
Surface Network Modelling and Production Optimization for the Implementation of Steam Flooding in a Heavy Oil Reservoir

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Abstract

Heavy and highly viscous crude oils are not usually produced economically with primary and secondary recovery and are becoming an important ingredient in sustainable hydrocarbon supply. In addition to reservoir-scale modelling, an important part of the field implementation is the design of the surface gathering, injection and processing network (steam enhanced-oil-recovery or EOR), as steam flooding is a thermal enhanced-oil-recovery (EOR) method to enhance oil mobility by injecting steam into the reservoir, which also lowers oil viscosity. Numerous studies are available on the numerical simulation of the steam flooding process itself, but little attention has been paid to the design of the surface network that implements the process. The present study is based on a heavy-oil reservoir that is being treated with steam flooding in order to develop production and injection well network models of the reservoir using the commercial multiphase-flow simulator PIPESIM. This involves nodal analysis of the well and reservoir deliverability before and after steam injection and a sensitivity analysis of tubing diameter, flow-line diameter, choke size, separator pressure, water cut, reservoir temperature, and reservoir pressure to quantify their effects on production. The results indicate that the oil mobility and production rate are significantly enhanced in many cases by steam injection, that an increase in tubing ID, flow-line ID, choke size and reservoir pressure up to a certain limit may also lead to production rate increase, but that separator pressure has little effect on production rate, and that production rate decreases with increasing water cut up to some maximum value. The optimum set of parameters is then used to produce a network configuration that increases production rate compared to the base. The results are used as a practical guideline for the design of surface facilities for steam-flooding projects in similar heavy-oil reservoirs with economic requirements.

Introduction

The hydrocarbon deposits enclosed in subterranean rocks called petroleum or crude oil. Still, it is the most prominent primary energy source globally and is used to fulfill the energy requirements of industries, commerce, and residential households and as the raw material for chemical products like plastics, pharmaceuticals, and detergents (Murshed et al., 2021).

To extract oil and gas from a reservoir, enough energy is needed to force fluids to flow from the reservoir to the surface through the entire fluid flow path, overcoming frictional and gravitational losses along the way. The total pressure loss across the production system is the sum of the pressure losses across each individual component reservoir, completion, tubing, choke, flow line and surface processing equipment, and is a function of the flow rate, as well as the fluid properties at each point in the system (Guo, 2011). Any one of the components that is oversized or restrictive

can reduce the well's deliverability, and isolating and optimizing the performance of each part of the production system is critical to economical field operation (Bieker et al., 2007).

Demand for oil around the world is still growing at a faster rate than the output that can be achieved from reservoirs by primary and secondary recovery alone, especially for heavy, high-viscosity crude oils that are largely immobile in native reservoir conditions. This gap is filled by enhanced oil recovery (EOR) methods, one of which is steam flooding for heavy oil reservoirs, which involves injecting heat into the reservoir that reduces the viscosity of the oil and makes it more mobile. Numerical simulation of steam flooding on a reservoir scale has been extensively studied whereas the design and optimization of the corresponding surface network (injection and production wells and surface facilities such as chokes, separators, boilers, heat exchangers, and compressors that need to operate as a whole in order to make the process economic) has received less attention.

In this study, this gap is filled by applying the commercial software PIPESIM (PROducing Information from PIPE Simulations) to design and optimize the surface facilities needed for the implementation of steam flooding in a heavy, dead-oil reservoir using nodal analysis. In particular, the aims of this work are to:

- Study the systematic correlation between the surface facilities and injection and production wells during the implementation of the steam-flood; and
- Use PIPESIM to run network modeling and well modeling, along with a sensitivity analysis, to assist with design of surface facilities and wells for steam flooding.

To guide this investigation, the study seeks to answer the following research questions:

- How does steam injection affect well deliverability compared to unheated production?
- How do surface-facility parameters influence production capacity?
- What optimum ranges of reservoir parameters maximize production?
- Can an optimized network configuration improve production further?

Literature Review

Numerical modelling of the reservoir and operational-scale parameters for steam flooding has indicated that recovery is better in high quality (light) crude-oil, as these are more mobile and have a more favourable mobility ratio, and improved in water-wet reservoirs as compared to oil-wet reservoirs due to lower adhesion tension. The best recovery for heavy oil reservoirs was achieved with high SQ at intermediate IR or medium SQ at high IR, and in general, the increase in IR for a given SQ improved the recovery rate (Raza et al., 2022).

Nodal analysis is also applied at field scale as it was applied in the Hurricane field to optimize production rates across eleven wells by use of tubing size, flow-line configuration, gas-lift injection pressure, and skin factor, and by implementing a flow-assurance study to address hydrate formation, wax deposition and severe slugging (Al-Qasim et al., 2019). A few other nodal-analysis studies have used reservoir, well and fluid property data to calculate the pressure distribution causing production, the effect of the bottom-hole equipment on the production capacity, and the intersection of the inflow and outflow performance curves at a given solution node, where one of these pressures is known and the other is unknown, e.g., a pressure at the wellhead or at the bottom-hole (Dala et al., 2015; Jansen, 2017).

The thermal recovery is sensitive to operational parameters as seen in field applications. A typical recovery factor for the reservoir conditions studied (Perez & Escobar, 2016) is about 20%, and in one horizontal alternating steam-drive study, the bottom-hole steam quality (BHSC) was assumed to be 55%, which is incorrect as the steam quality is actually 80% at the reservoir bottom-hole. Steam quality and injection temperature were also found to have significant interaction on recovery, with high steam quality and high injection temperature showing highest recovery and

low to moderate steam quality and injection temperature combinations showing comparatively similar, low recovery performance (Kirmani et al., 2021).

Wellbore to surface modeling tools have been developed to integrate the subsurface and surface simulators. Another method integrated a surface-network simulator with a reservoir simulator to enhance the accuracy of the forecasts for black-oil and dry-gas systems, but it suffered from a lack of treatment for well-efficiency factors and condensate treatment (Venkataraman & Mueller, 2000). Purpose-built production-assurance tools that integrate the pipeline hydraulic model (Pipesim) with a spreadsheet-based database have also been used to track well performance, plan new wells, and identify production losses (Gouhar et al., 2019), and the integration of reservoir simulation and lift system optimization via nodal analysis has also been used to evaluate combined well-reservoir performance over time (Noor et al., 2017).

PIPESIM is a comprehensive, steady-state multiphase-flow simulator commonly used in industry to design and optimize complete surface networks of wells, and individual wells as well, even in complex looped and cross-connected configurations. The applications reported include the following: design of wells, pipelines, and surface facilities; identification of production bottlenecks and flow-assurance risks (corrosion, erosion, hydrate formation); optimal pump and compressor placement; water and gas injection network design; and full-field deliverability against demand (Pashinsky et al., 2018). For steam-injection wells, modelling the pressure gradient with the Beggs and Brill correlation has been shown to be suitable for vertical well design, with a difference of around 1.3% from the simulator result for the pressure gradient, given the same pressure, temperature, quality and rate inputs at the well-head (Waltrich et al., 2019).

This set of works not only establishes that reservoir- and fluid-quality effects on steam-flood recovery are well-understood numerically, but also that nodal analysis and network simulators like PIPESIM are proven design tools for wells and surface facilities. Relatively few publications, however, have combined both aspects for the surface network of wells, chokes, separators, and steam-generation equipment needed to implement steam flooding on a field scale. In this context, the present study aims to fill this gap by applying the nodal analysis technique, base-case network modelling and systematic sensitivity analysis for the design of surface facilities for the implementation of steam-flooding in a heavy dead-oil reservoir.

Materials and Methods

Reservoir and Well Deliverability

Reservoir deliverability refers to the amount of oil or gas that can be produced from a reservoir at a particular bottom-hole flowing pressure and is typically represented by the inflow performance relationship (IPR), which is a plot of the bottom-hole flowing pressure (P_{wf}) vs production rate over the range of reservoir to surface conditions (Economides, 1994, 2013; Jansen, 2017). The shape of the IPR curve is dependent on the reservoir drive mechanism: an approximately straight line for water-drive reservoirs and/or reservoirs above the bubble point; a straight line with slight curvature near abandonment for gas-cap-drive reservoirs; and a distinctly curved line for solution-gas-drive reservoirs and/or reservoirs below the bubble point (Economides, 2013).

