, keeping in mind the benefits of a win-win arrangement.

1) Payment of Upfront Capital

A means of financing an expansion or guaranteeing capacity in an expansion can be accomplished by custom users paying the capital portion of the processing fee up front. In this instance, facility owners wishing to expand their facility may approach area producers to solicit commitments to the throughput increase (or area producers can initiate an expansion under similar conditions). The cost of the expansion is carried by those facility owners wanting additional capacity, as well as by the custom users who are willing to commit to a guaranteed capacity. Once the facilities are built, the custom users pay an operating fee for their throughput, just as an owner would, up to their guaranteed capacity. In addition, the custom users pay both the capital and operating components of the fee for any surplus capacity they use, typically under similar terms as an owner would. If the custom user processes its volumes through any portion of the facility that it did not finance (i.e., a particular functional unit), it would pay a capital component for that functional unit.

The main advantage to the facility owners from this type of fee is their ability to finance an expansion through capital supplied from custom users. The owners still have to charge the custom users the operating portion of the fee and therefore may have the administrative burden associated with 13th month adjustments.

The custom user is able to receive guaranteed capacity without having to pay a premium for it and has no liability for the facility. However, the custom user ends up paying for an asset that it does not end up owning. Also, the operating component of the fee is not a known amount, particularly in the case of expansions when operating costs cannot be accurately predicted.

2) Tying Fee to Price of Oil, Gas or NGL

In the standard JP-05 calculation, or any of the variations described so far, it is also possible to build an element of commodity hedging into the fee. The fee is first calculated using the mutually agreed upon fee structure so that the resultant fee falls within the JP-05 guidelines. Then the fee is inflated or deflated based on the actual annual average price of oil, gas or NGL against a set annual average reference price for these commodities.

To reduce the administrative burden, this calculation is best done annually as part of the 13th month adjustment. A set range of prices for oil, gas or NGL is established as appropriate for the fee structure. It is best to adopt a publicly available standard price for use in these calculations, such as NYMEX, AECO-C Hub, or Edmonton posted crude pricing. If the price of oil, gas or NGL on an annualized basis deviates from this standard, then the processing fee is adjusted accordingly.

Both the facility owners and the custom users under either the high or low commodity price scenarios share the advantages and disadvantages of this type of commodity price-adjusted processing fee. The advantage to the facility owner in the low price scenario is that this formula provides a means of retaining custom user processing volumes, which should result in lower unit operating costs. The cost to the facility owner to retain these volumes is a lower per-unit fee income while this low-price scenario exists. The advantage of this type of fee structure to the custom users is that it provides an increased level of certainty in their return on investment, since as commodity prices drop below a mutually agreed upon level, the processing fee also decreases based on the negotiated formula.

The situation is reversed as commodity prices increase and eventually surpass the agreed-upon level. In this high commodity price scenario, the process fee escalates based on the negotiated formula. The facility owners' benefit from increased fee revenue in this situation, while the custom users now pay a higher unit fee but should also be realizing better overall economic returns due to increased operating margins.

3) Products in Lieu of Processing Fees

Another variation of gas processing charges is the facility owners taking all products derived from the gas in lieu of or as partial payment for processing. This type of processing fee was prevalent a number of years ago, particularly for gathering and processing of solution gas. Once again, the fee should initially be calculated using JP-05 guidelines to ensure a fair and reasonable fee, and then a formula to determine products in lieu can be developed. These "products in lieu of" types of processing arrangements typically do not include any provisions to change the fees or price with increasing or decreasing product prices.

The royalty implications of these arrangements are usually not well defined in the processing agreements. The custom user may be required to pay royalties based on the products taken by the processor. If the processor is to pay these royalties, it must be made aware of the lease agreement terms.

4) Wellhead Gas Purchases

The sale of gas at the wellhead or battery outlet is another variation of processing fees that can be used when the facility owner owns and operates all of the facilities for processing and gathering the gas. The producer (custom user) sells the gas to the facility owner at a price that should approximate the selling price of the gas and products less the processing costs. The processing costs should be within the JP-05 relevant range. The wellhead purchase price is usually fixed and the agreement is long term.

The wellhead purchase is advantageous for both parties. The producer has no capital invested in gathering systems and processing facilities and does not need to market its own products. The facility owner, typically, has no partners in the facilities and is free to construct and operate them as it wishes. Typically, in wellhead purchase arrangements, the processor has long-term marketing arrangements for both the gas and products. This arrangement also works well for situations where there is a significant producer credit risk for the owners of a facility.

Disadvantages in this arrangement for processing are that the producer cannot deduct the cost of facilities and processing from its royalties. Also, the lease agreement may require calculating royalties based on a set price, which may be higher than the actual wellhead purchase price.

If an operator does not own the facility 100%, the operator should resolve capacity utilization issues with respect to the purchased volumes with the other facility owners prior to implementing any wellhead purchase agreement.

9 Resolution of Processing Fee Disputes

The need to update the Jumping Pound Gas Processing Fee Guidelines was identified by the C2C Dispute Resolution Task Force for the Canadian Petroleum Industry and the EUB. Some companies were concerned about fee negotiations, and there was an escalation in EUB common processor applications and company objections to proposed facilities in 2002-2004. Some companies were not able to effectively negotiate fees to process new gas without some form of regulatory intervention. Feedback from a number of companies identified a number of roadblocks to their negotiations:

- delays and lengthy timelines;
- very positional correspondence and/or not being willing to meet;
- inappropriate tactics or poor negotiation approaches;
- nondisclosure of information, no details on how the fee was calculated, or inappropriate use of the Jumping Pound Guidelines; and
- wide gaps between the parties on desired fees so there was no willingness to negotiate.

The focus of the C2C ADR Council and JP-05 Task Force is to assist companies to resolve disputes more effectively and efficiently. The C2C ADR Council's *Let's Talk Handbook* emphasizes proper negotiations using ADR tools and techniques, and the JP-05 Recommend Practice provides an industry standard that the parties can use in their negotiations (e.g., to reduce the gap in fee negotiations).

Key Documents and Reference Material

- C2C Handbook for Appropriate Dispute Resolution

  This joint industry task force report, endorsed by the EUB, NEB, and 10 industry organizations, provides many useful examples, tools, and techniques to assist companies in their resolution efforts without regulatory involvement. The *Let's Talk Handbook* may be obtained through the C2C Council Web site.

- EUB Appropriate Dispute Resolution (ADR) Program and Guidelines for Energy Industry Disputes

  The details of the EUB ADR program are outlined in *Informational letter (IL) 2001-1*. This IL and annual ADR reports provide comments and recommendations on C2C disputes. They are available on the EUB Web site at www.eub.gov.ab.ca/BBS/public/ADR/index.htm.

- EUB Directive 065: Resources Applications Guide for Conventional Oil and Gas Reservoirs

  Directive 065 provides detailed application requirements for equity applications that may include a fee component.

The flowchart at the end of this chapter provides a high-level outline of options and procedures that companies may consider to effectively and efficiently resolve processing fee disputes.

1) Fee Discussions

- Where initial discussions have failed, parties are encouraged to engage in effective negotiations (C2C Handbook and JP-05 Recommended Practice) that include relevant disclosure and justification of the data used in the fee negotiations. The JP-05 Task Force and C2C ADR Council, the regulators, and the industry associations all encourage open and timely discussions. The C2C ADR Council's *Let's Talk Handbook* presents a useful cost-benefit tool that lists factors, such as costs for internal resources, external resources, lost opportunities, time value of money, and chances of success, that should be considered if the dispute is not resolved in a timely manner.

2) Negotiations

- Good preparation is the key to a successful negotiation, and the C2C ADR Council's *Let's Talk Handbook* includes an excellent Situation Assessment / Problem Solving Planner, which will help analyze the current situation and identify the best fit of available options.
- For negotiations or other forms of ADR, the parties should engage in collaborative discussions and disclose all relevant information so that full understanding of each other's objectives and interests can be achieved. The parties can develop privacy and confidentiality agreements where necessary.
- Disclosure can be an iterative process whereby each party should understand the need for the information and why it has been requested. As a minimum, parties should disclose the input data used in the JP-05 calculations.
  - As outlined in item 5 below, any EUB application to set fees must include a tabulation of values used in the fee calculation and a discussion of the basis and/or source for each value used in the calculation. If methods were used other than the Jumping Pound calculations, you must include a detailed discussion of how the fee was obtained and why the EUB should use another methodology than Jumping Pound.

