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Weyburn CO_2 Miscible Flood Conceptual Design and Risk Assessment

W. BARNHART
PanCanadian Petroleum Limited
C. COULTHARD
CSC Project Management Services

Abstract

For the three years leading up to the end of 1995, a multi-disciplinary project team evaluated the business opportunity of injecting carbon dioxide into a portion of the Weyburn Unit to improve recovery. As with any project of this magnitude, a comprehensive analysis of the opportunities and risks in the project had to be clearly defined and evaluated.

A risk assessment using a Monte Carlo simulation approach was undertaken to combine the technical with the non-technical issues associated with the project in order to define the full cycle opportunities and risks. The risk assessment process was used to optimize the project configuration, to focus the team on key issues, and to find ways to mitigate the risks inherent in the project.

Key uncertainties impacting the range in expected project returns appeared in the areas of commodity prices, reservoir performance, costs and fiscal terms. The risk assessment process and conceptual development plan, incorporating studies and analysis completed up to the end of 1995, is the subject of this paper.

Introduction

The Weyburn Unit, covering an area approximately 180 km^2, is approximately 130 km southeast of Regina, Saskatchewan (Figure 1). The Unit is operated by PanCanadian Petroleum Limited on behalf of the working interest ownership. The field was discovered in 1955 and produced under primary depletion until an inverted nine spot waterflood was implemented in 1964. Production at the end of 1995 averaged 3,150 m^3/d of medium-sour crude from 650 oil producers, of which 90 were horizontal wells. At that time, it was postulated that more than $116 \times 10^6 m^3$ of oil was expected to remain in the reservoir after the completion of waterflood operations, or 65% of the original $178 \times 10^6 m^3$ in place. This large remaining oil in place represented a very attractive target for an enhanced recovery process.

The Midale beds of the Weyburn field were deposited on a shallow carbonate shelf in the Williston basin. The reservoir is uniformly divided into the upper Marly, a chalky inter-tidal dolostone with limestone interbeds, and a lower Vuggy zone, a heterogeneous and highly fractured subtidal limestone. A more complete reservoir characterization was discussed by Elsayed et al.[1]

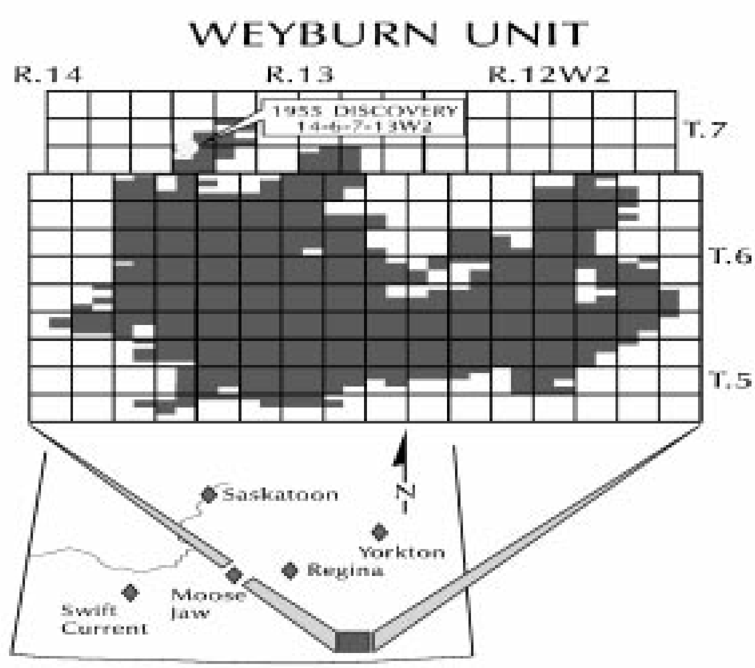

FIGURE 1: Weyburn unit outline.

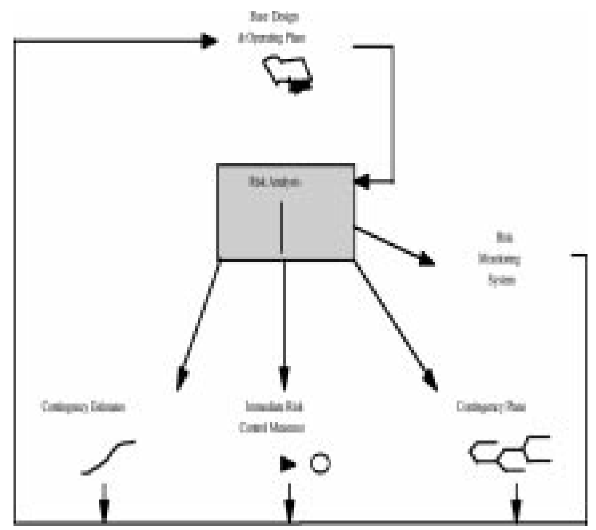

FIGURE 2: Risk analysis is the centerpiece of a risk management process.

An analogy to the Weyburn field can be drawn from the Midale Unit, situated just east of the Weyburn field. Shell Canada Ltd., the operator of the Unit, implemented a CO_2 injection pilot in 1984 which was completed in 1988. Due to encouraging results from the pilot[2], Shell implemented a "CO_2 demonstration project," an eight pattern flood in 1991 which was designed to improve oil recovery from the area and provide technical and economic data to further assess full scale development potential. This flood is still in progress.

