PE 7023

Advanced Production Engineering

Term Project

Onshore Gas Condensate Well

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STATEMENT OF THE PROBLEM

X Company is planning to develop an onshore gas condensate field. Your team was contracted to simulate a real lift production design for this field, and evaluate the economic feasibility of this reservoir. Reservoir data, fluid properties, wellbore and pipeline profile are given in detail as follows. You are assigned to design the production plan for this field for **at least 10 years**. Your proposed production plan should consider at least the following aspects:

1. Determine the optimum pipeline and tubing sizes. Discuss the logic that you use to select pipeline and tubing sizes.
2. Should chokes be installed, why or why not? If chokes are needed, where should they be installed?
3. Determine if any artificial lift method will be necessary? If it is need, consider different artificial lift methods, including ESP, PCP, sucker rod pumps and gas lifting, and select the most optimal artificial lift system for the reservoir and production conditions given. Indicate, when the wells we need artificial system method to produce;
4. Determine if any multi-phase pump installation at the surface is needed.
5. Analyze potential flow assurance issues, i.e., erosion and hydrate formation.
6. Determine erosional velocity profile for production tubing and flow line.
7. Determine the temperature-pressure profiles from downhole to surface separator.
8. Should the pipeline be insulated or heated? Why or why not?
9. Discuss the uncertainty generated by applying different multiphase flow models in tubing and pipeline in terms of pipeline and tubing sizing, artificial lift selection and optimization, flow assurance management, production forecast, etc.
10. Consider an economic component of this project (a rough approximation is fine; you may consider the oil price of $45 per barrel or gas price of $2 per Mcf). Is this project economically feasible?

Information

The reservoir has two clusters, as shown in Fig.1. Cluster A has 5 vertical wells, connecting to a manifold by means of pipes 1, 2, 3, 4 and 5; while cluster B has three horizontal wells, connecting to a manifold by pipe 6, 7, and 8. The production is transported through pipeline A, B and C to a separator system with 500 psia.

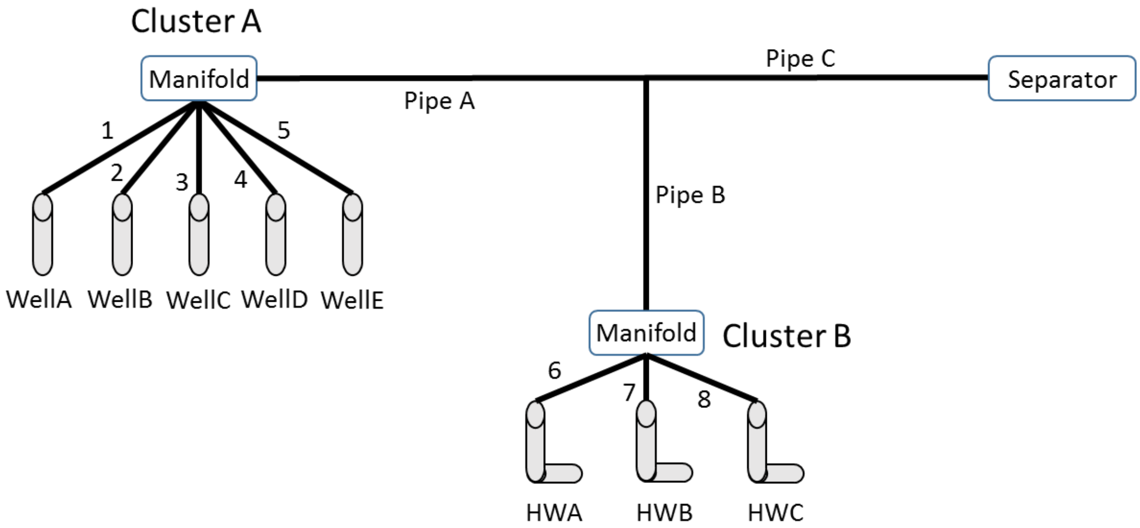
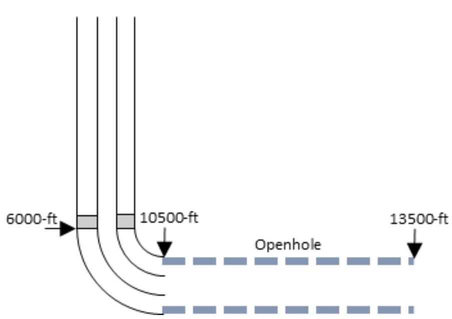


Fig. 1. Well locations

1. Casing Configuration
   1.1. Well A, B, E, D, and E are vertical wells, and they all have the following casing configuration:
      - Depth: 8000 ft
      - Borehole diameter = 11 inch.
      - Outer diameter of casing = 9.625 inch
      - Inner diameter of casing = 8.631 inch
      - Annulus between borehole and casing is cemented.
      - Estimated heat transfer coefficient of wellbore = 2 BTU/hr/ft^2/°F

   1.2. Well HWA, HWB and HWC are horizontal wells, and they all have the following configuration:
      - Well trajectory is shown as below, the detailed trajectory is listed in the following table.



Well Trajectory in Cluster B

MD	TVD	MD	TVD	MD	TVD
ft	ft	ft	ft	ft	ft
0	0	7786.458	7540.754	9192.708	8279.985
400	400	7812.5	7558.954	9218.75	8288.548
450	450	7838.542	7577.001	9244.792	8296.912
500	500	7864.583	7594.896	9270.833	8305.074
5900	5900	7890.625	7612.636	9635.417	8398.006
5950	5949.994	7916.667	7630.22	9661.458	8403.102
6000	5999.954	7942.708	7647.648	9687.5	8407.99
6050	6049.846	7968.75	7664.919	9713.542	8412.671
6100	6099.635	7994.792	7682.03	9739.583	8417.142
6150	6149.287	8489.583	7975.511	9765.625	8421.406
6800	6767.058	8515.625	7989.221	9791.667	8425.46
6850	6811.306	8541.667	8002.75	9817.708	8429.305
6900	6854.93	8567.708	8016.099	9843.75	8432.941
6950	6897.899	8593.75	8029.265	9869.792	8436.368
7000	6940.184	8619.792	8042.248	9895.833	8439.584

7050	6981.756	8645.833	8055.048	9921.875	8442.59
7100	7022.587	8671.875	8067.663	9947.917	8445.387
7150	7062.411	8697.917	8080.092	9973.958	8447.972
7200	7101.157	8723.958	8092.335	10000	8450.347
7250	7139.459	9036.458	8224.435	10200	8464.298
7300	7177.761	9062.5	8234.187	10400	8473.022
7350	7216.063	9088.542	8243.742	10600	8478.257
7708.333	7485.256	9114.583	8253.1	10700	8479.304
7734.375	7503.904	9140.625	8262.26	13500	8489.078
7760.417	7522.404	9166.667	8271.222		

- Casing:
  Outer diameter of casing = 9.625 inch

  Inner diameter of casing = 8.631 inch

  To MD 10500ft
- Openhole in lateral section:
  Borehole diameter = 8 inch

  From MD10500ft to MD13500ft.

2. Reservoir information
   2.1.Cluster A:
   - Initial P_{RI} = 3500 psia
   - Reservoir temperature = 150 °F
   - IPR from multipoint test:

Q (mmscf/d)	P_{wf} (psia)

13.4	2000
17.65	1200
18.99	800

- Pressure decline curve approximation:

$P_R = P_{RI} – 0.012×Q_{TG}$

P_R: average reservoir pressure, psia;

P_{RI}: Initial reservoir pressure, psia;

Q_{TG}: Cumulative gas production, mmscf/d

2.2.Cluster B:

- Initial P_{RI} = 3500 psia
- Reservoir temperature = 150 °F
- Reservoir Area = 1950 acres
- Reservoir thickness = 100 ft
- Permeability = 1 mD (assume the same for all direction)
- Pressure decline curve approximation:

$P_R = P_{RI} – 0.014×Q_{TG}$

P_R: average reservoir pressure, psia;

P_{RI}: Initial reservoir pressure, psia;

Q_{TG}: Cumulative gas production, mmscf/d

2.3.Temperature gradient and heat transfer coefficient:

Heat transfer coefficient = 2 BTU/hr/ft^2/°F

TVD (ft)	T (F)
0	50

3000	91.4
5000	119
6000	132.8
7000	146.6
8000	160.4

3. Pipeline information
   3.1.Pipe A-B
   - Pipe A: 10 miles
   - Pipe B: 15 miles
   - Pipe C: 20 miles
   - Ambient temperature = 50 °F.

Pipeline profile

	Elevation at a particular point [ft]		
% of total Length	Pipe A	Pipe B	Pipe C
0	0	0	0
20	500	-100	200
40	100	100	800
60	80	450	1500
80	-20	500	1500
100	0	200	1000

3.2. Pipe 1 – 8:

- Length: 1 miles
- Rate of undulation (1/1000ft): 10 ft
- Ambient temperature = 50 °F.

4. Fluid Properties

Gas Composition						
Component	Mol	Mol wt	Crit T °F	Crit P psia	Acentric factor -	Normal Tb °F
N2	0.0312	28.014	-232.51	492.32	0.04	-320.35
CO2	0.0479	44.01	87.89	1069.87	0.225	-109.3
C1	0.6161	16.043	-116.59	667.2	0.008	-258.79
C2	0.0648	30.07	90.05	708.35	0.098	-127.39
C3	0.0269	44.097	205.97	615.76	0.152	-43.69
iC4	0.0063	58.124	274.91	529.06	0.176	10.85
nC4	0.0068	58.124	305.69	551.1	0.193	31.19
iC5	0.0020	72.151	369.05	490.85	0.227	82.13
nC5	0.0017	72.151	385.61	489.38	0.251	96.89
C6	0.0044	84	458.33	441.98	0.2818	155.894
CHCmp_1	0.0058	96	495.338	410.07	0.311	202.658
CHCmp_2	0.0060	107	539.33	380.05	0.3324	233.6
CHCmp_3	0.0038	121	589.334	349.01	0.371	280.58
CHCmp_4	0.0026	134	609.332	326.09	0.4151	324.14

CHCmp_5	0.0016	147	673.322	306.08	0.4606	365
CHCmp_6	0.0013	161	712.328	286.06	0.4941	402.08
CHCmp_7	0.0033	204.76	818.492	274.89	0.5637	486.482
CHCmp_8	0.0008	331	1166	172.06	0.84	762.926
Water	0.1667	18.01	705.47	3208.24	0.344	212

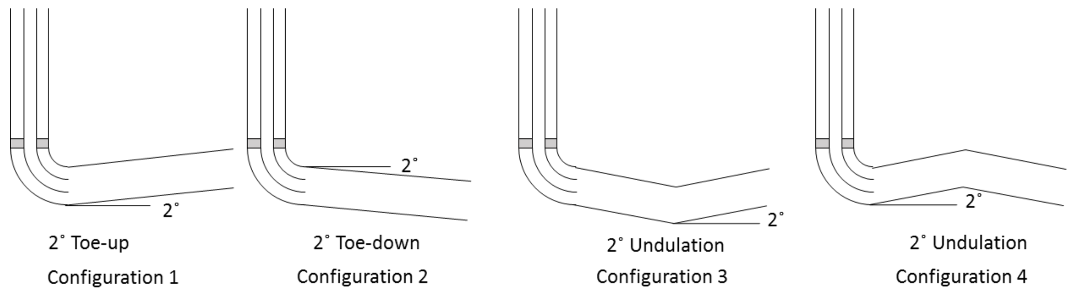
If use gas lifting, the following composition can be chosen.

Gas Composition for Gas Lifting						
Component	Mol	Mol wt	Crit T °F	Crit P psia	Acentric factor -	Normal Tb °F
C1	0.7711	16.043	-116.59	667.2	0.008	-258.79
C2	0.1123	30.07	90.05	708.35	0.098	-127.39
C3	0.0909	44.097	205.97	615.76	0.152	-43.69
iC4	0.0098	58.124	274.91	529.06	0.176	10.85
nC4	0.0090	58.124	305.69	551.1	0.193	31.19
iC5	0.0035	72.151	369.05	490.85	0.227	82.13
nC5	0.0017	72.151	385.61	489.38	0.251	96.89
C6	0.0017	84	458.33	441.98	0.2818	155.894

Horizontal well configuration

For the Horizontal Well in Cluster B, if you have the following four options for the lateral section: toe-up, toe-down, and undulations, which one you will select and why? You should consider all the aspects as listed in the Base Case for the four configurations and compare with each other.

(The well configuration above end of curvature is the same as the base case. The total length of the lateral section is the same as the base case.)



SOLUTION OF THE PROBLEM

1. Flowline Size Selection

For fixed tubing size (ID=4.5”) and for choke bean size=2” case, we tried 5 pipeline size combinations for pipes A, B and C:

Table 1: Flowline size cases.

	Pipe A(in)	Pipe B(in)	Pipe C(in)
case 1	20	20	30
case2	26	26	36
case 3	12	12	18
case 4	12	20	30
case 5	12	20	24

Results are tabulated (Table 2) for each case:

Table 2: Results for different cases.

