CARBON DIOXIDE PRODUCTION FROM COAL-FIRED POWERPLANTS FOR ENHANCED OIL RECOVERY IN SASKATCHEWAN: A NEW FEASIBILITY STUDY

P. TONTIWACHWUTHIKUL C.W. CHAN W. KRITPIPHAT D. SKOROPAD D. GELOWIT A. AROONWILAS C. JORDAN F. MOURITS M. WILSON L. WARD

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P. Tontiwachwuthikul
C.W. Chan, W. Kritpiphat
D. Skoropad, D. Gelowit
A. Aroonwilas, C. Jordan
University of Regina
F. Mourits
CANMET/NRCan
M. Wilson
Saskatchewan Energy and Mines
L. Ward
SaskPower

ABSTRACT

In order to sustain the current production capacity of conventional oil in Western Canada, enhanced oil recovery (EOR) technologies must be increasingly applied. Among these, carbon dioxide (CO_2) flooding is a highly attractive possibility. A large amount of CO_2 is being produced by coal-fired power plants in this region. The CO_2 is currently discharged into the atmosphere and could be a major contributor to the so-called greenhouse effect, which would lead to global warming. Thus, the concept of capturing CO_2 and utilizing it as a flooding agent in EOR processes is currently generating much interest among oil, utility and coal companies.

This paper demonstrates how cogeneration concepts, together with process optimization strategies, help to reduce the CO_2 production cost by utilizing low-pressure steam and waste heat from various sections of the power generation process. Based on these concepts and strategies, results from this study show that the recovery cost of CO_2 from a coal-fired power plant can range between \$0.50-2.00/mscf. If the cost is approximately \$1.25/mscf, the production cost of a barrel of incremental oil would be less than \$18. Therefore, even at today's modest oil prices, there is room for profit to be made operating a CO_2 flood with flue gas extracted CO_2. The technical and economical feasibility of the concepts are evaluated and the practical implications for the Saskatchewan resources are discussed.

INTRODUCTION

The concept of capturing carbon dioxide from coal-fired power plants and utilizing it as a flooding agent for enhanced oil recovery (EOR) processes is currently drawing much interest from oil, utility and coal companies in Western Canada. Implementation of such a scheme would provide two important benefits: (i) the captured CO_2 could be marketed as a flooding agent which would generate revenues, and (ii) CO_2 emissions to the atmosphere would be reduced. Since CO_2 emissions are considered to be the main contributor to the possible serious environmental problem of global warming, the proposed scheme could become an important instrument to reduce such emissions at minimal incremental cost to the environment.

In the past few years, a few pilot test projects on CO_2 extraction from the Canadian coal-fired power plants (such as the Sundance and Boundary Dam projects) were organized by consortia of oil companies in collaboration with government organizations and utility companies; these projects were primarily aimed at using the recovered CO_2 for EOR applications. A variety of process technologies available from gas processing, including chemical gas absorption, cryogenic separation, dry bed adsorption, and membrane separation processes, were screened. The selection process resulted in the chemical gas absorption process being chosen as it had better overall economical advantages and a proven operability record over other processes[1,2]. However, the pilot plant results demonstrated that, even though this process technology was technically feasible, chemical gas absorption capital and operating costs were too high for EOR applications in the current crude petroleum market. The primary reason for the high cost of CO_2 extraction was that a substantial amount of energy was required for the process.

The major objective of this study is to further develop and evaluate ways to extract CO_2 from coal-fired power plants as efficiently and economically as possible using the amine absorption process. This paper will demonstrate how cogeneration concepts, together with process optimization strategies, can help to reduce CO_2 production costs. The economics and technical feasibility of the concepts are described and the practical implications of this study in the province of Saskatchewan are discussed.

NEW FEATURES AND DESIGN ASSUMPTIONS[1]

Figure 1 shows a simplified diagram of the proposed CO_2 extraction plant. It has been modified and extended from the previous works[3,4]. The concept of energy management and optimization, as familiar as the cogeneration concept, is applied to reduce the steam and electricity expenditures. In this study, a cogenerating power plant in which steam and electricity are generated, will be used in conjunction with the CO_2 recovery plant. Waste heat is minimized to improve the overall energy efficiency of the plant by (i) utilizing high grade steam for driving turbines to produce electricity and/or to compress CO_2, and (ii) recycling waste heat (low grade or low pressure steam) from the turbine outlet to the reboilers of the CO_2 extraction process for solvent regeneration. Therefore, the reboilers can be considered to be the heat sink of the steam cycle for the power plant. Instead of using conventional heat rejection through a set of low-pressure-steam-turbine condensers and cooling towers, this study introduces a new feature of CO_2 production with two advantages. First, the condensers and cooling towers will be replaced by the reboiler of the CO_2 extraction plant; the replacement will reduce the capital cost of the power plant and the long-term operating and maintenance (O&M) costs. Second, the steam generation unit (boiler) will be eliminated from the CO_2 extraction process; removal lowers the value of the capital and O&M costs in the CO_2 recovery plant. Thus, as shown, simple heat management/co-generation concepts can reduce the costs of both plants.

Two other features were also introduced in order to reduce the cost of CO_2 production. First, optimization techniques were used to search for optimal design and operating criteria for the CO_2 extraction plant. Second, coal is used as fuel instead of natural gas (which was used in most of the previous studies) for producing the make-up steam to the solvent regeneration units. Coal is used because the price of natural gas in Saskatchewan is approximately three times more expensive than that of coal for an equivalent heating value.

The major assumptions in this study are as follows: (i) the proposed plant is capable of extracting 8,000 tonnes of CO_2 per day from flue gases from an existing 300 MW power plant and its cogeneration unit or coal-fired boiler; (ii) the cost studies are based on a 10% internal rate of return and a 10-year project life, and (iii) the cost of electricity is assumed to be $0.06/kWh. All currencies are reported in Canadian dollars (Nov. 1992), unless they are stated otherwise.