Input data forming the basis of this assessment incorporated some of the Midale information as well as opinions from internal experts, industry consultants and other analogous CO_2 floods in the Permian Basin[3].

Traditional Evaluation Process

Traditional engineering, design, and estimating methodology sets out a logical step-by-step process which leads through the project life cycle. Such a process uses single point estimates for project outcomes, capital cost, operating cost, plant performance and revenue streams. Inherent in the analysis is a set of assumptions developed by individual members of the project team. These assumptions are often buried in the analysis and are not communicated internally between members of the project team and the decision makers.

This process tends to focus on one project strategy and often fails to consider the impacts of alternative environments on project outcomes. The single point result of the analysis is seldom right and surprises are encountered during project execution. More importantly, this approach fails to identify project improvements which could provide significant increases to the project's value, and the resulting analysis fails to clarify project control priorities to mitigate the negative impact of unplanned events.

Risk and decision analysis techniques can be used to improve the quality of key project planning decisions in the formative stages of new project development. Early utilization of the process provides the team with a tool for ongoing decision making as the project moves forward.

Risk Analysis Process

Risk analysis is the centerpiece of a risk management process (Figure 2). Risk analysis is used to quantify uncertainties in a project by placing it in an uncertain environment and calculating the likelihood of various outcomes within that environment. The process[4] should support the management of risk in more significant ways:

1. Provides a significant benefit in developing insight and understanding about the impact of risk on the project outcomes. This generally leads to a change in direction in the project either in the form of design changes or some other project plan revisions.

2. Provides for the development and review of contingency and risk mitigation plans. Given certain changes in the project environment, the ability of the analysis to test "what-if" scenarios prepares the project team for the appropriate response before the fact.

3. Forms the basis for a dynamic risk monitoring system over the life of the project. Analysis of the risks as the project proceeds provides an ideal mechanism to forecast the future end result of the project.

A rigorous process is employed to conduct risk and decision analysis. Figure 3 illustrates the five step process, from framing the problem through to implementation.

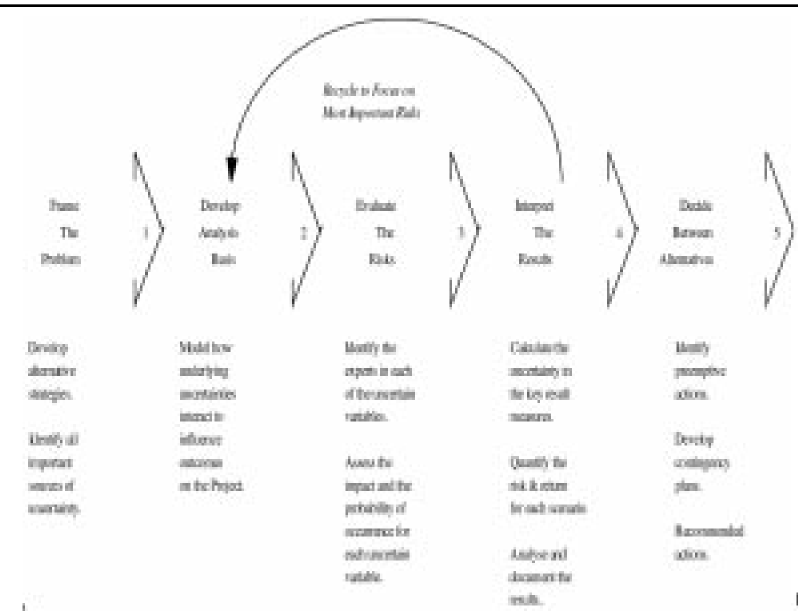

FIGURE 3: Five steps in a risk and decision analysis process.

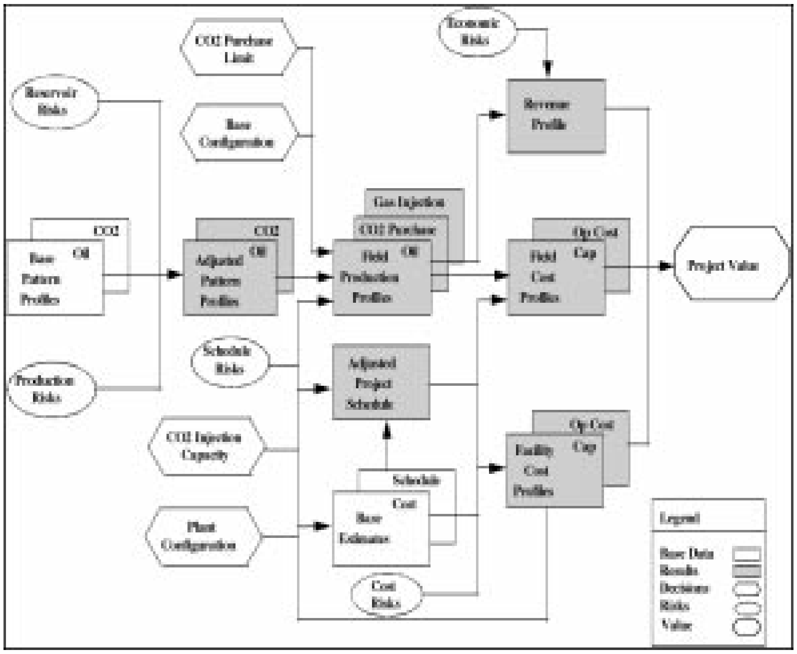

FIGURE 4: Weyburn risk analysis model structure.