CASE 1: 20/20/30

	Gas		Oil		Gas		Oil			
Year	ClusterA	ClusterB	ClusterA	ClusterB	Cumulative A	Cumulative B	Cumulative A	Cumulative B	pR A	pR B
1	16.7323	30.08997	548.6355	986.606	30536.4475	32948.51715	1001259.788	1080333.461	3133.563	3038.721
2	13.19875	24.40548	432.7739	800.22	54624.16625	59672.51775	1791072.155	1956574.251	2844.51	2664.585
3	10.73607	19.49284	352.0253	639.141	74217.494	81017.17755	2433518.328	2656434.084	2609.39	2365.76
4	8.825585	15.12265	289.3822	495.85	90324.18663	97576.4793	2961640.843	3199389.396	2416.11	2133.929
5	7.34184	11.7921	240.7317	386.646	103723.0446	110488.8288	3400976.195	3622766.547	2255.323	1953.156
6	6.252651	9.325144	205.0182	305.758	115134.1327	120699.8615	3775134.41	3957571.338	2118.39	1810.202
7	5.382274	7.48176	176.4795	245.316	124956.7828	128892.3887	4097209.498	4226192.249	2000.519	1695.507
8	4.630615	6.157405	151.8333	201.892	133407.6551	135634.7472	4374305.27	4447264.317	1899.108	1601.114
9	4.04954	5.045879	132.7804	165.447	140798.0656	141159.9847	4616629.5	4628428.782	1810.423	1523.76
10	3.552484	4.146107	116.4824	135.945	147281.3489	145699.9718	4829209.88	4777288.338	1732.624	1460.2

CASE 2: 26/26/36

	Gas		Oil		Gas		Oil			
Year	ClusterA	ClusterB	ClusterA	ClusterB	Cumulative A	Cumulative B	Cumulative A	Cumulative B	pR A	pR B
1	16.76741	30.13164	549.7869	987.972	30600.52325	32994.1458	1003361.093	1081829.669	3132.794	3038.082
2	13.24196	24.44742	434.1906	801.595	54767.10025	59764.0707	1795758.938	1959575.975	2842.795	2663.303
3	10.71811	19.4045	351.4364	636.245	74327.651	81011.9982	2437130.368	2656264.14	2608.068	2365.832
4	8.778203	15.04211	287.8286	493.209	90347.87148	97483.10865	2962417.563	3196327.776	2415.826	2135.236
5	7.301484	11.68619	239.4084	383.173	103673.0798	110279.4867	3399337.893	3615902.102	2255.923	1956.087
6	6.210124	9.221956	203.6238	302.374	115006.5561	120377.5285	3770951.328	3947002.07	2119.921	1814.715
7	5.330414	7.422042	174.779	243.358	124734.5616	128504.6645	4089923.003	4213478.97	2003.185	1700.935
8	4.5773	6.045019	150.0852	198.207	133088.1341	135123.9603	4363828.493	4430515.964	1902.942	1608.265
9	4.004132	4.932431	131.2915	161.727	140395.675	140524.9723	4603435.48	4607607.138	1815.252	1532.65
10	3.507577	4.031572	115.01	132.189	146797.0031	144939.5436	4813328.73	4752354.422	1738.436	1470.846

CASE 3: 12/12/18										
	Gas		Oil		Gas		Oil			
Year	**ClusterA**	**ClusterB**	**ClusterA**	**ClusterB**	**Cumulative A**	**Cumulative B**	**Cumulative A**	**Cumulative B**	**pR A**	**pR B**
1	15.61985	26.80286	512.1593	878.826	28506.22625	29349.1317	934690.7225	962314.7985	3157.925	3089.112
2	12.67548	22.52203	415.6165	738.464	51638.97725	54010.75455	1693190.835	1770932.988	2880.332	2743.849
3	10.45919	18.6443	342.9465	611.319	70726.999	74426.26305	2319068.198	2440327.622	2651.276	2458.032
4	8.787028	15.07127	288.118	494.165	86763.3251	90929.3037	2844883.548	2981437.859	2458.84	2226.99
5	7.490059	12.24518	245.5916	401.502	100432.6828	104337.7758	3293088.218	3421082.111	2294.808	2039.271
6	6.344086	9.972412	208.0163	326.981	112010.6397	115257.5669	3672717.965	3779125.977	2155.872	1886.394
7	5.539349	8.289421	181.6298	271.798	122119.9517	124334.4829	4004192.35	4076744.678	2034.561	1759.317
8	4.829075	6.869471	158.3406	225.24	130933.0135	131856.5537	4293163.945	4323382.368	1928.804	1654.008
9	4.241506	5.71276	139.0748	187.313	138673.762	138112.0259	4546975.455	4528490.103	1835.915	1566.432
10	3.749825	4.810695	122.9531	157.736	145517.1926	143379.7369	4771364.863	4701210.585	1753.794	1492.684

CASE 4: 12/20/30										
	Gas		Oil		Gas		Oil			
Year	**ClusterA**	**ClusterB**	**ClusterA**	**ClusterB**	**Cumulative A**	**Cumulative B**	**Cumulative A**	**Cumulative B**	**pR A**	**pR B**
1	16.13559	30.08795	529.0701	986.54	29447.45175	32946.30525	965552.9325	1080260.972	3146.631	3038.752
2	12.93285	24.30116	424.0555	796.799	53049.903	59556.07545	1739454.22	1952756.205	2863.401	2666.215
3	10.56056	19.51338	346.2704	639.815	72322.925	80923.22655	2371397.7	2653353.74	2632.125	2367.075
4	8.80891	15.14444	288.8355	496.564	88399.18575	97506.38835	2898522.488	3197091.429	2439.21	2134.911
5	7.43409	11.7446	243.7565	385.088	101966.4	110366.7254	3343378.1	3618762.899	2276.403	1954.866
6	6.349367	9.31954	208.1895	305.574	113553.9948	120571.6217	3723323.938	3953366.429	2137.352	1811.997
7	5.457385	7.543826	178.9423	247.351	123513.7224	128832.1111	4049893.635	4224215.774	2017.835	1696.35
8	4.696751	6.174946	154.0018	202.467	132085.293	135593.677	4330946.92	4445917.577	1914.976	1601.689
9	4.119456	5.064175	135.0729	166.047	139603.3002	141138.9486	4577454.963	4627738.932	1824.76	1524.055
10	3.624598	4.159022	118.847	136.368	146218.1915	145693.0777	4794350.738	4777062.111	1745.382	1460.297

CASE 5: 12/20/24										
	Gas		Oil		Gas		Oil			
Year	**ClusterA**	**ClusterB**	**ClusterA**	**ClusterB**	**Cumulative A**	**Cumulative B**	**Cumulative A**	**Cumulative B**	**pR A**	**pR B**
1	16.04064	29.77417	525.9567	976.251	29274.168	32602.71615	959870.9775	1068995.174	3148.71	3043.562
2	12.90071	24.2396	423.0014	794.781	52817.96375	59145.07815	1731848.533	1939280.369	2866.184	2671.969
3	10.62881	16.69716	348.5081	547.475	72215.542	77428.46835	2367875.815	2538765.932	2633.413	2416.001
4	8.814388	15.84821	289.0151	519.64	88301.8001	94782.2583	2895328.373	3107771.184	2440.378	2173.048
5	7.459575	12.33601	244.5921	404.48	101915.5245	108290.1893	3341708.955	3550676.237	2277.014	1983.937
6	6.378715	9.753831	209.1518	319.814	113556.6794	118970.6342	3723410.99	3900872.348	2137.32	1834.411
7	5.431139	7.95315	178.0817	260.772	123468.508	127679.3334	4048410.093	4186417.797	2018.378	1712.489
8	4.744697	6.481851	155.5739	212.53	132127.5801	134776.9603	4332332.46	4419138.585	1914.469	1613.123
9	4.16085	5.327282	136.4302	174.674	139721.1313	140610.3341	4581317.575	4610406.396	1823.346	1531.455
10	3.66316	4.390964	120.1114	143.973	146406.3983	145418.4397	4800520.88	4768057.16	1743.123	1464.142

It is worth to be mentioned that all the prices of the pipelines checked and they are approximately does not make so much difference. Therefore, here our criterion is just to get more oil and gas production (total profit). All the results are plotted in the Figure 1 to 6.