3) Consideration of ADR

- Early involvement of third parties who focus on the resolution process could save significant time and resources.
- Any party may suggest to the others that ADR be considered if reasonable attempts to negotiate have been unsuccessful. Parties should consider the regulatory process or the courts as the last resort.
  - As outlined in item 5 below, any EUB application to set fees must include documentation of what negotiations were carried out respecting fees and where the impasse lies. You are expected to have made substantial efforts, including face-to-face meetings involving individuals with the necessary authority.

4) Agreement on Resolution Process and Procedures

- The first step in the C2C or EUB ADR process is a meeting to discuss the nature and extent of the dispute and agree on a course of action. This first meeting is called a Situation Assessment Meeting (SAM) or, if held within the context of the EUB program, a Preliminary ADR (PADR) meeting. The meeting is run by a third-party ADR professional and may address

- the variety of ADR options,
- the appropriate participants and level of authority,
- potential barriers to resolution and options to break the impasse,
- required information and the process for obtaining and exchanging it,
- confidentiality, privacy, and disclosure, and
- timing and deadlines.

- The SAM or PADR meeting is of limited duration and low cost, and the outcome is usually a signed process agreement outlining the next steps, which could include resumption of negotiations, arbitration, engaging third-party experts, mediation or, where appropriate, having some of the issues addressed through a regulatory hearing.

5) Regulatory process—EUB *Guide 65: Resources Applications for Conventional Oil and Gas Reservoirs*

- Sections of *Directive 065* provide detailed requirements for application for common carriers, purchasers and processors in accordance with Part 9 of the Oil and Gas Conservation Act (OGCA). A detailed discussion is provided in chapter 10 of this report.
- An applicant may choose to file an application the EUB to set fees at the same time as it files an application under 48, 50 or 53 of the OGCA. However, in most cases where the EUB is prepared to grant a common carrier, purchaser, or processor order, the application for setting the fee is likely to be deferred to allow for additional negotiations.
- *Directive 065* outlines a number of EUB expectations regarding negotiations, including the following:
  - You should have made substantial efforts to resolve the situation prior to filing an application. The EUB application should be the last resort.
    - You must document face-to-face discussions, timelines, and degree of efforts made to resolve the dispute.
    - You must not withhold critical information until the hearing.
  - You are expected to continue resolution efforts on a voluntary basis even after the application is filed. EUB staff will direct companies to follow the EUB ADR program.

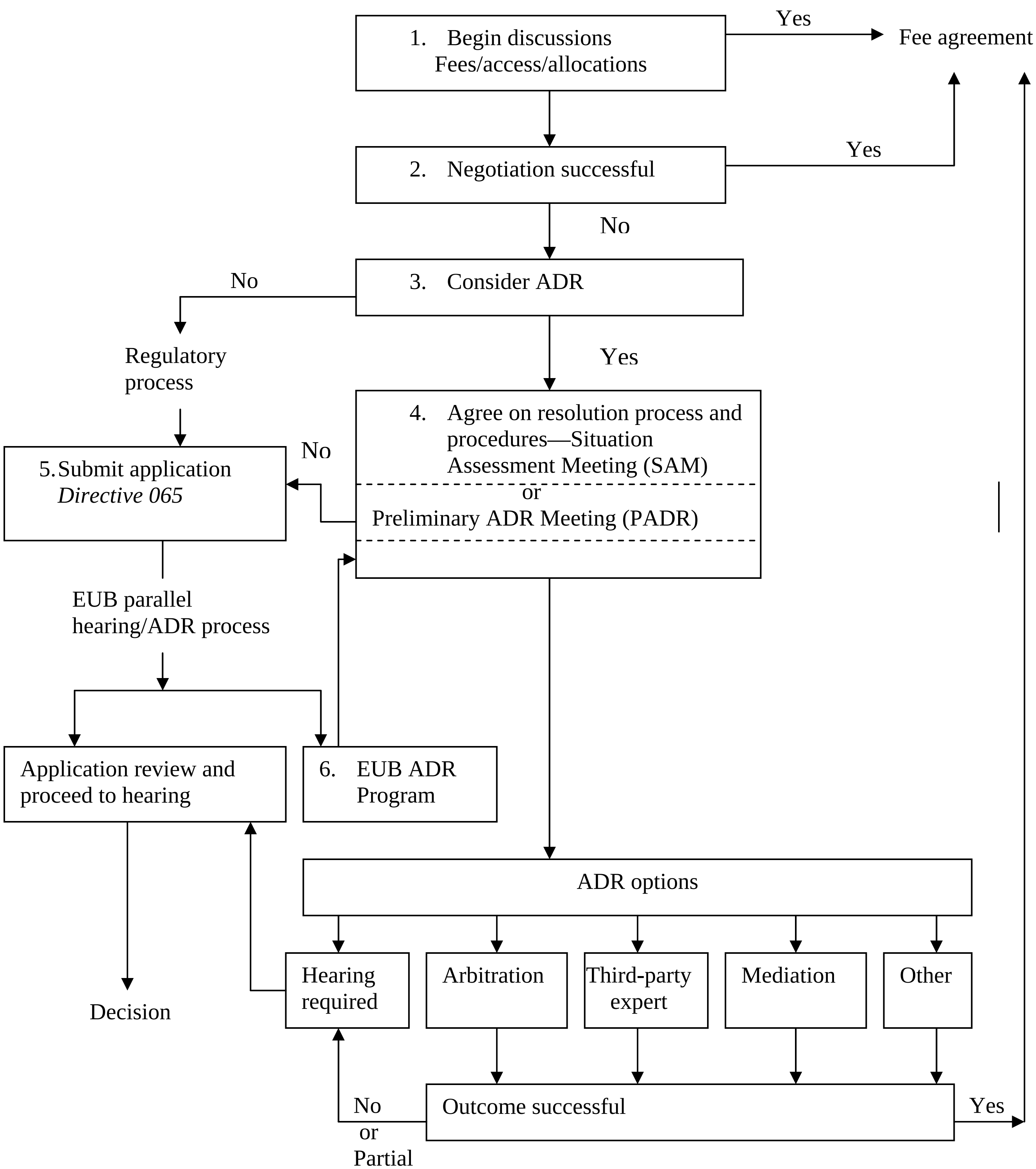
- The EUB has adopted the recommendations of the C2C regulatory alignment team of the C2C Task Force to deal with delays and abuse of the regulatory process, including
  - adopting procedures to quickly dismiss frivolous matters or to establish a date for a hearing as soon as possible;
  - using regulatory cost provisions to permit the EUB to award costs where a cost application has been submitted; and
  - clarifying the admissibility and timing of new evidence at a hearing subsequent to ADR.

The EUB has confirmed its support for the JP methodology as an industry standard in its *Decision 97-2*. If an alternative way of calculating fair processing fees is proposed, it should include a detailed justification as why the EUB should not use the JP approach for the case in question.

6) EUB ADR Program

- The processing of the application will proceed and the implementation of ADR will not delay the timing for a decision on the need for and timing of a hearing.
- The EUB will require all companies in the dispute attend, as a minimum, a PADR meeting to explore possible resolution options. (EUB staff, excluding the application coordinator, attend the PADR meeting, whereas they do not normally attend a pre-application SAM meeting.)
- Should a party not attend a PADR meeting, it must provide reasons in writing, which will then be included with the hearing material.

JP-05 Resolution of Processing Fee Disputes



10 Regulatory Considerations

10.1 Introduction

As the main regulatory body, the EUB was in support of the principles that led to the establishment of JP-90/95. The EUB considers industry solutions to processing fee disputes to be a much more preferable option to a regulatory intervention. The EUB has and continues to support the goals of establishing industry-acceptable guidelines to fee setting. It believes that an industry-acceptable fee structure would promote negotiation of custom processing fees that are fair, reasonable and that enhance resource development consistent with the public good.

10.2 Rights and Obligations

The EUB may issue a declaration of a common processor of gas under Section 53 of the Oil and Gas Conservation Act (OGCA). The OGCA affords each owner the opportunity of obtaining its share of the production of gas from any pool and provides for economic, orderly, and efficient development in the public interest.

