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NWT OIL AND GAS

ROYALTY REGIME

Energy, Mines and Resources Secretariat
May 1985

Energy, Mines and Resources Secretariat,
Government of the NWT,
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SECTION 1

NWT OIL AND GAS ROYALTY REGIMES
Executive Summary

	Alberta Oil	Alberta Gas	Norman Wells Oil	Pointed Mountain Gas	Canada Lands Bent Horn (Oil)	Canada Lands Polar Gas
Lease Terms	5-21 years	5-21 years	21 years (3 terms) Total 63 years	21 years (renewable)	Exploration Agreement 5 years Production Licence 10 years (renewable)	Exploration Agreement 5 years Production Licence 10 years (renewable)
Royalty Rate	Sliding scale to a maximum of 45%	22% on base production, 45% on production above base	5% royalty on company's 66 2/3% share of production	10% Royalty on 76% of production 15% Royalty on 24% of production	10% Basic royalty	10% Basic royalty 40% Progressive incremental royalty on profits over 25%
Royalty Calculation Location	at Wellhead	after Processing	at Wellhead after deduction for transport tariff	after Processing in Fort Nelson, B.C.	at Wellhead	after Processing
Royalty Collection	Alberta Petroleum Marketing Commission	Dept. of Energy and Natural Resources	Northern Affairs Program, DIAND	COGLA	COGLA	COGLA
Crown Ownership	part ownership in oil sand plant (Syncrude)	-	one third ownership by Govt.Canada	-	25% Federal back-in applicable. PetroCanada majority shareholder in Panarctic Bent Horn Project.	25% Federal back-in applicable.
Product Marketing	Alberta Petroleum Marketing Commission	Producer	Esso Resources Agent for Crown Share	Amoco/WestCoast	Panarctic	Polar Gas
Annual Production Levels	42,758,000 m^3 conventional 9,295,000 m^3 oilsands	44,977,462 10^3m^3	1,600,000 m^3	216,000 10^3m^3	Phase 1 16,800 m^3 Phase 2 67,200 m^3	8,343,000 10^3m^3
Value of Production Millions $	8,662 conventional 2,367 oilsands	$4,734	$385	$15	$4	$700
Annual Royalties Millions $	$3,009 conventional $384 oilsands	$1,634	$9 - $10	$1.5 - 2	Phase 1 approx. .01 Phase 2 .04	$50 (extremely variable)
Timespan of Project	-	-	25 more years	10 more years	Phase 1 3 years Phase 2 7 years	25 years+
Development and Production Approval	Energy Resources Conservation Board Dept. of Energy and Natural Resources		COGLA	COGLA	COGLA	COGLA
Transportation Regulation	Public Utilities Board National Energy Board (NEB) Energy Resources Conservation Board		National Energy Board (NEB)	NEB	NEB	NEB
Major Transporter	Interprovincial Pipelines	Nova TransCanada	Interprovincial Pipelines	WestCoast	Panarctic	Polar Gas (TransCanada)
Major Legislation	Various	Various	1944 Agreement Oil and Gas Production and Conservation Act	1976 Agreement	Canada Oil and Gas Act Oil and Gas Production and Conservation Act	Canada Oil & Gas Act

ᓄᓇᑦᓯᐊᕐᒥ ᐅᕐᓱᐊᓗᓐᓄᑦ ᐊᒻᒪᓗ ᑳᓯᓄᑦ ᑮᓇᐅᔭᑦ

ᒐᕙᒪᒃ ᑯᓄᑦ

(ᓇᐃᓪᓕᑎᒋᐊᕐᓯᒪᔪᖅ)

ᑖᓐᓇ ᐸᐃᒃ ᑹᑦᔪᖅ ᐅᖃᐅᓯᖃᕐᓯᒪᔪᖅ ᖃᓄᖅ ᑮᓇᐅᔭᐃᑦ ᐱᔭᐅᖃᑦᑕᓪᒪᕆᑖ ᐅᓯᕐᓗᒃᓄᑦ ᐊᒻᒪᓗ ᑳᓯᓄᑦ ᒐᕙᒪᒃ ᑯᓐᓄᑦ ᑐᕋᓕᖅᑦ. ᐅᖃᐅᓯᖃᕐᓯᒪᑦᑎᐊᕐᑐᖅ ᖃᓄᑎᒋ ᐊᒥᓱᑎᒋᖅᓂᒃ ᑮᓇᐅᔭᓂᑦ ᐊᑭᓕᓴᖃᓪᒪᕆᑖ ᐊᒻᒪᓗ ᑭᒃ ᑯᑦ ᒐᕙᒪᒃ ᑯᓂ ᓄᐊᕐᓯᕙᓪᒪᕆᑖ ᑮᓇᐅᔭᓂᒃ.

ᓄᓇᑦᓯᐊᕐᒥ ᒐᕙᒪᒃ ᑯᑦ ᒫᓐᓇᕿᓗᑦ ᑮᓇᐅᔭᓂᒃ ᐱᓖᕐᑐᒃ ᓴᐅᓕᕐ ᑐᓚᓗᐊᑦ ᑲᓇᑕᐅᑉ ᒐᕙᒪᒃ ᑯᒥᖕᒑᕐᑕᖕᑦ ᑕᐃᒪᓕ ᖃᐅᔨᒥᐊᑎᐊᕐᑲᕋᑦ ᑕ ᖃᓄᑎᒋ ᐊᑭᓕᒃ ᑕᐅᔭᑎᐊᕐᑲᓪᒪᕆᑖ ᐊᒻᒪᓗ ᖃᓄᖅ ᐱᔭᐅᕙᓪᓕᐊᔪᓐᓇᓪᒪᕆᑖ.

ᐋᔾᑕᒥᐅᑦ ᑮᓇᐅᔭᓕᓪᒪᑎᐊᓗᒃᒪᑕ ᐱᒃ ᔪᑎᒋᓗᐊᕐᑐᒍ ᑮᓇᐅᔭᒃ ᓴᔪᓪᒪᑎᐅᓪᒪᑕ ᐅᕐᓱᐊᓗᒃᓄᑦ ᐊᒻᒪᓗ ᑳᓯᓄᑦ. ᒫᓐᓇᓂ ᓄᓇᑦᓯᐊᕐᒥᐅᑦ ᑮᓇᐅᔭᕐᑕᕋᔪᖃᑦᑕᓕᕐᑐᓚᓗᐊᑦ ᐅᕐᓱᐊᓗᒃᑰᑦ ᐊᒻᒪᓗ ᑳᓯᓄᑦ ᓱᓕ ᐊᑐᓕᐅᕐᓯᒪᕗᓇᑦᑎᒍ ᐅᕐᓱᐊᓗᐃᑦ ᐊᒻᒪᓗ ᑳᓰᑦ,

ᓄᓇᑦᓯᐊᖅ ᐅᕐᓱᐊᓗᖃᐅᑐᒪᑎᐅᓪᒪᑦ ᐊᒻᒪᓗ ᑳᓯᖃᓪᒪᑎᑦᑐᓂ ᑕᕝᕙ ᐊᑖᓂ ᑎᑎᕋᕐᓯᒪᔪᑦ ᑕᒃ ᑯᓴᐅᔾᑦ:

	ᐅᕐᓱᐊᓗᒃ $10^6 M^3$	ᐋᔾᑕᒥ ᑳᓯ $10^9 M^3$	ᐅᕐᓱᐊᓗᒃ $10^6 M^3$	ᓄᓇᑦᓯᐊᕐᒥ ᑳᓯ $10^9 M^3$
ᐱᔭᐅᔪᓐᓇᖅᑐᑦ ᑲᑎᑦᑐᒥᑦ ᐅᕐᓱᐊᓗᒃ ᑳᓯᑦᓗ	1,900	2,750	2,500	5,500
ᐊᑐᕐᑕᐅᔭᑎᒃᓯᒪᔪᑦ ᐊᒥᓱᓂᖏᑦ	1,200	1,000	-	-
ᓯᓚ ᐊᑐᖅᑕᐅᓚᐅᖏᑦᑐᑦ ᐅᕐᓱᐊᓗᒃ ᑳᓯᑦᓗ	700	1,750	2,500	5,500
ᐊᑐᖅᑕᐅᕙᒃᑐᑦ ᑲᑦᑐᒥᑦ ᐊᕐᖁᑭᑕᓖᑦ	62	76	1.5	0.2
ᐊᒥᓱᓂᖏᑦ ᐊᕐᖁᒧᑦ ᓄᕈᓚᐅᖏᓂᖏᓂ ᐅᕐᓱᐊᓗᑦ ᐊᒻᒪ ᑳᓰᑦ	10	26	-	-

ᑕᕝᕙᓂ ᑕᑯᒃ ᓴᐅᔪᖅᑲᖁᓗᐊᕐᑐᖅ ᐋᔾᑕᒃ ᑯᑦ ᐅᕐᓱᐊᕐᑯᑎᒋᔭᖏᑦ ᐊᒻᒪᓗ ᑳᓯᕐᑯᑎᒋᔭᖏᑦ ᓄᕈᒎᕐᑐᓚᓗᐊᑦ ᑭᓯᐊᓂᓕ ᓄᓇᑦᓯᐊᕐᒥᐅᑉ ᐱᑕᓕᓪᒪᑎᐅᔾᑦ ᐊᒥᓯᒪᑎᓐᓂᒃ.

ᐅᑭᐅᖅᑕᖅᑐᒥᐅᑕᐅᔪᑦ ᑮᓇᐅᔭᑦ ᓄᐊᑦ ᔭᔪᒃ ᓴᐅᖏᑦ ᑐᒐᓄᐊᑦ ᐅᕐ ᓯᐊᓄᖅᑯᑎᒃ ᑎᓐᓄᑦ ᐊᓪᓚᓗ ᒫᓯᖅᑯᑎᒃ ᑎᓄᑦ ᐋᕗᑖᒥᐅᒥᑐᑦ ᐱᕐ ᔪᓂᒥᓐ ᓄᒍ ᐅᕐ ᓯᐊᓄᖅᑯᓂᒥᔭᕗᑦ ᒫᓯᖅᑯᓂᒥᔭᕗᑦᓗ ᐊᑯᑐᔪᓪ ᒪᓂᐊᓄᒃ ᒪᑕ ᕿᓂᑕᐅᒥᐊᖏᑕ ᐊᓪᓚᓗ ᐊᐅᓚᓂᖃᑦ ᑕᓂᐊᖏᑕ. ᓇᓂᔭᐅᓯᒪᓂᑦ ᑎᑦ ᓄᒥᓂ ᐅᕐ ᓯᐊᓄᐃᑦ ᐊᓪᓚᓗ ᒫᓯᑦ ᐊᑐᖅᑕᐅᔪᒪᓐ ᓂᐊᑐᐃᓐ ᓇᐸᓪ ᒪᑕ ᓇᓂᔭᐅᕋᑦ ᑎᑦ ᓄᒥᑦ ᐅᕐ ᓯᐊᓄᐃᑦ ᒫᓯᑦ ᓗ ᑲᓇᑕᒥ ᐊᑭᑐᔪᓪ ᒪᑎᐊᓄᒃ ᒪᑕ. ᑕᑦ ᐸ ᐊᑖᓂ ᑎᑎᕋᐅᔭᑦ ᓯᒪᔪᖅ ᖃᐅᔨᑎᒃ ᑎᒥᐊᓂᑦ ᒥᒪᑦ ᐊᑭᒥᖃᑦ ᑕᑕᖏᓐ ᓂᑦ ᐅᕐ ᓯᐊᓄᒃ ᑖᕐ ᔪᔪᑦ ᐊᓪᓚᓗ ᒫᓯᑖᕐ ᔪᔪᑦ ᐊᑐᖅᑕᐅᔪᒪᓐ ᓂᐊᖅᑐᑎᑦ ᐱᔭᐅᓚᐅᖅᑎᑦ ᓄᒥᑦ ᓅᓇᐅᑉ ᐃᑭᐊᖕᓂᑦ.