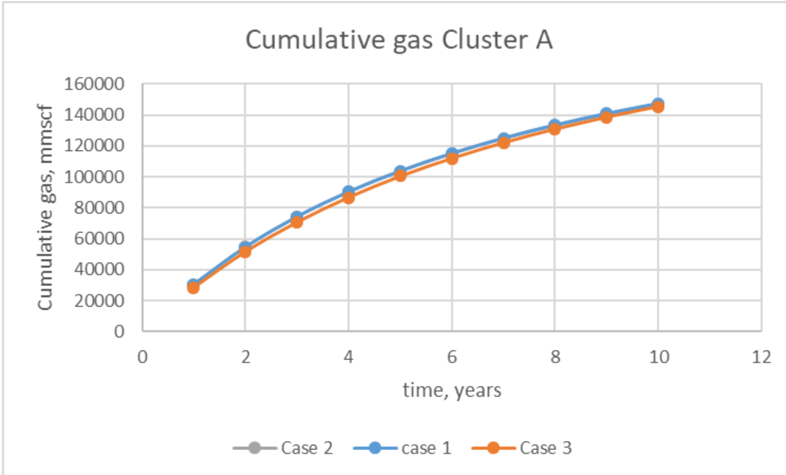


Figure 1

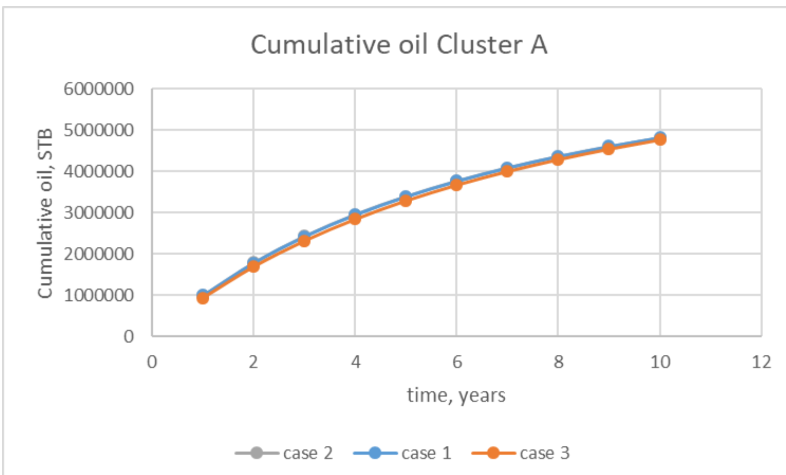


Figure 2

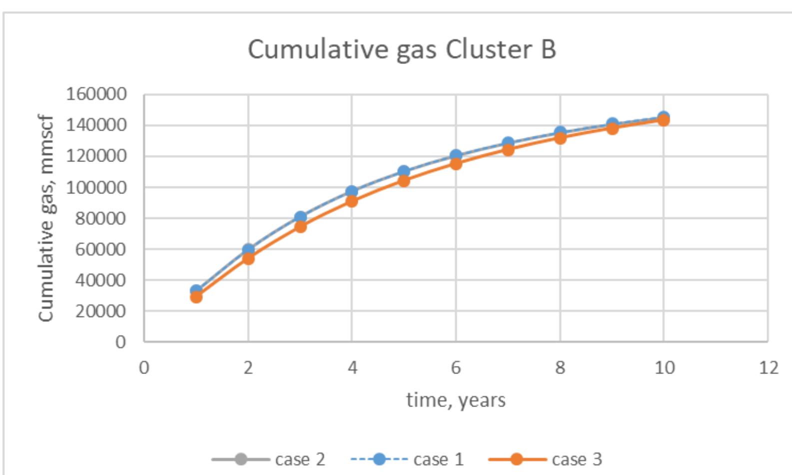


Figure 3

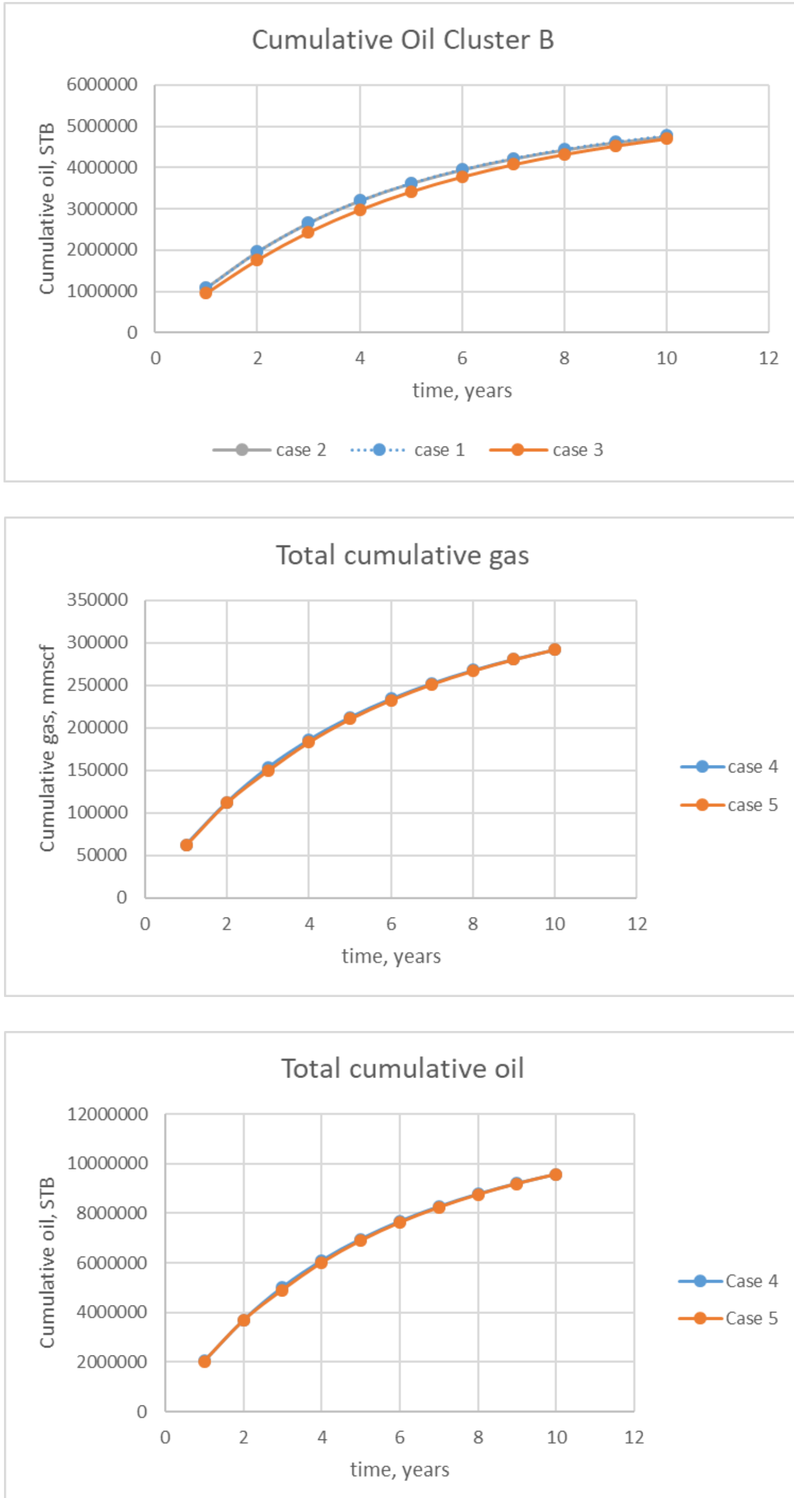


Figure 4

From the plots it is obvious that the optimum dimeter case is case 5, since the increase of diameter of C didn't make any difference.

Pipeline Selection:

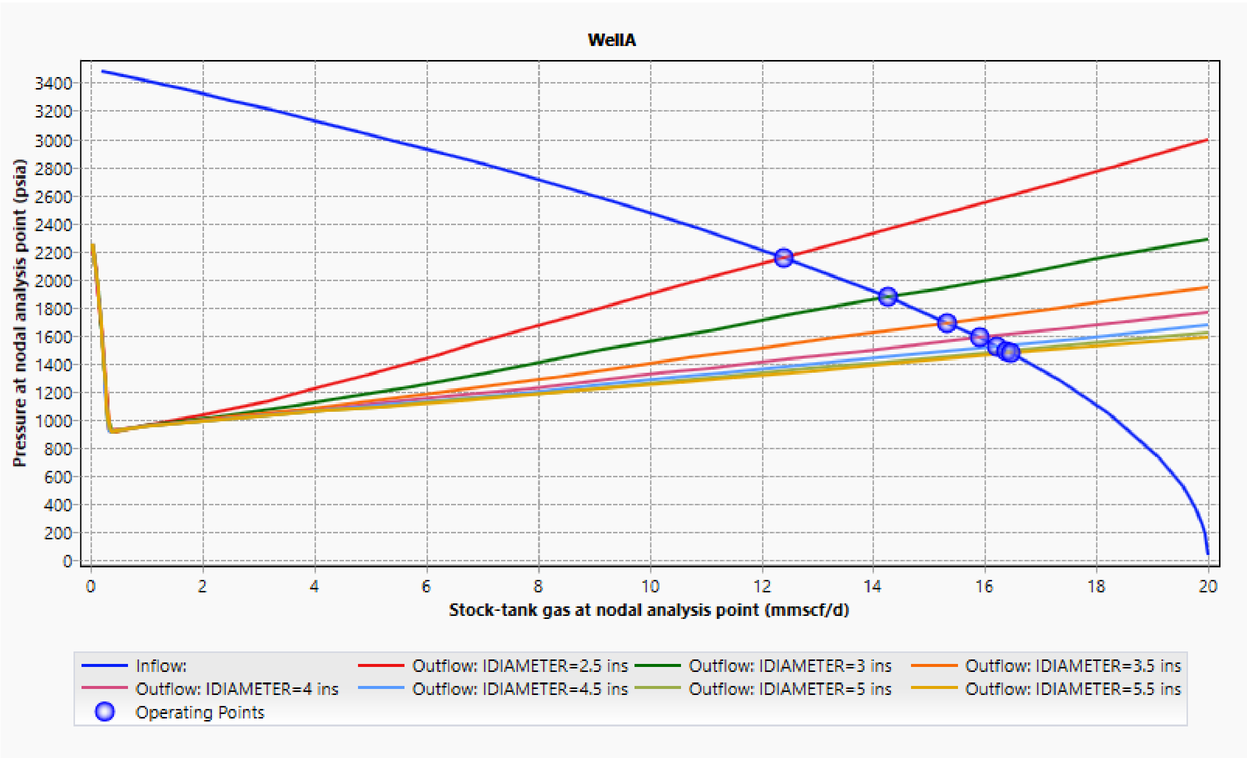


Figure 5: Nodal analysis for pipeline diameter selection for cluster A.

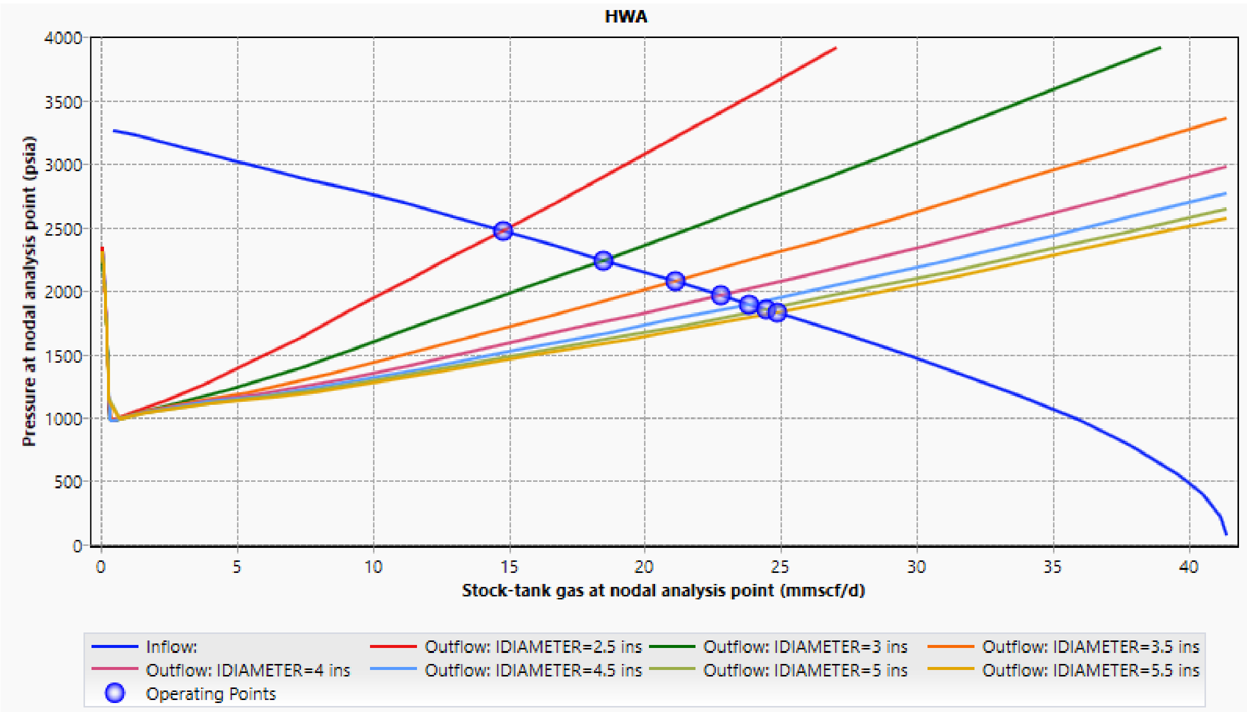


Figure 6: Nodal analysis for pipeline diameter selection for cluster B.

From the nodal analysis, it is clear that after 4.5 inches of pipeline diameter, there is convergence. As a result, we have chosen 4.5 inches pipeline size for both clusters.

2. Tubing Size Selection

After having selected pipeline size we fixed it and started to change the tubing sizes for cluster A and cluster B separately. Choke bean size was chosen as 2 inch (the largest). The reason why we do separately, because our reservoir parameters are not the same. Our criteria was choosing the tubing size that we can have more cumulative gas and oil production (economically). We performed nodal analysis for different tubing sizes. After having chosen optimal dimeter, we performed 20 years production to see if we have liquid loading at early years. Thus, we took liquid loading issue into the consideration using the LL critical gas flow rate option in Pipesim. For each time when we performed network simulation as a reservoir pressure we have inputted the reservoir pressure calculated for each cluster using the equation given in the statement of the problem of the project. Let's check nodal analysis first for both cluster A and cluster B. For visual example, we have taken IPR vs OPR curve at 10th year pressure data (Figure 7). At 10th year reservoir pressure was 1700 psi and wellhead pressure was 650 psi. From the figure it is obvious that there is not any meaning to choose diameter larger than 4 inch. So we have chosen 4 inch ID tubing for the wells of cluster A.

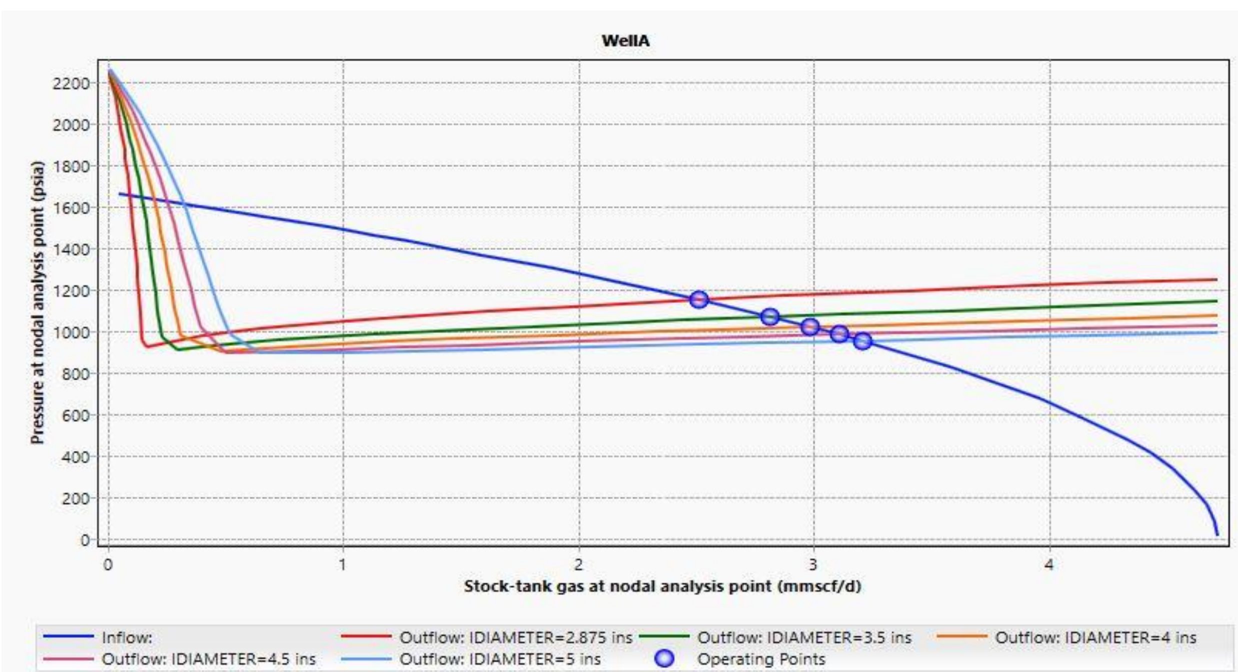


Figure 7: IPR vs OPR for different tubing sizes for vertical wells at 10th year.

For cluster B, 5 inch diameter was the best by means of higher revenue (Figure 8).