A Chemical absorption process technology was selected for capturing CO_2 from the flue gas. This study consists of two parts: (1) MEA (monoethanolamine) technology; and (2) AMP (2-amino-2-methyl-1-propanol -- a sterically hindered amine) technology.

Monoethanolamine (MEA) is the most commonly used solvent. Amine Guard III and IV, both recently commercialized by Dow Chemical Co., have low energy requirements ranging from 39,000 to 50,000 Btu/lb-mole of CO_2 recovered (1.95-2.50 MMBtu/tonne of CO_2). This study employs a value of 50,000 Btu/lb-mole of CO_2 as the basis for the heat requirement for MEA in Part 1.

For Part 2, AMP technology is a relatively new technology that would further lower the production costs of the CO_2 process. The heat requirement for an aqueous AMP solution was determined from our pilot plant data. It was confirmed that AMP consumes approximately 20-25% less energy than MEA. Therefore, 40,000 Btu/lb-mole of CO_2 (2 MMBtu/tonne of CO_2) is the heat requirement used as the basic assumption for the design of this study in Part 2

CASE SCENARIOS

In order to cover a wide variety of options for the investment of building a cogeneration power plant and the

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[1] *For more detail regarding the full report of this study, please contact the first author at the University of Regina.*

CO_2 recovery plant, four case scenarios of process integration between the CO_2 recovery plant and cogenerating power plant were evaluated for Parts 1 and 2.

Case A: Maximized electrical production

Under this case scenario, a cogeneration plant of 300 MW would be built and about 230 MW of surplus electricity would be sold to the electric grid. It is the largest plant size that the power company in Saskatchewan would consider as an option in their investment program.

Case B: 80-120 MW electrical production

This case represents an 80-120 MW cogeneration power plant generating an amount of steam just enough for a CO_2 recovery plant producing 8,000 tonnes/day of CO_2, so that the set of cooling towers can be replaced with a set of reboilers. This is referred to as the "cooling tower/reboiler replacement". Electrical and steam efficiencies are calculated from available information. Deductions have to be made for losses in electricity and thermal energy. As a result, values of 31.7% for electrical efficiency and 45.3% for steam efficiency are used in this design. About 3% of electrical losses are caused by size and/or stage reductions of the low-pressure steam turbine in order to improve the quality of steam[5].

Case C: Null electricity production

This case scenario is for self-contained CO_2 production, with break-even thermal and electrical requirements. The cogenerating power plant is designed to generate just enough electricity for the CO_2 recovery plant (within ±10 MW). The cooling tower/reboiler replacement is also implemented in this case scenario, similar to Case B. The major difference between the Case B scenario and the Case C scenario is the electricity-to-steam ratio of the co-generating power plant. Following Limaye (1987), a 15% electrical efficiency and a 67% steam efficiency are used for this case.

Case D: Buy-back electricity

This final case scenario illustrates the production cost of CO_2 from an optimized CO_2 recovery plant. About 50-60 MW of electricity has to be supplied by the existing electrical grid, while the steam required by the reboilers of the regenerators is generated by a coal-fired boiler. Atmospheric fluidized bed combustor (AFBC) technology, one of the popular clean coal technologies, is selected as the operation mode for the coal-fired boiler in this study. An AFBC boiler that burns lignite coal with limestone at low temperatures (760-954^{o}C) tends to emit low levels of nitrogen (NO_X) and sulfur (SO_X) oxides.

The engineering design for all the cogenerating power plants and boilers in this study is based on the use of Saskatchewan lignite coal, which is low in sulfur content. The coal composition and the heating value are presented in Table 1.

In order to match the power plant size with a CO_2 production rate of 8,000 tonnes/day, the size and coal consumption of the cogenerating power plants/boilers are determined by mass and energy balances. The amount of CO_2 produced from the associated cogenerating power plant is also estimated in order to obtain the most manageable portions of the flue gas flow between the existing 300 MW power plant and the cogenerating power plants/boilers. Table 2 summarizes the estimated specifications of all case scenarios in Parts 1 and 2. The net reductions of CO_2 and SO_2 emissions are also calculated and presented in Figure 2.

RESULTS AND DISCUSSION

Figures 3 and 4 show the important economic parameters such as CO_2 cost, payback period, and return on investment for the individual cases of Parts 1 and 2. The total investment cost and the annual operating and maintenance (O&M) cost are also summarized in the table in Figure 3.

For Part 1 (MEA technology), the maximized electrical production (Case A) generates approximately 230 MW of net electricity. With an estimated coal price of \$12.50/tonne, CO_2 can be produced for well below \$1.00/mscf.

The next case (Case B) represents an 80-120 MW conventional power plant, which generates an amount of steam just enough for the CO_2 recovery plant producing 8,000 tonnes/day of CO_2. This case scenario is similar to Case A, however, the return on investment is lower and the payback period is slightly longer. CO_2 can be produced at about \$1.00/mscf with a coal price of \$12.50/tonne.

In Case C, there is no net electricity production from the cogeneration unit. All electricity generated through cogeneration is utilized in the facility. A distinct trend in these cases is that as the production rate of electricity decreases, the return on investment decreases and the payback period increases. Again, at \$12.50/tonne of coal, the CO_2 price ranges from \$1.40 to \$1.83/mscf.

Case D represents a facility that generates only CO_2. An atmospheric fluidized bed boiler is used to provide the heat required for the CO_2 recovery plant. Electricity in this case is bought back from the grid. This case requires the lowest capital investment. However, the CO_2 price is the highest, approximately \$1.57 to \$1.83/mscf.

In Part 2, AMP is evaluated utilizing the same case scenarios as in Part 1. As little is known about the industrial operating characteristics of this solvent, much of this study relies on in-house pilot plant test data and theoretical calculations. The trend across the case studies in Part 2 is similar to that of Part 1; however, the return on investment and payback period are more attractive using AMP technology. In most cases, the price of CO_2 is about 10% to 20% lower due to the fact that AMP needs less heat for solvent regeneration. An exception is found in the case of 80-120 MW, for which a slightly higher price of CO_2 is obtained. This is due mainly to the significant decrease in revenue from electricity sales.

