Petroleum Economics

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Petroleum Economics

Introduction

The exploration and production of oil and gas is a commercial enterprise. Therefore, projects in which an oil and gas production company spends its capital and effort must be evaluated for their economic worth. The first step in performing a proper economic evaluation involves creating an economic model of the project. This model can then be used to calculate the profitability of the project. Once the model is built, the input to the economic model (i.e., prices, expenses, and capital costs) can be varied to determine the sensitivity of each variable to the outcome of the project.

The purpose of this course is to educate one on how to prepare economic models of oil and gas projects and how to use those economic models to determine the economic viability of petroleum projects. For this purpose, this course will concentrate on discussing economics before income taxes (BFIT). The methods of depreciation and depletion will be briefly discussed as they apply to income tax calculations.

The outline of this course is as follows:
- Understanding petroleum projects
- Units of measurement in the petroleum industry
- How oil and gas production is forecast
- Ownership in oil and gas projects
- Forecasting revenue
- Operating expense calculations
- Production taxes
- Capital costs
- Calculation of net income
- Net Present Value
- Calculation of payout and rate-of-return
- Price, expense, and capital cost escalations
- Calculation of economic limit
- Building an economic model

Understanding Petroleum Projects

What is the definition of an oil and gas project?

A petroleum project is an investment of capital used to develop petroleum.

Petroleum is defined as oil and gas. The project can be as simple as drilling and producing a well, installation of an oil or gas pipeline, a water flood of an oil field, installation of a gas plant. Most large petroleum projects are really the sum of a lot of small projects. Therefore, large projects can be modeled by modeling all of the small projects of which it is comprised.

Because petroleum projects involve the discovery and production of natural resources, they have risk associated with them. The evaluation of this risk is a subject in and of itself and will not be discussed in this course.

Before an economic model of a petroleum project can be created, an understanding of the project is necessary. The project must be defined before any economic model can be developed. Shown in the Figure 1 below is a petroleum project – an oil well. Notice there is a timeline within which are various stages of the project. Also outlined are the items which need to be considered when creating an economic model.

Figure 1
Oil Well Project

Table 1 lists the project stages and the economic items for each stage of the project. Drawing a diagram and preparing a table of a petroleum project is an excellent way to make sure that one understands the project and that everything is being accounted for within the life of the project. Once the project is defined and the various economic items are accounted for within that project, an economic model can be developed.

Table 1
Oil Well Project

Projet Stage	Economic Items	Details
Drilling	Capital cost	Capital required to pay for drilling and completion
Production	Revenue	Revenue derived from the sale of oil and gas
	Operating Expense	Expenses incurred to produce the well
	Production taxes	Taxes paid on the sale of oil and gas
	Capital cost	Capital required for maintenance of well and surface equipment
Abandonment	Capital cost	Capital required to plug well and remediate surroundings

Most petroleum projects will follow a similar pattern to the one shown above. Each project will have an initial development stage followed by a production stage and finally an abandonment stage. Shown below in Figures 2 and 3 are diagrams of a petroleum pipeline project and a gas plant project, respectively. Looking at the figures, one readily sees the similarity between those projects and the one above. Understanding this similarity will be key to creating viable economic models of petroleum projects.
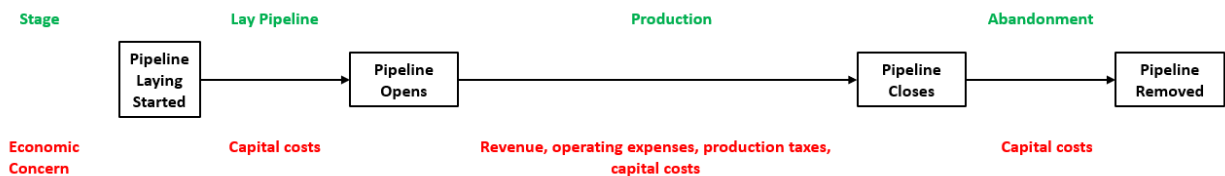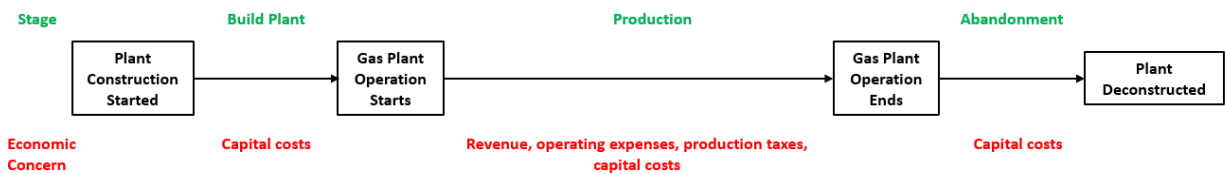
Figure 2
Petroleum Pipeline Project

Figure 3
Gas Plant Project

Units of Measurement in the Petroleum Industry

Before one can begin to discuss petroleum economics, one must understand the units of measurement used in petroleum industry. Oil, gas, and natural gas liquids are the principal quantities being produced, transported, and sold in the petroleum industry. If one is to perform economic calculations, one must use the proper units of measurement to do so.

Oil is produced, transported, and sold in the units of barrels (abbreviated bbl or bbls). A barrel is defined as 42 US gallons and is defined at 60 ^{o}F and 14.65 pounds per square inch absolute (psia). When oil volumes are large, they may be referred to or reported in thousands or millions of barrels (Mbbl or MMbbl, respectively). Oil production rates are measured in barrels per day (bbl/d) or barrels per month (bbl/m).

Natural gas, sometimes referred to as "gas" is measured in standard cubic feet (scf) at 60 ^{o}F and various pressures in and around 14.65 psia. Each US state has their own pressure standard for the measurement of gas volumes. Since a standard cubic foot is quite small in regard to the production, transportation, and sale of natural gas, the volumes are reported in thousands of standard cubic feet (Mscf). Large volumes of gas may be referred to in millions or billions of standard cubic feet (MMscf or Bscf, respectively). Production rates of gas are measured in thousands of standard cubic feet per day (Mscfd) or millions of standard cubic feet per day (MMscfd).

Natural gas sometimes contains components that are removed by production equipment or gas plants and subsequently liquified. These are referred to as natural gas liquids (NGL). The heavier portions of the NGL are sometimes called condensate. NGLs are expressed in units of barrels (bbl). The measurements of production rates for NGL and condensate are the same as that for oil.

Although oil and gas can and almost always is measured at or close to the well from which they are produced, it is the measurement at the point of sale (POS) that is of interest when calculating economics. Measurements at or close to the well are known as wellhead volumes. Measurements at the POS are known as sales volumes.

There are special considerations that must be accounted for in the sale of natural gas. Natural gas can be sold directly from the production equipment near the well, or can be sold for further processing to remove any liquid components that might be in the gas. If sold directly from the well, the gas is sold at a price based on the heating value of the gas. We will not give details of how the heating value is determined, but suffice it to say that the price is based on the components of the natural gas. Heating value is measured in

British Thermal Units (btu), for which 1 btu is the amount of heat required to raise the temperature of 1 pound of water 1 °F. As an example, methane, the most common component of natural gas has a heating value of 1,010 btu/scf. For 1 Mscf of methane, the heating value would be 1,010 Mbtu/Mscf.

Natural gas that is sold to a gas plant for further processing can be sold in its natural state or sold after processing by a gas plant. If sold in its natural state, the purchaser will buy the gas based on its heating value. If sold after processing by the gas plant, the plant will either charge a fee for processing or keep some of the separated products as a fee for processing the gas. After processing, the lightest 1 or 2 products (methane and ethane) are sold as a gas and the heavier products are sold as natural gas liquids. After keeping a portion of the products for fees, the remaining volumes are paid to the producer of the gas. If gas is being processed by a gas plant, there will be a contract describing the processing arrangement. When performing an economic analysis involving gas plants, one must read the contract to accurately account for revenue and fees associated with natural gas.

The unit of currency used in the US is, of course, the dollar ($). When dollar amounts become large, it is common to abbreviate the amounts as thousands or millions of dollars (M$ or MM$).

Natural gas is priced in dollars per thousand btu ($/Mbtu). As previously described, gas production is measured in thousands of standard cubic feet per day (Mscfd). If the heating value of the gas is 1,000 Mbtu/Mscf, there is no price adjustment as the base used is 1,000 Mbtu/Mscf. If the gas price ($/Mbtu) and heating content (Mbtu/Mscf) are known, then the price of gas in $/Mscf can be computed using the following:

$$Price\ in\ \$/Mscf = Price\ in\ \$/Mbtu * \frac{Heating\ Value\ in\ Mbtu/Mscf}{1,000}$$

Below, in Table 2 are the units of measurement for volumes and flow rates of petroleum.

Table 2
Petroleum Measurement Units

Volume Units of Petroleum

Product	Units	Abbreviation
Oil	Barrels	bbl
	Thousand barrels	Mbbl
	Million barrels	MMbbl
Natural Gas	Thousand standard cubic feet	Mscf
	Million standard cubic feet	MMscf
	Billion standard cubic feet	Bscf
Condensate	Barrels	bbl
	Thousand barrels	Mbbl
	Million barrels	MMbbl
NGL	Barrels	bbl
	Thousand barrels	Mbbl
	Million barrels	MMbbl

Production Rate Units of Petroleum

Product	Units	Abbreviation
Oil	Barrels per day	bbl/d
	Barrels per month	bbl/m
Natural Gas	Thousand standard cubic feet per day	Mscfd
	Million standard cubic feet per day	Mscfm
	Thousand standard cubic feet per month	MMscfd
	Thousand standard cubic feet per month	MMscfm
Condensate	Barrels per day	bbl/d
	Barrels per month	bbl/m
NGL	Barrels per day	bbl/d
	Barrels per month	bbl/m

How Oil and Gas Production is Forecast

A forecast of estimated oil and/or gas production will be a part of every petroleum economics project. Therefore, this course will present some information on common methods used to forecast oil and gas.

Oil and gas accounting is done on a monthly basis. Oil and gas production and any associated production taxes are also reported and paid to the government on a monthly basis.

Oil and gas production forecasts can be done by using production decline formulas, manual forecasting, or by use of reservoir simulation. No matter which of these methods is used, the economic modeling will be identical. All of these methods can likely forecast oil and gas production on a daily, monthly, or yearly basis. The forecasting recommended by this course is on a monthly basis since this is the minimum amount of time over which production and associated revenues, expenses, and taxes will be reported.

