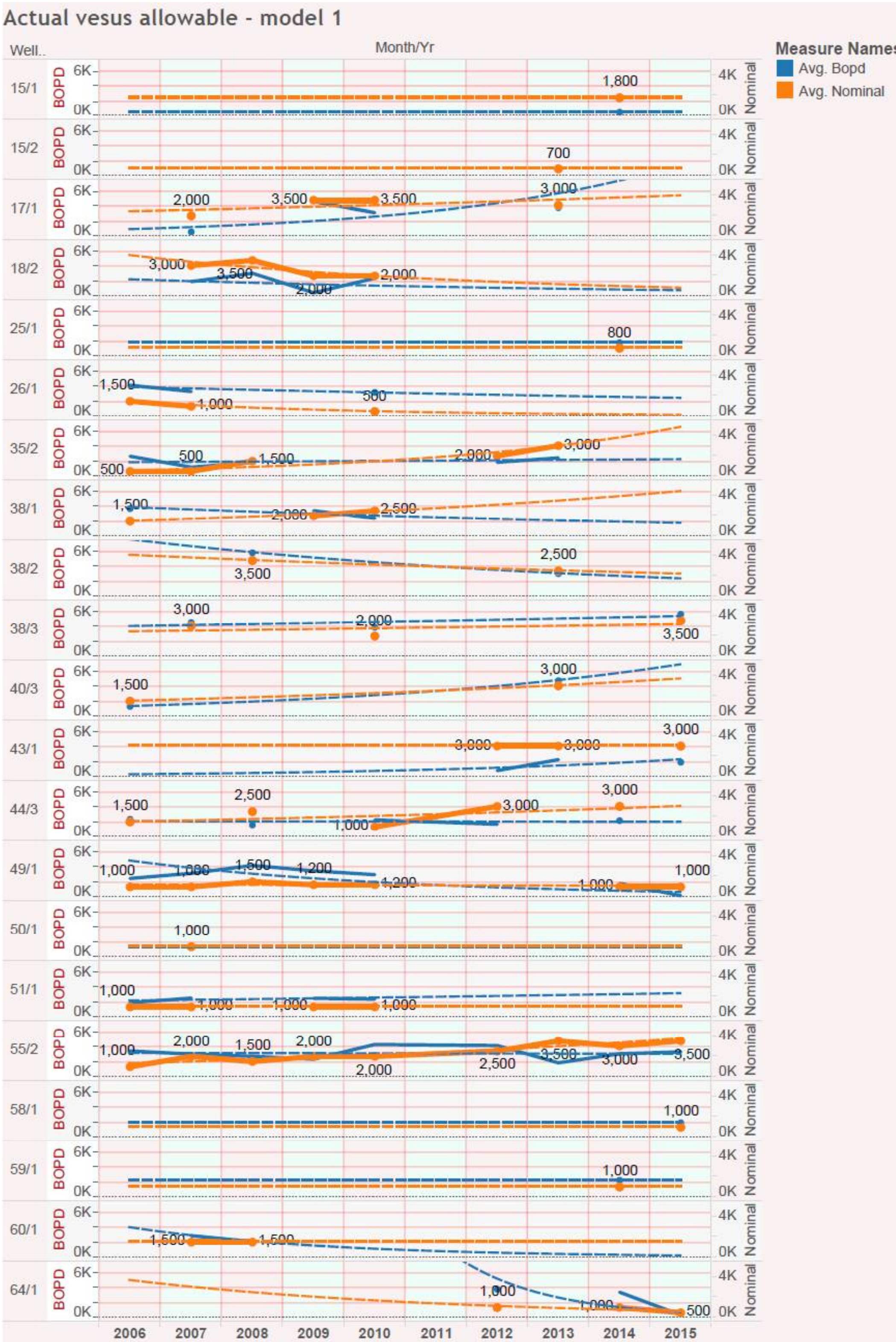
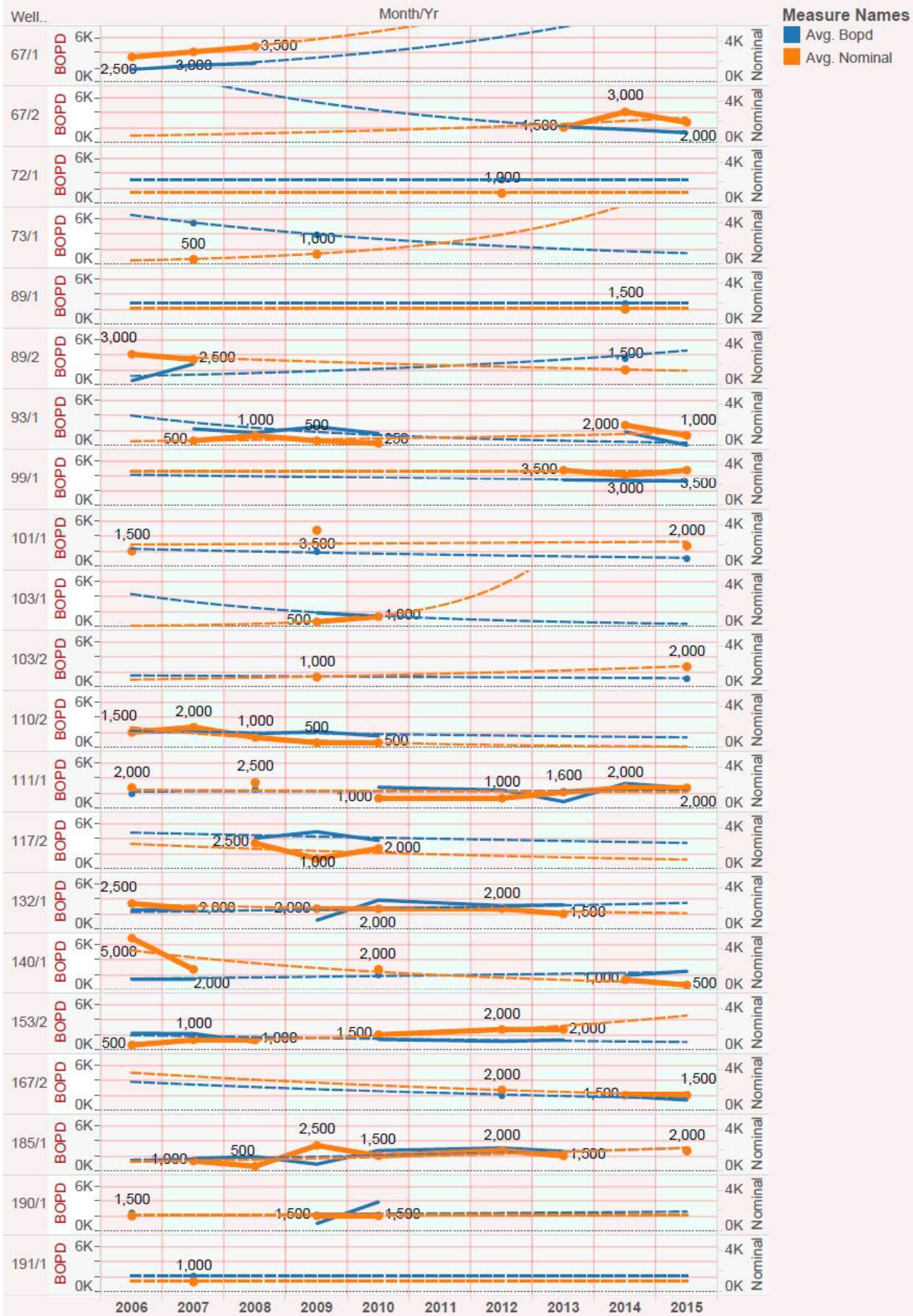
Appendices

Appendix 1 - Well trends model 1

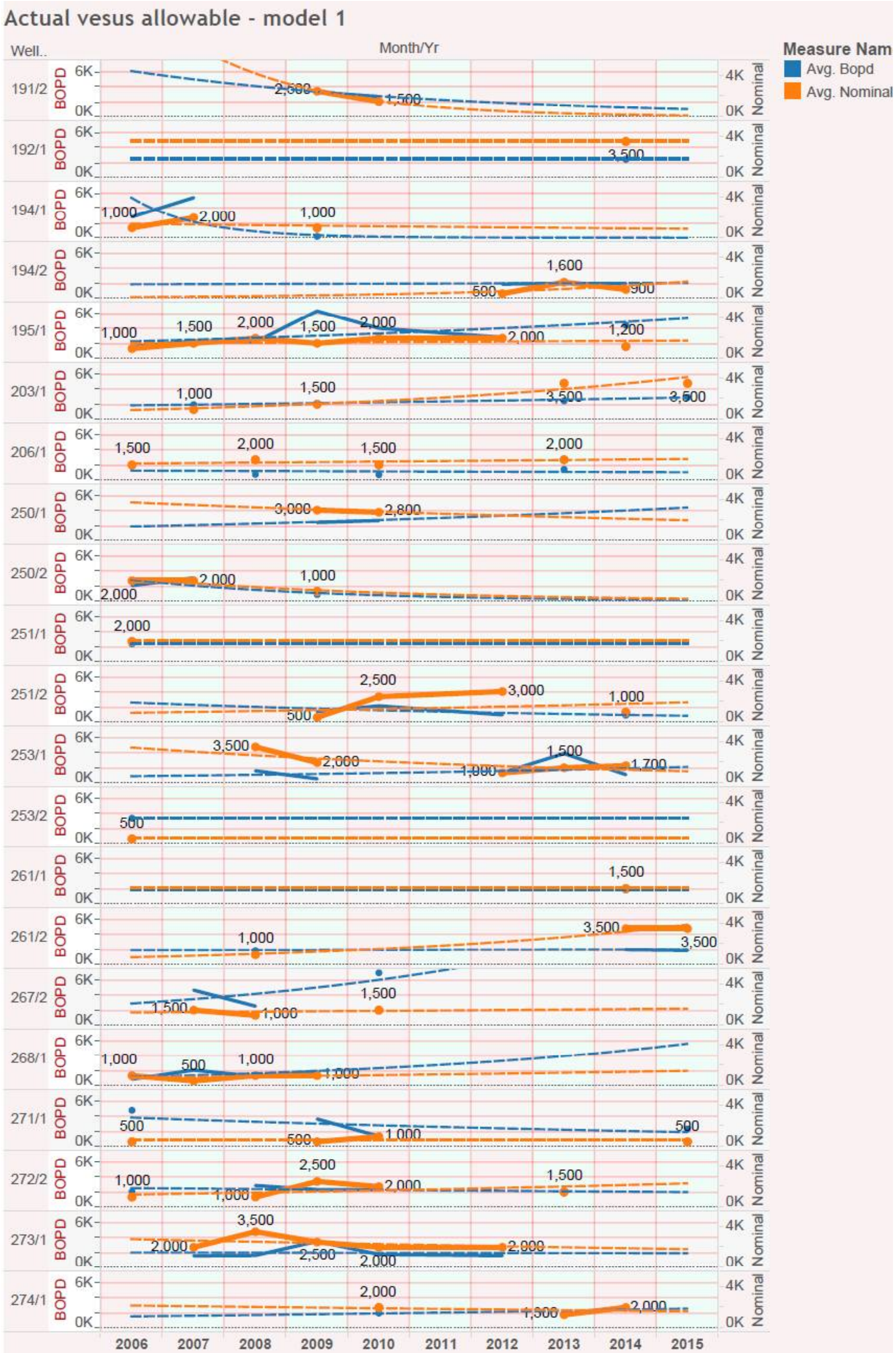


The trends of Avg. Bopd and Avg. Nominal for Month/Yr Year broken down by Well-no. Color shows details about Avg. Bopd and Avg. Nominal. The data is filtered on F3 and Month/Yr. The F3 filter ranges from 1 to 1. The Month/Yr filter ranges from 1/12/2006 to 1/12/2015.