Step 1—Frame the Problem

The first step in framing the problem is to define the preferred project strategy and its alternatives. The strategy table charts the alternative paths through the decision options.

The project team then identifies all sources of risk to the project in a brainstorming session. These risks are graphically charted to demonstrate the impacts on the project outcome using an influence diagram. The Weyburn project's influence diagram is illustrated in its simplest form in Figure 4. In this influence diagram, hexagons are key project decisions, ovals represent project risks, arrows represent the flow of the risks and interactions, while the rectangles represent key calculations for the major project components. The octagons are the measurement criteria for project outcomes[5].

Step 2—Develop the Analysis Base

Modeling the project environment is an important second step. As discussed by Goodyear et al.,[6] the risk model is designed to quantify the impact of change in value or probability of the uncertain variables upon the expected value of each alternative, or upon the components which make up that value—i.e., capital cost, operating cost, productivity, schedule, etc.

Step 3—Evaluate the Risks

The risk evaluation step is the key to success of the risk analysis process. Because the quality of the analysis is dependent on the experts' judgment, it is important that these people are selected based on their credibility with the decision makers.

A series of assessment meetings are held to assign a range of values to each risk variable. Interview techniques are designed to avoid biases in the experts' judgment. Often, expert opinion from outside the project brings an independent alternative view on the important variables. The experts are asked to provide both probabilities of occurrence and the quantification on the impact of each variable on the project results.

The experts also provide a description of the environment that would lead to the extremes. Sharing these "stories" provides an important communication function among the experts. Documentation of the assessment and the insights behind the extreme values is important when considering ways and means to mitigate the risks.

Step 4—Interpret the results

The interpretation step involves running the analysis model to determine the key risk contributors and to compare decision and strategy alternatives on a "risked value" basis. At this stage the initial results are fed back to the experts. This may require focus upon and re-examination of the most critical variables. This step is repeated until the project team and experts are satisfied that the model reflects a realistic picture of the project.

Step 5—Compare Alternatives

The analysis model is used to produce a risk adjusted picture of the project. A set of graphical tools are then used to describe the uncertainty in the project.

Cumulative probability curves can be used to compare the alternatives. Probabilities of achieving required results can be read directly from these curves. Figure 5 shows an example of a comparison of two hypothetical options. The significant upside opportunity for Option B would not be apparent in a single point analysis. In addition, the degree of uncertainty can be measured by examining the slope of the distribution. A vertical line indicates

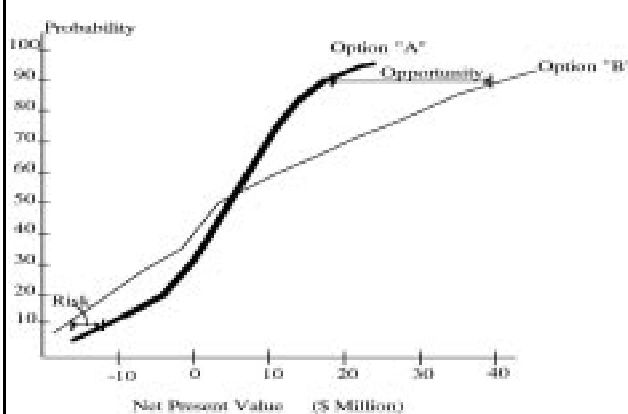

FIGURE 5: Probability distribution showing risk and opportunities.

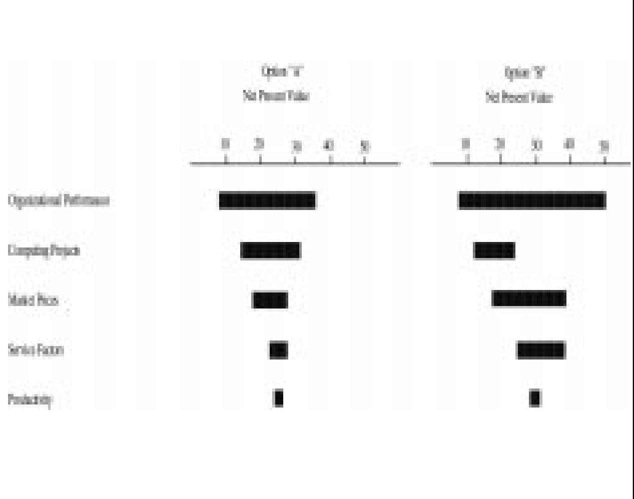

FIGURE 6: Tornado diagram.

no uncertainty, while a horizontal line indicates extreme uncertainty.

Tornado diagrams (Figure 6) demonstrate the impact of key risk variables contributing to uncertainty in the project. Each risk variable is, in turn, set at the assessed P_{10} and P_{90} range while all other variables are set at their expected values. The model is then run to determine the range in outcomes for each variable range. The results are then ranked in descending order with variables contributing the most uncertainty appearing at the top of the diagram.

Weyburn Risk Analysis Model

The Weyburn risk analysis model was constructed using an integrated suite of technologies and software packages. A Microsoft Excel spreadsheet application and @Risk, an add-on package to Excel, were used to model the project.