All case studies presented here are based on currently available technologies which could be implemented in a short period of time. The cost figures shown here are conservative estimates and they could therefore be reduced further. For example, the cost for the power plant is based on that for the complete plant, which includes a set of low-pressure-steam-turbine condensers and cooling towers. For this type of process integration (cogeneration), the condensers and cooling towers may not be needed, hence the overall cost of the power plant can be reduced by 5% to 10%. In all of the case studies, the plant is assumed to have a working life of 10 years and zero value after that. Normally, these types of CO_2 separation units should have about 10% to 20% of their original value at the end of 10 years. For the cogeneration plant, the remaining value would be much greater. In addition, the cost of CO_2 extraction could also be reduced if high absorption capacity solvents (e.g. newly engineered absorbents), and high-efficiency packed columns (e.g. structured packings), are used. If all these factors are included, further substantial cost savings could be realized.

ECONOMIC ASPECT OF EOR APPLICATIONS

In July of 1995, the average West Texas Intermediate Oil Price was \$17.33 US or \$23.65 Cdn (assuming an exchange rate of \$1.3644 Cdn to \$1 US). Hence, the utilization of CO_2 flooding will be economically feasible for EOR operations when the production cost of crude oil from EOR is well below this price.

A economic relationship between the production cost of crude oil and the CO_2 cost was given by Hyland et al. (1985). Although it is a simple calculation that can be only a guideline of the real economics, it gives a reasonable estimate of the CO_2 price at which the CO_2 flooding project would be profitable[7,8]. The cost of CO_2 (P_{CO2}, \$/mscf) can be expressed at the function of the oil production cost (P_{oil}, \$/barrel) and internal rate of return (r) as follows:

$$P_{CO_2} = \frac{F_{tax} P_{oil}/R - (R_g - 1) P_{recycle}}{1 + R_g \beta} \qquad (1)$$

where

$$\beta = \frac{e^{rT_{lag}} - 1}{1 - e^{-r(T_c - T_{lag})}} \qquad (2)$$

R is the displacement efficiency measured in mscf of CO_2 purchased per extra barrel of oil recovered. R_g denotes the ratio of total injected CO_2 to purchased CO_2. The excess, R_g-1, is the ratio of the "wellhead recycled CO_2" to the purchased CO_2. The wellhead recycled CO_2 usually comes out with the crude oil, and can be extracted and re-injected into oil reservoirs at a cost of $P_{recycle}$. T_c is the project life of CO_2 flooding for EOR projects. F_{tax} represents the fraction of gross income after severance tax and royalties are taken away. T_{lag} is a lag time for injection of CO_2 before extra oil is produced.

Equation (1) assumes that the cost of injected CO_2 is the principal operating cost and does not include the oil field operating cost or the capital cost of the project. Normally, the capital cost per barrel of oil recovered can be negligible since most of the existing facilities are already in place; the cost per barrel of new facilities, such as the local pipeline and platform facilities, is less expensive compared to the operating costs for the CO_2 flooding projects. However, neglecting the oil field operating cost may overestimate the economical feasibility of the CO_2 flooding for EOR projects. To be more realistic, we have extended this equation to include the oil field operating cost (P_{field}, \$/barrel) as follows:

$$P_{CO_2} = \frac{(F_{tax} P_{oil} - P_{field})/R - (R_g - 1) P_{recycle}}{1 + R_g \beta} \qquad (3)$$

It is also possible to represent the above relationship in terms of the total displacement efficiency (R_T) and the percentage of the wellhead recycled CO_2 ($R_{recycle}$). R_T is defined as the net CO_2 consumption measured in mscf of total injected CO_2 per extra barrel of oil recovered, while $R_{recycle}$ is the ratio of the wellhead recycled CO_2 to the total injected CO_2. Thus,

$$R_T = R \cdot R_g \qquad (4)$$

and

$$R_{recycle} = (R_g - 1)/R_g \qquad (5)$$

Rearranging Equations (3) to (5) yields:

$$P_{oil} = \frac{P_{field} + R_T\left[(1 + \beta - R_{recycle}) P_{CO_2} + (R_{recycle}) P_{recycle}\right]}{F_{tax}} \qquad (6)$$

For EOR projects, AOSTRA (1993) has determined that the average net CO_2 consumption per barrel of incremental oil is 6 mscf (R_T = 6 mscf/bbl). For a special relief of Petroleum Revenue tax, the EOR royalty scheme until payout is probably 1% of the oil price with no tax paid, i.e., F_{tax} = 0.99 (F_{tax} = 0.55-0.81 for typical projects). Average oil field operating costs, P_{field}, are approximately $4.50/bbl in southeastern Saskatchewan. It is assumed that the wellhead CO_2 can be recycled at a cost of approximately $1/mscf, while T_e and T_{lag} are set at 10 years and 3 years respectively. Figure 5 illustrates the production cost of crude oil versus the cost of purchased CO_2 at 100% consumption of fresh CO_2 ($R_{recycle}$ = 0), and 0-30% of internal rate of return (IRR).

Previous studies have estimated a CO_2 recovery cost ranging from $2.00 to $3.50/mscf[1, 9-12]. As a result, based on 10% IRR, Figure 5 presents $25.09 to $40.50/bbl of the crude oil production cost. The oil price needs to be even higher where the greater rate of return is desire. Compared with a current oil price of $23.65, the use of CO_2 as the flooding agent would not be economic right now because of the high cost of CO_2.

Using the concepts proposed in this study, the production cost of CO_2 would be reduced significantly and ranges between $0.50 to $2.00/mscf. Assuming that the actual cost would fall in the range of $1.25 to $1.50/mscf, the production cost of incremental oil would be approximately $17.39 to $19.95/bbl at 10% rate of return. Therefore, even at today's modest oil prices, there is substantial room for profit to be made operating a CO_2 flood with flue gas extracted CO_2.