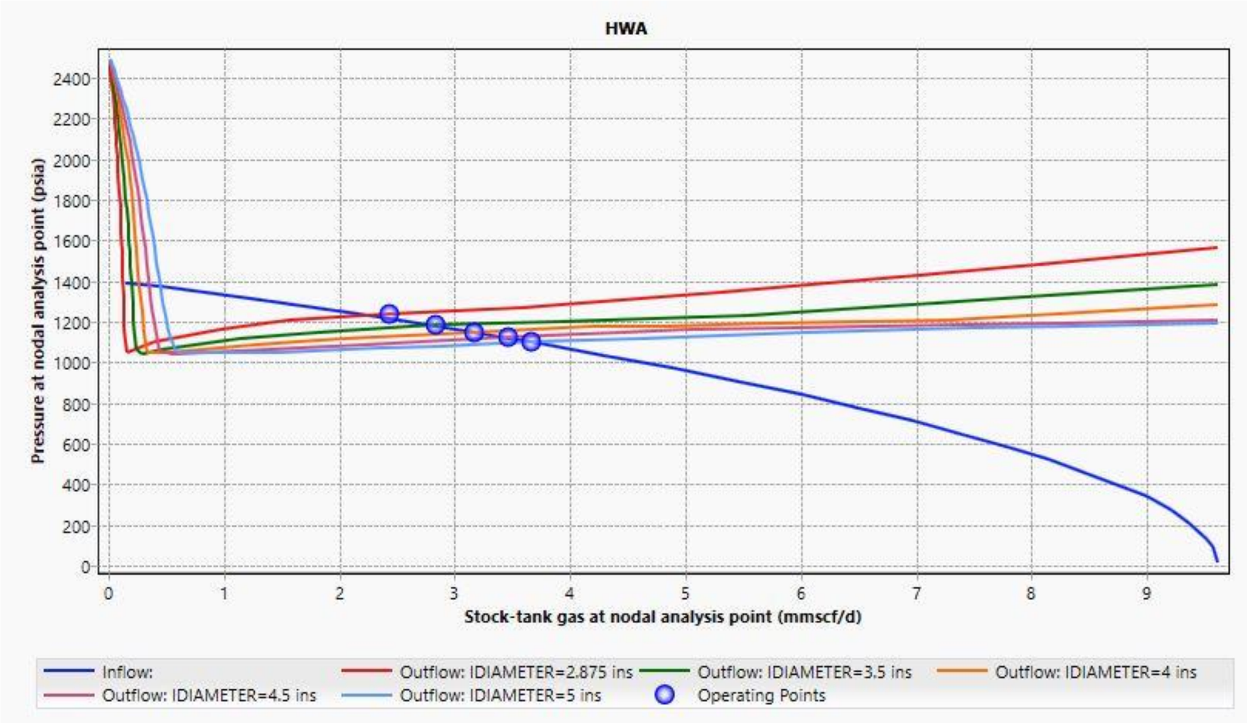


Figure 7: IPR vs OPR for different tubing sizes for horizontal wells at 10^{th} year.

With these diameters we have produced higher oil and gas rate and thus our profit was higher as given in the Table 3.

However, this is not our only criterion. As mentioned above, we also checked liquid loading issue for both cluster A and cluster B while choosing tubing size. So given these diameters, we did not have any liquid loading in both cluster A and cluster B till 10^{th} year. To check this elevation vs LL critical gas rate graph was plotted and intersection between it and our gas rate was checked (Figure 8). From the figure as you can see, we have liquid loading in cluster A at 10^{th} year, cluster B at 8^{th} year. Therefore, we applied gas lift.

3. Gas lift design

To design gas lift we have used 50^{0} F gas injection temperature. We tried different injection pressures and 1000 psi was optimum since the pressure more than 1000 psi has resulted our liquid flow rate to decrease. To choose optimum gas injection rate we have used optimization of Pipesim, and get 1mmscf/D injection rate as optimum (Figure 9).

Table 3: Revenue calculation for our base case (no-gas lift; cluster A 4in; cluster B 5in).

Year	Gas rate A	Gas rate B	Oil rate A	Oil rate B	Well head pressure A	Well head pressure B	Cumulative A	Cumulative B	pR A	pR B	Pressure Differential A	Pressure Differential B	Total oil (STB/d)	Total gas (mmscf/d)	Gas reven ($)	Oil reven($)	Oil cumul revenue($)	Gas cumul revenue($)	Total cumul revenue($)	Total revenues per year ($)
1	15.90867	27.25156	521.63	893.5387	879.0151	966.9695	29033.32275	29840.4582	3151.6	3082.234	2272.585	2115.264	1415.168	43.16023	117747561.9	86867950.3	86867950	1.18E+08	2.05E+08	2.05E+08
2	12.83517	22.67434	420.852	743.4581	799.2367	877.5029	52457.508	54668.8605	2870.51	2734.636	2071.273	1857.133	1164.311	35.50951	96505175.1	71196401.2	1.58E+08	2.14E+08	3.72E+08	1.68E+08
3	10.52378	18.66173	345.064	611.8906	751.8128	809.3376	71663.4065	75103.45485	2640.039	2448.552	1888.226	1639.214	956.9548	29.18551	79280985.7	58489306.7	2.17E+08	2.94E+08	5.1E+08	1.38E+08
4	8.807892	15.34373	288.802	503.0984	713.9879	755.0739	87737.8094	91904.8392	2447.146	2213.332	1733.158	1458.258	791.9005	24.15162	65751574.5	48508046.1	2.65E+08	3.59E+08	6.24E+08	1.14E+08
5	7.46339	12.57537	244.717	412.328	688.2656	718.539	101358.4962	105674.8694	2283.698	2020.552	1595.432	1302.013	657.0452	20.03876	54781433.8	40414862.3	3.05E+08	4.14E+08	7.2E+08	95196296
6	6.392289	9.980557	209.597	327.2478	669.5361	689.7863	113024.4236	116603.5793	2143.707	1867.55	1474.171	1177.764	536.8446	16.37285	45189274.68	33338272.5	3.39E+08	4.59E+08	7.98E+08	78527547
7	5.430548	7.923412	178.062	259.797	676.1073	671.2794	122935.1737	125279.7154	2024.778	1746.084	1348.671	1074.805	437.8593	13.35396	37173772.48	27424863.6	3.66E+08	4.96E+08	8.63E+08	64598636
8	4.758084	6.376053	156.013	209.0614	660.9723	660.9673	131618.677	132261.4934	1920.576	1648.339	1259.604	987.3718	365.0743	11.13414	31330562.67	23114059.9	3.89E+08	5.28E+08	9.17E+08	54444623
9	4.176997	5.302113	136.96	173.8485	653.4583	656.6326	139241.6965	138067.3072	1829.1	1567.058	1175.641	910.4251	310.8081	9.47911	26857666.52	19814192	4.09E+08	5.55E+08	9.64E+08	46671859
10	3.683067	4.426628	120.764	145.1426	649.3278	654.6453	145963.2938	142914.4648	1748.44	1499.197	1099.113	844.5522	265.9067	8.109695	23137509.87	17069653.3	4.26E+08	5.78E+08	1E+09	40207163
11	3.260356	3.692497	106.904	121.0715	647.7327	655.1153	151913.4435	146957.7491	1677.039	1442.592	1029.306	787.4762	227.9754	6.952853	19986867.83	14745281	4.41E+08	5.98E+08	1.04E+09	34732149
12	2.898759	3.11301	95.0475	102.071	647.4863	654.723	157203.6787	150366.495	1613.556	1394.869	966.0696	740.1461	197.1185	6.011769	17397962.25	12835320.4	4.54E+08	6.15E+08	1.07E+09	30233283
13	2.589217	2.611731	84.8979	85.63484	647.6341	656.7181	161928.9997	153226.3404	1556.852	1354.831	909.2179	698.1131	170.5327	5.200948	15170332.94	11191893.5	4.65E+08	6.3E+08	1.1E+09	26362226
14	2.32141	2.195291	76.1167	71.98036	648.2292	659.0105	166165.5729	155630.1841	1506.013	1321.177	857.7839	662.1669	148.0971	4.516701	13280833.79	9797919.51	4.75E+08	6.44E+08	1.12E+09	23078753
15	2.11524	1.778041	69.3566	58.29936	642.5401	667.2109	170025.8859	157577.139	1459.689	1293.92	817.1493	626.7092	127.656	3.893281	11614535.79	8568613.38	4.83E+08	6.55E+08	1.14E+09	20183149
16	1.895775	1.494264	62.1606	48.99473	646.9285	670.018	173485.6753	159213.3581	1418.172	1271.013	771.2434	600.995	111.1553	3.390039	10192016.91	7519154.6	4.91E+08	6.65E+08	1.16E+09	17711172
17	1.707403	1.259655	55.9841	41.30224	650.262	672.4879	176601.6858	160592.6803	1380.78	1251.702	730.5178	579.2146	97.28631	2.967058	8990665.4	6632859.62	4.98E+08	6.74E+08	1.17E+09	15623525
18	1.539521	1.059951	50.4794	34.75422	654.0045	673.6385	179411.3116	161753.3266	1347.064	1235.453	693.0598	561.8149	85.23359	2.599472	7940544.34	5858132.45	5.03E+08	6.82E+08	1.19E+09	13798677
19	1.393608	0.8785448	45.695	28.80619	657.0672	673.1437	181954.6462	162715.3332	1316.544	1221.985	659.477	548.8416	74.50122	2.272153	7010682.312	5172129.35	5.09E+08	6.89E+08	1.2E+09	12182812
20	1.265815	0.7347841	41.5048	24.09249	659.5582	670.5457	184264.7586	163519.9218	1288.823	1210.721	629.2647	540.1754	65.59732	2.000599	6229401.929	4595741.61	5.13E+08	6.96E+08	1.21E+09	10825144
21	1.1462	0.6191315	37.5828	20.30041	663.6015	667.669	186356.5736	164197.8708	1263.721	1201.23	600.1196	533.5608	57.88318	1.765332	5539527.985	4086787.69	5.17E+08	7.01E+08	1.22E+09	9626316

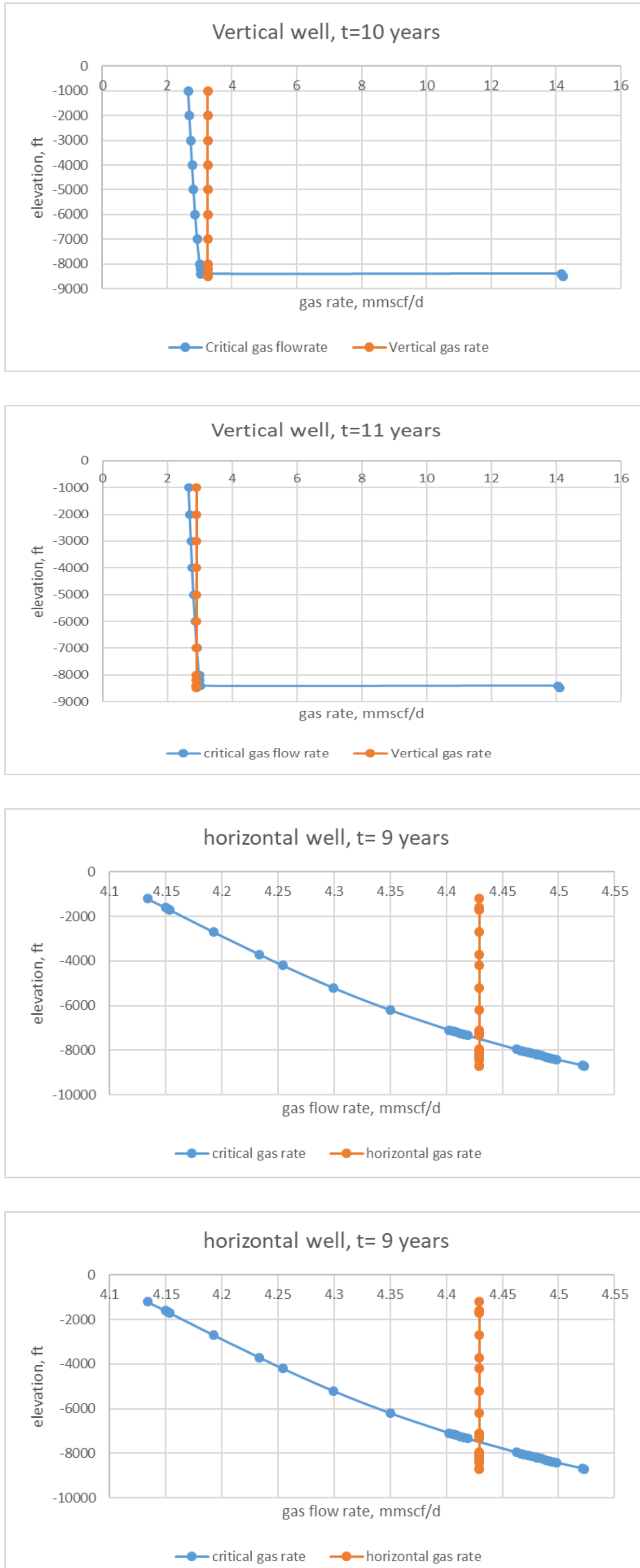


Figure 8: Liquid loading investigation (no-gaslift).