The tubing performance relationship (TPR), also known as the outflow performance relationship (OPR), models the relationship between wellbore flow rate and pressure that can be achieved for a given well completion and surface constraint (Chen, 2017). The bottom-hole (or any other point) in the system is the solution node, the IPR is the inflow to the node and the TPR/OPR is the outflow from the node. The intersection of the IPR and OPR curves represents the unique combination of flow rate and pressure at which the system will operate in this study, and is collectively called production capacity of the well, which is solved numerically by the simulator, but the curves are held for graphical interpretation (Beggs, 2003; Guo, 2011; Ertekin, 2019).

Steam Flooding

Thermal EOR processes include steam flooding, which involves the production of steam on the surface and injection of steam into the reservoir through special wells. The induced heat also reduces the viscosity of the heavy oil and along with the hot-water condensed from the steam creates an artificial drive that pushes the mobilized oil toward the production wells, similar to water flooding, but with the added viscosity reduction effect (Sheng, 2013). The surface and wellbore requirements of these steam-generating and injection operations dictate that proper design of the steam generating facilities, water-treatment systems, insulated injection wellbores and flow lines, and instrumentation for pressure and quality control on the steam-separation train be economically implemented (Barge et al., 2009).

Simulation Software

The surface and wellbore network models, which were used in the study, were developed using a steady-state multiphase-flow simulator, PIPESIM, widely used across the petroleum industry for the design, optimization, and flow-assurance analysis of wells and surface networks throughout the producing life of a field (Pashinsky et al., 2018). PIPESIM includes a network of wells, flow lines and surface equipment in a single network environment, thus capturing the interplay between wells and shared surface equipment directly.

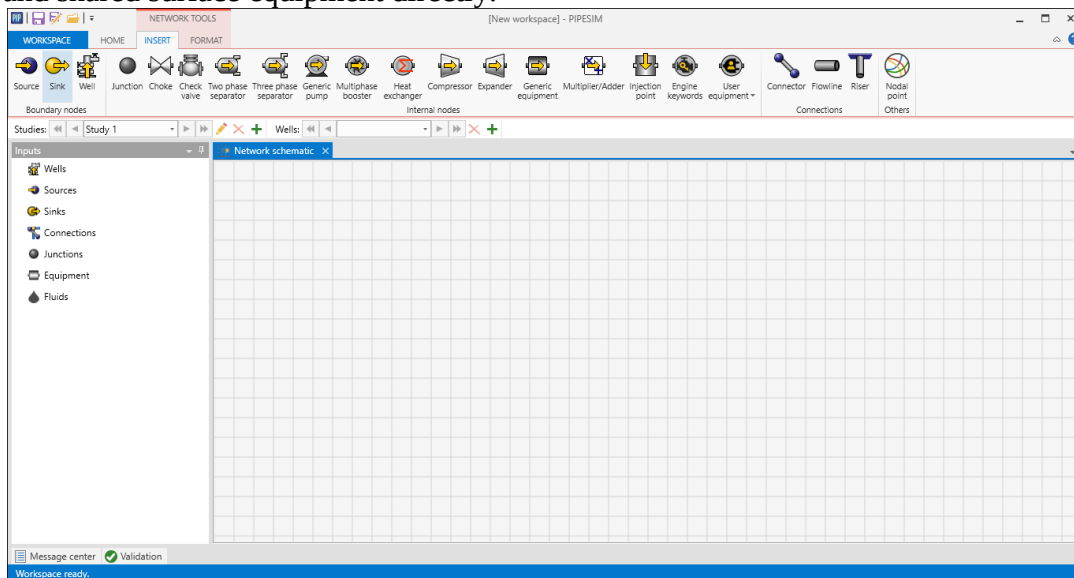


Figure 1. PIPESIM network-modeling interface used to construct the production and injection well networks.

Methodology

This study consisted of four steps: (i) review basic concepts of nodal analysis, steam flooding, and surface facility operation; (ii) review of published literature on the application of nodal analysis, thermal EOR and surface-network design (Section 2); (iii) construction of base-case injection- and production-well network models in PIPESIM using reservoir, well, and fluid data from a published reservoir study on steam flooding; and (iv) sensitivity analysis and optimization of the set of surface equipment involved, to determine an optimum network configuration.

Base Network Model

The network consists of a single vertical injection and production well. Due to a limitation in the modelling program used in the simulator, a steam-source and a black-oil fluid could not be included in the same network file, so the system was modelled as two separate sub-networks: the

injection-well network and the production-well network, with the water stream from the production-side separator modelled conceptually as being fed to the injection-side network. The injection sub-network (Figure 2) includes a steam source, a gas compressor which increases the steam pressure in the injected steam to the necessary wellhead pressure, connecting flow lines and the injection well. The ambient surface temperature is 45°F, the reservoir pressure is 2500 psia, and the reservoir productivity is 8 STB/day·psi. The depth of the casing is 1500 ft, the depth of the packer is 1453 ft, and the depth of the nodal point is 1500 ft. The measured vertical depth of the injection well is 1950 ft. The fluid is injected into the surface well and at the surface the well is connected to the steam source via flow lines FL_2 (6.065 in x 200 ft) and FL_3 (3.068 in x 200 ft), along with a 99% effective steam trap.

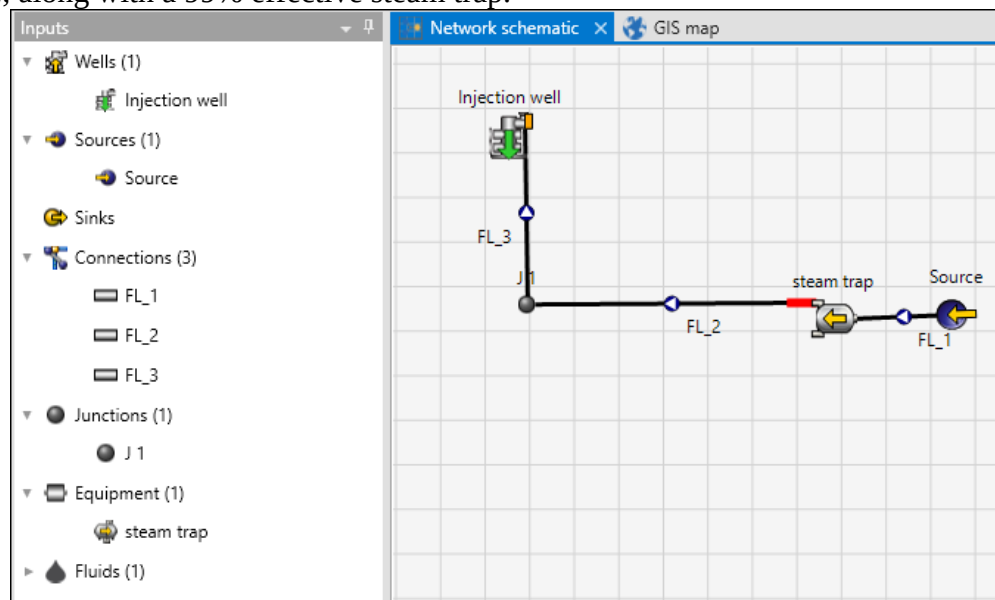


Figure 2. Base network model for the injection well.

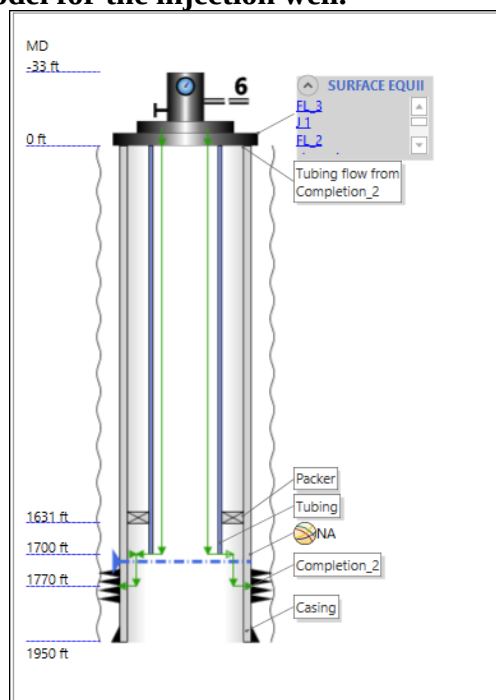


Figure 3. Injection well completion, casing, and tubing configuration.