MS Excel[7] is an application used by most members of the project team. With this tool, the algorithms could be investigated by the team, thus reducing the “black box” syndrome. This adds to the credibility of the model and acceptance by the project team.

Due to the complicated nature of “rolling-out” the individual patterns in the EOR flood, a set of functions were written in “C” programming language and saved in a dynamic link library (DLL). These functions are called by the spreadsheet as required.

@Risk[8] is a separate software package which facilitates a Monte Carlo analysis. In a simulation, a number of outcomes are calculated and recorded. Each of these outcomes is a product of an iteration, where each variable is randomly assigned a value from its discrete probability distribution. The outcomes can then be analysed to determine the probability of a specific result.

The model is designed to function in three modes. The base case mode has all the risk variables set at their base values. The variables have no impact on the calculation and the single point estimate for the project is calculated.

In the sensitivity mode, each variable is set at its expected value. The calculated project outcome approximates the result of the Monte Carlo analysis. The sensitivity of each variable can be tested by changing its value and observing the change in the project outcome.

In the probability mode, the analysis uses a Monte Carlo simulation to calculate the range of possible project outcomes in order to measure the project’s performance in a number of different environments.

Base Case Assumptions

The term “base case” is used to describe results calculated using all of the base estimates for schedule, production, capital and operating costs. The base case contains a number of assumptions which reflect the current project design and can be tested by the risk analysis model. The following assumptions were embedded in the Weyburn base case.

- CO_2 pipeline capacity – 4,000 Tne/d
- Minimum CO_2 contract volume – 3,000 Tne/d
- Recompression facilities – central or satellite
- Recompression facilities – process 4,000 Tne/d
- Initial field injection capacity – 6,000 Tne/d
- Venting of excess CO_2 – minimized

Production Profiles

The base case estimates for oil production, and CO_2 injection and reproduction were developed using pseudo-miscible and compositional model studies. A series of parametrics were run incorporating symmetric 9-spot (80 acre spacing) patterns in a line drive injection configuration with two horizontal production wells per pattern. The key variant between the two modelling techniques was the fact that the pseudo-miscible models assume no mass transfer between CO_2 and the reservoir fluids, while the compositional models incorporated 100% mass transfer effects. In general, results from the pseudo-miscible models showed higher CO_2 recovery and lower oil recovery when compared to the compositional models.

Using each modelling technique, eight pattern production-injection profiles were developed for shoal and inter-shoal depositional environments[1] and for two reservoir fluid pressure-volume-temperature (PVT) regions. These PVT regions represent distinctly different CO_2-oil interaction characteristics that exist in the EOR area. These regions were experimentally established in the laboratory[9]. PVT region 2 had a minimum miscibility pressure (MMP) of approximately 14.4 MPa while PVT region 3 has a MMP of approximately 13.5 MPa.

The risk model subsequently combined the pseudo-miscible and compositional model profiles assigned to each pattern into one representative profile based on a weighted percentage of mass

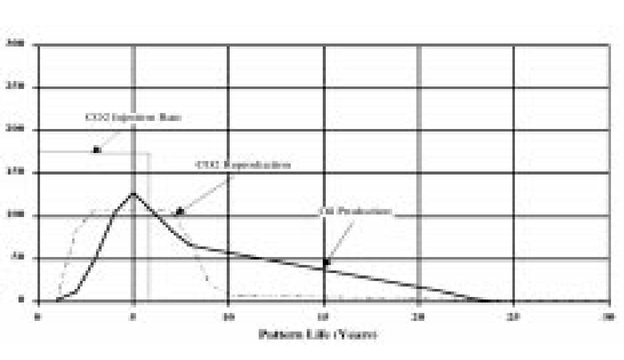

FIGURE 7: Combined production model – shoal pattern in PVT region 2.

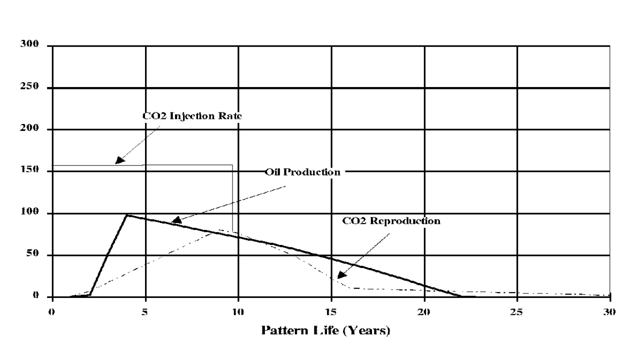

FIGURE 8: Combined production model – intershoal pattern in PVT region 2.

transfer specified by the team through a "mass transfer" risk variable. The base case used a weighted profile incorporating 20% of the pseudo-miscible and 80% of the compositional model results. Examples of these "adjusted" profiles are illustrated in Figures 7 and 8 for a shoal and inter-shoal pattern in PVT region 2, respectively.

For each pattern type, the planned recovery (area under the profile) and the peak production rate (height of the profile) were determined. The area, height, and gas breakthrough duration were subsequently adjusted by reservoir and production risk variable assessments provided by the experts to calculate "risk adjusted" pattern profiles.

A roll-out schedule is calculated which accumulates total oil and gas production, gas injection and CO_2 purchase profiles based on pipeline capacity, pattern firing order, and the size of the field to be developed at any one time.

Pattern and Facility Cost Matrix

Pattern development and tangible capital costs were scheduled according to the base case roll out schedule.