The total displacement efficiency (R_T) and the lag time (T_{lag}) can vary upon the geometries and geophysics of reservoirs. Hence, they have a great impact on the economics of CO_2 flooding in EOR projects, as well as the production of CO_2 from the flue gas of power plants. Figures 6 and 7 summarize the effects of R_T and T_{lag} on the production cost of crude oil for individual cases of Parts 1 (MEA) and 2 (AMP). These figures are based on the following assumptions: r = 0.10, P_{field} = $4.50/bbl, $P_{recycle}$ = $1.00/mscf, T_e = 10 years, F_{tax} = 0.99, and $R_{recycle}$ = 0.50.

The oil production costs are similar in trend for Figures 6 and 7. The production cost of crude oil increases proportionally with an increase in the total displacement efficiency, while it increases exponentially with an increase in the lag time. At the different case scenarios, the higher the CO_2 cost, the greater the influence of R_T and T_{lag} on the oil production cost. Hence, the oil production costs are least expensive for the case of the maximized electrical production where the CO_2 is recovered and sold at the cheapest cost. Using MEA technology, the production cost of crude oil, at the typical 6 mscf/bbl of the net CO_2 consumption and 3-year lag time, is about $11.05, $14.53, $19.53 and $20.47 per barrel for Cases A to D, respectively. For AMP technology, the production cost will be as low as $10.11, $14.82, $18.58, $19.42 per barrel for Cases A to D

Figure 8 illustrates the total cost of recovered oil versus mscf CO_2/bbl of incremental oil production at various percentages of wellhead recycled CO_2. The Figure can be used to estimate the total cost of recovered oil at any operating condition of the wellhead recycled CO_2 injection, over the life of reservoirs. The CO_2 flood is economically feasible unless the total cost of recovered oil is higher than the oil price in the petroleum market.

In addition, sensitivity of the electricity cost on the recovered oil price was also studied at the conditions of 50% fresh CO_2 and 50% wellhead recycled CO_2, as shown in Figure 9. The variation of electricity costs does not change the recovered oil cost for Case C since there is no electricity produced or sold in this case. For Cases A and B, the total cost of recovered oil decreases with an increase in the price of electricity because the increase would raise the electrical sale revenue, which in turn lowers the production cost of CO_2. This contrasts with Case D where additional money is needed to buy electricity from the grid.

CONCLUSIONS

Carbon dioxide production from coal-fired power plants was studied. It was found that the production of CO_2 can become technically feasible, economically feasible and environmentally friendly where the concepts of cogeneration and optimization are applied to reduce the steam and electricity expenditures. The recovery cost of CO_2 in this study can range between $0.50-2.00/mscf, which can translate to a recovered oil price of $17.39 to $19.95/bbl. Therefore, even at today's modest oil prices, flue gas extraction can be an economically viable and attractive CO_2 supply source for CO_2-enhanced oil recovery projects.

ACKNOWLEDGMENTS

Financial support from Natural Sciences and Engineering Research Council (NSERC), SaskPower, Saskatchewan Energy and Mines, CANMET, Prairie Coal and Wascana Energy is gratefully acknowledged.

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Table 1: Composition and Heating Value of Saskatchewan Lignite Coal

Ultimate Analysis		
	Components	***% by weight, wet basis***
	Moisture	33.7
	Carbon	36.3
	Hydrogen	2.4
	Nitrogen	0.6
	Sulfur	0.5
	Ash	14.5
	Oxygen	12.0
		100.0%
	Heating Value	14,400 kJ/kg (6190 Btu/lb)

Table 2: Summary of engineering design for all case scenarios in Parts 1 and 2

Case Scenarios	Net Power, MW	New Cogeneration Power Plant		Existing 300-MW Plant*
		Plant Size, MW	Coal Consumption, tonnes/day	Minimum Operating Load, % peak load
Part 1: MEA				
Case A: Maximized	231	300	5,184	28.8
Case B: 80-120 MW	118	204	3,241	66.3
Case C: Null electricity	2	55	2,192	86.5
Case D: Buy-back electricity	-54	-1.6	1,766	94.7
Part 2: AMP				
Case A: Maximized	236	300	5,184	28.8
Case B: 80-120 MW	86	163	2,593	78.8
Case C: Null electricity	-7	44	1,754	95.0
Case D: Buy-back electricity	-52	-1.3	1,413	100.0

* Based on 90% CO_2 removal, except Case D (Part 2) in which a higher CO_2 removal efficiency in the absorbers (>91.1%) is required.