The production sub-network (Figure 4) consists of the production well, a surface choke, a two-phase separator, and two sinks representing the stock-tank oil and produced-water streams. The production well has a measured and true vertical depth of 1950 ft and is completed across three

intervals at 1523 ft, 1613 ft, and 1658 ft; the tubing extends to 1500 ft, with the packer set at 1492.6 ft and the nodal point at 1510 ft. Ambient surface temperature is 44°F, increasing to 165°F at 1950 ft, with a reservoir pressure of 2500 psia and a productivity index of 8 STB/day·psi. At surface, the well connects through flow line FL_1 (20 in internal diameter, 200 ft length) to a production choke (2 in bean size), then through a trunk line and junction to a two-phase separator (100% efficiency), from which the hydrocarbon stream flows to a stock tank at 50 psia and the water stream is routed to the injection side.

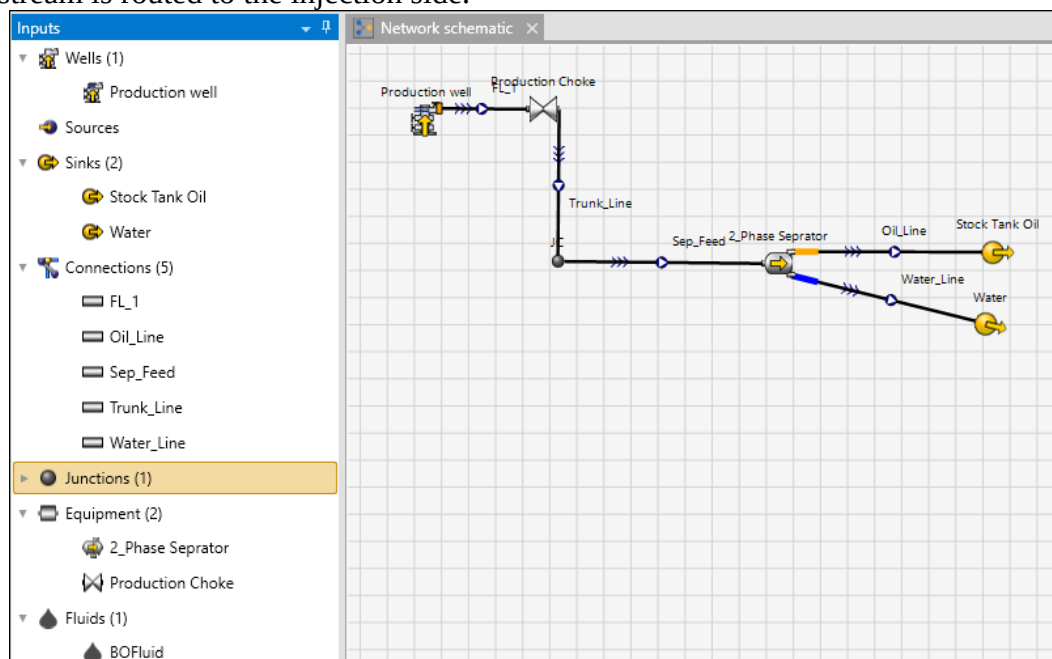


Figure 4. Base network model for the production well.

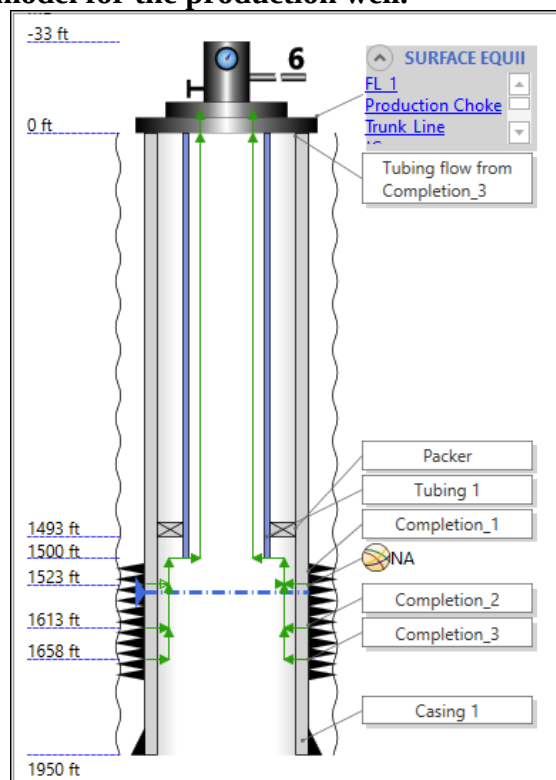


Figure 5. Production well completion, casing, and tubing configuration.

Reservoir, Well, and Fluid Data

The reservoir, well, PVT, and initial flowing-condition data used to build and validate the base model, adapted from the reservoir characterization of Raza et al. (2022), are summarized in Tables 1-4.

Table 1. Production well data.

Parameter	Value
Measured depth (MD)	1950 ft
True vertical depth (TVD)	1950 ft
Tubing depth	1500 ft
Tubing inside diameter (ID)	3.548 in
Tubing outside diameter (OD)	4 in
Tubing inside roughness	0.001
Casing depth	1950 ft
Casing inside diameter (ID)	6.435 in
Casing outside diameter (OD)	7.625 in
Casing inside roughness	0.001

Table 2. Injection well data.

Parameter	Value
Measured depth (MD)	1950 ft
True vertical depth (TVD)	1950 ft
Tubing depth	1700 ft
Tubing inside diameter (ID)	3.548 in
Tubing outside diameter (OD)	4 in
Tubing inside roughness	0.001
Casing depth	1950 ft
Casing inside diameter (ID)	6.366 in
Casing outside diameter (OD)	7 in
Casing inside roughness	0.001

Table 3. PVT properties.

Parameter	Value
Oil gravity	15° API
Gas gravity	0
N ₂	0%
CO ₂	0%
H ₂ S	0%
GOR (R _{rs})	0%

Table 4. Initial flowing-condition data.

Parameter	Value
Reservoir pressure (Pr)	1500 psi
Reservoir temperature (Tr)	165°F

Parameter	Value
Wellhead pressure (Pwh)	300 psi
Liquid production (Ql)	40 STB/day
Water cut	0%
Oil production (Qo)	40 STB/day
Water production (Qw)	0 STB/day
Gas production (Qg)	0 STB/day

Sensitivity Analysis Design

After validation of base model, a sensitivity study was done on the production well by varying one parameter at a time while keeping the other parameters at base case values, for tubing internal diameter, flow line internal diameter, choke (bean) size, separator pressure, water cut, reservoir temperature and reservoir pressure (with reservoirs being evaluated separately for the three completion intervals). The procedure outlined in Section 3.1 was used to calculate the IPR curve and OPR curve at the bottom-hole node and/or the wellhead node for each case and the production capacity was obtained where the two curves intersect. The combination of parameters that resulted in the most desirable production rate with minimal pressure drop across the network, and without harming the reservoir, was then used to create an optimal network configuration.

Results and Discussion

Production Well Performance Before Steam Injection

Using relative-permeability data through Darcy's law, IPR and OPR curves were developed at the bottom-hole and wellhead nodes for the base reservoir condition, before the steam is injected (Table 5, Figure 6; Table 6, Figure 7). This is when the well is pumping at a relatively low rate of ~ 44.9 STB/day and is not economically viable, and steam injection is added to mobilize the oil and improve the deliverability.

Table 5. Nodal analysis at the bottom-hole node, outlet pressure 300 psi, before steam injection.

Node	ST liquid rate (STB/d)	Pressure at node (psia)	Input THP (psia)
Bottom-hole	44.91	11111.2	300

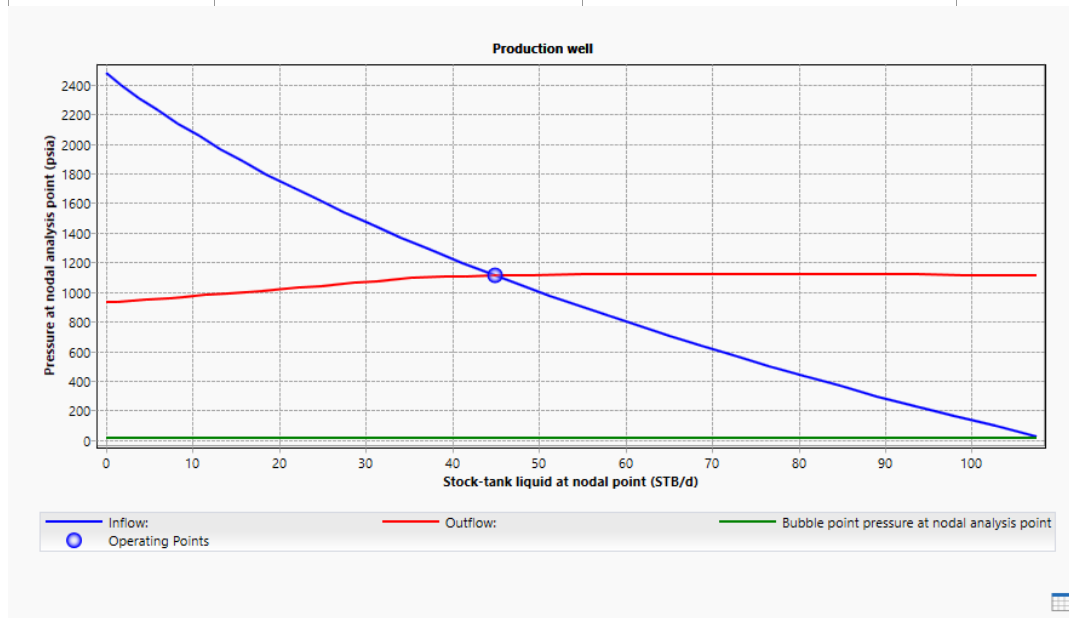


Figure 6. IPR-OPR intersection at the bottom-hole node before steam injection.