Facility costs were developed by Optima Engineering and Constructors who looked at facility requirements to provide recompression, water treating, emulsion treating, and gas processing for the base project assumptions. These costs were then adjusted by cost and schedule risk assessments, as well as through decisions on CO_2 purchase and injection capacities and plant configuration.

Detailed estimates for compression and pattern facilities are presented in Table 1.

Project Schedule

The base case schedule sets the timing for pre-project activities and the construction of field and plant facilities. The following time estimates were used to allocate pre-project expenses, initial capital costs, and injection start date.

Conceptual approval	1994 – 10
AFE date	1996 – 07
Construction complete	1998 – 07
Commissioning start	1998 – 04
Start of injection	1998 – 07

The base case schedule indicated two years were required for pre-AFE engineering, environmental and regulatory approvals.

Decision Analysis

The risk analysis model was used to test the six design criteria identified by the project team and to calculate the probability distribution of the results. These design options had associated risks which directly affected project results. These 73 risk variables were grouped into 9 conditioning, 14 schedule, 15 production, 12 economic, 11 capital and 12 operating cost categories.

Table 1: Centralized and de-centralized base capital (MM$).

Initial Phase In:	**Centralized**	**De-centralized**
Plant Upgrades	13.95	13.95
Satellite Compression	52.60	70.14
Pattern Hookups	14.50	17.74
Pattern Tangibles	14.05	14.05
Total:	**95.10**	**115.88**
PROJECT EXPANSION:		
Pattern Development	36.45	36.45
Satellite Compression	0.0	112.18
Pattern Tangibles	93.94	93.94
Pattern Hookups	103.35	88.94
Total:	**233.74**	**331.51**

When the design sizes are changed, capital and operating costs are adjusted using appropriate scaling factors. By progressively changing the base case design parameters and recording the results, the risk model was used to develop an "optimized design case." The following steps established the combination of plant configuration and pipeline capacity which produced the highest value for the project:

Step 1 – set initial plant compression capacity at 2,500 Tne/CD, which is the minimum size recommended by the design engineers. This is equivalent to an ultimate capacity of 3,800 Tne/CD (2,500/0.65).

Step 2 – vary field injection capacity and test various pipeline capacities to develop a maximum NPV. This indicated that a maximum field injection capacity of 8,500 Tne/CD provided the best result. The pipeline capacity was then varied to develop an optimized initial delivery rate. This process indicates that a pipeline delivering 6,000 Tne/CD would improve project returns.

Step 3 – confirm initial plant capacity by varying its size, setting field injection at 8,500 Tne/CD and the pipeline capacity at 6,000 Tne/CD. The 3,800 Tne/CD capacity yielded the best combination of net present value, rate of return and lowest capital cost.

The optimized project is summarized as follows:

- CO_2 pipeline capacity – 6,000 Tne/d
- Minimum CO_2 contract volume – 4,500 Tne/d
- Recompression facilities – Central
- Recompression facilities – 3,800 Tne/d
- Initial field injection capacity – 8,500 to 9,000 Tne/d
- Venting of excess CO_2 – minimized

The centralized plant configuration was confirmed as the preferred option as it provided a higher return on investment than the de-centralized case. This design option will be presented in the remaining sections of this paper.

Risk Assessment Results

A probability analysis was run to investigate the effect of the risk variables on production, costs, schedules and fiscal terms as established by "the experts."

Oil Production

Figure 9 represents the probability distribution for oil production, showing a high degree of uncertainty in this variable. The main cause for this result arises from the uncertainty in original oil in place and expected incremental recoveries assessed for each pattern. Upside potential is significant, which is indicated by the area under the straight line between the P_{mean} and the P_{90} value on the cumulative probability curve. The corresponding P_{10} and P_{90} range in incremental recovery is 13.5% to 21.0% of the original

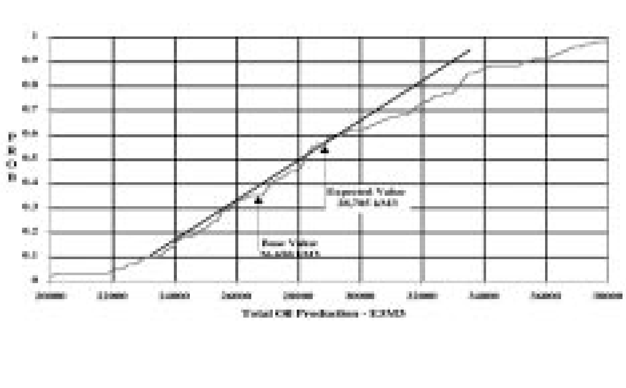

FIGURE 9: Optimized total oil production volume.

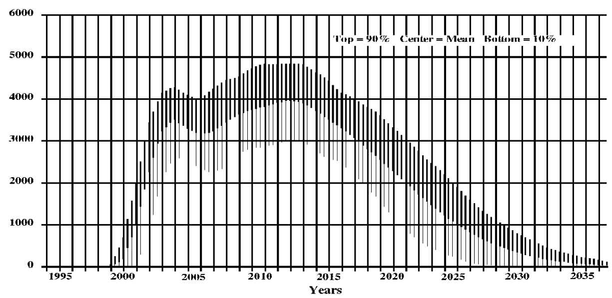

FIGURE 10: Optimized incremental oil production profile.