The owner has recourse to apply for the declaration of a common processor if it has been unsuccessful in negotiating access to an existing plant. An order under Section 53 of the OGCA obliges each common processor, among other things, to process gas that may be made available for processing in the plant without discrimination in favour of one producer or owner against another in the pool. If there is a dispute as to the processing fee to be paid to the common processor, either the common processor or an owner may also apply under Section 55(2) for the EUB to set the fee.

An applicant may choose to file an application for the EUB to set the processing fee at the same time as it files an application under Section 53. However, in most cases where the EUB is prepared to grant a common processor order, the application for setting the processing fee is likely to be deferred to allow for additional negotiations.

Under Section 56 of the OGCA, an applicant filing a common processor application has the option of requesting that the common processor order be effective retroactive to the date of the application. The EUB considers such a request in light of the particular situation and has the discretion to grant the request, deny it, or provide some measure of retroactivity other than that requested.

In evaluating an application for a common processor order (refer to EUB *Directive 065*), among other things, the EUB considers whether the applicant has demonstrated the following:

- Producible reserves are available for processing and processing facilities are needed.
- Reasonable arrangements for use of processing capacity in the subject processing plant could not be agreed to by the different parties. The EUB expects the applicant to provide evidence that substantial efforts were undertaken to negotiate a resolution prior to filing its application. The application should be a last resort. Even after the application is filed, the EUB expects that the applicant should continue its efforts to reach resolution, including the use of third-party mediators as discussed in chapter 9.
- The proposed common processor operation either is the only economically feasible or most practical way to process the gas in question or is clearly superior from an environmental standpoint. To that effect, the applicant must demonstrate why the proposed common processor operation is superior to the alternative of building new

facilities or using other facilities or any other alternatives that might be available. For each of the plausible alternatives, the applicant must submit economic analysis, including a detailed itemization of all costs (excluding sunk costs), forecasts of production and revenue streams, and tabulation of before-tax rate of return and present value analyses of net cash flow at set discount rates. It is important to recognize that all information submitted to the EUB as part of the application, including the economic assessment, is a matter of public record.

If pursuant to Section 55(2) of the OGCA, an applicant requests that the EUB set the processing fee to be charged by the common processor, the applicant must include in its application

- documentation of discussions indicating what negotiations were carried out respecting processing fees and where the impasse in the negotiation is;
- a statement as to what, in the applicant's view, the processing fee should be and why it is more reasonable and fair than the one offered;
- a detailed tabulation of the calculation, along with justification of the numbers used, should the proposed fee be based on an industry-wide acceptable guideline such as JP-05; and
- a detailed discussion of why the EUB should consider other methodologies if the applicant is advocating deviation from current industry guidelines for fee setting.

10.3 Misconceptions Related to What Circumstances Would Prompt a Common Processor Application

Many industry players are under the misconception that if there is no drainage issue or if access is already provided, there might not be justification for a common processor order or processing fee setting.

The EUB, in fact, considers all factors that may prevent a party from obtaining a fair value for the resource. Drainage is only one of several equity-related issues. There are others, such as existing contractual terms, that are unfair and may lead to less than optimal resource recovery. For example, a fee that is so high that part of the resource is deemed unrecoverable and/or is flared might negatively impact conservation or generate undesirable and avoidable environmental impacts.

Some industry members may believe that if the plant is at full capacity and if there are other economically viable alternatives, there may not be much ground for a common processor order and, if the rate is disputed, fee setting. That is not necessarily so. It all depends on whether building new facilities to connect to a more distant plant or building a new plant would have any undesirable environmental impacts.

The Task Force believes that clarifying these issues may aid in bringing parties together sooner rather than later to negotiate access and fees if they recognize that the EUB will indeed be considering all relevant issues raised by the applicant.

11 Cost Treatment and Dispute Resolution for Royalty Holders

Chapter 5 of the JP-90 Gas Processing Fee Guidelines addressed the situation, which arose in the mid- to late-eighties, of royalty owners' payments being eroded by the industry exercising contractual rights to subtract gathering, compression and processing deductions from royalties paid. Chapter 5 of JP-90 is included in the Appendix D to this report.

The JP-90 Task Force recognized at the time that valid existing royalty agreements

- were outside its purview;
- could indeed have circumstances where gathering, compression and processing deductions could actually exceed royalty revenue; and
- were best dealt with by negotiating a clear and concise cost term in future royalty agreements.

As such, the JP-90 Task Force made suggestions to address the issue of allowable deductions on a go-forward basis.

The key principles to be applied to future royalty leases, as identified by the JP-90 committee, were

- deductions should not exceed royalty revenues;
- deductions should be fair and reasonable;
- existing agreements with specific terms should not be affected; and
- a process for resolving disputes should be provided.

The JP-05 Task Force is still in agreement with these recommendations but recognizes that negotiation and content of royalty agreements remain outside the scope of this Recommended Practice.

Having regard for the foregoing, it is the recommendation of the JP-05 Task Force that in royalty agreements, deductions should be fair and reasonable. Therefore, where a royalty agreement specifies deductions that are fair and reasonable, the Task Force endorses the use of the JP-05 calculation methodology to determine these deductions.

The calculation of the fee for any particular set of circumstances requires the collection of certain data for input to the fee calculation spreadsheet. The spreadsheet will calculate both the “upper limit” and “lower limit” fees for a particular situation. It does not determine where the appropriate fee may be between these limits, which is discussed elsewhere in this Recommended Practice.

The spreadsheet has a number of data input cells that are highlighted. All other cells are either fixed or are calculated from the data input. There is no data input on the second, “Lost GCA,” tab, as all numbers are carried over from the first tab. The highlighted cells are labeled as follows:

Original Facility Capital Cost—The first cell requiring input is “Original Facility Capital Cost.” This number is generally available from the original AFE for construction or from the “Allowable Cost” (commonly referred to as Gas Cost Allowance) submission for the facility. The GCA form is referred to as the AC2 form. An example of this form is attached as Appendix C. If the facility is older than 25 years and original cost records are unavailable, it may be necessary to put 50% of the estimated current replacement cost in this cell. In such cases, the spreadsheet would have to show the facility as being built in the current year and only the lower limit result (capital component) would have meaning. For very old facilities, the upper limit capital component will always be twice the lower limit capital component.

Depreciated Capital—The second cell requiring input is “Depreciated Capital.” This cell is only used for the “lost GCA” calculation and generally should be zero for any facility older than 10 years. The number is available from the same AC2 form or may be estimated by reducing the original cost by 10% per year that the facility has been in existence.

GCA Depreciation—This cell is again only used if lost GCA is to be calculated. It is 10% of the facility cost or may be obtained from the AC2 form. Note that if the spreadsheet is being used for an oil or water handling facility not subject to GCA, both the depreciated capital and the GCA depreciation should be zero.

Original Facility Start-up Year—This is self-explanatory. It is used to calculate the current replacement cost of the facility by taking the original cost and inflating it 3% per year to the current year. The replacement cost is used in the upper limit capital fee calculation.

Major Capital Addition Year—The spreadsheet has been set up to account for one major capital addition constructed after the original construction. The year input allows the spreadsheet to calculate the replacement value of the addition separately from the original facility. If more than one major addition has taken place, the spreadsheet would have to be modified or off-line calculations would have to be done.

Major Capital Addition Cost—This is the actual cost for the one major addition that the spreadsheet can handle. In effect, the spreadsheet calculates a fee for the original facility and a fee for the expansion and adds the two together.

Facility Capacity—This is the daily actual capacity of the facility under current operating conditions. Fees are calculated per unit of capacity, so it is critical that this input be technically correct. Although the units are referred to as e^3 m^3/d, any gas or liquid system of units will work.

Owners' Throughput—This input is the current daily throughput by owners in the facility.

Third-Party Throughput—This is the current plus expected throughput of all third parties in the facility. If the fee is being calculated in anticipation of additional third-party volumes, these volumes should be included in this number.

Annual Operating Cost—This input should be the expected annual operating cost, including operator's overhead (often 10% of the cost). If the facility does not have an overhead rate specified, such as for a 100% owned facility, 10% should be added to the actual costs. If the facility has some other overhead specified by agreement, that number should be used.