Table 6. Nodal analysis at the wellhead node, outlet pressure 300 psi, before steam injection.

Node	ST liquid rate (STB/d)	Pressure at node (psia)	Input THP (psia)
Wellhead	44.91	303.1	300

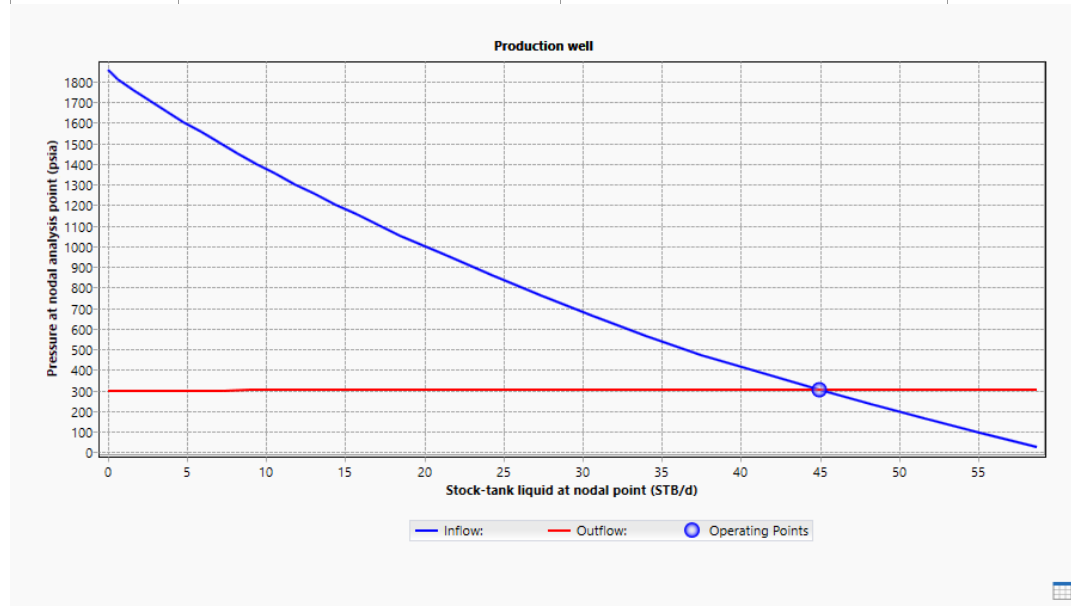


Figure 7. IPR-OPR intersection at the wellhead node before steam injection.

Production Well Performance After Steam Injection

The same nodal-analysis procedure was applied at the bottom-hole and wellhead nodes after the steam injection (Tables 7-8, Figures 8-9). Compared to the pre-injection case, the production rate rose by about two orders of magnitude, indicating that oil viscosity was significantly lowered and the mobility enhanced by the heat generated by the steam injection.

Table 7. Nodal analysis at the bottom-hole node, outlet pressure 300 psi, after steam injection.

Node	ST liquid rate (STB/d)	Pressure at node (psia)	Input THP (psia)
Bottom-hole	11,549.0	890.4	300

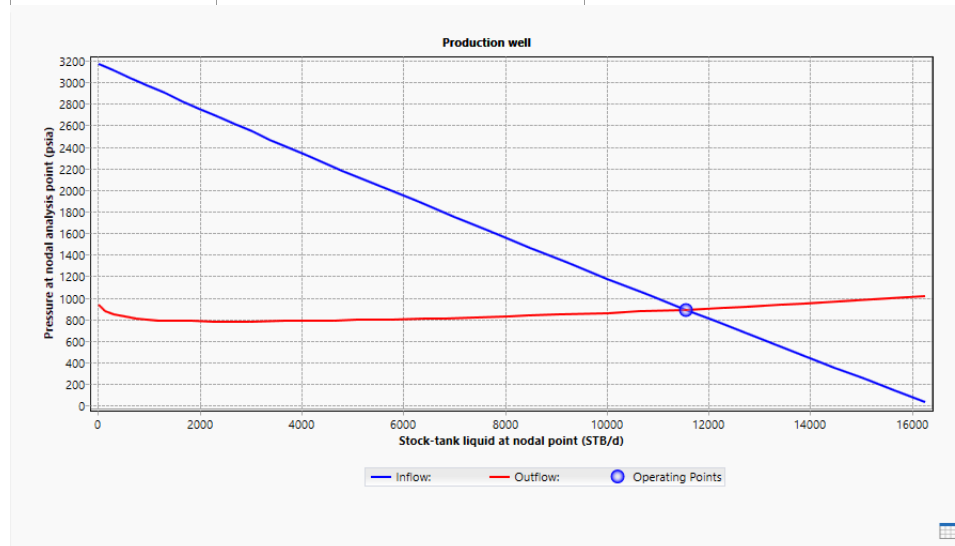


Figure 8. IPR-OPR intersection at the bottom-hole node after steam injection.

Table 8. Nodal analysis at the wellhead node, outlet pressure 300 psi, after steam injection.

Node	ST liquid rate (STB/d)	Pressure at node (psia)	Input THP (psia)
Wellhead	11,549.0	331.7	300

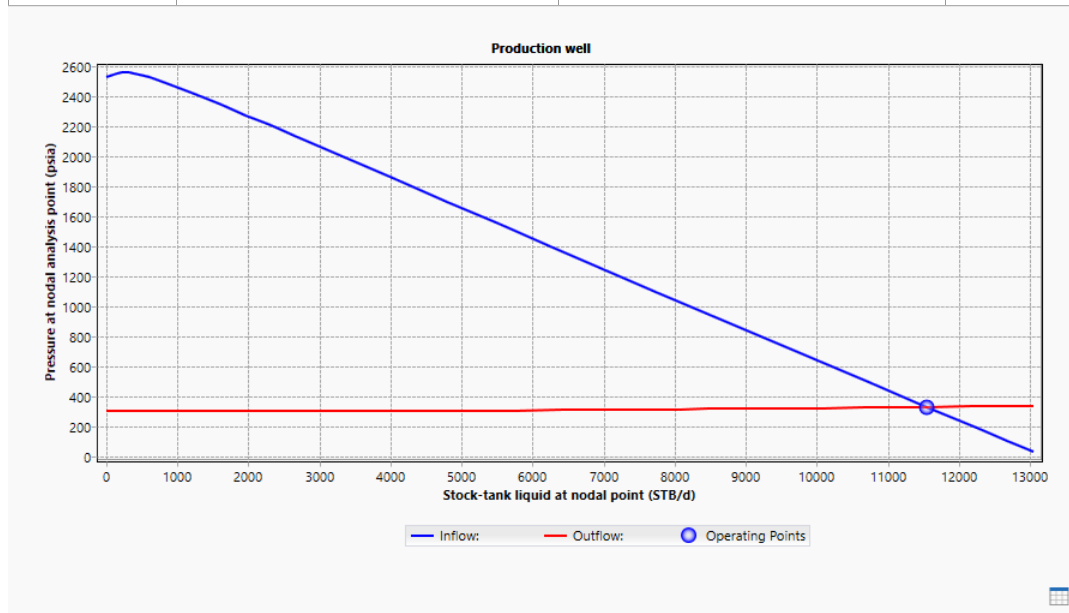


Figure 9. IPR-OPR intersection at the wellhead node after steam injection.