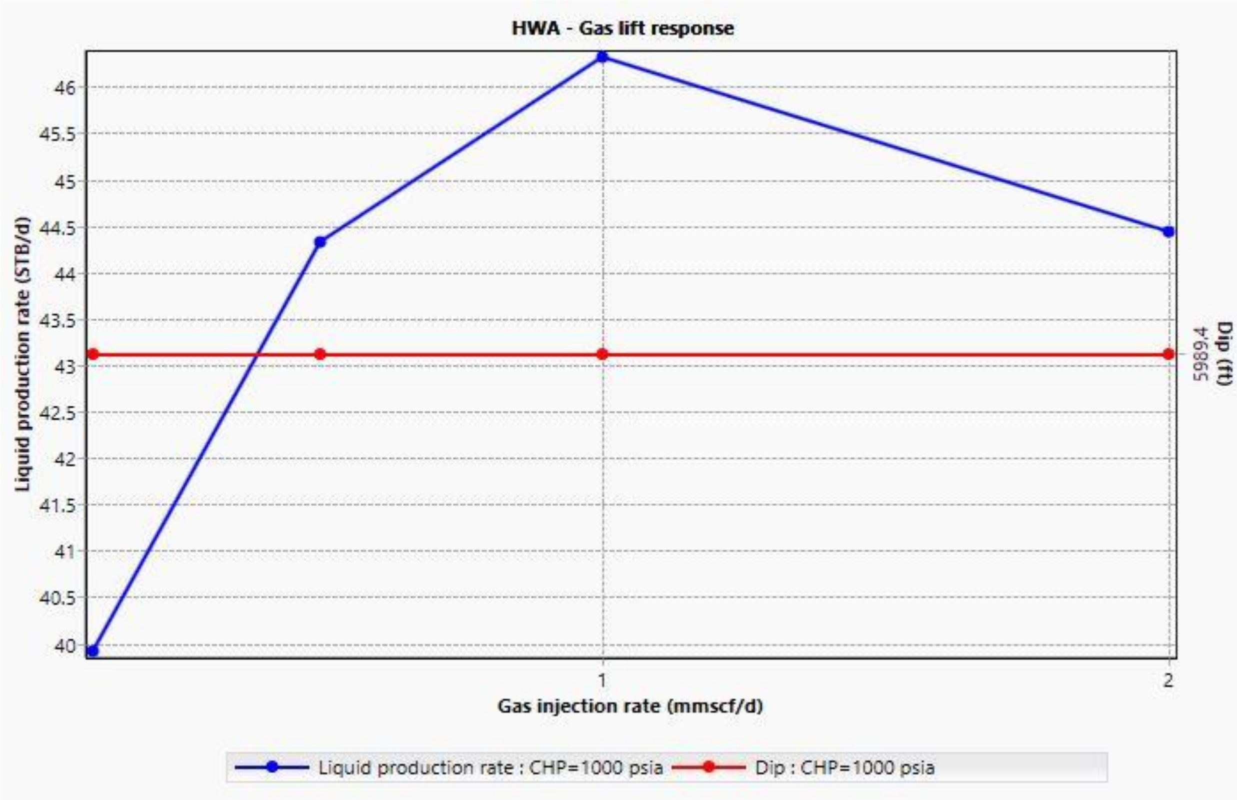
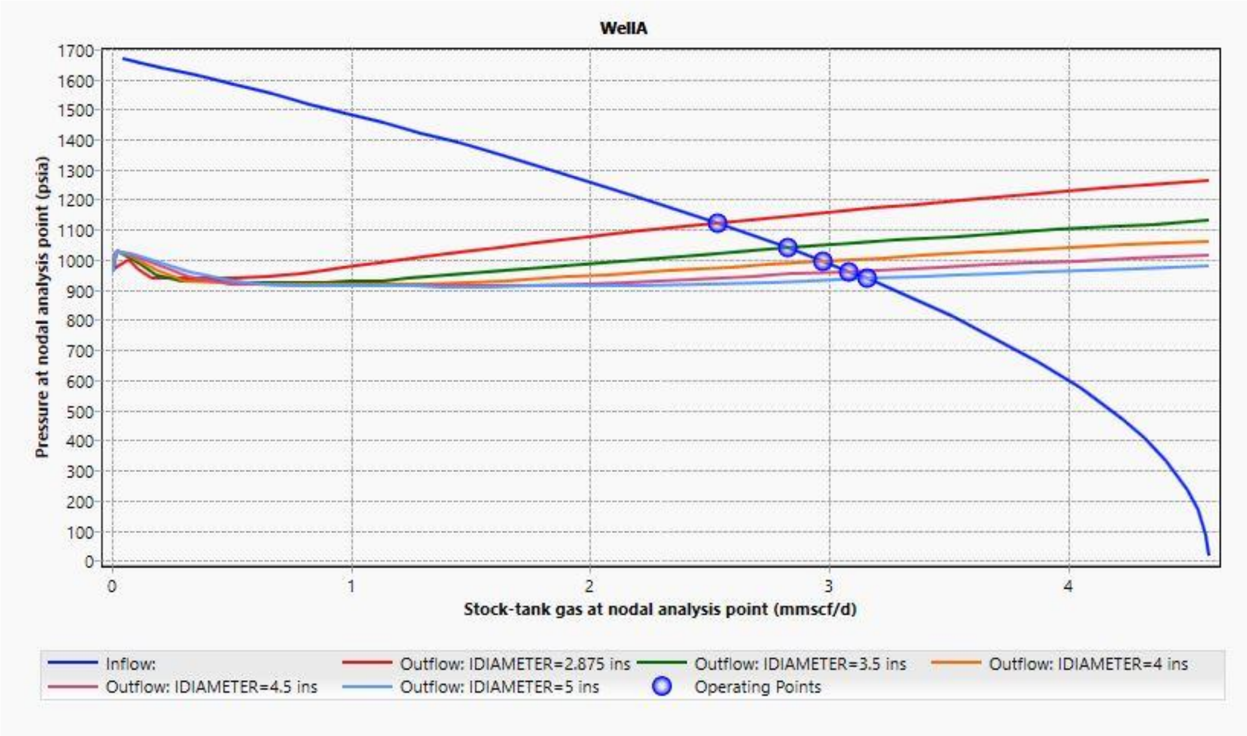


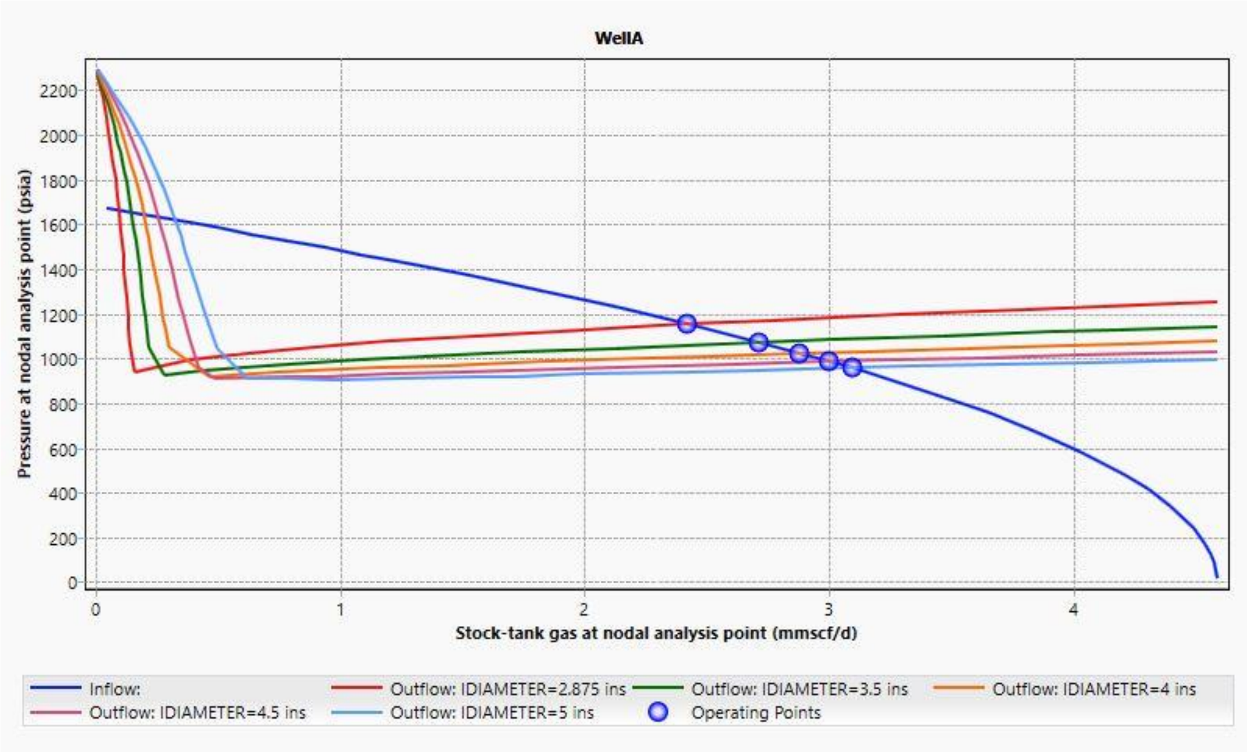
Figure 9: Gas lift injection rate design.

We can also check how gas lift affected our IPR vs OPR curve for vertical well for different tubing sizes (Figure 10), and for the horizontal well (Figure 11). From the figures we see how our OPR has changed, and our flow rates increased our bottomhole flowing pressure, which is critical in the case of liquid loading. That is, it means it will decrease pressure drop in the tubing and thus our flow rate will be higher than LL critical gas rate eventually.

In horizontal well in gas lift case, 5 inch tubing OPR showed totally different behavior comparing to other tubing IDs. This is because at that diameter our gas velocity can't defeat critical gas velocity, since at higher diameter the velocity is much lower. Therefore, with this diameter (ID_{hor}=5 in) after applying gas lift for 2 years (between 9 and 11), further injection did not help us to get over liquid loading (Figure 12). From the Figure 12 we see that at 12th year our rate is lower than critical gas rate. We tried changing injection rate and or pressure as well as choke bean size, but it did not help. This indicates that tubing size for horizontal well has not been chosen optimally. However, vertical well has shown good results and gas lift helped us to produce our wells 5 years more.

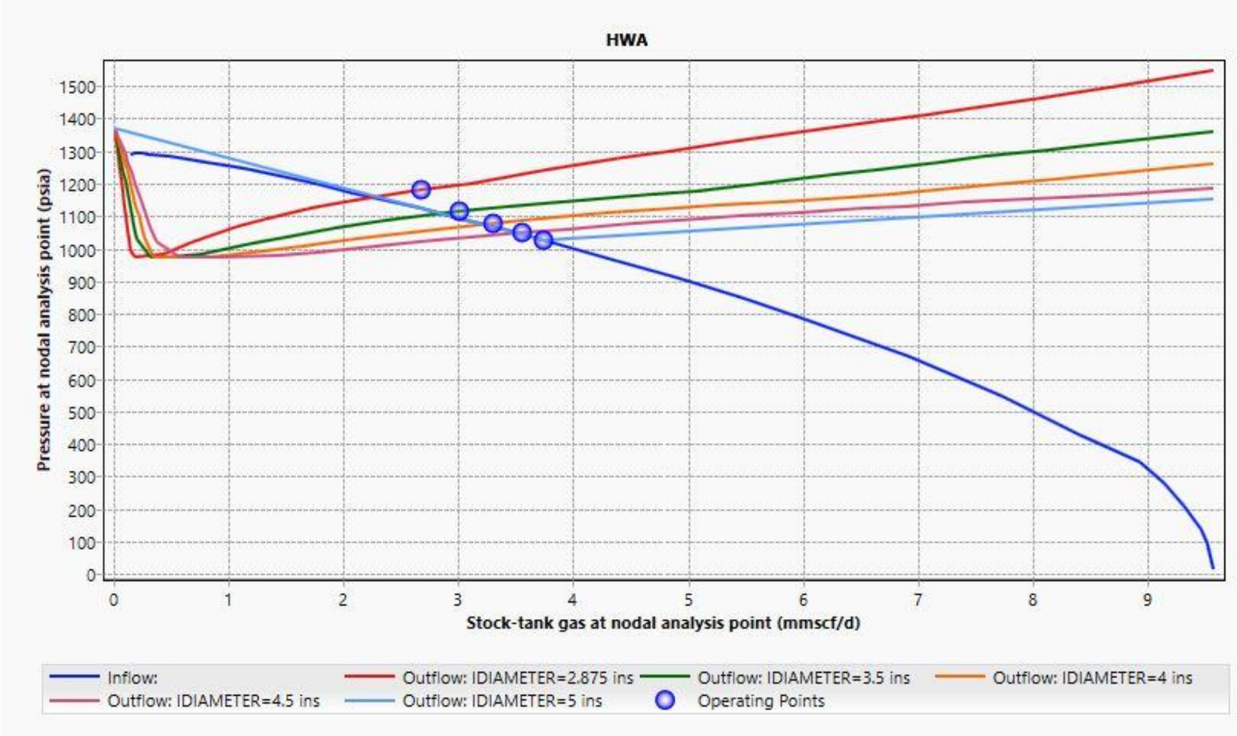


a)

