Oil & Gas Modeling – Certification Quiz Questions

Module 6 – Complex NAV Model (Region-by-Region)

20. You are building a complex NAV model for an E&P company, with separate projections for the production and cash flows from the Proved Developed (PD), Proved Undeveloped (PUD), and Probable (PROB) wells across the company's main regions of operation.

    What are the **MOST LIKELY** differences in these forecasts?

    This question has **2 correct answers** and 3 incorrect answers. You must select **BOTH** correct answers and no incorrect answers to earn a point for this question.

    a. You will most likely apply a lower Reserve Credit to the PROB production and cash flows than you will to the PUD and PD production and cash flows.

    b. In all the projections, you must apply the Reserve Credit(s) separately to the production and the CapEx since the CapEx is a fixed cash outflow that does not necessarily trend with production.

    c. You normally group together all the PD wells and forecast the production decline rate based on simple, fixed percentages; by contrast, you might forecast individual PUD/PROB wells separately, with varying decline rates each year.

    d. Normally, you deduct Royalties from the PUD and PROB Revenue to calculate the Operating Income; with the PD Revenue, you must adjust for both Working Interests and Royalties.

    e. You often use different Type Curves and oil/gas/NGL splits for PUD and PROB wells, so the production and cash flow profiles look different even within the same region.

21. The screenshot below this question shows the summary assumptions from one of the regional tabs of your complex NAV model for a Canadian E&P company with operations in Alberta and Saskatchewan.

Each answer choice corresponds to a highlighted area in this image and explains the "approximation logic" that went into this specific assumption.

Which of these explanations is the **LEAST REASONABLE**?

Veren Inc. - Kaybob Duvernay - Production and Drilling Forecasts

($ in Millions CAD Except Per Share and Per Unit Data in CAD or USD as Stated)

Production & Drilling Assumptions:	Units:	
Region Name:	Name	Kaybob Duvernay

Pre-Tax PV by Reserve Type in Region:	Res. Credit:	C$ M:
Proved Developed (PD):	100.0%	$ 2,006.8
Proved Undeveloped (PUD):	100.0%	1,324.0
Probable (PROB):	75.0%	810.8
Total:		**$ 4,141.7**

Expense Assumptions:		
Royalty Rate (% Revenue):	%	11.0%
Operating Expenses per BOE:	C$ / BOE	$ 7.65
Transportation Expenses per BOE:	C$ / BOE	4.50

PD Assumptions:		
Estimated Allocation of PD Reserves:	%	30.0%
Gross PD Reserves in Region:	MBOE	100,593
Projected Year 1 PDP Production:	BOE / d	48,000
PD Reserve Life Ratio:	# Years	5.7
Production Decline Rate:	%	17.5%
Post-Toggle Production Decline Rate:	%	17.5%
Future PD CapEx % Revenue:	%	3.0%

Commodity Split (Applies to All Well Types):		
% Natural Gas:	%	40.2%
% Natural Gas Liquids (NGLs):	%	24.2%
% Oil:	%	35.6%
Total:	%	**100.0%**

Sub-Region Name:	IP30 Rate BOE / d:	Oil %:	NGL %:	Gas %:	Ave
Vol. Oil	850	50.0%	35.0%	15.0%	
Liq. Rich	1,250	45.0%	35.0%	20.0%	
Lean Gas	1,500	20.0%	10.0%	70.0%	
Total or Avg.:	**1,155**	**35.6%**	**24.2%**	**40.2%**	

PUD + PROB Assumptions:	Units:	
Average EUR:	MBOE	1,231
Potential Future Locations (Net):	# Wells	525
Unbooked %:	%	60.0%
Net PUD + PROB Locations:	# Wells	210
Net PUD + PROB Reserves:	MBOE	258,500
Gross PUD + PROB Reserves:	MBOE	290,449
% Total PUD + PROB All Regions:	%	32.1%
PUD Percentage:	%	50.6%
Gross PUD Reserves from Statements:	MBOE	129,508
Gross PROB Reserves from Statements:	MBOE	126,443
Estimated Gross PUD Locations:	# Wells	105
Estimated Gross PROB Locations:	# Wells	103
# New Gross Wells Drilled per Year:	# Wells	45
High	# Wells	55
Mid	# Wells	45
Low	# Wells	35
12-Month IP Rate % IP30:	%	45.0%
Estimated 12-Month IP Rate:	BOE / d	520
Post-Toggle 12-Month IP Rate:	BOE / d	520
Initial D&C Cost Per Well:	C$ M	$ 10.94
Post-Toggle D&C Cost per Well:	C$ M	10.94

a. To estimate the Gross PUD + PROB Reserves, take the Net PUD + PROB Reserves and divide by (1 – Royalty Rate); the Royalty Rate is 11% in this region, per cell G16.