Sensitivity Analysis

The production rate reported for each parameter varied is one of the intersections between the IPR and OPR curves calculated at the parameter value indicated at a node defined in section 3.1; the production capacity and node pressure are tabulated below and the curve families shown in the accompanying figures are the intersections between the IPR and OPR curves.

Tubing internal diameter

The production capacity rose rapidly with a tubing ID of 1 to 3 in and then gradually up to 5 in (Table 9, Figure 10), suggesting that a tubing ID that is too small is highly flow-restrictive, but the advantage of increasing the ID beyond 3 in diminishes as frictional losses become less significant.

Table 9. Sensitivity of production to tubing internal diameter.

Tubing ID	ST liquid rate (STB/d)	Pressure at node (psia)
1 in	1,999.4	2,752.4
2 in	7,772.8	1,601.7
3 in	10,977.0	996.6
4 in	11,772.0	849.1
5 in	11,964.3	813.6

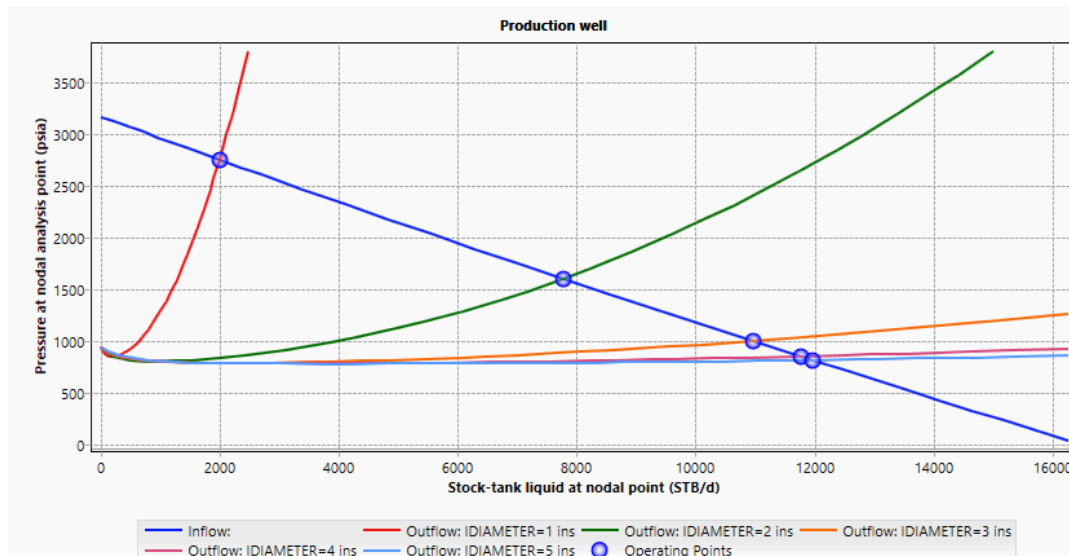


Figure 10. Effect of tubing internal diameter on the IPR-OPR intersection.

Flow-line internal diameter

As the flow line diameter was increased from 2 to 4, production rate increased from 2 to 4, but then fell flat at approximately 11,666 STB/day for ID ≥ 6 (Table 10, Figure 11) indicating that once a certain size the flow line does not control the system pressure drop and that additional line size increase does not yield any additional production advantage.

Table 10. Sensitivity of production to flow-line internal diameter.

Flow-line ID	ST liquid rate (STB/d)	Pressure at node (psia)
2 in	10,665.5	1,054.7
4 in	11,639.0	873.7
6 in	11,665.8	868.7
8 in	11,665.8	868.7
10 in	11,665.8	868.7
12 in	11,665.8	868.7

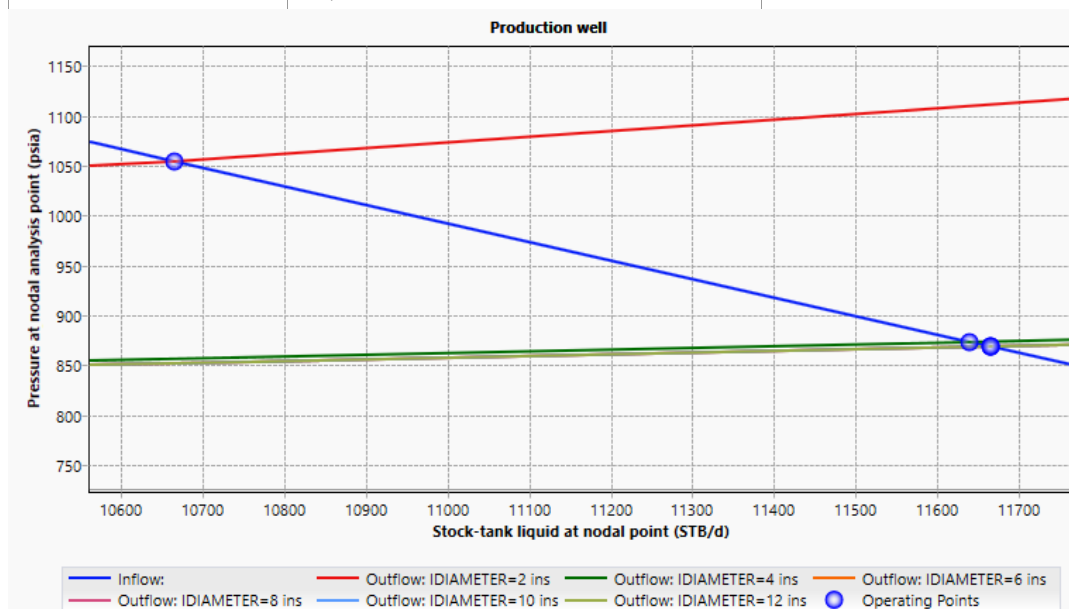


Figure 11. Effect of flow-line internal diameter on the IPR-OPR intersection.

Choke (bean) size

Production rose with choke size to approximately 3-4 in after which rates approached an asymptote near 11,690 STB/day (Figure 12, Table 11). The practical choke size should also account for the asymptotic increase in production rate, but the decrease in backpressure control at larger bean sizes.

Table 11. Sensitivity of production to choke (bean) size.

Bean size	ST liquid rate (STB/d)	Pressure at node (psia)
1 in	9,635.0	1,247.8
1.5 in	11,244.9	946.8
2 in	11,549.2	890.4
2.5 in	11,636.8	874.1
3 in	11,670.8	867.8
3.5 in	11,684.8	865.2
4 in	11,692.0	863.9

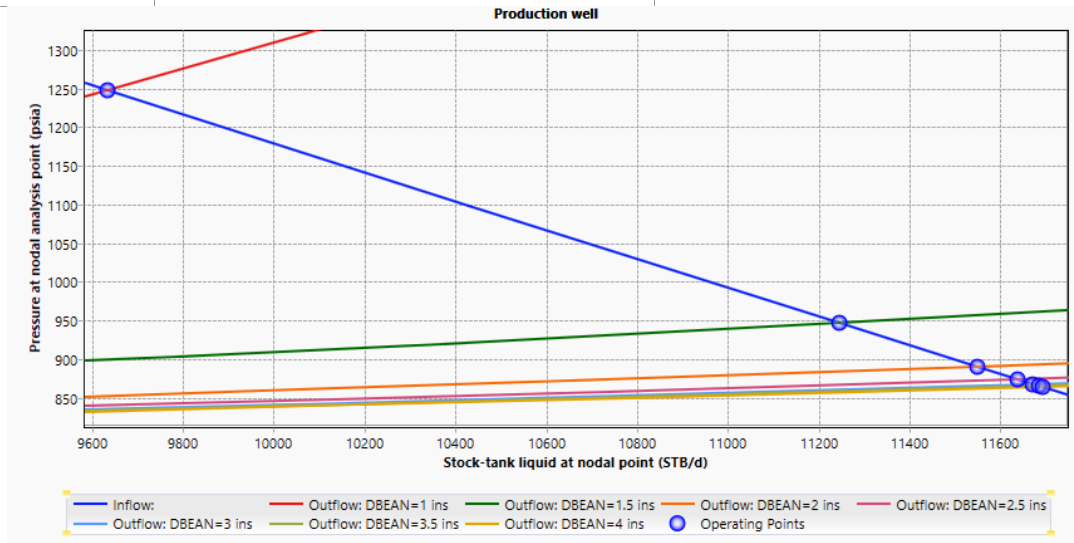


Figure 12. Effect of choke (bean) size on the IPR-OPR intersection.