It is appropriate for the number to be a rolling average of the costs for however many years it would take to include one turnaround cost for those facilities that have significant turnaround expenditures.

Year (today)—This is literally what year is it today. This is used to determine what the replacement cost of the facility is by inflating the original cost by the number of years since it was built.

EXAMPLES

EXAMPLE OF THE LIFE CYCLE OF FEES FOR A FACILITY

Facility cost:	$10,000,000
Year built:	2004
Capacity	1000 e^3 m^3/d

CASE 1

Year:	2006
Owner throughput:	750 e^3 m^3/d
Third-party request:	50 e^3 m^3/d
Operating cost:	$1,000,000/year (rolling average)

Upper limit capital fee calculation:	$6.06/$e^3$ m^3/d
Lower limit capital fee calculation:	$5.71/$e^3$ m^3/d
Operating cost fee:	$3.57/$e^3$ m^3/d
Lost GCA fee[1]:	$0.43/$e^3$ m^3/d

Negotiation Basis

Facility is not full.
There are no plans to fill it with owner gas.
Agreement will be 30-day termination, reasonable efforts.

Negotiation Results

Parties agree on a fee of $6.14/$e^3$ m^3/d, including capital and lost GCA.
Operating cost to be paid on a throughput basis with a 13th month adjustment.

Reasoning

Lost GCA declines over time.
Fee should tend to lower limit, as facility has lots of spare capacity.
Contract has short termination clause if circumstances change.
Operator is not willing to provide an "all-in" fee despite ease of administration due to concerns over escalating operating costs.

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[1] See page 51 for Lost GCA fee calculation

CASE 2

Year:	2007
Owner throughput:	800 e^3 m^3/d
Third-party request:	50 e^3 m^3/d
Operating cost:	$1,000,000/year (rolling average)
Upper limit capital fee calculation:	$6.24/$e^3$ m^3/d
Lower limit capital fee calculation:	$5.71/$e^3$ m^3/d
Operating cost fee:	$3.36/$e^3$ m^3/d
Lost GCA fee[2]:	$0.26/$e^3$ m^3/d

Negotiation Basis

Facility is not full.
There are no plans to fill it with owner gas.
Agreement will be 30-day termination, reasonable efforts.

Negotiation Results

Parties agree on a fee of $5.97/$e^3$ m^3/d, including capital and lost GCA.
Operating cost to be paid on a throughput basis with a 13th month adjustment.

Reasoning

Lost GCA declines over time and is minor in this case.
Fee should tend to lower limit, as facility has lots of spare capacity.
Contract has short termination clause if circumstances change.
Operator is not willing to provide an "all-in" fee despite ease of administration due to concerns over escalating operating costs.

[2] See page 53 for Lost GCA fee calculation

CASE 3

Year:	2009
Owner throughput:	900 e^3 m^3/d
Third-party throughput:	50 e^3 m^3/d (Company A)
Third-party request:	50 e^3 m^3/d (Company B)
Operating cost:	$1,000,000/year (rolling average)

Upper limit capital fee calculation:	$6.62/$e^3$ m^3
Lower limit capital fee calculation:	$5.71/$e^3$ m^3
Operating cost fee:	$2.86/$e^3$ m^3
Lost GCA fee:	$0.00/$e^3$ m^3 (facility is full)

Negotiation Basis

Facility is full.
Company B wants firm service.
Company A is happy with reasonable efforts service.
Operator is not willing to guarantee capacity, as their new geologist has been finding additional production the last two years.

Negotiation Results

Company A agrees to continue to pay the fee negotiated in 2007 of $5.97/$e^3$ m^3.
Company B agrees to $6.62/$e^3$ m^3 and gets higher priority than Company A.
Both companies agree to pay a fixed operating cost fee of $2.86/$e^3$ m^3 for administrative ease (operating costs have been consistent for 5 years).

Reasoning

Even though lost GCA is gone, the Company A fee of $5.97/$e^3$ m^3 is between the upper and lower limit. Company B should pay at the upper limit due to the guarantee provided. Everyone likes a fixed “all-in” fee.

CASE 4

Year:	2015
Owner throughput:	400 e^3 m^3/d
Third-party throughput:	200 e^3 m^3/d (Company A and B)
Third-party request:	50 e^3 m^3/d (Company C)
Operating cost:	$1,500,000/year (rolling average)
Upper limit capital fee calculation:	$7.91/$e^3$ m^3
Lower limit capital fee calculation:	$5.71/$e^3$ m^3
Operating cost fee:	$6.59/$e^3$ m^3
Lost GCA fee:	$0.00/$e^3m^3$ (facility is fully depreciated)

Negotiation Basis

Company A and B have been paying $5.97 plus operating costs for some time. Company B gave up firm capacity some time ago when throughputs fell off. The operator revised the operating cost fee to actual costs when unit operating costs started to escalate with inflation and declining throughput. Company A and B have been grumbling about the operating costs and have suggested there may be another facility that would take their gas.

Negotiation Results

The operator offers Company C the same fee as Company A and B have been paying. Company C gets the operator to agree to $5.71/$e^3$ m^3 due to the low throughputs and concern about operating costs. The operator offers the same deal to Company A and B. All third parties commit their gas to the facility for two years. The operator agrees to fix the fee for two years.

Reasoning

All parties recognize the threat to the facility's viability. The lower limit fee is justified in an under-utilized plant. The operator benefits from operating cost dilution with the additional throughput.

CASE 5

Year:	2034
Owner throughput:	200 e^3 m^3/d
Third-party throughput:	500 e^3 m^3/d
Operating cost:	$1,500,000/year (rolling average)
Capital addition.	$2,000,000

Upper limit capital fee calculation:	$15.01/$e^3$ m^3
Lower limit capital fee calculation:	$7.51/$e^3$ m^3
Operating cost fee:	$6.12/$e^3$ m^3
Lost GCA fee:	$0.15/$e^3$ m^3

The capital fee is a combination of the fee for the original investment and for the new investment required.

Negotiation Basis

The third parties have been paying a fee since 2028 that has been 50% of each year's upper limit fee (escalates at 3% per year). The 2034 fee prior to capital addition is $6.94/$e^3$ m^3.
The operator wants a higher fee due to the major capital investment.

Negotiation Results

The parties eventually agree to $10.00/$e^3$ m^3 with no inflation escalator. The third parties agree to dedicate their gas to the facility for 5 years. The operator agrees to provide firm capacity to each third party up to the volume produced in 2034.

Reasoning

The operator still has substantial production, which it is protecting by making the additional capital expenditure. The fee agreed is a compromise between the operator's desire to get a payout on the additional capital invested and the third party's desire to pay lower limit fees in a facility that is not full.

CALCULATIONS ASSOCIATED WITH EXAMPLES

JP-05 CALCULATION SPREADSHEET

Case 1

	(shaded)	=Input Cells
Original Facility Capital Cost ($)	10,000,000	
Undepreciated Capital ($)	8,000,000	From AC2 Form (used for lost GCA only, or may be calculated as original capital reduced 10% per year, usually zero after year 10)
GCA Depreciation	1,000,000	From AC2 Form (used for lost GCA only or may be calculated as 10% of total capital in first 10 years, zero thereafter)
Original Facility Start-up Year	2004	
Major Capital Addition Capital Cost ($)	-	
Major Capital Addition Year	-	
Facility Capacity (e^3 m^3/d)	1,000	Per operating day
Owners' Throughput (e^3 m^3/d)	750	Per operating day
Third-party Throughput (e^3 m^3/d)	50	Per operating day
Facility Operating Days/Year	350	Default to 350
Capital Cost Inflation Rate (%)	3	Default to 3%
Inflated Total Capital ($)	10,609,000	Capital*$1.03^{(age)}$
Rate of Return (%)	20	Fixed!
Annual Operating Cost ($)	1,000,000	Includes overhead; may be rolling average
Year (today)	2006	
Upper Limit Capital Fee	6.06	$/$e^3$ m^3
Lower Limit Capital Fee	5.71	$/$e^3$ m^3 (not less than 50% of upper limit)
Operating Cost Fee	3.57	$/$e^3$ m^3
Lost Gas Cost Allowance Fee	0.43	$/$e^3$ m^3 (decreases to zero after year 10 assuming no new capital)
Upper Limit All-In Fee	**10.06**	
Lower Limit All-In Fee	**9.71**	