When oil and gas is initially produced it is known as primary production. In most cases, the primary production rate declines over time. There are, however, a few exceptions to this as in the case of a strong water-drive reservoir or production rates that may be limited to production facilities. Production from a strong water-drive reservoir may initially be flat. However, as oil or gas is produced, the water moves toward the well and eventually begins to be produced at which time the oil or gas production begins to decline. In cases where the production is limited by production facilities (i.e., offshore production, pipeline limits, etc.), the production is curtailed. As time passes, the reservoir pressure declines to a point when the well can no longer produce at the curtailed rate and production begins to decline.

To increase production and reserves in oil and gas wells, water or other fluids (gas, CO_2, etc.) may be injected into the reservoir. This is most common in oil reservoirs rather than gas reservoirs. To inject fluids requires additional wells be drilled, or some of the existing producing wells be converted to injection wells. The purpose of these injected fluids is to increase the reservoir pressure and push oil and gas to the production wells. If this occurs during or after primary production, this is known as secondary recovery. If some form of secondary recovery has already been done, then it is known as tertiary recovery. The oil and gas production from secondary and tertiary recovery projects will typically increase until some point in time and then eventually decline as those injected fluids, along with oil and gas is produced.

When production is forecast using a reservoir simulator, the forecast is usually the production that is estimated for a given time frame. This time frame can be a day, month, or even a year. Since reservoir simulation is a specialized discipline and not within the scope of this course, it will only be said that it is recommended that monthly time frames be specified for the forecast. Reservoir simulation is expensive and time-consuming. For that purpose, reservoir simulation is usually undertaken only on large projects.

Manual forecasting may be used in the case of an analog model, such as a forecast for a secondary or tertiary recovery project. In those cases, the production may be flat or rise over time and then eventually decline. If manual forecasting is used, then the forecast of production is recommended to be on a monthly basis.

Regardless of whether a well is under primary, secondary, or tertiary production, it should be evident that production from wells will eventually decline. That being the case, this course will present information about methods used to forecast production decline. These methods are known as decline curve forecasts.

Not long after petroleum was first discovered it was observed that production rates declined over time. Upon studying production data, a mathematical relationship was found relating the decline in production rate with time. Based on the observed data, two distinct types of decline profiles were seen – exponential decline and hyperbolic decline. In exponential decline, the rate of decline (usually expressed as a percentage loss in production rate per year) is constant as time progresses. The other decline profile observed is known as hyperbolic decline. In hyperbolic decline, the decline rate is seen to decline as time progresses. The rate of production decline is related to the decline in reservoir pressure. To this day, no one is exactly sure why production out of some reservoirs decline exponentially versus hyperbolically.

Figures 4 and 5 are graphs of forecasts following exponential and hyperbolic declines over time. Figure 4 show the forecasts projected on a Cartesian scale. From figure 4, it is difficult to tell the difference in curve shape between exponential and hyperbolic decline. However, when the forecasts are plotted on a semi-log scale, the difference becomes quite apparent. The exponential decline forecast is easily recognizable as it forms a straight line on semi-log scale. Within the oil and gas industry it is customary to plot production and production forecasts on semi-log scales.

When using production to estimate decline curve parameters, it is imperative that the wells be producing at full capacity. Any curtailment of flow rate will invalidate the use of decline curves.
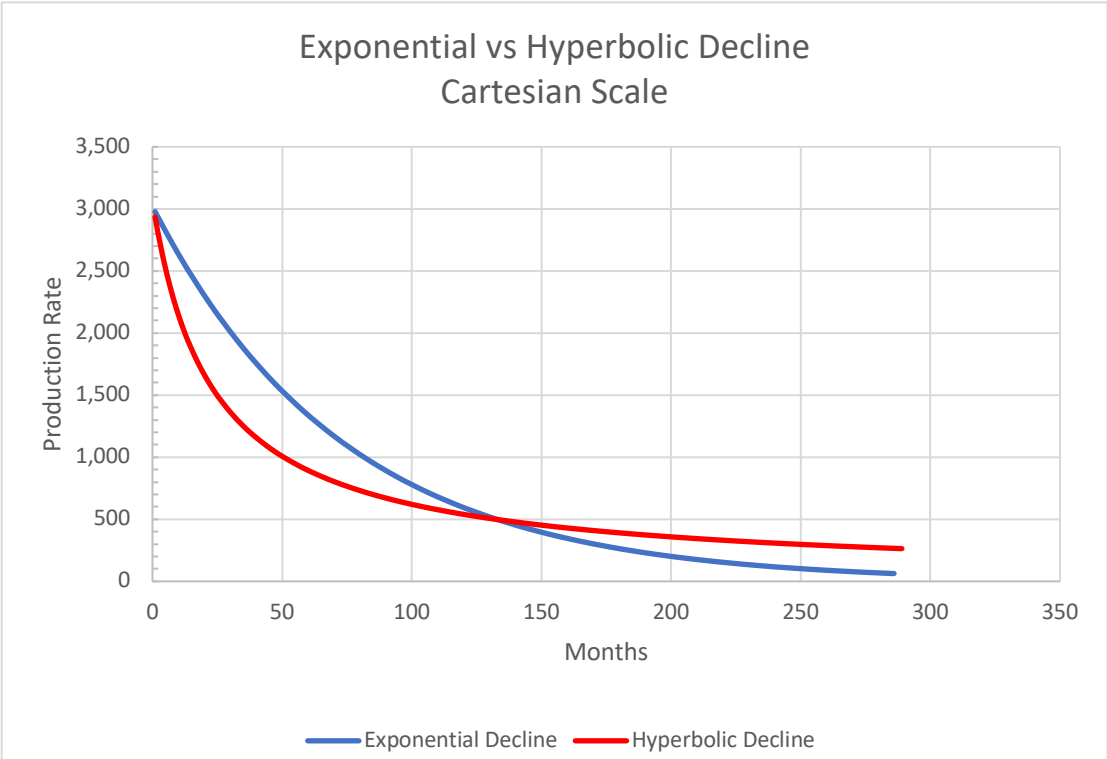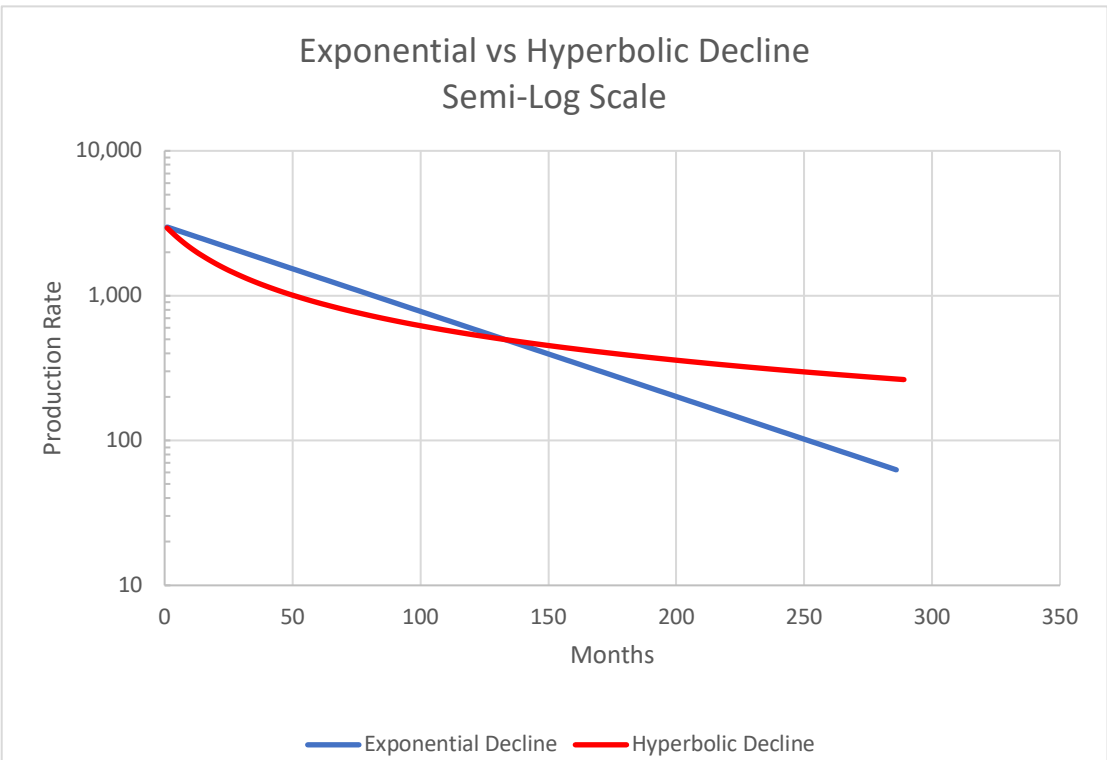
Figure 4

Exponential vs Hyperbolic Decline
Cartesian Scale

Figure 5

Exponential vs Hyperbolic Decline
Semi-Log Scale

Exponential Decline

A production rate that declines by the same percentage each time period is known as exponential decline. If the exponential decline rate is 8% per year, it means that the production rate at the end of the year will be 8% less than at the beginning of the year. The equation below shows the relationship between producing rates, time, and exponential decline rate:

$$q = q_i * (1 - d)^t$$

where,

q = producing rate at time t
q_i = initial producing rate at time t_o
d = decline rate per time period
t = time at which the calculation of q is desired

When using any of the decline equations, one must make sure that the time used in the equation matches the decline rate time frame. If one uses yearly decline rates, then the time used in the equation must be in years. If monthly decline rates are used, the time used in the equation must be months. All decline rates used in the equations are decimal, even though most times the percentage decline rate is used in discussions. The production rates, on the other hand, can be production rates over any time frame. Production rates can be daily, monthly, yearly, fortnightly, etc. Both production rates in the equation (initial and final) must be in the same units.

Example Problem:

Given an initial production rate of 120 barrels per day and an exponential decline rate of 8% per year, what is the producing rate 1 year and 2 years later?

Solution:

Since the decline rate and the time frame are both in years, one can use the exponential decline rate equation to find the production rate one year and two years hence as:

End of year 1 $\qquad\qquad q = 120 * (1 - 0.08)^1 = 110.4\ bbl\ per\ day$

End of year 2 $\qquad\qquad q = 120 * (1 - 0.08)^2 = 101.6\ bbl\ per\ day$

Note that the units for the production rate are in barrels per day. Notice also that the ratio of any year to the previous year is (1 – d). In this case (1 – d) = 0.92. Shown below is the relationship between production rate at the end of year 2 divided by the production rate at the end of year 1:

$$\frac{101.6}{110.4} = 0.92 = (1 - 0.08) = (1 - d)$$

It is sometime necessary to change the decline rate in one set of time units to a decline rate in another time unit. The next several equations show how to change decline rates between various sets of units.

