Oil & Gas Modeling – Certification Quiz Questions

Module 1 – Upstream Industry and NAV Model

1. Which of the following financial model features would you expect to see for an Upstream company, but **NOT** a Midstream or Downstream company?

    a. Operating scenarios based on commodity prices and/or margins.

    b. Granular forecasts based on individual "units," such as oil/gas wells in specific regions.

    c. Maintenance vs. Growth CapEx, as drilling new wells is always far more expensive than maintaining existing ones.

    d. All of the above.

2. You are reviewing a company's Type Curve and Economics for a single "average well" in the Eagle Ford shale in the U.S. The key parameters in the company's estimates are shown in the image below this question.

    In short, management has estimated a 124% IRR and an NPV-10 of $6.3 million when natural gas prices are $3.00 per Mcf.

    When you recreate their analysis, however, you get a 95% IRR and an NPV-10 of $10.4 million. A summary of your version is shown in another image below this question.

    What is the **MOST LIKELY** explanation for this discrepancy?

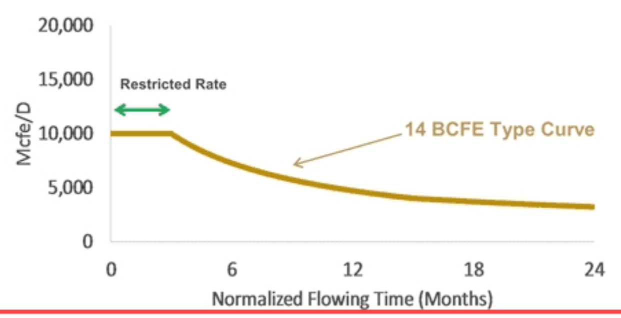
Fasken Lower Eagle Ford Gas

SilverBow RESOURCES

Single Well Economics

Summary	
Drilling Locations	22
Target D&C ($mm) [2]	$4.7
NPV 10 ($mm)	$6.3
IRR (%)	124%
Type Well Assumptions	
Completed Lateral Length (ft)	7,500
Proppant (lbs/ft)	1,500
Wellhead EUR (Bcfe)	14
% Gas	100%
EUR / 1,000' (Bcfe)	1.9
Type Curve	
Restricted Rate (Mmcfepd / 1000')	1.34
Flat Period (Days)	90
30 Day IP (Mmcfepd)	10
Initial Decline Following Flat Period	60%
B-Factor	1.2
Terminal Decline	5%
Operating Cost	
Fixed LOE ($/well/month)	$1,309
Variable LOE ($/Mcfe)	$0.02
Trans. & Proc. ($/Mcfe)	$0.39

Type Curve[1]



IRR Sensitivity

		Gas / WTI / NGL Price	
		$3.00 / $50 / $20	$3.50 / $60 / $24
T.C. EUR Bcfe	14.0	124%	194%

(1) Type curves are derived from the actual production of historical, comparably drilled and completed wells (comparables include geology, reservoir, target placement, lateral placement, frac placement, size and success). Type curves are representative of the expected production from location count wells and do not represent a high or low rate/EUR for a given area. Type curves are representative of qualified proved undeveloped, probable, or possible reserve categories.

(2) Cost includes location construction, 4 wells/drill pad, 7,500' completed lateral length, 1,500 lb/ft proppant, 10 days of flowback, tubing installation, and facilities hook-up.

Single Well - Production and Cash Flows:

