



Information Bulletin ODBU 03-02

November, 2003

TO: EOR WORKING INTEREST OWNERS

Enhanced Oil Recovery Royalty Relief Program

In June 2003, the Alberta Department of Energy (ADOE) announced changes to the Enhanced Oil Recovery (EOR) Royalty Relief Program to encourage the development of commercial carbon dioxide (CO₂) schemes. The program changes outlined in Information Letter 2003-16 dated June 17, 2003, are described here in detail.

The EOR Royalty Relief Program is open to applications for new EOR schemes and expansion of existing EOR schemes. This includes EOR schemes injecting hydrocarbons, nitrogen, carbon dioxide, chemicals or other approved materials.

Temporary Tertiary-Factor (TTF)

ADOE is introducing a temporary T-factor for new schemes and expanded EOR schemes. The TTF is intended for those schemes utilizing new, or less established methodologies, such as CO₂ injection for enhanced oil recovery, where the information necessary to establish a T-Factor is not readily available.

- A TTF of .7 applies to CO₂ patterns in new EOR schemes.
- A TTF for new schemes using other injected materials will be established upon approval of the scheme.
- Development of new patterns in existing EOR schemes will carry an average of the current T-factor and the TTF for the expanded area.
- The TTF will apply for the first two years after injection commences and can be extended for one additional year upon application to and approval by the ADOE.
- The ADOE will retroactively adjust the EOR royalty relief for two years if the calculated T-factor is greater than the TTF. If the calculated T-factor is less than the TTF, no adjustment will be made by ADOE.

- The TTF royalty feature terminates in 2008 but schemes approved in 2007 and 2008 will continue for their two-year duration, with the possible extension to a third year upon application to and approval by the ADOE.

Increased Allowance for Recognition of the Value of Net CO₂

Acquired CO₂ Injection Costs

- All EOR schemes approved between 2003 and the end of 2008 will be eligible for a 10% uplift on the value of the net CO₂ injected.
- The 10% uplift will apply for a period of 8 consecutive years following commencement of CO₂ injection.
- Any previously approved schemes already injecting CO₂ will receive the 10% uplift beginning in 2003, for the 8-year term.
- Net CO₂ injected will be based on the total CO₂ injected less CO₂ reproduced at the EOR schemes as reported by each working interest owner.
- Acquisition cost includes the arms length cost of the CO₂ and physically transporting the CO₂ to the site; or the cost of service calculation for non-arms length acquisition of CO₂.

CO₂ Reporting

For revised Schedule 5 examples, blank documents and completion instructions refer to *Appendix A*.

Cost of Service Calculation

The ADOE has developed a cost of service (COS) calculation methodology for valuing non-arm's length acquisition of CO₂ injectant. Refer to *Appendix B* for details.

CO₂ Processing Costs

On-site processing of CO₂ is recognized as follows:

- Capital costs are eligible.
- Operating costs are included in the 5% increase in overhead allowance.

Recognition of Capital Costs

Capital Cost Eligibility

For capital cost to qualify in an EOR scheme they must be incremental to the base recovery scheme. The capital costs must not qualify for Gas Cost Allowance (GCA); must contribute to incremental oil production as a direct result of the injection of an approved material; and, there must be active injection of approved substances in the scheme and pattern. If the eligibility of specific capital costs is in doubt, the operator may request an advance ruling from the ADOE.

The ADOE recognizes CO₂ is more corrosive than other approved materials; therefore, additional capital costs for EOR schemes injecting CO₂ include:

Proration of Central Facilities

- The development and replacement of central facilities may be required due to the injection of CO₂ in EOR schemes with multiple injectants. ADOE will allow capital costs of central facilities to be prorated in a reasonable and fair manner.
- The capital costs of central facilities will be prorated based on the volumetric throughput of fluids during the first 12 months of operation from the date of commissioning of the asset or the first date of CO₂ injection. The facility CO₂ annual throughput volume and the facility total annual throughput volumes would include all fluids. A simple example calculation is provided as follows:

$$\text{Eligible Prorated Cost} = \text{Facility Capital Cost} \times \frac{\text{Total Throughput from CO}_2 \text{ Patterns}}{\text{Total Facility Throughput}}$$

- Operators may request prior approval from ADOE for other methods of prorating specific central facilities.

Pipelines

- The installation and replacement of pipelines used entirely within and exclusively for CO₂ EOR schemes is an allowed cost. These costs will be allowed if incurred for a period up to two full years after CO₂ injection ceases. (Note: for non-CO₂ schemes only installation is normally allowed.)