To change decline rate from yearly to monthly:

$$d_m = 1 - (1 - d_y)^{\left(\frac{1}{12}\right)}$$

where,

d_m = monthly decline rate (decimal per month)
d_y = yearly decline rate (decimal per year)

To change decline rate from monthly to yearly:

$$d_y = 1 - (1 - d_m)^{12}$$

Example Problem:

Convert a yearly decline rate of 8% to a monthly decline rate. Given an initial production rate of 120 bbl per day, use the converted decline rate to calculate the production rate after 2 years (24 months).

Solution:

Monthly decline rate $\qquad d_m = 1 - (1 - 0.08)^{\left(\frac{1}{12}\right)} = 0.006924 \; per \; month$

Production rate end of year 2 $\qquad q = 120 * (1 - 0.006924)^{24} = 101.6 \; bbl \; per \; day$

Notice that the production rate is identical to the solution of the previous example problem.

It is necessary to be able to calculate the oil or gas forecast between two endpoint production rates or over a certain period of time. If an initial and final production rate is known, then the following equation can be used to calculate the oil or gas production between those endpoints as:

$$N_p = \frac{(q_i - q)}{-\ln{(1-d)}}$$

where,

N_p = cumulative oil or gas volume
q_i = initial production rate
q = ending production rate
d = decline rate (decimal per time period)

To use this equation, the time period used in the decline rate must match the time period used in the producing rate. If the decline is decimal per year, then the production rate must be units per year. If the time units for the decline and production rate are the same, then this equation can be used as is. However, if the production rate is in daily units and the decline rate is yearly, then the following equation will properly convert units:

$$N_p = \frac{365 * (q_i - q)}{-\ln{(1-d)}}$$

If the production rate is in units per month and the decline is yearly, then this equation should be used:

$$N_p = \frac{12 * (q_i - q)}{-\ln{(1-d)}}$$

In cases where the initial production rate and decline rate are known, cumulative production at a time in the future can be calculated as:

$$N_p = \frac{q_i * (1 - (1-d)^t)}{-\ln{(1-d)}}$$

If the decline rate is yearly and the production rate in units per day, the production rate must be multiplied by 365 to get a correct value of N_p. Similarly, if the decline rate is yearly and the production rate in units per month, then the production rate must be multiplied by 12 to calculate N_p properly.

The following example problem will illustrate how to calculate cumulative forecast volumes.

Example Problem:

An oil well produces at an initial rate of 150 bbl per day. The production rate declines at a rate of 15% per year. What is the production rate at the end of year 3? How much oil has been produced by the end of year 3?

Solution:

The production rate at the end of year 3 is calculated as:

$$q = q_i * (1 - d)^t = 150 * (1 - 0.15)^3 = 92.1 \; bbl \; per \; day$$

There are two ways one can calculate the cumulative oil. Let's calculate it both ways to check the results. Since we know the starting and ending production rates (daily rates) and the decline rate (yearly decline), the cumulative oil can be calculated as:

$$N_p = \frac{365 * (q_i - q)}{-\ln(1-d)} = \frac{365 * (150 - 92.1)}{-\ln(1 - 0.15)} = 129{,}995 \; bbl$$

Using the initial production rate, yearly decline rate, and time, we can use this equation to calculate the cumulative forecast production:

$$N_p = 365 * \frac{q_i * (1 - (1-d)^t)}{-\ln(1-d)} = 365 * \frac{150 * (1 - (1 - 0.15)^3)}{-\ln(1 - 0.15)} = 129{,}995 \; bbl$$

Hyperbolic Decline

Hyperbolic decline occurs when the rate of decline decreases over time. The amount of decrease in the decline rate is constant and is defined by something termed the "b" factor. Notice in Figures 4 and 5 that there is a bend in the hyperbolic decline curve. This is especially noticeable in Figure 5 when plotted on a semi-log scale. The amount of bend in the curve is dependent on the b factor. The higher the b factor, the more the curve bends. The steepness of the hyperbolic decline curve is determined by the initial decline rate of the production (or forecast). If the b factor is zero, the rate decline is exponential.

The b factor and initial decline rate are determined by fitting a hyperbolic curve to production data. There are a number of petroleum economic software programs available that can be used to fit curves to the production data. It can also be done manually, but is rather time consuming.

It was initially thought that the value for the b factor could not exceed the value of 1.0 as most reservoirs had b factors less than 1.0. However, with the advent of hydraulic fracturing and production from shale, b factors as high as 2.0 have been observed. When the b factor is equal to 1.0, it is known as harmonic decline. When discussing hyperbolic decline, it is intended to also include harmonic decline.

To forecast production rates at future times following hyperbolic decline, the following equation ca be used:

$$q = \frac{q_i}{(1 + b * d_i * t)^{\frac{1}{b}}}$$

where,

q = production rate at time t
q_i = initial production rate
b = b factor
d_i = initial hyperbolic decline rate (not the initial effective decline rate – see below)
t = time

The decline rate is a hyperbolic decline rate and must be calculated from the effective decline rate. The effective decline rate is the decline that would occur if it were exponential. To calculate the hyperbolic decline rate use:

$$d_i = -\ln(1 - d_e)$$

where d_e is the effective decline rate.

If the b factor is not equal to 1.0, the following equation will calculate the cumulative volume between an initial and final production rate:

$$N_p = \frac{q_i{}^b}{d_i * (1 - b)} * (q_i^{(1-b)} - q^{(1-b)})$$

Using the initial rate, initial hyperbolic decline rate, and b factor not equal to 1.0, the cumulative production to a future time can be calculated as:

$$N_p = \frac{q_i}{d_i * (1 - b)} * (1 - (1 + b * d_i * t)^{\left(\frac{b-1}{b}\right)})$$

Remember that the units must be consistent. If using daily rates and yearly declines, the rate must be multiplied by 365. If monthly rates are used with yearly declines, the rate must be multiplied by 12.

For the case of harmonic decline when the b factor is equal to 1.0, the equations are much simpler. The following equations can be used to calculate cumulative production between two production rates or at some future point in time:

Based on initial an ending production rates:

$$N_p = \frac{q_i}{d_i} * \ln\left(\frac{q_i}{q}\right)$$

When using the initial rate, initial hyperbolic decline, and time, use:

$$N_p = \frac{q_i}{d_i} * \ln(1 + d_i * t)$$

The following example problem will be used illustrate the use of hyperbolic decline equations in calculating future rates and cumulative production volumes. For this example, we will use gas production.

Example Problem:

A shale gas well initially produces at a rate of 2,500 Mscfd (thousand standard cubic feet per day). The reservoir is known to produce hyperbolically with a b factor of 1.20. The effective initial decline rate has been calculated to be 65% per year.

What is the producing rate and cumulative gas production at the end of year 2?

Solution:

The first thing to calculate is the hyperbolic decline rate as:

$$d_i = -\ln(1 - d_e) = -\ln(1 - 0.65) = 1.0498$$

The rate at the end of year 2 is calculated as:

$$q = \frac{q_i}{(1 + b * d_i * t)^{\frac{1}{b}}} = \frac{2,500}{(1 + 1.2 * 1.0498 * 2)^{\frac{1}{1.2}}} = 876 \ Mscfd$$

The cumulative volume can be calculated from the initial and ending rate as:

$$N_p = 365 * \frac{2,500^{1.2}}{1.0498 * (1 - 1.2)} * \left(2,500^{(1-1.2)} - 876^{(1-1.2)}\right) = 1,014,165 \ Mscf$$

The cumulative volume can also be calculated as:

$$N_p = 365 * \frac{2,500}{1.0498 * (1 - 1.2)} * \left(1 - (1 + 1.2 * 1.0498 * 2)^{\left(\frac{1.2-1}{1.2}\right)}\right) = 1,014,083 \ Mscf$$

The difference between the two volumes is round-off error.

Table 3 lists equations used to calculate future rates and volumes for exponential, hyperbolic, and harmonic declines.

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Table 3
Properties of Decline Types

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Decline Type	Rate Time	Cumulative Volume
Exponential	$q = q_i * (1-d)^t$	$N_p = \dfrac{(q_i - q)}{-\ln{(1-d)}}$ or $N_p = \dfrac{q_i * (1 - (1-d)^t)}{-\ln{(1-d)}}$
Hyperbolic	$q = \dfrac{q_i}{(1 + b * d_i * t)^{\frac{1}{b}}}$	$N_p = \dfrac{q_i{}^b}{d_i * (1-b)} * (q_i{}^{(1-b)} - q^{(1-b)})$ or $N_p = \dfrac{q_i}{d_i * (1-b)} * (1 - (1 + b * d_i * t)^{\left(\frac{b-1}{b}\right)})$
Harmonic	$q = \dfrac{q_i}{(1 + d_i * t)}$	$N_p = \dfrac{q_i}{d_i} * \ln{\left(\dfrac{q_i}{q}\right)}$ or $N_p = \dfrac{q_i}{d_i} * \ln{(1 + d_i * t)}$

Additional Forecasting Methods

Although it is perfectly suitable to forecast production using decline curves, secondary products (gas in the case of an oil well, condensate and NGL in the case of gas wells) can also be calculated using ratios to the primary product.

For oil wells where the gas production closely follows the oil production, one can use the ratio of gas to oil to forecast the gas production. The ratio of gas to oil is known as the gas-oil-ratio, or GOR and is expressed in units of standard cubic feet per barrel (scf/bbl). For reporting and economic calculations, it is proper to calculate the gas rates in Mscf. To calculate the gas production, given the oil production and GOR, use the following formula:

$$q_g = \frac{q_o * GOR}{1,000}$$

where,

      q_g = gas production (Mscfd or Mscfm)
      q_o = oil production (bbl/d or bbl/m)
      GOR = gas-oil-ratio (scf/bbl)

For gas production, we can have associated condensate and NGL production. Although the ratio of these products to gas production can change over time, their production can be forecast as ratios to gas production. The ratios of condensate production to gas production and NGL production to gas production are called Condensate Yield, and NGL Yield, respectively. When using yields, one must use the wellhead gas volumes and not sales gas volumes. The units for condensate and NGL yields are barrels per million standard cubic feet (bbl/MMscf). The following equations can be used to calculate condensate and NGL production as ratios of gas production:

$$q_c = q_g * Yield_c * 1,000 \qquad\qquad q_{NGL} = q_g * Yield_{NGL} * 1,000$$

where,

      q_c = condensate production (bbl/d or bbl/m)
      q_{NGL} = NGL production (bbl/d or bbl/m)
      q_g = wellhead gas production (Mscfd or Mscfm)
      $Yield_c$ = condensate yield (bbl/MMscf)
      $Yield_{NGL}$ = NGL yield (bbl/MMscf)

Ownership in Oil and Gas Projects

Understanding the types of ownership in oil and gas projects is critical to the economic assessment of those projects. The types of ownership in oil and gas projects typically fall into the following categories:

- Working interest
- Revenue interest
- Royalty interest

A working interest is an ownership in an oil and gas project that pays capital costs and operating expenses. By definition, a working interest must be greater than 0% and less than or equal to 100%. The sum of all the working interest owners in a project must add up to 100%.