Case 1
LOST GAS COST ALLOWANCE CALCULATION

A	Undepreciated Capital ($)	8,000,000	From AC2 Form (transferred from page 1)
B	GCA Rate of Return (%)	15	Fixed
C	Return on Capital ($)	1,200,000	B*A
D	Depreciation ($)	1,000,000	From AC2 Form (transferred from page 1)
E	Total Capital GCA ($)	2,200,000	C+D
F	Owners' Throughput (e^3 m^3/d)	750	Per operating day
G	Third-party Throughput (e^3 m^3/d)	50	Per operating day
H	Total Throughput	800	F+G
I	Capacity (e^3 m^3/d)	1,000	Per operating day
J	Custom Gas Factor	0.0625	G/H
K	Lost GCA Allocation ($)	27,500	E(1-G/I)-E*F/H
L	Alberta Tax Rate (%)	11.50	
M	Federal Tax Rate (%)	23.00	
N	Effective Crown Royalty Rate (%)	25.00	
O	Combined Effective Tax Rate[3] (%)	32.50	L+[M(1-.25*.35)]
P	Lost GCA Factor (%)	27.24	N(1-L-M*percent deductible crown royalty for year 2006)/(1-O)
Q	Lost GCA ($)	7,491	P*K
R	Lost GCA Fee ($/$e^3$ m^3)	0.43	Q/(G*350)

NOTE: Rows L through P are subject to changes in provincial and federal tax structure.
The 2007 planned tax rates and the elimination of Resource Allowance have been used here.

[3] Combined effective tax rate is equal to provincial tax plus effective federal rate after adjusting for the fact that 35% of the resource allowance is deductible for income tax purposes or that 65% of crown royalty is an allowed deduction for 2006 federal tax calculation

JP-05 CALCULATION SPREADSHEET

Case 2

		=Input Cells
Original Facility Capital Cost ($)	10,000,000	
Undepreciated Capital ($)	7,000,000	From AC2 Form (used for lost GCA only or may be calculated as original capital reduced 10% per year, usually zero after year 10)
GCA Depreciation	1,000,000	From AC2 Form (used for lost GCA only or may be calculated as 10% of total capital in first 10 years, zero thereafter)
Original Facility Start-up Year	2004	
Major Capital Addition Capital Cost ($)	-	
Major Capital Addition Year	2004	
Facility Capacity (e^3 m^3/d)	1,000	Per operating day
Owners' Throughput (e^3 m^3/d)	800	Per operating day
Third-party Throughput (e^3 m^3/d)	50	Per operating day
Facility Operating Days/Year	350	Default to 350
Capital Cost Inflation Rate (%)	3	Default to 3%
Inflated Total Capital ($)	10,927,270	Capital*$1.03^{(age)}$
Rate of Return (%)	20	Fixed!
Annual Operating Cost ($)	1,000,000	Includes overhead; may be rolling average
Year (today)	2007	
Upper Limit Capital Fee	6.24	$/$e^3$ m^3
Lower Limit Capital Fee	5.71	$/$e^3$ m^3 (not less than 50% of upper limit)
Operating Cost Fee	3.36	$/$e^3$ m^3
Lost Gas Cost Allowance Fee	0.26	$/$e^3$ m^3 (decreases to zero after year 10 assuming no new capital)
Upper Limit All-In Fee	**9.86**	
Lower Limit All-In Fee	**9.33**	

Case 2

LOST GAS COST ALLOWANCE CALCULATION

A	Undepreciated Capital ($)	7,000,000	From AC2 Form
B	GCA Rate of Return (%)	15	Fixed
C	Return on Capital ($)	1,050,000	B*A
D	Depreciation ($)	1,000,000	From AC2 Form
E	Total Capital GCA ($)	2,050,000	C+D
F	Owners' Throughput (e^3 m^3/d)	800	Per operating day
G	Third-party Throughput (e^3 m^3/d)	50	Per operating day
H	Total Throughput	850	F+G
I	Capacity (e^3 $m^{3/}$d)	1,000	Per operating day
J	Custom Gas Factor	0.0588	G/H
K	Lost GCA Allocation ($)	18,088	E(1-G/I)-E*F/H
L	Alberta Tax Rate (%)	11.50	
M	Federal Tax Rate (%)	21.00	
N	Effective Crown Royalty Rate (%)	25.00	
O	Combined Effective Tax Rate (%)	32.50	L+M
P	Lost GCA Factor[4] (%)	25.00	Equals to N
Q	Lost GCA Charge ($)	4,522	P*K
R	Lost GCA Fee ($/$e^3$ m^3)	0.26	Q/(G*350)

NOTE: Rows L through P are subject to changes in provincial and federal tax structure.
The 2007 planned tax rates and the elimination of Resource Allowance have been used here.

[4] See Section 6.2

JP-05 CALCULATION SPREADSHEET

Case 3

		=Input Cells
Original Facility Capital Cost ($)	10,000,000	
Undepreciated Capital ($)	5,000,000	From AC2 Form (used for lost GCA only or may be calculated as original capital reduced 10% per year, usually zero after year 10)
GCA Depreciation	1,000,000	From AC2 Form (used for lost GCA only or may be calculated as 10% of total capital in first 10 years, zero thereafter)
Original Facility Start-up Year	2004	
Major Capital Addition Capital Cost ($)	-	
Major Capital Addition Year	2004	
Facility Capacity (e^3 m^3/d)	1,000	Per operating day
Owners' Throughput (e^3 m^3/d)	900	Per operating day
Third-party Throughput (e^3 m^3/d)	100	Per operating day
Facility Operating Days/Year	350	Default to 350
Capital Cost Inflation Rate (%)	3	Default to 3%
Inflated Total Capital ($)	11,592,741	Capital*$1.03^{(age)}$
Rate of Return (%)	20	Fixed!
Annual Operating Cost ($)	1,000,000	Includes overhead; may be rolling average
Year (today)	2009	
Upper Limit Capital Fee	6.62	$/$e^3$ m^3
Lower Limit Capital Fee	5.71	$/$e^3$ m^3 (not less than 50% of upper limit)
Operating Cost Fee	2.86	$/$e^3$ m^3
Lost Gas Cost Allowance Fee	0.00	$/$e^3$ m^3 (decreases to zero after year 10 assuming no new capital)
Upper Limit All-In Fee	**9.48**	
Lower Limit All-In Fee	**8.57**	

Case 3

LOST GAS COST ALLOWANCE CALCULATION

A	Undepreciated Capital ($)	5,000,000	From AC2 Form
B	GCA Rate of Return (%)	15	Fixed
C	Return on Capital ($)	750,000	B*A
D	Depreciation ($)	1,000,000	From AC2 Form
E	Total Capital GCA ($)	1,750,000	C+D
F	Owners' Throughput (e^3 m^3/d)	900	Per operating day
G	Third-party Throughput (e^3 m^3/d)	100	Per operating day
H	Total Throughput	1,000	F+G
I	Capacity (e^3 m^3/d)	1,000	Per operating day
J	Custom Gas Factor	0.1000	G/H
K	Lost GCA Allocation ($)	-	E(1-G/I)-E*F/H
L	Alberta Tax Rate (%)	11.50	
M	Federal Tax Rate (%)	21.00	
N	Effective Crown Royalty Rate (%)	25.00	
O	Combined Effective Tax Rate (%)	32.50	L+M
P	Lost GCA Factor (%)	25.00	Equals to N
Q	Lost GCA Charge ($)	-	P*K
R	Lost GCA Fee[5] ($/$e^3$ m^3)	0.00	Q/(G*350)

NOTE: Rows L through P are subject to changes in provincial and federal tax structure.
The 2007 planned tax rates and the elimination of Resource Allowance have been used here.