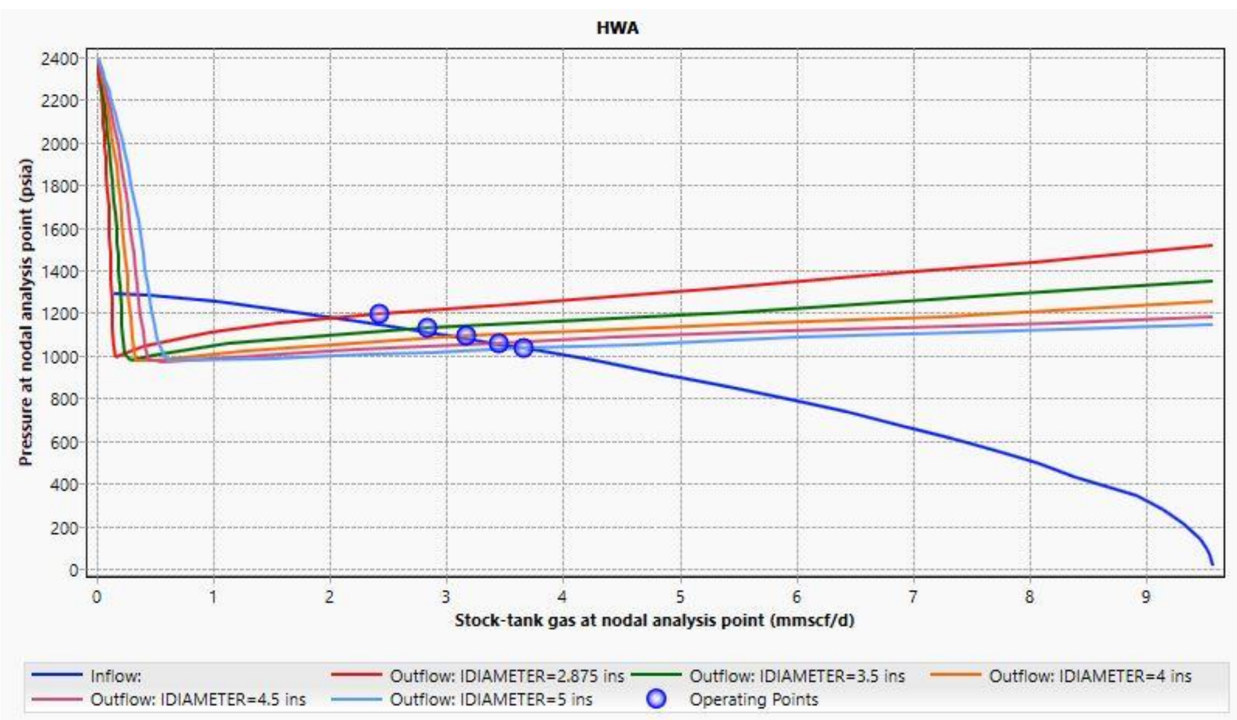


b)

Figure 10. Vertical well nodal analysis for gas lift (a); no gas lift (b) cases.

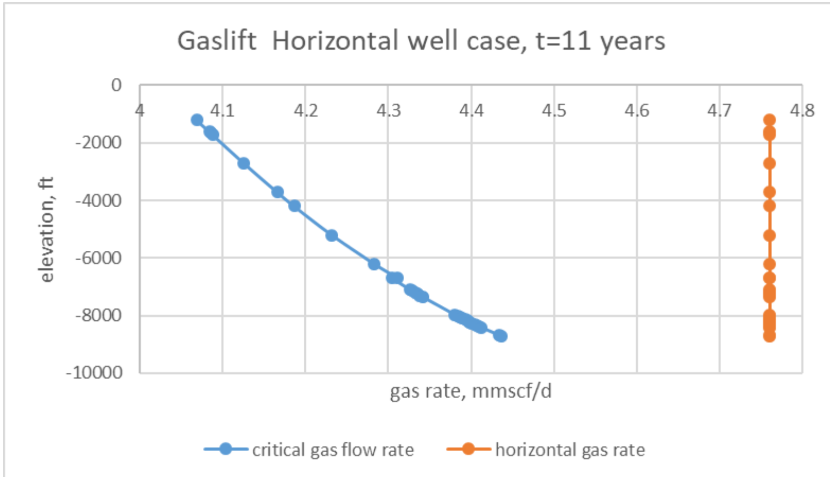


a)



b)

Figure 11. Horizontal well nodal analysis for gas lift (a); no gas lift (b) cases.



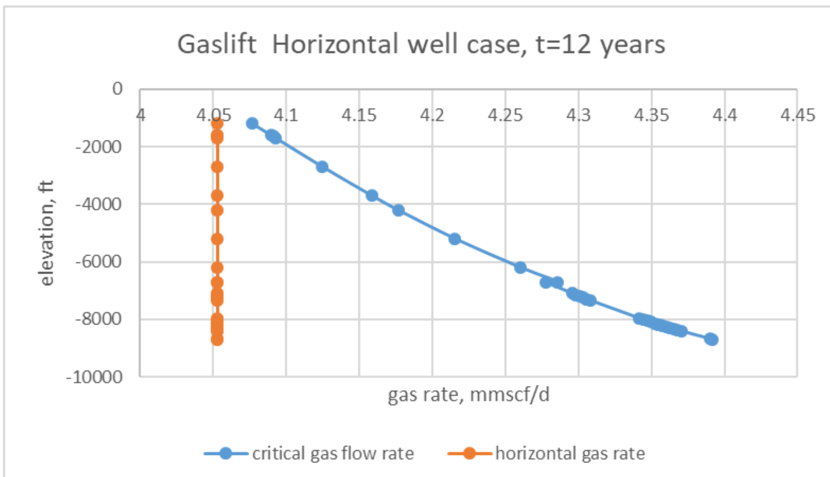


Figure 12: Gas lift effect comparison of horizontal well.

Therefore, we have changed tubing size of horizontal well from 5 to 4 inch. As a result, we 18 years production from vertical well and 17 year of production from horizontal well, because we had to shut in cluster B since we couldn't get rid of liquid loading even with gas-lift (Table 3).

To compare the cases better, we also plotted total revenue vs time for both final cases in which we only change horizontal well diameter (Figure 13). This is also our economic component comparison plot (section 10 in the statement of the problem).

To do so we have also considered expenditure of gas lift, therefore we extracted what we inject. From plots it is obvious that the case where we have 4 inch in all clusters and when we inject gas lift was the best case. So our **base case is: ID (A) = ID (B) = 4 inch; Gas lift injection rate = 1mmscf/day; Flowlines: ID (A) = 12 inch; ID (B) = 20 inch; ID(C) = 24 inch.**

Table 3: Different tubing size scenarios for gaslift case.

ARTIFICIAL LIFT FOR A 2mmscf/d - 1 mmscf/d for cluster B - 5 in cluster B																					
Year	Gas rate A	Gas rate B	Oil rate A	Oil rate B	Well head pressure A	Well head pressure B	Cumulative A	Cumulative B	pR A	pR B	Pressure Differential A	Pressure Differential B	Total oil (STB/d)	Total gas (mmscf/d)	Gas reven ($)	Oil reven($)	Oil cumul revenue($)	Gas cumul revenue($)	Total cumul revenue($)	Total revenues per year ($)	
1	15.90867	27.25156	521.63	893.5387	879.0151	966.9695	29033.32275	29840.4582	3151.6	3082.234	2272.585	2115.264	1415.168	43.16023	117747561.9	86867950.3	86867950.34	117747561.9	204615512	2.05E+08	
2	12.83517	22.67434	420.852	743.4581	799.2367	877.5029	52457.508	54668.8605	2870.51	2734.636	2071.273	1857.133	1164.311	35.50951	96505175.1	71196401.2	158064351.6	214252737	372317089	1.68E+08	
3	10.52378	18.66173	345.064	611.8906	751.8128	809.3376	71663.4065	75103.45485	2640.039	2448.552	1888.226	1639.214	956.9548	29.18551	79280985.7	58489306.7	216553658.3	293533722.7	510087381	1.38E+08	
4	8.807892	15.34373	288.802	503.0984	713.9879	755.0739	87737.8094	91904.8392	2447.146	2213.332	1733.158	1458.258	791.9005	24.15162	65751574.5	48508046.1	265061704.4	359285297.2	624347002	1.14E+08	
5	7.46339	12.57537	244.717	412.328	688.2656	718.539	101358.4962	105674.8694	2283.698	2020.552	1595.432	1302.013	657.0452	20.03876	54781433.8	40414862.3	305476566.7	414066731	719543298	95196296	
6	6.392289	9.980557	209.597	327.2478	669.5361	689.7863	113024.4236	116603.5793	2143.707	1867.55	1474.171	1177.764	536.8446	16.37285	45189274.68	33338272.5	338814839.2	459256005.7	798070845	78527547	
7	5.430548	7.923412	178.062	259.797	676.1073	671.2794	122935.1737	125279.7154	2024.778	1746.084	1348.671	1074.805	437.8593	13.35396	37173772.48	27424863.6	366239702.8	496429778.2	862669481	64598636	
8	4.758084	6.376053	156.013	209.0614	660.9723	660.9673	131618.677	132261.4934	1920.576	1648.339	1259.604	987.3718	365.0743	11.13414	31330562.67	23114059.9	389353762.7	527760340.8	917114104	54444623	
9	4.194482	6.423219	137.533	169.7045	649.5175	657.583	139273.6066	139294.9182	1828.717	1549.871	1179.199	892.2881	307.2374	10.6177	29376708.91	19657078.7	409010841.3	557137049.7	966147891	49033788	Start Artificial lift cluster B
10	3.702988	5.437428	121.417	137.5162	644.2382	650.8441	146031.5597	145248.9019	1747.621	1466.515	1103.383	815.6713	258.9335	9.140416	25423873.52	16747506.5	425758347.9	582560923.3	1008319271	42171380	
11	3.282387	4.621095	107.626	110.9099	641.5936	646.9392	152021.916	150309.0009	1675.737	1395.674	1034.143	748.7348	218.5361	7.903482	22100910.6	14303887	440062234.9	604661833.9	1044724069	36404798	Start Artificial lift Cluster A
12	5.111883	4.11766	88.3489	94.53785	634.0168	630.6825	161351.1025	154817.8386	1563.787	1332.55	929.77	701.8678	182.8867	9.229543	27676048.35	11914003.5	451976238.4	632337882.2	1084314121	39590052	Cluster B started loading. We shut down this cluster
13	4.594226	-	71.9408	-	631.7645	-	169735.5649	-	1463.173	-	831.4087	-	71.9408	4.594226	16768924.9	5908138.2	457884376.6	649106807.1	1106991184	22677063	
14	4.188786	-	59.2199	-	622.4731	-	177380.0994	-	1371.439	-	748.9657	-	59.21989	4.188786	15289068.9	4863433.47	462747810	664395876	1127143686	20152502	
15	3.831857	-	48.1596	-	617.2939	-	184373.2384	-	1287.521	-	670.2272	-	48.15962	3.831857	13986278.05	3955108.79	466702918.8	678382154.1	1145085073	17941387	
16	3.507715	-	38.4326	-	612.1812	-	190774.8183	-	1210.702	-	598.521	-	38.43258	3.507715	12803159.75	3156275.63	469859194.5	691185313.8	1161044508	15959435	
17	2.747431	-	30.1025	-	615.0807	-	195788.8799	-	1150.533	-	535.4527	-	30.10247	2.747431	10028123.15	2472165.35	472331359.8	701213437	1173544797	12500288	Cluster A started Loading. We shut this cluster

Gaslift injection case where cluster A wells diameters are 4 inch; cluster B wells diameters 5 inch.

