

Lost Dome Field Enhanced Oil Recovery Planning

Final Report

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PETE 4720 – Petroleum Engineering Design II
Final Report
Group #10
Project #5

The objective of this project is to choose an appropriate field and develop reservoir simulations to determine the optimal EOR scenario. This report provides a detailed project plan to complete said project objective. Work flows and Gantt charts are broken down and discussed in detail as well as the possible risks involved and their mitigations.

In addition to the main purpose of the report, further information and data on the Lost Dome Field and Tensleep Formation are provided to gain a better understanding as to why this field was selected for the purpose of this project as well as brief information on main EOR methods, reservoir modeling, and an economic evaluation.



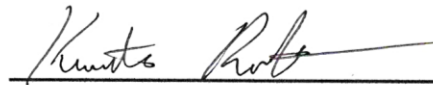
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EXECUTIVE SUMMARY

A project was selected from a possible list of six after careful consideration by each individual. The project description states that the team will select a field with sufficient data already available in the Enhanced Oil Recovery Institute (EORI) database and perform a reservoir characterization and simulation in order to develop an optimal enhanced oil recovery (EOR) scenario.

After review of potential candidates, the Lost Dome Field was selected. The Lost Dome Field consists of six producing oil wells, making it feasible for analysis by the team members in the time available. The field is located in the Wind River Basin in Wyoming and produces from the Tensleep Formation, which is a geological formation of Pennsylvanian to very early Permian age.

A workflow diagram was created to assist the planning process and to ensure the project objectives were satisfied. The project plan was divided into four phases. A Gantt chart was constructed to assist in the scheduling process. A risk analysis was also completed.

The team performed research in Phase I. Different EOR methods were researched and analyzed. Additionally, a preliminary screening was done to determine if certain EOR methods were applicable to the Lost Dome Field and Tensleep Formation. Reservoir modeling was also researched and different reservoir modeling softwares were examined.

Data was acquired from the EORI and reviewed by the team. The data consists of field information, well information, and reservoir properties. Specific findings from the data review will be further discussed in this report.

In the remaining phases, the reservoir characterization produced information such as average porosity, average permeability, and original oil in place. Integration of the static model, dynamic model, and the economic evaluation led to the final recommendation for CO₂ flooding.

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NOMENCLATURE

CMG – Reservoir simulation technologies provided by the Computer Modeling Group

CO₂ – Carbon Dioxide

EOR – Enhanced Oil Recovery

EORI – Enhanced Oil Recovery Institute

MS – Microsoft

NC – Not Critical

OOIP - Original Oil In Place

NCF – Net Cash Flow

NPV – Net Present Value

OCR – Optical Character Recognition

PETREL – Schlumberger owned exploration and production software

PI – Profitability Index

WOGCC – Wyoming Oil and Gas Conservation Commission

1. INTRODUCTION

1.1 INTRODUCTION TO PROJECT

Petroleum Engineering Design I (PETE 4720) is a senior design course that is part of the petroleum engineering undergraduate curriculum at the University of Wyoming. The course description states that students will participate in the design and development of petroleum reservoirs using principles and skills learned in the Petroleum Engineering program. Also, students will be involved in the application of software for design and analysis of the drilling, reservoir and production of petroleum fields. Petroleum Engineering Design I represents the first part of two -capstone design courses with the second course being Petroleum Engineering Design II (PETE 4735). The goal of the course is to have students apply the knowledge and skills gained from previous courses to relevant, real-world projects. The Design I course is focused on the planning and scheduling of the project and will include environmental, economic, health, and safety aspects.

The critical aspects of a successful senior design project were studied. A project was selected from a possible list of six after careful consideration by each individual. The project description states that the team will select a field with sufficient data already available in the Enhanced Oil Recovery Institute (EORI) database and perform a reservoir characterization and simulation in order to develop the optimum enhanced oil recovery (EOR) scenario. In order to meet the project objectives, reservoir modeling will be used to create static and dynamic models. The static model will accomplish the reservoir characterization objective. A dynamic model will be used to compare the results of different EOR methods. The optimum EOR scenario will be based on the dynamic model simulation results and an economic evaluation.

The Lost Dome Field was chosen by the team after a review of potential fields because of its small size making it manageable by a small team. The Lost Dome Field consists of six producing wells and two wells that have been permanently abandoned. The total number of wells made the Lost Dome Field a good fit for the team as the data analysis would not be overwhelming. Additionally, the time constraint of one semester for data analysis required a smaller field to be selected. The Lost Dome Field produces from the Tensleep Reservoir, which consists of sandstone with few carbonates and shale. The Tensleep is the largest oil producing formation in Wyoming.

The team has also performed research on different EOR methods. The methods of EOR that were researched include: miscible CO₂ flooding, chemical flooding, and thermal flooding. Additionally, a preliminary screening was done to determine if certain EOR methods were applicable to the Lost Dome Field and Tensleep Formation. Characteristics such as depth,

formation type, and the specific gravity of the produced oil were examined in the screening. Reservoir modeling was also researched and different reservoir modeling softwares were examined. The focus of the reservoir modeling research was to differentiate between static and dynamic models.

The first semester of the Senior Design course focused on planning and scheduling. . A workflow diagram was created to assist the planning process and to ensure the project objectives were satisfied. The project was divided into four phases. The first phase was dedicated to planning and scheduling. It included tasks such as project selection, field selection, creating a workflow diagram, creating a Gantt chart, performing research, risk analysis, and data acquisition. The second phase deals with the construction of a static model. The Petrel software will be used for the static model. Phase II tasks include formatting the data, inputting the data, and building the geological model and geophysical model. The focus of Phase III is the dynamic model. CMG (Computer Modeling Group) software will be used to construct the dynamic model. Phase III will be similar to Phase II, but an important task is history matching. If the history matching is not correct, the team will return to Phase II and edit the static model. If the history matching is correct, the team will proceed with the future production prediction. Finally, Phase IV will consist of economic evaluation and a final recommendation for the optimum EOR scenario.

Data was acquired from the EORI and reviewed by the team. The data consists of field information, well information, and reservoir properties. One potential issue concerning the data has emerged. Modeling software requires well log data in the form of LAS file format. The well log data that was obtained from the EORI contains only images of the log files. Another potential issue may be data insufficiency. Because of these issues, the team plans to contact the operator of the Lost Dome Field, Everest Oil and Gas, LLC. While the project objectives can still be achieved without the additional data, it will definitely improve the accuracy of the models and make the project more feasible for the team.

1.2 PROJECT SELECTION

Once the group was formed, each group had the option to pick between 6 different projects provided by the mentors. After collaborating amongst the group, project 5 was selecting based on the team members' area of expertise.

1.2.1 PROJECT OBJECTIVES

The objective of this project is to select a field with sufficient data already available in the Enhanced Oil Recovery Institute (EORI) database and perform a reservoir

characterization and simulation in order to develop the optimum EOR scenario. These simulations will be done using PETREL and CMG software to generate a static and a dynamic model of the chosen field. In this case, the Lost Dome field in the Tensleep formation was chosen due to the fact that there are only six wells to be studied. There are also an estimated four million barrels of oil in place left in the Tensleep formation, making the field a potentially good candidate for enhanced oil recovery (EOR).

2. BACKGROUND

2.1 LOST DOME FIELD

Lost Dome is the field that was picked in Wind River Basin. Wind River Basin, located in central Wyoming, is large sedimentary and structural basins that formed in the Rocky Mountain region during Laramide deformation. Lost Dome oil field was first developed in 1998 and it is still producing today. The oil production reached its peak in 2001 and has been decreasing yearly. The cumulative production up to March 2016 is 1,670,454 barrels of oil.

2.2 TENSLEEP FORMATION

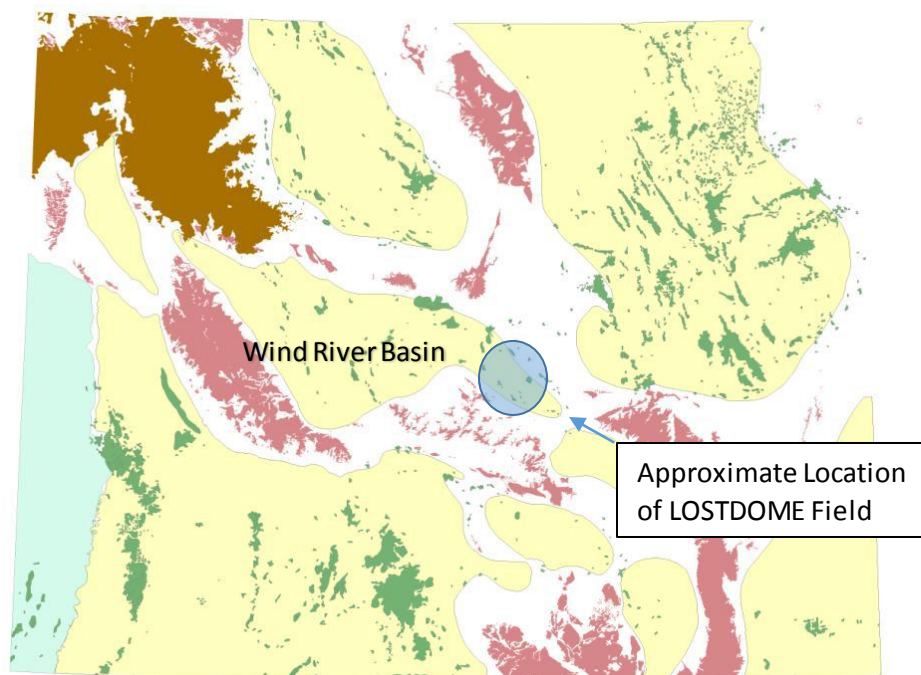


Figure 1 - The map of the Tensleep Formation in Wyoming and location of Wind River Basin

The Tensleep formation, located in Wyoming, discovered in 1928, is the largest oil producing formation in Wyoming. The main rock type of the formation is sandstone with some carbonate and shale. Up to 2011, the cumulative oil production was 1.6 billion barrel, which takes up 23% of the cumulative oil production in Wyoming. 5.6 million barrels of oil produced in 2010 with 98%. More than 4 billion barrels of oil may exist in the residual oil zone. Thus, Tensleep formation has large potential within EOR methods to produce.

Tensleep formation has specific characteristics, such as a large range of oil API gravities and various wettability depending on reservoir oil and rock properties.

2.3 PROJECT STAKEHOLDERS

The term “project stakeholder” refers to an individual, group, or organization, who may affect, be affected by a decision, activity, or outcome of a project. For the senior design project, multiple stakeholders can be identified. First of all, the project team is a major stakeholder. The project team will have the most control of the final outcome of the project, but there will be other stakeholders that have influence as well. The project sponsor has been identified as Dr. Brian Toelle. Dr. Toelle is the team’s project sponsor as well as the team’s mentor. The project management team consists of Dr. Brian Toelle, Dr. Xeubing Fu, and Professor Kenneth Baum, all from the University of Wyoming. The Enhanced Oil Recovery Institute at the University of Wyoming is also a project stakeholder because of the EORI’s ability to affect the project by assisting the team and providing data. Also, the final outcome of the project may affect the EORI since the team will share information with the EORI. Similarly, Everest Oil and Gas, LLC, can be considered a project stakeholder for the same reasons.

2.4 OVERVIEW OF EOR

There are three stages of oil field development. The first stage is primary recovery, during which the oil is forced out by pressure. In secondary recovery, water flooding or gas injection is used to maintain the pressure that continues to move oil to the surface. The last stage is tertiary recovery, also known as enhanced oil recovery, introducing fluids which could consist of gases that are miscible with oil (typically carbon dioxide), steam, air or oxygen, polymer solutions, gels, surfactant-polymer formulations, alkaline-surfactant-polymer formulations, or microorganism formulations.

EOR is significant to the oil field development. Primary recovery typically provides access to only 5%-10% of a reservoir’s total oil capacity. Secondary recovery techniques can increase productivity to a third or more. Tertiary recovery enables producers to extract up

to over half of a reservoir's original oil content, depending on the reservoir and the EOR process applied.