ᐊᑭᒥᖃᑦ ᑕᖅᑕᖏᑦ ᐅᕐ ᓯᐊᓄᐃᑦ
ᓅᓇᐅᑉ ᐃᑭᐊᖕᓂᑦ ᐱᔭᐅᒪᐃᓪ ᒪᑕ

1) ᐅᕐ ᓯᐊᓄᐃᑦ ᓇᓂᔭᐅᓯᒪᓂᑎᑦ ᑐᑦ ᐋᕗᑖᒥ ᓅᓇᐅᑉ ᐃᑭᐊᖕᓐᓂ	\$4.50 - \$6.00
2) ᐊᑭᒥᐸᒃ ᑕᖏᑦ ᓄᑖᓂᒃ ᓇᓂᓯᒪᐃᓪ ᒪᑕ ᐋᕗᑕᒥ	\$ 16 - \$25
3) ᑐᒃ ᑐᔫᖅᑑᑉ ᐃᒪᖕᓂ ᐅᕐ ᓯᐊᓄᒃ - ᓅᓇᑦ ᓯᐊᕐ ᑕᑎᐅᖕᓂ	\$8 - \$36
4) **Hibernia - Newfoundland** ᑕᑎᐅᖕᓂ	\$10 - \$14
5) **Alsands** - ᐅᕐ ᓯᐊᓄᐃᑦ ᓯᐅᕿᒥᑦ ᑐᑦ ᐋᕗᑕᒥ	\$33 - \$48

ᑎᑎᕋᐅᔭᖅᓯᒪᔪᒥ 1-ᒥᑦ ᑐᖅ ᑖᒃ ᑯᓴᐅᑎᒃ ᑎᒪᑦ ᐊᑭᐅᐸᒃ ᑐᓂᒃ ᐅᕐ ᓯᐊᓄᒃ ᓄᑦ ᓅᓇᐅᑉ ᐃᑭᐊᖕᓂ ᓇᓂᔭᐅᓯᒪᔪᓂᒃ ᐅᐊᑦ ᑎᐊᕈᐊᓄᒃ. ᑖᒃ ᑯᐊᓂ ᐅᕐ ᓯᐊᓄᐃᑦ ᓄᕙᔪᓂᕐ ᒪᑕ ᒪᓐᓇ. ᑎᑎᕋᐅᔭᕐ ᓯᒪᔪᒥ 2-ᒥ ᑖᒃ ᑯᓴᐅᑎᒃ ᑎᓪ ᒪᑦ ᐊᑭᒥᐸᑦ ᑕᖏᓐᓂᒃ ᓇᓂᔭᐅᕋᑖᕐ ᑎᐊᓚᐅᖅᑐᑦ ᐱᔭᐅᑎᑦ ᓄᒥᑦ ᐅᕐ ᓯᐊᓄᐃᑦ. ᑖᒃ ᑯᐊᑕᐅᖅ ᐅᕐ ᓯᐊᓄᐃᑦ ᓅᕙᐸᓂᐊᓂᑐᑦ. ᓇᓂᓯᑲᓂᕐ ᓯᒪᔪᖃᕈᓐᓂᖅ ᐅᕐ ᓯᐊᓐᓂᒃ. ᑎᑎᕋᐅᔭᖅᓯᒪᔪᖅ ᑕᑯᒃ ᓴᐅᑎᒃ ᑎᓪ ᒪᑦ ᐊᑭᒥᐸᒃ ᑕᖏᓐᓂᑦ ᑐᒃ ᑐᔫᖅᑑᑉ ᐃᒪᖕᑕ ᒥᒃ ᓵᓂᒃ ᐊᑭᖃᑉ ᐸᓪ ᒪᖕᑕ ᖃᓄᖅ; ᓇᓂᓯᓯᒪᓪ ᓄᐊᒪᑎᓕᖃᑕ ᓅᓇᐅᑉ ᐃᑭᐊᖕᓂᖕᑦ ᑎᑕᐅᔪᓐ ᓇᕿᔭᓪ ᒪᖕᑕ ᐊᓪᓚᓗ ᐊᐅᓚᑦ ᑎᑕᐅᖃᑕᓪ ᓄᑎᒃ. ᑐᒃ ᑐᔫᑦ ᑑᑉ ᐃᒪᖕᓂ ᐊᑭᒥᔭᖏᑦ ᐱᖃᑕᐅᖏᓪ ᒪᑕ ᓯᕗᓪ ᓕᑦ ᕹᒥ ᓇᓐᓂᔭᐅᓂᑎ-ᓚᐅᑦ ᑕᖕᓄᑦ. ᑎᑎᕋᐅᔭᑦ ᓯᒪᔪᖅ 4 ᑕᑯᒃ ᑕᐅᑎᒃ ᑎᓪ ᒪᑦ ᐊᑭᒥᔭᐅᓯᒪᔪᓂᑦ ᓂᐅᕙᐅᑏᒥ ᐅᕐ ᓯᐊᓄᒃ ᓄᑦ. ᑕᐃᒪᓂ ᑭᓯᐊᓂ ᐋᖅᑭᑦ ᑕᐅᓯᒪᕗᑦ ᐊᑦ ᑯᒍᓐ ᓄᑦ ᐊᑐᑎᖃᓐ ᓂᐊᑐᒥᔭᐅᓗᓂ ᑲᓇᑕᒧᑦ. ᑎᑎᕋᐅᔭᑦ ᓯᒪᔪᖅ 5 ᑕᑯᒃ ᑕᐅᑎᒃ ᑎᕗᖅ ᐊᑭᒥᔭᖏᓐᓂᒃ ᐱᔭᐅᖃᑕᓐ ᓂᑎᔭᖏᓐᓂᑦ ᓯᐅᕿᔫᒥᑦ ᑐᑦ ᐅᕐ ᓯᐊᓄᐃᑦ ᐋᕗᑕᒥ. ᐊᑭᑐᔪᓪ ᒪᑎᐅᒪᓗᐊᖅ ᑭᓯᐊᓂ ᐅᕐ ᓯᐊᓄᓪ ᒪᑎᐅᕗᖅ ᐊᓪᓚᓗ ᓇᓂᔭᐅᓯᒪᓂᑦ ᑐᑎᓗ.

ᐅᖃᕐ ᓯᒪᒪᒪ ᐅᕐ ᓯᐊᓄᓪ ᒪᑎᐅᓂᖃᑦ ᑐᒍ ᐊᓪᓚᓗ ᒫᓯᓐ ᒪᑎᐅᓂᖃᑦ ᑐᒍ ᓅᓇᑦ ᓯᐊᕐ ᒥ ᐊᓪᓚᓗ ᐊᑭᒥᔭᖕ ᑕᐃᒪᒃ ᓴᐃᓐ ᓇᑲᓴᐅᓪ ᒪᑦ ᓅᓇᐅᑉ ᐃᑭᐊᖕᓂᑦ ᐱᔭᐅᔪᑎᒥᔪᓐ ᓇᕿᔭᖅ ᑕᖏᓄᑦ ᑕᐃᒪᒃ ᓴᐃᓐ ᓇᖅ ᑕᐅᖅ ᓄᑖᕈᔪᑎᑐᑦ ᐅᕐ ᓯᐊᓄᒃ ᑎᑐᑦ ᐊᓪᓚᓗ ᒫᓯᑎᑐᑦ ᓇᓂᔭᐅᓯᒪᔪᓂ ᑲᓇᑕᐅᕐ ᐊᓯᒃ ᑐᓯᒪᓂᖏᓂ. ᐅᕐ ᓯᐊᓄᐃᑦ ᐊᓪᓚᓗ ᒫᓯᑦ ᐱᑎᑦᐊᕈᐸᓪ ᑎᐊᓂᐊᕐ ᒪᑕ ᓅᓇᑦ ᓯᐊᕐ ᒥ ᐸᓐ ᓇᐃᔭᕐ ᓯᒪᑦ ᑎᐊᑎᐊᖃᕐᑕ.

ᖃᐅᔨᒐᒃ ᓯ ᐊᑭᒋᒐᔭᖅᑕᕆᓐᓂᑦ ᐅᖅᓱᐊᓗᐃᑦ ᐊᒻᒪᓗ ᑳᓲᑦ ᓄᓇᑦᓯᐊᖅᒥ ᑭᓇᐅᔭᖅᑕᐅᒍᐸᒃᑐᓂᒃ ᒐᕙᒪᒃ ᑯᓐᓄᑦ ᑲᑦᑎᓇᐅᓂᖅᓴᐅᓛᖅᑯᑦ ᐋᔭᑕᒥᐅᓂᒃ. ᖃᐅᔨᒥᐊᕐᒍᐊᓗᒥᒃ ᑎᑎᖃᐅᔭᖅᓯᒪᕙᖅ 1 ᑎᑭᓪᓗᒍ 3-ᒧᑦ.

ᖃᐅᔨᒍᑦᑕ ᑲᑦᑎᐅᑎᒥᕙᓂᑦ ᒐᕙᒪᒃ ᑯᑦ ᑭᓇᐅᔭᖅᑕᖃᑦᑕᓪᓚᕆᑦᑖ ᖃᐅᔨᒥᐊᑎᐊᖃᕋᔭᑎᕗᑦ ᖃᓄᑎᒥ ᐊᑭᖃᕋᔭᓪᓚᕆᑦ ᓄᓇᐅᑉ ᐃᑭᐊᖑᓂᑦ ᐱᔭᖅᑕᐅᒥᐊᖑ.

ᓄᓇᑦᓯᐊᖅ ᒐᕙᒪᒃ ᑯᕆᑦ ᖃᐅᔨᒪᔭᑎᐊᖃᓪᒥᒪᑕ ᖃᑦ ᓗᓈᕈᕆᑦ ᑐᓄᑦ ᓇᓪᒥᓂᖅᑕᒍᔭᑎᐊᖃᑦᑐᓂᒃ ᐅᖅᓱᐊᓗᓂᒃ ᐊᒻᒪᓗ ᑳᓯᓂᒃ ᖃᐅᔨᓴᑎᐊᓚᐅᕆᓐᓂᕆᓂ ᖃᓄᑎᒥ ᑭᓇᐅᔭᑕᕈᓐᓇᕋᔭᓪᓚᕆᒥᒃ ᑲᑉᐸᓂᐅᕙᓂᒃ.

ᑕᐃᒪᓕ ᐊᒥᒃ ᓯᒪᑎᐅᓪᓚᑕ ᐊᑭᑕᐅᔭᑎᐊᓖᑦ ᐊᑲᐅᕆᒍᑕᐅᕙᑦ ᐱᖃᑕᐅᓗᑎᒃ ᑲᓇᑕᐅᑉ ᒐᕙᒪᒃ ᑯᕆᑦ ᓄᓇᑦᓯᐊᖅᒥᐅᑦ ᓄᐊᑦᑎᒥᐊᓚᐅᕆᓐᓂᕆᓂᑦ ᑭᓇᐅᔭᓂᒃ ᓇᓪᒥᓂᑎᔭᓪᒥᓂᑦ ᐅᖅᓱᐊᓗᒃᓂᑦ ᐊᒻᒪᓗ ᑳᓯᓂᑦ - ᑭᓯᐊᓂᓕ ᐱᓕᕆᓐᓇᕋᓯᐊᓐᓂᐊᖅᑯᒍᑦ ᑖᒃ ᑯᐊ ᐊᑲᐅᕆᕙᑕᐅᕙᑦ ᐊᖅᑭᑦ ᑕᐅᖅᑯᓪᓗᒥᑦ.

ᑭᖑᓕᖅ ᐸᖑᓕᖅ ᑐᖅ ᑎᑎᖃᐅᔭᖅᓯᒪᕙᖅ ᑐᓴᕈᒥᓇᓪᒪᑎᑦ ᑐᒥᒃ ᐱᑕᖃᓪᒪᑦ ᒪᖅᑯᕚᓂᑦ ᒪᓐᓇᓘᓕᕙᓂᑦ ᐊᒻᒪᓗ ᒪᖅᑯᑲᓐᓂᓂᑦ ᐅᖅᓱᐊᓗᑖᕈᓐᓇᕈᑎᒃᓴᓂᑦ ᑳᓯᓂᒃᓗ ᓄᓇᑦᓯᐊᖅᒥ.

	ᒪᓐᓇ ᑕᑯᒃ ᓴᐅᕙᑦ			ᐱᔭᐅᑐᐃᓐᓇᑎᐊᓖᑦ
	ᓄᐊᒪᓐ ᐱᐊᖅᓴ	Point Mountain	Ben Horn	Polar Gas
ᐊᒥᓲᓂᑎᔭᕆᑦ ᑲᓇᑕᐅᑉ ᒐᕙᒪᒃ ᑯᕆᑲ ᐱᕚᒃ ᑕᕆ ᓄᓇᑦᓯᐊᑉ ᒐᕙᒪᒃ ᑯᕆᓂᑦ ᐅᖅᓱᐊᓗᒃᓄᑦ ᑳᓯᓄᓗ ($ ᒥᓕᐊᓐᒍᕙᑦ)	$9 - 10	$1.5-2	$.01	$50
ᐊᑭᒋᒐᔭᖅᑕᕆᑦ ᐅᖅᓱᐊᓗᐃᑦ ᑳᓯᓗ ᓴᓇᔭᐅᕙᑦ ᑐᑦ ($ ᒥᓕᐊᓐᒍᕙᑦ)	$385	$15	$4	$700
ᐊᒥᓲᓂᑎᔭᕆᑦ ᐊᕆᓂᕆᑕ ᐅᖅᓱᐊᓗᐃᑦ ᑳᓯᓪᓗ (10^3M^3)	1,600,000	216,000	16,800	8,343,000
ᐸᑭᑕᓂᑎᓂᐊᖅᑕᕆᑦ ᐱᓕᑎᐊᑦ (ᐊᖅ ᕋᒍᓄᑦ)	25 ᓯᓕ	10 ᓯᓕ	10	25+

ACREFOOT is a unit of volume often used in oil reservoir analysis. It is the equivalent volume of hydrocarbon needed to cover an acre to a depth of one foot.

API a measurement indicating the flow point of oil. The higher the API the lighter the oil. The lighter the oil the less refining required. For example, conventional Alberta or Middle East oil usually has an API of 40° or higher. Lloydminster heavy oils range in API from 13° to 18°. These heavy oils require extensive refinery upgrading.

BATTERY a group of storage tanks used to store oil.

BITUMEN Bitumen is a heavy oil substance commonly found in oilsands. In its natural state it is commonly called tar or asphalt. Converting Bitumen into useable oil products requires extensive upgrading.

CANADA OIL AND GAS ACT
an act which regulates the disposal and administration of petroleum and natural gas rights of the Crown in Canada lands.

CANADIAN OIL PRICES
under the Western Accord, Canadian oil prices will go to world levels. The Canadian "benchmark" price for oil is established FOB Montreal. Oil produced west of Montreal is discounted according to the equivalent cost of transport to Montreal. Oil prices are stated in U.S. dollars.

CLOCKED WELL PRODUCTION
this is a measurement performed by the well operator to determine the flow rate of a well and is used in determining the appropriate management of an oil or gas pool.

COMMERCIAL DISCOVERY
means the discovery of an oil or gas field that could be commercially produced given reasonable market conditions and an appropriate transportation mode.

CONSERVATION each oil pool has an optimum operating range which results in a maximum volume of oil production over time. Operating beyond this range results in a lower level of recoverable oil as a percentage of reserve size. To operate within the optimum range each oil pool should ideally be entered separately.

CONTROL PROCESSING UNIT
before going into the pipeline, oil is prepared for transport through a CPU. Water is also treated in the CPU

CROWN INTEREST (SHARE)
the proportion of a lease which is retained by the Crown for the purpose of oil and gas activities.

CROWN ROYALTY SHARE
the proportion of the production from a well which belongs to the Crown.

DRY VS. WET GAS
wet gas have condensable hydrocarbons in it. Dry gas does not.