A revenue interest is an ownership in the revenue derived from the sale of oil, gas, and any other production from the project. A revenue interest can be an ownership of a working interest owner or a royalty owner. For a working interest owner, the revenue interest is sometimes referred to as the net revenue interest and is equal to the working interest less any royalty interests. The revenue interest owner pays its share of any production taxes and transportation fees for sale of oil, gas, and other production. All revenue interests in a project must sum to 100%.

A royalty interest is a revenue interest that is owned by the lessor of the mineral rights of an oil or gas well. For the purpose of leasing rights to drill and develop, the mineral owner will negotiate a royalty interest in the project. Normal royalty interests range from 1/8th to 1/4th of the gross sales. This is sometimes referred to as the royalty burden as it is an expense paid by the working interest owners. Petroleum pipelines and gas plants typically do not have royalty interests associated with them. The royalty interest does not have any working interest associated with it. It is certainly possible, however that one of working interest owners could also own the mineral rights and be a royalty interest owner.

Associated with some projects is an ownership known as an overriding royalty interest (ORRI). The ORRI is not a direct ownership in the project, but a percentage of the sales paid to a third party. The third party could be a geologist or company that discovered a petroleum field or brokered a deal with the working interest owners. Typical ORRIs are in the range of 2% to 5% of the gross sales. Like other revenue interest owners, an ORRI pays its share of any production taxes and transportation fees.

The revenue interest of a working interest owner can be calculated as follows:

$$Revenue\ Interest = Working\ Interest - Working\ Interest * (Royalty\ Interest + ORRI)$$

Where the royalty interest and ORRI are net of any ownership by the working interest owner. The following example problem will show how the working interests and revenue interests are calculated.

Example Problem:

Two working interest owners are proposing to drill a well. The owners have secured a lease for the proposed well. The mineral owner has agreed to lease the rights to drill and develop for a royalty of 1/8th. The idea to drill and develop in this particular location was brought to the working interest owners by a geologist who will receive a 2% ORRI.

Owner A owns 60% (0.60) of the project. What is the working interest of owner B? What is each owner's revenue interest (all revenue interest owners in the project)?

Solution:

All working interests in a project must add to 100%, so:
$$Owner\ B = 100 - Owner\ A = 100 - 60 = 40\% = 0.40$$

Revenue interest for the royalty owner (mineral owner) is defined in the problem as:
$$Royalty\ Interest = \frac{1}{8} = 0.125 = 12.5\%$$

Revenue interest for Owner A:
$$A\ Revenue\ Interest = 0.60 - 0.60 * (0.125 + 0.02) = 0.513 = 51.3\%$$

Revenue interest for Owner B:
$$A\ Revenue\ Interest = 0.40 - 0.40 * (0.125 + 0.02) = 0.342 = 34.2\%$$

The revenue interest for the ORRI is stated as 2% = 0.002

Check that the revenue interests add to 100%:
$$Total\ Revenue\ Interest = .125 + 0.513 + 0.342 + 0.02 = 1.000 = 100\%$$

Forecasting Revenue

Revenue in a petroleum project is derived from the sale of oil, gas, or other petroleum products or a fee received for the processing of oil, gas, or other petroleum products. For the purpose of discussing how to calculate revenue, we will use the production from oil and gas wells as the basis, since this is the most common petroleum project. However, an example at the end of this section will include calculating revenue from fees associated from petroleum transport.

For petroleum projects, gross revenue is simply a price (of fee) multiplied by volume. Net revenue is calculated as the gross revenue multiplied by the revenue interest. For sales of a given quantity of oil or gas, gross revenue for oil and gas is calculated as:

$$Gross\ Oil\ Revenue = P_o * Q_o$$

$$Gross\ Gas\ Revenue = P_g * Q_g$$

where,
   Gross Oil Revenue = gross revenue of oil sales ($)
   Gross Gas Revenue = gross revenue of gas sales ($)
   P_o = oil price ($/bbl)
   P_g = gas price ($/Mscf)
   Q_o = oil volume (bbl)
   Q_g = gas volume (Mscf)

Notice the volumes for oil and gas are totals and not daily or monthly rates. If it is desired to calculate the daily or monthly gross revenue, then production rates can be substituted in the formulas to get:

$$Gross\ Oil\ Revenue = P_o * q_o$$

$$Gross\ Gas\ Revenue = P_g * q_g$$

where,
   Gross Oil Revenue = gross revenue of oil sales ($/d or $/m)
   Gross Gas Revenue = gross revenue of gas sales ($/d or $/m)
   P_o = oil price ($/bbl)
   P_g = gas price ($/Mscf)
   q_o = oil volume (bbl/d or bbl/m)
   q_g = gas volume (Mscfd or Mscfm)

Where secondary products are forecast using ratios (GOR and Yields), the gross revenue can be easily calculated as follows.

Oil wells with secondary GOR:

$$Gross\ Revenue = Q_o * (P_o + P_g * \frac{GOR}{1,000})$$

Gas wells with secondary Yields:

$$Gross\ Revenue = Q_g * (P_g + P_c * Yield_c * 1,000 + P_{NGL} * Yield_{NGL} * 1,000)$$

where,

    Gross Revenue = gross revenue ($)
    P_o = oil price ($/bbl)
    P_g = gas price ($/Mscf)
    P_c = condensate price ($/bbl)
    P_{NGL} = NGL price ($/bbl)
    Q_o = oil volume (bbl)
    Q_g = gas volume (Mscf)
    GOR = gas-oil-ratio (scf/bbl)
    $Yield_c$ = condensate yield (bbl/MMscf)
    $Yield_{NGL}$ = NGL yield (bbl/MMscf)

The net revenue is calculated as the gross revenue multiplied by the revenue interest as:

$$Net\ Oil\ Revenue = Gross\ Oil\ Revenue * Revenue\ Interest$$

$$Net\ Gas\ Revenue = Gross\ Gas\ Revenue * Revenue\ Interest$$

where,

    Net Oil Revenue = net revenue of oil sales ($/d or $/m)
    Net Gas Revenue = net revenue of gas sales ($/d or $/m)

Example Problem:

A working interest owner has a 100% working interest and an 87.5% revenue interest in an oil well. In a given month, the well has produced 1,250 bbl of oil. The GOR on the well is 600 scf/bbl. The oil and gas prices during the month were $48.85 per bbl and $2.72 per Mscf of gas. A truck hauls away the oil for $1.50 per bbl and a pipeline transports the gas for $0.25 per Mscf.

What is the gross and net revenue to the working interest owner for oil and gas sales?
What is the revenue for the truck that hauls the oil?
What is the revenue to the pipeline that transports the gas?

Solution:

The gross revenues for oil and gas are:

$$Gross\ Revenue = 1,250 * \left(48.85 + 2.72 * \frac{600}{1,000}\right) = \$63,102.50$$

The net revenue to the working interest owner is:

$$Net\ Revenue = 63,102.50 * 0.875 = \$55,214.68$$

The truck receives revenue for the oil as:

$$Truck\ Revenue = 1,250 * 1.50 = \$1,875.00$$

The truck receives revenue for transporting gas. The gas volume is:

$$Q_g = 1,250 * \frac{600}{1,000} = 750\ Mscf$$

The pipeline revenue is:

$$Pipeline\ Revenue = 750 * 0.25 = \$187.50$$

Operating Expense Calculations

Operating expenses are the expenditures required to maintain the operation of a petroleum project. Operating expenses can be classified into the following:
- Fixed expenses
- Overhead expenses
- Variable expenses
- Transportation expenses

Fixed and overhead expenses are those expenses that are fairly constant from month to month and do not change appreciably with the amount of oil and gas produced, transported, or processed. Variable expenses are those expenses that are directly related to the production and processing of oil and gas. Transportation expenses are fees that are charged to transport oil and gas, usually by a third party.

To estimate expenses for a given petroleum project, one must review the operating statement. Careful review allows one to classify the various expenses on the statement. Overhead expenses and transportation expenses are fairly easy to determine. However, the allocation of expenses as either fixed or variable can be challenging. As an example, a compressor that is required for gas production could be a fixed or variable cost depending on the arrangement for compression. If the compressor is owned by a third party and compression is charged as a fee based on the production rate of gas, then it is a variable expense. On the other hand, if the compressor is leased by the operating company, then the expense would be fixed because the monthly lease payment is not dependent on the amount of gas being compressed.

Expenses for a particular working interest owner are calculated by multiplying the gross expense by the working interest. The exception this rule are transportation expenses which are charged to the revenue interest volumes.

Fixed Expenses

Expenses that are fairly consistent month-to-month are referred to as fixed expenses. The following are typical fixed expenses:
- Wages and salaries of operating personnel
- Site and road maintenance
- Equipment leases

When using fixed expenses, the expense is usually expressed in the units of dollars per month ($/m), since accounting in the oil and gas industry is done on monthly basis.

Overhead Expenses

Expenses that are charged to a particular oil and gas project by the operator or supervising office are known as overhead expenses. Oil and gas operating agreements specify an overhead expense for the operator of the project. The overhead expense is to reimburse the operator for the management of the project and the expense of accounting and reporting. These expenses are a monthly expense.

Variable Expenses

Of all the expenses in an oil and gas project, variable expenses are the most difficult to determine. Listed below are some expenses that are typically variable:

- Electricity for timed pumping
- Third-party compression fees
- Downhole pump replacement
- Chemical treatments

The expenses for electricity and compression fees can be found directly from the operating statement as they will appear on each monthly statement. To calculate expenses for downhole pump replacement and chemical treatments, operating statements over several months or years may have to be inspected. The variable expenses for those items are calculated by dividing the expense by the amount of oil or gas produced during the interval between treatments.

Variable expenses are dollars per unit of production ($/bbl or $/Mscf).

Transportation Expenses

Transportation expenses are expenses charged to move oil and gas from a location of production to another location for refining or end use. Once oil and gas are produced, it is owned by the revenue interest owners. Therefore, transportation expenses are charged to the revenue interests. In effect, it is like a deduction from the oil and gas sales price.

Transportation expenses are in units of dollars per unit ($/bbl or $/Mscf).