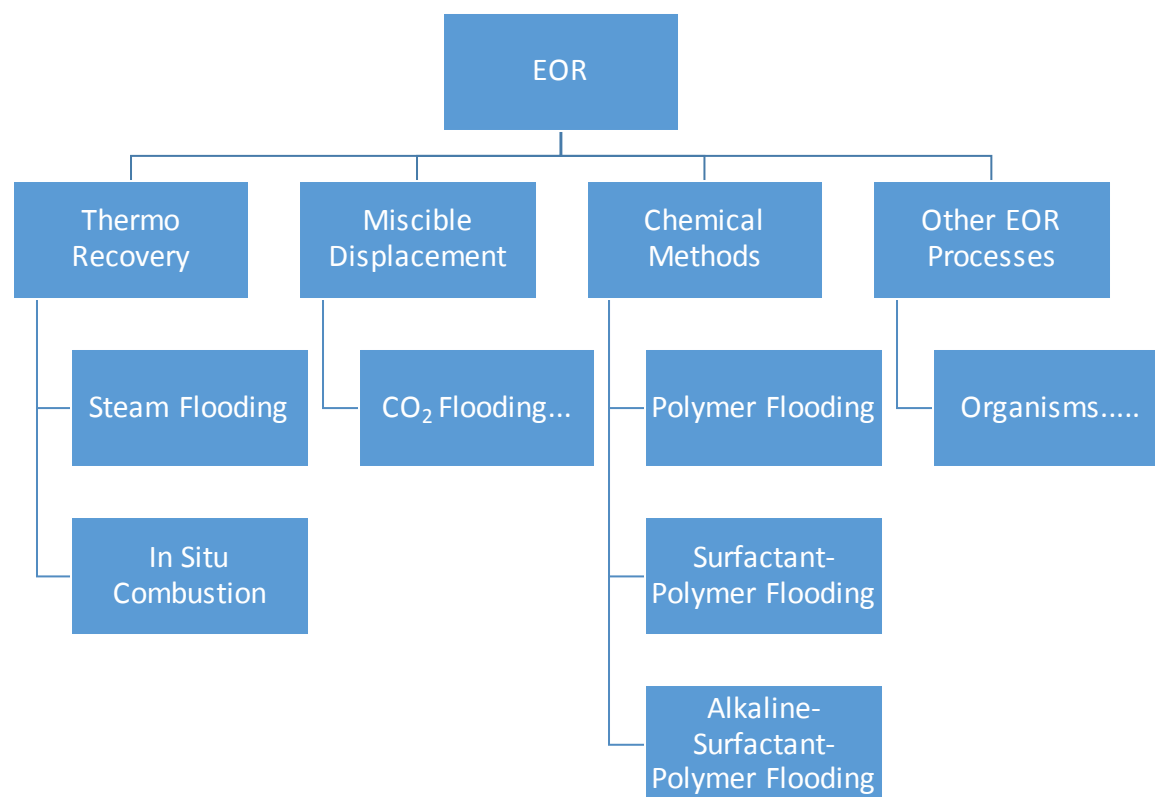


Figure 2 - The EOR methods structural graph

Referring to Figure 2, the first EOR mechanism is thermal EOR. The most typical one is the steam flooding. The hot temperature of steam can reduce the viscosity of the oil. Another way of thermal EOR is, in situ combustion or “fire flooding”. In this process, air or oxygen will be injected and the oxidation of some oil will produce heat and the heat will decrease the viscosity of the remaining oil.

The second EOR mechanism is miscible displacement. This method is always referred to supercritical CO₂ flooding to displace the oil. When at or above the critical point of pressure and temperature, supercritical CO₂ can maintain the properties of a gas while having the density of a liquid. Injected miscible CO₂ will mix thoroughly with the oil within the reservoir such that the interfacial tension between these two substances effectively disappears. CO₂ can also improve oil recovery by dissolving in, swelling, and reducing the viscosity of oil.

The third method utilizes chemical procedures. There are three kinds of chemical processes including polymer flooding, surfactant-polymer flooding and ASP flooding. In the polymer flooding, water-soluble polymers increase the viscosity of the injected water, leading to a more efficient displacement of moderately viscous oils. Surfactant can decrease the water-oil interfacial tension. For some oils, alkaline may convert some acids within the oil to surfactants that aid oil recovery. The alkaline may also play a beneficial role in reducing surfactant retention in the rock.

The last one is other EOR process such like microorganisms, foams, etc. But those methods still need to be well developed before used into the oil field development.

2.4.1 FEASIBILITY OF EOR METHODS

According to the data obtained so far, the API gravity of the oil produced in Lost Dome is around 24°. Average thickness of the pay zone is 275 ft. The depth of the Lost Dome oil field in Tensleep is 4,983 ft. The average temperature of the formation is 126.05 °F. The primary rock type is sandstone in the Tensleep Formation.

Flooding a reservoir with CO₂ can occur immiscibly or miscibly depending on several conditions (reservoir temperature, reservoir pressure, injected gas composition, oil composition). For the selected field, the API gravity is 24°, which makes it an applicable candidate since the criteria is API > 22. The depth of the reservoir is > 5,000 ft., which meets the criteria of Depth > 4,000 ft. with API gravities ranging from 22° to 27.9° (see Table 1). Oil saturation, composition of C₅ and C₁₂, and oil viscosity are yet to be determined.

Steam injection is beneficial in cases where the API gravity of the oil is between 10° and 20° API. In this case, the well is at 24° API; however, there are some cases where steam distillation can be an important recovery mechanism, so volatile high gravity crudes may still be a consideration for steam flooding. Other characteristics of a well that would benefit from steam injection include shallow depths less than 3000 feet or sand thicknesses greater than 30-50 feet for minimal heat loss and higher permeability of 500 md or more for the flow of more viscous oils.

From the summary table of the EOR methods, in terms of data that has been gathered, it can be determined that Polymer Flooding is a better choice than the ASP and Alkaline Flooding, since the reservoir property is over the range such like temperature and depth that ASP and Alkaline Flooding should fit.

Table 1 – EOR Method Criteria

EOR Method	Gravity (°API)	Formation Type	Net Thickness (ft.)	Depth (ft.)	Temperature (°F)
Miscible CO ₂	> 22	Sandstone or Carbonate	Wide Range	> 2,500	NC
MI cellar/Polymer, ASP, and Alkaline Flooding	> 20	Sandstone Preferred	NC	> 9,000	> 200
Polymer Flooding	> 15	Sandstone Preferred	NC	< 9,000	> 200
Combustion	> 10	High-porosity sand/ sandstone	> 10	< 11,500	> 100
Steam	> 8	High-porosity sand/ sandstone	> 20	< 4,500	NC

2.5 RESERVOIR MODELING

The project description states that a reservoir characterization and simulation must be performed in order to develop the optimum enhanced oil recovery scenario. Reservoir models will be necessary to carry out these processes. In the oil and gas industry, computer models are constructed for specific petroleum reservoirs. The constructed models allow for improved estimations of petroleum reserves and influenced decision-making regarding the development of an oil and/or gas field. Reservoir models can be constructed in the form of one dimensional, two dimensional, or three-dimensional. Furthermore, reservoir models are often defined as static models or dynamic models.

A static reservoir model is often referred to as a geological model. The main purpose of the geological model is to provide a static description of the reservoir, usually prior to production. Essentially, the static model will represent the structural framework of the reservoir. Analyzing and integration of well data and seismic data can produce the structural framework. The well data includes “tops” or the geological markers that indicate the depth of different subsurface formations. Seismic data can supplement the well data as well as provide information such as fault geometry. Figure 3 depicts an example of the process of combining well and seismic data in order to produce a structural model. The static model should also include petro-physical properties such as porosity, permeability, water saturations, and hydrocarbon saturations. The static model allows for a strong initial understanding of the reservoir and its characteristics.

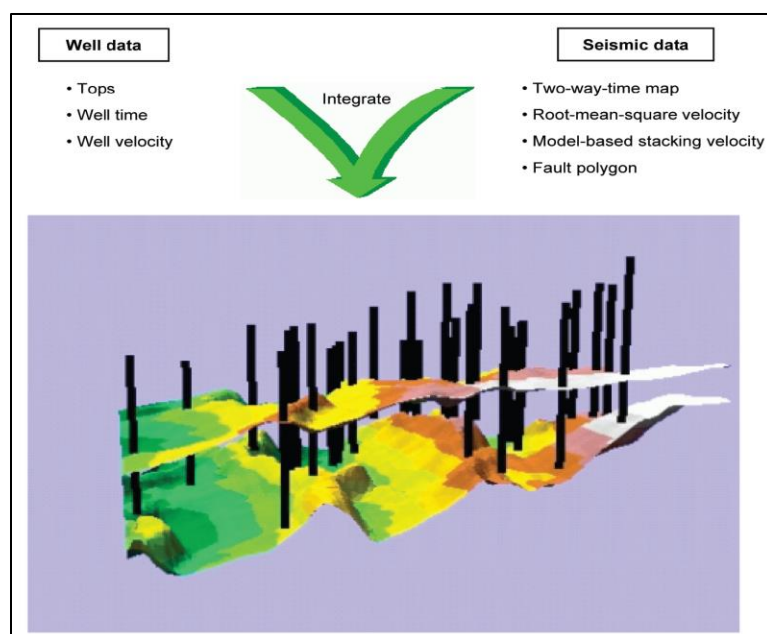


Figure 3 – Example of Integration of Seismic and Well Data

Once a static reservoir model is constructed, it can be used as the input for a dynamic reservoir model. Dynamic models simulate the flow of fluids within the reservoir throughout its production lifetime. The dynamic model is used to forecast ultimate hydrocarbon recovery on the basis of a given production scheme, or to compare the effects of different recovery methods. Modern models can build three-dimensional representations from single-well scale to full-field scale. Also, today's models can include natural fracture simulation and fault transmissibility's as well as saturation changes of the different phases (oil, water, gas) with respect to pressure depletion or maintenance. Dynamic reservoir models are very powerful tools in the oil and gas industry.

Many software programs exist that are capable of constructing static or dynamic reservoir models. There are some programs that will even do both. For this specific project, it has been decided that two different software programs will be used for the construction of a static and dynamic model. First, the static model will be built using Petrel, a Schlumberger owned exploration and production software platform that provides an integrated solution from exploration to production. Second, the dynamic model will be built using Computer Modeling Group (CMG) reservoir simulation software. These two programs were chosen because of their availability to petroleum engineering students at the University of Wyoming.

Using CMG as the software for the dynamic model, basic raw data such as geological maps, PVT data, core analysis, production data, and perforation/completion invents will have to be imported into Builder in order to complete the dataset which will be for IMEX. Using the builder software within CMG, we will have our data imported to run the black oil simulation known as IMEX. Converting the data to IMEX is validated and processed that will generate output graphic files. IMEX will create results in the 3D dimension, result graphs, and result reports to view the simulation output.

Potential issues that could be encountered while running the dynamic model would be a lack of data present. Without the consent of releasing data by Everest Oil and Gas, our data input is restricted to past production and field history shown on the Wyoming Oil and Gas commission website. This strict limitation might become a data hurdle for the future of this model and essentially the project.

3. PROBLEM STATEMENT

The following problem statement was given in the selection of project number 5:

Enhanced Oil Recovery Planning - For this project a team would select a field with sufficient data already available in the EORI database and perform a reservoir characterization and simulation in order to develop the optimum EOR scenario.