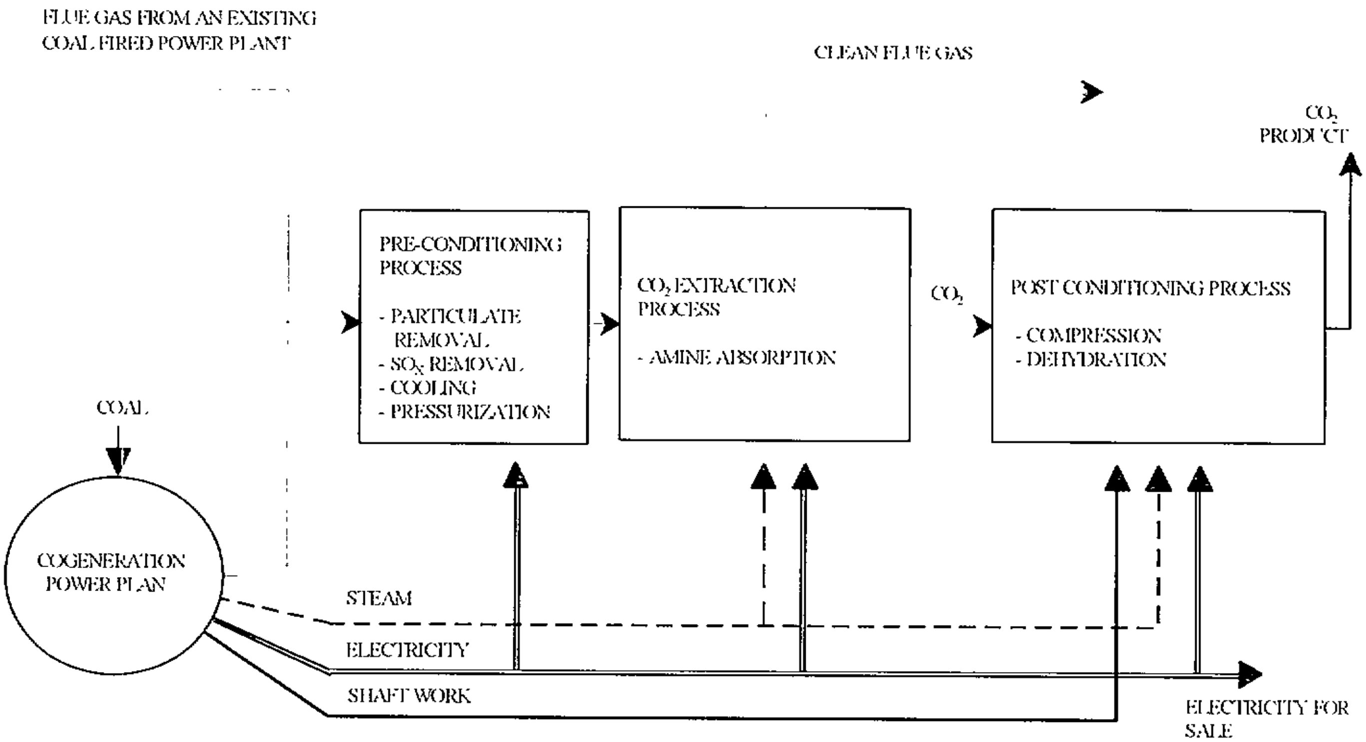


Figure 1: Simplified flow diagram of the proposed CO_2 extraction plant

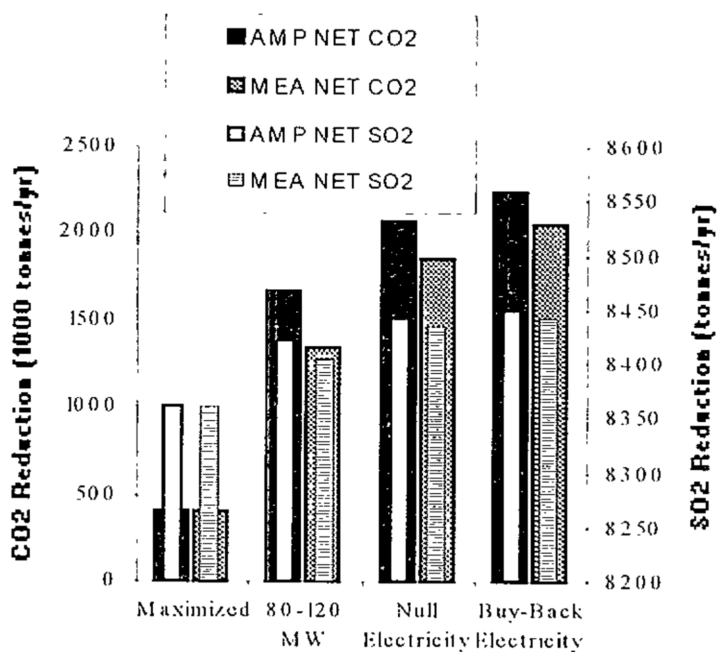
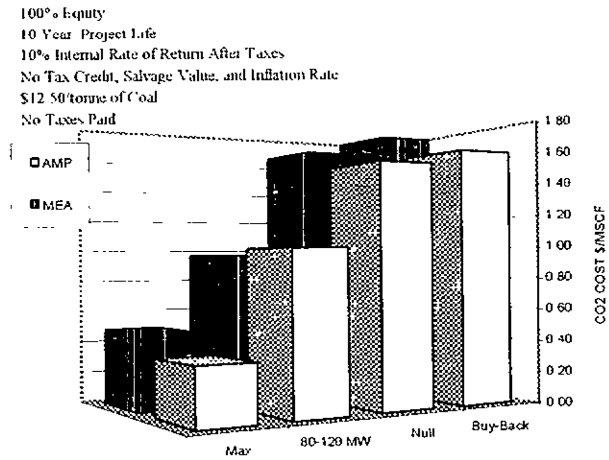


Figure 2: Net reduction of CO_2 and SO_2 emissions



	MEA				AMP			
	Maximized	80-120 MW	Null	Buy-Back	Maximized	80-120	Null	Buy-Back
Power Plant	387 00	280 97	185 12	30 22	387 00	245 77	161 92	26 44
CO2 Plant	194 81	194 81	194 81	224 93	165 81	165 81	165 81	195 93
Total	581 81	475 78	379 93	255 15	552 81	411 58	327 73	222 37
O&M	52 83	37 82	30 31	28 07	53 54	33 29	27 12	25 57

- All costs are given in millions of dollars except O&M given in million of dollars/yr
- O&M does not include electrical costs

