Compagnie Pétrolière et Gazière, INC.

REQUEST FOR PROPOSAL
RFP #: SR – F3.P

TITLE: OIL AND GAS EXPLORATION AND PRODUCTION
CLOSING DATE AND TIME: NOVEMBER 26. 2018 @ 5:00 PM

Oil & Gas Exploration and Production: SR – F3.P

Background and Purpose

By responding to this Request for Proposal (RFP), the Proposer agrees that s/he has read and understood all documents within this RFP package.

Submission Details

Responders to this RFP should supply:

- A business report up to 5 pages (not including cover page or table of contents), including any supporting plots and tables.
- The commented code used to produce the results.
- You can refer to previous reports in this final submission.

The report should address **all points described in the "Objective" section** below.

The report should be returned in the following way:

- Electronic (mailto: Aric_LaBarr@ncsu.edu; Subject Line: Oil & Gas Exploration – Full Report)

Objective

The basic business model discussed involves making investments in land rights, geologic data, drilling (services and hardware), and human expertise in return for a stream of oil or gas production that can be sold at a profit. This project will be broken down into 4 phases. This model has multiple, significant risk factors that determine the resulting project's profitability, including:

- Drilling Risk (Phase 1). High drilling costs can often ruin a project's profitability. Although companies do their best to estimate them accurately, unforeseeable geological or mechanical difficulties can cause significant variability in actual costs.
- Production Risk (Phase 2). Even when drilling discovers oil or gas reservoirs, there is a high probability that point estimates of the size and recoverability of the hydrocarbon reserves over time are wrong.
- Price Risk (Phase 2). Along with the cyclical nature of the oil and gas industry, product prices can also vary unexpectedly during significant political events such as war in the Middle East, overproduction and cheating by the OPEC cartel, interruptions in supply such as large refinery fires, labor strikes, or political uprisings in large production nations (e.g., Venezuela in 2002), and changes in world demand.
- Dry-Hole Risk (Phase 3). Investing drilling dollars with no resulting revenue from oil or gas because none is found in the penetrated geologic formation.

Here are the goals from the analysis:

- Simulate the distribution of Net Present Value from the scenario described below.
- Calculate the expected return from the scenario, as well as measures of risk – such as Value at Risk and Expected Shortfall.
- Make a recommendation on whether the company should invest in the scenario described based on your above numbers.

Main Assumptions

- The drilling outcome can be a “dry hole” or an “oil discovery”.
- There are initial costs, which are incurred whether the well is dry, or a discovery.
- If the well is a discovery, a revenue stream is computed for the produced oil over time using assumptions for product price, and for the oil production rate as it declines over time from its initial value. Expenses are deducted for royalty payments to landowners, operating costs associated with producing the oil, and severance taxes levied by states on the produced oil.
- The resulting net cash flows are discounted at the weighted average cost of capital (WACC) for the firm and summed to a net present value (NPV) for the project. Each of these sections of the model is now discussed in more detail.

Phase 1 – Drilling Risk

Drilling costs are incurred **before** oil production begins – Year 0 (assumed to be 2018). These costs can vary significantly due to geologic, engineering, and mechanical uncertainty. The worksheet “Drilling Cost” in the Excel file “Analysis_Data.xlsx.”, lists the drilling cost for different types of wells over the past 30 years.

- Simulate possible future values of 2019 drilling costs.
    - Currently, only previous information is available for 1960 – 2007 due to changes in reporting regulations.
    - Since the industry has changed tremendously over those decades, only the information from 1990 – 2006 will be useful for this analysis. 2007 was an outlier and should be ignored.
    - Instead of looking at the distribution of actual costs, the Company’s analysts recommend simulating possible annual changes in costs to get to 2019. They have calculated arithmetic changes in the data set already, but they are open to other options if you explain why you chose them.
    - Instead of focusing on costs for oil, gas, and dry wells individually, the Company’s analysts recommend to treat them all equally and assume an average cost applies to them all.
    - A recent report has come out from the U.S. Energy Information Association detailing changes in costs from 2006 to 2019 with the details here:
        - From 2006 to 2012 changes were relatively consistent in their distribution. This distribution is discussed below.
        - From 2012 to 2015 costs tended to decrease on average by 9.17% per year with a maximum of 22% and minimum of 7%.
        - From 2015 to 2018 costs tended to increase on average by 5% per year with a maximum of 6% and minimum of 2%.
        - 2019 is forecasted to follow the same increase distribution as from 2015 to 2018.
    - Previously the *Price Analysis* group has worked under the assumption that these arithmetic changes from one year to the next from 2006 to 2012 follow a Normal distribution. Use QQ-plots or formal tests to see if you agree.
    - Build a kernel density estimate of the distribution of arithmetic changes from 2006 to 2012, using the 48 observations described above.
- Simulate possible future values of 2019 drilling costs under both the assumption of Normality as well as under the kernel density estimate you created. Make a recommendation for which one you feel the company should use.