4. PLAN

4.1 PROJECT WORKFLOW

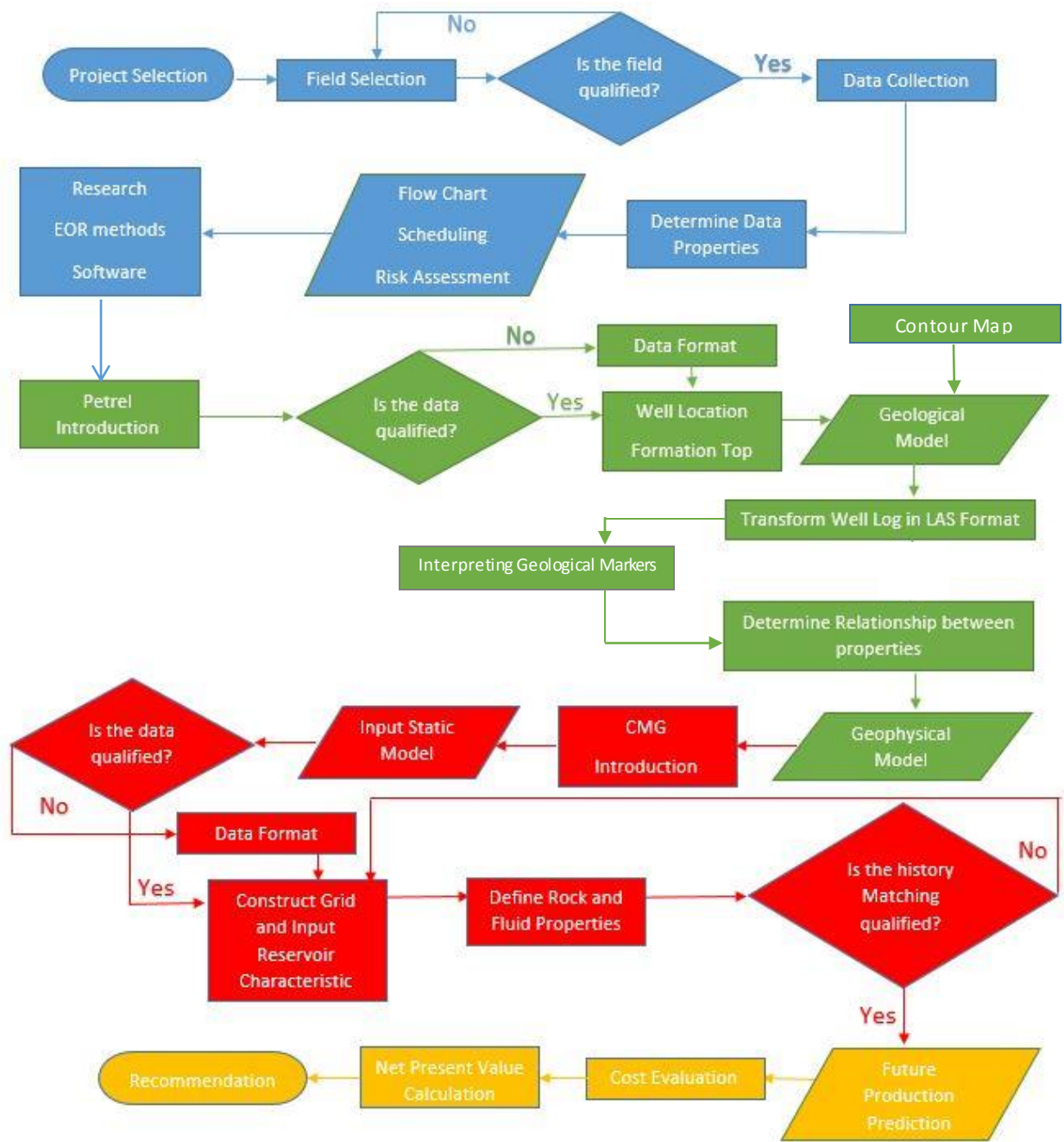


Figure 4 - Workflow Chart

A flow chart is a specific diagram with specific graphic symbol to describe the algorithm. A flow chart can be a technological process or a management process. At this point, a workflow will help with decision making, mediating mistakes, and planning. In this workflow, it is made known that the team planned to separate the project into four phases. In this project, Petrel will be used to build a static model and CMG to build a dynamic model. After obtaining the final model and predicting the future production, the team will give the stakeholders the final recommendation. By using different shapes for the components, the updated workflow distinguishes between project tasks, major decision points, deliverables, data sources, and the start and end of the project.

There are differences in the workflow within the phases when comparing to the workflow in the last report in terms of the addition of more specific tasks. Between the geological model and geophysical model, transforming the well log data into an LAS file and determining the relationship with properties have been added. A change also happened between the second and third phase. If the history matching is not accurate, the group will check the reservoir characteristic and rock and fluids properties instead of going back to phase two to check the static model. The reason is that the given well data and well log data are accurate. Checking the accuracy of the static model is not an effective way to check the history matching or the fit of the water production and oil production curve.

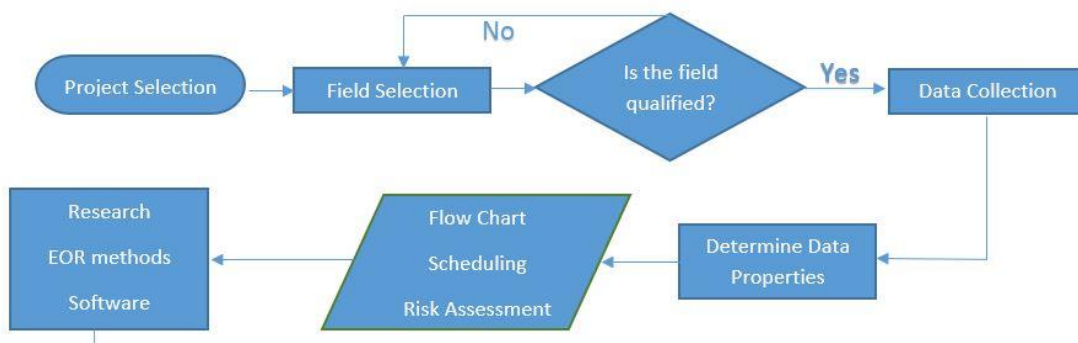


Figure 4a - Phase I in the flow chart

The first phase is shown above. The main purpose of the first phase is to do the project planning. The group finished all the tasks in the first phase and show the tasks in the Lost Dome Field Enhanced Oil Recovery Planning Report submitted in December, 2015.

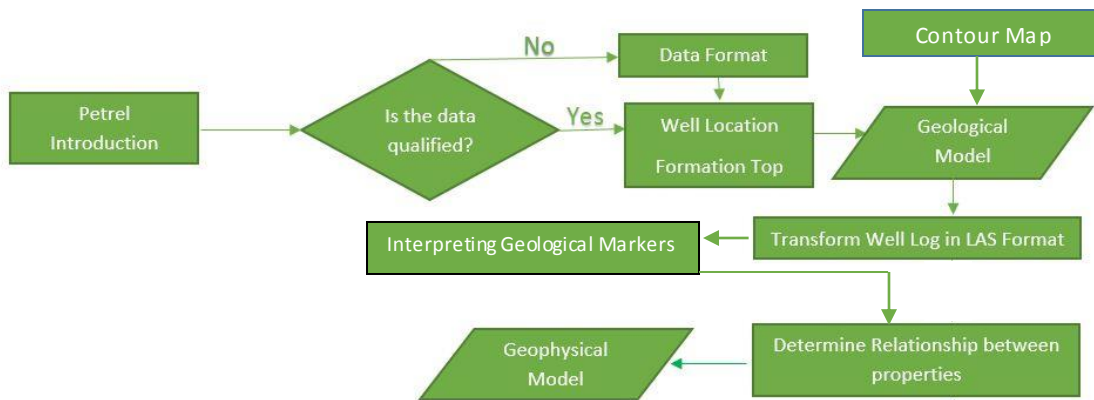


Figure 4b - Phase II in the flow chart

In the second phase, the main goal is to build a static model, especially a geological model and geophysical model. In this phase, the group has finished the geological model.

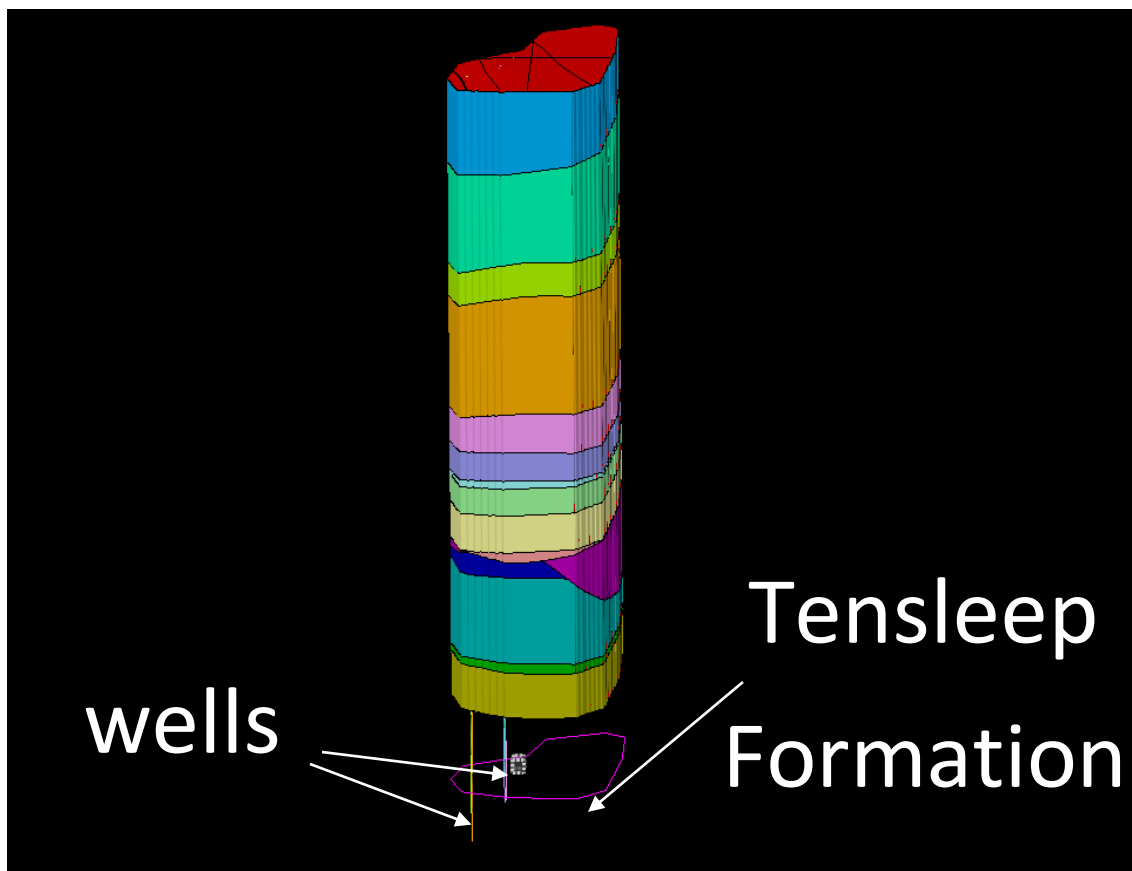


Figure 5- Horizon Tops for Lost Dome Field with Petrel

In Figure 5, the geological model is shown. The Tensleep Formation is identified as well as the six producing wells. The well location and formation top data collected in the first phase was used to finish the geological model.

The next step in phase two is to transform the well log data into LAS file. The well log data from Wyoming Oil and Gas Conservation Commission is in pdf format, which is not a qualified format for Petrel. In order to transform the well log data from pdf file to LAS file, the group contacted Neurolog and are trying to use their software to transform the data. The LAS file will then be input into Petrel. With that, the group can build our geological model with geophysical properties. For instance, gamma ray log and density log can show the information about the formation rock type and porosity respectively. Additionally, in order to have a better understanding of the future injector location, the permeability of the formation will also be acquired. The group still needs to find the best relationship between the permeability and porosity in the specific area in Lost Dome Field. The geophysical model will include the properties such like porosity, rock type, permeability and water saturation.

The third phase starts with the introduction of CMG. In the third phase, the purpose was to build a dynamic model and make a production prediction. First, the static model was uploaded into CMG. After that, the process is similar to that in phase two. The team determined the grid size and reservoir characteristics. The rock type and fluid type will also be determined. The important part is the history matching. History matching is an important standard to measure the accuracy of the simulation. The History matching includes initial reservoir pressure, original oil in place, water production curve and oil production curve. The history matching for our reservoir was very incorrect and could not be used due to the lack of data on the field. So the reservoir simulation had to be abandoned. Fields similar to ours were researched in order to obtain results of what a CO₂ flood on our field would most likely produce.

The fourth phase was to conduct an economic evaluation to determine the feasibility of an EOR operation on our field. Certain financial factors such as gross and operating revenues, operating expenditures, depreciation, tangible and intangible drilling costs, loss forward, taxable income, and different types of net cash flows were used to determine the viability of a CO₂ EOR project.