Actual vesus allowable - model 1

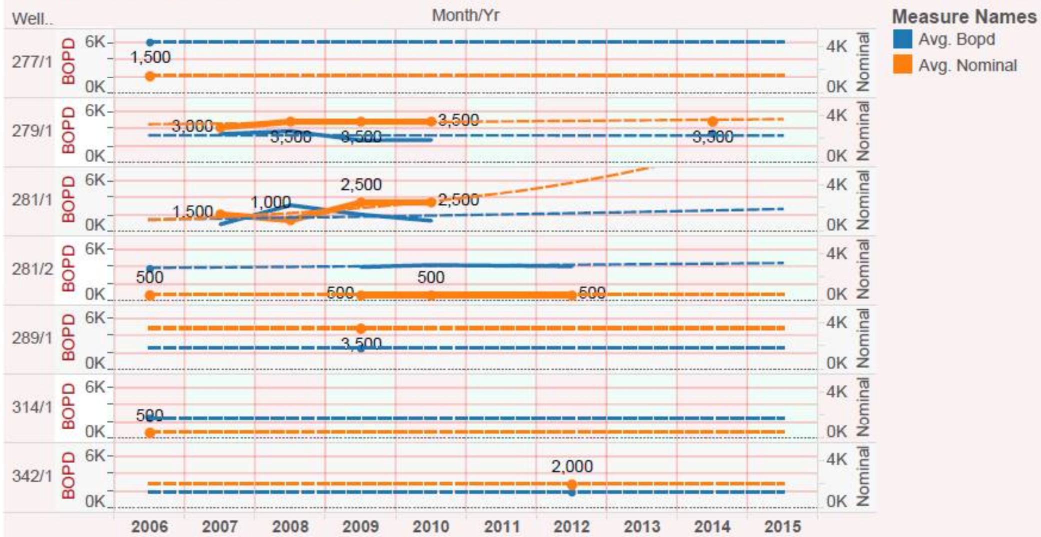


The trends of Avg. Bopd and Avg. Nominal for Month/Yr Year broken down by Well-no. Color shows details about Avg. Bopd and Avg. Nominal. The data is filtered on F3 and Month/Yr. The F3 filter ranges from 1 to 1. The Month/Yr filter ranges from 1/12/2006 to 1/12/2015.



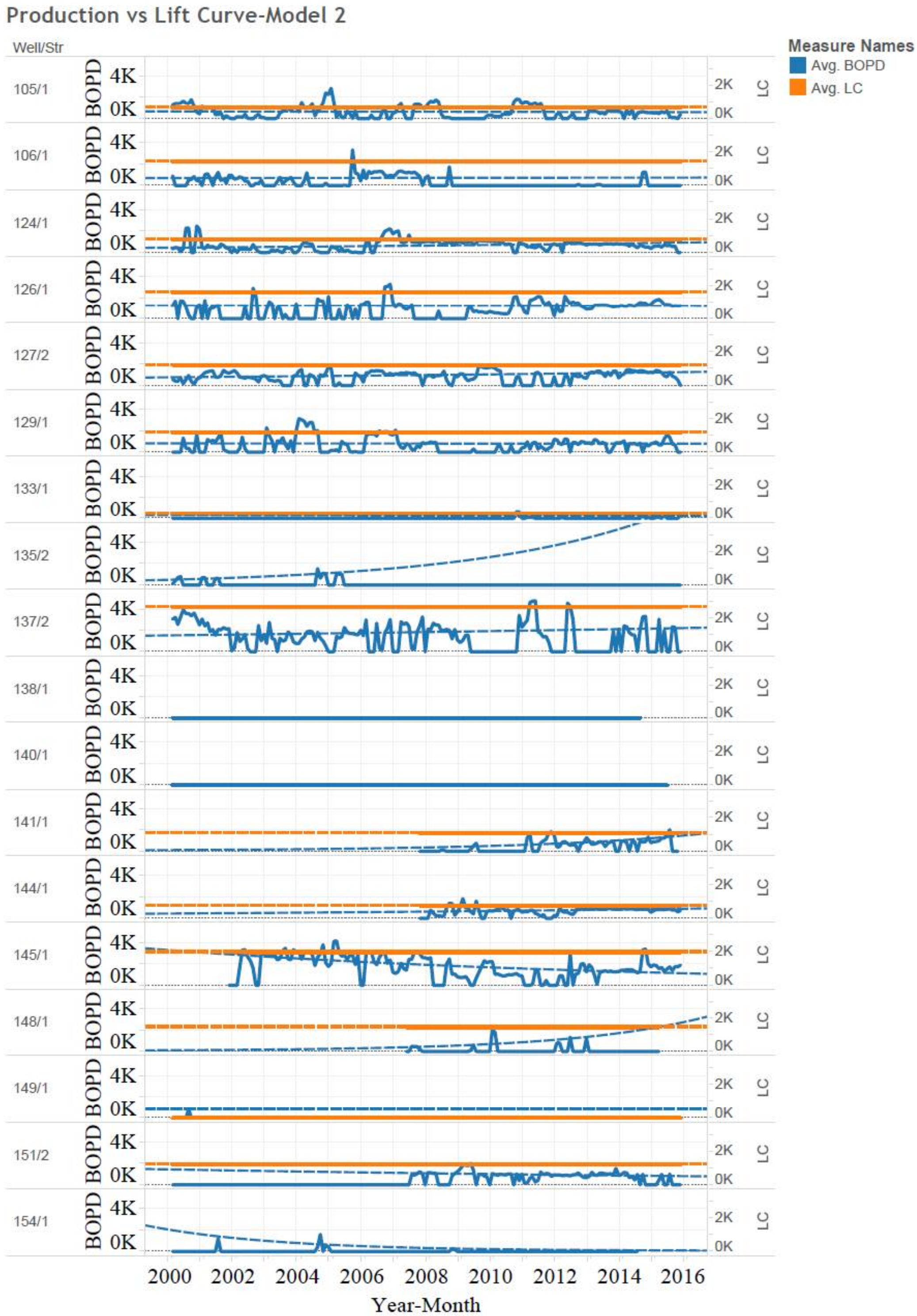
The trends of Avg. Bopd and Avg. Nominal for Month/Yr Year broken down by Well-no. Color shows details about Avg. Bopd and Avg. Nominal. The data is filtered on F3 and Month/Yr. The F3 filter ranges from 1 to 1. The Month/Yr filter ranges from 1/12/2006 to 1/12/2015.

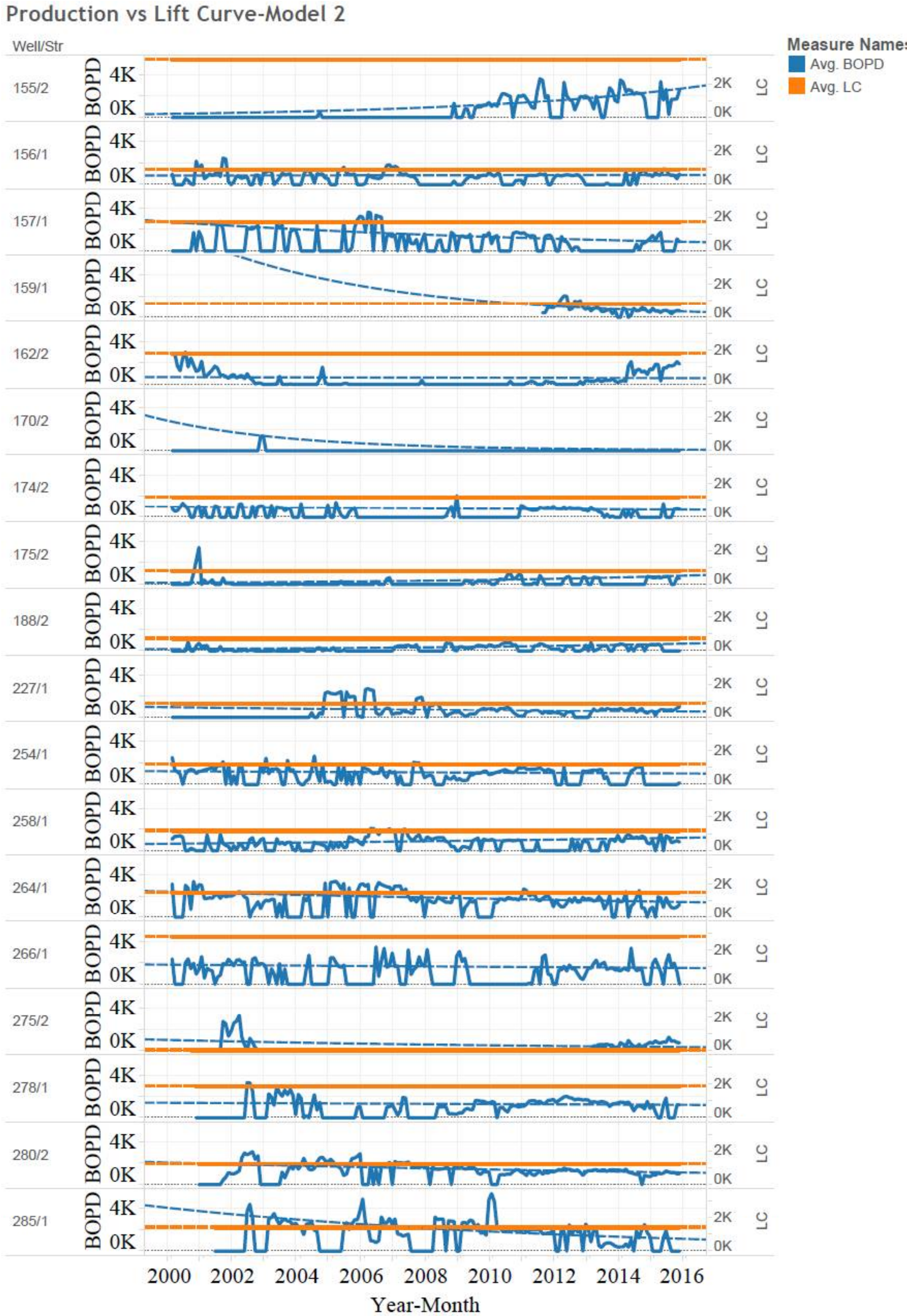
Actual vesus allowable - model 1



The trends of Avg. Bopd and Avg. Nominal for Month/Yr Year broken down by Well-no. Color shows details about Avg. Bopd and Avg. Nominal. The data is filtered on F3 and Month/Yr. The F3 filter ranges from 1 to 1. The Month/Yr filter ranges from 1/12/2006 to 1/12/2015.

Well trends model 2





Model 2 trends of Avg. Bopd and Avg. Calculated Lift Oil Rate for Year/Month Month broken down by Well/Str.

Appendix 2 - Well extrapolation model 1

Well	p-value	DF	Coeff.	Std. Err.	t-value	p-value	Intercept	Curve
W32a	N/A	5	0	Not enough data. Assumed steady			25.2781	Average
W 31	0.4195	123	2.49002	3.07389	0.810054	0.419474	4972.07	Uniform
W1	0.0021	120	0.63329	0.201597	3.14136	0.002118	1262.57	Linear
W10	0.6485	127	-0.1087	0.237969	-0.456902	0.648522	226.435	Normal
W11	0.7813	114	0.04338	0.155879	0.278285	0.781298	78.4608	Average
W12	< 0.1	38	9.98877	1.72203	5.80059	< 0.1	20019.6	Uniform
W13	0.0016	130	0.21111	0.065362	3.22987	0.001569	-416.986	Expo
W14	0.3	59	-0.7386	0.190677	-3.87359	0.271	1496.74	Linear
W2	0.3603	123	0.1233	0.13428	0.918213	0.360304	-238.054	Linear
W21	0.015	129	0.09001	0.036501	2.46602	0.014975	-173.453	EXPO
W22	0.3105	77	0.18189	0.17818	1.0208	0.310544	358.397	Expo
W23	0.7737	129	0.03397	0.11793	0.288093	0.773738	-60.4484	PDF
W23a	0.198	97	2.86651	2.21147	1.2962	0.197982	5730.52	Normal
W24	0.2547	118	-0.1861	0.162559	-1.14469	0.254654	382.421	Poly
W25	0.1919	18	-1.5563	1.14771	-1.35604	0.191855	3144.2	Average
w26	0.6731	30	-0.6982	1.63876	-0.426028	0.673129	1424.74	Uniform
W27	0.7773	127	1.40216	4.9463	0.283476	0.777273	-2772.45	Expo