Frequency of Replacement

- Capital costs will occur more frequently for CO₂ and the increased frequency of eligible capital expenditures will be recognized.

Overhead Allowance Trigger

- New EOR schemes that are injecting mainly CO₂ will receive an additional 5% overhead allowance rate immediately. Vertical schemes will receive 20% and Horizontal schemes will receive 30% total overhead allowance.
- Existing EOR schemes will receive the additional 5% overhead if CO₂ injection exceeds an injection ratio of 50% for the year calculated as follows:

$$\text{CO}_2 \text{ Injection Ratio} = \frac{\text{Annual CO}_2 \text{ Injection Volume}}{\text{Annual Total Approved Injectant Volume}}$$

- The scheme will receive the extra 5% overhead each year that the greater than 50% CO₂ injection ratio is met. To qualify participants must report the eligibility of the scheme for the additional 5% on the revised Schedule 5. Refer to *Appendix A* for details.

Other Changes

CO₂ Projects Royalty Credit Program

An EOR scheme may receive benefits under the CO₂ Projects Royalty Credit Program.

- Eligibility of costs for the EOR Royalty Relief Program will not be affected by claims under the CO₂ Projects Royalty Credit Program.
- Any benefits received under the CO₂ Royalty Credit Program will be deducted from the Total Allowed Costs for the year. Refer to *Appendix C* for the revised Schedule 1 document.

All EOR Royalty Relief Program claims are subject to audit by the department's Compliance and Assurance group.

Should you have any questions, please contact Beverley Murray at (780) 427-2193 or Marcel Sale at (780) 422-9124.

Jane Clerk
Business Unit Leader
Oil Development Business Unit

Appendix A

SCHEDULE 5



EOR - NONHYDROCARBON FLUIDS INJECTED

ENERGY

Participant: 1 Business Associate ID: 2
 Project Name: 3
 Prepared By: 4 Telephone: 5
 Date Prepared: 6 Reporting Year: 7
 CO₂ Injection > 50%: Yes No 8

Product: CO₂

Month	A	B	C	D
	Total CO ₂ Injected E3M3	Total CO ₂ Produced E3M3	Total CO ₂ Acquired (Net Volume Injected) E3M3	Cost to Acquire Injected CO ₂ \$
January	9	10	11	12
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				
Total	13	14	15	16



Carry forward to Schedule 1

I
Uplift %
10%

Total CO₂ Injected Cost

F	Net volume injected	17	(A-B)
G	Average CO ₂ price	18	(D/C)
H	Net volume value	19	(F*G)
	Total CO ₂ uplift	20	(I*H)



Carry forward to Schedule 1



ENERGY

SCHEDULE 5

EOR - NONHYDROCARBON FLUIDS INJECTED

Participant: _____ 1
 Project Name: _____ 3
 Prepared By: _____ 4
 Date Prepared: _____ 6
 Product: Other _____ 8

Business Associate ID: _____ 2
 Telephone: _____ 5
 Reporting Year: _____ 7

Month	Total Injected Volume E3M3	Total Injected Cost \$
January	9	10
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		
Total	11	12



Carry forward to Schedule 1



ENERGY

SCHEDULE 5

EOR - NONHYDROCARBON FLUIDS INJECTED

Participant: _____

Business Associate ID: _____

Project Name: _____

Prepared By: _____

Telephone: _____

Date Prepared: _____

Reporting Year: _____

CO₂ Injection > 50%: Yes No

Product: CO₂

Month	A	B	C	D
	Total CO ₂ Injected	Total CO ₂ Produced	Total CO ₂ Acquired	Cost to Acquire Injected CO ₂
	E3M3	E3M3	(Net Volume Injected) E3M3	\$
January	10	0	10	\$20
February	10	0	10	\$20
March	10	0	10	\$20
April	12	2	10	\$20
May	16	6	10	\$20
June	16	6	10	\$20
July	16	6	10	\$20
August	16	6	10	\$20
September	16	6	10	\$20
October	16	6	10	\$20
November	16	6	10	\$20
December	16	6	10	\$20
Total	170	50	120	\$240



Carry forward to Schedule 1

I
Uplift %
10%

Total CO ₂ Injected Cost		
F	Net volume injected	120 (A-B)
G	Average CO ₂ price	\$2 (D/C)
H	Net volume value	\$240 (F*G)
	Total CO ₂ uplift	\$24 (I*H)