4.2 PROJECT SCHEDULE

Lost Dome

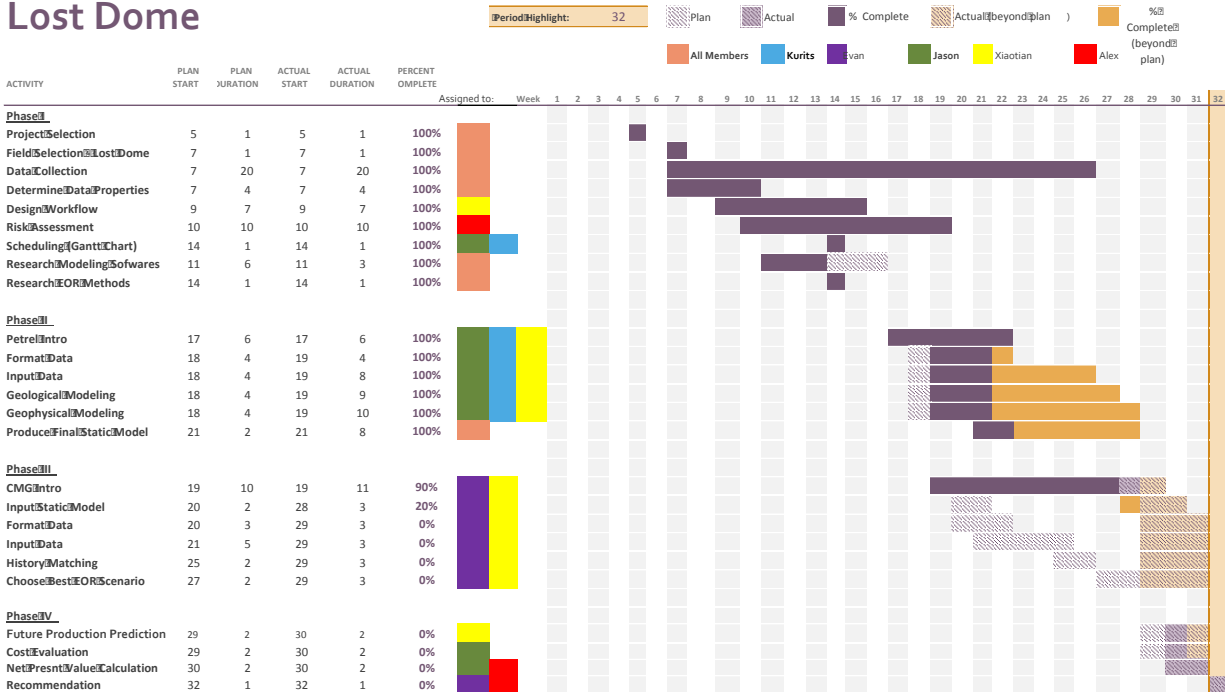


Figure 6 – Gantt chart

Project scheduling is very important to the success of an operation. It ensures duties will be done in an organized manner and gives adequate time to complete each task. For the project, the team used a Gantt chart to represent the project schedule. The Gantt chart is similar to the workflow in that the tasks and phases are consistent. The workflow does not include dates or the duration of certain tasks, which is what makes a Gantt chart more useful for scheduling, as it includes these aspects.

The Gantt chart schedule is organized on a weekly basis. Scheduling a several month project day by day would be too specific for the team’s current level of experience. To be consistent with the workflow diagram, the schedule is split into four phases. The dates of this schedule are certain to change slightly, however the goal is to follow the plan as closely as possible. Very little is known about the future aspects of the project, so keeping the plan simple is important.

Phase I of the project is completed. It entailed the first semesters' tasks and deliverables. Some tasks were assigned and due at specific dates while others were tasks the team members thought necessary to complete. As you can see in Figure 6, the task of Data Acquisition overlaps with following phases. This is because as the team works with softwares to construct models, more data will be required. Most time in this phase was used to learn effective planning strategies rather than working on the project itself.

The deliverable from Phase II is the output of a static model of the reservoir. All throughout this phase, the team will be learning about Petrel, the software that was chosen based on the fact that an introductory course will be offered. Started inputting data as soon as possible because we will undoubtedly run into complications with this software and be required to learn more about it in order to remedy the complications. As shown in Figure 6b, the dates have been pushed back due to the inability to get LAS files for the logs. Neuralog has been used to convert the image logs to LAS format. This phase also overlaps with the next phase. The static model has been finished, so this phase is complete.

Phase III is very similar to Phase II. The large deliverable from this phase is to complete a dynamic model. CMG has been chosen as the software for this deliverable based on the same reasons Petrel was chosen to design the static model. As you can see from Figure 6c, this phase has a few more tasks that will need to be completed. The team anticipates this software will be much more involved than that used in Phase II. All data acquisition (starting in Phase I) should be completed near the end of Phase III. Evan has been learning about CMG in to get the dynamic model started. As you can see in Figure 6c some tasks have been pushed back due to complications in Phase II. The team is currently having problems with importing the static model into CMG.

The final phase of the project is Phase IV. It takes up the final three weeks of this semester. As you can see in Figure 6d, there are just four tasks. By the start of this phase, all other deliverables should be produced, and all other tasks completed. This phase is for the team to assess the economic considerations based on the results of the models as well as making sure all aspects of project are presentable, accurate, and reasonable. Essentially, three weeks will be required to make sure the models are sufficient and to add or refine any information necessary.

Kurtis, Tim, and Jason were responsible for most of the work done in Phase II since they were available to attend the introduction to Petrel. Evan took the lead on Phase III with assistance mainly from Tim. Since Phase III was the most involved, team members assisted when they could. Jason did the majority of Phase IV.

5. RISK ANALYSIS

Risk Analysis is a systematic process for identifying and evaluating the procedures that can influence the objective of the project.

According to the project, the followings are five main potential risks and their mitigations:

Data inaccuracy: In this project, the first important task for us is to build the static model, geological model. In order to build the model, the data that is needed includes the well information, well log data, seismic data, etc. The potential risk we could meet would be the inaccurate format of the data and at this time the group is facing the risks as predicted. The geological model is finished, but because of the absence of LAS file, the group is trying to contact Neuralog and use the software to transform the well log data from pdf format to LAS format to build the geophysical model.

Data insufficiency: Before we identified that we may have insufficient data such like insufficient well log or seismic. So far the well log data is enough. The role of seismic data in this project is to determine the existence of the fault and the location of the fault. According to the information from the judges and mentor, the determination of fault is not necessary. So far the data insufficiency problems have not influenced the project too much.

Unfamiliarity of the software: In this project, the software is fundamental. So far, according to Petrel Introduction from Matthew Johnson from EORI and CMG Introduction from Dr. Fu, the group has got rid of most of the unfamiliarity of the software.

Disagreement of the stakeholder: Every project has stakeholders. In this case, the stakeholder is the team's mentor, Dr. Toelle. The disagreement of Dr. Toelle may give the group disappointment. Last semester, lacking of important components in the workflow and inconformity between workflow and Gantt chart were the disagreements from the stakeholder. This semester, falling behind on schedule or producing an inaccurate model will also cause other disagreements from the stakeholder.

Safety of group members: Good health of group member is the basic prerequisite for the project. Although one of our previous member left because of the course problem, the group had another new member and the group is going to work well.

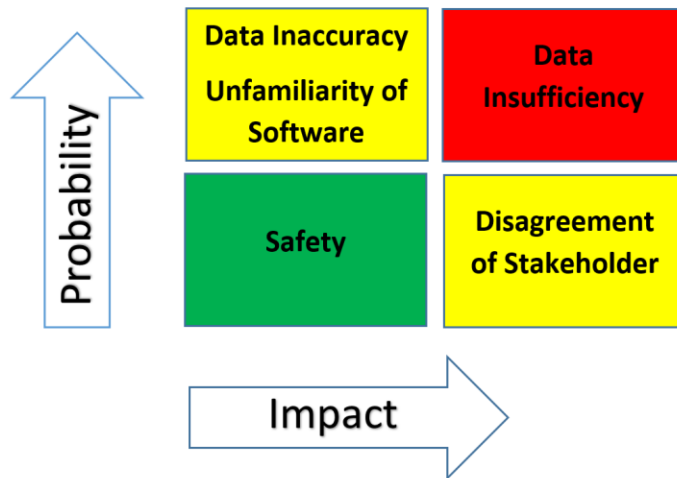


Figure 7 - Risk Chart

The risk chart is used to evaluate the probability and impact of the risks to the whole project. In this chart upper right box means high impacts on the project. The bottom right and upper left box means the risk will have moderate impact on the project. The lower left box shows that the risk can have little impact on the project. As we predicted, the data insufficiency became the biggest problem and caused our project to fall behind schedule before completing phase IV.

6. DATA REVIEW

The team was provided with an excel workbook containing various well information from the EORI for the wells in the Lost Dome field. With this information, API numbers, locations, well status, well top data, production data, and reservoir properties were obtained. With further research into the EORI and Wyoming Oil and Gas Conservation Commission websites, images of the well logs, in jpeg form, were obtained. This data is all pertinent to the creation of the static and dynamic models; however, we are lacking buildup or drawdown tests as well as the LAS files for the well logs. This additional data will aid in the completion of the static and dynamic models required for this project. As mentioned in the risk analysis, without the required data, the project could fail.

7. PROJECT RESULTS

7.1 RESERVOIR CHARACTERIZATION

Decline curve analysis is a means of predicting well performance and life based on past production history. Production data for the Lost Dome Field was obtained from the WOGCC website. The data was then plotted on a semi-log plot using MS Excel. The plot was analyzed in order to determine if a hyperbolic, harmonic, or exponential decline curve would best fit the data. Exponential decline will appear as a straight line when using a semi-log plot. Since the data did not generate a straight line, it was clear that the Lost Dome Field production was not declining exponentially. Hyperbolic and harmonic decline will appear as a slightly curved line when using a semi-log plot, which is consistent with the Lost Dome Field data. Therefore, it was determined that the field was experience hyperbolic or harmonic decline so the following equation was used:

$$q = \frac{q_i}{(1 + b a_i t)^{\frac{1}{b}}} \quad (\text{Eq. 1 - Hyperbolic Decline})$$

where q is the production rate at time t , q_i is the initial production rate, b is the decline curve exponent, a_i is the initial decline rate, and t is time. In order to achieve the best fit possible, different combinations of q_i , a_i , and b were used. To achieve the fit that can be seen in Figure 8, the values chosen were $q_i = 648.6$ bbl/d, $a_i = 0.50$, and $b = 0.90$. With this information, the team can predict future production from the Lost Dome Field. The team then hopes to compare the results of the enhanced oil recovery simulation to the decline curve results.

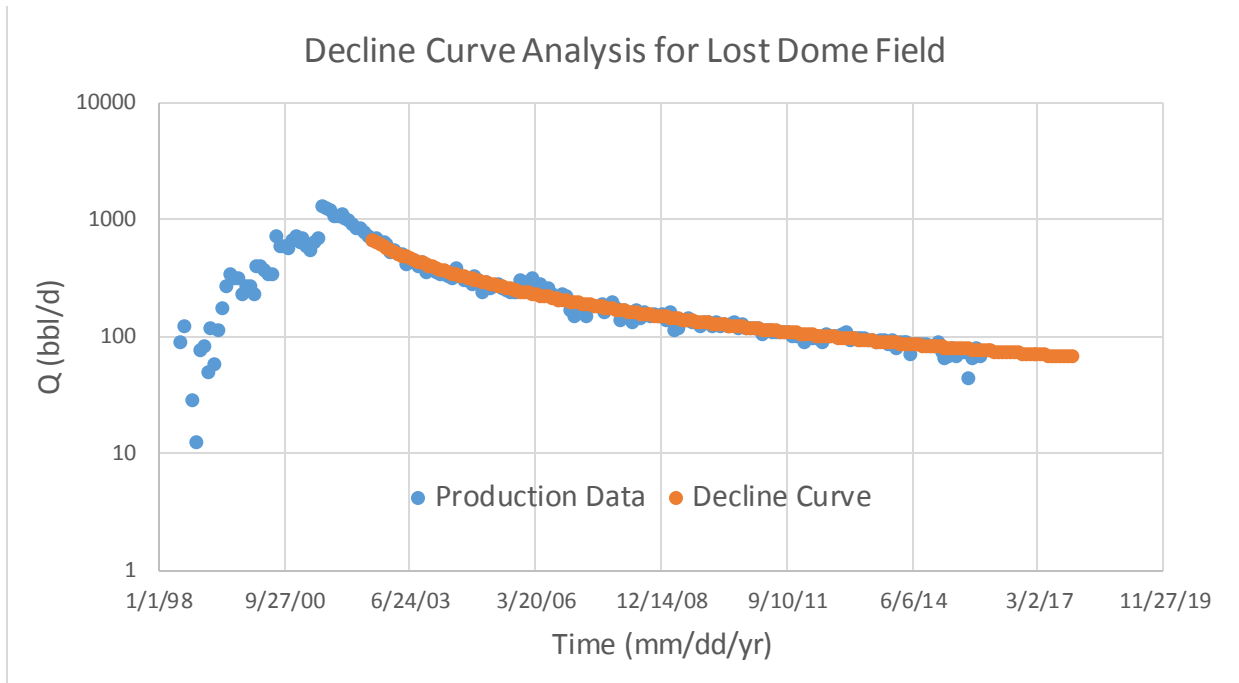


Figure 8 – Historical production data and decline curve for Lost Dome Field.