[5] There is no lost GCA since facility is full

JP-05 CALCULATION SPREADSHEET

Case 4

		=Input Cells
Original Facility Capital Cost ($)	10,000,000	
Undepreciated Capital ($)	-	From AC2 Form (used for lost GCA only or may be calculated as original capital reduced 10% per year, usually zero after year 10)
GCA Depreciation	-	From AC2 Form (used for lost GCA only or may be calculated as 10% of total capital in first 10 years, zero thereafter)
Original Facility Start-up Year	2004	
Major Capital Addition Capital Cost ($)	-	
Major Capital Addition Year	2004	
Facility Capacity (e^3 m^3/d)	1,000	Per operating day
Owners' Throughput (e^3 m^3/d)	400	Per operating day
Third-party Throughput (e^3 m^3/d)	250	Per operating day
Facility Operating Days/Year	350	Default to 350
Capital Cost Inflation Rate (%)	3	Default to 3%
Inflated Total Capital ($)	13,842,339	Capital*$1.03^{(age)}$
Rate of Return (%)	20	Fixed!
Annual Operating Cost ($)	1,500,000	Includes overhead; may be rolling average
Year (today)	2015	
Upper Limit Capital Fee	7.91	\$/e^3 m^3
Lower Limit Capital Fee	5.71	\$/e^3 m^3
Operating Cost Fee	6.59	\$/e^3 m^3
Lost Gas Cost Allowance Fee	0.00	\$/e^3 m^3 (decreases to zero after year 10 assuming no new capital)

Upper Limit All-In Fee	**14.50**
Lower Limit All-In Fee	**12.30**

Case 4

LOST GAS COST ALLOWANCE CALCULATION

A	Undepreciated Capital ($)	-	From AC2 Form
B	GCA Rate of Return (%)	15	Fixed
C	Return on Capital ($)	-	B*A
D	Depreciation ($)	-	From AC2 Form
E	Total Capital GCA ($)	-	C+D
F	Owners' Throughput (e^3 m^3/d)	400	Per operating day
G	Third-party Throughput (e^3 m^3/d)	250	Per operating day
H	Total Throughput	650	F+G
I	Capacity (e^3 m^3/d)	1,000	Per operating day
J	Custom Gas Factor	0.3846	G/H
K	Lost GCA Allocation ($)	-	E(1-G/I)-E*F/H
L	Alberta Tax Rate (%)	11.50	
M	Federal Tax Rate (%)	21.00	
N	Effective Crown Royalty Rate (%)	25.00	
O	Combined Effective Tax Rate (%)	32.50	L+M
P	Lost GCA Factor (%)	25.00	Equals to N
Q	Lost GCA Charge($)	-	P*K
R	Lost GCA Fee[6] ($/$e^3$ m^3)	0.00	Q/(G*350)

NOTE: Rows L through P are subject to changes in provincial and federal tax structure.
The 2007 planned tax rates and the elimination of Resource Allowance have been used here.

[6] There is no lost GCA since facility is fully depreciated

JP-05 CALCULATION SPREADSHEET

Case 5

		=Input Cells
Original Facility Capital Cost ($)	10,000,000	
Undepreciated Capital ($)	2,000,000	From AC2 Form (used for lost GCA only or may be calculated as original capital reduced 10% per year, usually zero after year 10)
GCA Depreciation	200,000	From AC2 Form (used for lost GCA only or may be calculated as 10% of total capital in first 10 years, zero thereafter)
Original Facility Start-up Year	2004	
Major Capital Addition Capital Cost ($)	2,000,000	
Major Capital Addition Year	2034	
Facility Capacity (e^3 m^3/d)	1,000	Per operating day
Owners' Throughput (e^3 m^3/d)	200	Per operating day
Third-party Throughput (e^3 m^3/d)	500	Per operating day
Facility Operating Days/Year	350	Default to 350
Capital Cost Inflation Rate (%)	3	Default to 3%
Inflated Total Capital ($)	26,272,625	Capital*$1.03^{(age)}$
Rate of Return (%)	20	Fixed!
Annual Operating Cost ($)	1,500,000	Includes overhead; may be rolling average
Year (today)	2034	
Upper Limit Capital Fee	15.01	$/$e^3$ m^3
Lower Limit Capital Fee	7.51	$/$e^3$ m^3 (not less than 50% of upper limit)
Operating Cost Fee	6.12	$/$e^3$ m^3
Lost Gas Cost Allowance Fee	0.15	$/$e^3$ m^3 (decreases to zero after year 10 assuming no new capital)

Upper Limit All-In Fee	**21.29**
Lower Limit All-In Fee	**13.78**

Case 5

LOST GAS COST ALLOWANCE CALCULATION

A	Undepreciated Capital ($)	2,000,000	From AC2 Form
B	GCA Rate of Return (%)	15	Fixed
C	Return on Capital ($)	300,000	B*A
D	Depreciation ($)	200,000	From AC2 Form
E	Total Capital GCA ($)	500,000	C+D
F	Owners' Throughput (e^3 m^3/d)	200	Per operating day
G	Third-party Throughput (e^3 m^3/d)	500	Per operating day
H	Total Throughput	700	F+G
I	Capacity (e^3 m^3/d)	1,000	Per operating day
J	Custom Gas Factor	0.7143	G/H
K	Lost GCA Allocation ($)	107,143	E(1-G/I)-E*F/H
L	Alberta Tax Rate (%)	11.50	
M	Federal Tax Rate (%)	21.00	
N	Effective Crown Royalty Rate (%)	25.00	
O	Combined Effective Tax Rate (%)	32.50	L+M
P	Lost GCA Factor (%)	25.00	Equals to N
Q	Lost GCA ($)	26,786	P*K
R	Lost GCA Fee ($/$e^3$ m^3)	0.15	Q/(G*350)

NOTE: Rows L through P are subject to changes in provincial and federal tax structure.
The 2007 planned tax rates and the elimination of Resource Allowance have been used here.

JP-90

In a letter dated August 4, 1989 the Honourable Rick Orman, Alberta Minister of Energy, expressed concerns about excessive gas processing charges causing hardship for some producers and royalty owners, encouraging proliferation of gas plants and hampering conservation of solution gas. He indicated that he would prefer that industry address this situation and develop a solution that does not require regulatory intervention and suggested that peer arbitration might be a part of that process. He requested that each producer association consider the issue and suggest a framework for solution.

In response to this letter the Canadian Petroleum Association (CPA), the Independent Petroleum Association of Canada (IPAC) and the Small Explorers and Producer Association of Canada (SEPAC) established a joint industry task force (JP-90 Task Force) to consider the problem and recommend a solution.

The JP-90 Task Force determined that its objectives were:

1) To develop a fee structure guideline that is sufficiently flexible to promote negotiation of custom processing arrangements that are fair and reasonable to both facility owners and custom users including producers, royalty holders and penalty partners; and,
2) To develop an effective dispute resolution process for use in those cases where negotiations have failed.

It was recognized that it was necessary to develop guidelines that fairly represented the risks to facility owners and other parties associated with custom processing operations. In order to be flexible, and at the same time recognize the risks associated with each party, the guidelines would have to provide a well defined relevant range of custom processing fees. It was agreed that to facilitate the acceptance and utilization of the guidelines the methods adopted should be easily understood and familiar to the industry, government and regulatory bodies.

It was the view of the JP-90 Task Force that if these features were incorporated, the guidelines would provide a fair framework within which negotiations and disputes could be resolved.

The fee structure guidelines were intended to be applied on a go forward basis since the Task Force acknowledged that there is sanctity of existing contracts. However, in situations where disagreements exist within existing contracts as to the methodology of fee determination or ambiguity in terms, etc, the fee guidelines described in the report could be used as an objective benchmark for comparative purposes.

With regard to its second priority, the Task Force was to comment on the disputes involving royalty holders.

Through 1989, there were a number of complaints presented to the Alberta Public Utilities Board (PUB), Alberta Energy Minister and the Farmers’ Advocate of Alberta from freehold and gross overriding royalty holders. Although the specific details of the complaints were not released, it is understood that they are related to gathering, compressing or processing costs that are being deducted from royalty revenues. In some cases the cost deductions exceed the royalty entitlement, and the royalty holders were actually being invoiced for the excess. The lease agreements and contracts in question are often ambiguous with respect to allowable cost deductions.

The JP-90 report was endorsed by the industry associations and the regulatory agencies, and was issued in January of 1990. Upon publication, the Petroleum Joint Venture Association (PJVA) became the custodian of the document.

JP-95

In late 1994, the PJVA saw the need for a review of the JP-90 Report based on the introduction of royalty simplification in Alberta and for a better industry-wide understanding of the fee guidelines. Thus, the JP-95 Task Force was formed.