b. To estimate the Decline Rate for the PD Reserves, take the Gross PD Reserves and divide by the Year 1 PDP Production in BOE / d. 3,000 days means the rate is close ~10%, 2,000 means it's closer to ~20%, and 1,000 means it's closer to ~30%.

c. To estimate the Transportation Expenses per BOE, take the weighted-average Revenue in $ per BOE across all oil/gas/NGL production, subtract the Operating Netback of $37.50, and subtract the OpEx per BOE of $7.65.

d. For the New Gross Wells Drilled per Year, take the projected Drilling CapEx in this region this year and divide by the estimated D&C Cost per Well of $10.9 million.

e. To estimate the 12-Month IP Rate for new wells, take the company's estimated Year 1 production in the region, subtract the PDP contribution, and divide by 50% of the New Gross Wells Drilled (~22.5 here).

22. In the same complex NAV model, you are forecasting the Book DD&A using the Unit-of-Production (UOP) method and the Tax DD&A using the Declining Balance method with a 30% rate.

    For example, if the company spends $1,000 on Drilling CapEx, it will record Depreciation for 30% * $1,000 = $300, and the remaining balance will be $700. Then, it will record Depreciation for 30% * $700 = $210, and the remaining balance will be $490.

    For the Tax DD&A, you are also depleting/depreciating the company's existing Net PP&E balance at 10% per year, with the rate falling to 5% over time.

    A partial image of this schedule is shown below this question.

    Given this description, what is the **MAIN REASON** why the Tax DD&A tends to be higher than the Book DD&A in the first few years of the model?

	C	D	H	I	J	K	L	M	N
102									
103	**DD&A Schedule (Unit-of-Production - Book Basis):**								
104	(-) PD Reserves - DD&A (UOP Depletion Basis):	*C$ M*		696.3	586.5	494.1	417.5	350.9	295.8
105	(-) PUD Reserves - DD&A (UOP Depletion Basis):	*C$ M*		264.2	717.2	951.1	906.7	773.1	707.2
106	(-) PROB Reserves - DD&A (UOP Depletion Basis):	*C$ M*		-	-	77.4	321.5	581.9	637.9
107	**Total DD&A (Book Basis):**	*C$ M*		**960.4**	**1,303.7**	**1,522.7**	**1,645.7**	**1,706.0**	**1,641.0**
108									
109	**DD&A Schedule (Accelerated - Tax Basis):**								
110									
111	Existing Net PP&E and ROU Assets:	*C$ M*	$ 10,794.5	$ 9,715.1	$ 8,743.5	$ 7,880.0	$ 7,124.4	$ 6,476.7	$ 5,937.0
112	Assumed Annual DD&A %:	*%*		10.0%	9.0%	8.0%	7.0%	6.0%	5.0%
113	Estimated DD&A:	*C$ M*		1,079.5	971.5	863.6	755.6	647.7	539.7
114									
115	Depreciation % Remaining Balance:	30.0%							
116									
164	**Total DD&A (Tax Basis):**	*C$ M*		**1,304.1**	**1,581.9**	**1,729.9**	**1,756.9**	**1,696.0**	**1,504.6**

a. This 30% rate for the Declining Balance method is higher than the Production Decline Rate for most of the PUD/PROB wells, so it significantly accelerates the DD&A of the Drilling CapEx.

b. The UOP method implies low Book DD&A numbers because there doesn't seem to be much of a "ramp" in production over time; even modest acceleration makes the Tax DD&A numbers higher.

c. It's not possible to answer this question without seeing the CapEx broken out for the PD, PUD, and PROB Reserves.

d. The Tax DD&A is higher mostly because of the 10% assumption applied to the Net PP&E and ROU Assets in the first year; if this percentage were slightly lower, the Book and Tax DD&A would be nearly the same.