No gas lift																					
Year	Gas rate A	Gas rate B	Oil rate A	Oil rate B	Well head pressure A	Well head pressure B	Cumulative A	Cumulative B	pR A	pR B	Pressure Differential A	Pressure Differential B	Total oil (STB/d)	Total gas (mmscf/d)	Gas reven ($)	Oil reven($)	Oil cumul revenue($)	Gas cumul revenue($)	Total cumul revenue($)	Total revenues per year ($)	
1	15.92029	24.98078	522.0106	819.0831	877.0628	924.3773	29054.52925	27353.9541	3151.346	3117.045	2274.28285	2192.66734	1341.094	40.90107	112816966.7	83230440.3	83230440.3	112816966.7	196047407	196047407	
2	12.83972	21.11471	421.0019	692.3203	797.9101	850.1171	52487.01825	50474.56155	2870.156	2793.356	2072.24568	1943.23904	1113.322	33.95443	93106192.9	68688863.8	151919304	205923159.6	357842464	161795056.7	
3	10.53902	17.76305	345.5641	582.4242	748.5176	783.7576	71720.72975	69925.1013	2639.351	2521.049	1890.83364	1737.29098	927.9883	28.30207	77368502.5	57078404.2	208997708	283291662.1	492289370	134446906.7	
4	8.811373	14.70753	288.9162	482.2383	712.4042	744.5209	87801.48548	86029.84665	2446.382	2295.582	1733.97797	1551.06125	771.1545	23.5189	64371002.15	47489535.2	256487243	347662664.3	604149908	111860537.3	
5	7.45852	12.21341	244.5575	400.4598	688.2116	713.534	101413.2845	99403.5306	2283.041	2108.351	1594.82899	1394.81657	645.0173	19.67193	53970965.9	39816941.3	296304185	401633630.2	697937815	93787907.23	
6	6.387587	10.18947	209.4427	334.0978	669.5172	691.5518	113070.6308	110561.0003	2143.152	1952.146	1473.63523	1260.5942	543.5405	16.57706	45629631.85	33663150.8	329967336	447263262	777230598	79292782.68	
7	5.436828	8.453056	178.2682	277.1633	674.0914	682.4845	122992.8419	119817.0966	2024.086	1822.561	1349.9945	1140.07615	455.4315	13.88988	38356614.84	28297497.5	358264833	485619876.8	843884710	66654112.37	
8	4.79204	7.208821	157.1263	236.3666	652.5529	663.3679	131738.3149	127710.7556	1919.14	1712.049	1266.58732	1048.68152	393.4929	12.00086	33278263.99	24550961.6	382815795	518898140.8	901713936	57829225.59	
9	4.173373	5.635535	136.8408	184.7809	652.3385	664.1001	139354.7206	133881.6664	1827.743	1625.657	1175.40485	961.556571	321.6217	9.808908	27574633.1	20343129.5	403158924	546472773.9	949631698	47917762.65	
10	3.675157	4.564214	120.5048	149.6539	649.3944	656.8158	146061.8821	138879.4807	1747.257	1555.687	1097.86301	898.87147	270.1587	8.239371	23409951.71	17270652.6	420429577	569882725.6	990312303	40680604.33	
11	3.252279	3.728152	106.639	122.2406	648.2882	654.343	151997.2913	142961.8072	1676.033	1498.535	1027.7443	844.1917	228.8796	6.980431	20035471.23	14781133.4	435210710	589918196.9	1025128907	34816604.67	
12	2.890795	3.161772	94.78631	103.6699	648.2017	655.2045	157272.9922	146423.9475	1612.724	1450.065	964.522394	794.860235	198.4562	6.052567	17475682.43	12892660	448103370	607393879.3	1055497250	30368342.46	Cluster A and B started Loading. Apply Gas lift
13	5.104174	4.608221	88.10345	110.4908	636.3911	633.7549	166588.1097	151469.9495	1500.943	1379.421	864.551584	745.665807	198.5943	9.712395	28722239.09	12679930	460783300	636116118.4	1096899419	41402169.09	
14	4.341524	3.612923	63.99554	78.16749	624.8548	628.145	174511.391	155426.1002	1405.863	1324.035	781.008508	695.889597	142.163	7.954447	23758863.97	9107336.79	469890637	659874982.4	1129765620	32866200.76	
15	3.950332	3.177984	51.81322	64.11551	622.8861	626.0814	181720.7469	158905.9927	1319.351	1275.316	696.464937	649.234703	115.9287	7.128316	21378496.76	7414452.45	477305090	681253479.1	1158558569	28792949.21	
16	3.630076	2.831607	41.98606	52.98102	616.1959	622.5537	188345.6356	162006.6023	1239.852	1231.908	623.656473	609.353867	94.96708	6.461683	19450996.73	6058744.94	483363835	700704475.9	1184068310	25509741.67	
17	3.037694	2.508305	33.28276	42.65831	613.4945	622.3751	193889.4272	164753.1963	1173.327	1193.455	559.832374	571.080152	75.94107	5.545999	16580771.05	4835334.89	488199169	717285246.9	1205484416	21416105.94	Cluster B started Loading. We shut down this cluster of wells.
18	2.374023	-	26.01119	-	618.0998	-	198222.0191	-	1121.336	-	503.235971	-	26.01119	2.374023	8665183.95	2136168.98	490335338	725950430.9	1216285769	10801352.93	Cluster A started Loading. We shut down this cluster of wells.

Gaslift injection case where cluster A wells diamters are 4 inch; cluster B wells diameters 4 inch.

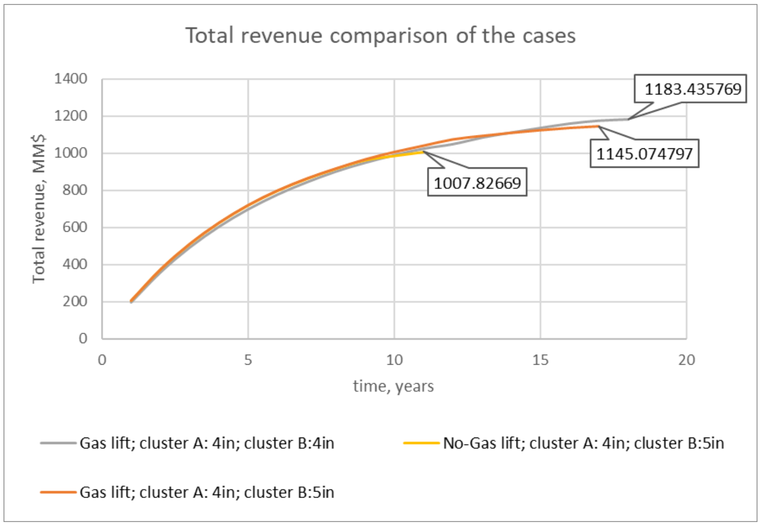


Figure 13: Comparison of cases.

4. Choke Installation

Chokes has to be installed to secure our facilities and control flow rate. To choose its bean size, we performed Nodal analysis for it (Figure 13). it to be large enough, not to have so much pressure drop and to have maximum flow rate. Therefore, we chose choke bean size as 1.5 inch. However, after 10 years we decreased it to 1 inch, since our nodal analysis has changed. (Figure 14).

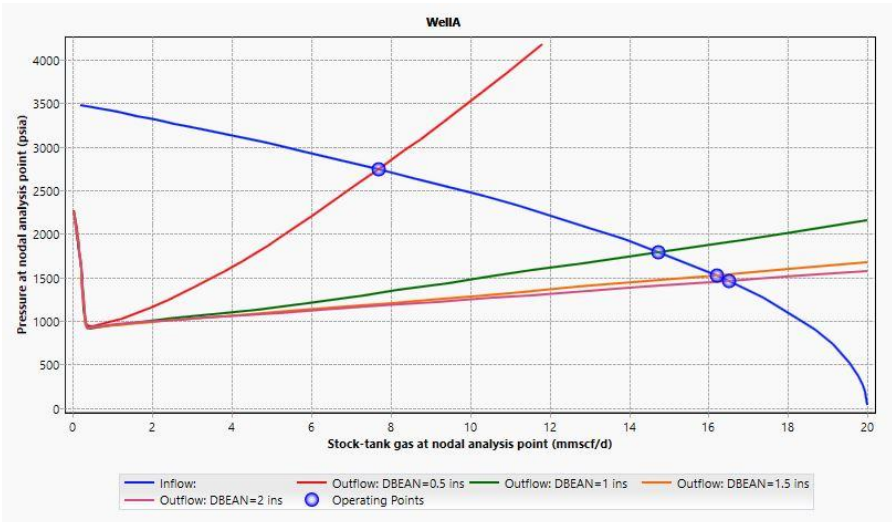


Figure 13: Choke nodal analysis for 1st year.

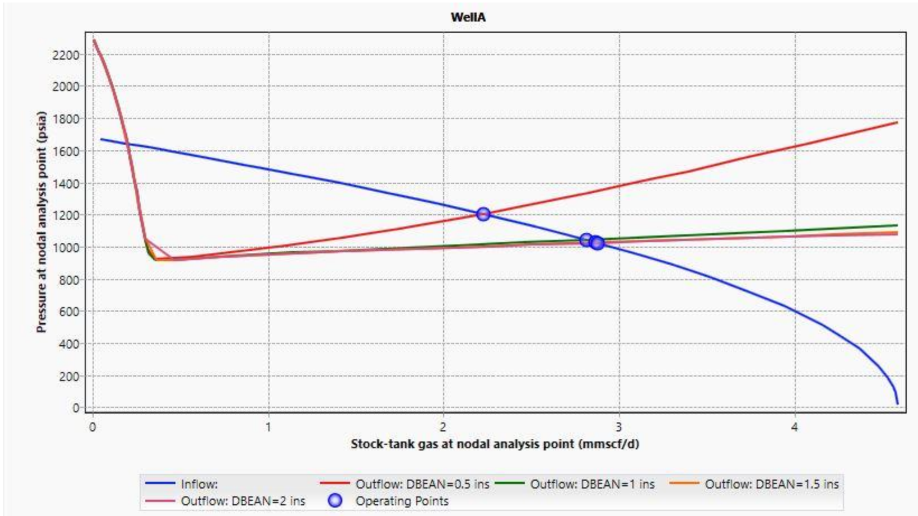


Figure 14: Choke nodal analysis for 10th year.

5. Artificial Lift Selection

As mentioned above we have chosen gas-lift method to prevent our flow from liquid loading. In horizontal well it is hard to use sucker rod and PCP as well as ESP pumps. However, in vertical well, the reason that we don't choose other artificial methods is that our well is gas condensate and our volumetric liquid rate is very lower than gas rate.

Gas injection design has been performed in the section of tubing selection above. It gained us 5 more year production.

6. Multiphase pump selection

We don't need to put multiphase pump, because we have enough pressure difference between last junction and separator.

7. Flow Assurance

Erosion:

For the wells of each cluster we have checked erosional velocity and plotted it for the 1st and 12th years against our mixture velocities (Figure 15). From plots as you see only in the first year at the above section of the horizontal well we have cross with erosional velocity. However, this wouldn't cause any serious problem.

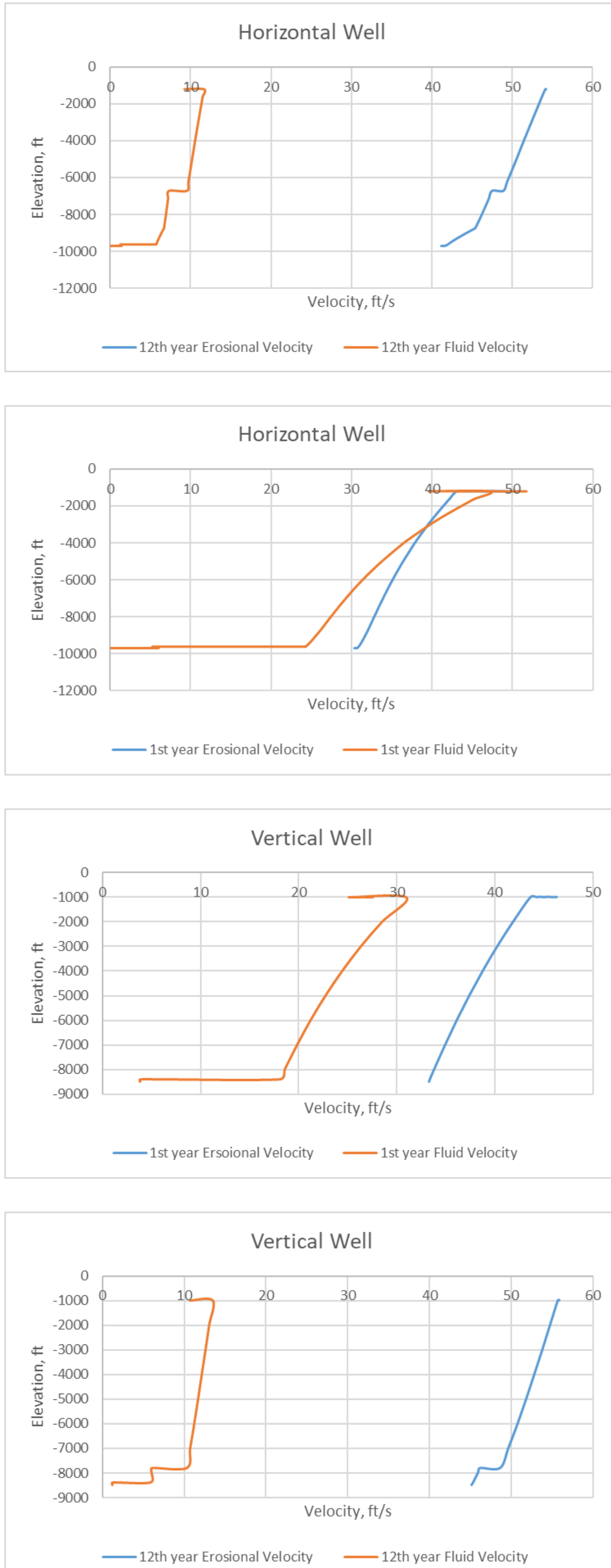


Figure 15: Erosional velocity profile at different years.