Separator pressure

The computed production rate and node pressure (Table 12, Figure 13) did not change with OPR from 0 to 100 psi. This means that, in the range and configuration tested, separator pressure is not a critical parameter on well deliverability and operating pressure can be chosen by process or economic considerations without penalty in production rate.

Table 12. Sensitivity of production to separator pressure.

Separator outflow pressure	ST liquid rate (STB/d)	Pressure at node (psia)
0 psi	11,549.0	890.4
20 psi	11,549.0	890.4
40 psi	11,549.0	890.4
60 psi	11,549.0	890.4
80 psi	11,549.0	890.4
100 psi	11,549.0	890.4

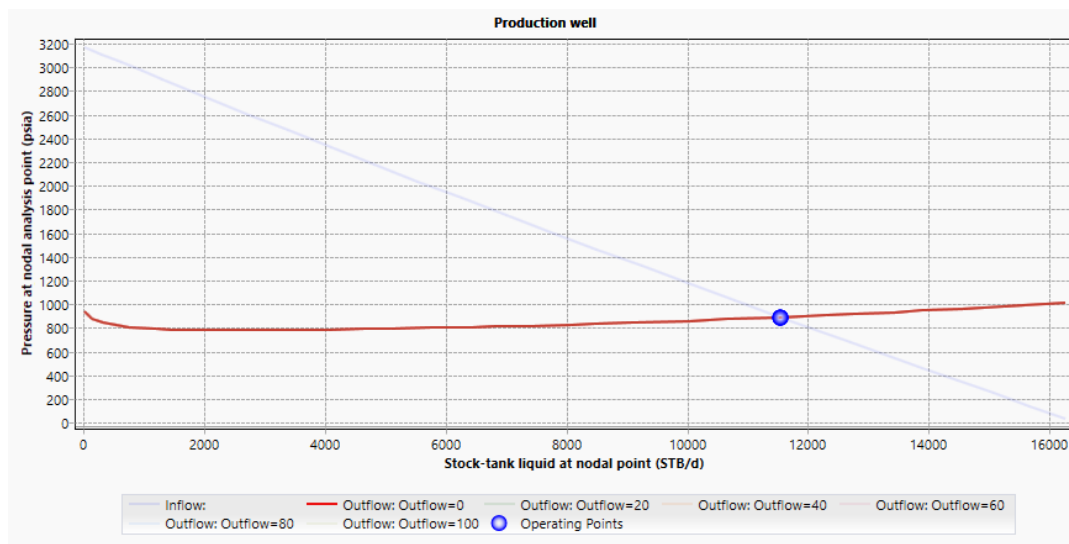


Figure 13. Effect of separator pressure on the IPR-OPR intersection.

Water cut

As water cut increased from 10% to 80% (Table 13, Figure 14), production decreased monotonically as is expected when the water fraction of the produced liquid stream increases, which decreases the oil mobility ratio and increases the effective viscosity of the produced liquid stream. The highest liquid production was achieved with the lowest water cut tested.

Table 13. Sensitivity of production to water cut.

Water cut	ST liquid rate (STB/d)	Pressure at node (psia)
10%	17,318.9	1,019.8
20%	14,901.7	960.7
30%	13,643.3	934.1
40%	12,858.5	913.7
50%	12,289.4	902.8
60%	11,972.1	897.4
70%	11,697.1	892.8
80%	11,465.4	888.9

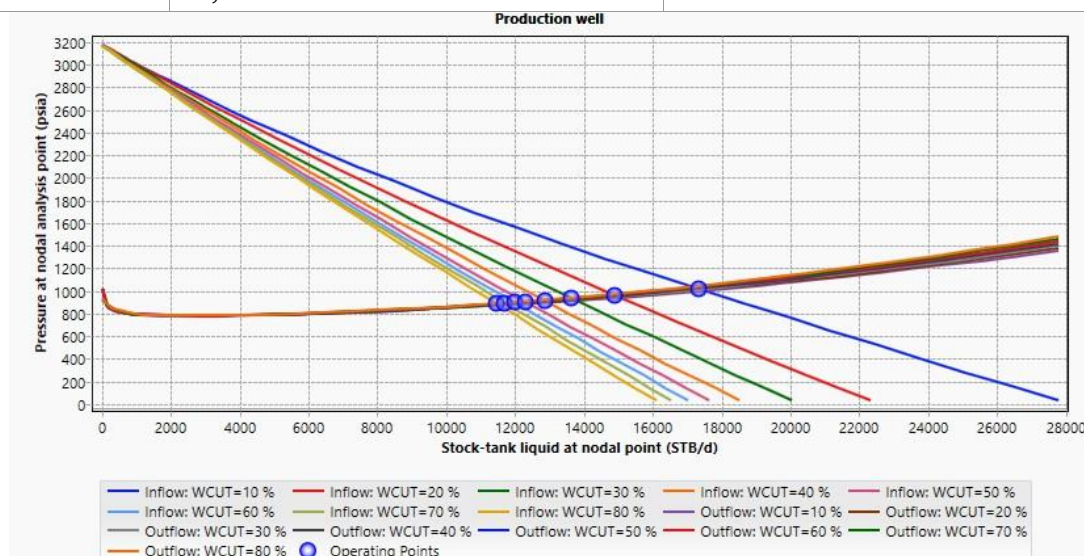


Figure 14. Effect of water cut on the IPR–OPR intersection.

Reservoir temperature

As the reservoir temperature was increased from 100°F to a maximum of approximately 400°F (18,657.9 STB/day), production rate increased greatly, but gradually began to decrease with increasing reservoir temperature up to 1000°F (Table 14, Figure 15). This is a non-monotonic response, meaning that the upper limit to the temperature increase is not strictly the potential maximum, but the injection temperature must be chosen to be close to the observed optimum, rather than as high as is practicably possible, so as not to cause any damage to the reservoir but still be economical.

Table 14. Sensitivity of production to reservoir temperature.

Temperature	ST liquid rate (STB/d)	Pressure at node (psia)
100°F	7,975.3	825.4
200°F	8,083.5	828.8
300°F	11,833.7	925.5
400°F	18,657.9	1,096.7
500°F	18,079.8	1,071.3
600°F	14,759.1	971.2
700°F	10,823.6	874.4
800°F	8,737.6	834.9
900°F	8,350.1	828.9
1000°F	8,056.1	825.9

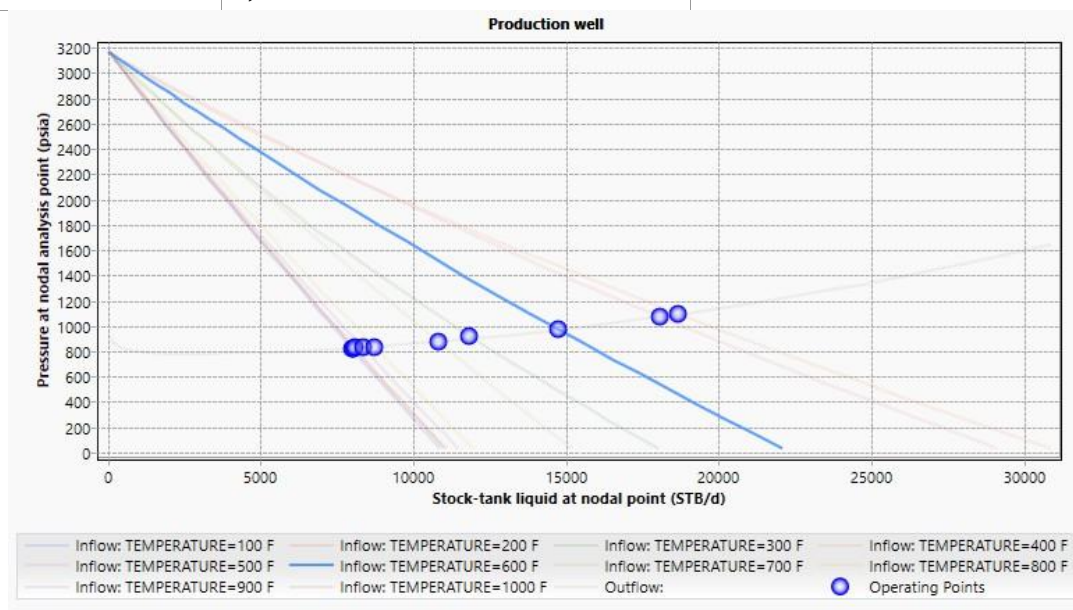


Figure 15. Effect of reservoir temperature on the IPR-OPR intersection.