The JP-95 Task Force was given the following mandate:

1) Clarify the intent and use of JP-90 as an equitable processing fee guideline that promotes negotiations;
2) Assess the impact of recent Alberta gas royalty changes on the calculation of lost gas cost allowance (GCA); and
3) Assess simplification of the administration of processing fees.

The report addressed the mandate as outlined above, with emphasis on clarifying the intent and use of the JP-90 Report. While the fee guidelines were applicable to both oil and gas processing, the discussions in both JP-90 and JP-95 report focused on gas processing as it is a more predominant use of the fee guidelines. Also, in developing the report, the JP-95 Task Force considered processing situations in both Alberta and British Columbia, and included references regarding any differences that should be considered when negotiating processing agreements in the two provinces. The JP-95 Task Force believed that JP-90 is applicable to other jurisdictions with due consideration to changes in investment and tax circumstances. JP-95 also addressed the increasing presence of companies who are purchasing or building facilities solely for the purpose of custom processing producers' volumes.

The report followed the JP-90 calculation, addressing each part of the calculation and explaining the basis for developing each component: return on capital, the rate base and relevant range, operating costs, special fee considerations, and application of fees. It addressed lost GCA, and discussed the jurisdictional considerations for Alberta and British Columbia. JP-95 included examples of several processing fee calculations, as well as definitions for terminology used in the report.

JP-95 was intended to be used in conjunction with JP-90, as JP-95 did not address royalty owner treatment, or tools and processes for negotiation of fee disputes. JP-95 was released to the industry in April 1996, and was endorsed by the Canadian Association of Petroleum Producers (CAPP), SEPAC and the PJVA. The document was accepted in principle by the Alberta EUB, and was cited in subsequent industry hearings before the EUB as an accepted practice for companies to use to negotiate custom fees.

Appendix B—Consumer Price Index

Year	INDEX (2000=100)	Inflation Rate (%)
2004	109.783	1.9
2003	107.736	2.8
2002	104.837	2.2
2001	102.532	2.5
2000	100.000	2.7
1999	97.327	1.7
1998	95.680	1.0
1997	94.745	1.6
1996	93.233	1.6
1995	91.787	2.2
1994	89.839	0.2
1993	89.673	1.8
1992	88.051	1.5
1991	86.745	5.6
1990	82.133	4.8
1989	78.398	5.0
1988	74.668	4.0
1987	71.780	4.4
1986	68.778	4.2
1985	66.023	4.0
1984	63.513	4.3
1983	60.872	5.8
1982	57.526	10.8
1981	51.818	12.5
1980	46.164	10.2
1979	41.898	9.1
1978	38.387	8.9
1977	35.246	8.0
1976	32.630	7.5
1975	30.359	10.8
1974	27.396	10.9
1973	24.711	7.6
1972	22.963	4.8
1971	21.917	2.8
1970	21.312	3.4
1969	20.618	4.5
1968	19.729	4.1
1967	18.955	3.6
1966	18.301	3.7
1965	17.641	2.5
1964	17.218	1.8
1963	16.914	1.8
1962	16.620	1.2
1961	16.427	0.9
1960	16.286	1.3
1959	16.075	1.1
1958	15.904	2.6
1957	15.498	3.2
1956	15.018	1.4
1955	14.804	0.2
1954	14.771	0.6
1953	14.689	-0.9
1952	14.821	2.5
1951	14.459	10.4
1950	13.095	3.0
1949	12.718	3.2
1948	12.323	

Appendix C—SAMPLE ALBERTA ENERGY AC2 FORM

ALLOWABLE COSTS
CAPITAL COST ALLOWANCE
AC2-V2
PRODUCTION YEARS 1997 AND ONWARDS

PART 1: IDENTIFICATION

1.1 **AB** (PROV.) **GP** (FAC TYPE) **0001775** (EUB FACILITY CODE)

1.2 **10036660** (FACILITY COST CENTRE CODE)

1.3 **West Culp 5-34-78-25w5 Gas Plant** (DESCRIPTION OF FACILITY COST CENTRE)

1.4 **0F3F** (FACILITY COST CENTRE OPERATOR ID)

1.5 **DEVON CANADA** (FACILITY COST CENTRE OPERATOR NAME)

1.6 PRODUCTION YEAR **2003**

1.7 DATE PREPARED **2004** (YR.) **07** (MO.) **21** (DY.)

1.8 **Donna Tohm** (CONTACT PERSON)

1.9 **(403) 213-7833** (TELEPHONE)

PART 2: CAPITAL COST ALLOWANCE CALCULATION

	ALLOWABLE CAPITAL COSTS ($)
2.1 CUMULATIVE ALLOWABLE CAPITAL JAN 1 OR ________	15,036,150
2.2 ALLOWABLE CAPITAL COST JAN 1 OR ________	11,531,940
2.3 CAPITAL ADDITIONS (CARRIED FROM PART 3) ________	4,545
2.4 CUMULATIVE ALLOWABLE CAPITAL DEC 31 OR ________	15,040,695
2.5 ALLOWABLE CAPITAL COST BEFORE DEPRECIATION DEC 31 OR ________	11,536,485
2.6 DEPRECIATION 12 /12 ________	1,648,069
2.7 ALLOWABLE CAPITAL COST AFTER DEPRECIATION DEC 31 OR ________	9,888,416

	RETURN ON AVG. CAPITAL($)
2.8 AVERAGE CAPITAL	10,710,178
2.9 LAND	0
2.10 AVG. SPARE PARTS INVENTORY	0
2.11 TOTAL	10,710,178

	CAPITAL COST ALLOWANCE($)
2.12 RETIREMENTS	0
2.13 DEPRECIATION	1,648,069
2.14 RETURN ON AVG. CAPITAL 12 /12	1,606,527
2.15 CAPITAL COST ALLOWANCE	3,254,596

2.16 **7** REMAINING USEFUL LIFE (YRS.)

PART 3: CAPITAL ADDITIONS

3.1 ADDITIONS/DISPOSITIONS/RETIREMENTS	3.2 TYPE	3.3 AMOUNT($)
AFE 0009322 capital additions to gas plant	A	2,603
AFE 02350161 capital additions to plant meter skid	A	1,942
	3.4 TOTAL	4,545

PART 4: CAPITAL COST ALLOWANCE ALLOCATIONS

4.1 CLIENT ID	4.2 CLIENT NAME	4.3 CCA DISTRIBUTIONS %
0F3F	DEVON CANADA	50.43270
0039	TALISMAN ENERGY INC	41.79460
0KX8	ACCLAIM ENERGY INC	1.10787
0WP4	ACCLAIM OIL AND GAS LTD.	0.22157
	4.4 CUSTOM PROCESSING ADJUSTMENT FACTOR %	6.44326
	4.5 TOTAL CAPITAL COST ALLOWANCE ALLOCATED	100.00000

PART 5: CUSTOM PROCESSING ADJUSTMENT FACTOR CALCULATION

5.3 UNIT 10^3m^3 [X] m^3 [ ] t [ ]

5.1 CLIENT ID	5.2 CLIENT NAME	5.4 CUSTOM VOLUMES
0TD9	ADVANTAGE OIL & GAS LTD	7,443.4
	5.5 TOTAL CUSTOM VOLUMES	7,443.4
	5.6 TOTAL FACILITY COST CENTRE THROUGHPUT	115,522.3
	5.7 CUSTOM PROCESSING ADJUSTMENT FACTOR %	6.44326

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5.0 GUIDELINES FOR COST TREATMENT & DISPUTE SETTLEMENT FOR ROYALTY HOLDERS

The following section identifies the procedures available to the Royalty Holders to resolve disputes.

5.1 BACKGROUND

As noted earlier, there are a number of complaints before the PUB, the Energy Minister and the Farmers' Advocate by freehold and gross overriding royalty holders. These issues are commonly concerned with gathering, compressing or processing deductions from royalty revenues and occur between the royalty owner and the producer. In these instances the producer may be a custom user or a facility owner or both. The substance of the disagreements includes the producer's contractual entitlement to deduct costs either on a go forward basis or retroactively, and differences as to what is "fair and reasonable".