Period	Production Curve: Gas (Mmcf)	NGLs (MBbl)	Oil (MBbl)	Total: (Mmcfe)	Decline Rate:	Cash Flow: Cash OpInc ($ M)	CapEx ($ M)	Cash Flow ($ M)
0						$ -	$ (4.7)	$ (4.7)
1	2,555	-	-	2,555		6.6	-	6.6
2	1,207	-	-	1,207	(52.8%)	3.1	-	3.1
3	837	-	-	837	(30.6%)	2.2	-	2.2
4	652	-	-	652	(22.1%)	1.7	-	1.7
5	539	-	-	539	(17.3%)	1.4	-	1.4
6	462	-	-	462	(14.3%)	1.2	-	1.2
7	406	-	-	406	(12.2%)	1.0	-	1.0
8	363	-	-	363	(10.6%)	0.9	-	0.9
9	329	-	-	329	(9.4%)	0.8	-	0.8
10	301	-	-	301	(8.4%)	0.8	-	0.8
11	278	-	-	278	(7.7%)	0.7	-	0.7
12	258	-	-	258	(7.0%)	0.7	-	0.7
13	242	-	-	242	(6.5%)	0.6	-	0.6
14	227	-	-	227	(6.0%)	0.6	-	0.6
15	214	-	-	214	(5.6%)	0.5	-	0.5
16	203	-	-	203	(5.2%)	0.5	-	0.5
17	193	-	-	193	(5.0%)	0.5	-	0.5
18	183	-	-	183	(5.0%)	0.5	-	0.5
19	174	-	-	174	(5.0%)	0.4	-	0.4
20	165	-	-	165	(5.0%)	0.4	-	0.4
21	157	-	-	157	(5.0%)	0.4	-	0.4
22	149	-	-	149	(5.0%)	0.4	-	0.4
23	142	-	-	142	(5.0%)	0.4	-	0.4
24	135	-	-	135	(5.0%)	0.3	-	0.3
25	128	-	-	128	(5.0%)	0.3	-	0.3
26	122	-	-	122	(5.0%)	0.3	-	0.3
27	116	-	-	116	(5.0%)	0.3	-	0.3
28	110	-	-	110	(5.0%)	0.3	-	0.3
29	104	-	-	104	(5.0%)	0.3	-	0.3
30	99	-	-	99	(5.0%)	0.2	-	0.2
31	94	-	-	94	(5.0%)	0.2	-	0.2
32	89	-	-	89	(5.0%)	0.2	-	0.2
33	85	-	-	85	(5.0%)	0.2	-	0.2
34	81	-	-	81	(5.0%)	0.2	-	0.2
35	77	-	-	77	(5.0%)	0.2	-	0.2
36	73	-	-	73	(5.0%)	0.2	-	0.2
37	69	-	-	69	(5.0%)	0.2	-	0.2
38	66	-	-	66	(5.0%)	0.2	-	0.2
39	62	-	-	62	(5.0%)	0.1	-	0.1
40	59	-	-	59	(5.0%)	0.1	-	0.1
Total:	**11,807**	-	-	**11,807**		**$ 30.0**	**$ (4.7)**	**$ 25.3**

a. Your version assumes an entire year to drill a new well and get some initial production, but it’s often faster than that in real life.

b. Your version may not be escalating gas prices and per-well expenses over time, but the company’s version seems to do this.

c. The production curves might differ (e.g., the company's version might use a more front-loaded profile but with lower cumulative production over the first 5 – 10 years).

d. The well's EUR is 14.0 Bcfe, but since your version does not account for the production after Year 40, the total production adds up to only 11.8 Bcfe, which undercounts the long-term cash flows by ~16%.

3. You are building a NAV model for an E&P company, and you're starting the process by forecasting the annual production for its Proved Developed (PD) Reserves.

   Unfortunately, the company does not disclose the weighted average decline rate each year for its existing PD Reserves. It only publishes the overall decline rate for everything, including new wells, which is approximately 20%.

   What is the **BEST** approach for estimating the decline rate(s) specifically for the PD wells and their annual production?

   a. Start with a low decline rate, such as 5%, and keep increasing it each year to reflect an accelerating decline from the PD wells over time.

   b. Start at this 20% decline rate and make it decrease each year until it reaches a lower terminal rate, such as 5%.

   c. Use Goal Seek to set a constant decline rate based loosely on the company's R / P Ratio (e.g., the PD Reserves should fall to ~0 in the Year 15 – 20 range if the R / P Ratio is ~15).

   d. Start at a much higher decline rate, such as 40%, and make it fall to the company-estimated level of 20% over time.

4. You are now working on the PUD Well projections in this same NAV model. The company plans to drill 50 – 100 wells annually to develop its Proved Undeveloped Reserves and modestly increase its annual oil and gas production.

What are the **TOP THREE (3)** most important differences in this part of the model?

You must select **ALL THREE (3)** correct answers and no incorrect answers to earn a point for this question.

a. The production decline rates should NOT be constant because these are brand-new wells.

b. The mix of oil, gas, and natural gas liquids (NGLs) might differ from the percentages used for the PD Reserve production.

c. You must aggregate the production of a single "average well" over all the wells drilled in these PUD Reserves, which creates a waterfall-like schedule.

d. CapEx for these wells should be significantly higher than for the PD Reserve production because growth is always more expensive than maintenance.

e. It's critical to use the mid-year convention in the production estimates to account for the fact that if 100 wells are drilled in a year, the "average" drill date will be June 30th rather than January 1st.

f. You must set up complex "Remainder" formulas that handle the case where a single well has not finished producing its EUR by the final year in the model.

g. The company's hedges (swaps, collars, etc.) and market price differentials are likely to differ significantly because the commodity price risk is different.