Figure 3: CO_2 cost and a summary of investment costs

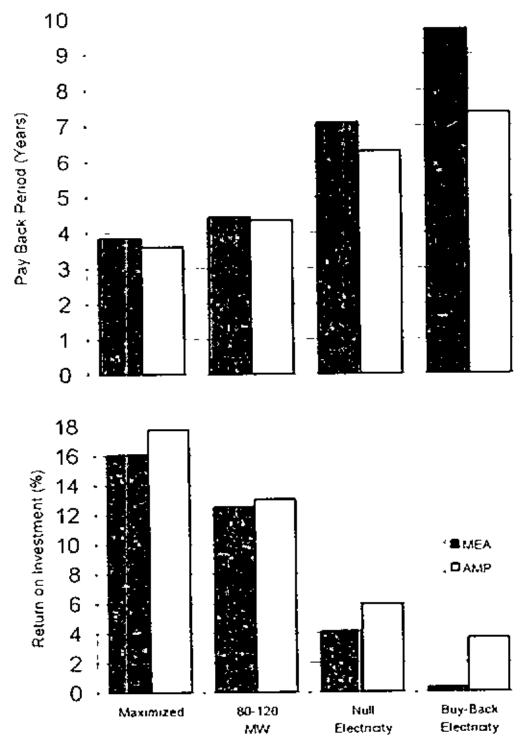


Figure 4: Payback period and return on investment

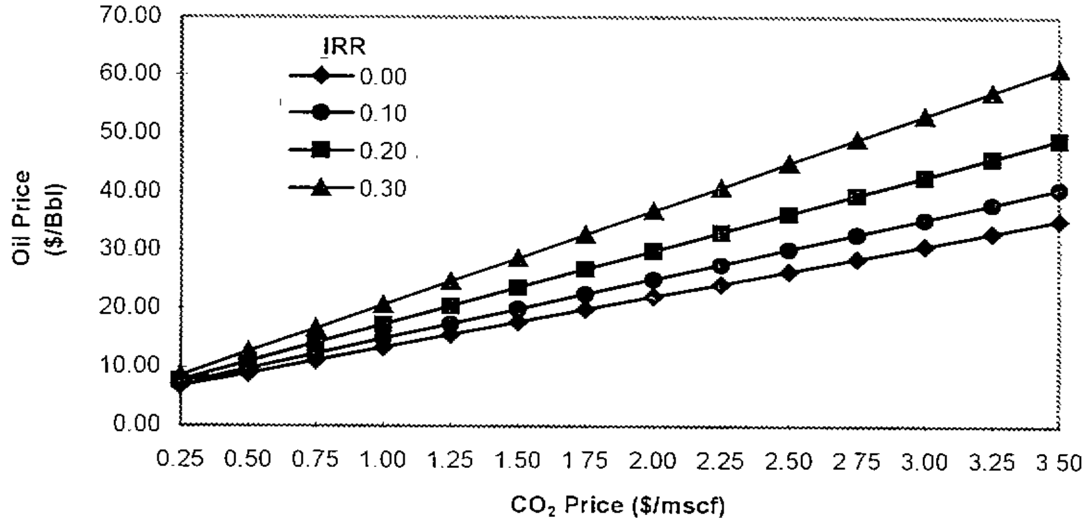


Figure 5: Relationship between oil production costs and CO_2 costs, at 0-30% internal rate of return

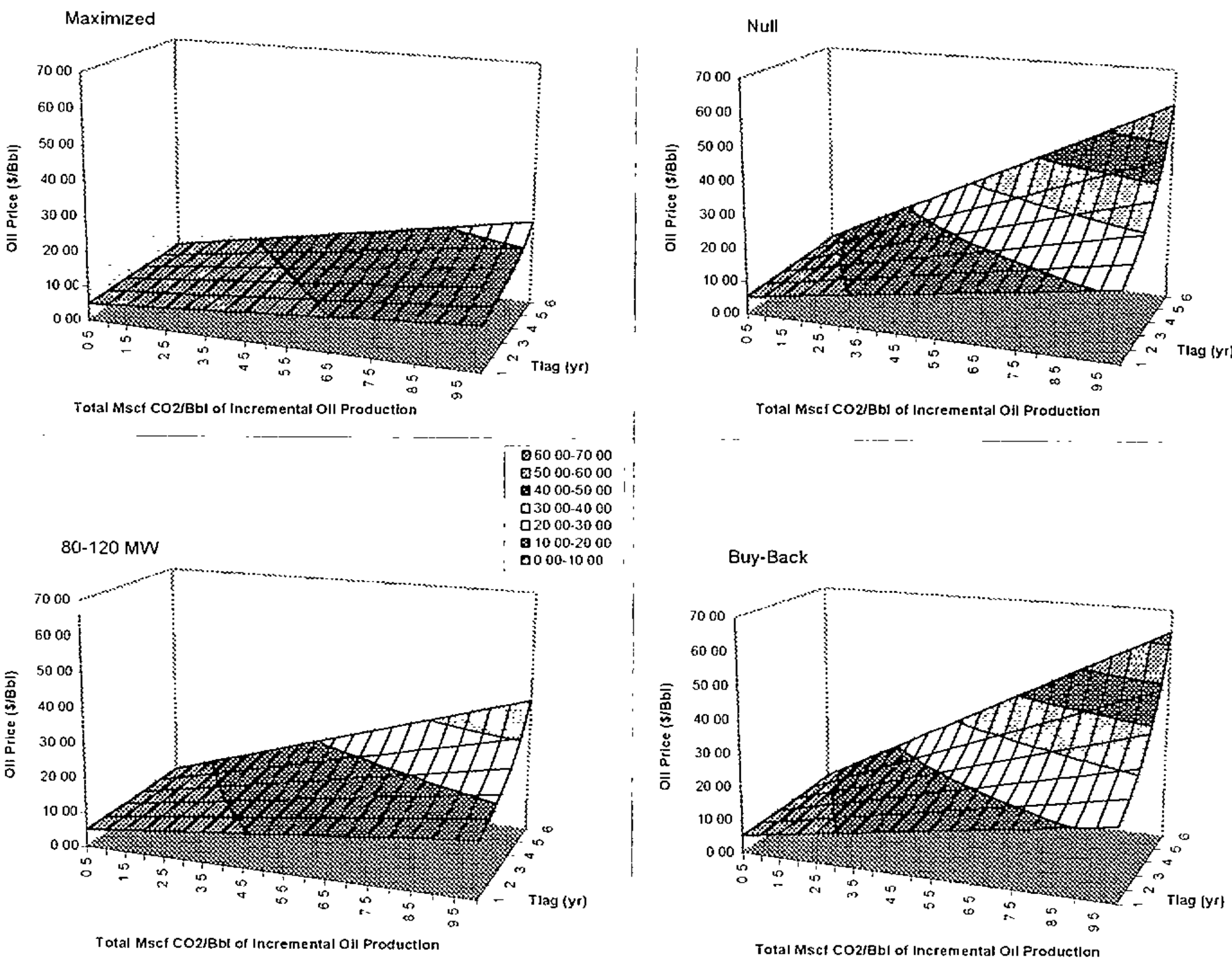


Figure 6: Total cost of recovered oil vs. the total displacement efficiency and the lag time for individual case scenarios in Part 1: MEA technology