W27a	0.0604	19	9.59623	4.80568	1.99685	0.06037	-1931.5	Average
W28	0.0157	125	0.3695	0.15087	2.44914	0.015706	-729.733	Average
W28a	0.3382	10	40.5608	40.3234	1.00589	0.338189	-81678.7	Uniform
W29	0.0415	86	-0.0145	0.072051	-0.200631	0.841461	36.2169	Uniform
W26a	0.0126	129	-0.2061	0.081403	-2.53164	0.012553	423.494	Uniform
W31a	0.7	129	0.09598	0.027467	3.49423	0.652	-184.984	Linear
W29a	0.1924	128	0.24852	0.189659	1.31034	0.192427	-490.891	Expo
W31ab	0.2161	118	3.16484	2.54496	1.24357	0.216121	-6340.71	PDF
W32	0.007	37	-6.8314	2.5838	-2.64393	0.01195	13775.8	Linear
W34a	0.0071	100	0.03571	0.133627	0.267245	0.789831	-63.7533	Uniform
W33	0.0552	37	0.21345	0.317458	0.672385	0.505516	-421.254	Expo
W33ab	0.0759	104	3.1036	1.73095	1.793	0.07588	-6202.79	Average
W34	< 0.1	13	-6.1345	0.975131	-6.29097	< 0.1	12369	Average
W35	N/A	7	0	Not enough data. Assumed steady			17.3778	Average
W36	0.0032	37	14.4398	4.58181	3.15155	0.003213	-29050.3	EXPO
W36a	< 0.1	98	-48.837	8.65115	-5.64516	< 0.1	98327.7	Linear
W39	0.05	121	-9.4631	7.89451	-1.1987	0.232988	19132.8	Expo
W40	0.0128	125	-0.3399	0.134561	-2.52633	0.012775	691.864	Uniform
W41	0.8212	124	-0.0331	0.146187	-0.226511	0.821177	75.9364	Linear
W42	0.2	118	-0.2954	0.075981	-3.88817	0.167	603.626	Expo

W43	0.383	113	-0.0872	0.099572	-0.875767	0.383015	184.397	Expo
W44	< 0.1	106	-0.6673	0.163911	-4.07118	< 0.1	1354.45	Average
W45	0.0392	108	-0.4697	0.22503	-2.08746	0.039199	953.925	Uniform
W46	0.0413	96	-0.1302	0.157751	-0.825257	0.411272	269.688	Average
W47	0.1249	73	3.16003	2.03558	1.5524	0.124891	-6327.28	Uniform
W48	0.3579	72	2.95777	3.19673	0.925249	0.357927	-5938.34	Linear
W49	0.0894	70	0.01349	0.101129	0.133399	0.894261	-19.5609	Linear
W50	0.15	19	3.12491	3.11752	1.00237	0.328761	-6273.22	Expo
W51	0.4579	68	0.31918	0.427533	0.746572	0.457895	-631.358	Normal
W52	< 0.1	61	9.2041	1.51753	6.06517	< 0.1	-18502.5	PDF
W53	0.0684	19	-0.993	Not enough data. Assumed steady			2009.33	Linear
W54	0.0094	18	5.07668	1.74559	2.9083	0.009376	-10218.1	Uniform
W55	0.5056	21	-0.4305	0.635646	-0.677272	0.505626	874.805	Expo
W56	0.005	18	27.702	8.65936	3.19908	0.004973	-55781.5	Linear
W57	0.0825	19	2.42063	1.32058	1.833	0.08252	-4865.29	Average
W59	0.0687	14	-0.94	Not enough. Assumed steady			1904.32	Uniform
W60	N/A		0	Not enough. Assumed steady			1627	uniform
W61	N/A		0	Not enough data. Assumed steady			2274	Uniform
W30	N/W		0	Not enough. Assumed steady			1287	Uniform
w26a2	N/A		0	Not enough data. Assumed steady			3049	Average

W58	N/A		0	Not enough. Assumed steady	5520.68	PDF
W9	N/A		0	Not enough. Assumed steady	9.36482	Average
W35	N/A		0	Not enough. Assumed steady	12.0115	Uniform
W7	N/A		0	Not enough. Assumed steady	995.67	Average

Appendix 3 - Well extrapolation model 2

Well	p-value	DF	Coeff.	Std. Err.	T-Value	p-value	Intercept	Model
105	0.624175	137	-2.14E-05	4.35E-05	-0.49105	0.624175	7.75922	Uniform
106	0.901598	68	9.89E-06	7.97E-05	0.124105	0.901598	14.9366	Uniform
124	0.26	164	0.134	3.59E-05	3.73349	0.2601	0.841939	Distribution
126	0.809185	125	-5.66E-06	2.34E-05	-0.24199	0.809185	0.690596	Uniform
127	< 0.1	153	8.82E-05	2.06E-05	4.29402	< 0.1	4.07126	Uniform
129	0.917614	125	-5.09E-06	4.91E-05	-0.10365	0.917614	5.47287	Uniform
133	0.80782	10	-8.24E-05	0.33	-0.24977	0.80782	10.0965	Uniform
135	0.008156	13	0.479	0.154	3.11822	0.0081557	-7.12765	Distribution
137	0.08394	124	6.52E-05	3.74E-05	1.74227	0.0839402	7.93904	Uniform
141	< 0.1	49	0.521	0.103	5.07521	< 0.1	-18.7985	distribution
144	0.021496	86	0.129	5.51E-05	2.34192	0.0214958	-0.042844	Uniform
145	0.901598	68	-0.19	2.85E-05	-6.66415	0.901598	14.5845	Average
148	0.062021	10	0.658	0.313	2.10054	0.0620213	9.68935	Uniform
149	N/A	0	-0.1	6.05E-05	-1.70471	0.0021401	-1.44257	Average
151	0.092229	78	-0.68	0.218	-3.13706	0.0922293	5.64582	Uniform
155	< 0.1	67	0.382	7.30E-05	5.23063	< 0.1	9.28102	Uniform
156	0.70382	127	1.08E-05	2.83E-05	0.381027	0.70382	-13.1272	Uniform
157	0.901598	68	-0.21	3.48E-05	-5.93	0.901598	6.8685	Average
159	0.166	47	-0.48	0.117	-4.0927	0.1662	13.1876	Distribution
162	0.619587	88	-2.73E-05	5.48E-05	-0.4982	0.619587	27.4715	Uniform
170	0.008156	13	-0.66	Model assumed steady		0.0081557	4.1682	Average
174	0.029288	77	-6.19E-05	2.79E-05	-2.22103	0.0292877	6.82931	Distribution
175	< 0.1	63	0.325	7.30E-05	4.44757	< 0.1	5.8615	Average
188	< 0.1	95	0.269	4.85E-05	5.53978	< 0.1	-11.8456	Uniform
227	0.051707	125	-0.11	5.56E-05	-1.96436	0.051707	-10.1578	Uniform

254	0.264115	131	-3.36E-05	3.00E-05	-1.12153	0.264115	7.09427	Average
258	0.778	135	0.112	3.25E-05	3.43877	0.7776	10.0414	Average
264	< 0.1	151	-8.83E-05	1.57E-05	-5.63942	< 0.1	2.58344	Uniform
266	0.185006	110	-3.19E-05	2.40E-05	-1.33386	0.185006	8.77453	Uniform
275	0.264115	131	-0.2	7.54E-05	-2.70243	0.264115	6.70591	Uniform
278	0.4496	114	-2.58E-05	3.40E-05	-0.7587	0.4496	8.14858	Uniform
280	< 0.1	149	-0.11	1.64E-05	-6.50838	< 0.1	9.68935	Average
285	< 0.1	121	-0.22	3.15E-05	-7.06253	< 0.1	14.2677	Average
312	0.628802	55	-4.26E-05	8.75E-05	-0.48614	0.628802	1.6837	Distribution

Appendix 4 - Questionnaire analysis results

1. Production can be optimized based on sound understanding of all contributing factors

Answer Options	Strongly Disagree	Disagree	Undecided	Agree	Strongly Agree	Rating Average	Response Count
Rating	1	0	3	21	65	94.50%	90
						answered question	**90**
						skipped question	**1**

2. Check most important factor that impacts production the most

Answer Options	Demand	Supply	Price	Technology		Rating Average	Response Count
	64	6	15	5	Demand	70%	90
						answered question	**90**
						skipped question	**1**

3. Importance of including items below in an integrated model

Answer Options	Strongly Disagree	Disagree	Undecided	Agree	Strongly Agree	Rating Average	Response Count
Plant overall capacity (Oil, Water and Gas)	0	0	8	36	45	89%	89
Reservoir long term production model	0	0	3	31	55	95%	89
Well production model	0	0	3	32	43	82%	89
Separation Capacities (Phase I, II, and III)	0	0	6	34	49	91%	89
Storage and Loading	0	0	11	49	29	85%	89
Pipelines Flow Rates	0	0	9	50	30	88%	89
Equipment (Compressors, Pumps, Valves)	0	0	10	48	31	87%	89
						answered question	**89**

						skipped question	**2**

4. Rate the functions that contribute to the production improvement below:

Answer Options	Strongly Disagree	Disagree	Undecided	Agree	Strongly Agree	Rating Average	Response Count
Planning	4	0	1	29	51	88%	85
Data Mining	3	3	4	40	35	82%	85
Integrated Simulation Model	3	3	4	48	34	90%	85
Mathematical models	18	12	22	21	12	36%	85
						answered question	**85**
						skipped question	**6**

5. Importance of Routine Maintenance

Answer Options	Strongly Disagree	Disagree	Undecided	Agree	Strongly Agree	Rating Average	Response Count
Plant	5	0	10	32	40	79%	87
Well	1	0	1	27	58	93%	87
Separator	2	0	3	28	44	79%	87
Storage and Loading	12	11	24	28	12	44%	87
Compressors, pumps, pipelines network	9	5	4	36	33	76%	87
						answered question	**87**
						skipped question	**4**

6. Importance of considering lost repair time in the model for:

Answer Options	Strongly Disagree	Disagree	Undecided	Agree	Strongly Agree	Rating Average	Response Count
Plant	4	4	13	40	27	73.60%	88
Well	0	0	0	27	61	97.70%	88
Separator	0	0	0	40	48	97.70%	88

Storage and Loading	14	10	4	48	12	66%	88
Compressors, pumps and Pipelines	14	11	5	35	23	63.70%	88
						answered question	**88**
						skipped question	**3**

7. Data mining, profiling and extrapolation importance

Answer Options	Strongly Disagree	Disagree	Undecided	Agree	Strongly Agree	Rating Average	Response Count
Maintenance History	7	7	8	39	26	71.40%	87
Reservoir Performance	1	2	3	33	48	89%	87
Well Flow Testing	4	3	3	35	42	84.60%	87
Separation Ratios (all phases)	3	2	4	35	33	74.70%	87
						answered question	**87**
						skipped question	**4**

8. Flow Bottlenecks importance in a model

Answer Options	Strongly Disagree	Disagree	Undecided	Agree	Strongly Agree	Rating Average	Response Count
Treatment and Stabilization	7	3	8	37	23	65.90%	88
In-Flow Lines	7	5	7	37	32	75.80%	88
Bypasses	4	2	21	42	29	78%	88
Valves, Junctions and Manifolds	13	6	5	39	25	70%	88
						answered question	**88**
						skipped question	**3**

9. Additional comments

Answer Options	**91**
answered question	**24**
skipped question	**67**

Appendix 5 - Sampling reference

Table 1. Sample Size for ±3%, ±5%, ±7%, and ±10% Precision Levels where Confidence Level Is 95% and P=.5.

Size of Population	Sample Size (n) for Precision (e) of:			
	±3%	±5%	±7%	±10%
500	a	222	145	83
600	a	240	152	86
700	a	255	158	88
800	a	267	163	89
900	a	277	166	90
1,000	a	286	169	91
2,000	714	333	185	95
3,000	811	353	191	97
4,000	870	364	194	98
5,000	909	370	196	98
6,000	938	375	197	98
7,000	959	378	198	99
8,000	976	381	199	99
9,000	989	383	200	99
10,000	1,000	385	200	99
15,000	1,034	390	201	99
20,000	1,053	392	204	100
25,000	1,064	394	204	100
50,000	1,087	397	204	100
100,000	1,099	398	204	100
>100,000	1,111	400	204	100

a = Assumption of normal population is poor (Yamane, 1967). The entire population should be sampled.