Phase 2 – Production and Pricing Risk

"Year 0" Expenses:

In addition to the drilling costs in Phase 1, there are additional Year 0 expenses that occur **before** oil production begins. These expenses are:

1. *Seismic and Lease Costs*. To develop their proposal, our team will need to purchase seismic data to choose the optimum well location, and to purchase the right to drill on much of the land near the well. The cost of these items depends on the number of wells in the project. Uncertain assumptions include leased acres **per well**, which are Normally distributed with a mean of 600 and a standard deviation of 50 acres per well (lower number of wells means lower number of acres to buy); the price per acre is $960[1]. The number of seismic sections **per well** is Normally distributed with a mean of 3 sections and a standard deviation of 0.35 per well (lower number of wells means lower number of sections to purchase data on); the seismic costs per section are $43,000[2].
2. *Completion Costs*. If it is determined that there is oil present in the reservoir (**and we have not drilled a dry hole**), engineers must prepare the well to produce oil at the optimum sustainable rates. For this particular well, we hypothesize that his cost is Normally distributed with a mean of $390,000 and a standard deviation of $50,000.
3. *Professional Overhead*. The project team annual costs in salary and benefits per well depends on the time that the project team spends on the well. We believe the salary and benefit cost is best represented by a triangular distribution, with a most likely cost as $215,000, with a minimum of $172,000 and a maximum of $279,500. This will remain constant across the lifetime of a well, but would potentially be different for different wells. These costs are incurred during Year 0 as well for drilling, but stop after Year 0 if the well is dry.

Production Risk:

A multi-year stream of oil can be characterized as an initial oil production rate (measured in barrels of oil per day, BOPD), followed by a decline in production rates as the natural reservoir energy and volumes are depleted over time. Our hypothetical production stream is described with two parameters:

1. IP. The initial production rate tested from the drilled well. This is the rate the oil is produced at Year 1.
2. Decline Rate. A declining production rate that describes the annual decrease in production from the beginning of the year to the end of the same year. To simplify the problem, we will assume each well has the same decline rate for every year of its life, but this could be different across wells.

Production rates in BOPD for our model are calculated by:

$$Rate_{Year\ End} = (1 - Decline\ Rate) \times Rate_{Year\ Begin}$$

Yearly production volumes in barrels of oil are approximated as:

$$Oil_{Volume\ Year} = 365 \times \frac{\left(Rate_{Year\ Begin} + Rate_{Year\ End}\right)}{2}$$

Previous research has shown that:

- The IP's follow a Lognormal distribution with a mean of 420 BOPD and a standard deviation of 120 BOPD.
- The rate of decline is Uniformly distributed between 15 and 32 percent.

- We incorporate an additional constraint in the production model; we have imposed a **correlation coefficient of 0.64 between the IP and the decline rate** assumptions that are drawn from their respective distributions during each trial of the simulation.

Revenue Risk:

Revenues from the model flow from the sale of the oil production. There are two assumptions in our model that represent risks in our prospect:

- Oil prices have shown substantial volatility over the last years (reference). For example, the price of a barrel of crude oil was $30.38 in 2000, $56.64 in 2005, and around $100 in 2013. Given this variability, it is really hard to make forecasts by looking into historical performance, future prices, etc. In these cases, it is better to use the long-term forecasts provided by an organization such as the World Bank of EIA. These forecasts run up to 2040 and apart from the expected value, they provide the best and worst cases as well. This data can be found in the worksheet “Price Projections” in the Excel file “Analysis_Data.xlsx”. Use the information there to build distributions for the next 15 years (2019, 2020, etc.) of the project.
- Net revenue Interest. Oil companies must purchase leases from mineral interest holders. Along with paying cash to retain the drilling and production rights to a property for a specified time period, the lessee also generally retains some percentage of the oil revenue produced in the form of a royalty. The percentage that the producing company retains after paying all royalties is the net revenue interest (NRI). Our model represents a typical West Texas scenario with an assumed NRI distributed Normally with a mean of 75% and a standard deviation of 2%. This calculation is done per well for the entire life of the well.

Note: **The annual revenues before the royalty payments are simply (Oil Price X Annual Production).** These annual revenues are then multiplied by the assumed NRI to reflect dilution of revenues from royalty payments to lessees.