Reservoir (static) pressure

The reservoir pressure was stepped up for each of the three completion intervals (1523 ft, 1613 ft and 1658 ft) to ensure consistency of the pressure-support response between completions. In all three cases production rose monotonically with reservoir pressure from 1000 to 3200 psia (Tables 15–17, Figures 16–18) and rates and pressures were essentially the same in the three completions, regardless of the completion interval analyzed.

Table 15. Sensitivity of production to reservoir pressure — Completion 1 (1523 ft).

Static reservoir pressure	ST liquid rate (STB/d)	Pressure at node (psia)
1000 psia	8,191.3	828.9
1500 psia	8,995.1	841.9
2000 psia	9,773.5	855.5
2500 psia	10,533.2	869.8
3000 psia	11,264.7	884.5
3200 psia	11,549.4	890.3

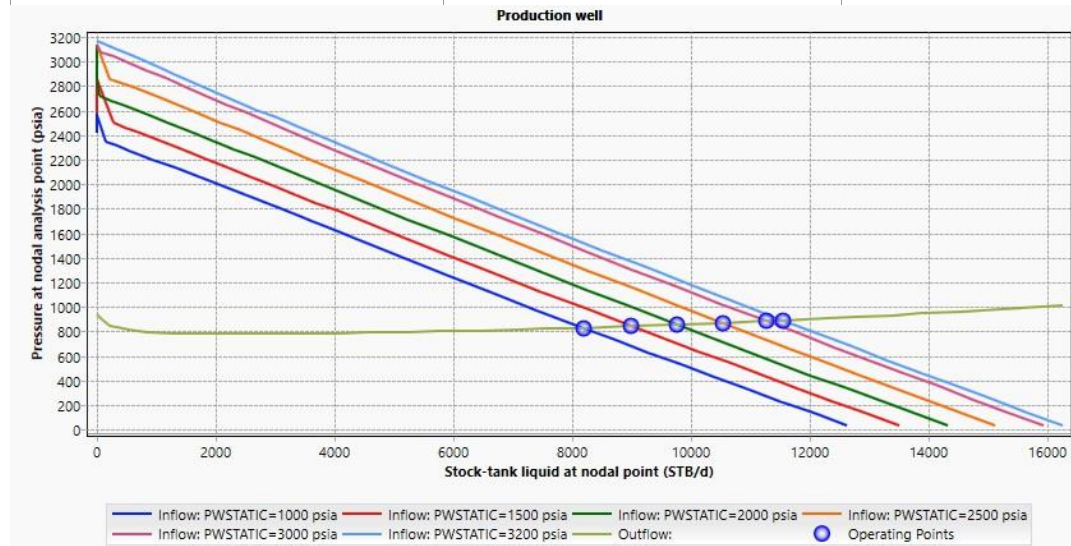


Figure 16. Effect of reservoir pressure on production Completion 1.

Table 16. Sensitivity of production to reservoir pressure Completion 2 (1613 ft).

Static reservoir pressure	ST liquid rate (STB/d)	Pressure at node (psia)
1000 psia	8,190.8	828.9
1500 psia	8,994.6	841.9
2000 psia	9,774.2	855.5
2500 psia	10,533.6	869.8
3000 psia	11,264.8	884.5
3200 psia	11,549.0	890.4

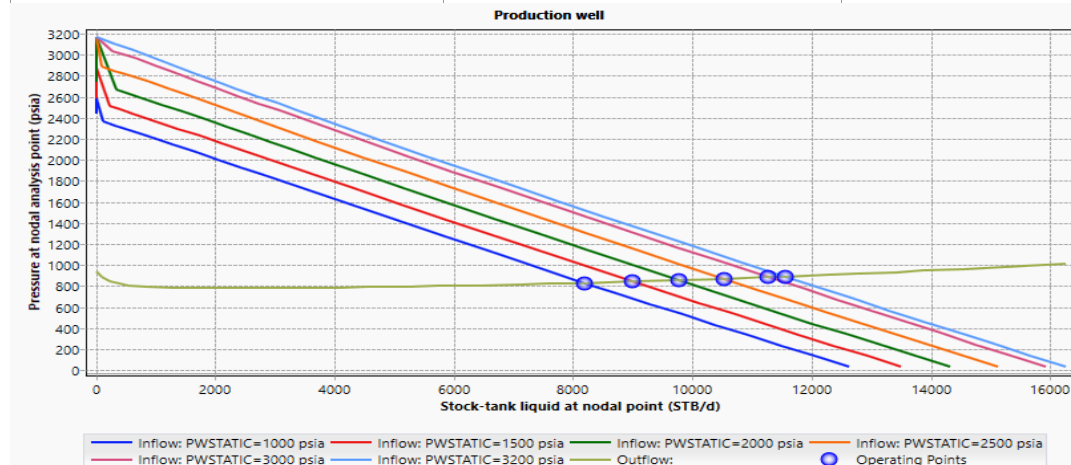
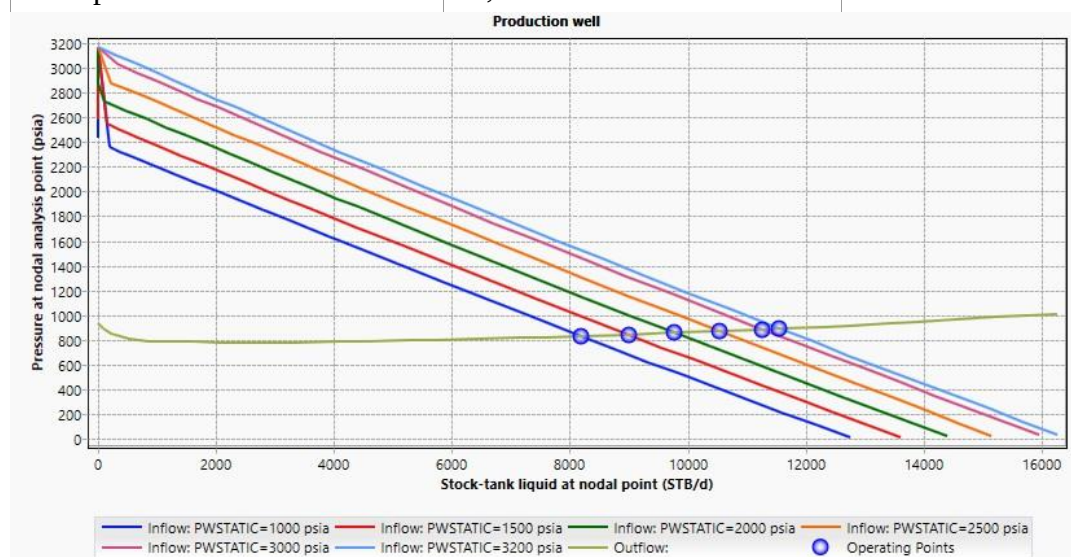


Figure 17. Effect of reservoir pressure on production Completion 2.

Table 17. Sensitivity of production to reservoir pressure Completion 3 (1658 ft).

Static reservoir pressure	ST liquid rate (STB/d)	Pressure at node (psia)
1000 psia	8,190.9	828.7
1500 psia	8,994.1	841.9
2000 psia	9,774.4	855.5
2500 psia	10,533.8	869.8
3000 psia	11,264.9	884.5
3200 psia	11,549.0	890.4

**Figure 18. Effect of reservoir pressure on production Completion 3.**

Network Simulation Results

Injection well network

The injection sub-network was simulated using the input conditions in Table 18; the resulting pressure and temperature profile across the steam source, compressor, and completion is given in Table 19. Compression raised the steam temperature from 250°F at the source to approximately 722°F at the wellhead, providing the thermal energy required for delivery into the reservoir at the completion.

Table 18. Injection well network — input conditions.

Element	Type	Pressure (psia)	Flow unit	rate	Temperature (°F)	Fluid
Injection well	Well, /Completion	3200	STB/d	680		Water
Steam source	Source	300	STB/d	250		Water

Table 19. Injection well network — simulated output.

Element	Type	Pressure out (psia)	Temperature (°F)
Completion	Completion	3200	708.5
Gas compressor	Compressor	3495.9	721.8
Steam source	Source	300	250
Injection well	Well	9494.8	721.8

Production well network before steam injection

The network simulation (Table 21) also verifies the results from the nodal analysis in Section 4.1, indicating a production rate of 40.3 STB/day, as this is a relatively low rate without steam injection. The produced fluid temperature is also relatively low because of the lack of steam injection, and the pressure drop across the choke, completions and separator, is approximately in the mid-800s.

Table 20. Production well network input conditions before steam injection.