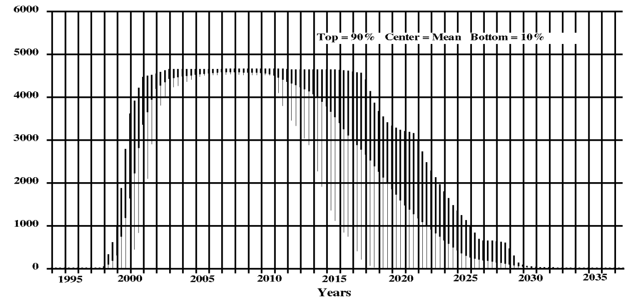

FIGURE 11: Optimized gas injection profile.

oil in place, respectively, with a P_{mean} value of 17.0%.

Oil production is influenced by reservoir and flood operating parameters, and is independent of project configuration. Figure 10 shows the annual oil production profile with its P_{90} and P_{10} probability range. As patterns are added to the limit of the injection capacity, oil production is maintained. Production levels diminish after 15 years since no additional patterns are added after the 65th pattern.

CO_2 Use and Consumption

The risk model was used to investigate the expected performance of the flood in the areas of gas injection and CO_2 purchase requirements.

A gas injection profile, Figure 11, was developed which showed the effect of the field injection capacity constraint and the considerable uncertainty around the duration of gas injection, with a range of 19 to 30 years.

The annual CO_2 purchase volume profile, Figure 12, indicates an expected pipeline operating life of 26 years, with a range of between 15 to 27 years. The rate of purchase is fairly constant since optimized field injection and pipeline capacity control demand and delivery rates. The timing of CO_2 purchases is influenced by the uncertainty in slug size, the breakthrough duration, and CO_2 recovery rates.

Gas Utilization

The efficiency of the flood can be measured by calculating a CO_2 utilization factor. The risk from reservoir losses can result in poorer production performance and can ultimately affect the profitability of the project. This factor is calculated by dividing the total volume of gas injected by the total oil produced. The literature[3] indicates most reservoirs flooded with CO_2 expect utilization factors ranging between 8.0 to 17.0 MSCF/BBL. The higher the number, the less efficient the flood.

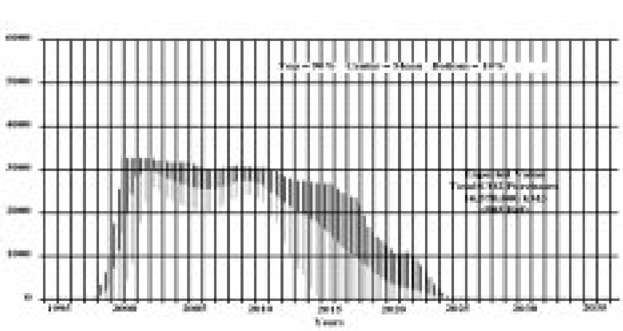

FIGURE 12: Optimized CO_2 purchase profile.

The risk model results indicated that the expected gross gas utilization per barrel of oil produced would be 6.2 MSCF/BBL, which is less than the base case value of 7.5 MSCF/BBL (Figure 13). The expected higher oil recoveries and smaller CO_2 slug sizes predicted by the risk model are attributed to the lower gas utilization per barrel factor, and indicates a more efficient flood is expected than represented by the base case production models.

Project Schedule

The optimized results (Figure 14) indicate an expected delay in project start-up, primarily because of delays in the front end process leading to major expenditure approvals (AFE). In house "conceptual approval" is expected to be later than assumed in the base schedule. It is also expected that the negotiations with government regulatory and environmental agencies will take considerably longer than currently planned due to the potential importation of a U.S. CO_2 supply. Should a "Made in Canada" solution be

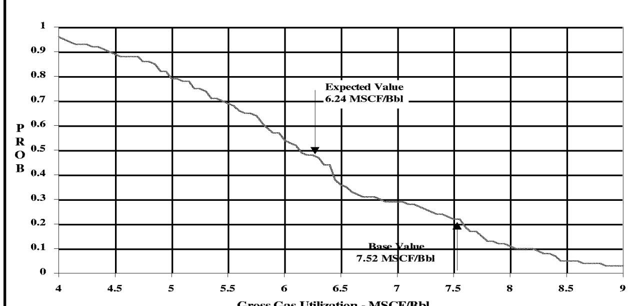

FIGURE 13: Gross gas utilization.

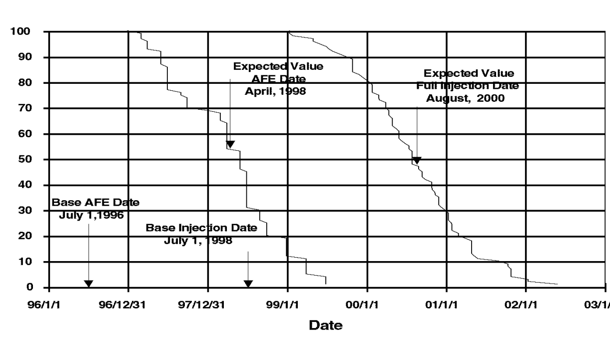

FIGURE 14: Project schedule.