Appendix 6 - Simulation parameters

The entry points can be production barrels, market demand, resources or injection volumes. Entry point's generation is a random number process that follows a probability model or time based profile. The fluid is generated with all its phases (Oil, Water and Gas). The trends follow fixed, linear, exponential or polynomial distributions which are configured at each well. The separation produced material is labeled as O, W or G is labeled as 1, 2 and 3. This is intended to segregate them in the reservoir and prevent them from being counted again during the separation process. The table below represents the constraints based on initial design and assumptions for production management by the Company;

Table A-1 Facilities and reservoir parameters

Parameter	**Estimates**[11]
Average gas production to market	65% of production
Stabilizers, spheroids stage III	375, 480 MPOPD
Main oil line capacity	480 MBOD
Water wells capacity	541 MBWPD
Gas injection wells capacity	335 MSCFPD
Total shutdown	2 weeks in 30 years
MOL psi at facility	511 BOPD
MOL psi at destination	152
Flow lines psi	300
Annulus surface pressure	Sea line pressure (SLP) + 100 = 900
GOR (I, II, III)	860, 77 and 43 respectively.
Compressor capacity	200 MSCFD. Time to inject 1 MSCFD is (24/200=0.12 hour).
Volume of oil in place (barrels)	25 Billion
Average daily gas injection	350 MMSCFD (20% for the model)
Production duration (100 years)	Half way through recovery time
Material balance (5.5 billion barrels)	22% recovered of oil in place
Desired water injection ratio	1.5 to 2 BWPD /BOPD in 2018
Desired gas injection ratio	1 MSCF/Barrel of oil
Gas oil ratio limit average/string	2 SCF/STB to 4 by 218
Maximum Well limit	3 BOPD
Decline ratio (existing practice)	6% company strategy
Water injection decline per year	5% company strategy
Oil Equivalent	0.5 for injected Water to 1 beyond 2020
Oil equivalent for 1 MSCF Gas	0.15 barrels

Table A-2 Static assets capacities - model 1

Total no. of wells	55 producers, 12 water injectors and 2 gas injectors.
Water injection requirement	1.2 to 1.5 BWPD /BOPD

[11] Data is based on ERP system

Gas injection ratio	0.35 MSCF/Barrel of Oil
Water injection capacity	150, BWPD
Average gas production capacity	100 MMSCED
Gas injection capacity	30 to 35 MMSCFD
Gas to market	70 MMSCFD

Table A-3 Static assets capacities – model 2

Total no. of wells	30 producers, one gas injector and 12 water injectors.
Water injection ratio	1.2 to 1.5 BWPD /BOPD
Gas injection requirements	0.35 MSCF/Barrel of Oil
Water injection capacity	75 BWPD
Average gas production capacity	80 MMSCED
Gas injection capacity	20 to 25 MMSCFD
Gas to market	50 MMSCFD
Average condensate production	0 BCPD

Table A-4 Wells parameters

Well Parameters	**Outage Period**
Well capacity	Well test and lift curve
Well shut-in time	Decline to 50% and engineering judgement – natural decline or integrity issues
Well allowable	Well not to exceed a limit set by reservoir engineering
Decline assumption	The natural decline of production is recovered by
Well workover and activation	A resource is used to hold and release the well until change in condition is triggered
Well stimulation	Rig-less operation, every 2-3 years
Production rate BOPD	Time per 1 barrels-hours 24/BOPD
3000	8
2500	9.6
2	12
1500	16
1	24
500	46
Injection rate BOWD	Time per 1 barrels-hours = (24/ BOWD)
3	8
4	6
5	4.8
6	4
7	3.4

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Appendix 7 - Separators parameters

Separators are represented by work centers that produce oil, water and gas. Retention is required per barrel to secure effective separation in each phase. The retention time is the volume of the liquid that passes in the vessel divided by the liquid flow rate. For most applications retention times of between 30 seconds and 3 minutes have been found to be sufficient (average is 0.43 hours/K-barrels based on Capacity 55K/day). It is very important to work to optimize the 3 stages of separation (use of PVT simulators) based on a number of criteria:

- No storage is available offshore
- Fluid characteristics and pipeline design
- Operating pressure and maximum allowable pressure in the system
- Well Inflow performance pressure, maximum allowable surface pressure and flow assurance
- Operational guidelines

For 55k barrels capacity separator that processed X barrels during Y days of operations, the retention time is equal to X/(Y*24). The simulation model for future events will also be based on available operating separators. Due to effective parallel processing, only single modules are shut-down for maintenance (total 9 modules). In the simulator, the retention time will be configured based on time per 1K barrels of oil. Therefore, the table below summarizes the different separation phases (I, II and III) maximum capacities.

Table A-5 - Separators settings

Separator type	Diameter (m)	Length (m)	Capacity/Day BOD	Retention Time (hours/1KBOPD)
1	1.05	5	18,200	1.318
2	1.20	5	24,200	0.991
2	1.30	5	27,500	0.87
4	2.5	10	55,	0.42
Stage	Phase	No.	Capacity	Time in system/1 units
Phase I	I	9	45	0.533
Phase II	II	8	55	0.436
Phase III	II	3	250	0.096

Appendix 8 - Tanks, pipes and joints retention time

Used for storage, stabilization and final water separation at atmospheric state. Storage tanks capacities vary from 800K barrels to 1MM barrels distributed between 14 crude storage tanks handling on the average 600M Barrels per day from all fields. Therefore, with weekly shipments of 4MM Barrels from all fields, there are no bottlenecks. Including the storage constraints in the model will help to conduct economic analysis for the market demand changes

Gas is passed to another company for liquefaction, storage and marketing through a 36” line with less than one KM length. Shipment can handle the daily average of 1,100 MMSCFD. Condensate storage and handling of 250MBD is not constrained (2 tanks of 500K and shipment accommodate one full tank every 2 days).

The routine subsea inspection program uses Remote Operated Vehicle (ROV) accompanied with intelligent pigging (without production interruption) for corrosion monitors and frequent line cleansing by non-intelligent pigs for flow assurance. Inspection results are accompanied with recommendations for immediate actions (repairs or pressure de-rating) and long term recommendations (endorsement or replacement). Pipelines are designed to run over 35 years and 50 years with major repairs. Therefore, replacement action will not be considered in the model (although it can be added easily at a later stage). The flow assurance simulator is used to adjust the well choke valves settings. Pipeline availability are more important than flow rate simulation. This is because flow rates reduction is already accounted for by the historical data impact on the well model. All small pipelines are used as well connectors that have an on/off state only and can accept the flow based on the flow sources as designed. However, all lines will be subject to interruption through normal flushing (pigging), inspection (intelligent pigging) and repairs (MTTR and MTBF). The maximum flow capacity is based on the Pipeline diameter and velocity [(Flow Rate = $(0.25*\pi)*(\text{Velocity})*(\text{Pipe Diameter})^2$] (not modeled)**.** Liquids velocity is one meter / sec and gas velocity for gas pipeline is 60 SCF/sec.

By design, the flow rate at the manifold or joint connecting with many radials, is capable of taking all inflow fluid. The gathering line is also designed to take the multiphase fluid. The fluid change in PVT is subject to a special simulator (PIPESIM) that produces new settings or adjustments to the flow rates so that this optimization is maintained. They can be represented by a queue with priority based on the proposed simulator.

This study follows the will be using the following flow formulation:

Total Flow at Manifold = ∑flow-rates considering all connected pipelines

GOR at manifold= ∑GOR*Flow-Rate/∑Flow-Rate

Therefore, the manifold will be simulated as a queue with no waiting time. [12]

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[12] All data is obtained from the engineering records process flow diagrams.

Appendix 9 - Maintenance configuration

The configuration of the plant is based on multiple facilities / platforms (separation phases (I, II and III), water injection, gas processing, gas injection, stabilizers, storage tanks, metering facilities, water treatment, oil loading and shipping.

The following table represents the planned and unplanned maintenance outages as a result of routine and breakdown maintenance in ERP. This data was summarized by the maintenance system history records database.

Table A-6 - Maintenance parameters

Item	Maintenance Time (MTTR)	MTBF[13]	Applicability	Represented by
Pipelines	1 day / year 1 week/ 5 years	20 year	Life time 35-50 years. Pigging speed 1m/sec	Routing arrow for flow lines
Vessels	2 weeks/year	1 year 7 years	Separators, scrubbers stabilizers	Activity
Water processing	2 weeks	2 years	Backup units available	Activity
Water wells - injectors	1 Months	5 years	Backup available	Activity
Gas Injection system	1 Month 5 years	10 years	On stream tie-in only long term impact	Activity
Oil metering	1 Week yearly 1 month/ 5yr	No impact	Back-up in place	Entry point to activity
Storage	1 week/ year 3 months	1 year 7 years	Minimal constraints	Storages and Queues
Shipping to market	No impact	12 days / year	Weather may impact delay 1 or 2 days per 2 months	End point
Wells	3-6 months	10 years	Section 3.7	Activities
Gas compressors	1 week 1 month	Yearly. 24 hours	Backup in place	Activity
Rigs	2 years	30 days	Average lost time 4 – 6 Weeks	Resource

Rigs time lost as a result of weather conditions or tug boat availability is not in the model based on the wells off-days since the rigs are idle at the same time. Efficiency is used when the failure probability is not available (example below when BTTR = 3 weeks which is 6% of the year or = Flow-performance/Capacity (Subramanian, S.K., Husin, S.H., Yusop, Y. and Hamidon, A.H., 2009)

Efficiency = 100% - Maximum impact of un-availability

Efficiency = 100% - Max. (Un-available asset)

Efficiency = 100% - 6% = 94%

[13] Records of maintenance summaries are based on the ERP system

Appendix 10 - Simulation model 1 results

Well no.	Actuals (BOPD)	Targeted Actual 1M	Model Used	Coeff1	Coeff2	Intercept	Time setting (1 Barrels)	1month Sim-validation	6 months simulation	10K hours simulation forecast ()	10K hours with New W. ()
W1	2409.161	72274.8	Linear	8	12	-729.733	9.961973	660	428	891	893
W10	527.4731	15824.2	PDF				45.49995	140	95	366	366
W11	3284.867	98546	Average			9	7.306233	1020	558	1276	1274
W12	1389.567	41687	Uniform	8	20	7	17.27157	420	242	636	636
W13	295	8850	Expo	0.013467		-25	81.35593	120	66	170	171
W14	2620.667	78620	Linear	-0.73861	0	1496.74	9.157975	810	498	1223	1220
W2	1444.387	43331.6	Normal		16	25.2781	16.61604	450	254	566	566
W21	300.5	9015	EXPO	0.02556		-49.3316	80.126	30	22	67	66
W22	1171.742	35152.3	Expo	0.066583		-131.107	20.48233	320	211	604	604
W23	527.4731	15824.2	PDF				45.49995	150	92	194	194
W23a	741.1786	22235.4	Normal		0	30	32.38086	210	124	295	298
W24	3062.299	91869	Poly	-0.04392	176.706	-177714	7.83725	890	482	1048	1048
W25	1662.385	49871.6	Average		0	15	14.43709	480	288	599	610
w26	5954.037	178621	Uniform	2	6	-219.4	4.030879	1830	1078	2240	2237

W26a	2778.408	83352.2	Uniform	7	10	19	8.638041	720	446	1048	1100
w26a2			PDF				9.795718		0		334
W27	305	9150	Expo	-0.245		496.45	78.68852	90	178	381	390
W27a	602	18060	Average	0	0	10	9.1	210	96	236	236
W28	1502.059	45061.8	Average			15	15.97807	420	262	592	610
W28a	1705.264	51157.9	EXPO	0.02037		43.786	14.07407	490	242	538	560
W29	2580	77400	Uniform	6	0	11	9.3	750	448	1122	1125
W29a	919.8353	27595.1	Uniform		25		26.09163	270	175	360	364
W30			Average	0	0	7.5	7		0	60	1050
W31	960.6912	28820.7	Uniform	24	26	23	24.98201	270	154	358	356
W31a	2547.194	76415.8	Linear	0.211109	0	-416.986	9.422134	780	488	1021	1023
W31ab	741.1786	22235.4	PDF				32.38086	150	98	334	334
W32	2047.109	61413.3	Linear	0.254518	0	-480.891	11.72385	600	182	347	352
W32a	2131.935	63958.1	Average		0	9	11.25738	630	372	864	864
W33	919.8353	27595.1	Expo	0.105578		-209.506	26.09163	240	136	299	299
W33ab	3000	90000	Average	26	30	10	8	990	614	1269	1320