Total operating expenses are calculated as:

$$OPEX = FC + OH + Q_o * C_o + Q_g * C_g + Q_{NGL} * C_{NGL}$$

where,

>   *OPEX* = gross operating expense ($/time period)
>   *FC* = fixed cost ($/time period)
>   *OH* = overhead ($/time period)
> Q_o = oil production (bbl/per time period)
> Q_g = gas production (Mscf/per time period)
> Q_{NGL}= NGL production (bbl/per time period)
> C_o = oil expense ($/bbl)
> C_g = gas expense ($/Mscf)
> C_{NGL} = NGL expense ($/bbl)

Net operating expense is the operating expense net to a working interest owner in a project. Net operating expense is:

$$Net\ Operating\ Expense = WI * OPEX$$

where,

>   Net Operating Expense = operating expense net to a working interest owner
>   *WI* = working interest (decimal)
>   *OPEX* = gross operating expense ($/time period)

Example Problem:

An oil well produced both oil and gas. The working interest owner has a 50% working interest and a 43.75% revenue interest. For the month, the well produced 1,500 bbl of oil and 30,000 Mscf of gas. In reviewing the operating statement, the following was found:

Salaries and wages	$800 per month
Road maintenance	$400 per month
Compressor rental	$3,500 per month
Monthly overhead charges	$300 per month
Oil transportation fee	$2.50/bbl
Gas transportation fee	$0.30/Mscf

It was also found that the well's downhole pump must be replaced every 50,000 bbl at a gross expense of $75,000.

What are the fixed monthly expenses net to the working interest?
What is the variable expense net to the working interest?
What are the transportation expenses net to the revenue interest?
What is the total expense for the month?

Solution:

Gross Fixed Expenses = 800 + 400 + 3,500 = $4,700 per month
Net Fixed Expenses = 0.5 * 4,700 = $2,350 per month

Gross Variable Expense = Pump replacement = $75,000 / 50,000 bbl = $1.50/bbl
For Production of 1,500 bbl, Gross Variable Expense = 1.50 * 1,500 = $2,250
Net Variable Expense = 0.5 * 2,250 = $1,125

Gross Transportation Expenses = 2.50 * 1,500 + 0.30 * 30,000 = $12,750
Net Transportation Expenses = 0.4375 * 12,750 = $5,578.12

Total Net Expenses = Fixed + Overhead + Variable + Transportation
= 2,350 + 0.5 * 300 + 1,125 + 5,578.12 = $9,20.12

Production Taxes

Production taxes are taxes levied by a government on the sale of oil and gas. These taxes fall into two categories; severance taxes and ad valorem taxes. Severance taxes are paid to the state government and ad valorem taxes are paid to the county government.

Severance taxes are calculated as either (sometimes both) a percentage of the sales revenue or a dollar per unit of production. Some states have both types of taxes on oil and gas. Since severance taxes are on based on the sales revenue, each revenue interest owner will pay their share of the taxes.

Ad valorem taxes are sometimes a percentage of sales revenue or based on the value of the surface equipment. Ad valorem taxes that are a percentage of sales revenue are paid by the revenue interest owner. If the ad valorem tax is based on the value of the surface equipment, it is paid by the working interest owner. A review of the operating statement and local tax law will reveal the appropriate tax policy.

The following formulas can be used to calculate severance taxes:

$$Oil\ Net\ Severance\ Tax = RI * Q_o * (P_o * T\%_o + T\$_o)$$

$$Gas\ Net\ Severance\ Tax = RI * Q_g * (P_g * T\%_g + T\$_g)$$

$$NGL\ Net\ Severance\ Tax = RI * Q_{NGL} * (P_{NGL} * T\%_{NGL} + T\$_{NGL})$$

where,

RI = revenue interest
Q_o = oil production (bbl)
Q_g = gas production (Mscf)
Q_{NGL} = natural gas liquid production (bbl)
P_o = oil price ($/bbl)
P_g = gas price ($/Mscf)
P_{NGL} = NGL price ($/bbl)
$T\%_o$ = oil severance tax rate (% of revenue in decimal)
$T\$_o$ = oil severance tax rate ($/bbl)
$T\%_g$ = gas severance tax rate (% of revenue in decimal)
$T\$_g$ = gas severance tax rate ($/Mscf)
$T\%_{NGL}$ = NGL severance tax rate (% of revenue in decimal)
$T\$_{NGL}$ = NGL severance tax rate ($/bbl)

Ad valorem taxes that are based on the value of the surface equipment are paid by the working interest owner. As such, they are an annual fixed payment. For these cases, ad valorem taxes should be treated as a fixed monthly expense (by dividing the annual tax by 12).

For ad valorem taxes based on percentage of sales, the formula shown below should be used:

$$Net\ Ad\ Valorem\ Tax = RI * T\%_a * (Q_o * P_o + Q_g * P_G + Q_{NGL} * P_{NGL})$$

where,

$T\%_a$ = ad valorem tax rate (% of revenue in decimal)

Example Problem:

Given are the following; a working interest of 25% and revenue interest of 20%, oil production of 800 bbl, gas production of 20,000 Mscf, NGL production of 8 bbl, oil price of $48.00/bbl, gas price of $3.20/Mscf, NGL price of $30.00/bbl. The severance tax rates are 5% of oil, gas, and NGL revenue and $0.125/bbl of oil. Ad valorem tax rate is 1.5% of revenue.

Calculate the severance and ad valorem taxes.

Solution:

Severance taxes:

$$Oil\ Net\ Severance\ Tax = 0.20 * 800 * (48.00 * 0.05 + 0.125) = \$404.00$$

$$Gas\ Net\ Severance\ Tax = 0.20 * 20{,}000 * (3.20 * 0.05 + 0) = \$640.00$$

$$NGL\ Net\ Severance\ Tax = 0.20 * 8 * (30.00 * 0.05 + 0) = \$2.40$$

Total severance tax = 404.00 + 640.00 + 2.40 = $1,046.40

Ad valorem taxes:

$$Net\ Ad\ Valorem\ Tax = 0.20 * 0.015 * (800 * 48.00 + 20{,}000 * 3.20 + 8 * 30.00)$$
$$= \$307.92$$

Capital Costs

Capital costs are those costs invested to develop a project. Although capital costs are an expense item, they are different by definition. While expenses are required for the ongoing operation of a project, capital costs are for the purchase of permanent equipment and structures that are necessary over the life of the project. In petroleum projects capital costs can be as follows:

- Oil and gas leases
- Drilling an oil or gas well
- Completion of oil and gas wells
- Casing and tubing for oil and gas wells
- Surface equipment
- Gas plants
- Gathering or transportation pipelines
- Road construction
- Power installation

In this course, we are primarily dealing with petroleum economics that are calculated without considering Federal and State income taxes. When calculating economics before income taxes, we assume a capital costs to be an expense for the calculation of net income, net present value, payout, and rate-of-return (to be discussed in later sections). The calculations for those items on an after-tax basis, however, are different. The reason for this is that tax law dictates that capital costs be expensed over the life of the project or a time period specified in the tax law. The method for expensing capital costs over time is by using depreciation or depletion. This is known as "capital recovery".

This course will not discuss the details of calculating Federal and state income taxes. We will, however, discuss the method by which capital costs are expensed over the life of petroleum projects and how they affect the after-tax calculation of net income, net present value, payout, and rate-of-return. The choice of depreciation or depletion of capital costs is based on the type of project in which the capital was invested. For some projects, both depreciation and depletion are required for the capital recovery.

In petroleum projects, we see both depreciation and depletion used. For this course, we will only introduce the concepts of depreciation and depletion so the reader will become familiar with the terms and potential uses. Since tax law regarding depreciation and depletion change, it is recommended that a tax professional be consulted prior to calculating depreciation and depletion.

By definition, depreciation is the reduction in value of something over time. As a tax item, it is considered to be the loss of value of a capital item over time. The time is either the life expectancy of the capital item, or a time specified by tax law. There are several different types of depreciation that are allowed for the recoupment of capital costs. A few are listed below:

- Straight-line
- Double declining balance
- Sum of the year's digits
- Units of production

Recent tax law has allowed for the complete expense of certain capital items. The example below shows how to use depletion calculations to expense capital costs.

Straight-line depreciation is often used to recover capital costs for tax deduction purposes. Straight-line depreciation is calculated as:

$$DEPR_{SL} = \frac{CAPEX}{T}$$

where,

$DEPR_{SL}$ = straight-line depreciation per year ($)
$CAPEX$ = capital cost ($)
T = time over which the CAPEX is to be depreciated (years)

Example Problem:

An oil and gas company recently leased land in order to pursue an exploration opportunity. The leases are for a term of 5 years. The leased encompassed 12,000 acres. The leases were prepaid leases at $15 per acre. Per tax law, these leases must be depreciated over their term. There is not yet any oil or gas production from any of these leases. If straight-line depreciation is used, what is the deductible capital cost for the first year?

Solution:

The total capital cost is:

Capital Cost = 12,000 acres x $15/acre = $180,000

1st Year Capital Deduction = $180,000 / 5 years = $36,000 / year

The example problem showed a case where there is no oil or gas production. For cases where capital costs have been incurred and there is oil or gas production, then a different method is used to recover capital costs for tax purposes. In natural resource projects, there is a loss in value as these natural resources are produced over time, known as depletion. Any capital investments in these projects are also assumed to deplete with time at the same rate as the loss of resources. To align the capital recovery with the loss of resources, the units of production (UOP) method is used. The UOP method is calculated by dividing the production by the expected production during the life of the project.

To calculate the depletion for a given time period using the UOP method, the following equation should be used:

$$UOP\ Depletion = \frac{Production\ during\ time\ frame}{Expected\ Production\ over\ project\ life}$$

The units of production must be the same for the numerator and denominator. The UOP depletion will be a decimal fraction. Since income taxes are done on calendar years, the time frame is usually a year. The expected production over the project life are the oil and gas reserves of the project.

Based on tax law, there are two types of depletion; cost and statutory. Cost depletion is the depletion calculated as shown in the equation above. Statutory depletion is an amount of depletion stated in the tax law. At present, the Federal statutory depletion allowance is 15% (0.15). Oil and gas companies are able to calculate their depletion using both types of depletion and use the largest of the two for their tax calculations. The example below will demonstrate how to calculate depletion.

Example Problem:

An oil well was drilled and began producing in the current tax year. The total capital to drill and complete the wells was $2,400,000. The reserves of the well are estimated to be 200,000 barrels of oil. The production of oil in the current tax year were 40,000 barrels. What is the UOP depletion calculation for the well? Should the company use cost or statutory depletion for tax calculations?

Solution:

$$UOP\ Depletion = \frac{40,000}{200,000} = 0.20$$

Statutory depletion = 0.15, so this company should use cost depletion. The tax depletion deduction is:

$$Tax\ depletion = 0.20 * 2,400,000 = \$480,000$$

Net Income

Net income is calculated as:

$$Net\ Income = RI * Gross\ Revenue - RI * Production\ Taxes - WI * Operating\ Costs - WI * Capital\ Costs$$

where,

RI = revenue interest (decimal)
WI = working interest (decimal)

Another way to calculate net income is:

$$Net\ Income = Net\ Revenue - Net\ Production\ Taxes - Net\ Operating\ Expenses - Net\ Capital\ Costs$$

The net income calculated above is the cash flow prior to income tax expenses. This is known as net income BFIT (before income tax). The net income is also sometimes referred to as the cash flow. A positive net income indicates that the revenue exceeded the production taxes plus expenses plus capital costs. A negative cash flow indicates that production taxes plus expenses plus capital costs exceeded the revenue.