ENHANCED OIL RECOVERY
the use of unconventional methods for oil recovery such as chemicals, steam, oil waste products, CO_2, or water. These techniques are estimated to increase Canadian oil resources by 3150 million barrels.

FREEHOLD MINERAL RIGHTS
mineral rights owned by a person other than the Crown.

FIELD one or more pools located in close proximity either horizontally or vertically are called a field.

HEAVY OIL high viscosity or thick oil. Heavy oil deposits are located around Lloydminister on the Alberta/Saskatchewan border and are in addition to oilsand deposits. Canadian heavy oil resources are estimated at 47 billion barrels.

HYDROCARBONS Organic compounds of hydrogren and carbon whose densities, boiling points, and freezing points increase as their molecular weights increase. The smallest molecules are gaseous; the largest are solids.

HYDROGEN SULPHIDE a chemical impurity (H_2S) which causes the foul smell in "sour" natural gas. It is both poisonous and corrosive.

INSITU the extracting of oil from the subsurface. The Insitu method is used as an alternative to oil sand mining in those locations where surface mining is impractical. The Cold Lake Project uses INSITU techniques.

LNG (Liquified Natural Gas)
natural gas (mainly methane) that has been liquified under high pressure and low temperature. As a liquid, natural gas can be conveniently transported to areas where pipelines are not available.

LPG (Liquified Petroleum Gas)
heavier hydrocarbons (mainly Butanes and Propane) that have been liquified at moderate pressures. As liquids, these hydrocarbons can be conveniently transported to industrial or domestic users.

OIL & GAS PRODUCTION AND CONSERVATION ACT
an act requiring companies to report production, distribution and sales information to the Federal Minister. The equivalent act in Alberta is the Energy Resource Conservation Act. Royalties are calculated using the figures and returns provided to government under this Act.

VISCOSITY a measure of the resistance of a liquid to flow. Viscosity is a term used to describe the ease with which a substance flows. The viscosity of petroleum products is commonly expressed in terms of the time required for a specific volume of liquid to flow through a hole of specific size.

WELL a hole in the ground completed or being drilled
i) for the production of oil and gas;
ii) for injection into an underground formation;
iii) as an evaluation well or test hole, or
iv) to or at a depth of more than 150 metres for any purpose,
but does not include one to discover or evaluate a solid inorganic mineral and that does not or will not penetrate a stratum capable of containing a pool or oil sands deposit.

ZONE similar to a rock unit - see ROCK UNIT

RESOURCES unproduced oil and gas which is believed, with reasonable certainty, to exist.

ROCK UNITS a rock stratographic unit. Pools of oil were formed during a number of different geological periods. It is often the case that one pool of oil will form above another pool; the two pools being separated by a layer of non-permeable rock. Each rock unit may be different in terms of the porosity of the host rock. Other differences include:
- different oil, gas, water ratios
- different oil viscosity
- different oil pressures within the pools
- percentage of oil ultimately recoverable

ROYALTY the mineral owner's share of production resulting from drilling on an oil and gas lease, theoretically the economic rent.

SATURATION a measure of the extent to which pore space in sand or rock is occupied by Bitumen or oil.

SEPARATION PLANT "oil" coming from the ground is usually co-mingled on a field by field basis and consists of water, oil and gas. This "oil" is taken by pipeline to a separation plant where it is separated into its component parts.

SIGNIFICANT DISCOVERY is a discovery of oil or gas which looks promising and which would require further drilling to determine whether or not production would be possible.

SPECIFIC GRAVITY the ratio of the weight of a given volume of substance at a given temperature in relation to its equivalent in water. Gasoline, for example has a gravity of between .840 and .876, so is lighter than water, which has a gravity of 1.000. Specific gravity relates to API.

SWEET VS. SOUR GAS sweet gas contains no sulphur and requires less treatment.

SYNTHETIC OIL the oil product of an upgrading process which uses bitumen, heavy oil or coal as the beginning substance.

TARSANDS same as oilsands

UNITIZATION unitization is a method of allocating production between resource owners.

OIL SAND MINING	About 10% of Canadian oil sand deposits are recoverable from the surface. These deposits are mined using conventional mining techniques. Syncrude and Suncor are two companies using this technique. Insitu techniques are used for subsurface deposits.
OILSANDS	sandstone that yields oil. This oil occurs as Bitumen. Bitumen is commonly known as tar or asphalt. Canadian resources are estimated at 24300 million barrels.
OIL SHALE	fine grain rocks containing oil. Oil shale is mined like coal. The U.S. has significant economically viable deposits. Canadian reserves are estimated at 280 million barrels. The most promising deposits are in New Brunswick.
OIL PRICES	world oil prices are based on the value of light Arabian crude - a high quality oil. Lower grades of oil receive lower prices. Oil quality is tied to API.
PENTANES PLUS	a mixture mainly of pentanes and heavier hydrocarbons which ordinarily may contain some butanes and which is obtained from the processing of raw gas, condensate or crude oil (see Raw Natural Gas and Table 2(A)).
PERMEABILITY	permeability is a word used to describe the degree to which a liquid or gas can flow through an object.
POOL	a pool is a single oil or gas reservoir. A pool may be described in terms of its geographical area or in rock units.
POROSITY	porosity is a ratio describing the pore space available within a substance. The greater the pore space, the greater the ease with which a substance can soak up a liquid or gas. A sponge has high porosity, an iron bar has low porosity. Oil and gas do not sit in underground lakes. They sit in host rocks with a high degree of permeability and porosity.
PROCESSING PLANT	a plant for the extraction from gas of hydrogen sulphide, helium, ethane, natural gas liquids or other substances, but does not include a wellhead separator, treater or dehydrator.
RAW NATURAL GAS	is a light hydrocarbon in its unprocessed form. The principal components of natural gas are methane (80%), ethane (7%), propane (6%), isobutane (1.5%), butane (2.5%), pentane plus (3.0%)
RESERVES	the unproduced but economically recoverable oil and gas that is in place within a formation.
RESERVOIR	a porous and permeable rock formation in which recoverable oil and/or gas has been trapped.
NATURAL GAS	is the natural gas used as heating fuel and is in fact methane. Methane is a light, gas hydrocarbon (CH_4) with a boiling point of -258°F. Methane is also an important feedstock for the petrochemical industry.

Table 2(A)

Classification of Crude Petroleum and its Components

Boiling Point Range °C	-150	0 50 100 150 200 250	350	500	1000+
General Classification	← Petroleum Gases →	← Light Distillate → ← Middle Distillate →	← Heavy Distillate →	← Residue	→
Main Components	← Petroleum Gases →	← Gasolines → (light – heavy) ← Gas Oils → (light – heavy) ← Lubricating Oils → ← Kerosines → (light – heavy) ← Fuel Oils → (light – heavy) ◄ Naphthas ►		← Asphaltenes	→
Hydrocarbon Range	← C_4 and lower → ← Pentane Plus → ← Liquid → ← Solid				→
	C_1 C_4 C_5 C_8 C_{14} C_{16}				C_{60}
US Bureau of Mines Correlation Index	Paraffinic-Paraffinic	Paraffinic-Naphthenic Naphthenic-Paraffinic	Naphthenic-Naphthenic		
Base Classification	Paraffinic (Light)	Mixed (Aromatic)	Naphthenic (Heavy)	Asphaltic	
Typical API Gravity Range	38°–47°	37°–30°	25°–15°		
Specific Gravity	0.835–0.800	0.840–0.876	0.900–0.970		

Note. The classifications shown in this table are intended to be representative, and no precise demarcations are implied.

SECTION 3
INTRODUCTION

The purpose of this document is to provide a description of the essential components that make up the management and accounting framework which allow for the collection and verification of Oil and Gas royalties in the NWT.

Before Resource Management and Revenue Sharing discussions begin between the GNWT and the Federal Government, an understanding of the existing royalty regime is essential. As such, this document provides an important stepping stone in the process of negotiations.

Alberta's royalty regime has been examined in Section 7 of the document because it represents a mature system from which NWT residents can learn. There are differences between Alberta and the NWT. There are also similarities. The GNWT, in the development of its royalty regime, can benefit from Alberta royalty regime strengths and avoid its weaknesses.

Currently, the NWT produces small quantities of oil and gas. Resource management issues are important, however, because the NWT oil and gas sector has the potential for tremendous growth.

Table 3(A) illustrates the oil and gas potential of the NWT in relation to Alberta. One important difference between the Alberta and NWT figures is that most of Alberta's conventional oil and gas has been located while NWT oil and gas resources are for the most part speculative.

Table 3(A) **Oil and Gas Potential**

	Alberta Oil $10^6 m^3$	Alberta Gas $10^9 m^3$	NWT Oil $10^6 m^3$	NWT Gas $10^9 m^3$
Initial Established Reserves	1,900	2,750	2,500	5,500
Cumulative Production to date	1,200	1,000	-[2]	-
Remaining Reserves	700	1,750	2,500	5,500
Annual Production	62	76	1.5	0.2
Life Index[1]	10	26	40	72

1 All life index figures are calculated on the basis of Annual Alberta Oil and Gas Production
2 Negligable quantities when compared to total

Source: Alberta Publication, GSC 83-31

There are energy producing alternatives to oil and gas available but it is unlikely that these alternatives will become sufficiently important to significiantly reduce the role of oil and gas. In fact, there are some major sources of oil and gas available in Canada other than those resources located in the NWT. The East Coast has significant deposits of oil and gas. Alberta has an estimated 250 10_9m_3 of oil ultimately available from its oilsands. However, none of this oil and gas is inexpensive to produce as Table 3(B) indicates. In terms of economic viability, northern oil and gas could have a considerable edge over some seriously considered alternatives.

Table 3(B) Estimated Costs of Oil Production

Conventional Alberta Oil	Enhanced Oil Recovery from Conventional Fields	Beaufort Sea Oil	Hibernia	Alsands
\$4.50 - \$6.00	\$16 - \$25	\$8 - \$36	\$10 - \$14	\$33-\$48

Source: Economic Council of Canada

Notes:

1. Enhanced oil recovery and Beaufort Sea scenarios both incorporate a 10% discount rate only. Hibernia and Alsands scenarios incorporate a range of discount rates from 5 to 10%. Conventional oil incorporates actual financing costs.

2. The Beaufort Sea scenario assumes a single island in the shallow offshore. Minimum economic reserve size was assumed at 200 MMB (max. of 1000 MMB). Onshore developments are considered less expensive than deep water developments.

3. All costs FOB wellhead, in constant 1983 dollars.

4. Hibernia development based on reserves of 1200 MMB. Technological difficulties in North Atlantic (iceberg alley) may result in differing platform designs increasing oil costs somewhat.

Oil and gas development will occur in the NWT. It is just a matter of time. Several major proposals have already been forwarded and discarded due to current oil and gas prices or prevailing interest rates. The GNWT wishes to have an equitable and efficient resource management structure in place during the early stages of resource development so as to avoid the difficulties associated with major policy shifts during larger scale activities.

Royalty rates on oil and gas in the NWT are unlikely to be as high as those prevailing in Alberta. Under the National Energy Program, the Alberta Government was going to receive almost one third of the oil and gas revenues generated within the province. Between 1981 and 1986 the Alberta Government was going to receive $61 billion in royalties, $8 billion in land payments and $4 billion in oil company corporate profits.

Royalty rates in the NWT are currently much lower than in Alberta. Norman Wells, for instance, pays a 5% royalty on sixty-six and two thirds of production, Pointed Mountain pays a 11% royalty and Bent Horn is expected to pay an oil royalty of about 10¢ per barrel.

These royalties are lower in part because northern costs of production are higher. This is fair, since a royalty should represent a return to the resource owner equal to the difference between the value of a [illegible]rce and its full cost of production.

Another reason why royalties will be lower in the NWT than in Alberta is risk. People, and companies, are generally risk averse and usually require a higher potential level of profit before committing resources to a risky venture. Besides being more expensive, oil and gas operations in the NWT are more risky. The odds of finding a commercial discovery are lower and the reserve requirements necessary to warrant production are higher. To encourage companies to explore in the NWT it is likely that an incentive would be required above that offered in Alberta. One such incentive was the Petroleum Incentive grants which paid up to 80% of exploration costs.

With the Petroleum Incentives Program being phased out, new incentives will be required. In the Western Accord, the Federal Government indicated that it intends to use Royalty Incentives to encourage frontier oil and gas exploration. Royalty incentives would, in effect, be a reduction in the royalty rate payable. While the Federal Government has offered to consult with the GNWT, it is obvious that the introduction of royalty incentives would further reduce royalty revenues which might otherwise be available to governments.

An issue which will have an as yet undetermined impact on royalty levels is native claims. In some cases, as in the COPE settlement, the GNWT will not receive royalties from 7 (1)(a) lands because the subsurface recources are owned by the Inuvialuit. In other cases, claim settlements may result in an overriding royalty on large sections of land. Obviously, if part of the resource rent is flowing to native organizations, a reduced royalty share would remain for the GNWT.*

* The GNWT supports the land claims process and recognizes the importance of resource ownership in securing long term benefits from development.

The final issue which will influence royalty levels in the NWT is the fiscal policy of the Federal Government. In theory, there must be a value attached to a resource prior to its extraction and production in order for there to be a royalty. If Federal policy increases the cost of production by raising taxes or regulatory burdens, or if the Federal Government lowers the sales price of production through market intervention, the royalty component of a resource can quickly disappear. In practise, the Federal Government should maintain an oil and gas industry tax structure in the NWT which leaves room for the establishment of a reasonable royalty component.

The Alberta Government's approach to the calculation of royalties from its oil sand resources is different from its approach taken on royalty calculation for conventional oil. Each developer signs a separate agreement. The components of royalty calculation are, however, essentially the same.

This royalty system is being closely looked at by other jurisdictions because it is considered fair and flexible. It is fair because royalty levels are based to a large degree on profits. It is flexible because agreements can be re-negotiated with relative ease if project specific economic environments change dramatically.