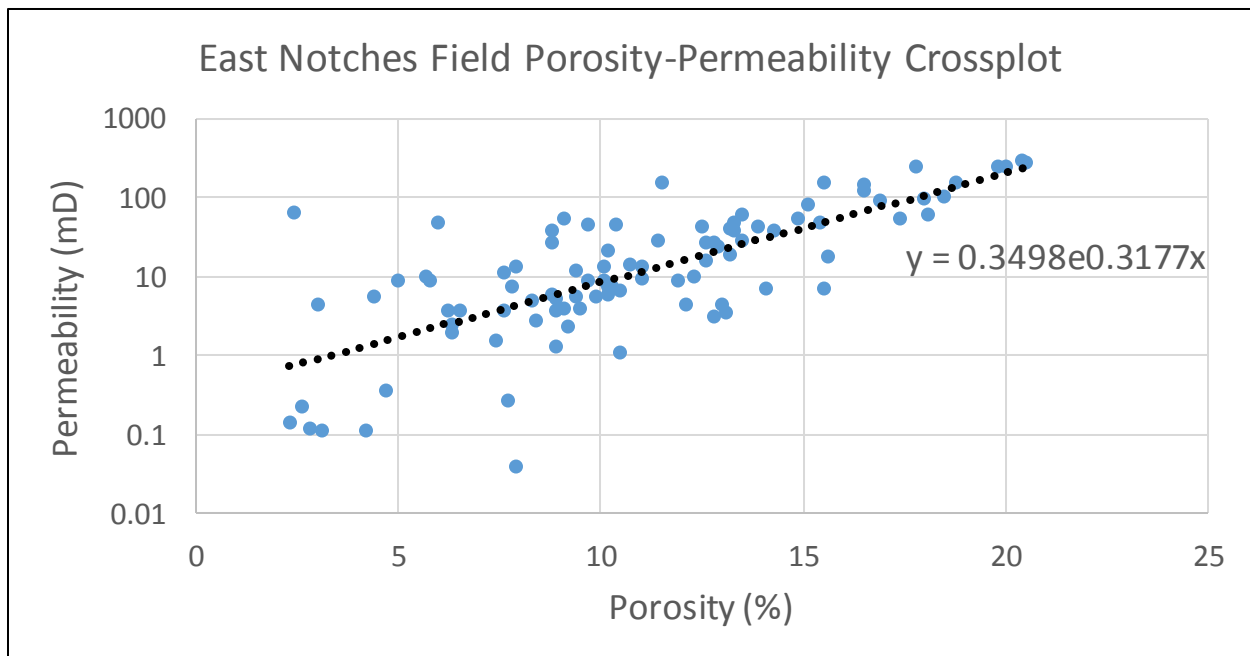


Figure 9 - Porosity-Permeability crossplot from the East Notches Field.

Because no core analysis data is available specifically for the Lost Dome Field, nearby fields were examined. The East Notches field, located approximately 10 miles away from the Lost Dome Field, contains a core analysis report. The East Notches Field is located in the Wind River Basin and produces from the Tensleep formation, similar to the Lost Dome Field. The core analysis report contains information regarding porosity, permeability, fluid saturations, and rock type description. With this data, the team was able to generate a porosity-permeability cross plot (Figure 9).

The plot is a semi-log plot with permeability on the y-axis and porosity on the x-axis. With the plotted data, a line of best fit was added. The equation of the line will allow our team to determine the permeability of the Tensleep Formation in the Lost Dome Field. It is certainly an assumption that the characteristics of the Tensleep will be the same 10 miles apart. However, the team agreed that this was the best available way to determine the permeability.

The construction of the static model began with a basic Petrel introduction course given by Matt Johnson from EORI. The main topics of the session included how to create and save a project and how to correctly format and input data such as well locations, well tops, and well logs. This information was very helpful and allowed the team to gain some familiarity with the Petrel software.


With a basic understanding of how to use Petrel, the team began formatting and inputting the available data for the Lost Dome Field. The first step was to create a well header file. The well header file contains information such as API numbers, surface latitude and longitude, total depth, and elevation of the kelly bushing. EORI provided the team with the necessary well header information. Table 2 shows the well header file in MS Excel. After saving the file in text-tab delimited format, it was imported into Petrel. Once imported, the spatial configuration of the wells could be viewed in 2-D or 3-D windows.

Table 2: Lost Dome Field well header information.

Name	API	Surface Lat	Surface Long	TD (TVD)	TD (MD)	Elev (KB)
Lost Dome #1	2522864	43.177527	-106.749508	5000	5000	5532
Lost Dome #2	2522950	43.17875	-106.75223	5000	5547	5530.5
Lost Dome #3BH	2522942	43.18193	-106.75387	4848	5768	5504
Lost Dome #4H	2522949	43.18186	-106.7538	4850	6000	5505
Lost Dome #5	2523004	43.17868	-106.75157	4885	5758	5530
Lost Dome #6H	2523002	43.17881	-106.75236	4895	5752	5531

The next step was to obtain wellbore deviation surveys from the Wyoming Oil and Gas Conservation Commission. Lost Dome Field consists of four horizontal wells, one deviated well, and one vertical well. However, only four surveys were available: three horizontal well surveys and the deviated well survey. The surveys consist of data such as measured depth, inclination, azimuth, true vertical depth, northings, eastings, vertical section, and dogleg rate (Figure 10). The surveys were scanned images so they needed to be formatted properly before the team could make use of them. Optical Character Recognition (OCR) software was used to convert the scanned image into text that was then edited. Petrel only requires the measured depth, inclination, and azimuth in order to trace the wellbore path. Petrel uses a minimum curvature method to calculate an x, y, and z, coordinate for the position of the well bore. Once the scanned image was converted into a MS Excel workbook, it was saved as a text-tab delimited file and imported into Petrel. The same procedure was followed for the other three wellbore deviation surveys. When all of the surveys were in Petrel, the wellbore traces could be seen in a 3-D window.

Table 3 – A directional drilling survey.

Sperry-Sun Drilling Services								
<i>Survey Report for Lost Dome Federal #5 - S.S./MWD</i>								
BreitBurn Energy Co. LLC				Natrona County				
Wyoming				Sec. 13-T37N-R83W				
Measured Depth (ft)	Incl.	Azim.	Vertical Depth (ft)	Northings (ft)	Eastings (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	
0.00	0.000	0.000	0.00	0.00 N	0.00 E	0.00		
238.00	0.750	206.000	237.99	1.40 S	0.68 W	-1.18	0.32	
475.00	1.500	197.000	474.95	5.76 S	2.27 W	-4.35	0.32	
754.00	1.750	167.000	753.84	13.40 S	2.38 W	-7.46	0.31	
997.00	2.250	167.000	996.69	21.67 S	0.47 W	-8.96	0.21	
1283.00	3.500	169.000	1282.32	35.71 S	2.46 E	-11.80	0.44	
1499.00	4.000	172.000	1497.86	48.64 S	4.76 E	-15.16	0.25	
1750.00	3.750	164.000	1748.29	66.20 S	8.24 E	-18.48	0.24	
2027.00	2.250	173.000	2024.90	80.30 S	11.40 E	-21.13	0.57	
2247.00	2.000	183.000	2244.75	88.42 S	11.73 E	-24.02	0.20	

Well log data was also necessary for the construction of the static model. The WOGCC website contains scanned images of well log reports (Figure 10). However, Petrel requires well logs to be in LAS file format to allow for interpretation and modeling. The transformation of the well logs from scanned images to LAS files proved to be difficult since

the University of Wyoming no longer has software licenses for programs that would allow for such transformations. Therefore, the team contacted Neuralog, Inc., a company that owns software which allows for the conversion of scanned image logs to LAS file logs. Neuralog was very generous and offered a free trial of the Neuralog software. After setting up the proper scale, grid, and depth specific to each log, the curve was traced manually. Then, the log was exported and saved as an LAS file. This process was very detail-oriented and time consuming. Once the appropriate logs were transformed, they were imported into Petrel. The digitized well logs allowed for interpretation and petrophysical modeling, which will be discussed later.

The EORI provided the team with well top data. Well top data, or formation top data, consists of the depth of geological layers encountered in oil and gas wells. The well tops file contains information such as the well's API number, the name of the geological formation, and the depth of each geological formation. Once the file was saved as a text-tab delimited file, it was imported into Petrel. With the addition of the well top data, the geological model was essentially finished. The well locations, wellbore paths, well log data, and formation boundaries could then be visualized in the 3-D window.

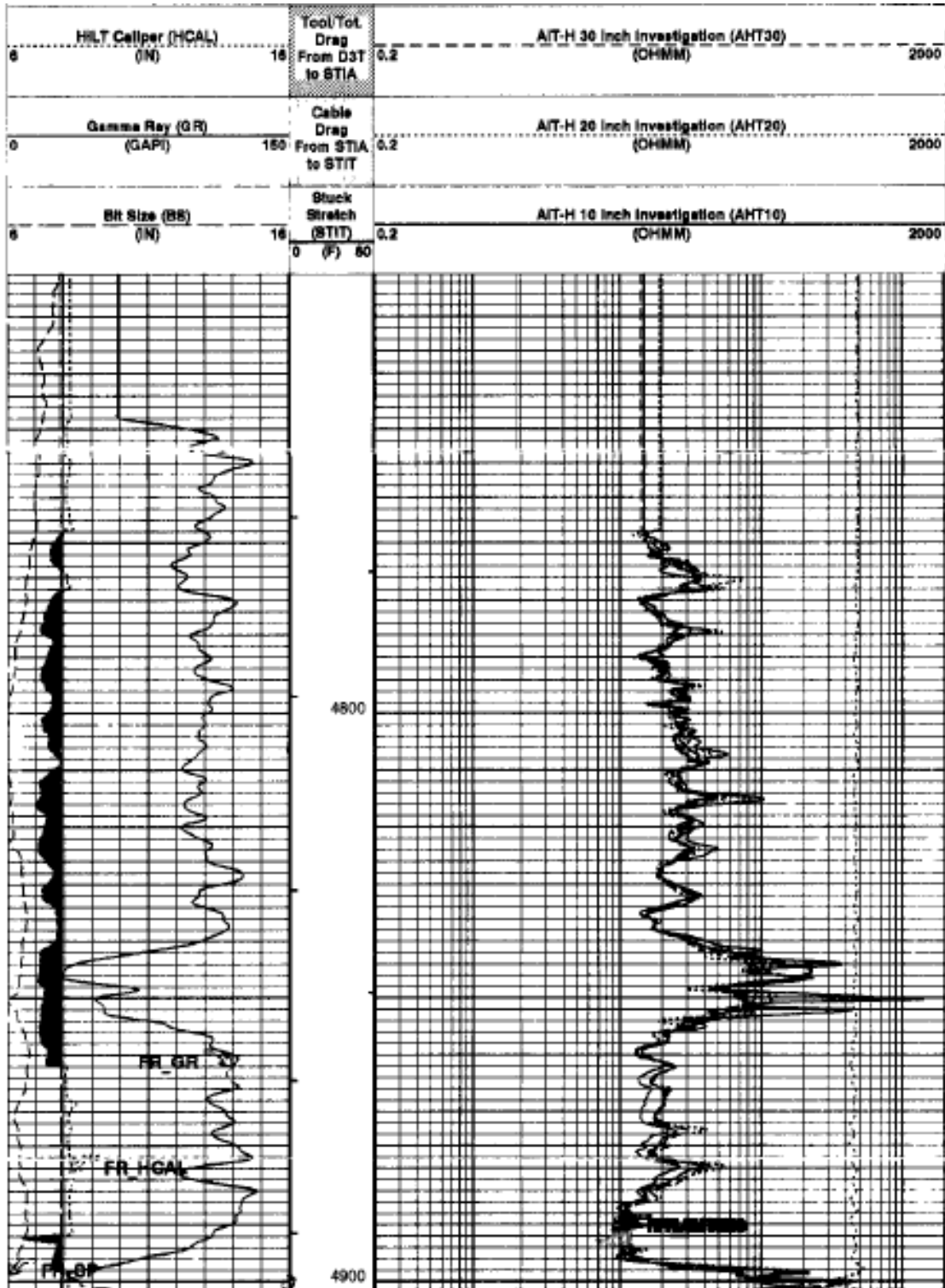


Figure 10 - Example of the scanned well log images.