The royalty holders concerns began to emerge in 1986 when natural gas and crude oil prices plummeted. Prior to that time, royalty holders were generally satisfied with their revenues. Producers in many cases were content to not exercise their contractual right to charge the royalty holder with the proportionate share of gathering, compressing and processing costs. However, the price shock in 1986 brought with it a strong impetus for producers to economize. As a consequence, the industry exercised its contractual right and the practice of deducting costs grew. The combined effect of reduced product prices with increased deductions significantly eroded the royalty holder revenue, resulting in the royalty holder complaints.

With "fair and reasonable" cost deductions it seems unlikely that a producer costs could exceed revenues, but in fact, there are several situations where costs will justifiably exceed revenues. For example, the cost of gathering and processing solution gas may be higher than the gas revenue, but this excess cost is offset by the crude oil revenue. A company may have contractual market obligations that may result in a short-term loss, but the expectation of higher future prices or production volumes may justify operating at a loss for an interim period.

The following sections describe guidelines that could reduce problems in royalty leases which are negotiated in the future, and should provide a method for resolution of existing royalty holder concerns. Suggestions are also included on how a royalty holder can manage risks in the terms of his lease.

5.2 PRINCIPLES OF THE GUIDELINES

There are a number of factors that should guide agreements with royalty holders. These guidelines are aimed primarily at small, freehold royalty holders who do not have the benefit of corporate land and legal staff to protect their interests; but they may also be applicable to overriding royalty holders, working interests subject to penalty, and non-arms length working interest owners.

The Task Force identified the following general principle to be applied to royalty leases:

1) Cost deductions for gathering, compressing and processing should not exceed royalty revenues for:

- non-associated gas streams

- combined solution gas & crude oil streams
- solution gas streams under royalty leases that are separate from crude oil royalty leases.

2) Cost deductions should be fair and reasonable.

3) Royalty holders should have a means to negotiate and manage the cost risks taken in royalty revenues.

4) Existing agreements with specific cost deduction terms should not be affected.

5) Solutions for both existing and future royalty leases should be provided.

6) A process for resolving disputes should be provided.

7) The need for regulatory intervention should be minimized.

5.3 FUTURE ROYALTY LEASES

With the knowledge of the problem created by the ambiguity of the expense deduction clause, royalty agreements negotiated in the future should have cost terms that are clear and concise. The lease documents should be written in a manner that results in no uncertainty as to royalty rates and any allowances that may reduce the royalty entitlement.

For arms length processing where, for example, the producer contracts with a third party to gather, compress or process the stream under a custom processing fee arrangement, the cost deductions should be equal to the actual custom processing fees paid. Because this is the same out of pocket fee paid by the producer, it is the correct fee to charge the royalty holder for his share of the production. However, a stop-loss provision should be included to ensure that the royalty holder does not get charged costs greater than the value of the royalty. The stop-loss provision places a heavier financial burden on the producer, providing him greater incentive to remedy an uneconomic production situation, but does not permit the royalty holder to obtain profit at the direct expense of the producer. To remedy the situation, the producer may, for example, choose to modify his marketing arrangements or renegotiate fees to make the production economic or, failing that, shut-in the uneconomic production.

For non-arms length processing where the producer is also the facility owner, the deductions for gathering, compressing and processing should be calculated according to the lower limit of the JP-90 recommendation. This will result in a fee that is the sum of:

- actual operating costs plus an overhead allowance (10%), allocated on the basis of throughput; plus
- depreciation expense; plus
- a return on rate base equal to the depreciated capital investments, allocated on the basis of the design capacity.

Although this calculation should generally result in processing fees that are less than the royalty revenue, the same stop-loss provisions should apply.

The Task Force recognized in any project there may be a mix of arms length and non-arms length transactions. For example, the producer may install well site facilities and gathering lines and contract the downstream processing to a third party. In these cases the combined deductions would be calculated by applying the appropriate method to each of the facility segments.

For those situations involving solution gas production along with the crude oil, the fees should be determined as described above. However, these fees may exceed the value of the gas since gas conservation costs may be in excess of the gas revenues. In this case, the solution gas is a by-product, and the regulatory requirement for gas conservation becomes a cost to the principal business of producing crude oil. The royalty holder would not normally expect to be protected from loss on this solution gas stream alone. The combined crude oil and solution gas stream revenues must be considered when viewing the residual profitability after costs are deducted.

Notwithstanding the above, if a royalty lease is held by an arms length party for solution gas alone, a stop-loss provision should be incorporated in the lease to ensure that costs do not exceed revenues for this stream. The producer should pay these excess costs, offsetting the loss with revenues from the crude oil stream.

In all cases where the stop loss provision is involved, the producer should not create a negative account for the royalty holder to be paid out of future royalty revenues.

5.4 FREEHOLD ROYALTY HOLDER RISK MANAGEMENT

It is important for the freehold royalty holder to understand and manage the exposure to cost deductions in their lease. The terms of a lease relating to deductions for gathering, compressing and processing should be specifically stated. Additional terms may be negotiated to reflect the level of risk that the freeholder is prepared to take. Some alternatives that may offer the freeholder the appropriate protection are:

- A lower gross royalty with no cost deductions. This guarantees the freeholder a minimum percentage of the sales revenue but this has the disadvantage that, in a higher price environment, upside value for the freeholder would not be realized.
- A cost deduction cap expressed as a percentage of the royalty revenue. Alberta Crown royalty regulations currently specify such a cap, which limits the cost deductions to 95% of the gross royalty payable. Some existing freehold leases have been negotiated down to as low as a 50% cap on cost deductions.
- A fixed fee per unit of volume deducted from the royalty revenue, which may or may not be adjusted periodically to account for escalating costs, perhaps tied to some indicator such as the Consumer Price Index.
- A fixed royalty revenue per unit of volume, with no deductions. This may include a means to adjust revenues to account for changing prices.
- Some other calculation that may be developed at the time the royalty lease is negotiated that better suits the unique situation.

Overriding royalty holders, working interests subject to penalty and non arms length working interest owners may wish to negotiate similar risk management terms into their contracts.

5.5 SETTLEMENT OF DISPUTES IN EXISTING ROYALTY LEASES

Some royalty agreements in existence today have explicit cost deduction terms which were negotiated and written into the lease. In recognition of the sanctity of these existing contracts, they should not be affected by these guidelines. However, there are some royalty agreements that are not specific. Ambiguity may exist in phrases such as “fair and reasonable costs may be deducted” or “fair market value of production at the wellhead”. These phrases may result in substantial differences in expected royalty revenues.

If a royalty holder believes that costs are being deducted inappropriately, they should formally notify the producer and request an explanation of the deductions. If the producer cannot justify the cost deductions then adjustments should be made. The guidelines described above should serve as an objective basis for establishing “fair and reasonable” fees for future royalty leases. The Task Force expects that this communication and subsequent negotiation will eliminate the majority of the complaints.

In those circumstances where the negotiations between the royalty holder and the producer fail, the parties may agree to use the mediation or arbitration procedures described earlier. If the producer is unresponsive, the royalty holder may have a legitimate claim for default under Section 15 of the CAPL 1988 Petroleum and Natural Gas Lease or similar clauses in other leases. If the default clause is applicable, the procedure could lead to a settlement that may involve litigation.

As a last resort, and in those cases where the disagreements arise over the level of deductions, the dispute could be referred through the Minister of Energy for hearing by the PUB. Royalty holder complaints should be accompanied by documented evidence of communication between the royalty holder and the producer, demonstrating that negotiations between the parties have failed. If the producer has been unresponsive to the royalty holder, this documentation may consist only of the royalty holder’s unanswered registered letters. The producer should be served concurrently with the same complaint application that is filed with the Energy Minister and the PUB. The realization that the royalty holder is adamant about his concerns may be enough to motivate the producer to negotiate in good faith with the royalty holder at this point.

Once the PUB has reviewed the complaint, it may hold a pre-hearing conference where the parties would be brought together to discuss the issues to be heard at the hearing. This presents another opportunity for the parties to resolve their differences. Failing resolution at this point, a hearing would proceed.

The PUB hearing should be designed to resolve only the specific dispute and should not be expanded to deal with other arrangements between other parties. This resolution process as described prior to complaints to PUB is expected to resolve all but the most difficult disputes. Such cases should not result in regulatory intervention upon other parties that either have or are in the process of resolving their differences.