W34	2110.425	63312.7	Uniform	8	16	8	11.37212	570	356	744	744
W34a	527.4731	15824.2	Uniform	4	10	15	45.49995	160	124	182	242
W35	741.1786	22235.4	Average			25	32.38086	240	154	319	319
W35			Uniform	12		28	10.21059		0	30	1047
W36	1084.1	32523	EXPO	0.077882		-154.32	22.13818	329	160	322	322
W36a	2000.91	60027.3	Linear	0.090012	0	-173.453	11.99455	620	358	748	744
W39	2092.144	62764.3	Expo	0.306655	0	-614.516	11.47148	630	416	739	739
W40	1394.935	41848.1	Uniform	12		16	17.2051	440	286	590	594
W41	2136.552	64096.6	Linear	0.09253	0	-158287	11.23305	640	612	1270	1270
W42	301	9030	Expo	-0.245		496.45	79.73422	90	116	236	236
W43	919.8353	27595.1	Expo	0.48558		-975.554	26.09163	300	164	135	135
W44	2179.484	65384.5	Average			10	11.01178	720	486	999	998
W45	3029.226	90876.8	Uniform	7		12	7.922817	880	492	1114	1114
W46	1108.667	33260	Average			9	21.64762	300	196	407	407
W47	2669.267	80078	Uniform	6	0	21	8.991234	810	546	1122	1122
W48	1170.198	35105.9	Linear	0.181886	0	-358.397	20.50934	300	178	381	381

W49	2007.258	60217.7	Linear	0.633288	0	-1262.57	11.95661	580	290	615	617
W50	1961.494	58844.8	Expo	0.072105	0	-141.847	12.23557	540	334	743	743
W51	3307.452	99223.5	Normal			8	7.256342	970	544	1109	1109
W52	960.6912	28820.7	PDF				24.98201	270	152	356	356
W53	2153.484	64604.5	Linear	0.248518	0	-490.891	11.14473	540	320	664	662
W54	3345.452	100364	Uniform	20		60	7.173918	930	562	1380	1380
W55	3404.698	102141	Expo	0.232003		-462.919	7.049084	990	594	1278	1278
W56	3509.18	105275	Expo	-0.20608	0	423.494	6.839205	1010	544	1156	1156
W57	3513.228	105397	Average	0	0	10	6.831324	1020	594	1270	1271
W58			Average	0	0	8	8.287178		0		
W59	3614.495	108435	Uniform	5	8		6.639932	870	460	1365	1367
W60	3996.558	119897	uniform	2		6	6.005167	1140	576	1193	1193
W61	5762.207	172866	Uniform	16	0	34	4.165071	1650	960	1987	1985
W7			Average				81		0		
W9	960.6912	28820.7	Uniform	2	0	7	24.98201	270	142	372	372
	110093.5	3302806						31949	19045	41830	44403

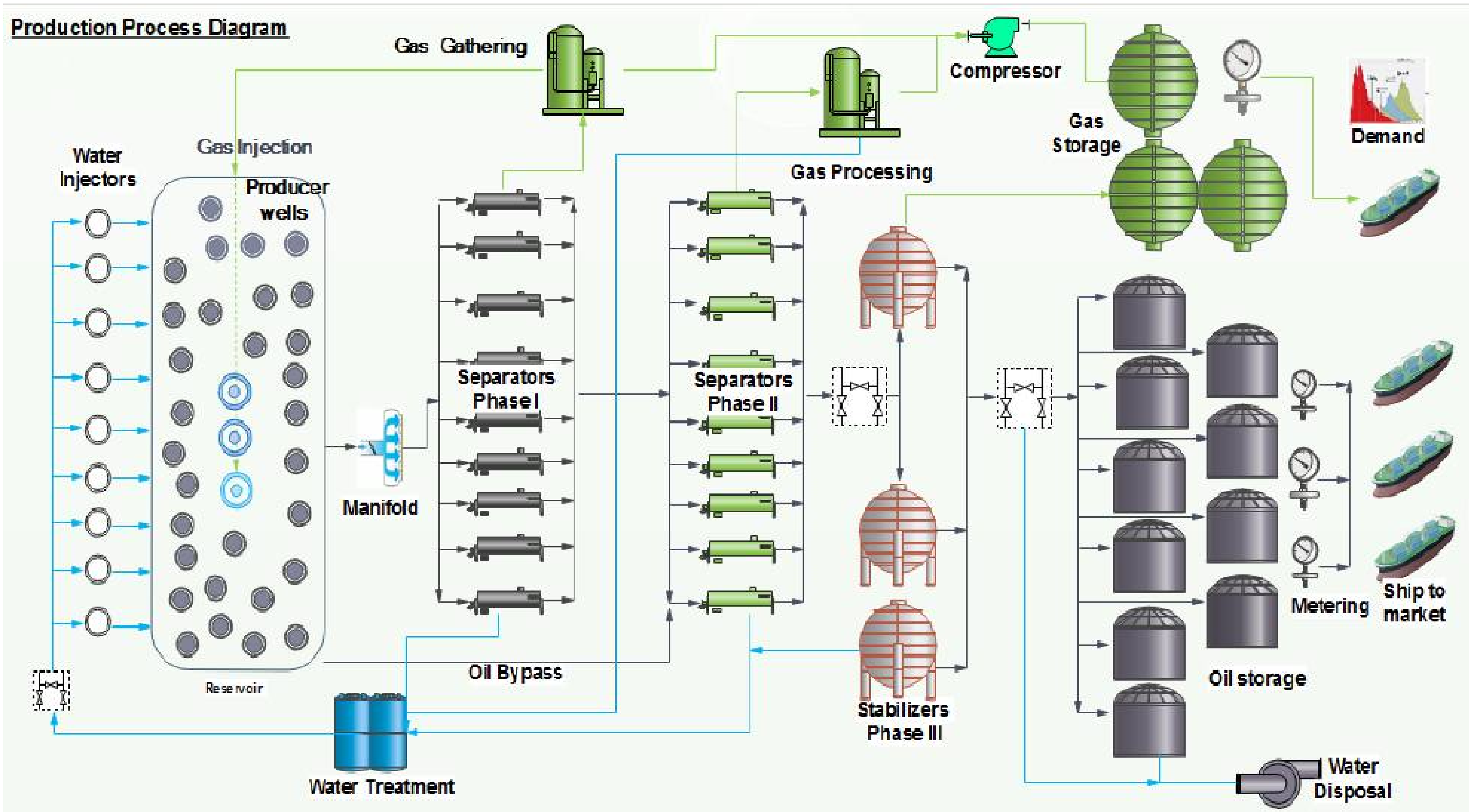
Appendix 11 - Simulation model 2 results

								Simulation BOPD ()			
Well	**(BOPD)** Prod.	**p-value**	**Coeff. Value**	**Intercept**	**Model**	**Lower B**	**Upper B**	**1M**	**12M**	**24M**	**24M new wells**
105	3665	0.624175	-0.02135	7.75922	Uniform	70	300	4	36	77	78
106	25418	0.901598	0.009893	14.9366	Uniform	15	30	24	275	624	623
124	16514	0.2601	0.1338	0.841939	Distribution	22		17	198	411	412
126	37970	0.809185	-0.005659	0.690596	Uniform	15	30	39	421	904	905
127	38300	< 0.1	0.08823	4.07126	Uniform	15	30	40	432	478	885
129	38569	0.917614	-0.005086	5.47287	Uniform	15	30	39	444	880	881
133	610	0.80782	-0.08241	10.0965	Uniform	70	300	3	36	117	16
135	15992	0.0081557	0.4789	-7.12765	Distribution	22		17	194	413	414
137	0	0.0839402	0.06521	7.93904	Uniform	13	15		0		
141	13518	< 0.1	0.5211	-18.7985	distribution	22		13	161	359	358
144	23429	0.0214958	0.129	-	Uniform	15	30		0		

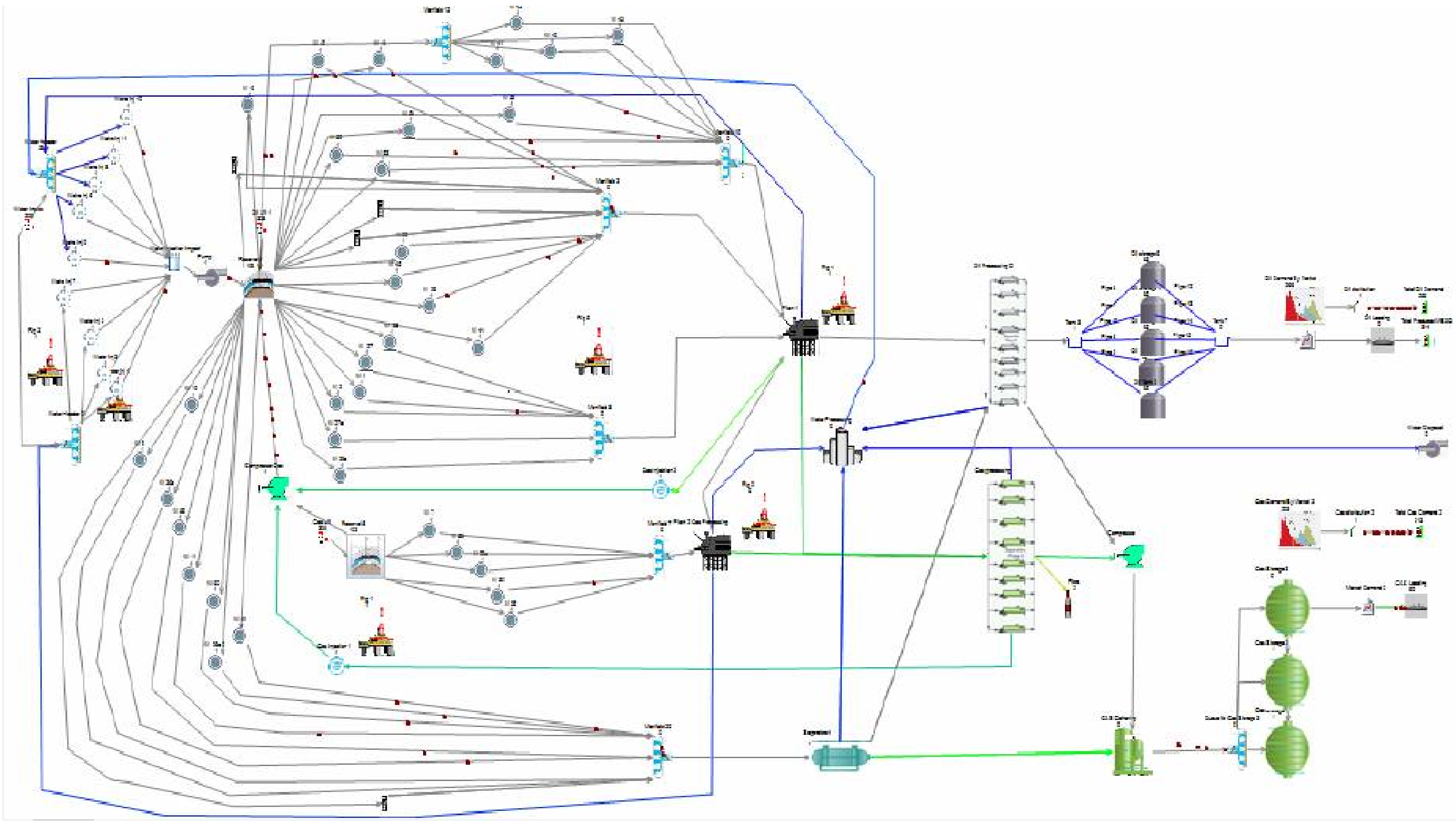
				0.0428437							
145	46615	0.901598	0.009893	14.5845	Average	13		47	530	534	1084
148	0	0.0620213	0.6578	9.68935	uniform	20	40	0	0	0	0
149	2417	N/A	0	-1.44257	average	200		3	20	69	70
151	0	0.0922293	-0.1031	5.64582	Uniform	20	30	0	0	0	0
155	82419	< 0.1	0.3818	9.28102	Uniform	4	10	82	955	2002	2001
156	25582	0.70382	0.01077	-13.1272	Uniform	15	25	26	302	618	620
157	1734	0.901598	0.009893	6.8685	Average	200		2	24	50	48
159	20134	0.1662	-0.4797	13.1876	Distribution	22		21	242	448	447
162	59919	0.619587	-0.02732	27.4715	Uniform	6	14	59	725	1455	1456
170	0	0.0081557	0.4789	4.1682	Average	1		0	0		
174	9679	0.0292877	-0.06194	6.82931	Distribution	23		10	120	251	252
175	17399	< 0.1	0.3248	5.8615	Average	32		18	210	427	426
188	13733	< 0.1	0.2689	-11.8456	Uniform	20	60	13	185	353	353
227	32753	0.051707	-0.1092	-10.1578	Uniform	15	30	31	304	741	743
254	2395	0.264115	-0.03362	7.09427	Average	200		3	38	75	73