Carry forward to Schedule 1



ENERGY

SCHEDULE 5

EOR - NONHYDROCARBON FLUIDS INJECTED

Participant: _____

Business Associate ID: _____

Project Name: _____

Prepared By: _____

Telephone: _____

Date Prepared: _____

Reporting Year: _____

Product: Other N₂

Month	Total Injected Volume E3M3	Total Injected Cost \$
January	10	\$10
February	10	\$20
March	10	\$20
April	12	\$10
May	16	\$20
June	16	\$20
July	16	\$20
August	16	\$10
September	16	\$20
October	16	\$20
November	16	\$20
December	16	\$10
Total	170	\$200



Carry forward to Schedule 1



EOR - NONHYDROCARBON FLUIDS INJECTED

ENERGY

Participant: _____

Business Associate ID: _____

Project Name: _____

Prepared By: _____

Telephone: _____

Date Prepared: _____

Reporting Year: _____

CO2 Injection > 50%: Yes No

Product: CO₂

Month	A	B	C	D
	Total CO ₂ Injected E3M3	Total CO ₂ Produced E3M3	Total CO ₂ Acquired (Net Volume Injected) E3M3	Cost to Acquire Injected CO ₂ \$
January				
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				
Total				

↑
Carry forward to
Schedule 1

I
Uplift %
10%

Total CO ₂ Injected Cost		
F	Net volume injected	(A-B)
G	Average CO ₂ price	(D/C)
H	Net volume value	(F*G)
	Total CO ₂ uplift	(I*H)

←

Carry forward to
Schedule 1



ENERGY

SCHEDULE 5

EOR - NONHYDROCARBON FLUIDS INJECTED

Participant: _____

Business Associate ID: _____

Project Name: _____

Prepared By: _____

Telephone: _____

Date Prepared: _____

Reporting Year: _____

Product: Other _____

Month	Total Injected Volume E3M3	Total Injected Cost \$
January		
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		
Total		



Carry forward to Schedule 1

INSTRUCTIONS FOR COMPLETION OF SCHEDULE 5

Page 1 NON-HYDROCARBON – CO₂

- 1.) Participant – The complete corporate or individual name of the client filing this schedule.
- 2.) Business Associate ID – The identifier assigned to the participant of the scheme.
- 3.) Project Name – The name of the enhanced oil recovery scheme as approved by the Alberta Energy and Utilities Board (AEUB).
- 4.) Prepared By – The name of the individual that prepared the schedule.
- 5.) Telephone – Telephone number of the individual that prepared the schedule.
- 6.) Date Prepared – The year, month and day that this schedule was prepared or amended.
- 7.) Reporting Year – The year in which the CO₂ was actually injected.
- 8.) CO₂ Injection > 50% – Select either Yes or No to verify if CO₂ injection reached the required 50% injection ratio to receive an additional 5% overhead for the reporting year.
- 9.) Total CO₂ Injected – Total volume of CO₂ injected in the month.
- 10.) Total CO₂ Produced – Total volume of CO₂ that was produced in the month.
- 11.) Total CO₂ Acquired – Total CO₂ Injected less Total CO₂ Produced (A – B = C).
- 12.) Cost to Acquire Injected CO₂ – Cost to transport and acquire the injected CO₂ for the month. Costs for CO₂ acquired but not injected are not allowed.
- 13.) Total – Total CO₂ injected for the year.
- 14.) Total – Total CO₂ produced for the year.
- 15.) Total – Total CO₂ acquired for the year.
- 16.) Total – Total cost to acquire the injected CO₂ for the year. This amount is carried forward to Injectant costs on the Schedule 1 and receives the overhead allowance.
- 17.) Net volume injected – Total CO₂ Injected less Total CO₂ Produced (A – B).
- 18.) Average CO₂ price – Total Cost to Acquire Injected CO₂ divided by Total CO₂ Acquired (D/C).
- 19.) Net volume value – Net volume injected multiplied by the Average CO₂ price (F * G).
- 20.) Total CO₂ uplift – Net volume value multiplied by the 10% uplift for CO₂ (H * I). This amount is carried forward to Operating Costs on the Schedule 1, but does not receive the overhead allowance.