Example Problem:

A gas well in which a working interest owner owns 50% working interest and 43.75% revenue interest had a gross revenue of $53,000 for the month. That same month the well paid the state $2,600 in production taxes. No capital was spent during the month, but the gross expenses were $7,200. What is the net income for the working interest owner during the month?

Solution:

The net income is calculated as:

$$Net\ Income = 0.4375 * 53,000 - 0.4375 * 2,600 - 0.50 * 7,200 = \$40,500$$

Net Present Value

The value of money changes with the passing of time. If one were to place a given amount of money in a bank saving account at an interest rate of 5% per year, the amount of money in the account at the end of the year would be 5% more than the amount initially deposited. Conversely, if one were to borrow a given amount of money from the bank at an interest rate of 5% per year, the amount of money owed to the bank at the end of the year would be 5% more than the amount initially borrowed. This is known as the time value of money.

To account for the time value of money as it relates to petroleum projects (and any other investment project), the concept of net present value (NPV) is introduced. Net present value (NPV) is a method of calculating the relative worth of a project over time. This is done by taking the net income generated in a certain period of time and reducing it to account for the time over which the net income was received relative to the start date of the project. This reduction of the value of net income over time is known as "discounting". The net present value is also referred to as the "net discounted value" or "discounted cash flow".

The purpose of NPV calculations is to provide a method for making the economically optimal choice from among a group of mutually exclusive alternatives. Suppose a company has a problem for which several solutions have been suggested. The company calculates economics on all the projects and finds that the net income from all of them are nearly identical. Some of the solutions require more capital cost, but also have higher net incomes. Some solutions have low capital costs, but higher expenses. How does a company choose the most economic solution? The answer depends on the net present value of the solution, which takes time into account. A high NPV is a better choice than a lower NPV, all things being equal.

It should be mentioned that the NPV method is only one of the metrics used in evaluating economic worth. Other factors should always be considered when making economic choices. All projects involve the optimization of time, money, equipment, and people. Notice the statement in the paragraph above, "all things being equal." For example, a certain solution to the project may have the highest NPV, but require twice the capital as all other possible choices and may be prohibitive to the company.

The rate used to discount future income is known as the discount rate. In essence, it can be thought of as the cost of capital or a lending rate. If a company were to borrow the entire amount of capital needed to invest in a petroleum project, the project would have to pay back all the capital plus the interest on the loan. The discount rate chosen for a

project is typically close to the lending rate charged by banks. The net present value is usually calculated at the end of a time period. The net present value of income at the end of a given time period is calculated as:

$$NPV_t = \frac{NI_t}{(1 + d)^t}$$

where,

NPV_t = Net present value for time period t
NI_t = Net income for time period t
d = discount rate (decimal)
t = time from project start date

Example Problem:

Given the net incomes as follows and a discount rate of 10%, calculate the NPV at the end of years 1 and 2.

Year	Net Income ($)
1	350,000
2	250,000
3	100,000

Solution:

NPV year 1:

$$NPV_1 = \frac{350,000}{(1 + 0.1)^1} = \$318,182$$

NPV year 2:

$$NPV_2 = \frac{250,000}{(1 + 0.1)^2} = \$206,612$$

Payout and Rate-of-Return

Payout and rate-of-return are two additional metrics that are used to measure the economic viability of petroleum projects. Both of these metrics apply to the payback of the capital cost from net income. When calculating the project economics, it is necessary to input the capital cost as if it were an expense.

Payout is defined as the point in time when the cumulative net income equals the capital cost. In some petroleum projects, the calculation of payout is simple if the monthly income is fairly constant (i.e., gathering system, pipeline, gas plant). In cases of oil and gas wells, this is more complicated as the income from wells are declining. For projects where income is fairly constant, the payout can be calculated as:

$$Payout = \frac{CAPEX}{NI_m}$$

where,
  $Payout$ = time to pay back capital cost (months)
  $CAPEX$ = capital cost ($)
  NI_m = net income per month ($/month)

Example Problem:

A project has a capital cost of $200,000 and an average monthly revenue of $25,000 per month. What is the expected payout of the capital cost?

Solution:

$$Payout = \frac{200,000}{25,000} = 8\ months$$

The net income for oil and gas wells is typically forecast using an in-house or commercially available economics program. These programs calculate net income on a monthly basis and are able to quickly estimate payout.

Rate-of-return (sometimes abbreviated ROR) is the discount rate needed to calculate a net present value of zero. As the discount rate is increased, the NPV decreases. Eventually, there is a discount rate that will yield an NPV of zero. That discount rate is known as the rate-of return. Unless one is using an economic software package, interpolation is usually required to calculate the rate-of-return.

Example Problem:

A project has a capital cost of $180,000. Shown below is the net income and NPV at various discount rates. What is the expected rate-of-return?

					Values in $				
Year	Revenue	Expenses	Capital Cost	Net Income	NPV @ 10%	NPV @ 15%	NPV @ 20%	NPV @ 25%	NPV @ 30%
1	108,000	26,000	180,000	-98,000	-89,091	-85,217	-81,667	-78,400	-75,385
2	75,200	24,500	0	50,700	41,901	38,336	35,208	32,448	30,000
3	62,000	22,000	0	40,000	30,053	26,301	23,148	20,480	18,207
4	50,000	18,600	0	31,400	21,447	17,953	15,143	12,861	10,994
5	35,000	9,500	0	25,500	15,833	12,678	10,248	8,356	6,868
Total	330,200	100,600	180,000	49,600	20,143	10,051	2,080	-4,255	-9,316

Solution:
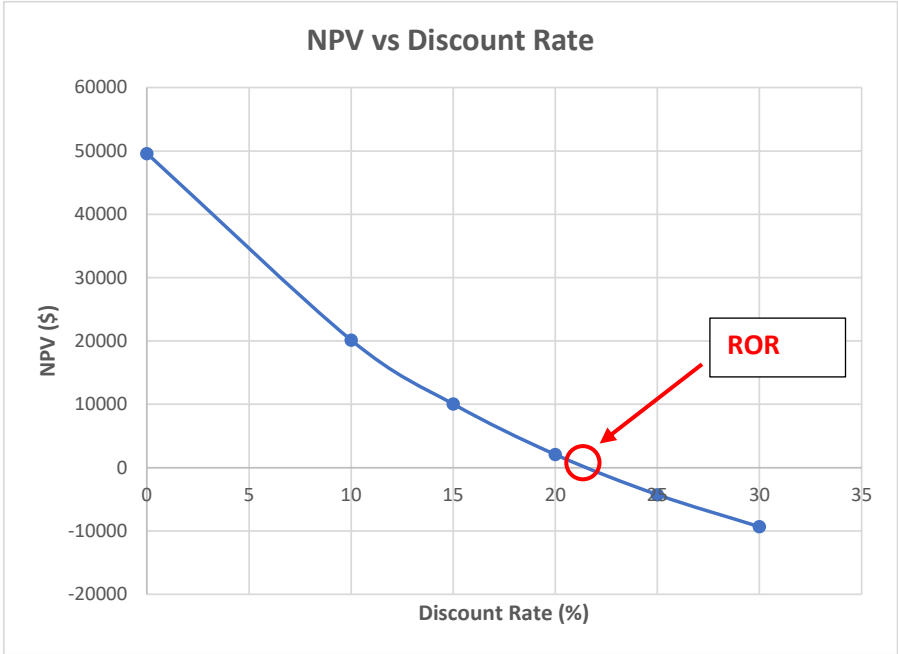
The rate-of-return can be calculated either through interpolation or graphically. At a 20% discount rate, the NPV is positive and at 25% it is negative. The rate-of-return will be between those two discount rates.

Using interpolation, the rate-of-return is calculated as:

$$ROR = 20 + 5 * \frac{2,080}{\left(2,080 - (-4,255)\right)} = 21.6\%$$

Graphically, the rate-of-return is shown below:

Price, Expense, and Capital Cost Escalations

In the simplest cases of petroleum economics, the product prices, operating expenses, and capital costs are held constant throughout the lives of the properties being modeled. When modelling project economics, this case is almost always evaluated and considered to be a "base case".

If the base case is not economically justifiable it indicates there must be increases in product prices or decreases in expenses or capital (or all three) to justify the project. It also introduces an additional risk into the economics that should be modelled to understand the impact of those variables. At other times it may be desirable to understand the impact in the changes of prices, expenses, and capital costs on the project. It is especially true concerning the possibility of price decreases and expense and capital cost increases. Economics based on changes in current prices, expenses, and capital costs are typically referred to as "sensitivity cases".

To account for the changes in prices, expenses, and capital costs, one can introduce escalations or de-escalations to those variables. The changes in prices, expenses, and capital costs can be done at any time interval, but are usually done annually or monthly. If there is a constant annual increase (or decrease) in one of the variables beginning in the 2nd year (i.e., the first year has no escalation/de-escalation and then X% per year afterward), then the value of the variable in any year can be calculated as:

$$V_t = V_i * (1 + i)^{(t-1)}$$

where,
  V_t = variable at time t (price, expense, capital cost)
  V_i = variable at time to (initial price, expense, capital cost)
  i = annual increase or decrease (decimal)
  t = time in years

For some projects, prices, expenses, and capital cost increases are dictated by contractual arrangement. When modelling economics for any petroleum project, one must inquire to understand the effect of any contract or operating agreement on the economic variables. The modelling of some projects may require performing economics subject to the pricing, expense, and capital cost assumptions of a financial institution providing funds for the project.

Listed below are some of the contracts or agreements that may affect project economics:
- Operating agreements
- Gas plant processing agreements
- Gas contracts
- Transportation contracts
- Financing agreements
- Internal company guidelines

The changes in prices specified by financial institutions or internal company guidelines are commonly known as "price decks". When using price decks, one simply uses the price as specified for the particular time period over which it is defined. For example, if a price is specified as XX $/unit in year 3, then that price is manually input and used as the price in year 3.

Example Problem:

An oil well has an initial price of $40 per bbl. A sensitivity case is being performed which specifies an escalation rate of 5% per year. What is the oil price to use in year 4?