258	26127	0.7776	0.1116	10.0414	Average	20		27	330	653	656
264	23832	< 0.1	-0.08834	2.58344	Uniform	15	25	24	325	606	603
266	51360	0.185006	-0.03194	8.77453	Uniform	8	16	51	552	1230	1232
275	23364	0.264115	-0.03362	6.70591	Uniform	15	30	24	324	584	582
278	38639	0.4496	-0.02576	8.14858	Uniform	14	18	39	426	891	890
280	31972	< 0.1	-0.1069	9.68935	Average	200		31	325	720	721
285	27112	< 0.1	-0.2225	14.2677	Average	20		28	348	685	688
312	16879	0.628802	-0.04255	1.6837	Distribution	23		16	205	383	380
	768049							751	8687	16940	17897

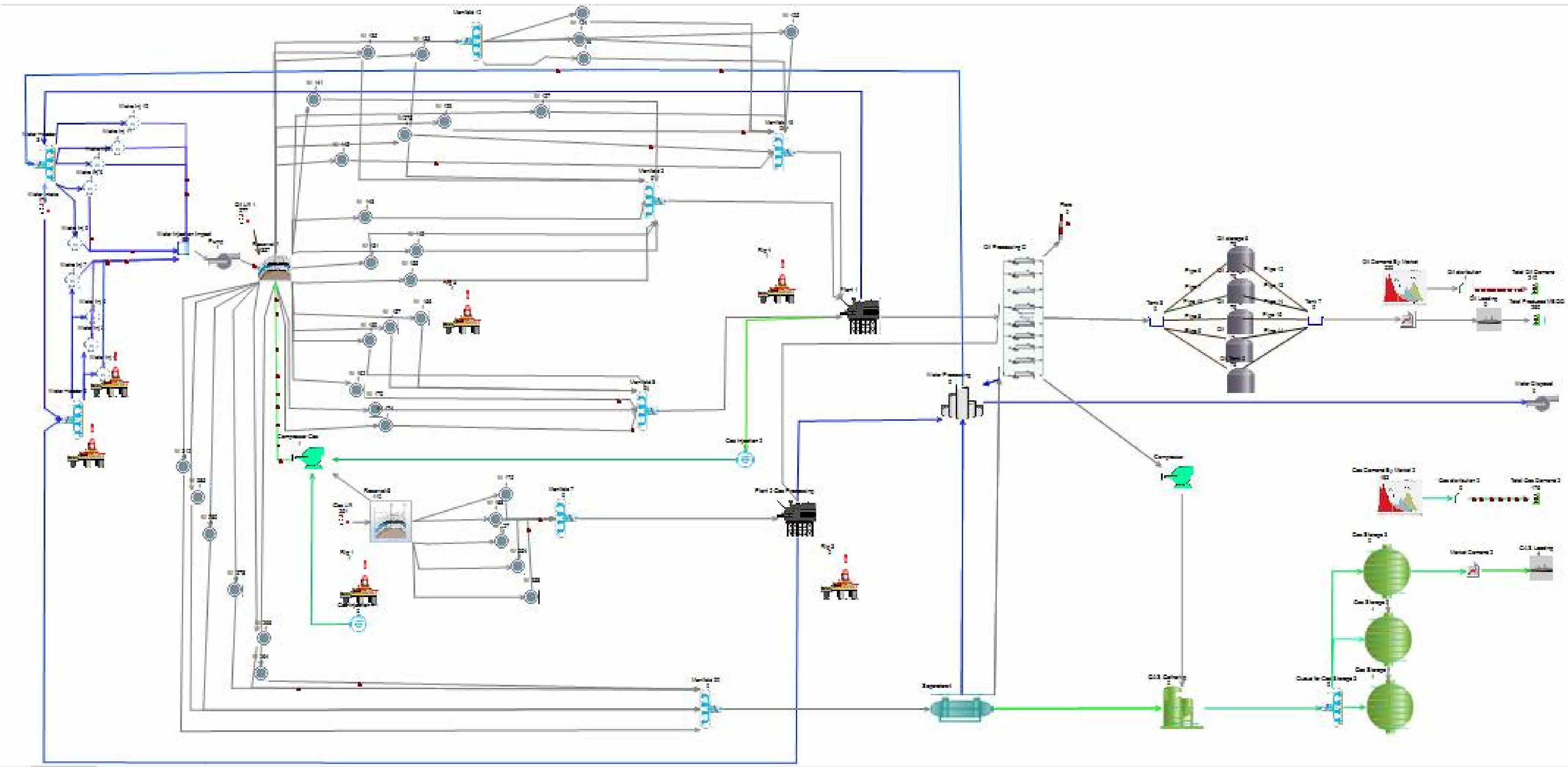
Appendix 12 - Process model



Appendix 13 - Simulation model 1



Appendix 14 - Simulation model 2



Appendix 15 - Production long term plan

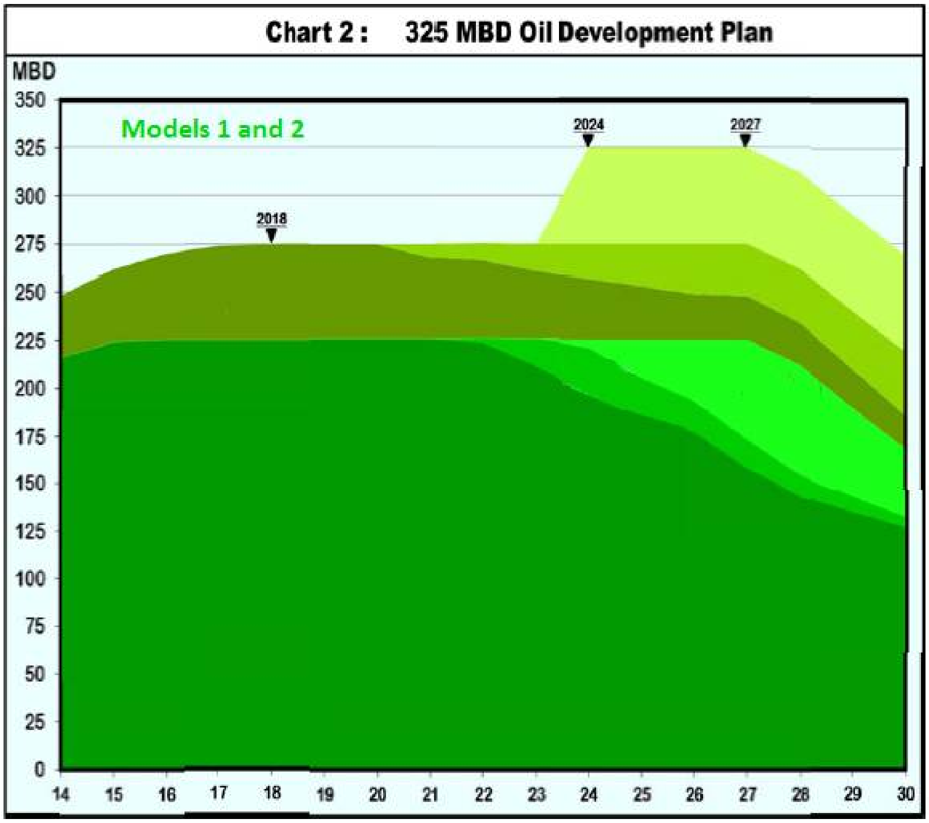
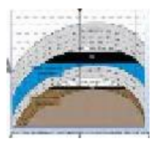
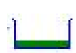


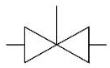
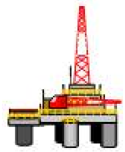
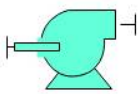
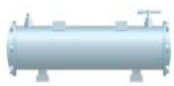
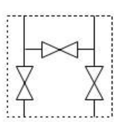
Figure A-1 Production plateau

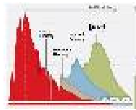
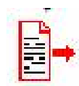
Appendix 16 - Simulation Objects Graphics

The graphical representation of the assets in the simulation model and the process diagram are listed in the following table:

Table A-7 Simulation objects

Object	Settings
	**Reservoir** Symbol for reservoir and modeling of recovery overtime which is a typical exponential with a probability distribution of a simple moving average during primary and secondary recoveries
Water Well Oil well Gas well	Well production/injection profile is linear, exponential or polynomial based on the data trend and level of confidence constrained by the lift curve limits
→	**Pipe/Flow** Lines are subject to maintenance associated with the wells
	**Offshore Plant** Separators bundled in one plant for phase I. The bypass has a manifold to distribute flow equally between the destination separators
	**Tank, Storage** Storage is an idle queue with capacity constraint
	**Tank Loading** Also used for collecting, metering or distributing fluid between the processes being served
	**Queue** Used to provide delay in the system for separation retention time control
	**Gas processing** Facility for final separation and dehydration prior to storage and refrigeration

	**Manifold** One pipe node distributing fluid for separation among several vessels
	**Valve** Used to control or divert the flow
	**Rigs** Used for drilling and well stimulation, development and maintenance resource
	**Compressor** Used to accelerate the gas flow for transportation through the pipelines into the next phase of treatment and dewatering
	**Pump** Used for flow assurance control and acceleration of fluid through the system after separation
	**Separator** Oil, gas and water separator
	**Offshore tower:** A cluster of 2, 4, 6 or 9 wells. Each well can produce from a different zone but fluid is commingled through one manifold and flowline
	**Gas storage** Gas refrigerating, liquefaction and storage prior shipment to market
	**Spheroid** Stabilization and third stage separation of gas and impurities
	**Diverter valves** Used for diverting the produced water back to the injection well

	**Market demand** Graphical representation of the market based on the generated demand values following
	**Water treatment** Filtration and treatment from bacteria prior injection into the reservoir
	**Transport** Loading vessel for shipping to market
	**Production entry point** Represents the reservoir fluid model from the reservoir into the wells.