A well designed royalty should not cause resource producers to change or distort their methods or levels of operation. A royalty should reflect the value of a resource prior to its extraction or refinement. A royalty should be fair to the resource producer and sensitive to special circumstances. Royalty revenue calculation, collection, verification and administration should be easy to understand.

The GNWT may soon be receiving, collecting and even setting royalties. A basic understanding of the nature of royalties is critical if the GNWT is to establish its credibility and capability in this endeavour.

SECTION 4

POINTED MOUNTAIN GAS

4.1 Introduction

Exploration activities in the area surrounding the Southwest corner of the N.W.T. occurred in the 1960's. Three separate gas fields were discovered as a result; Beaver River, Kotaneelee and Pointed Mountain. Although all three gas fields are in close proximity, only Pointed Mountain is in the N.W.T.

During the first three months of 1972 Westcoast Transmission, a gas transport company, built a gas pipeline from Fort Nelson, B.C. to Pointed Mountain. Amoco, owner of the gas rights in the Pointed Mountain field, began production from the field in October 1972 at an initial rate of 2,000 10^3m^3 per day. The pipeline has remained, the only means of transporting Pointed Mountain gas out of the N.W.T. Once in Fort Nelson, Pointed Mountain gas is processed for use by energy consumers in the United States.

To date 7,400,000 10^3m^3 of gas has been produced from the Pointed Mountain field. There is an estimated 840,000 10^3m^3 of recoverable gas remaining. Gas production from Pointed Mountain is expected to continue at a declining rate until the mid 1990's. The Pointed Mountain field is currently producing 630 10^3m^3 per day, this being about 1/3 of its original capacity. The minimum level of production currently required to maintain the economic viability of the field is 280 10^3m^3 per day. Pointed Mountain is the only gas field in the area still in production today. Kotaneelee produces intermittently and Beaver River has been depleted.

4.2 Lease Agreement

The lease agreement is the cornerstone on which exploration development and production occur. Amoco's lease agreement covers the terms and conditions under which Amoco can maintain its interest in the Pointed Mountain field. Specifically the agreement stipulates the regulations under which Pointed Mountain operations can proceed, the method used to allocate raw gas production to the lease areas and the royalty provisions which apply to production sold.

Amoco signed a lease agreement with the Federal Government on March 24, 1976, which covers operations of the Pointed Mountain gas field. This agreement was deemed to have commenced on September 1, 1972 just prior to first commercial gas production. The agreement is still in force today and will likely remain so until field depletion occurs.

Amoco holds some leases in the Pointed Mountain field pursuant to Section 56 of the Canada Oil and Gas Land Regulations. The lease rental under these regulations is 50¢ per acre for the first year and $1 per acre for each subsequent year (Section 78(1))[1]. A royalty rate of 10%

1 This payment is in effect a minimum royalty.

of the market value of gas at the extraction plant is payable on production sold (Section 85 (1)(c)). Royalty amounts are paid on or before the 25th day of the month following the month for which the royalty is payable (Section 85(2)).

Amoco's remaining leases were obtained pursuant to Oil and Gas Land Order No. 1-1961, SOR/61-461. On these leases the Canada Oil and Gas Land Regulations apply but, in addition, other provisions as spelled out by this Order also apply. Specifically with respect to royalties, these additional leases include the provision for a bonus royalty as calculated by the following schedule:

Table 4(A)

Bonus royalty Schedule

(1)Gas Production from One Acre and One Horizon during one month (in thous. of cubic feet)	(2) Allocated Sales/ Acre Factor converted from (1) to 10^3m^3 per hectare per month	(3) Royalty Rate Percentage on Gas Produced & Sold
0 to 50	0 to 3.48 10^3m^3	5%
50 to 100	3.48 to 6.96 10^3m^3	.17 10^3m^3(gas) + 15%
100 to 200	6.96 to 13.92 10^3m^3	.7 10^3m^3(gas) + 20%
over 200	Over 13.92 10^3m^3	15% on Total Volume of gas sold

The Canada Oil and Gas Land Regulations which apply to all of the Pointed Mountain leases, have two further provisions important in the calculation of royalties. Section 86 states that no royalty is payable for oil and gas consumed by the permittee or lessee (Amoco) for drilling, production, mining, quarrying, extracting or treating purposes in the permit or lease area, or returned to a formation or flared.

Finally, Section 87 states that where, in the opinion of the Governor in Council, a reduction in the royalty would enable a lessee to continue producing oil or gas for a longer period, the Governor in Council may reduce the royalty by such amount and for such period as he considers advisable.

The volume of gas recoverable from Pointed Mountain is estimated in the 1976 Agreement in Acre Feet and prorated between the nine separate leases. Based on this proration 76.28% of the total recoverable gas will be subject to a flat royalty of 10% on the volume of production. The balance, 23.72%, will be subject to a flat royalty of 10% plus a bonus royalty determined by Table 4 (A).

Total production is pooled irrespective of the actual leases from which production is obtained. This pooled production is then prorated in accordance with Schedule C of the 1976 Agreement; reproduced here as Table 4(B).

Table 4(B)

Pointed Mountain Nahanni Zone Tract Factors

Government Lease Numbers	Amoco Lease #'s	Reservoir Volume in Acre/Feet		Reservoir Volume Percentages	
703-70	17479	7,342,976		.3832	
704-70	17480	11,208		.0006	subject to 10%
705-70	17481	3,457,542	76.28	.1805	royalty
838-70	17866	3,803,567		.1985	
707-R-70	17483	36,950		.0019	
708-R-70	17484	1,488,195		.0777	
709-R-70	17485	486,753		.0254	subject to 10%
710-R-70	17486	1,697,810	23.72	.0886	royalty plus
529-R-69	16958	834,604		.0436	bonus royalty
		19,159,605		1.000	

4.3 Production Reporting

Production and conservation of oil and gas occur in the Northwest Territories pursuant to the Oil and Gas Production and Conservation Act. This act is of general application and, as a result, Pointed Mountain gas production is subject to its provisions.

The purpose of this act, and its regulations, is to ensure the efficient operation, management and conservation of oil and gas properties from society's viewpoint with due consideration for safety and environmental protection. The Oil and Gas Production and Conservation Act's scope of authority is spelled out in Section 12 of the Act.

One aspect of regulation with importance to royalty calculations is the requirement for lease operators to report activities and maintain records. Part 13 of the Oil and Gas Production and Conservation regulations states that production records will be kept and reported. It is these records on which royalty calculations are based.

The government agency responsible for administering the Oil and Gas Production and Conservation regulations is the Canadian Oil and Gas Lands Administration (COGLA). COGLA is responsible for the verification of information received from producers.

Gas is a difficult product to measure but it is reasonable to speculate that the amount of gas produced and reported by the operator should equal the amount received and purchased by the pipeline operator after an allowance for shrinkage. If there were unusual gas volume measurement difficulties either the project operator or the pipeline operator would be short changed and would flag the problem for the regulator. To a large degree, it is on this basis that production reporting is done.

4.3.1 Shrinkage

Shrinkage is an important factor because it is significant and because shrinkage may not be subject to royalties if it occurs while in the possession of the producer (Canada Oil and Gas Lands Regulations Sec. 86).

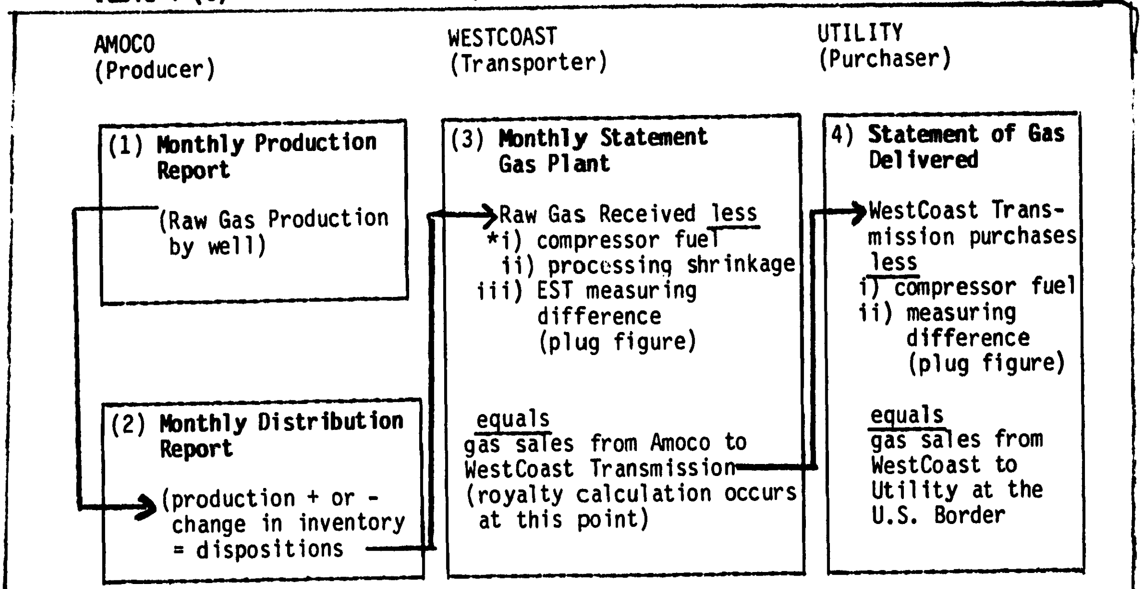
Gas suffers from a significant shrinkage factor. In the case of Pointed Mountain, a shrinkage factor of 15% between the field at Pointed Mountain and the processing plant in Fort Nelson is not uncommon. A shrinkage factor of 30 or 40 percent, between the point of raw gas production and final consumer use, could easily occur.

Shrinkage can occur for several reasons. The most common include 1) gas used as a compressor fuel in the line itself, 2) gas processing shrinkage, and 3) gas measuring differences. The amount of gas used as compressor fuel is a function of the distance of the pipeline. Gas loss during processing is a function of raw gas quality. Finally, gas measurement differences, which can be as high as 10% on total product volume, occur because of the inaccuracies inherent in the calibration of the gas measuring devices used. Since this measuring difference can be positive or negative, the long term impact of measuring differences may be of minor significance.

4.3.2 Production Reporting Flowchart

Table 4(c) is a flowchart illustrating the checks and balances incorporated into the gas production reporting system. As mentioned in the previous section on shrinkage, measuring differences can be substantial so on each form where "measuring differences" occur, this is in effect a "plug figure". Provided the "plug figure" appears reasonable in size, no further verification would normally be required.

Table 4 (c) Production Reporting Flowchart



* The three shrinkage factors in the Monthly Statement - Gas Plant relate to shrinkage which occurs between Pointed Mountain and the gas plant in Fort Nelson plus the shrinkage which occurs during processing at the gas plant. The two shrinkage factors in the Statement of Gas Delivered relate to shrinkage which occurs between the gas plant in Fort Nelson and the point of delivery to the utility. Point of delivery for a U.S. customer would be the U.S. border.

4.4 Regulation

4.4.1 COGLA

Canada Oil and Gas Lands Administration administers the Oil and Gas Production and Conservation Act for the Pointed Mountain field using the Canada Oil and Gas Production and Conservation Regulations. These regulations stipulate government's requirements of industry in the use and maintenance of oil and gas properties. The regulations are detailed and technical and cover all phases of oil and gas field development. Auditing and verification of compliance with these regulations is an integral part of the COGLA function. COGLA responsibilities North of 60° consist of DIAND's former responsibilities.

4.4.2 National Energy Board

Pointed Mountain gas is deemed to be exported from the Northwest Territories through British Columbia to the United States. As a result, the National Energy Board has jurisdiction over the WestCoast Transmission pipeline system. Rates are set and cost allocation methods are determined by the NEB.

Amoco, the Pointed Mountain's project operator, receives its revenues on a "netback basis" from WestCoast Transmission. WestCoast receives its revenue from purchasers, removes its cost of service revenue requirement, and allocates the remaining revenues back to producers in Alberta and the NWT. In British Columbia, revenues are paid by WestCoast to the British Columbia Petroleum Corporation which in turn distributes revenues back to producers.

Pointed Mountain gas operations need to be self supporting if they are to be profitable for Amoco. Gas from the Pointed Mountain field must bear the burden of the pipeline transport costs to the U.S. border out of its sales revenue. Amoco must consider this transportation cost burden in its operation of the Pointed Mountain field. Unlike oil which has a wellhead value determined by subtracting transport costs, gas is not valued for royalty purposes until it has been processed. As a result, increasing gas transport costs are not reflected through a reduction in royalty payments.

The volume of gas being shipped from Pointed Mountain has declined from 2,000 10^3m^3 per day in 1972 to 630 10^3m^3 per day today. By the 1990's gas shipments are expected to drop to 280 10^3m^3 per day. The cost of operating the WestCoast line has not changed substantially over the years and as a result the "per unit" cost of transporting gas has increased as the throughput has dropped. At current gas prices, the Pointed Mountain field becomes uneconomic to operate once gas production volumes drop below a rate of 280 10^3m^3 per day.

4.4.3 Royalty Collection

Royalties are set for the Pointed Mountain field by the Canada Oil and Gas Land Regulations and by Oil and Gas Land Order No. 1-1961 as stipulated by the 1976 Agreement. COGLA administers these regulations and calculates, collects, and verifies the correctness of the royalties received.

This is worthy of note because royalty collection is handled differently in Alberta (see Section 7). In Alberta the Energy Resources Conservation Board carries out a function similar to COGLA with respect to the administration of Production and Conservation Regulations. Royalty matters, however, are handled by the Alberta Government Department of Energy and Natural Resources, which is responsible for the calculation, collection and verification of royalties.

4.4.4 Department of Indian and Northern Affairs

DIAND oil and gas related responsibilities in the case of Pointed Mountain have been transferred to COGLA.