Hydrates:

For hydrates to occur temperature plays much more role than pressure does. Our ambient temperature in the flow line is 50 ^{o}F, and the pressure at wellhead is 650 psi. At that condition from our phase diagram, we see that we get hydrate in the flowline. Therefore, we have to insulate our flowline (Figure 16).

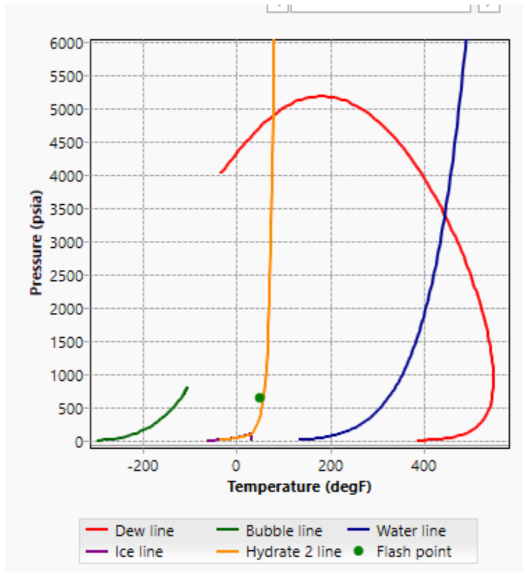


Figure 16: Hydrate issue in the flowline.

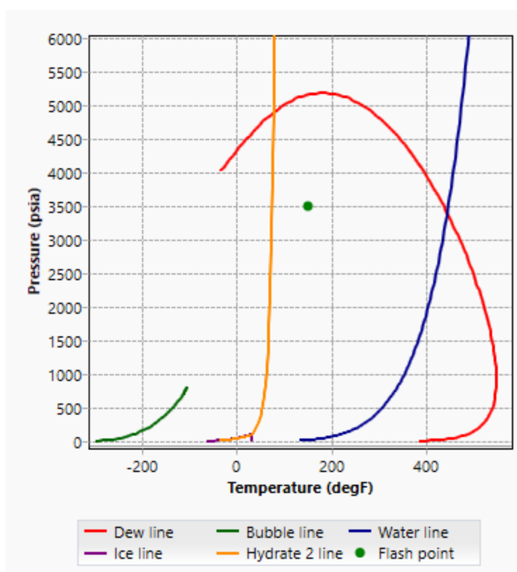
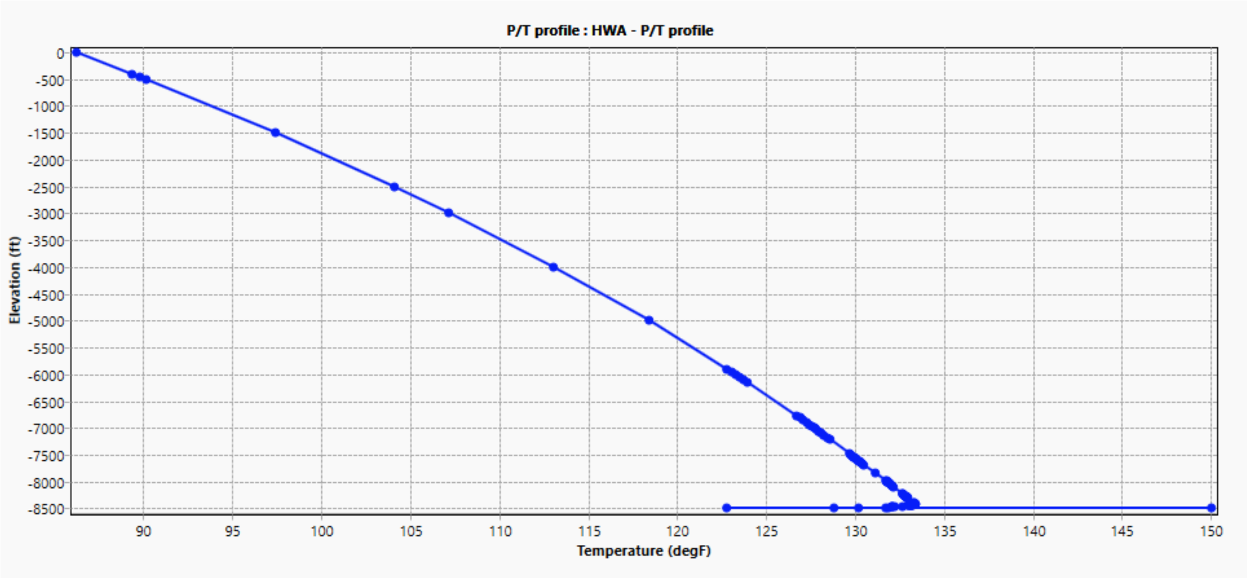
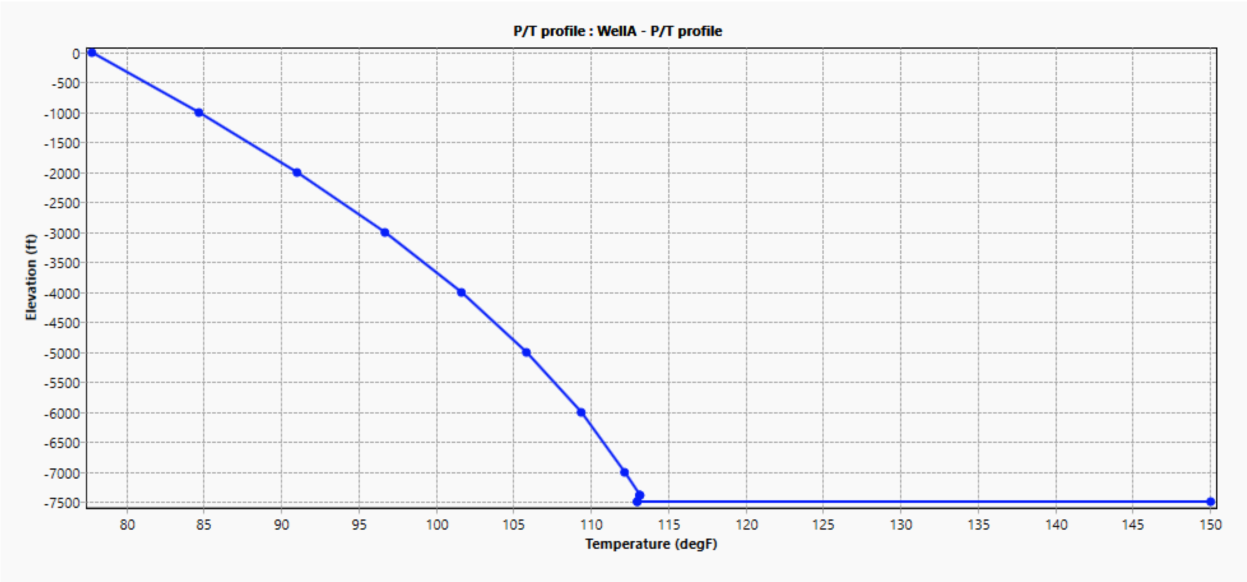


Figure 17: Hydrate issue in the tubing.

8. Temperature profile



Horizontal well



Vertical well

9. Different Multiphase Flow Models

For both cluster A and B, as source we have used Baker Jardine. However, as correlation, for vertical wells Hagedorn & Brown (HB), and for horizontal wells Beggs & Brill (BB) correlation have been used. HB correlation is based on the experiments conducted on vertical wells.

For cluster B, BB correlation is appropriate because BB correlation is for all inclination angles. It has shown slug flow patterns deviation part of our wells which is reasonable because in this correlation, flow patterns consider only horizontal well case.

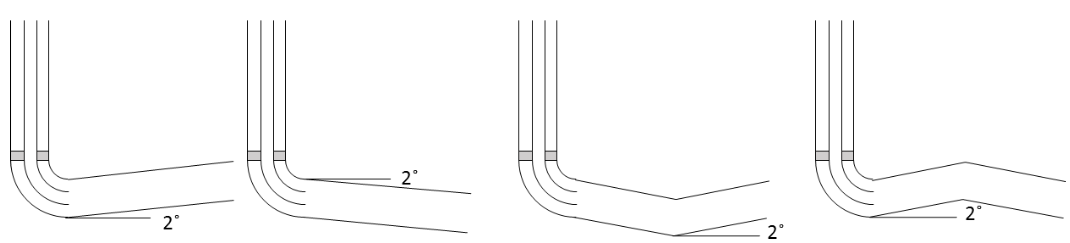
It would be better to use combined model of Zhang et al. to get flow patterns correctly, but since this correlation works slow and since we did not use flow patterns in our optimization we have used BB and HB for horizontal and vertical well respectively. As to the accuracy of the models, Zhang et al. Unified model is more accurate than other models because it estimate pressure drop, liquid hold up and flow pattern more accurately.

10. Economic Component

As we have shown in the tubing selection section, economically, considering gas lift expenditures and total revenue of oil and gas, the best model is to use:

- Cluster A:
    - Tubing size: 4 inch
    - Choke size: 1.5 inch till 10th year; after 10th year we use 1 inch diameter choke
    - Use gas lift: Injection rate = 1mmscf starting from 12th year
- Cluster B:
    - Tubing size: 4 inch
    - Choke size: 1.5 inch till 10th year; after 10th year we use 1 inch diameter choke
    - Use gas lift: Injection rate = 1mmscf starting from 9th year
- Flowline A: 12 in
- Flowline B: 20 in
- Flowline C: 24 in

11. Horizontal Well Configuration



Toe-up Toe-down 1st undulation 2nd undulation

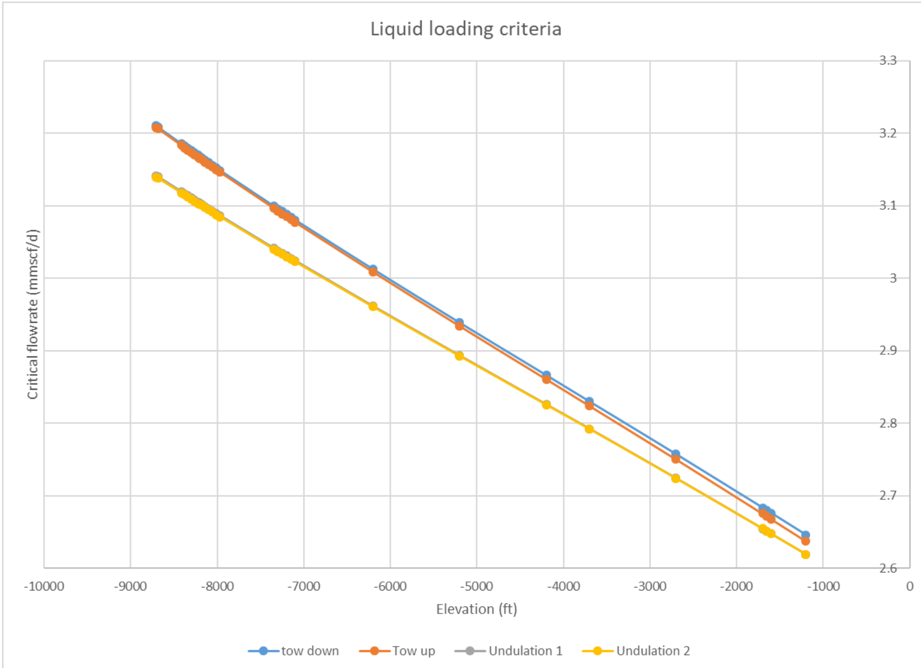


Figure 18: Critical gas flow rate for different horizontal well configurations.

From the figure it is unusual that in toe-down and toe-up showed approximately the same results. This could be because of the gravitational effect on liquid phase. Both undulation configurations showed lower q_c values than toe up and toe down cases.

Furthermore, in all configurations, flow rate showed approximately the same results.

Considering LL critical gas flow rate from the figure we would choose undulation 2 configuration which has the lowest LL critical gas flow rate.

CONCLUSIONS

- Cluster A:
  - Tubing size: 4 inch
  - Choke size: 1.5 inch till 10^{th} year; after 10^{th} year we use 1 inch diameter choke
  - Use gas lift: Injection rate = 1mmscf starting from 12^{th} year
- Cluster B:
  - Tubing size: 4 inch
  - Choke size: 1.5 inch till 10^{th} year; after 10^{th} year we use 1 inch diameter choke
  - Use gas lift: Injection rate = 1mmscf starting from 9^{th} year
- Flowline A: 12 in
- Flowline B: 20 in
- Flowline C: 24 in
- Erosion may occur at the early years in the wells of cluster B
- Hydrates doesn't occur in the tubing, but it occurs in flowlines. Therefore, we need to insulate flowlines.
- Unified Zhang et al. model has less uncertainty than others
- Economically best model has been decided considering prices of the oil and gas and expenditure of gas lift approximately
- As horizontal well configuration, we have chosen the undulation 2 option.