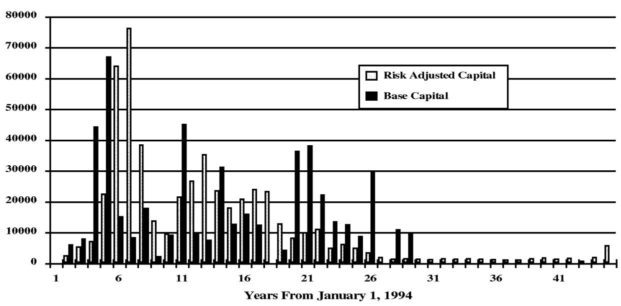

FIGURE 15: Capital expenditure profile.

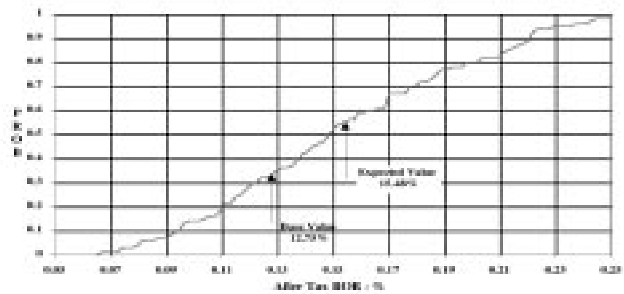

FIGURE 16: After tax rate of return.

TABLE 2: Project sensitivity measured through change in rate of return.

Risk Variable	Nominal Value	+1% Rate of eturn	-1% Rate of Return
WTI Oil Price ($US 1997)	19.40	+0.96	-0.92
Exchange Rate ($US/$CND)	0.82	-0.06	+0.07
Inflation Rate (%/YR)	3.00	+1.0	-1.0
$C0_2$ Copst ($US/MCF)	1.15	-0.12	+0.15
OOIP (E^6M_3/pattern)	2.67	+0.20	-0.28
Shoal Recovery (% of OOIP)	17.7	+3.5	-3.5
Shoal Prod. Rate (M3/D)	174.0	+34.0	-30.0
Surtax on Gross Revenue (%)	3.6	-1.78	+1.72

found to supply CO_2 to the project, the delay to start up of the project may be mitigated.

Capital Costs

A comparison of the base case capital and the risked capital annual expenditures (Figure 15) shows a shift in the schedule which is attributed to the front end delays in the project approval process. It is anticipated that capital expenditures will escalate faster than the general economy during the first phase of construction.

Unlike typical mega-projects with high initial capital requirements, the optimized design leads to the distribution of capital costs over many years, by phasing in facility capital and adding patterns only when required. The optimized project design accelerates and smoothes out the capital profile.

Project Economics

An economic component was incorporated in the risk model to enable the project team to evaluate the impact of the current regulatory and tax structure on the project. Fiscal “switches” embedded in the model allowed the project team to change the absolute values for royalty, tax rates and other EOR regulatory components in order to evaluate the effects on project returns. For the purposes of this paper, rate of return and cash flow will be discussed in detail while net present values will be discussed in general terms.

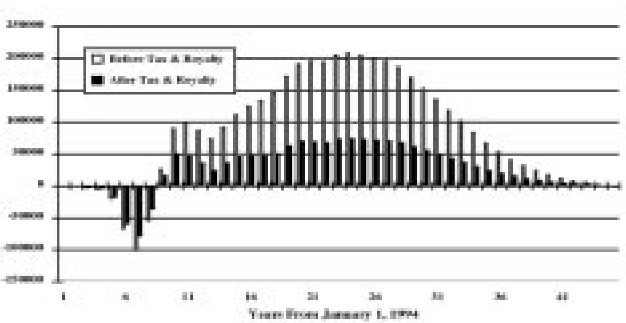

FIGURE 17: Cash flow.

Rate of Return

The distribution for rate of return (Figure 16) indicates an expected value of 15.5% and a 10/90 range of 9.5% to 22%. There is an 85% probability that the rate of return will be above 10%.

Cash Flow

The before tax and after tax cash flow (Figure 17) indicates a positive trend by the year 2002. Lower cash flows in 2005 – 2007 reflect the construction of the second phase of the recompression plant. In addition, revenues fall off slightly as initial patterns phase out just before new patterns come fully on stream.

The extent of the project’s contribution to provincial and federal income is well illustrated in this cash flow profile. The project team very quickly identified that a strategy had to be formulated to ensure that all of the project stakeholders shared equitably in the project.

Sensitivity Analysis

The major contributors to project uncertainty can be graphically represented using tornado diagrams. The use of these diagrams help to illustrate the key uncertainties of the project and provides a relative measure of their influence on expected project performance and economic viability. Even though the risk assessment process reviewed risk variables in market, production, CO_2 costs, capital costs, operating costs and schedule categories, only the first two categories will be discussed.

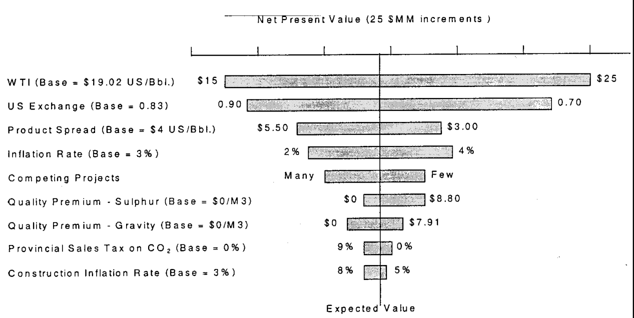

FIGURE 18: Market contributors to uncertainty in NPV.