4.5 Royalty Calculation

Pointed Mountain gas production royalties are calculated on the basis of monthly sales from Amoco to WestCoast after transportation to and processing at Fort Nelson (see Table 4(C)). The "sold volume" of gas is then prorated back to the Pointed Mountain field on the basis of volumes of gas deemed by the 1976 Agreement to be in place on a lease by lease basis (see Table 4(B)). Under the 1976 Agreement 76.28% of Pointed Mountain gas production is to be subject to a 10% royalty and 23.72% is to be subject to a 10% royalty plus a bonus royalty as calculated by Table 4(A). In fact, Pointed Mountain leases are not very productive and so it is unlikely that a lease required to pay a bonus royalty would produce over 3.48 $10^3 m^3$ of gas per hectare per month. Therefore, the bonus royalty can be calculated at 5% on 23.72% of production.

Table 4(D) is an example of exactly how royalty figures are calculated. The data used is the February 1985 actuals.

Table 4(D)

Pointed Mountain Royalty Calculations
(February 1985)

Raw Gas Produced	18236.2 $10^3 m^3$
Shrinkage Factor (appx. 10%)	1801.0 $10^3 m^3$
Residue Gas Sold	16435.2 $10^3 m^3$
Sale Price per $10^3 m^3$ to WestCoast	$86.134657

Royalty Percentage	Percent of Gas Applicable	Value of Gas	Value of Royalties
10% flat rate	.7628	1079850.30	107985.03
10% + 5% Bonus	.2372	335789.87	50368.36
	1.00	1415640.10	158353.39

4.5.1 Aggregate Royalty Figures

As mentioned in 4.1, there is 840,000 $10^3 m^3$ of recoverable gas remaining. From previous royalty calculations in Table 4(D) it is apparent that an average royalty of 11.19% is charged. If all the gas in the Pointed Mountain field could be immediately extracted and purchased at a sale price to WestCoast Transmission of $86.134657 per $10^3 m^3$ the Royalty paid would be approximately $6.9 million (see Table 4(E)).

Table 4(E)

Aggregate Royalty Value

(1)	840,000 10^3m^3	10^3m^3 gas remaining
(2)	(.7628 x .10) + (.2372 x .15) = .1119	average royalty rate
(3)	= .15	average shrinkage factor
(4)	$86.135	price per 10^3m^3 at Fort Nelson
(5)	1.0 - .15 = .85	Residual gas after shrinkage
(6)	840,000 x .85 x $86.135 x .1119 =	$6.9 million

Pointed Mountain gas production is declining and will continue to decline until the mid 1990's at which point production is expected to become uneconomical.

SECTION 5

NORMAN WELLS OIL

5.1 Introduction

In 1919 Imperial Oil drilled its first well at Norman Wells. By 1921 it had lease rights to one third of the Norman Wells oilfield, called the Proven Area. The Norman Wells field produced intermittently between 1919 and 1944 for the purpose of supplying local markets. A small refinery producing about 80 m^3 of petroleum products per day was built for this purpose. Oil field operations were expanded in 1944 with the signing of an agreement between Imperial Oil and the Government of Canada. Production expansion was necessitated by war time fuel requirements and the building of the Alaska Highway. The expansion, called the Canol Pipeline Project, included the drilling of sixty wells and the construction of a four inch diameter pipeline from Norman Wells to Whitehorse. Refinery capacity was increased during this same period.

The Canol pipeLine was dismantled in 1945 at the end of the war after only one year of operation.

Between 1945 and 1984 Norman Wells continued to operate at a moderate level, most recently at around 475 m^3 per day. A primary function of operation has been to supply local markets with petroleum products.

In 1980 Imperial (Esso) proposed an expansion of its oilfield production and the construction, by Interprovincial Pipe Line Ltd., of a pipeline from Norman Wells to Zama, Alberta - a distance of 866 kilometers. The project started in 1982 and was complete by 1985. At a cost of nearly one billion dollars, the Norman Wells expansion was one of the few hydrocarbon projects undertaken during the tenure of the National Energy Program. Once full production is reached, Norman Wells will be the third largest producing oilfield in Western Canada at about 4000 m^3 per day.

5.2 Lease Agreement

The Norman Wells agreement of 1944 was signed between Imperial Oil Limited and the Government of Canada under the authority of the War Measures Act and the Dominion Lands Act. The agreement was re-signed in 1966 at the end of the first twenty-one year term. According to the original terms of the agreement, it is to remain in place for three consecutive twenty-one year terms, the final expiry date being 2007.

This Agreement establishes the terms and conditions of Imperial Oil's tenure of the Norman Wells field. It specifically provides for the leasing of the field, the calculation of royalties, and the provision of a crown interest in field operations.

The 1944 Agreement stipulates that Norman Wells operations are subject to sections 57 to 85 and sections 87 to 92 of the Regulations for the Disposal of Petroleum and Natural Gas Rights, the property of the Crown in the Northwest Territories and the Yukon of 1944. The lease agreement and these regulations provide the basis for Norman Wells oil field operation today.

Imperial Oil is the owner of petroleum and natural gas leases in respect to approximately one-third of the lands in the proven area issued under regulations established by Orders in Council P.C. 154 of January 19, 1914 and P.C. 331 of January 11, 1921. Imperial Oil obtained oil and gas permits issued under Order in Council P.C. 742 of January 28, 1943 covering the remaining two thirds of the lands in the Proven Area. The oil and gas permits of 1943 required that Imperial Oil relinquish one half of the permit area to the Crown. The Crown, through this provision retained a one third interest in the Proven Area. Further, in the interests of efficiency, the Crown appointed Imperial Oil operator of the Crown share and agreed to develop the Proven Area as a single unit with one third of costs and one third of revenues accruing to the Crown.

All permits held by Imperial Oil prior to the 1944 agreement covering the Proven Area were cancelled and re-issued under the terms and conditions stipulated by the 1944 Agreement.

As previously mentioned, the 1944 Agreement is specific with respect to royalty and Crown ownership provisions. Both these issues will be dealt with separately.

5.2.1 Royalty Provisions

Under the 1944 Agreement, Section 6, Imperial Oil is permitted to use, free of royalty, oil and gas from the proven area for production and development purposes. Under Section 7, one-third of production at the wellhead is deemed to be the property of the Crown while two-thirds is the property of Imperial Oil. Section 8 states that Imperial Oil will pay a five percent royalty on its two-thirds of production. Section 9 gives the Crown the right to take its royalty share and its one-third interest share in kind at the wellhead or in cash after certain product processing and marketing costs are deducted. Finally, Section 9 stipulates that royalty cash payments (if the royalty is taken in cash) shall be made on the twenty-fifth day in the month following the month for which the royalty is owed. Section 10 stipulates that Imperial Oil shall keep full and complete records showing the produced, inventoried and disposed amounts of oil and gas from the proven area.

The key to the calculation of royalties is the "wellhead value". Under a competitive market scenario, oil from the wellhead could be sold and the proceeds used to determine the royalty. Norman Wells had a captive market. No value could be placed on oil in its raw state so the wellhead value of oil was not easily determined. To get around this obstacle, the value of useable oil products was determined. The costs of production were then subtracted with the remaining value being the deemed wellhead value on which royalties were calculated.

Under Section 16 of the agreement, provision was made for the calculation of royalties in the event of a pipeline. Since the existance of the pipeline provides a market for the crude oil, these new royalty provisions are in effect today. The wellhead value of crude oil is now determined as the sale price received by Esso Resources at Zama for its product less those expenses incurred in handling, transporting, delivering and marketing.

5.2.2 Crown Ownership Provisions

One-third of the oil and gas in the Norman Wells field belongs to the Crown. The Crown may take its share in either cash or kind. Under Section 14 of the 1944 Agreement Imperial Oil is made an agent of the Crown in the disposal of the Crown product share. Also, under Section 14 Imperial Oil shall endeavor to obtain the best reasonable prices for products and shall sell the Crown share of products on identical terms.

Section 18 of the Agreement determines that the Crown's one-third share of revenues (if the share is taken in cash) shall be net of one-third of the costs of production and also net of 10% of the one-third production costs as a management fee. The specifics of how costs of production are to be determined is spelled out in Section 19.

Section 18 also stipulates that in the event of a loss (costs of production exceed sale price of products) Imperial Oil will carry the Crown's portion of the loss forward, interest free, on its records and apply this loss against subsequent Crown revenues. In the event that losses persist and a deficit on field operations becomes a long term problem, the Crown will not be liable for its one-third of the debt.

The Crown, under the 1944 Agreement, receives its one-third of net revenues annually on or before March 20 along with a yearly statement showing production, inventory, and disposal of oil and gas from the proven area. This provision has since been modified due to the current value of oil.

5.3 Production Reporting

Production and Conservation of oil and gas occur in the Northwest Territories pursuant to the Oil and Gas Production and Conservation Act. This act is of general application and as a result Norman Wells oil production is subject to its provisions. The application of this act is consistent with the 1944 Agreement in any case. Under the 1944 Agreement, Section 5, regulation is expressly covered in similar terms to those spelled out in this act and its regulations.

Specifics of the Oil and Gas Production and Conservation Act are spelled out in Section 4.3 as they relate to Pointed Mountain Gas Production, so will not be repeated here.

Verification of information under this act is the responsibility of COGLA. Here again, however, as with gas, production verification does not require many special provisions.

Oil is much easier to measure than gas and shrinkage factors are low, often no more than one percent of production.

Oil at Norman Wells is produced at the wellhead and shipped by pipeline to a separation plant where the oil is cleaned and separated into oil, gas and water. Oil production is measured at the separation plant and a Production Report is produced. From the separation plant the oil is stored in a group of tanks called a battery. From the battery the oil goes through a Central Processing Unit into the pipeline. Esso Resources, Imperial Oil's field operations arm, measures the amount of oil going into the pipeline for its Disposition Report, and in part, for for billing purposes. Interprovincial Pipelines (IPL) also measures the oil because it is responsible for the oils transport and for product transport cost billing. The amount of oil received by IPL is reported on a Statement of Purchases Report. All three of these reports should be comparable with a small allowance for shrinkage.

Oil metering devices are considered reliable. These metering devises are approved through government regulation and calculations are required by the oil producer from time to time as verification of meter accuracy. These calculations can be requested by government for the purpose of ensuring accuracy.

5.3.1 Shrinkage

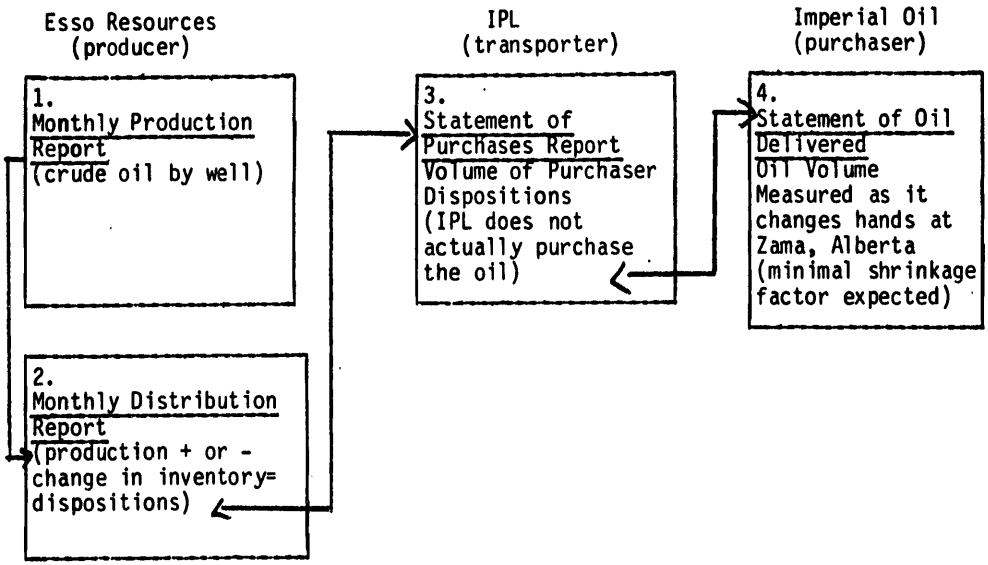
Oil shrinkage is minimal and can result from temperature changes in the oil, evaporation and spillage. Shrinkage, in the case of oil, is generally considered a cost of transportation and the dollar value of this loss is incorporated into the pipeline tariff. For this reason, production volumes for royalty calculations are determined at the Central Processing Unit prior to pipeline transport. With gas, as was explained with respect to the Pointed Mountain field, production volume calculations for royalty purposes are done at the point of gas delivery which occurs at the processing plant rather than at the wellhead as is the case with oil (see Section 4-5, Gas Royalty Calculations).

5.3.2 Production Reporting Flowchart

Production reporting works the same for oil as it does for gas. There are two exceptions; 1) Oil volumes can be accurately determined because of low shrinkage factors and, 2) inventory volumes play a much more important role in the determination of oil royalty calculations (gas is considerably bulkier and cannot be as economically or as easily stored).

Table 5(A)

Production Reporting Flowchart



The Reports are required by law but the information they contain is required for the normal conduct of business. The producer wants fair value for his production. The pipeline company wants correct volume information on which to set rates and the purchaser would require proof of oil volumes delivered before paying for product.

5.4 Regulation

5.4.1 COGLA

The Canadian Oil and Gas Lands Administration administers the Oil and Gas Production and Conservation Act using the Oil and Gas Production and Conservation Regulations. The technical aspects of Norman Wells Oil field production come under this act and its regulations. A summary of the regulations and COGLA's function are provided under section 4.4.1.

5.4.2 National Energy Board

The National Energy Board (NEB) regulates the Norman Wells Pipeline because it crosses a provincial boundary. In fact, IPL is regulated in its entirety by the NEB because its purpose is to transport oil from western to eastern Canada.

NEB regulation requires that the Norman Wells pipeline project pay for itself. During the early years of a pipeline's operation, depreciation and interest charges are high. These two factors constitute a major expense. As a pipeline ages, fixed costs decline as loans relating to the project are repaid. These factors are important in the determination of royalties in the case of Norman Wells because the cost of transport is deductable in establishing the wellhead price on which the royalty calculation is based. As an example, the interim pipeline tarrif for the Norman Wells to Zama line is $8.90 per barrel. By way of a comparison the cost of shipping oil from Edmonton to Montreal is about $2.00 per barrel even though the distance is considerably greater.