5. Suppose that an E&P company has set up 3-way collars on its natural gas production based on a sold call price of $5.00 per Mcf, a long put price of $3.50, and a sold put price of $2.50.

   The company has hedged approximately 100,000 Mmcf of its gas production for the year.

   What is the **impact on revenue** if the natural gas Market Price averages $2.25 per Mcf over the entire year?

   a. $25 million.

b. $50 million.

c. $75 million.

d. $100 million.

6. You are reviewing the output of a NAV model for the same E&P company discussed in the previous questions. The preliminary output is shown in the image below this question.

   The NAV model is based on an industry-standard 10% Discount Rate and 40-year forecasts for the revenue, expenses, and CapEx.

   You have split out the Present Value of each component separately so that you can assess the contributions of the different Reserve types and expense categories.

   Based on the output of this model in the different commodity price cases, what is the **BIGGEST** potential problem?

Long-Term Natural Gas Price:	$ / Mcf		$ 2.65	$ 3.50	$ 4.75
Long-Term NGL Price:	$ / Bbl		27.00	37.00	45.00
Long-Term Oil Price:	$ / Bbl		55.00	75.00	90.00
Category:		**Base Case:**	**Low**	**Mid**	**High**
(+) Proved Developed (PD) Reserves:	$ M	$ 11,424.8	$ 6,160.8	$ 11,424.8	$ 17,201.8
(+) Proved Undeveloped (PUD) Reserves:	$ M	2,192.1	(346.3)	2,192.1	5,122.8
Pre-Tax Asset Value:	$ M	**13,616.9**	**5,814.5**	**13,616.9**	**22,324.6**
(-) PV of G&A and Employee Compensation:	$ M	(2,377.9)	(1,795.1)	(2,377.9)	(3,024.4)
(-) PV of Exploration Expense:	$ M	(156.9)	(153.2)	(156.9)	(160.2)
(+/-) PV of Value of Hedges:	$ M	369.0	438.1	369.0	278.5
(-) PV of Cash Taxes:	$ M	(2,788.4)	(933.7)	(2,788.4)	(4,853.5)
After-Tax Asset Value:	$ M	**8,662.6**	**3,370.5**	**8,662.6**	**14,565.0**
(+) Value of Brokered Gas Business:	$ M	40.6	40.6	40.6	40.6
(+) Value of Undeveloped Land:	$ M	21.1	21.1	21.1	21.1
Total Asset Value:	$ M	**8,724.3**	**3,432.2**	**8,724.3**	**14,626.7**
(+) Cash & Investments:	$ M	304.5	304.5	304.5	304.5
(+) Net Operating Losses:	$ M	341.5	341.5	341.5	341.5
(+) Net Derivatives:	$ M	-	-	-	-
(-) Debt:	$ M	(1,694.8)	(1,694.8)	(1,694.8)	(1,694.8)
(-) Finance Leases:	$ M	-	-	-	-
(-) Asset Retirement Obligations:	$ M	(138.4)	(138.4)	(138.4)	(138.4)
(-) Unfunded Pensions:	$ M	-	-	-	-
(-) Preferred Stock:	$ M	-	-	-	-
Net Asset Value:	$ M	**7,537.1**	**2,245.0**	**7,537.1**	**13,439.5**
Diluted Shares Outstanding:	# Shares	243.387	243.387	243.387	243.387
NAV per Share:	$ as Stated	**$ 30.97**	**$ 9.22**	**$ 30.97**	**$ 55.22**
Premium / (Discount) to Current Share Price:	%	**(16.6%)**	**(75.2%)**	**(16.6%)**	**48.8%**

a. The Exploration Expense is questionable since a NAV Model typically assumes minimal-to-no new exploration; only the existing Reserves are developed.

b. The PV of Cash Taxes represents only 16 – 22% of the Pre-Tax Asset Value across the cases, so the Tax Rate may be too low.

c. The Present Value of the future cash flows from the PUD Reserves cannot possibly be negative, so the "Low" case may use incorrect assumptions or a flawed setup.

d. The Present Value of Hedges should not count toward the NAV because the company does not spend money to set up new hedges to replace ones that expire or get used up.

e. The PD / PUD “ratio” seems off because the PD Reserves should not account for over 75% of the company’s Pre-Tax Asset Value; this undercounts growth activities.