Solution:

The decimal increase is equal to:

$$i = \frac{5}{100} = 0.05$$

The oil price to use in year 4 is:

$$V_t = 40 * (1 + 0.05)^{(4-1)} = \$46.30 \; per \; bbl$$

Economic Limit

The term "economic limit" as used in petroleum economics specifies the production rate beyond which the net income becomes negative. The economic limit is the minimum production rate at which the net income is zero. The economic limit is important since the definitions of reserves dictate that reserves are those volumes which can be produced economically, or up to the economic limit.

Basically, the economic limit is reached when the revenues are equal to the expenses plus production taxes as shown in the equation below:

$$Net\ Revenue = Net\ Operating\ Expenses + Production\ Taxes$$

Since accounting is done monthly, it is convenient to schedule forecasting of petroleum projects monthly. This is especially true when dealing in complex projects with multiple sales products (oil, gas, NGL), escalated pricing, expenses, and capital costs. Most commercial petroleum economic software programs calculate net income on a monthly or even daily basis. Those programs can be set to halt economic calculations when a negative net income is detected. Looking at a monthly forecast, the economic limit is found as the production rate one month prior to the first month of negative net income.

For simple cases of non-escalating prices and expenses, the economic limit can sometimes be calculated by hand. Shown below is the derivation of a formula for calculating the economic limit of an oil well with an oil forecast and no gas production:

$$Net\ Revenue = RI * q_o * P_o$$

$$Net\ Operating\ Expenses = WI * (FC + OH) + WI * q_o * C_o$$

$$Net\ Production\ Taxes = RI * q_o * (P_o * (T\%_o + T\%_a) + T\$_o)$$

When combined and solved for the economic limit, one arrives at:

$$q_{oel} = \frac{WI * (FC + OH)}{RI * (P_o * (1 - (T\%_o + T\%_a) - T\$_o) - WI * C_o}$$

where,

q_{oel} = oil production economic limit (bbl/m)

RI = revenue interest

WI = working interest

P_o = oil price ($/bbl)

FC = fixed cost ($/m)

OH = overhead ($/m)

C_o = oil expense ($/bbl)

$T\%_o$ = oil severance tax rate (% of revenue in decimal)

$T\$_o$ = oil severance tax rate ($/bbl)

$T\%_a$ = ad valorem tax rate (% of revenue in decimal)

As can be seen, the calculation involves a lot of variables. It becomes a lot more complicated when we consider other production phases like gas and NGLs, each with their own prices, taxes, expenses, and escalations.

Example Problem:

Given an oil well with the following information, calculate the economic limit.

Working Interest: 0.5000   Revenue Interest: 0.4375

Oil Price: $42.00/bbl

Oil Production Tax: 5.2% of revenue and $0.15/bbl

Ad Valorem Tax: 1.2% of revenue

Fixed Cost: $2,500 per month

Overhead: $600 per month

Variable Cost: $1.50/bbl

Solution:

$$q_{oel} = \frac{0.5000 * (2,500 + 600)}{0.4375 * (42.00 * (1 - (0.052 + 0.012)) - 0.15) - 0.5000 * 1.50} = 95 \; bbl/m$$

Building an Economic Model

Commercial software is available to perform economic modelling of petroleum projects. This software is designed to primarily work in creating models for oil and gas production forecasting and summation. This type of software is used extensively in the reporting of oil and gas reserves and associated production forecasts. As a rule, this software is expensive and requires training to use properly. To justify the cost and maintenance of the software requires either a fairly large volume of oil and gas wells or complex price/expense/capital cost modelling to justify.

An alternative to purchasing commercial software is to create your own economic models. With the advent of spreadsheet programs, it is fairly easy to create economic models for use in petroleum projects. The various sections of this course provide the reader with the formulas necessary to calculate the revenues, expenses, production taxes, and capital costs needed to complete the models. There is quite a bit of work involved in creating one's own economic modelling program, but it is time well spent as it will deepen one's understanding of the various calculations involved in the model.

Figure 6 on the next page shows a typical output from a spreadsheet model. The output is similar to that created by commercial software. Figure 7 on the following page shows a typical input page that can be created to make the calculations shown in Figure 6. The calculations for this particular model are made monthly. The monthly calculations are created in a "work area" of the spreadsheet and shown in Figure 8. The yearly volumes and values shown on Figure 6 are calculated by summing monthly values for each time period as calculated monthly in figure 8.

As mentioned above, the output page shown in Figure 6 is typical of output from commercial software. This is a good template to use when performing economic modelling of petroleum projects. Starting with the columns on the left show the year followed in the next three columns by the gross production. This production is 100% of the production projected to come from the well. It is nice to show the gross production because this production can be gauged against actual production records expected for the well. The next three column list the net production to the revenue interest owned in the well. The next three column show the oil, gas, and NGL prices received for sales. Notice that some type of price deck has been input for these particular prices. These prices can be imported from another spreadsheet containing the prices or can be input directly into this spreadsheet. The next three columns calculate the gross revenue, net expenses, and net production taxes. The column after that is labeled "Net Operating Revenue" and is the gross revenue less the net expenses less the production taxes. This column is not required, but this particular output has it. The next column is the capital costs and notice

there are two capital costs for this well. The one listed in the year 2021 is for drilling and completing the well. The capital cost in year 2049 is for well abandonment and remediation of the well site. The next column is the net income followed by cumulative net present value at a discount rate of 12.5%. Notice that the net income in year 2049 is negative! This is not because the well is projected to produce beyond the economic limit (see the net revenue column), but due to the abandonment and remediation capital cost.

Figure 7 is a template that can be used to input project identifying information, decline curve values, production ratios, operating expenses, capital costs, production tax rates, and escalations. This is the input page for the calculations summarized in Figures 6 and 8. Notice that this is an oil well with a gas-oil ratio and a yield of NGLs. The oil initially declines hyperbolically with a b factor of 0.981 at an initial effective decline rate of 49.3% to a final exponential decline rate of 12%. There is an initial and final oil production rate of 10,000 and 50 bbl/m, respectively, but this spreadsheet will also check to see if the economic limit is reached each month. The calculations will cease if the economic limit is reached prior to the 50 bbl/m rate, otherwise it will continue to 50 bbl/m. This particular input (and output) allows the user to input a cumulative production volume for each of the products, which is important when forecasting producing wells.

Figure 8 shows the first 3 years (36 months) of monthly calculations for this well. Using the values input in Figure 7 and the specified price deck, values are calculated for each of the columns in Figure 8. Using monthly time frames it is quite simple to calculate production volumes and each of the economic parameters. By setting up formulas in the cells of Figure 6, one can easily summarize the monthly calculation of Figure 8 to obtain annual volumes and values.

A few of the output values shown in Figure 6 are not shown in Figure 8. The payout is calculated from a formula that looks at values in the cumulative net income column of Figure 8. The first month the cumulative net income becomes positive is the payout month. Note that on Figure 6 this value is listed in years. In addition to the NPV calculation at a discount rate of 12.5%, other NPVs are calculated in the work area. Some of those are listed in the lower right of Figure 6. Those additional NPV calculations are used to calculate the rate-of-return as seen in the lower left of Figure 6. The value shown is 100% and is the maximum value this particular spreadsheet was designed to calculate.

Figure 6

Example Well 1
Smith Field
Alfalfa, OK
American Company

<div align="right">

Proved
Undeveloped

</div>

Unified Operations, Inc.
Forecast of Reserves and Economics
as of January 1, 2021

	Gross Volumes			Net Volumes			Prices						Net			Cum NPV
Year	Oil (Mbbl)	Gas (MMcf)	NGL (Mbbl)	Oil (Mbbl)	Gas (MMcf)	NGL (Mbbl)	Oil ($/bbl)	Gas ($/Mcf)	NGL ($/bbl)	Gross Revenue (M$)	Net Expenses (M$)	Net Prod Taxes (M$)	Net Operating Revenue (M$)	Net Capital (M$)	Net Income (M$)	at 12.5% (M$)
2021	93.564	135.670	2.522	81.869	118.713	2.208	51.84	2.214	18.00	4,546.664	154.013	409.199	3,983.452	3,775.000	208.452	185.291
2022	60.658	87.955	1.636	53.076	76.963	1.431	53.00	2.250	18.50	3,012.672	116.337	271.140	2,625.195	0.000	2,625.195	2,259.519
2023	44.886	65.085	1.209	39.277	56.951	1.059	54.00	2.300	19.00	2,272.065	98.663	204.485	1,968.917	0.000	1,968.917	3,642.352
2024	35.606	51.629	0.959	31.157	45.176	0.840	55.00	2.350	19.50	1,836.182	88.578	165.256	1,582.348	0.000	1,582.348	4,630.204
2025	29.497	42.771	0.798	25.811	37.425	0.698	56.00	2.400	20.00	1,549.196	82.202	139.429	1,327.565	0.000	1,327.565	5,366.908
2026	25.165	36.490	0.679	22.021	31.929	0.594	57.00	2.450	20.50	1,345.604	77.918	121.105	1,146.581	0.000	1,146.581	5,932.482
2027	21.931	31.801	0.590	19.191	27.826	0.518	58.00	2.500	21.00	1,193.523	74.924	107.416	1,011.183	0.000	1,011.183	6,375.848
2028	19.299	27.985	0.521	16.888	24.485	0.457	59.00	2.500	21.50	1,067.437	72.621	96.070	898.746	0.000	898.746	6,726.129
2029	16.983	24.626	0.458	14.862	21.548	0.400	60.00	2.500	22.00	954.393	70.646	85.896	797.851	0.000	797.851	7,002.536
2030	14.944	21.669	0.403	13.077	18.960	0.355	60.00	2.500	22.50	840.014	68.964	75.602	695.448	0.000	695.448	7,216.697
2031	13.150	19.068	0.354	11.506	16.687	0.309	60.00	2.500	23.00	739.189	67.555	66.527	605.107	0.000	605.107	7,382.333
2032	11.574	16.784	0.313	10.127	14.687	0.277	60.00	2.500	24.00	650.990	66.388	58.588	526.014	0.000	526.014	7,510.320
2033	10.183	14.768	0.275	8.911	12.923	0.239	60.00	2.500	24.00	572.706	65.440	51.544	455.722	0.000	455.722	7,608.884
2034	8.964	12.998	0.241	7.842	11.374	0.213	60.00	2.500	24.00	504.070	64.697	45.365	394.008	0.000	394.008	7,684.632
2035	7.890	11.441	0.213	6.905	10.012	0.189	60.00	2.500	24.00	443.869	64.132	39.949	339.788	0.000	339.788	7,742.698
2036	6.948	10.075	0.187	6.081	8.816	0.163	60.00	2.500	24.00	390.815	63.736	35.174	291.905	0.000	291.905	7,787.039
2037	6.112	8.862	0.165	5.349	7.753	0.141	60.00	2.500	24.00	343.710	63.479	30.934	249.297	0.000	249.297	7,820.700
2038	5.382	7.803	0.145	4.710	6.829	0.130	60.00	2.500	24.00	302.795	63.366	27.251	212.178	0.000	212.178	7,846.166
2039	4.740	6.873	0.127	4.146	6.014	0.115	60.00	2.500	24.00	266.558	63.381	23.991	179.186	0.000	179.186	7,865.282
2040	4.165	6.039	0.113	3.643	5.285	0.101	60.00	2.500	24.00	234.219	63.489	21.080	149.650	0.000	149.650	7,879.473
2041	3.678	5.334	0.099	3.219	4.668	0.087	60.00	2.500	24.00	206.901	63.740	18.622	124.539	0.000	124.539	7,889.971
2042	3.246	4.706	0.087	2.841	4.118	0.075	60.00	2.500	24.00	182.558	64.080	16.430	102.048	0.000	102.048	7,897.617
2043	2.829	4.102	0.076	2.476	3.591	0.064	60.00	2.500	24.00	159.078	64.437	14.319	80.322	0.000	80.322	7,902.967
2044	2.520	3.654	0.069	2.205	3.198	0.057	60.00	2.500	24.00	141.666	64.992	12.749	63.925	0.000	63.925	7,906.752
2045	2.232	3.237	0.060	1.953	2.833	0.048	60.00	2.500	24.00	125.417	65.587	11.288	48.542	0.000	48.542	7,909.306
2046	1.944	2.819	0.052	1.701	2.468	0.048	60.00	2.500	24.00	109.384	66.180	9.845	33.359	0.000	33.359	7,910.866
2047	1.684	2.441	0.048	1.474	2.137	0.048	60.00	2.500	24.00	94.937	66.836	8.544	19.557	0.000	19.557	7,911.679
2048	1.530	2.219	0.040	1.340	1.942	0.040	60.00	2.500	24.00	86.218	67.712	7.760	10.746	0.000	10.746	7,912.076
2049	1.165	1.689	0.030	1.020	1.478	0.030	60.00	2.500	24.00	65.617	57.203	5.905	2.509	150.000	-147.491	7,907.230
2050	0.000	0.000	0.000	0.000	0.000	0.000	60.00	2.500	24.00	0.000	0.000	0.000	0.000	0.000	0.000	7,907.230
After	0.000	0.000	0.000	0.000	0.000	0.000	60.00	2.500	24.00	0.000	0.000	0.000	0.000	0.000	0.000	7,907.230
Total	**462.469**	**670.593**	**12.469**	**404.678**	**586.789**	**10.934**	**55.91**	**2.369**	**20.40**	**24,238.447**	**2,131.296**	**2,181.463**	**19,925.688**	**3,925.000**	**16,000.688**	**7,907.230**
Cumulative	0.000	0.000	0.000													
Ultimate	**462.469**	**670.593**	**12.469**													