5.4.3 Department of Indian and Northern Affairs

COGLA looks after the technical aspects of field operations but DIAND (Northern Affairs Program) is responsible for the administration of the 1944 Agreement. This includes calculation, collection and verification of royalties. It also includes those efforts required to maintain the Crown's one-third interest in the Norman Wells field.

This division of responsibility between COGLA and DIAND is similar to that between Alberta Energy Resources Conservation Board and the Department of Energy and Natural Resources in Alberta (see 4.4.3 Royalty Calculation) and departs from the practise at Pointed Mountain where COGLA is responsible for both technical aspects and royalty collection.

5.5 Royalty Calculations

The Norman Wells royalty is calculated on the basis of oil volume delivered to the Interprovincial Pipe Lines terminal in Norman Wells. The wellhead price of oil is determined by its market value in Zama Alberta less the cost of its transportation from Norman Wells.

The price of oil in Zama under the Western Accord is the world price less some additional transport costs required to reach the refinery.

The Norman Wells royalty is calculated as a flat five percent on two-third of sales volume of oil; the other one-third already being the property of the Crown is not subject to royalty. A final consideration in determination of the wellhead value is oil quality; lower quality oil sells at a discount. Norman Wells pipeline oil has a quality denoted as D_1S_2 and receives world price. Norman Wells oil used in the local refinery has a lower quality denoted as D_2S_2. This oil sells at a $3 per meter (40¢ per barrel) discount.

Table 5 (B) calculates the royalty payable on a meter of oil shipped by pipeline or processed in the local refinery at Norman Wells.

Table 5(B)

Royalty Calculations

Assumptions:

World Oil Price (D_1S_2) \$241 per m^3
Norman Wells/Zama Tarrif \$56 per m^3
Zama/Montreal tarrif \$13 per m^3
D_2/S_2 (Refinery crude price) \$238

1) Pipeline Oil Royalty (per m^3)

\$241	-	(\$56+\$13)	=	\$172	x	.05	x	.6667	=	\$5.73 per m^3
world price		pipeline tarrifs		wellhead oil price D_2S_1		royalty factor		production volume subject to royalty		royalty share pipeline oil

2) Refinery Oil Royalty (per m^3)

\$172	-	\$3	=	\$169	x	.05	x	.6667	=	\$5.63 per m^3
wellhead oil price D_2S_1		D_2S_2 discount		wellhead price D_2S_2		royalty factor		production volume subject to royalty		royalty share refinery oil

5.5.1 Aggregate Royalty Figures

During the first year of production the pipeline is expected to carry 1,482,000 m^3 of oil. From 1986/87 until 1991/92 pipeline volumes should be 1,700,000 m^3 per year. Production will then start declining at a more or less uniform rate to 720,000 m^3 by the year 2000. By 2008 oil production is estimated to be 420,000 m^3. Over the project life the pipeline will carry approximately 28,000,000 m^3. If over the next twenty five years the local refinery continues to produce at its current rate it could use about 4,000,000 m^3. These figures are consistent with current ultimate recoverable reserve estimates for the Norman Wells field of 40,000,000 m^3.

Table 5(C) Aggregate Royalty Figures

Assume:

i) A constant real price for transportation

ii) A real discount rate equal to the real rate of increase in world oil prices[2].

Year 1	Pipeline	1,482,000 m^3	x 5.73	=	8,491,860
	Refinery	173,375 m^3	x 5.63	=	976,101
					9,467,961
Year 2	Pipeline	1,700,000 m^3	x 5.73	=	9,741,000
	Refinery	173,775 m^3	x 5.63	=	976,101
Total 25 Year Lifetime of Project	Pipeline	28,000,000 m^3	x 5.73	=	160,440,000
	Refinery	4,000,000 m^3	x 5.63	=	22,520,000
					182,960,000

Given this assumption, the rise in world oil prices would be the mathematical reciprocal of the discount rate so an investor would be indifferent between receiving the value of a barrel of oil now or in twenty-five years. While this approach is somewhat simplistic and unrealistic, it avoids the requirement to discount future cashflows.

SECTION 6

CANADA LAND DEVELOPMENTS (OIL & GAS)

6.1 Introduction

Canada's energy resources are massive and their importance to the economy and to export growth cannot be overstated. The value of energy consumed by Canadians in 1982 was $43.2 billion. Energy exports accounted for $12.8 billion and domestic energy investments amounted to $20 billion. Hydrocarbons (oil and gas) are the major component of Canadian energy resources.

In the late 1940's it was recognized that Alberta had substantial hydrocarbon resources albeit in largely uneconomical amounts and locations. To help promote the oil industry and to provide greater self-sufficiency in oil, the Federal Government, in 1961, announced the National Oil Policy. This policy essentially provided a subsidy to domestic producers so that Canadian oil could be marketed in the face of cheaper imported oil. Subsidization took the form of a protected market area. Customers west of the Ottawa valley were supplied with expensive western Canadian oil while customers east of the Ottawa valley received cheaper imported oil. Oil exports to the United States were encouraged.

The 1970's saw the emergence of OPEC as a powerful monopolistic group of oil exporting nations. As a result, there were a series of oil "price shocks" in which the price of a barrel of oil rise from $1.59 in 1970 to $34 in 1984.

In response to this change in the value of oil and in recognition of oil's strategic importance, the Federal Government reacted in October 1980 with the National Energy Program. One purpose of this program was to subsidize the cost of imported oil by taxing the cheaper Canadian oil. The result was a "made in Canada" oil price. Other objectives of the National Energy Program included encouraging Canadian oil industry ownership and control, increasing Canada land exploration activities, securing national oil self-sufficiency and providing the Government of Canada with greater control over oil industry activities as well as with a significant share of hydrocarbon related revenues.

Many NEP objectives are embodied in the The Canada Oil and Gas Act. The purpose of this act is to regulate oil and gas interests in Canada Lands and to amend the Oil and Gas Production and Conservation Act.

Specific to Royalty determination the Canada Oil and Gas Act spells out the terms and conditions under which oil and gas leases are issued, production is permitted, the Crown interest is maintained and royalties are calculated.

6.2 Lease Agreement

Under the Canada Oil and Gas Act, lease agreements are termed Exploration Agreements. An Exploration Agreement (EA) gives the lessee the exclusive right to drill, to develop and to obtain a production licence for oil and gas (Section 9, 10). An EA normally requires the completion of specific work programs within specific periods. An EA may also include provisions specifying rental payments, cash bonus payments, disclosure of information requirements, equity participation by government or native organizations, and lease surrender, cancellation or transfer. Finally, an EA may include provisions dealing with Canadian employment and business content, affirmative action programs and Canadian ownership rates.

The term of an exploration agreement (EA) is normally five years but may be as much as eight. Exploration agreements may be re-negotiated for successive terms not exceeding five years (Section 16). There are, however, two exceptions:

A) Where drilling required has not been completed by the end of an EA term but has been properly undertaken, the EA may be extended as required;

B) Where a significant discovery has been made during the term of an EA, the EA can be extended until the discovery is no longer considered significant.

6.2.1 Royalties

The Canada Oil and Gas Act specifies the nature and amount of royalties which apply to Canada Lands. As well the controversial Canada Lands Back-in interest is described.

Basic Royalty

All oil and gas produced in Canada Lands and subject to the Canada Oil & Gas Land Act is liable for payment of a basic royalty of ten percent of the oil and gas that is produced (Section 40).

No royalty is payable on production of oil and gas used for drilling, producing, mining, quarrying, extracting, testing or treating purposes within the area under a production licence or where the oil or gas is injected into a formation for conservation purposes. Finally, no royalty is payable on flared gas.

The royalty is calculated on the basis of the fair market value of oil at the wellhead after production, and gas at the extraction plant after processing.

A royalty may be paid in cash or product at the discretion of the Minister.

The royalty should be paid on or before the twenty-fifth day of the month following the month in which the royalty is payable.

Section 40(4) and Section 42 specify the requirement to keep records and to file reports and returns.

Progressive Incremental Royalty

The Progressive Incremental Royalty is described in Section 41 of the Act and is in addition to the basic royalty. The purpose of this extra royalty is to extract a higher proportion of rent from those oil and gas leases which have high productivity levels and result in correspondingly high levels of profit for producers. The Progressive Incremental Royalty is forty percent of the net profit resulting from the operation of a production licence.

The determination of the Incremental Royalty liability hinges on the definition of profit. This definition is provided in the act under Section 41(5).

Back-in Interest

Under the Canada Oil and Gas Act Section 27, the Federal Government has the option to take a 25% working interest in petroleum development and production operations. The Crown incurs 25% of all development expenditures and receives 25% of all production. The legislation provides that back-in entry occurs at the time the development plan is approved. For exploration expenditures made after 1980 the Crown is deemed to contribute in relation to back-in exploration costs through Petroleum Incentive Grants. The Back-in Interest is not a royalty but deserves reference because of its significance.

6.3 Production Reporting

Production and Conservation of oil and gas occurs in the Northwest Territories pursuant to the Oil and Gas Production and Conservation Act. This act applies to Pointed Mountain (see section 4.3 of this report), to Norman Wells (see section 5.3) and to any other oil and gas developments which, from time to time, may occur in the N.W.T. Production reporting and the mechanics of this reporting have been described for Pointed Mountain and Norman Wells so will not be reiterated here.

6.4 Regulation

6.4.1 COGLA

COGLA regulates Canada Land Oil and Gas matters in the Northwest Territories except in the one case of Norman Wells where the administration of the 1944 Agreement is handled by the Northern Affairs Program of DIAND. COGLA administers the Oil and Gas Production and Conservation Act through regulation in a fashion identical to the cases of Pointed Mountain (see section 4.4) and Norman Wells (see section 5.4). The specifics were spelled out in these sections.

6.4.2 National Energy Board

If a pipeline crosses a provincial or national boundary the National Energy Board has regulatory authority. Such authority includes the setting of terms and conditions for construction and operation of a pipeline including rate determination. Pipeline regulation in the N.W.T. is the responsibility of COGLA in those cases where the pipeline does not cross a provincial or national border.

6.4.3 Royalty Collection

The regulations which are required to administer the Canada Oil and Gas Act have not yet been completed. The section dealing with royalties has not been written so the details of royalty calculation, collection and verification are not available. It would be reasonable to suggest that they would, in many ways, be similar to those regulations which apply to Pointed Mountain (in the case of gas) and Norman Wells (in the case of oil).

6.5 Royalty Calculation

The administrative details surrounding royalty calculations pursuant to the Canada Oil and Gas Act have not been written. However, some projects may be starting production shortly. Some basic issues are addressed here with respect to the Bent Horn oil project and the [illegible] Gas project.

6.5.1 Bent Horn Project

Panarctic's Bent Horn project on Cameron Island was recently approved. Under the proposal there are two phases. The first phase, covering three years, will involve the production and shipment of 100,000 ($16,800m^3$) barrels of oil per year. From year four to year ten, production and shipment will occur at a rate of 423,000 bbl ($67,200m^3$) per year. It is estimated that during three of the 10 years [illegible] conditions will not permit the shipment of oil.

Panarctic considered the Bent Horn project as a demonstration project and wanted royalty concessions on the project. The compromise agreed to between Panarctic and COGLA, but still subject to change, is that the basic 10% royalty will apply to the wellhead value of production but the wellhead value [illegible] the oil will be very low resulting in minimal royalties.

Although this arrangement may seem concessionary on the part of government, this is not necessarily the case. There is considerable leeway in the determination of the wellhead oil value on the Bent Horn project. The costs of Arctic transportation are high and while Panarctic tankers may be going to Rae Point to deliver fuel despite the existance of the Bent Horn project, this is no reason to expect that those tankers continuing on to Cameron Island should not charge fair and reasonable rates for this service against oil production from the Bent Horn field.

Both COGLA and Panarctic recognize the difficulty in determining the actual costs of transportation for Bent Horn production. For the moment, both parties have agreed to value Bent Horn oil at the wellhead at around $1 per barrel.

A ten percent royalty on a $1 barrel of oil is ten cents. One hundred thousand barrels of oil per annum would result in royalty payments of $10,000.

6.5.2 Polar Gas

Polar Gas has made application to the National Energy Board to construct a 36 inch transmission pipeline from Taqlu Gas field on Richards Island (NWT) to Edson Alberta. A 24 inch spur line, 15 miles in length would run to Parsons Lake (NWT) north of Inuvik. The overall transmission line would be 1318 miles (2120 km) long with five compressors and three heater stations.

The line would deliver 21.07 million cubic meters per day and would cost $3.3 billion to construct.

Polar Gas project approval is by no means a certainty. However, if it is built, the issue of royalties would be important from a government perspective.

Under the Canada Oil and Gas Act, royalties are based on the fair market value of gas at the extraction plant after processing. Clearly, the location of the extracton plant is important in the calculation of royalties. In their preliminary calculations, Polar Gas officials assumed that the existing royalty regime (10% Basic Royalty, 40% Progressive Incremental Royalty) remained in place throughout the project life. A number of different production scenarios were done and depending on the assumptions made, royalty payments varied significantly. As well, calculation of royalties in the distant future are suspect by the very fact that the future is so unpredictable. However, the following information serves as an illustration of the magnitude of royalties that government might receive from the Polar Gas Project. The assumptions made in this illustration are as follows: 1) Constant 1984 $; 2) .8 BCF per day; 3) project start-up 1991-projection to 2015; 4) three year royalty holiday as provided for within the existing act - first royalty payment made in 1994; 5) Progressive Incremental Royalty (PIR) payable continually only after 2004.

Table 6(A)

Polar Gas Royalties
$000,000

	Progressive Incremental Royalty (PIR)	Basic Royalty	Average Annual Royalty
1994 - 2003	50	476	*52
2004 - 2015	1230	611	*153

* Royalty payments are actually heavily weighted toward the end of the project. These averages grossly overstate the royalty payable during the initial periods of the project.