Appendix 17 - Wells maintenance programs models 1 and 2[14]

Table A-7 Wells maintenance program - model 1

Well no	Start	End	Repeat	Resource	Nominal Allowable
W 2	1/01/2017	10/01/2017	8760	Rig 2	2300
W 9	11/01/2017	20/01/2017	8760	Rig 2	800
W 11	20/01/2017	28/01/2017	8760	Rig 2	3200
W 12	30/01/2017	8/02/2017	8760	Rig 2	1400
W 13	9/02/2017	18/02/2017	8760	Rig 2	200
W 31	19/02/2017	28/02/2017	8760	Rig 2	2500
W 32	2/03/2017	11/03/2017	8760	Rig 2	1400
W 34	12/03/2017	20/03/2017	8760	Rig 2	200
W 33	21/03/2017	31/03/2017	8760	Rig 2	1100
W 35	1/04/2017	10/04/2017	8760	Rig 2	500
W 36a	11/04/2017	20/04/2017	4380	Rig 2	700
W 39	21/04/2017	30/04/2017	8760	Rig 2	3200
W 42	6/05/2017	10/05/2017	4380	Rig 3	1800
W 1	9/05/2017	15/05/2017	4380	Rig 5	3500
W 43	11/05/2017	15/05/2017	4380	Rig 3	2700
W 44	16/05/2017	20/05/2017	4380	Rig 3	800
W 45	21/05/2017	25/05/2017	4380	Rig 3	200
W 46	26/05/2017	29/05/2017	4380	Rig 3	400
W 47	30/05/2017	3/06/2017	4380	Rig 3	1500
W 48	4/06/2017	8/06/2017	4380	Rig 3	1800
W 49	9/06/2017	12/06/2017	4380	Rig 3	2500
W 50	13/06/2017	17/06/2017	4380	Rig 3	800
W 51	18/06/2017	21/06/2017	4380	Rig 3	900
W 52	22/06/2017	25/06/2017	4380	Rig 3	900
W 53	26/06/2017	30/06/2017	4380	Rig 3	2500
W 54	1/07/2017	5/07/2017	4380	Rig 3	700
W 55	6/07/2017	10/07/2017	4380	Rig 3	1900
W 10	11/07/2017	21/07/2017	4380	Rig 5	2
W 11	22/07/2017	31/07/2017	4380	Rig 5	900
W 12	2/08/2017	11/08/2017	4380	Rig 5	3100
W 13	12/08/2017	21/08/2017	4380	Rig 5	2
W 14	22/08/2017	31/08/2017	4380	Rig 5	600
W 56	1/09/2017	10/09/2017	4380	Rig 5	600
W 57	11/09/2017	20/09/2017	4380	Rig 5	600
W 58	21/09/2017	30/09/2017	4380	Rig 5	1100

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[14] Source 2016 Drilling bar chart

W 59	2/10/2017	11/10/2017	4380	Rig 5	1800
W 60	21/10/2017	31/10/2017	4380	Rig 5	1900
W 61	1/11/2017	20/11/2017	4380	Rig 5	1400
W 21	21/11/2017	30/11/2017	4380	Rig 4	2200
W 23	2/12/2017	11/12/2017	4380	Rig 4	300
W 23a	12/12/2017	21/12/2017	4380	Rig 4	900
W 24	22/12/2017	31/12/2017	4380	Rig 4	2
W 26a 2	2/01/2018	11/01/2018	4380	Rig 4	3
W 25	12/01/2018	22/01/2018	4380	Rig 4	1100
W 26	23/01/2018	29/01/2018	4380	Rig 4	2700
W 31ab	30/01/2018	8/02/2018	4380	Rig 4	1
W 33ab	9/02/2018	18/02/2018	4380	Rig 4	2
W 34a	19/02/2018	28/02/2018	4380	Rig 4	2
W 27	2/03/2018	11/03/2018	4380	Rig 4	3400
W 28	12/03/2018	21/03/2018	4380	Rig 4	800
W 35	22/03/2018	31/03/2018	4380	Rig 4	1900
W 36	1/04/2018	10/04/2018	4380	Rig 4	3200
W 26a	11/04/2018	15/04/2018	4380	Rig 4	3400
W 27a	16/04/2018	20/04/2018	4380	Rig 4	3300
W 28a	21/04/2018	25/04/2018	4380	Rig 4	3400
W 29a	26/04/2018	30/04/2018	4380	Rig 4	3400

Table A-8 Wells maintenance program - model 2

Well no	Start	End	Repeat	Resource	Nom Allowable
W 148	8/01/2018	14/01/2018	4380	Rig 4	2500
W 156	25/02/2018	6/03/2018	4380	Rig 4	2500
W 157	15/02/2018	24/02/2018	4380	Rig 4	2500
W 278	18/12/2017	27/12/2017	4380	Rig 4	2500
W 105	26/04/2017	30/04/2017	4380	Rig 3	2500
W 106	21/04/2017	25/04/2017	4380	Rig 3	1200
W 127	21/06/2017	25/06/2017	4380	Rig 3	1200
W 129	16/06/2017	20/06/2017	4380	Rig 3	1200
W 133	7/08/2017	16/08/2017	4380	Rig 5	1200
W 135	15/01/2017	24/01/2017	8760	Rig 2	1200
W 135	18/07/2017	27/07/2017	4380	Rig 5	3
W 141	25/01/2017	3/02/2017	8760	Rig 2	3
W 141	28/07/2017	6/08/2017	4380	Rig 5	3
W 145	6/04/2017	15/04/2017	8760	Rig 2	3
W 149	1/05/2017	5/05/2017	4380	Rig 3	3
W 151	6/05/2017	10/05/2017	4380	Rig 3	1
W 159	24/04/2017	30/04/2017	4380	Rig 5	1
W 162	17/12/2016	26/12/2016	8760	Rig 2	1

W 170	1/04/2018	5/04/2018	4380	Rig 4	1
W 174	6/04/2018	10/04/2018	4380	Rig 4	1
W 188	6/09/2017	15/09/2017	4380	Rig 5	1500
W 227	11/04/2018	15/04/2018	4380	Rig 4	1500
W 258	7/03/2018	16/03/2018	4380	Rig 4	3
W 264	6/10/2017	16/10/2017	4380	Rig 5	3
W 266	17/10/2017	5/11/2017	4380	Rig 5	2500
W 280	5/01/2017	13/01/2017	8760	Rig 2	2500
W 280	7/07/2017	16/07/2017	4380	Rig 5	2500
W 285	17/09/2017	26/09/2017	4380	Rig 5	2500
W 312	27/03/2017	5/04/2017	4380	Rig 2	2500
W275	11/06/2017	15/06/2017	4380	Rig 3	2500

Appendix 18 - Linear programming example

Optimize production based on 2 products light and heavy crude. The available quantities are 1 and 1400 barrels of oil to be shipped by 2 vessels. Vessel A has a capacity of 10 barrels light and 20 barrels heavy crude. Vessel B has a capacity of 15 light and 10 barrels of heavy crude. The cost of shipment A is $40 and Shipment B is $50. What will be the best deal for the distributor to deliver with minimum cost? Let X = no. of times needed by A and B for light crude and Y = no. of shipments needed by A and B for heavy crude (X and Y are real numbers). The option can be a combination of shipping according to the following LP model available options:

	SHIP A	SHIP B	AVAILABLE
LIGHT CRUDE	10	15	1
HEAVY CRUDE	20	10	1200

Objective is to minimise the cost : $F(X,Y) = 40 * X + 50 * Y$

Equation A-1 Optimizing with linear programming

Constraints: $(0 \leq 10X + 15Y \leq 1)$ and $(0 \leq 20X + 10Y \leq 1200)$

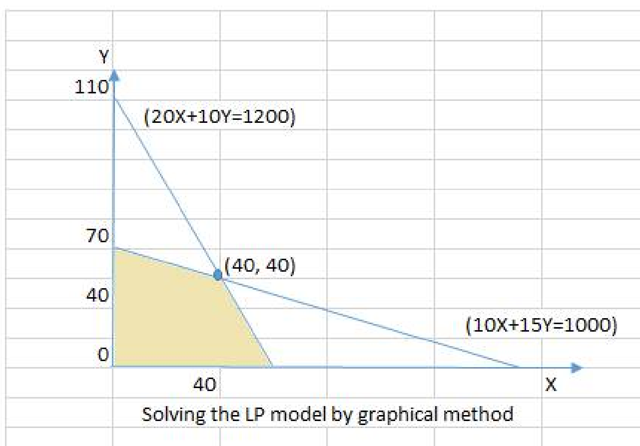

Figure A-2 LP graphical method

The problem is solved graphically at the intersection of the inequalities:

The answer is (40, 40). Therefore at cost of 40*50 + 40*40= $ 3600 is the feasible solution (Hillier, F. and Lieberman, G., 1975).

ADMA-OPCO Best Initiative Scheme

Application Form

Date	Applicant, team members name(s) & Job Title (max 4 applicants)	PF #	Extn.	Division/Business unit
26 Aug 14	Talal AL-Sayed Ebrahim AL-Shehi Hisham Hobaishy	040739 050479 000822	65253 65338 64540	ID/TSS

Title of Best Initiative	Asset Availability & Production Capacity Simulation Model

Category (Tick only 1))	Health Safety and environmental sustainability	Operational Integrity	Recovery and Sustainable Production	Cost Efficiency and Process Improvement	People and Capability Development
		x	x	x	

Priority Areas (if targeted): (Refer to notes on last page)	Recovery and Sustainable Production, Operational Integrity & Cost Efficiency

1. Provide an Executive Summary of the proposed Initiative:
Please describe briefly the idea and challenges or opportunities this initiative is addressing(100 words).

ADMA asset management has been following a deterministic approach in maintenance and asset availability. The concept of probability although being evaluated, however, it is not being used in a statistical model for computing production capacity.

This suggestion scheme is aimed to simulate a production model that planned availability as well as probability of failure, declined capacity analysis and considering IDBMS risks and remnant life.

Oil & Gas solutions which are based on best of breed applications; have been always facing challenges in synchronising plans and activities with production capacity. Typically, operational excellence will be further boosted once various authorities' plans and target tasks become more visible between business units and plans can be consolidated to satisfy the production target in an integrated simulation model.

Hence, a building this model will provide:

- **A visualised holistic process**
- **Overcome planning challenges by eliminating duplications**
- **Will take into account statically characteristics such as PoF, and MTBF**
- **Will have the potential to include decline curve and well model curves**
- **Will have results from existing process, reservoir simulators as well as drilling/maintenance & inspection plan**
- **Will be capable of long term planning considering LTDP and short term plans**
- **will enhance collaboration.**

On the information level, a unified production model will consolidate allocations and evaluate water cuts based on well testing and will be also capable of computing gas production and material balance.

2. Alignment with priority areas
Please describe how the idea addresses the Priority Area you have selected alignment ,targeting priority areas may allow you to receive higher score (max 100 words).

This process is expected to serve our Operational Excellence by binding the existing risks with the means of mitigating them.
Production Scenarios will be easy and possible to do for long term.
Cost efficiency due to integrated planning and effective capacity trending
Operational integrity due to integrity considerations in the model

3. Business Value :

- *Describe in measurable, verifiable terms the potential value of the initiative. Please make your estimates as tangible and quantifiable as possible in financial terms (USD). Only ideas that generate a net profit / sowing of ≥ USD100K are accepted.*
- *Please describe the estimated costs for implementing the initiative.*
- *Please indicate the costs and time associated in order to fully execute the proposed idea to generate the maximum deployable extent. (i.e how much and how long before the idea delivers maximum value)*

It will provide direct visibility to the planning authority of impact on production when critical tasks are to be executed or short and long term actions.

Estimated costs $50K for the software & Training.
Consultancy & customization $50K

The project could be ready Q3-2016.

4. Other Business *Benefits :*
Please describe the benefits this idea will deliver once implemented .These are benefits beyond financial impact (e.g reduction in HSE incidents, improvement in time to complete a process, increase in capabilities, etc).Please indicate whether these benefits are one-off or continuous.
Please indicate when do you expect these benefits are to be realized. Describe any risks and uncertainties associated with achieving these benefits (max 100 words)

This project would enable ADMA to determine the impact of adding new production facility, new wells, major maintenance activities, demand analysis, and more importantly trending of production if data mining is also included.

Please indicate the relevant area of benefits, give an estimate of how this impact has been realised

Category	Benefits
Health, safety and Environmental Sustainability	*N / A*
Operational Integrity	*Reduce risk of missing key repair activities or un-necessary duplication of WO*
Recovery and Sustainable Production	*N/A*
Cost Efficiency and Process Improvement	*Reduce time spent in recommended work and closing it in 2 systems*
People and Capability Development	*Reduce need to know where historic information can be found since WO can be accessed from either system*

5. Originality (max 200 Words):
Describe in what respects and to what degree the initiative is different from the status quo. Please give an indication as to whether your idea is new in ADMA-OPCO, new in the region or new in the world. (max 200 worlds).

This is a new concept in the use of simulation in planning.

Today, we are having short term plans but they are subject to determined plans with no accounting for unexpected changes. This model will allow for probabilistic events which in reality contributing missing some of the asset and hence impacting targets.