Working Interest	1.00000000		**NPV @ 5%**	11,576.456
Revenue Interest	0.87500000		**NPV @ 10%**	8,879.706
NRI	0.87500000		**NPV @ 15%**	7,104.356
			NPV @ 20%	5,862.064
			NPV @ 25%	4,950.516
Payout (yrs)	0.9		**NPV @ 30%**	4,256.422
Rate of Return (%)	100.0		**NPV @ 40%**	3,275.373
			NPV @ 50%	2,620.751

Figure 7

WELL INFORMATION									
Reserve Cat	Well Name	Field		County	State	Operator	Working Interest	Revenue Interest	NRI
PUD	Example Well 1	Smith		Alfalfa	OK	American Company	1.00000000	0.87500000	0.87500000

IDENTIFICATION CODES	
API Number	ID Code

OIL FORECAST							
Start Month	Start Year	Start Rate (Bbl/mo)	Ending Rate (Bbl/mo)	Annual Decline Rate (%)	b	Minimum Exp Decline (%)	Yield (bbl/MMcf)
1	2021	10,000	50	49.3	0.981	12.0	0.0

GAS FORECAST							
Start Month	Start Year	Start Rate (Mcf/mo)	Ending Rate (Mcf/mo)	Annual Decline Rate (%)	b	Minimum Exp Decline (%)	GOR (scf/bbl)
0	0	0	0	0.0	0.000	0.0	1,450

ADDITIONAL FORECAST INFORMATION						PRODUCTION TAXES						
Cumulative Oil (bbl)	Cumulative Gas (Mcf)	Cumulative NGL (bbl)	Gas Heating Value (btu/scf)	NGL Yield (bbl/MMcf)		Oil (%)	Oil ($/bbl)	Gas (%)	Gas ($/Mcf)	NGL (%)	NGL ($/bbl)	Adval Tax (%)
0	0	0	1,000	18.6		7.000	0.000	7.000	0.000	7.000	0.000	2.000

OPERATING EXPENSES				
Operating Expense ($/mo)	Well Expense ($/well/mo)	Oil Expense ($/bbl)	Gas Expense ($/Mcf)	NGL Expense ($/bbl)
2,800	600	1.210	0.000	0.000

OPERATING EXPENSE ESCALATIONS				
Operating Expense Escalation (%)	Well Expense Escalation (%)	Oil Expense Escalation (%)	Gas Expense Escalation (%)	NGL Expense Escalation (%)
2.0	0.0	2.0	0.0	0.0

CAPITAL COSTS														
Capital Cost 1 Month	Capital Cost 1 Year	Capital Cost 1 (M$)	Capital Cost 2 Month	Capital Cost 2 Year	Capital Cost 2 (M$)	Capital Cost 3 Month	Capital Cost 3 Year	Capital Cost 3 (M$)	Capital Cost 4 Month	Capital Cost 4 Year	Capital Cost 4 (M$)	Capital Cost 5 Month	Capital Cost 5 Year	Capital Cost 5 (M$)
1	2021	3,775.000	1	2049	150.000	0	0	0.000	0	0	0.000	0	0	0.000

Figure 8

Gross Volumes			Net Volumes			Values						
Oil	Gas	NGL	Oil	Gas	NGL	Gross Rev	Costs	Taxes	Net Oper Rev	Total Capex	Net Income	Cum Net Income
10000	14500	270	8750	12688	236	485.939	15.500	43.735	426.704	3775.000	-3348.296	-3348.296
9464	13723	255	8281	12008	223	459.887	14.851	41.390	403.646	0.000	403.646	-2944.650
8982	13024	242	7859	11396	212	436.458	14.268	39.281	382.909	0.000	382.909	-2561.741
8546	12392	230	7478	10843	201	415.284	13.741	37.376	364.167	0.000	364.167	-2197.574
8151	11819	220	7132	10342	193	396.094	13.263	35.648	347.183	0.000	347.183	-1850.391
7790	11296	210	6816	9884	184	378.536	12.826	34.068	331.642	0.000	331.642	-1518.749
7459	10816	201	6527	9464	176	362.481	12.425	32.623	317.433	0.000	317.433	-1201.316
7155	10375	193	6261	9078	169	347.711	12.058	31.294	304.359	0.000	304.359	-896.957
6875	9969	185	6016	8723	162	334.098	11.719	30.069	292.310	0.000	292.310	-604.647
6616	9593	178	5789	8394	156	321.494	11.405	28.934	281.155	0.000	281.155	-323.492
6375	9244	172	5578	8089	151	309.791	11.114	27.881	270.796	0.000	270.796	-52.696
6151	8919	166	5382	7804	145	298.891	10.843	26.900	261.148	0.000	261.148	208.452
5942	8616	160	5199	7539	140	295.100	10.790	26.559	257.751	0.000	257.751	466.203
5747	8333	155	5029	7291	136	285.458	10.549	25.691	249.218	0.000	249.218	715.421
5564	8068	150	4869	7060	131	276.366	10.323	24.873	241.170	0.000	241.170	956.591
5392	7818	145	4718	6841	127	267.796	10.111	24.102	233.583	0.000	233.583	1190.174
5230	7584	141	4576	6636	123	259.735	9.911	23.376	226.448	0.000	226.448	1416.622
5078	7363	137	4443	6443	120	252.196	9.723	22.698	219.775	0.000	219.775	1636.397
4934	7154	133	4317	6260	116	245.032	9.546	22.053	213.433	0.000	213.433	1849.830
4799	6959	129	4199	6089	113	238.338	9.379	21.450	207.509	0.000	207.509	2057.339
4670	6772	126	4086	5926	110	231.927	9.220	20.873	201.834	0.000	201.834	2259.173
4548	6595	123	3980	5771	108	225.923	9.069	20.333	196.521	0.000	196.521	2455.694
4432	6426	120	3878	5623	105	220.129	8.926	19.812	191.391	0.000	191.391	2647.085
4322	6267	117	3782	5484	102	214.672	8.790	19.320	186.562	0.000	186.562	2833.647
4217	6115	114	3690	5351	100	213.467	8.822	19.212	185.433	0.000	185.433	3019.080
4117	5970	111	3602	5224	97	208.366	8.696	18.753	180.917	0.000	180.917	3199.997
4022	5832	108	3519	5103	95	203.568	8.576	18.321	176.671	0.000	176.671	3376.668
3931	5700	106	3440	4988	93	198.999	8.462	17.910	172.627	0.000	172.627	3549.295
3844	5574	104	3364	4877	91	194.602	8.352	17.514	168.736	0.000	168.736	3718.031
3760	5452	101	3290	4771	88	190.305	8.247	17.127	164.931	0.000	164.931	3882.962
3681	5337	99	3221	4670	87	186.328	8.147	16.770	161.411	0.000	161.411	4044.373
3604	5226	97	3154	4573	85	182.449	8.050	16.420	157.979	0.000	157.979	4202.352
3531	5120	95	3090	4480	83	178.741	7.958	16.087	154.696	0.000	154.696	4357.048
3460	5017	93	3028	4390	81	175.148	7.869	15.763	151.516	0.000	151.516	4508.564
3392	4918	91	2968	4303	80	171.689	7.783	15.452	148.454	0.000	148.454	4657.018
3327	4824	90	2911	4221	79	168.403	7.701	15.156	145.546	0.000	145.546	4802.564

Conclusion

The purpose of this course was to introduce the reader to the basics of petroleum economics. It is hoped that at this point the reader should have an understanding and familiarity with the following:

- Basic timeline of a petroleum project
- Units of measurement in the petroleum industry
- Types of ownership in petroleum projects
- Various methods of forecasting production from oil and gas wells
- Calculations of revenue, expenses, production taxes, and net income
- Understanding of net present value
- Comprehension of payout and rate-of-return
- Understand the meaning of economic limit
- Basic understanding of how to create an economic spreadsheet model

It is also hoped that the course material presented here will provide enough information such that the reader can use it to model more complex petroleum projects like secondary and tertiary recovery, complex gathering systems and gas plants.