Another aspect associated with the construction of the static model deals with petrophysical modeling. The Petrel Petrophysical Modeling module enables the population of geocellular 3D grids with continuous data, which is essentially a pixelated contour map. The modules provided the tools the team needed to easily and accurately model reservoir properties such as porosity, permeability, and saturations. Using the well log data, well tops data, and core analysis data, petrophysical models of the Lost Dome Field have been constructed. Figures 13 and 14 show the neutron porosity distribution and permeability distribution, respectively, for the Tensleep formation.

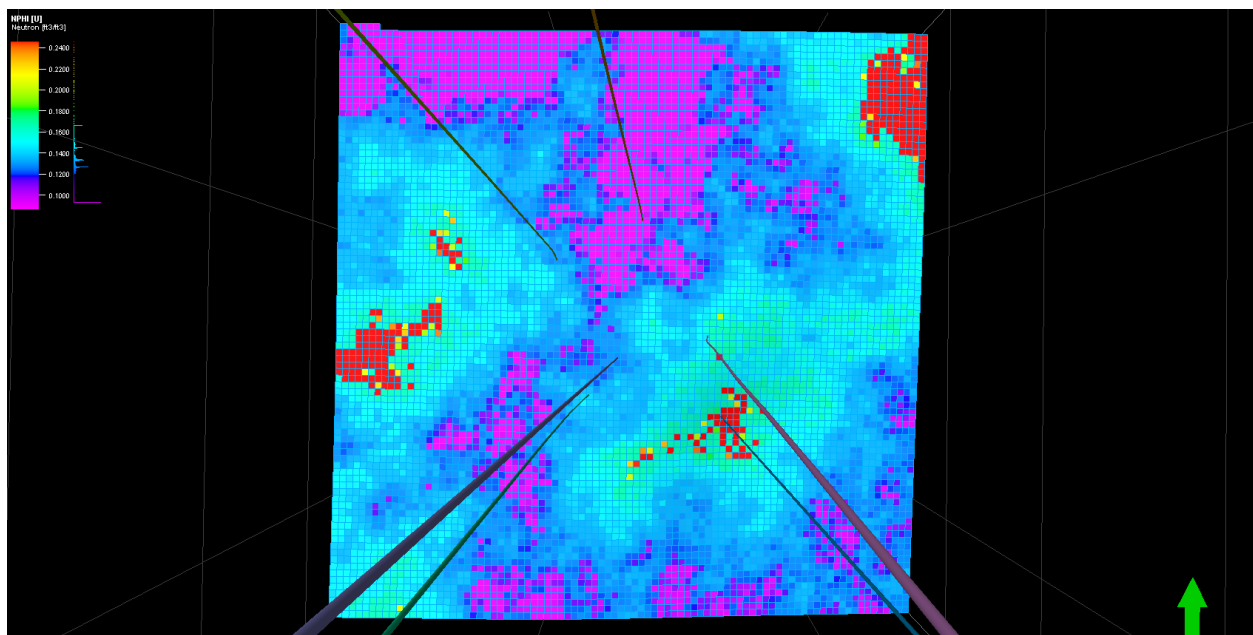


Figure 11 – Neutron porosity distribution

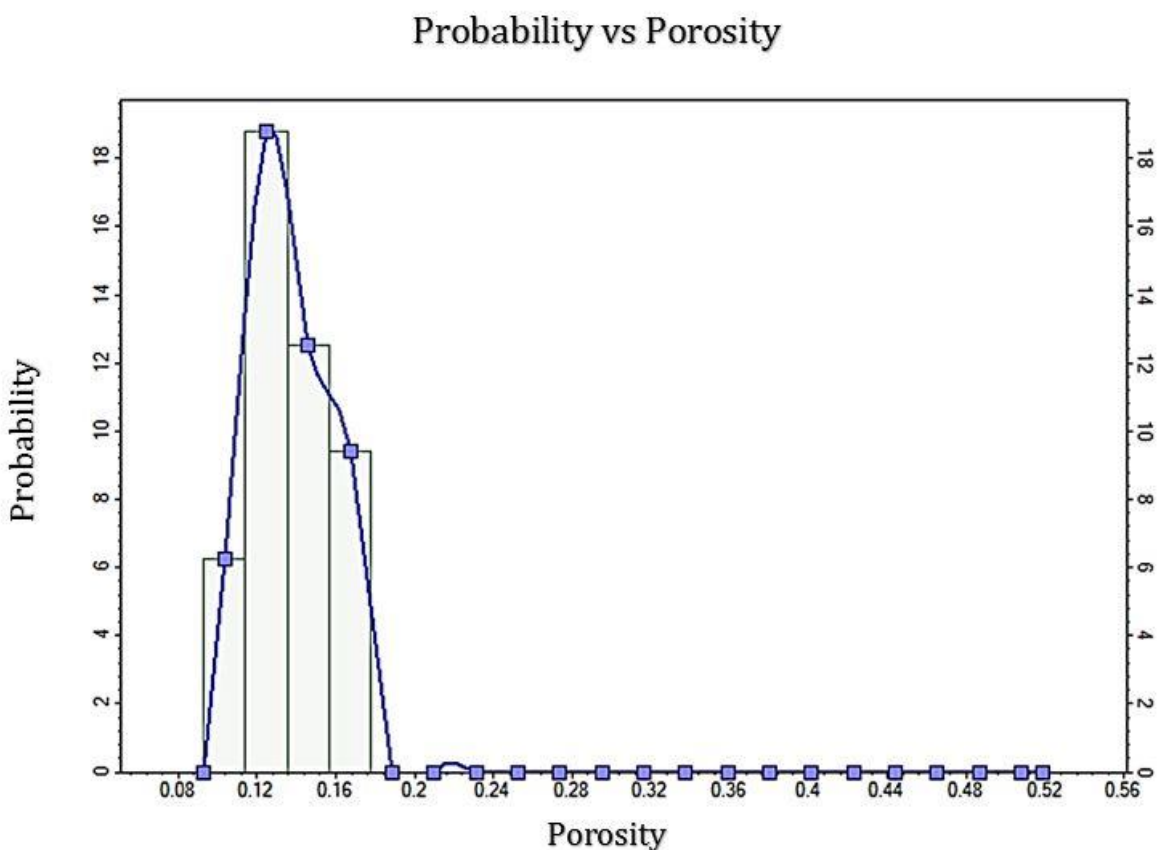


Figure 12– The relationship between Probability and Porosity

Figure 11 shows the Neutron porosity distribution of the reservoir. According to the information from color column, in the north eastern corner and western part of the reservoir have high porosity, but in the north part of the reservoir has relative low porosity. From figure 11, several wells were drilled in the low porosity area because those wells were horizontal wells and the horizontal wells were perforated in high porosity zones. From the figure 12, porosity from 12% to 16% has high probability. We suppose that the porosity of the reservoir is 13%.

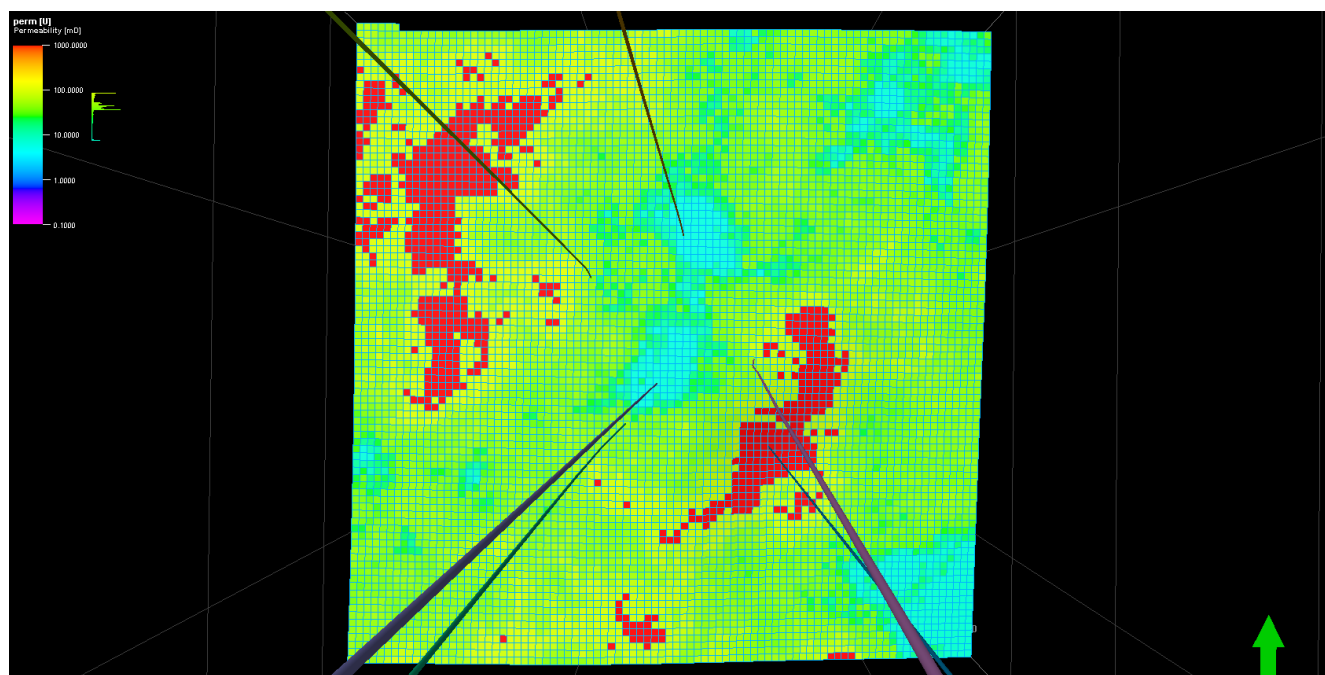


Figure 13 – Permeability distribution.

Normally, for conventional reservoir such as sandstone reservoirs, high porosity means high permeability. In the figure 13, we can find some high-permeability spots, but those spots do not have high permeability. The reason for those discrepancies is the upscaling from Petrel to CMG. The petrophysical model that is imported into CMG can only handle less than 10,000 grid blocks. Thus, the insufficient grids cause the inconsistency between porosity and permeability. But the range and average values of permeability are accurate. The color column of permeability distribution shows that the value of permeability ranges from 70mD to 80mD. The group consider the average of the reservoir is 75md.

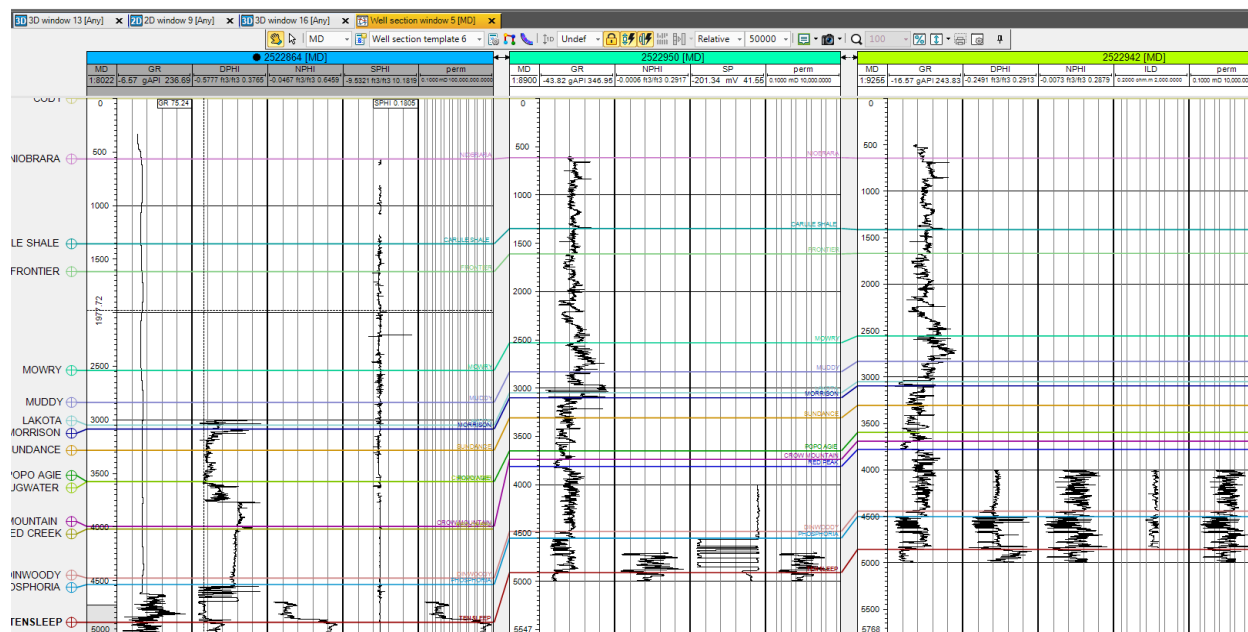


Figure 14 - Well top correlation and Well logs

Figure 14 is the well top correlation and well logs. With the resistivity log, water saturation and oil saturation petrophysical models can be generated. The issue is that the resistivity log is in Phosphoria Formation instead of Tensleep Formation. The lack of resistivity log is another potential issue in dynamic model.