Page 2 NON-HYDROCARBON – OTHER

- 1.) Participant – The complete corporate or individual name of the client filing this schedule.
- 2.) Business Associate ID – The identifier assigned to the participant of the scheme.
- 3.) Project Name – The name of the enhanced oil recovery scheme as approved by AEUB.
- 4.) Prepared By – The name of the individual that prepared the schedule.
- 5.) Telephone – Telephone number of the individual that prepared the schedule.
- 6.) Date Prepared – The year, month and day that this schedule was prepared or amended.
- 7.) Reporting Year – The year in which the nonhydrocarbon material was actually injected.
- 8.) Product: Other – Specify the approved nonhydrocarbon material injected.
- 9.) Total Injected Volume – The volume of nonhydrocarbon material injected for the month.
- 10.) Total Injected Cost – The cost to acquire and transport the injected material.
- 11.) Total – The total volume of nonhydrocarbon material injected for the year.

12.) Total – The total cost of the injected material for the year. This amount is carried forward to Injectant Costs on the Schedule 1 and receives the overhead allowance.

Appendix B

Cost of Service Calculation

- a. In cases where a “fair market value” cannot be established for the valuation of non-arms length acquisition of CO₂, a cost of service (COS) calculation will be used. The purpose of the COS calculation is to cover all prudently incurred costs for capture, separation, transport, and compression of CO₂.
- b. The COS calculation will apply to cost categories that are not eligible for any other government program, such as the Gas Cost Allowance (GCA) program, Sulphur Emissions Control Assistance Program (SECAP), Enhanced Oil Recovery (EOR) program. The intent is to avoid double dipping of costs between government programs.
- c. There are two main components to the COS calculation, namely a capital cost component and an operating cost component. The following formulas will be used to calculate the cost of CO₂ capture, separation, transport (with the exception of pipelines) and compression:

- i. Capital Cost Component:

The annual capital charge will be allocated on a unit throughput basis, as follows:

$$\text{Capital unit charge} = \frac{\text{Annual capital depreciation} + \text{Rate of return on depreciated capital}}{\text{Annual throughput}}$$

- Annual capital depreciation rate is 10% fixed straight-line.
- Rate of return on depreciated capital is 15% pre-tax.
- The depreciated capital is the average between the capital at the beginning of the year and the capital at the end of the year.
- There will be no floor on the undepreciated capital balance to determine the return on capital.
- Annual throughput is the volume of CO₂ that is recovered through the facility.

- ii. Operating Cost Component:

The annual operating charge will be allocated on a unit basis, as follows:

$$\text{Operating unit charge} = \frac{\text{Initial capital cost} \times 15\%}{\text{Annual throughput}}$$

- Initial capital cost refers to the purchase cost of the equipment.
- A 15% proxy is used to estimate operating cost as a function of capital cost.

- Annual throughput is the volume of CO₂ that is recovered through a facility.
- An annual inflation rate will be applied to the operating cost component. The inflation factor would be based on the nominal GDP factor from Statistics Canada 13-001-X1B annual data series (year-over-year % change).

d. The cost of service methodology for pipelines used to transport CO₂ is given below:

- The annual depreciation charge, capital return and operating costs for pipelines will be allocated on annual throughput basis.
- The pipeline allowed capital costs will be depreciated on a straight-line basis over its useful life, which is estimated at 20 years (5% straight-line depreciation).
- There will be no floor on the undepreciated capital balance to determine the return on capital.
- The allowed rate of return on capital (RORC) will be calculated using the pre-tax weighted average cost of capital formula, as follows:

$$\text{RORC} = (\text{Deemed Debt \%})(\text{Deemed Cost of Debt}) + \frac{(\text{Deemed Equity \%})(\text{Deemed Cost of Equity})}{(1 - \text{Deemed Corporate Income Tax Rate})}$$

- The deemed debt percentage is 45%.
- The deemed equity percentage is 55%.
- The deemed cost of debt is equal to the Bank of Canada long-term bond rate (LTBR) plus 1%.
- The deemed cost of equity is equal to the multi-pipeline rate, as published by the National Energy Board on an annual basis.
- Other parameters such as capital structure and corporate income tax rate will be revisited at the Department's discretion when there are significant market or tax changes.

e. Therefore, the overall cost to acquire CO₂ will be calculated as follows:

$$\text{Total cost of CO}_2 \text{ acquisition} = (\text{capital unit charge} + \text{operating cost unit charge}) \times \text{annual throughput}$$

Two sample calculations using the COS calculation are outlined below:

Example 1
Capture/Processing of CO₂ at a Coal Plant

Data

CO₂ Throughput = 1,000 mcf/day

Capital Cost = \$500,000

CO₂ Utilization = 50% (the operator uses 50% of the total CO₂ throughput)