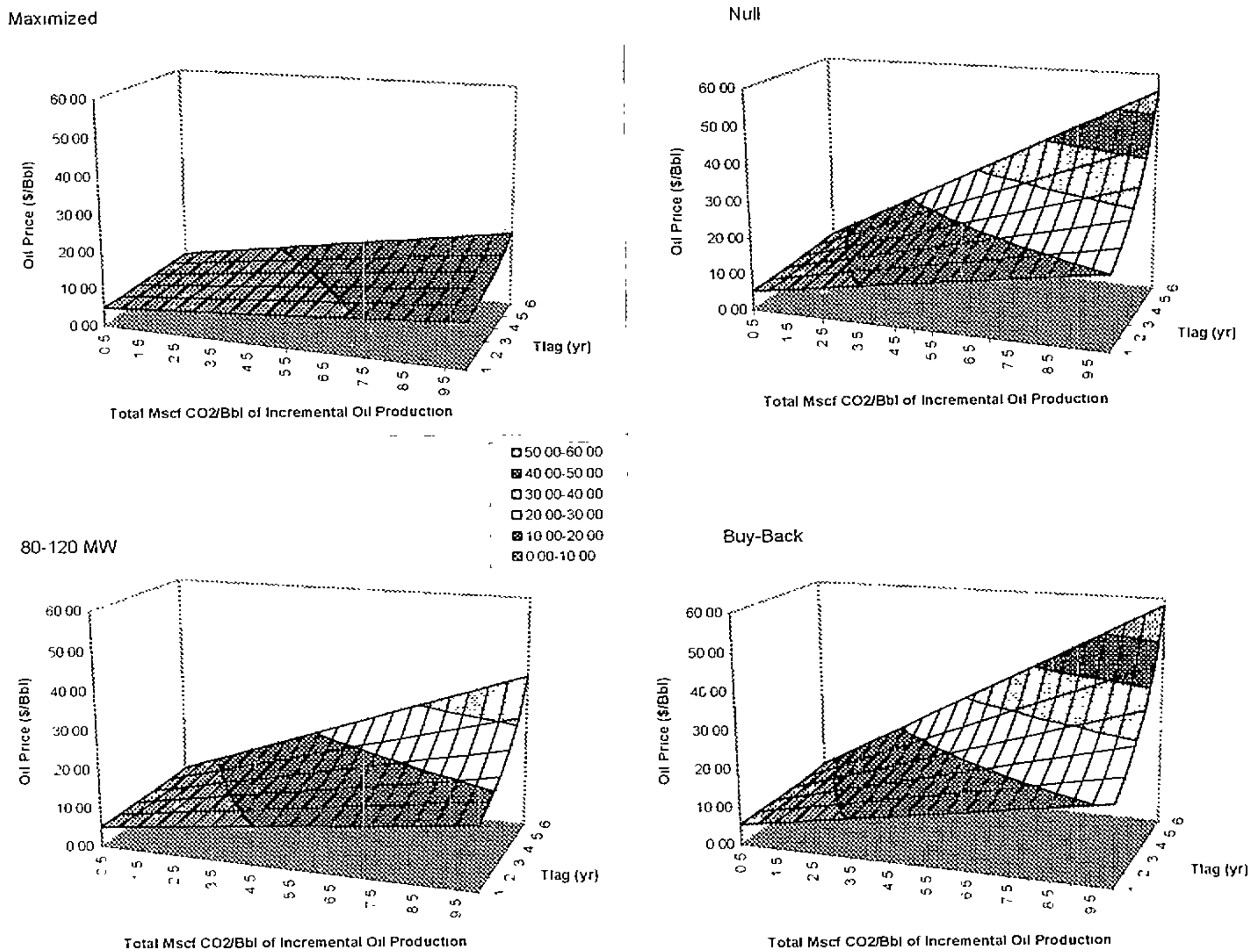


Figure 7: Total cost of recovered oil vs. the total displacement efficiency and the lag time for individual case scenarios in Part 2: AMP technology