Table 4 – Reservoir Characterization

Property	Value
Average Permeability	75mD
Average Porosity	13%
Drainage Area	150 Acres
OOIP	11 MMSTB
Oil Gravity	24.1 °API
Temperature	126 °F
Fracture Pressure	3589 psi
Reservoir Thickness	395 ft
Minimum Miscibility Pressure	2436 psi

Table 4 shows the basic properties of the reservoir. Oil gravity, temperature, reservoir thickness and fracture pressure are given by EORI. The group estimates that the primary recovery is 15%. The cumulative production until September 2015 is 1.6 MMSTB. We obtain the value of OOIP, 11 MMSTB. According to average porosity, OOIP and reservoir thickness, we obtain the value of the drainage area, 150 Acres.

$$MMP_{pure} = 1833.717 + 2.2518055T + 0.01800674T^2 - \frac{10349.93}{T} \quad (\text{Eq. 2})$$

With equation 2, we obtain the value of minimum miscibility pressure.

7.2 EOR SIMULATION

To efficiently run an EOR prediction for the six producing wells within the Tensleep formation we needed to accurately match our production history. As mentioned in section 4.1, paragraph 6, history matching for the output results from the black oil simulator (IMEX) has proved to be widely inaccurate. The inability to use resistivity logs for the Tensleep formation was determined as a major contributing factor for the imprecise history matching. Although we could only import well trajectories and the porosity map from Petrel, we were able to satisfy other areas of missing data and essentially run the IMEX production matching reports.

P R O D U C T I O N G R O U P S U M M A R Y

FILE: cmg evan11 april 27th.irf
Group: Default-Field-PRO

TIME	DATE	Oil Rate SC	Water Rate SC	Gas Rate SC	Gas Oil Ratio	Water cut SC -	Water Gas	Cumulative oil	Cumulative	Cumulative Gas	Number of Open
(day)		(bb1/day)	(bb1/day)	(ft3/day)	SC	%	Ratio SC	SC	water SC	SC	Wells in Group
					(ft3/bbl)	(%)	(bb1/ft3)	(bb1)	(bb1)	(ft3)	(%)
0.00000000	1998-07-01	6.10	0.00	581.96	95.42	0.00	0.00	0.00	0.00	0.00	1.00
184.000000	1999-01-01	6.07	1.10806e-007	579.26	95.42	1.82527e-006	1.91291e-010	1117.40	1.84532e-005	106620.47	1.00
549.000000	2000-01-01	1510.15	0.0905067	144096.16	95.42	0.00602239	6.31195e-007	291400.47	14.66	27804968.00	3.00
915.000000	2001-01-01	3610.53	0.763497	344510.94	95.42	0.0211612	2.21819e-006	1409811.63	204.23	134521968.00	5.00
1280.000000	2002-01-01	2998.97	0.934117	285290.44	95.13	0.0311382	3.27427e-006	2520796.00	541.57	240247728.00	5.00
1645.000000	2003-01-01	2683.44	0.986123	252352.81	94.01	0.0368521	3.92321e-006	3500252.25	901.51	332356512.00	5.00
2010.000000	2004-01-01	2462.85	1.01	229018.25	92.97	0.0410777	4.42106e-006	4399192.00	1270.32	415948160.00	5.00
2376.000000	2005-01-01	2293.06	1.02	210983.48	91.99	0.0446090	4.85233e-006	5238557.00	1644.43	493179264.00	5.00
2741.000000	2006-01-01	2152.92	1.03	196046.97	91.05	0.0477250	5.24507e-006	6024372.50	2019.32	564736384.00	5.00
3106.000000	2007-01-01	2032.13	1.03	183247.80	90.16	0.0505705	5.61234e-006	6766101.00	2394.35	631621888.00	5.00
3471.000000	2008-01-01	1922.51	1.02	171608.13	89.25	0.0533152	5.97768e-006	7467817.00	2768.43	694258752.00	5.00
3837.000000	2009-01-01	1822.92	1.02	160932.61	88.27	0.0559340	6.34106e-006	8135068.50	3141.63	753166912.00	5.00
4202.000000	2010-01-01	1732.42	1.01	151069.19	87.19	0.0583690	6.69933e-006	8767403.00	3510.76	808307200.00	5.00
4567.000000	2011-01-01	1649.60	1.00	141997.36	86.07	0.0606598	7.05324e-006	9369508.00	3876.07	860136256.00	5.00
4932.000000	2012-01-01	1573.40	0.989054	133681.30	84.95	0.0628441	7.40331e-006	9943799.00	4237.07	908299200.00	5.00
5298.000000	2013-01-01	1504.69	0.976636	126212.56	83.87	0.0648833	7.74220e-006	10494559.00	4594.53	955128448.00	5.00
5663.000000	2014-01-01	1442.86	0.964030	119524.40	82.83	0.0667866	8.06946e-006	11021202.00	4946.40	998754816.00	5.00
6028.000000	2015-01-01	1385.14	0.951397	113695.74	82.08	0.0686558	8.37104e-006	11526797.00	5293.67	1040255616.00	5.00
6393.000000	2016-01-01	1331.18	0.939949	109906.14	82.57	0.0705772	8.55304e-006	12012697.00	5636.75	1080372352.00	5.00

Figure 15 – IMEX Production History Field Report

As shown above for figure 15, the reported field history for January 1, 2016 is at a reported rate of 1331 bbls/day. The actual reported production data from the Wyoming oil and gas commission website is around 44 bbls/day. The only accurate column's in figure 15 is the dates and times. From Petrel, we were able to import our well trajectories and use any perforation depths that was at our disposal. The Wyoming oil and gas commission website reports completion dates for each specific well. This data helped us accurately set each specific well to start producing for its stated time. The noted difference's in real production rates vs IMEX simulation rates is primarily because of the insufficiencies in data imported into the black oil simulator. Without resistivity and permeability logs, it is almost impossible to produce accurate history matching.

7.3 ECONOMIC EVALUATION

Economics drives the entire oil and gas producing industry. Almost every decision is made on the basis of an economic evaluation. In many cases, the goal of a company is to make decisions that have the best chance of maximizing the present day profit. Because of the importance of economics, a great deal of attention was given to the feasibility of a CO₂ EOR project for the Lost Dome Field. The economic evaluation will cover topics such as the economic limit of the field, research of similar CO₂ projects in Wyoming, production and injection expectations, capital costs, and a spreadsheet analysis.

The Lost Dome Field has been under primary production for about 18 years now. From the decline curve analysis and historical production data, it is easy to see that production levels are fairly low right now and will continue to decrease. Therefore, it is important to determine the economic limit of the field, which is the production rate at which the field will no longer be profitable for the operator. Certain financial factors are needed to determine the economic limit and unfortunately the team was not provided with any of that information. But a literature search did produce useful information. Table 5 shows the annual operating costs for 10-well oil leases in different regions of the U.S. and at varying producing depths.

Table 5 – Lease operating expenditures for oil well leases in the U.S.

Region	Producing Depth			
	2,000-ft	4,000-ft	8,000-ft	12,000-ft
	Annual Operating Costs for 10-well Oil Lease (\$)			
California	218,700	296,100	515,000	773,600
Mid-Continent	185,600	222,500	424,000	525,700
South Louisiana	238,500	338,500	408,800	631,100
South Texas	231,200	277,400	349,300	639,500
West Texas	170,000	203,700	302,300	473,900
Rocky Mountains	255,700	285,400	394,200	555,300
Average	216,600	270,600	398,900	599,900

Because the Lost Dome Field is in the Rocky Mountain Region, produces from 5,000 feet, and contains 6 wells, interpolation was used to determine that the lease operating expenditures for the field is \$17,586 per month. The literature search produced other important economic factors. For instance, the royalty burden from a federal lease is 17.75% and the severance and ad valorem taxes in Wyoming are 6% and 7%, respectively. With this information, the following equation was used to determine the economic limit of the field;

$$EL_{oil} = \frac{WI \times LOE \left(\frac{1 \text{ month}}{30.4 \text{ days}} \right)}{NRI \left[P_o (1 - T_o) + P_g (1 - T_g) \left(\frac{GOR}{1000} \right) \right] (1 - T)} \quad \text{Eq. 3 - Economic Limit}$$

where EL_{oil} = Economic Limit for Oil Field (STB/d), WI = Working Interest (100%), LOE = Lease Operating Expenses (\$17,586/month), NRI = Net Revenue Interest (82.25%), P_o = Price of Oil (\$45/STB), T_o = Oil Severance Tax (6%), and T = Ad Valorem Tax (7%). Because there is no reported gas production, the GOR (gas-oil ratio) was assumed to be zero. With the above equation, the economic limit was determined to be 18 barrels per day. The last reported production rate for the field was 42 barrels per day. Therefore, the field hasn't quite reached the economic limit but it is definitely approaching it.

Due to the data insufficiency and consequent issues with CMG, the team decided that running the CO₂ simulation would result in inaccurate results. Thus, the team decided to study existing CO₂ EOR projects in Wyoming. The Big Sand Draw Field, Lost Soldier Field, and Wertz Field are all currently under CO₂ flooding. They are also relatively close to the Lost Dome Field, so they were chosen for analysis. Combining published literature with historical data, expected production and injection rates were obtained. Figures 16a, 16b, and 16c show the historical production data from the Big Sand Draw Field, Lost Soldier Field, and Wertz Field, respectively.

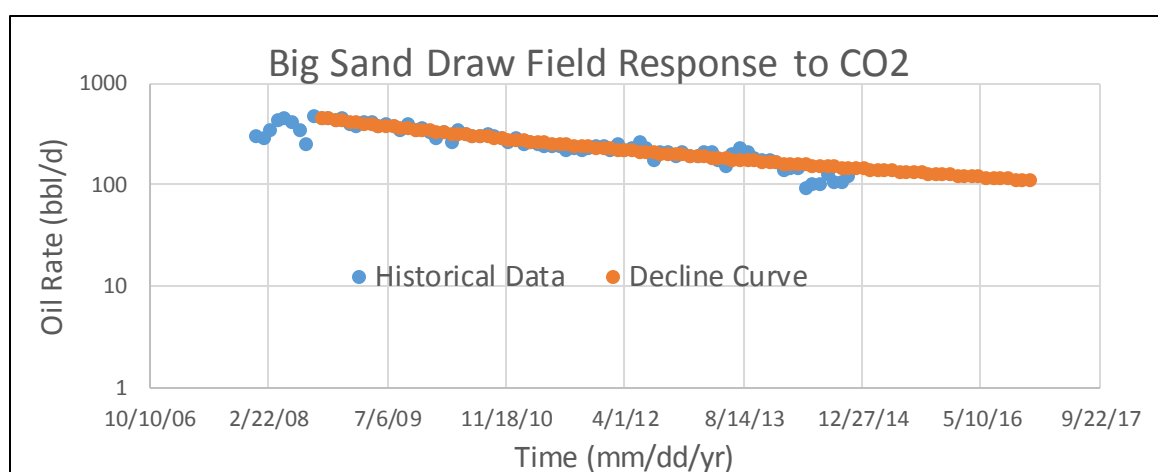


Figure 16a – Big Sand Draw Field's oil production after CO₂ flood.