Appendix 20 Literature review summary

Table A-9 Literature review summary and gaps of related reseraches

No	Author/year	Title, Method and Gap
1	(Aronofsky J., Williams A., 1962)	The use of Linear Programming and mathematical models in underground oil production Use of Linear Programming. The studied model is limited to flow of the multiphase fluid. It ignores decision variables related to GOR, WOR, pipeline flow, facilities, capacities, storage capacity, and plant availability. It ignores the production model.
2	(Clay, M., 1988)	An Approach to Real-Time Optimization (RTO) of the Central Gas Facility at the Prudhoe Bay Field Real time Software application reading plant status data. The use of real time data renders it as a process control system monitor daily operations. Study doesn't use key decision variables of dynamic model of plant availability, pipeline or demand.
3	(Gjesdal, A., Abro, E. and Midttveit, O., 1988)	Production Allocation of Tomorrow (MPFM and test separators) Uses MPFM and well testing to measure GOR and WOR for predicting allocations. Study doesn't use decision variables for plant availability, pipeline and storage capacities. The importance of accurate well allocation for reservoir management and production optimization is emphasized but can't address dynamic model or production forecast.
4	(Muellenberg, L., Barnes, D. and Humphrey, K., 1990)	A Production Optimization System for Western Prudhoe Bay Field, Alaska Incremental GOR strategy. The study suggests a production strategy based on high gas ratio for flow assurance perspective and not for long term production. The study didn't use key variables (i.e. WOR, pipeline-flow and plant capacity). The study doesn't use a model and relies on well priorities.
5	(Urbanczyk, C. H. and Wattenbarger, R. A., 1991)	Optimization of Well Rates Under Gas Coning condition IGOR with coning constraint. The study uses well priorities for flow assurance based on GOR but ignoring WOR or long term perspective. The study doesn't use modeling. A number of decision variables (i.e. WOR, pipeline-flow, and plant capacity) are not considered.
6	(Lo, C.W. and Holden, W., 1992)	Management Schemes for Rate Forecasts Linear Programing, decline curve analysis and Simulation. Study doesn't use key decision variables (GOR/WOR/Pipeline-flow, plant availability or capacity) and instead estimates the multiphase flow. The study assumes each well can produce any oil rate between the zero and the maximum flow for future total flow forecasts.
7	(Fang, W., Lo, K., 1996)	Field maintenance activities were is an important limiting factor for a production process because of its interruption to operations, cost

		and high value of replacement
8	(Khor, C. and Kamel, A., 1996)	Commercial reservoir simulators such as GeoQuest's and ECLIPSE (Schlumberger) and VIP (Landmark, 2001) are based on rules that consider the pressure optimization problem separately from the well rate allocation optimization.
9	(ABB Automation Inc., 2001)	Use of distributed control systems with specialised simulators to overcome the daily operational problems and unable to provide long term or stochastic based optimization.
10	(Alimonti, C., Sapienza, L. and Falcone, G., 2002)	Knowledge Discovery in Database Fuzzy Logic Use of Neural Network Fuzzy Logic to validate the phase metering. Study uses real time multiphase readings along with cleansed history data to correct produced volumes readings. However, it admits the absence of an integrated model to handle dynamic changes for better forecast. Study's main gap is ignoring decision variables for plant availability, pipeline-flow and storage capacities.
11	(Jazayeri, T. and Yahyai, A., 2002)	The study evaluated the economics of production at a constant price and demand but ignored market impact. It didn't address the economic impact of an increase in supply at a faster pace than an increase in demand as in the situation of the price drop in 2015.
12	(Saputelli, L. A., 2003)	Promoting Real-Time Optimization (RTO) of Hydrocarbon Producing Systems Use of Linear Programming and Simulation. The main gap is that the study assumes some key variables as constants. The model will optimize on-line to overcome operational constraints in steady state, but is not intended for dynamic model or future forecast (ignoring plant capacity variations and GOR/WOR/Flow variability).
13	(Wang, P., 2003)	Development and Applications of Production Optimization Techniques for Petroleum Fields Use of Linear Programming. Limited to gas lift and utilization of available gas lift capabilities. The gas is recycled to serve 4, 10 and 50 wells. Model doesn't formulate a full process chain system and doesn't account for use of well GOR/WOR.
14	(Kosmidis, V., Perkins, J. and Pistikopoulos, E., 2004)	Use of mathematical programming. The drawback to this approach is conditioned by the assumption that all of the wells are tied directly to a fixed-pressure separator for analyzing a pipeline network.
15	(Popa, C., Popa, A. and Cover, A. , 2004)	Linear modeling which qualified it for dealing with overcoming steady state operational constraints and faced challenges with dynamic models when decision variables (i.e. oil rates, gas rates and water cuts) are subject to change.

16	(Naus, M., Dolle, N. and Janson, J. D., 2004)	Optimization of Commingled Production using Infinitely Variable Inflow Control Valves Simulation and Sequential Linear Programing optimization technique. A case study limited for reservoir and a horizontal well with four inflow control valves. Expanding the model for full field will have limitations related to key decision variables (e.g. plant availability, pipeline and storage capacities) and not applicable for forecast.
17	(Schlumberger, Abingdon Technology Center Training, 2005)	Specialised simulators (e.g. PVTi, Eclipse 300, Pipesim, Prosper,). Used in semi-automated optimization models to identify only the key decision variables to model the reservoir behavior which served overcoming operational constraints.
18	(Saputelli, L., Nikolaou, M. and Economides, M., 2006).	The fields' dynamics due to flow and pressure changes was the main cause of the limitations for the long term optimization.
19	(Bieker, H., Slupphaug, O. and Johansen, T., 2006)	The technology to integrate Distributed Control Systems with real time data acquired from the digital instruments served the purpose of solving operational problems rather than optimization .
20	(Saputelli, L., Nikolaou, M. and Economides, M., 2006)	This was also concluded in **(Saputelli, L., Nikolaou, M. and Economides, M., 2006)** which reiterated that the use of multivariate analysis in oil and gas optimization has not been fully adopted in the hydrocarbon industry.
21	(Goh, K.C., Muncor, C., Overschee, P. and Briers, J., 2007)	Production Surveillance and Optimization With Data Driven Models Software substitute of missing readings from down-hole sensors. Study doesn't use decision variables (e.g. WOR/GOR, plant availability, and pipeline and storage capacity). It describes software using real-time surface and down-hole flow test data and an understanding of well performance but can't handle dynamic model for production forecast.
22	(Haavardsson, N. F., Huseby, A. B. and Holden, L., 2008)	Optimization using mathematical model for simplified production models that is constructed based on the simulation output for: wells, facilities and reservoir. The study does not address stochastic variables or extrapolation required for predictions of future asset performance.
23	(Cuacenetl, R., 2008)	New Life for Oil Field with Multiple Simulators Commercial SW with embedded methodology. All products ignore the changing nature of key variables at the well string (e.g. GOR/WOR). The integrated solution compromises a number of changing variables to be dealt with as constants.

24	(Palen, W. and Goodwin, A., 2008; Cuacenetl, R., 2008)	New life for old fields with multiple simulators from Schlumberger. Use of Avocet to overcome operational issues at the pipeline. Use of an integrated suite of applications to enhance production by 6%. The main solution is to handle operational constraints due to gas condensate formation in difficult terrain. Recovered opportunity 6%.
25	(Palen, W. and Goodwin, A., 2008)	Increasing production in a mature basin Debottlenecking of choke points and discrete event simulator. Increases production with no extra budget through identifying bottlenecks and process chokes. A manual process recovered 4% of the estimated 15% loss in production opportunity. Later the process was simulated under a RAM simulator. The RAM didn't address all decision variables but enhanced topside assets efficiency by 10-15%.
26	(Bonavita, N., Birkemoe, E., Slupphaug, O. and Storkaa, E., 2008)	Operational Performance excellence through production optimization in upstream industry ABB Software modelling. Description of products that needs to be integrated via SW tools. Study doesn't address decision variables for (GOR/WOR variability, plant availability, pipeline and storage capacity). The software solution has DCS embedded simulations (production, maintenance and process) to handle operational constraints in steady state. It can't handle dynamic model for production forecast.
27	(Charle, V., Ansari, I.I. and Khalid, M.M., 2009)	Linear Programming which faces limitations in modeling a dynamic oil field with large volume of variables and probability functions which calls for stochastic programming.
28	(Sokolowski, J. and Banks, C., 2010)	In a similar technique to reservoir simulation, the research uses the stochastic modelling and pattern recognition of the decision variables to configure a production process chain in a discrete event simulation model.
29	(Amos, H.C., Jacob Bernedixen, J., and Syberfeldt A., 2010)	The dynamic nature of oil fields with large volumes of variables and the differences between planning and executing the work introduced implementation time limitation due to changes in the settings by the time the optimization model is ready.
30	(Cramer, R., Scotanus, D., Ibrahim, K. and Colbeck, N., 2011)	Improving allocations and hydrocarbon accounting Software that reads from SCADA system and down-hole gauges. Study comes close to the use of accurate allocations for computing well allowable rates. But the computations relied on full flow rates and not the variable rates of WOR/GOR. It ignores other decision variables (i.e. plant availability, pipeline and storage capacities). The purpose is to describe oil accounting improvement techniques used by Shell FieldWare software, but doesn't address dynamic model or production forecast.

31	(McCaffrey, M., Ohms, D., Werner, M., Stone, C. and Baski, D., 2011)	Allocating Commingled Production Using Oil Geochemistry Use of geochemistry to identify the source of oil at the stock tank. Study doesn't use key decision variables for plant availability, pipeline-flow and storage capacity. Sampling of commingled flow for measuring actual formation production by which sampling depends on the quality of the initial chemistry in a steady state, but it can't handle dynamic model or production forecast. Study admits to inaccuracies in results.
32	(Mccaffrey, M., 2012)	Oil fingerprinting reduces allocation costs Use of geochemistry to identify the source of oil at the stock tank. Study is to meter the oil produced based on oil sampling to measure actual production from a certain zone based on original oil fingerprints with 95% accuracy. It depends on the quality of the initial chemistry for production volumes computations in steady state. Its purpose is to reduce metering costs and not to overcome production loss. It can't handle dynamic model or production forecast. Study doesn't address decision variables for plant availability, pipeline-flow and storage capacities.
33	(USA, Purdue Patent No. US20150309001 A1, 2012)	Methods of analyzing crude oil Shared same limitations of oil fingerprinting (Mccaffrety, M, 201)
34	(Dzubur, L. and Langvik, A., 2012)	A set of variables were recommended for short term optimization in Marlim field which excluded asset availability and market analysis.
35	(Tucker, R., Straub, T. and Feng, S., 2012).	Unplanned Downtime in the Gulf of Mexico: A Significant Production Loss Management Opportunity for Producers Data mining of 2008 to 2012 Company records. Business problem emphasis. No solution was identified. Identified 2 decision variables: Unplanned Downtime and Well testing Complexity. Lost production opportunity over 4 years is 12%
36	(Shah, N. and Mishra, P., 2012)	A theoretical mathematical model was developed based on the following variables;
37	(Codasa, A., Campos, S., Camponogarab, E., Gunneruda, V. and Sunjergae, S., 2012)	Relied on old readings of outdated well flow tests and missing recent flows' random changes.
38	(Dmour, H. N., 2013)	Use of impractical assumptions mandated by the nodal analysis technique in handling some variables as constants to solve the formulas.
39	(ADMA production annual report, 2014)	In-house application of one short term production forecast results Lift curve and Integer Programming. The program relied on asset status (on/off) for in-service or off-service and without values in between resulting with a 15% average lost production opportunity. Assumptions used and not all decision variables are modeled.
40	(Woo, J.H., Ho Nam, J.	Development of simulation model for subsea production

	and HeeKo, K., 2014)	optimization Use of discrete event simulator. Development of subsea optimization based on reliability and availability model to optimize flow through constrained manifolds. It is used for random variables of operational nature (asset reliability) with no data mining or trending to extrapolate future forecast.
41	(Chowdary, S., 2016)	(ABB Automation Inc., 2001), which were used to overcome the daily operational problems and unable to provide long term optimization.
42	(DNVGL RAM Discrete Simulator, 2016)	Reliability, Availability and Maintenance (RAM) basis for optimization using discrete event simulator. The Software product does not address production planning and forecasting.