Polar Gas is still in the early planning stages and the issues surrounding royalties have not been fully addressed by either Polar Gas or COGLA officials.

SECTION 7

THE ALBERTA OIL AND GAS ROYALTIES REGULATIONS

7.1 What is a royalty?

An oil and gas royalty is the mineral owner's share of production resulting from drilling on an oil and gas lease. Minerals are owned either by a government or by a freehold rights owner of the lease. The British North America Act (now the Constitution Act) gave ownership of the minerals in Alberta to the Alberta Government. When discussing royalties, the Alberta Government is referred to as the Crown.

7.2 History of Oil and Gas Royalty Development in Alberta

In 1898 the first oil and gas royalty in Alberta was established by federal regulation. The Alberta Government took over the administration of royalties in 1930 when control over resources was transferred to Alberta. The Alberta Government had its first oil and gas royalty regulation in 1931. A flat royalty rate, based on sales revenue, was used.

A new regulation was passed in 1941. It created a royalty rate which would vary with production levels (called a sliding scale). In 1948 a maximum royalty rate of 16.67% was added to the regulation.

In 1974 a new oil royalty regulation was introduced. To determine the royalty rates, it used a new sliding scale which was dependent upon both price and production levels. Natural gas and pentane royalty rates became dependent upon price. Fixed rates were set for sulphur and natural gas liquids. In 1978 natural gas regulations were changed to allow special consideration for low production wells.

Royalties from oil sands projects were collected by the Federal Government from 1910 to 1930, and by the Alberta Government since 1930. Royalties were often waived in the early years due to the uncertain nature of oil sands production. In 1963 the first major oil sands royalty regulation was created for the Great Canadian Oil Sand Ltd. project (now part of Suncor).

7.3 Oil and Gas Regulation and Control in Alberta

There are a number of organizations which have some input or effect on the discovery, production, transportation and sale of Alberta oil and gas.

7.3.1 Department of Energy and Natural Resources

The Department of Energy and Natural Resources is responsible for the administration of the Crown lands (government owned) in Alberta with regard to oil and gas. Two important areas handled by the department are the leasing of Crown lands and the regulations and royalties for oil, natural gas, and oil sands projects.

The department also provides an audit function. Producers estimate the royalties they owe and pay the estimated amount to the department. Energy and Natural Resources has an audit branch which verifies information received from producers. Field audits are conducted on a regular basis. These audits keep the department informed about individual firms and the industry. They also provide producers with information about interpretations and possible applications of government regulations and incentives.

7.3.2 Energy Resources Conservation Board

The Oil and Gas Conservation Act was written in 1932. In 1938 the Energy Resources Conservation Board (ERCB) was formally set up (although it was called the Petroleum and Natural Gas Conservation Board). The Board has up to seven members who are appointed by the Lieutenant Governor. There is a staff of 740 in fourteen departments. The head office is located in Calgary. Half of the funding for the Board is provided by the Alberta Government and half by the oil and gas industry through the levy of special taxes.

The Board has many functions. It handles all aspects of oil and gas conservation. Oil and gas production information is collected by the Board. It provides technical information on the industry, does analysis, and acts in a consultative capacity.

To ensure control of the use of the oil and natural gas resources, the ERCB has regulations which are in addition to the Energy and Natural Resources rules.

The Board has the power of inspection and performs field inspections. In the case of problems, the Board can close an area to travel, take over management of a well, plug a well, or stop production.

7.3.3 Alberta Petroleum Marketing Commission

The Alberta Petroleum Marketing Commission (APMC) was created in January 1974 under the Petroleum Marketing Act. It became the exclusive agent to market all petroleum produced in Alberta under Alberta Crown leases. It is also the exclusive agent to sell the lessees' share at the highest price it can obtain. The Commission's jurisdiction over natural gas was authorized by the Natural Gas Pricing Agreement (1975) which applies when there is a federal provincial pricing agreement, and the Natural Gas Price Administration Act (1980) which applies when there is no pricing agreement. In 1977 the Petroleum Marketing Act was amended to include the authority to acquire, price and market pentanes plus.

There are three members on the Commission. They are supported by a staff of seventy. The Head Office of the Commission is in Calgary with a second office in Edmonton.

7.3.4 Alberta Public Utilities Board

The Alberta Public Utilities Board operates under the Public Utilities Board Act (1980) and the Gas Utilities Board Act (1980). The Board has jurisdiction over Nova - an Alberta Corporation.

Nova operates a province-wide natural gas gathering system in Alberta. It sets its own rates, tolls, and other charges. The rates are set for each pipeline according to when and for whom the pipeline was built. The rates determined by Nova are incorporated in the Alberta Petroleum Marketing Commission's Alberta cost of service.

If a complaint has been made by an interested party, the Public Utilities Board can review and question the rates set by Nova and set just and reasonable rates, tolls and charges. In this way, the Board acts as an appeal board for the Alberta cost of service (see Gas).

The Board can also fix tariffs when the owner of a pipeline and a person with gas to be carried cannot reach an agreement on the price to be paid for the movement of the gas.

7.3.5 National Energy Board

The National Energy Board (NEB) establishes pipeline tariffs for the movement of gas through interprovincial or international pipelines such as TransCanada, Interprovincial or Westcan. In setting the tariffs, the Board considers all factors which affect whether the rates are reasonable and just. The tariffs can have three parts:

- schedules of rates
- terms and conditions of service
- a service agreement between the pipeline and its customers

The Board also handles export licensing for oil and gas. Licenses are issued as long as Canadian oil and gas needs are and will be met. In determining if there is a surplus available for export, current deliverability, current reserves and future deliverability are considered.

The price of gas in interprovincial trade is set by the Governor in Council of the Federal Government. The price is based on recommendations of the NEB. In making these recommendations, the NEB looks at factors including transportation costs, energy prices, the kinds of gas found in Canada, and the effect of prescribed prices on Canadian producers and consumers. This system of pricing may be affected by changes resulting from the Western Accord.

7.4 Leasing and Licensing

The Alberta Government always retains the title to oil and gas minerals. However, through leasing and licensing, the Crown does "dispose" of the mineral rights. Disposition is a renting of the mineral rights for a specific location. Areas which have undisposed rights are made available for sale upon a specific request from the oil and gas industry. The undisposed rights are sold in public land sales which are held approximately every two weeks.

7.4.1 Obtaining a Lease or License

The procedure for obtaining a lease or license is as follows:

1) A person or firm requests that the Department of Energy and Natural Resources advertise specific rights (posting request);

2) Energy and Natural Resources reviews the request and will accept it as is, modify it, or refuse it;

3) The Crown Mineral Disposition Review Committee reviews the posted rights with regard to surface environmental concerns. It may accept, deny or limit access to the rights;

4) Eight weeks before the sale date, a Public Offering of Petroleum and Natural Gas Rights notice is issued. It lists the terms and conditions of the sale and the time, place and date for sealed offers on the disposition to be accepted.

5) Offers must be tendered on time. A bank draft, certified cheque, or cash for the total amount tendered must be included with the offer. This amount includes the fee, rental and bonus. The bonus is paid on all sales. It is an additional payment above the standard costs. The bonus represents the premium the bidder is willing to pay for the rights.

6) The day after the sale, the name of the successful purchaser, the bonus paid per hectare and the average price per hectare are released.

7.4.2 Types of Lease and Licence Disposition

There are two forms of dispositions. Petroleum and natural gas leases are used where exploratory work has already been done. Petroleum and natural gas licenses are agreements to allow exploratory work. Licenses and leases may be given strictly for oil or gas but usually cover both.

1) Licenses

Licenses are granted where drilling exploration is required. They give the right to drill and to produce petroleum and natural gas. The size of the license area ranges from a minimum of one section to a maximum of between 29 and 36 sections (depending on the location of the license area in the province). License terms range from two to five years, also depending on the location.

All licenses for wells must be approved by the Energy Resources Conservation Board. Three factors are considered by the Board in approving a license. They are:

i) the need for a well,
ii) the proposed well location, and
iii) mitigative (moderating) considerations

Licenses are not approved if there is an existing well which is capable of production in the same drill spacing unit of the same pool. A drill spacing unit is an area within which there can only be one well drilled (see Oil, Spacing of Wells).

With Energy and Natural Resources approval, two licenses which are located close together may be grouped and treated as one. This would be done to fulfill drilling requirements or to enhance oil and gas conservation.

Licensed areas can be converted to leases by drilling. The leases are earned by drilling. The size of the earned lease depends on the number and depth of the wells drilled.

2) Leases

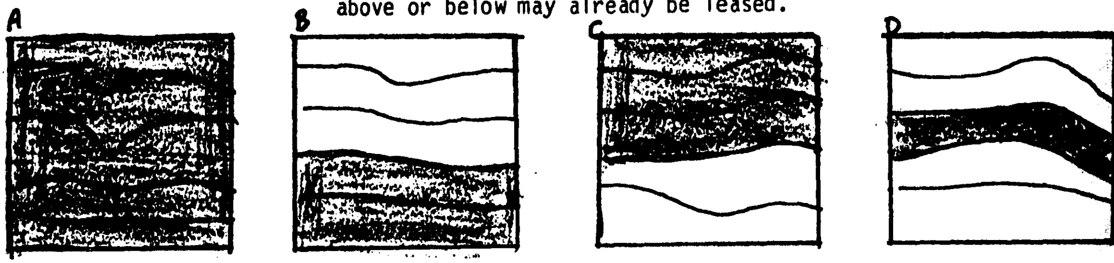
Leases grant an "exclusive right to explore for, work, win and recover all petroleum and natural gas within and under the lands described in the lease" (Current and Historical Gas Tenure Legislation in Alberta). The leases also assign the responsibility for royalty payment. Many of the Alberta leases have a 21 year term although current practice is to give shorter (5-10 year) lease terms.

Drilling is required to maintain title of a lease area. With Energy and Natural Resources' permission, leases can be grouped in order to fulfill the drilling requirement. Grouping means two or more leases are treated as a single lease. Each lease is made up of a certain number of sections. The number of sections which can be grouped depends on where the leases are located in the province and the depth of the well to be drilled.

Leases are continued (extended) on the basis of demonstrated productivity. This continuation is currently granted on a lease-by-lease basis. Lease continuation provides rights down to the base of the deepest productive stratigraphic interval (zone) over the entire lease location. If a lease does not include a producing well, the lessee (the person who has leased the rights) can get a one year extension on the lease to do further work.

7.4.3 Rights of a Lease or License

Leasing and licensing becomes complicated because various zones may be included in a lease or license. A zone is a stratigraphic interval or a layer below ground level which has unique geological characteristics. A disposition may include all zones (A), deep zones (B), shallow zones (C), a single zone (D) or a combination of zones. Other zones above or below may already be leased.



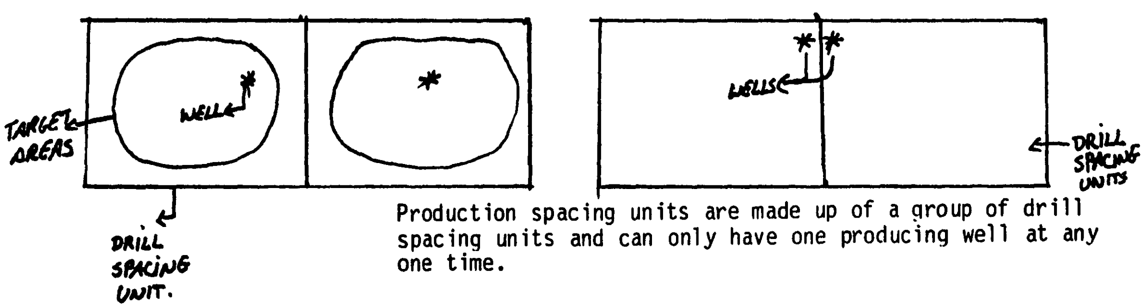
7.5 Oil

7.5.1 Spacing of Wells

The spacing of wells is regulated by the Energy Resources Conservation Board. Regulation encourages conservation and helps protect the rights of neighbouring well owners. Drill spacing units of a 1/4 section in size are defined. Only one well can be drilled in a drill spacing unit. Within the drill spacing unit, a target area is defined where drilling can occur (A). The target areas are defined so that two wells are not drilled side by side as in B.

A. With target areas

B. Without target areas



Production spacing units are made up of a group of drill spacing units and can only have one producing well at any one time.

The practises of pooling and unitization are encouraged by the Energy Resources Conservation Board. Both these practises are good for conservation. Pooling agreements occur when a lease area is smaller than a spacing unit. Unitization is where owners of rights over a certain pool group together so that the pool or field may be operated as a single unit. An operator is designated to manage the production of the pool on behalf of the group.

7.5.2 Movement of the Oil

Oil is pumped from a producing wellhead to a battery. A battery is a group of storage tanks. From the battery, the oil flows to a delivery point such as a pipeline or terminal. The oil then moves to a refinery where it is processed to become products suitable for end users.

Exploration and Development ———— Well ———— Battery ———— Pipeline ———— Refinery

The volume of oil produced in Alberta is controlled from the point of production to the point of sale. This is done through a series of reports. The Energy Resources Conservation Board and the Alberta Petroleum Marketing Commission receive reports from each point in the movement of the oil. The reports say what was received and what was sold or sent on. Monthly Production Reports are received from each well, Monthly Disposition Statements from each battery, and Monthly Oil Pipeline Gathering Operations Statements from the delivery point. The refineries submit refinery gate receipts.

7.5.3 Calculation of the Crown Royalty Share

The Alberta Crown takes its royalty at the point of production. The royalty is based on what is produced.

The Crown interest is the percentage of the lease that is owned by the government. The Crown royalty share is the amount of production owed to the government as a royalty. The Crown interest is used to determine the Crown royalty share.

The Crown interest is determined from the well data. The Crown royalty share is calculated from the production. The production is prorated back to the wells from the battery. This is done because there is less paperwork than with taking the production at each well. Finally, Energy and Natural Resources determines the proportion of the Crown royalty share that is sold.