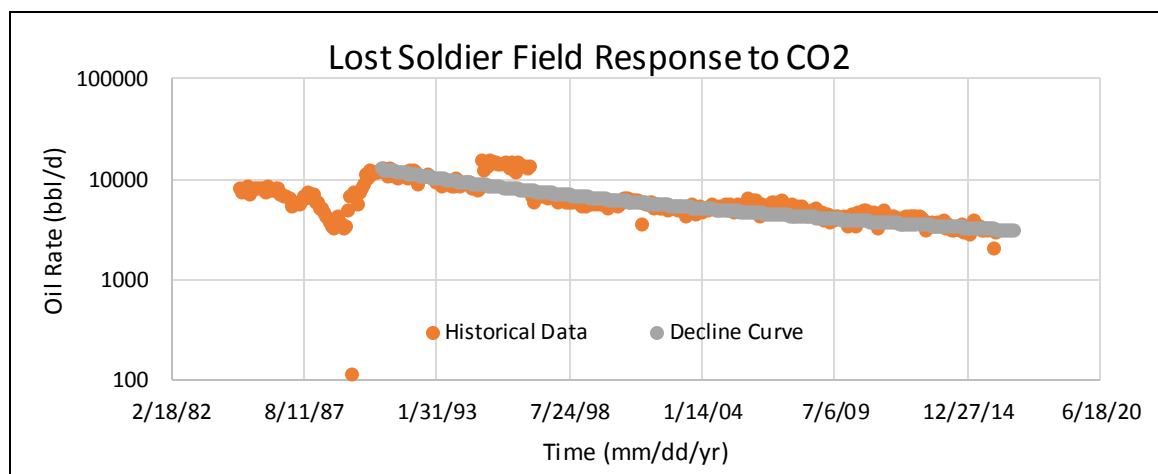


Figure 16b – Lost Soldier Field's oil production after CO₂ flood.

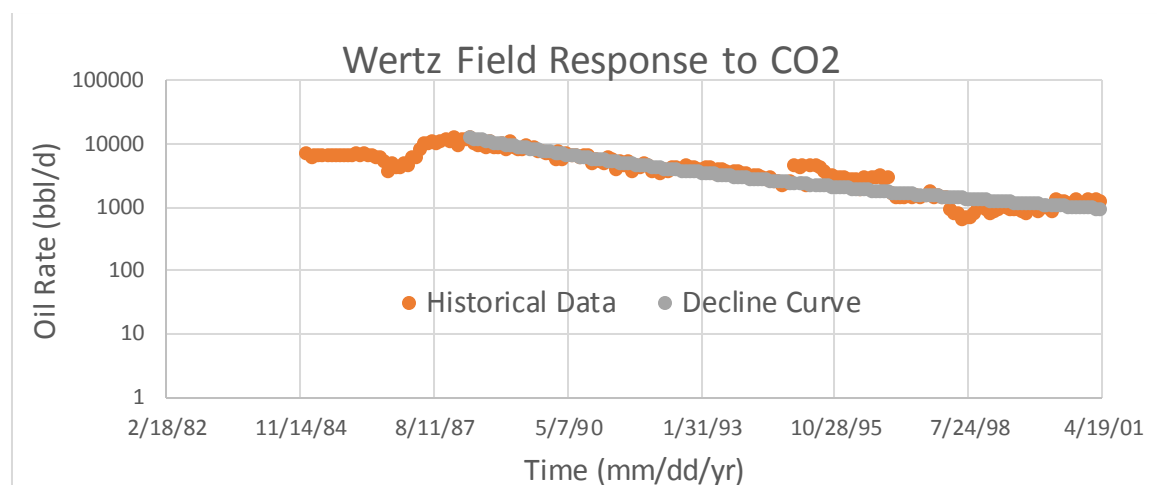


Figure 16c – Wertz Field’s oil production after CO₂ flood.

The data contains only the oil production rates after the CO₂ flood began. The decline curve parameters for the three fields were averaged, which produced the annual decline rate of 0.308 and a hyperbolic exponent of 0.383. Another observation was made that the peak oil production rate from the CO₂ flood was equal to or approximately 1.5 times greater than the peak production rate from primary recovery. Therefore, an assumption was made that the peak CO₂ production rate if the Lost Dome Field underwent a CO₂ EOR project would be 25% higher than its peak production rate under primary recovery. Also, CO₂ injection rates were analyzed from the fields and it was determined that each injector operated between 3 and 5 MMcf/d (million cubic feet per day), so it was assumed that the Lost Dome injector would inject gas at 4 MMcf/d.

The next step in the economic evaluation was to determine the capital costs of implementing the CO₂ flood operation. Capital costs are fixed, one-time expenses incurred on the purchase of land, buildings, construction, and equipment used in the production of goods or in the rendering of services. Put simply, it is the total cost needed to bring a project to a commercially operable status. Once again, a literature search produced useful information for determining the capital costs of a CO₂ EOR project. Table 6 shows the item and cost estimates that would be required for the field.

Table 6 – Capital costs for implementing a CO2 EOR project.

Cost Item	Cost Estimate
New Well Drilling (drilling only)	\$302-364/ft of depth
Working Over and Equipping an Existing Producer Well	\$231,980 per well
Equipping a New Producer or Converting another Well to Production	\$570,847 per well, plus \$35/ft of depth
Preparing and Equipping any Well for Injection	\$257,866 per well, plus \$35/ft of depth
Pipeline Costs	$\$85,281(D_{\text{inches}}^{0.9936614} * L_{\text{miles}}^{0.823146} * P_{\text{WTI}}^{0.1715248})$
CO2 Metering Station	\$250,000 per station

The total capital costs were determined to be \$5,273,170. This number takes into account the plan to drill and equip one injection well, working over and equipping the six existing producing wells, building a CO2 metering station, and constructing a spur pipeline. Figure 17 shows that the Lost Dome Field is only 4.5 miles away from the existing CO2 pipeline infrastructure, which was critical in keeping the capital costs at a minimum.



Figure 17 – Existing CO2 pipeline in Wyoming and location of Lost Dome Field.

With the capital costs and production/injection information, the team was able to perform an overall economic evaluation of the EOR project. Economic indicators such as net cash flow (NCF), net present value (NPV), and profitability index (PI) were produced using a MS Excel spreadsheet and following the procedures set forth in the Petroleum Economics course (PETE 4340). The most important aspects of the spreadsheet analysis will be discussed. First of all, the expected oil production rate was the main factor in calculating the gross revenue. The current oil price of \$45/STB was used. Net revenue was calculated by subtracting the royalty costs associated with producing from federally leased land. The CO₂ purchase rate was obtained from the initial injection rate of 4 MMcf/d and was declined steadily due to the fact that CO₂ purchases decline throughout the life of the project because the injected CO₂ will eventually be recycled and re-injected. Operating costs were calculated based on the literature data of \$3560 per well per month and \$0.72 per each barrel of produced fluid. Depreciation costs were determined using sum of year digits (SYD) depreciation. SYD depreciation was applied to the tangible drilling costs and other capital costs. According to tax law, the tangible drilling costs must be depreciated over the first 7 years of the project. The remaining capital costs were depreciated over 25 years, which was an estimate of the maximum life of the CO₂ EOR project. Salvage values, which are used in calculating depreciation costs, were estimated at 20% of original costs. SYD depreciation was chosen because it allows for a larger depreciation deduction to be taken in the early years of the project, which will help offset some of the large negative NCF's due to capital investment costs.

Net cash flow before tax (Figure 18) was determined by subtracting operating expenditures, depreciation, intangible drilling costs, and other capital costs from the net operating revenue. If the NCF before tax is negative, then the 30% corporate tax rate (assumed) is not applied. Also, a negative NCF before tax allows for a loss forward exemption in the following year. Once the NCF becomes positive, a 30% tax rate is applied and the net income after tax is produced. Because depreciation, tangible drilling costs, and loss forwards are not accounted for in the pre-tax model, they must be added to the after-tax model. Then, the NCF after tax is completed. The NCF after tax values for each month are added up and the cumulative NCF after tax is produced. After approximately 16 years of operation, the CO₂ project no longer is profitable. The cumulative cash flow at this point in time is \$4,220,406. Using an average discount rate of 10 percent, the NPV of the project was calculated and determined to be \$918,483. The profitability index of the project was calculated using the following formula.

$$PI = 1 + \frac{NPV}{PV \text{ of Capital}}$$

Eq. 4 – Profitability Index

With a present value capital costs of \$5,273,170 the profitability index was determined to be 1.174. This means that for every \$1 invested, \$1.174 would be returned. While the PI of the project was not a very high number, it still indicates that the CO₂ EOR is economical, even with the oil price of \$45/STB.

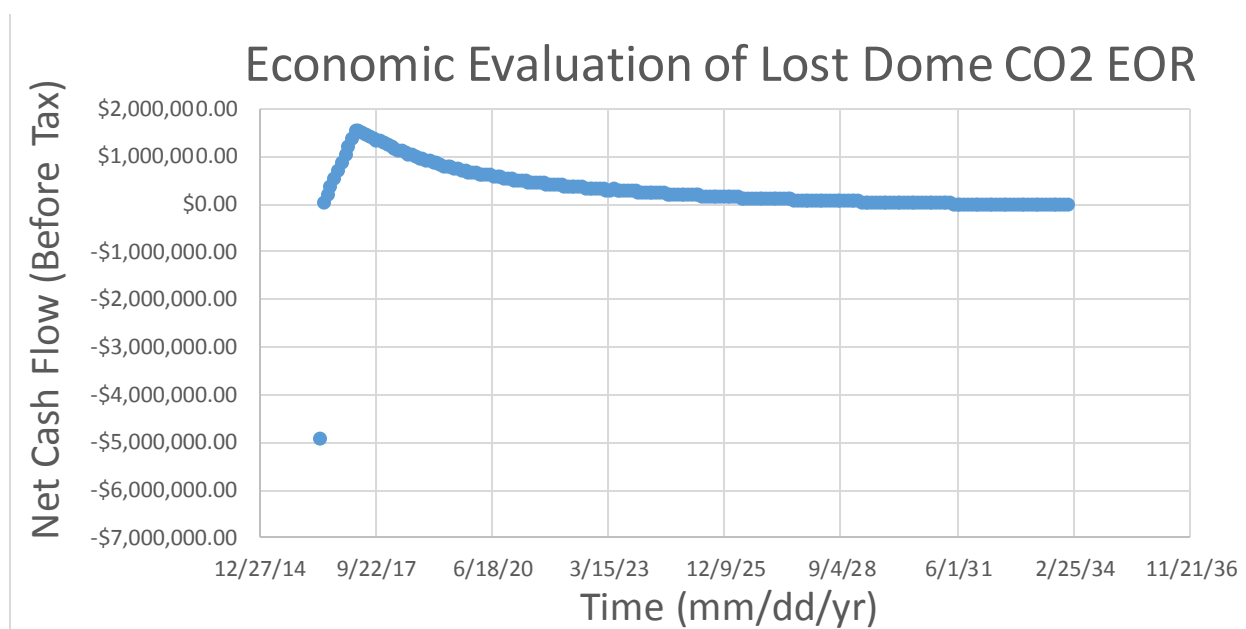


Figure 18 – Net Cash Flow (Before Tax) as a function of time.

7.4 RECOMMENDATION

According to the integration of static model, dynamic model and economic evaluation, the group have made a plan for the CO₂ flooding. The number of the injector will keep the same and the new injector will be drilled in the middle of the six producers. The new injector will go on line in December 20. The location of the new injector is -106.7533W, 43.1795N. The new injector will last until March, 2034.

8. SUMMARY

The Lost Dome Field project produced a lot of results. First of all, the project was planned in a way that allowed the team to gain an understanding of how real-life projects are organized in today's industry. The project workflow and Gantt chart proved to be very reliable tools in establishing an overall project plan. The risk analysis was important in identifying elements of the project that could lead to challenges. Although the team tried to mitigate the risks, the data insufficiency risk proved to be a large barrier throughout the entire project. The reservoir characterization produced information such as average porosity (13%), average permeability (75 mD), and original oil in place (~11 MMSTB). The team also gained a lot of experience with the Petrel software. The research performed throughout the project resulted in increased familiarity with reservoir modeling, EOR methods, and active EOR projects. While the CMG simulation attempts were not accurate, practice with the software was definitely useful. The economic evaluation aspect of the project reinforced the ideas and concepts of the petroleum economics course. This evaluation proved that a CO₂ EOR project for the Lost Dome Field is economical and should be pursued. Overall, the senior design project was very effective in combining all of the knowledge from previous courses and applying that knowledge to a real-life petroleum engineering project.

9. CONCLUSION

In conclusion, the senior design project had several problems. The main problem was a drastic lack of data. For an in depth reservoir simulation to be possible, there needs to be lots of information on the field that we were not able to obtain. The team was able to bypass some issues by doing research of similar fields and results of CO₂ floods. Although the group was able to overcome the challenges of insufficient data and create static and dynamic models, the project was a failure in the sense that the dynamic modeling could not be completed; therefore, the main objective of EOR simulation was not met.

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