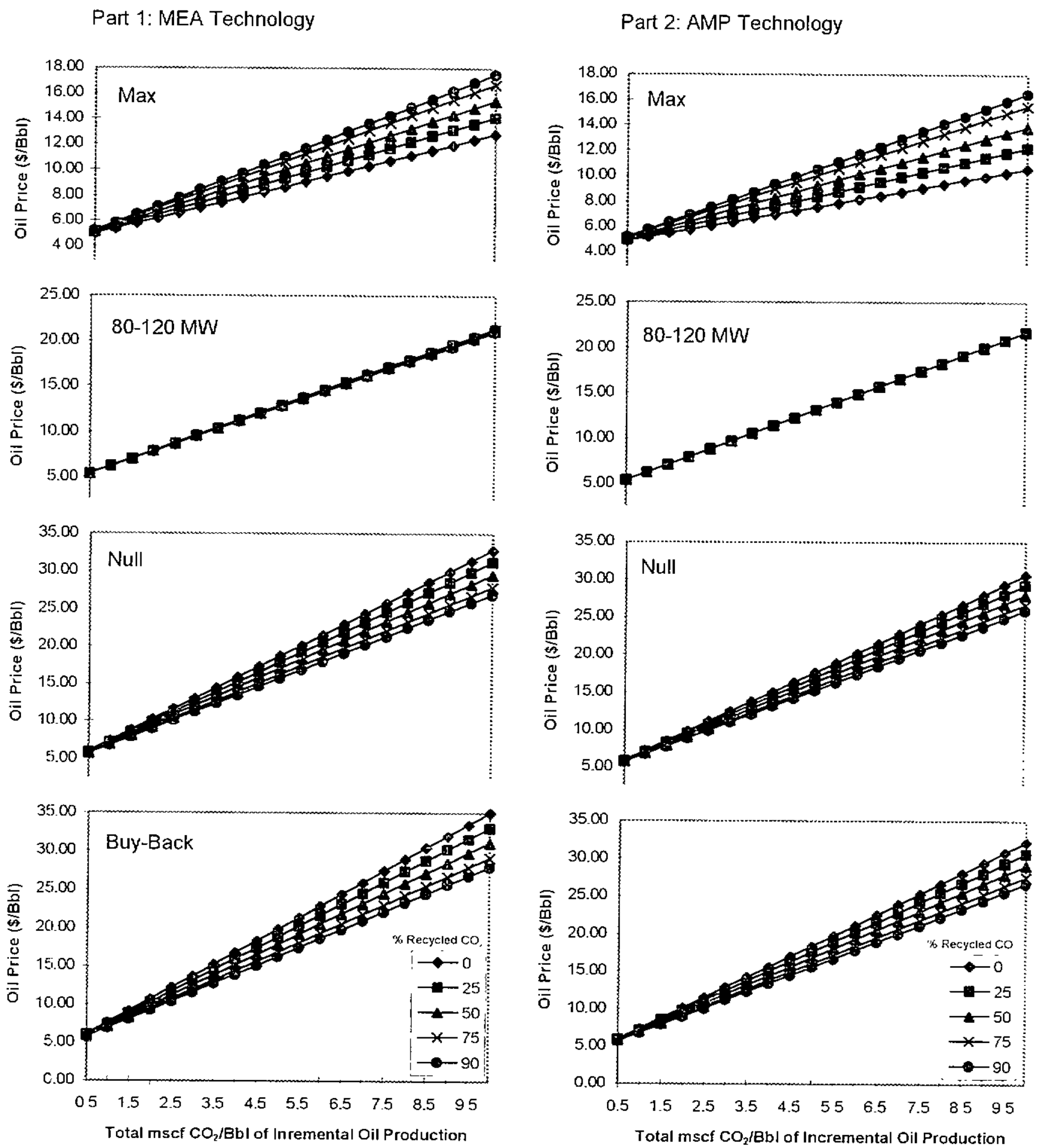


Figure 8: Total cost of recovered oil vs. mscf/bbl for different percentage of wellhead recycled CO_2, when 10% IRR and 3-years lag time are used

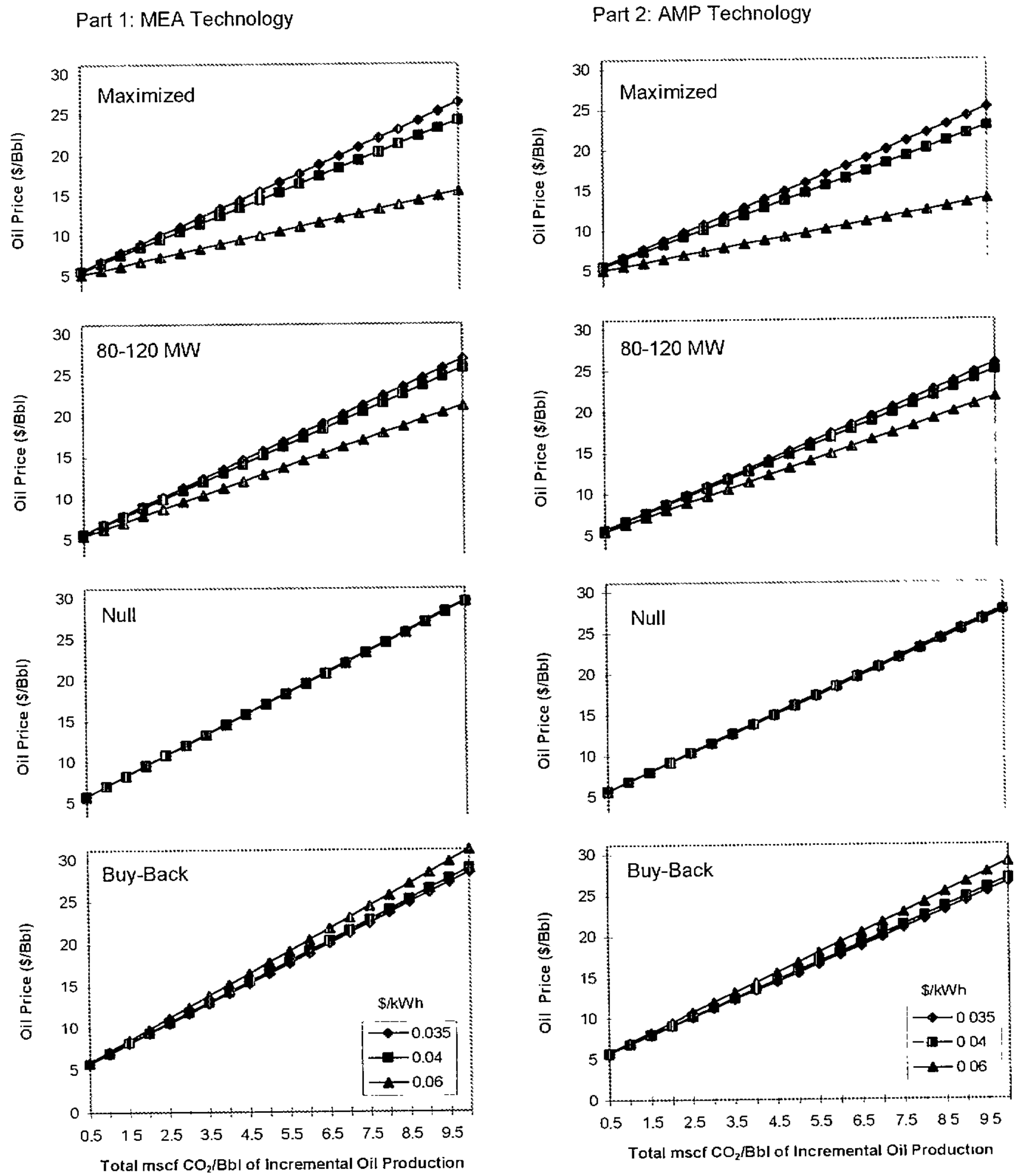


Figure 9: Sensitivity of electricity cost on total cost of recovered oil when 10% IRR and 3-years lag time are used