7.5.4 Calculation of the Royalty

The royalty is calculated by Energy and Natural Resources. To calculate the royalty, the department looks at the following elements:

- actual production by well
- ownership of the crude oil
- production category (new or old)
- appropriate price

"Old" oil is oil discovered prior to April 1, 1974. "New" oil is oil that was discovered after April 1, 1974, produced from an Enhanced Recovery Scheme which began after July 1, 1974, or produced from a pool which has started production again after a dormant period of at least three years.

The royalty is not cost-sensitive. Instead of a direct recognition of cost, cost is included as a factor of production. A sliding scale concept is used for the royalty. For example, if price or production increase, so does the royalty. The royalty has a maximum rate of 45%. The royalty also has a low productivity allowance.

Royalty Formula $R = S + KS \frac{(A-B)}{A}$

R = royalty payable in cubic metres
S = monthly productivity level
K = old oil royalty factor for the month
A = old oil par price for the month
B = select price of crude oil for the month

7.5.5 Disposition of the Crown Royalty Share

Under the Mines and Minerals Act, the Alberta Government takes its Crown share in kind. The government then pays the transportation costs to move its share from the point of production to the point of sale. The Alberta Petroleum Marketing Commission is supposed to sell that share within Alberta at a price that is in the public interest of Alberta. Initially the petroleum was only sold theoretically. However, since 1980 a direct sales marketing system has been implemented. Effective June 1, 1985 the Commission will be marketing the Crown's share of oil. It may also market small companies' shares to protect them against manipulation by the larger companies. The Commission accepts delivery at the outlet of a well battery or the inlet of a feeder pipeline system. It sells by contract, recovering the transportation costs from the delivery point to the point of sale from the contract buyer.

7.6 Gas

7.6.1 Spacing of Wells

The regulations regarding the spacing of wells for gas are the same as those discussed under oil. The only difference is that a drill spacing unit for a gas well is one Section in size rather than a 1/4 Section.

7.6.2 Movement of the Gas

Gas flows from a well to a battery. The battery feeds the gas to a gathering system. A gathering system is a system of pipelines that collects gas from a well. From the gathering system, the gas goes to an injection system, another gathering system, a gas processing plant, or, if it is sweet dry gas, it may be sold. An injector system is where other substances are injected into the raw gas. Sweet gas has no sulphur in it while dry gas contains no condensable hydrocarbons.

exploration and development — well — battery — gathering system — sold
- gathering system
- injection system
- gas processing plant

Gas is controlled from the point of production to the point of sale with a series of reports. The Energy Resources Conservation Board receives reports from each point through which the gas moves. Each report details the intake and outflow from that point. The reports from the well and battery are the same as those submitted for oil. Gathering systems file a Monthly Gas Gathering Statement and injection systems file a Gas Injection Operations Statement. Gas processing plants return a Monthly Gas Processing Statement and, if liquids are processed, a Monthly Gas Processing Plant Products Statement.

7.6.3 Calculation of the Crown Royalty Share

The Crown interest is determined from the physical land and the estimated reserves under the land. The Crown royalty share is determined from the Crown interest.

In gas, the Crown takes its royalty at the point of sale. The point of sale typically occurs immediately after processing. The royalty is not taken at the point of production because the value added to the gas through processing would be lost.

7.6.4 *Calculation of the Royalty*

The natural gas royalty calculation is complicated because the mineral produced at the well is raw natural gas and before it can be used it must be processed. Processing results in the following products: methane (80%), (methane is commonly referred to as natural gas), ethane (7%), propane (6%), isobutane (1.5%), butane (2.5%), and pentanes plus (3%). Sour raw natural gas also contains hydrogen sulphide, a foul smelling, poisonous substance from which fertilizers can be made.

The royalty rate is influenced by the following factors:
- the category of gas (old, new)
- the selling price/fair value
- production per well

"New" gas is gas from a pool discovered after December 31, 1973, gas discovered but not produced before January 1, 1974 and gas produced with crude oil in a conservation scheme and not sold before January 1, 1974. "Old" gas is gas discovered and produced before January 1, 1974.

The royalty rate for gas is a base rate of 22% plus 45% of the incremental production. It includes a percentage of any price and productivity increases. There is a low productivity allowance which brings the rate down to a minimum of 5%. Natural and processed gas used in gathering, production, processing, and exploration operations on Crown land are exempt from royalties.

The royalty rates for gas liquids and sulphur are calculated in a variety of ways. Pentanes plus use the same royalty formula as oil. Propane and butane use a flat rate of 30% and sulphur uses a flat rate of 16.67%.

7.6.5 **Government Cost Sharing with Industry**

The Crown shares in the costs between the point of production and the point of sale. These costs include capital and operating costs of gathering, compressing and processing the gas. The Crown pays a percentage of the costs equal to the gross royalty rate (gross royalties/sales).

7.6.6 Reporting and Collection of the Royalty

Energy and Natural Resources calculates the royalty using the Monthly Calculation of Natural Gas and Associated By-products Royalty reports. These reports are submitted by the operators. A yearly reconciliation ensures that the volumes reported by the operators during the year were correct. Gas Royalty Remittance Advice reports are submitted which give an operator a calculated estimate of the royalty payable. Payment of this estimate is due one month after the month of production.

The operators have three months to make a final adjustment to a month's estimate. They are charged interest on estimates which are wrong by more than 10%.

These royalties do not flow through the Alberta Petroleum Marketing Commission. They are remitted directly to Energy and Natural Resources by the producers.

7.6.7 Price Adjustment Flow-Back Pool

For natural gas, the Alberta Petroleum Marketing Commission runs a price adjustment flow-back pool. The difference between a set Alberta border price and the actual out-of-province selling price is placed in the pool. The pool is divided among those who sell through the Commission based on their share of the total gas sold. The pool is distributed in the form of credits against future amounts payable.

7.6.8 The Alberta Cost of Service

An important function of the Alberta Petroleum Marketing Commission is to estimate the Alberta cost of service. The price of gas to be consumed in Alberta is the lesser of: 1) Alberta border price plus price adjustment minus cost of service; 2) contract field price plus price adjustment. The cost of service is the final deduction in the netback pricing mechanism, introduced in 1975. The Alberta cost of service includes costs and charges that related to acquisition, movement, metering and processing of gas, some interest charges and other costs prescribed by regulation. The APMC attaches the charges to specific streams of gas.

The components of the costs are divided into non-Nova and Nova costs. From the non-Nova costs the Commission determines a base rate and a rate of return. Only direct or indirect costs actually incurred in relation to Alberta operations are eligible for inclusion in the Alberta cost of service. Three broad categories of costs, operations, financial and miscellaneous, are used. The Commission has ruled that it has no jurisdiction over the Nova costs. It accepts the costs as set out by Nova or the Alberta Public Utilities Board.

The destination of the gas affects the role of the commission in determining the cost of service. For gas to be consumed in Alberta, the cost of service (ACOS) is estimated and published irregularly in the Commission's information bulletin. When gas is going out of Alberta, the original buyers must apply for the determination of the Alberta cost of service each month for the gas purchased that month. The buyers may have to ask for more than one ACOS depending on the points of gas removal and supply.

The Alberta Petroleum Marketing Commission's Alberta Cost of Service rulings can be appealed or reviewed through the Alberta Public Utilities Board.

7.7 Oil Sands

The unique nature of oil sands projects is reflected in Energy and Natural Resources' approach to oil sands royalties. A separate royalty agreement is written up for each project which considers any special circumstances affecting the project.

The two major producing oil sands projects, Suncor and Syncrude, have different royalty schemes. Suncor pays royalties based on a sliding scale for synthetic crude oil and a fixed percentage for all other production. Syncrude does not pay conventional royalties; instead, the Province of Alberta receives a share of the net profits.

The Government of Alberta has tried to establish a basic royalty scheme for other oil sands projects. The scheme can be altered to meet the needs of a specific project. This scheme allows for two different rate structures: one up to project payout and another for postpayout.

Payout for a project is the point where costs and royalties equal revenues. The producer keeps a total of cost and royalties and a total of revenues from the start of the project to determine payout. Payout is that point where total accumulated costs equal total accumulated revenue.

An accumulated cost pool is used to keep track of costs until payout. Costs of capital, operating and overhead,return on investment, and royalties are placed in the pool. For this calculation, the following definitions are used:

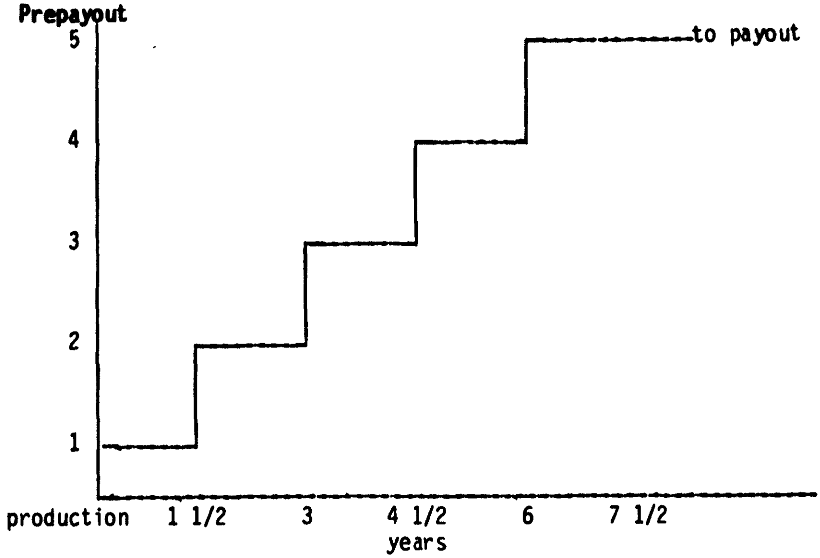
costs:	capital to point of production capital, operating and royalties from production to project payout
capital:	capital incurred and return on capital of 10%
operating:	operating and overhead at 10%

The costs which are included are any costs which are directly attributable to the project.

The rates used are as follows:

prepayout	Royalties begin with production. They are an escalating percentage of gross revenues. Payments begin at 1% and increase 1 % every eighteen months up to a maximum of 5%
postpayout	Royalties are 30% of the difference between revenues and costs (both capital and operating). Royalties are to be a minimum of a 5% gross royalty.

Table 7(A) Schedual of Royalties for Oil Sands Project



For all of the oil sands projects, royalties are collected on final products. These products include bitumen, synthetic oil, sulphur, coke and silica.

7.8 Freehold Mineral Tax

The Freehold Mineral Tax is levied pursuant to the Freehold Mineral Rights Tax Regulations. This act took effect June 6, 1983, replacing the Freehold Mineral Taxation Act. The tax affects freehold owners. Freehold rights owners control approximately ten percent of all mineral rights in Alberta.

The tax is based on oil and gas production. The variables used in calculating the tax are:

- the wellhead prices of oil and gas, and
- the amount of production per month

The tax has an effective rate of five percent on the gross value of production. There is a special low productivity allowance permitted in some instances.

Unlike the Department of Energy and Natural Resources Crown royalty calculations, the freehold mineral tax does not consider the differences between the old and new categories of oil and gas. Freehold tax revenues for 1983 were $177 million.

CONCLUSIONS

The Alberta system of oil and gas royalties has developed over the last sixty years. During that period oil and gas as a resource has changed in importance and as a result, so has the royalty structure. Socio-economic and environmental factors have become important components of oil and gas activities. Oil and gas development is recognized today as a potential "Engine of Growth" for the Alberta and Canadian economy. Oil and gas resources are also recognized as being both finite and of strategic importance to national economic health and security.

One result of the rise of importance of oil and gas is a royalty system today that is considerably different from thoseused in the past. Royalties are no longer designed exclusively for revenue generation. They are often designed with the intent of meeting a wider range of government priorities such as employment creation, resource conservation and frontier and infrastructure development.

When Alberta first implemented royalties, they were not designed for flexibility. Each time the economic or political importance of oil and gas changed, a new royalty system was developed to meet the new requirements. This has been particularly true over the last fifteen years. The result is that Alberta now has a number of oil and gas projects under different royalty systems. Besides making government administration increasingly complex and expensive, it creates a complicated set of rules and regulations which are difficult for industry to understand.

It was stated in the **Introduction** that the GNWT can learn from Alberta. Oil and gas as a commodity is always in a state of flux and the value of the resource is always changing. A well designed royalty system should recognized business fluctuations in the industry. Such a system reduces industrial risk on the downside while providing a fair return to resource owners on the upside.

A royalty system should be cost effective. A royalty system should not cost more to administer than it collects in royalties.

A royalty system should be fair to producers and to resource owners. A royalty system should be easy to understand and consistent.

Land should be leased for production on the basis of oil and gas pools versus drill spacing units. This reduces legislation requirements and improves production efficiency.

Decisions will need to be made by the G.N.W.T. in the following areas:

1) Should a royalty system be developed on the basis of project specific agreements, as in the case of Alberta Oil Sands projects or should legislation of general application be used?

2) Should the Crown Royalty Share be obtained at the wellhead or should government pay for its share of product processing before collecting its royalty share? The Oil royalty tends to be obtained at the wellhead while the natural gas royalty is obtained after processing. The advantage of collecting royalties after processing is the government shares in the value added to the product during processing. The disadvantage of collecting royalties in this way is the cost incurred by government in processing its royalty share and the additional administration required.

3) Should the Crown use royalty incentives or should incentives be offered outside the royalty system? Royalty incentives may be less costly and initially easier to administer. Non royalty incentives on the other hand can be activity or project specific and can provide government with greater flexibility.

4) The royalty is a shared volume of production, not money. Is the Crown going to allow the oil or gas company to be its agent in selling the Crown share as currently done in the NWT? Is the Crown going to sell its own share of production as in Alberta (APMC oil only)? Is the Crown going to sell its own share of production and the producers share as well, as in British Columbia (B.C. Petroleum Corporation, gas only)?

This conclusion identifies some of the considerations and issues which the GNWT may have to face if it is to take on the role of a Provincial government with respect to resource royalty determination, collection, verification and administration.