GDP Inflation Rate = 4%/year (this would normally change from year-to-year)

Analysis

Operating Cost = 0.15 x 500,000 = \$75,000/year

Depreciation = 500,000 x 10% = \$50,000/year

Return on Invested Capital = 0.15 x Average Capital

Year	Capital, Year- Beginning (\$)	Depreciation (\$)	Capital, Year- End (\$)	Average Capital (\$)	Depr. + RORC (\$)	Unit Capital Cost (\$/mcf)	Unit Operating Cost (\$/mcf)	Total Unit Cost (\$/mcf)	Total Cost per yr. (\$)
1	500,000	50,000	450,000	475,000	121,250	0.332	0.205	0.537	98,003
2	450,000	50,000	400,000	425,000	113,750	0.312	0.214	0.526	95,995
..									
..									
10	50,000	50,000	0	25,000	53,750	0.147	0.292	0.439	80,118

Note: Total cost per year = Total unit cost x total throughput x CO₂ utilization

Example 2
Transportation of CO₂ through a New Pipeline

Data

CO₂ Throughput = 1,000 mcf/day

Pipeline Cost = \$200,000

CO₂ Utilization = 30% (the operator uses 30% of the total CO₂ throughput)

Analysis

Operating Cost = \$0.05/mcf (based on actual auditable costs)

Depreciation = 200,000 x 5% = \$10,000/year

Rate of Return = 16% (this value would normally change from year to year)

Return on Invested Capital = 0.16 x Average Capital

Year	Capital, Year- Beginning (\$)	Depreciation (\$)	Capital, Year- End (\$)	Average Capital (\$)	Depr. + RORC (\$)	Unit Capital Cost (\$/mcf)	Unit Operating Cost (\$/mcf)	Total Unit Cost (\$/mcf)	Total Cost per yr. (\$)
1	200,000	10,000	190,000	195,000	41,200	0.113	0.050	0.163	17,849
2	190,000	10,000	180,000	185,000	39,600	0.109	0.050	0.159	17,411
.									
..									
20	10,000	10,000	0	5,000	10,800	0.030	0.050	0.080	8,760

Note: Total cost per year = Total unit cost x total throughput x CO₂ utilization



EOR Section 11 Royalty Relief Summary

ENERGY		
Scheme:	<u>Vertical - CO2</u>	Scheme ID: _____
Participant:	_____	WIO: <u>100.000000%</u>
		FOR THE CALENDAR YEAR ENDING DECEMBER 31, 20XX

CAPITAL COSTS	SCHEME	PARTICIPANT
Unamortized Balance, January 1, 20XX	5,000	5,000
Additions (Schedule 2)	<u>10,000</u>	<u>10,000</u>
Subtotal	15,000	15,000
LESS: Amortization @30%	<u>4,500</u>	<u>4,500</u>
Unamortized Balance, December 31, 20XX	<u><u>\$10,500</u></u>	<u><u>\$10,500</u></u>
INJECTANT COST		
Hydrocarbons Injected (Schedules 3 & 4)		0
LESS: Breakthrough Value (Schedule 12)		<u>0</u>
Subtotal		0
LESS: Present Worth @ 10%		<u>0</u>
Subtotal		0
Non Hydrocarbons Fluids Injected (Schedule 5)		440
OPERATING COSTS		
Consumed Energy (Schedule 6)		65
Transportation Costs (Schedule 7)		0
Annual Processing Allowance (Schedule 8)		0
Capital Amortization (as above)		<u>4,500</u>
Subtotal		5,005
Overhead Allowance @ 20%		1,001
CO ₂ uplift		<u>24</u>
Total Costs		\$6,030
\$6,030	x	48.501060%
Total Costs		\$2,925
Less: reduction in costs CO ₂ Project Royalty Credit, etc.		<u>-20</u>
Carry Forward Costs (Schedule 9)		0
TOTAL ALLOWED COSTS		<u><u>\$2,905</u></u>
ROYALTY RELIEF		
Relief Entitlement The Lesser Of:		519
\$2,905	x	17.8524%
Total Allowed Costs		Royalty Rate
OR	100.000000%	x 75,511
W.I.O.		Tertiary Royalty (Schedule 11)
LESS: Relief received (JAN. to DEC,20XX)		<u>0</u>
BALANCE OF RELIEF DUE/PAYABLE		<u><u>\$519</u></u>