Element	Pressure (psia)	Flow rate unit	Temperature (°F)	Fluid
Completion 1	1500	—	165	Black-oil fluid
Completion 2	1500	—	165	Black-oil fluid
Completion 3	1500	—	165	Black-oil fluid
Oil sink	400	STB/d	—	—
Water sink	200	STB/d	—	—

Table 21. Production well network simulated output before steam injection.

Element	Type	Pressure out (psia)	Temperature (°F)	ST oil rate (STB/d)	WCUT (%)
Production choke	Choke	404.5	553.3 ¹	40.3	0
Completion 1	Completion	1215.4	153.5	40.3	0
Completion 2	Completion	1215.7	161.1	26.5	0
Completion 3	Completion	1269.8	173.7	13.1	0
Oil sink	Sink	400	59.1	40.3	0
Two-phase separator	Separator	400.8	58.4	40.3	0
Production well	Well	405.7	52.0	40.3	0

¹ Reported as in the original simulation output; the anomalously high value at the choke is most likely a units/reporting artifact in the source data and should be re-verified against the PIPESIM case file before publication.

Production well network after steam injection

The simulated network (Table 23) indicates that the 680°F reservoir and completion temperatures (post-injection conditions) yield an oil production of 2655.6 STB/day at 76% water cut, significantly higher than the pre-injection case, and in good agreement with the results of nodal analysis (Section 4.2).

Table 22. Production well network input conditions after steam injection.

Element	Pressure (psia)	Flow rate unit	Temperature (°F)	Fluid
Completion 1	1500	—	680	Black-oil fluid
Completion 2	1500	—	680	Black-oil fluid
Completion 3	1500	—	680	Black-oil fluid
Oil sink	400	STB/d	—	—
Water sink	200	STB/d	—	—

Table 23. Production well network simulated output after steam injection.

Element	Type	Pressure out (psia)	Temperature (°F)	ST oil rate (STB/d)	WCUT (%)
Production choke	Choke	400.0	674.8	2,655.6	76
Completion 1	Completion	980.3	688.3	2,655.6	76
Completion 2	Completion	1,007.5	689.3	1,760.6	76
Completion 3	Completion	1,021.1	690.3	877.4	76
Oil sink	Sink	400.0	688.3	2,655.5	0
Water sink	Sink	200.0	673.8	0	100
Two-phase separator	Separator	400.0	673.6	2,655.6	0
Production well	Well	428.9	675.2	2,655.6	76

Optimized network configuration

The production network was re-simulated using the best parameter values determined in the sensitivity analysis (Section 4.3), an expanded tubing and flow-line ID, an increased choke size and operation at low water cut and near optimum reservoir temperature to produce the optimum configuration of the production network shown in Table 24. In comparison to the un-optimized post-injection scenario (Table 23), the optimized scenario results in a corresponding improvement in stock-tank oil rate from 2655.6 to 2678.8 STB/day at 76% water-cut, showing that the combined optimization provides a measurably incremental improvement in production once the base case is already optimized for steam injection.

Table 24. Production well network optimized configuration.

Element	Type	Pressure out (psia)	Temperature (°F)	ST oil rate (STB/d)	WCUT (%)
Production choke	Choke	414.4	673.6	2,678.8	76
Completion 1	Completion	962.3	688.5	2,678.8	76
Completion 2	Completion	989.6	689.4	1,776.1	76
Completion 3	Completion	1,003.1	690.4	885.1	76
Oil sink	Sink	400.0	671.3	2,678.7	0
Water sink	Sink	200.0	673.8	0	100
Two-phase separator	Separator	400.4	673.2	2,678.8	0
Production well	Well	447.7	673.7	2,678.8	76

Discussion

The nodal analysis and network simulation results indicate that in this heavy, dead-oil reservoir the deliverability of the well is mainly due to steam injection, and that the production rate is approximately 2 orders of magnitude larger than in the unheated case. From the above parameters of surface and completion, the optimum production increase is up to certain level of the tubing ID, flow-line ID, choke size and reservoir pressure after which further increase in these parameters do not provide significant increase in production and therefore would not be justified on economic basis; separator pressure also did not show any significant effect on the production

of oil in the region of study and hence can be selected on process basis rather than deliverability basis. The temperature of the reservoirs has a more complicated, non-monotonic response, with the deliverability of fluids reaching a maximum at a temperature in the range of 400°F, and then decreasing at higher temperatures, suggesting that the best reservoir temperature to target is not necessarily the highest possible temperature, but rather the optimum temperature. Clearly, as more water is in the system, less production is possible; further reinforcing the importance of maintaining a proper production level by controlling water handling and steam quality for the long term. The findings for a representative heavy-oil well and network configuration are offered as a practical guideline for sizing surface facilities in the development of similar heavy-oil steam-flooding wells and networks, and application of different reservoir and fluid conditions should be verified.

As a whole, these results indicate that the designing of the surface network can't be separated from the designing of the reservoir process, and that the sizing of the surface network is not more than to make it not be the control resistance after the surface network is designed, otherwise the capital cost of the surface network will be increased without any benefit of the deliverability. Separator pressure, on the other hand, never is a controlling resistance in the range of study and is typically downstream of the choke, and as such largely independent of the balance between inflow and outflow that determines the production capacity of the well. Perhaps most important from an operational point of view, the recovery rate is not monotonically increasing with reservoir temperature; this means that it is not necessary to strive to maximize the steam quality or injection rate, but just to seek the optimum that is observed here, and that a "more heat is always better" design philosophy might actually reduce the recovery relative to the optimum observed here. In addition, the consistency of the reservoir pressure response from all three completion intervals implies that, for this reservoir geometry, the placement of the completion is not as critical as maintaining reservoir pressure and controlling water-cut. Finally, the relatively small incremental benefit of the fully optimized network compared to the post-injection case (which is not optimized on the surface network) suggests that the majority of the production uplift is due to the implementation of the steam injection itself, with the surface network optimization providing a smaller, but still economically significant, secondary benefit. Though these results are based on a single representative well, it is important to keep in mind that these trends may be confounded by transient and multi-well conditions, and future work would benefit from expanding the analysis to these conditions to confirm the generality of these trends.

Conclusions

Overall, this study indicates that the reservoir temperature will rise as a result of the steam injection and this will significantly decrease the viscosity of the dead heavy oil, and permit the production of the heavy oil, plus boost the production rate from the well by nearly one order of magnitude over the no injection case. The internal diameter of the tubing, the internal diameter of the flow line, and the size of the choke all increase production capacity, but only up to a certain point; outside of that point no more production benefit is realized and it is not economically feasible to make them any larger; the effect of the separator pressure on the oil production rate is not measurable in the range of pressures studied. Reservoir pressure is proportional to production and water cut is inversely proportional to the production; in this case, reservoir temperature is not linearly related to production, but has an optimum value of ~400°F, and above this optimum temperature, further heating will decrease production, if not increase. The overall results of the integrated injection and production well network models developed in PIPESIM are able to predict the pressure and temperature distribution in the surface facilities, both before the initiation of steam injection and after steam injection, and they can be used as a useful basis for designing surface equipment for implementing the steam flood in a similar heavy-oil reservoir with validated results. The optimized network configuration, also derived from the sensitivity analysis,

further reinforces the benefits of using nodal analysis in concert with full network simulation when designing surface facilities for steam flooding, as it shows that a proper selection of surface-equipment sizing and operating parameters provides an incremental improvement in production once the steam injection is implemented, even when compared to an un-optimized base case.

Recommendations for Future Work

- Minimisation of heat loss and maintenance of the quality of steam from the generator to the injection wellhead by use of surface heat transfer equipment.
- Discuss how the network model can be extended to a multi-well field pattern, to determine the impact of various injection well patterns and spacing on field-scale sweep and production.
- Use reservoir and network simulation that is transient and time-dependent to capture the evolution of steam breakthrough, steam quality deterioration and rise in water cut as the project progresses beyond the steady-state snapshots used in the present study.
- If available, validate the PIPESIM nodal-analysis and network results with field or pilot-scale steam-flooding results to validate the pressure-gradient correlations and optimum parameter ranges obtained here.
- Include an explicit economic evaluation (e.g. capital and operating cost curves for tubing, flow-line, choke sizing etc.) into the sensitivity analysis, in order to be able to directly convert the "no worthwhile additional benefit" thresholds found in this study into cost-optimal design recommendations.
- Utilize the same nodal-analysis and network-simulation framework to investigate alternative or hybrid thermal EOR strategies (e.g., cyclic steam stimulation or continuous steam stimulation with additives).

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