Operating Expenses:

1. Operating Costs. Companies must pay for manpower and hardware involved in the production process. These expenses are generally described as a dollar amount per barrel. A reasonable West Texas cost would be Normally distributed with a mean of $2.25 per barrel with a standard deviation of $0.30 per barrel. The expenses would be the same for every well in a given year, but could change from year to year with the distribution above.
2. Severance Taxes. State taxes levied on produced oil and gas are assumed to be a constant value of 4.6% of revenue. Taxes are applied after the NRI.

The operating expenses are subtracted from the gross sales to arrive at net sales.

Net Present Value Calculation:

The final section of the model sums all revenues and expenses for each year (starting at Year 0), discounted at the weighted average cost of capital (WACC – which we assume for this model is 10 percent per year), and summed across years to compute the forecast of NPV for the project. The formulation used is the following:

$$NPV = -Initial\ Costs + \frac{FNR_{Year\ 1}}{1 + WACC} + \frac{FNR_{Year\ 2}}{(1 + WACC)^2} + \cdots + \frac{FNR_{Year\ 15}}{(1 + WACC)^{15}}$$

FNR is the final net revenues during the specified year.

The scope of this phase includes the following:

- Simulate the following two distributions using the information provided in this project RFP:
    - Cost of a single dry well.
    - Net Present Value of a single wet well.
- Use your results from the previous RFP to simulate drilling costs.

Phase 3 – Dry-Hole Risk

Companies often have proprietary schemes for quantifying the risk associated with not finding any oil or gas in their drilled well. In general, though, there are four primary and **independent** conditions that must all be encountered in order for hydrocarbons to be found by the drill bit:

1. Hydrocarbons must be present.
2. A reservoir must be developed in the rock formation to hold hydrocarbons.
3. An impermeable seal must be available to trap the hydrocarbons in the reservoir and prevent them from migrating somewhere else.
4. A structure or closure must be present that will cause the hydrocarbons (sealed in the reservoir) to pool in a field where the drill bit will penetrate.

These four factors are independent; the probability of a producing well is defined as:

$$P_{PW} = P_H \times P_R \times P_{Seal} \times P_{Structure}$$

We will assume only two of these can actually change. Figure 1 shows the probability distributions for each factor's Monte Carlo assumption.

Dry-Hole Risk Factor	*Mean*	*Standard Dev.*	*Min.*	*Max.*
Hydrocarbons	99%	5%	0%	100%
Structure	100%	0%	100%	100%
Reservoir	80%	10%	0%	100%
Seal	100%	0%	100%	100%

Each of the four risk factor assumptions in Figure 1 are Normally distributed, with the mean standard deviations for each distribution to the right of the assumption fields. In this example, the "Structure" and "Seal" risk factors do not inherit any risk (mean 1 and standard deviation of 0); therefore, these two don't have to be simulated. The "Hydrocarbons" and "Reservoir" should be drawn as random samples from their respective Normal distributions for each well. The ranges of these Normal distributions are confined and **truncated** between the min and max fields. The producing well probability is calculated for each well at each iteration; once this number is computed, you should identify whether each specific well is a Dry Hole or an oil-producing one. **The total number of planned wells is assumed a Uniform distribution between 10 and 30**. This will then tell you how many total producing wells you have.

If you know the probability of a producing well (randomly drawn from a combination of truncated Normal distributions as above), then you can simulate the number of producing wells using a combination of a Uniform distribution for the count and a Bernoulli distribution for whether the well is producing (wet) or dry. The output from a Bernoulli distribution (Binomial distribution with n = 1) is either a 1 or 0. The input to this distribution is the probability you get a 1. Once you calculate the probability a well is wet, you can calculate whether the well is producing from the Bernoulli distribution.

The scope of this phase includes the following:

- Run a simulation for the number of wells in the project that includes whether the well is producing or dry.
- Provide a histogram of the distribution of the proportion of wells that is wet – you will need to know how many wells are dry and how many are wet for each simulation to calculate this.
- Provide your histograms for the probability of hydrocarbons and probability of reservoir.

Phase 4 – Final Report

Once the previous pieces of the RFP are complete, the combined results can form the whole understanding of the net present value across the entire project. You can refer to previous reports in this final report.

Here are the goals from the analysis:

- Simulate the distribution of Net Present Value from the entire project (all of the wells).
- Calculate the expected return from the scenario, as well as measures of risk – such as Value at Risk and Expected Shortfall.
- Make a recommendation on whether the company should invest in the scenario described based on your above numbers.

Data Provided

The following set of data is provided for the proposal:

- The data set **ANALYSIS_DATA** contains the following two sets of information:
    - Estimated drilling costs for Crude Oil, Natural Gas, and Dry Wells. These costs are collected from 1960 – 2007. The geometric annual change on these costs has been calculated.
    - Oil price projections from 2019 – 2050. There are estimates of the high, low, and actual price of oil (reference price).