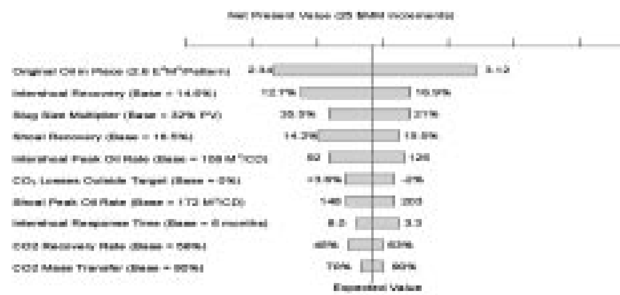

FIGURE 19: Production contributors to uncertainty in NPV.

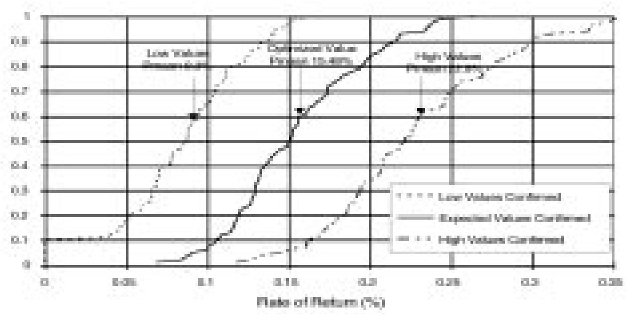

FIGURE 20: Impact of production risk variables - range of uncertainty.

Market Influence Tornado

Figure 18 presents a market tornado diagram showing the uncertainty range in oil prices, exchange rates, and light-heavy spread as well as the relative effect on the NPV of the project. This project, as with all projects, are highly affected by the environment in which it must operate. The project has been positioned based on a number of market assumptions and related ranges of uncertainties. The mitigation of market fluctuations is not in the control of the project team but the project is better understood in terms of these market influences.

Production Tornado

Figure 19 represents the production tornado diagram which indicates that most of the risk comes from uncertainty in the original oil in place, incremental recovery rate and the CO_2 slug size. The Midale CO_2 demonstration project may mitigate some of the uncertainty. If this project confirms the Weyburn production variables at 100% certainty of their expected values, the project would have the characteristics of the central probability distribution curve in Figure 20. The envelope of distributions demonstrate the impact if the demonstration project confirms the production variables with 100% certainty at their assessed P_{10} and P_{90} values. There is a negligible risk of the distribution being outside these ranges.

Another way of representing the effect of risk variables on project economics is through the use of sensitivity tables. Table 2 presents selected examples of project sensitivities in relation to a per cent shift in the rate of return measure resulting from a change in the identified risk variable.

Conclusions

1. The risk analysis provides an evaluation tool to develop a clear understanding of the project and its environment, to identify and document key risks, to improve communication within the team and to develop a strategy to mitigate risks to acceptable levels.
2. In an ever changing environment, the risk model answers “what if” scenarios allowing the project team to develop appropriate responses. It provides management the tools required to select projects with acceptable levels of risk.
3. For the Weyburn project, a number of potential delays to the base case schedule production start date of July 1998 were identified. A comprehensive monitoring program of major milestones from initiation to capital expenditure approval needs to be developed to maintain the schedule.
4. Project design and the balance between pipeline, installed recompression and injection capacities are important design decisions. The value of the project was significantly improved with an optimized design.
5. Negotiations with government and CO_2 suppliers must be initiated early in the project cycle in order to ensure favourable project returns to the Unit owners.
6. The uncertainty in oil recovery, slug size, CO_2 recovery rates, peak production rates, break-through response time, and CO_2 mass transfer could be further defined by the Midale CO_2 demonstration project.
7. The risk assessment and analysis process is continuous over the life cycle of the project, and is the centerpiece of a dynamic risk monitoring management process.

NOMENCLATURE

M	=	thousands
MM	=	millions
1 TNE	=	(metric tonne) 17.2 MSCF
AFE	=	approval of funds expenditure
P_{10}	=	on an upwardly sloping cumulative frequency distribution curve, a 10% chance exists that a value will be less that the P_{10} value.
P_{90}	=	on an upwardly sloping cumulative frequency distribution curve, a 90% chance exists that a value will be less that or equal to the P_{90} value.
P_{mean}	=	expected value on the cumulative frequency distribution curve is the average of all possible outcomes.

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Authors' Biographies

William Barnhart, a staff engineer with PanCanadian Petroleum Ltd. in Calgary, graduated with a B.Sc. in civil engineering from the University of New Brunswick in 1981. Initially with Mobil Oil Canada, he conducted reservoir studies on the Hibernia offshore project prior to joining PanCanadian in 1985. Since then, he has directed numerous reservoir studies, risk assessments, and property evaluations on both carbonate and clastic reservoirs in western Canada and internationally. He is currently a member of APEGGA, SPE, and the Petroleum Society.

Chris Coulthard, a senior consultant for CSC Project Management Services in Calgary, graduated with a B.A. (Honours) from the University of Guelph in 1986. His expertise is focussed on the application of risk analysis and computer modelling techniques to assist in strategic decision analyses for large-scale projects. Before joining CSC, he developed artificial intelligence applications for Canadian Pacific Ltd.