ARTIFICIAL LIFT INFRASTRUCTURE PLANNING FOR SHALE GAS PRODUCING HORIZONTAL WELLS

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Abstract:

Artificial lift methods (ALMs) are used in horizontal shale-gas-producing wells in order to lift the accumulated fluids in the well and to help sustain well performance. This paper presents deterministic and stochastic mathematical programming models to solve the artificial lift infrastructure planning problem. The decisions are which ALMs to deploy and their installation and removal times. The objective is to maximize (expected) net present value of the well for its lifetime. The deterministic model is a discrete-time large-scale nonconvex mixed-integer nonlinear program (MINLP). Using the special structure of the nonlinear terms, we formulate an equivalent mixed-integer linear program (MILP). A set of formulation tightening constraints are shown to decrease the solution times for both MINLP and MILP up to two orders of magnitude. We incorporate the impact of uncertainty in ALM-dependent production rates, and develop a stochastic mixed-integer linear programming model (SMILP). For the case study, the value of the stochastic solution is $ 163,831, which is a 5 % increase with respect to the deterministic solution.

Keywords

Artificial lift methods, horizontal shale gas, stochastic mixed-integer programming

Introduction

Recent advancements in equipment combined with hydraulic fracturing techniques allowed the production of natural gas from previously inaccessible sources such as shale formations. These developments considerably increased the quantity of shale gas available for production (Robbins, 2013).

The typical lifetime of a horizontal gas well is shown in Figure 1. The production can be categorized into three stages (Bondurant et al., 2007). During the first stage, the well produces naturally. The produced fluids are mostly gas with fine liquid droplets dispersed in it. As the production continues, liquid flowrate decreases faster compared to the decrease in gas flow rate. When the gas flow rate drops below a critical value, i.e., below the loading flowrate, liquid accumulates at the bottom of the well, and gas production stops. During this second stage of production, the well should be deliquified using one or more of the Artificial Lift Methods (ALMs) to maintain production. At the last stage of production, the reservoir pressure decreases below the wellhead pressure, and external energy and mechanical assistance are required to remove the fluids and extend well lifetime. Because large amounts of fluid are injected to the shale formation during the fracturing process, shale gas wells often require deliquification to unload the well relatively quickly, generally within their first or second year of production. Typical lifetime of a well is around 20-25 years, and hence, multiple ALMs may be installed in horizontal wells for achieving desirable well production performance after the first stage.

Artificial lift methods can be divided into two types. Passive systems (e.g., velocity strings, plunger lift and foam lift) naturally carry liquid from the wellbore because

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sufficient energy remains in the reservoir. The active systems (such as sucker rod pump, well head compressors and gas lift) add energy to the system, and are generally implemented once the reservoir pressure drops below the wellhead pressure (Valbuena, 2015).

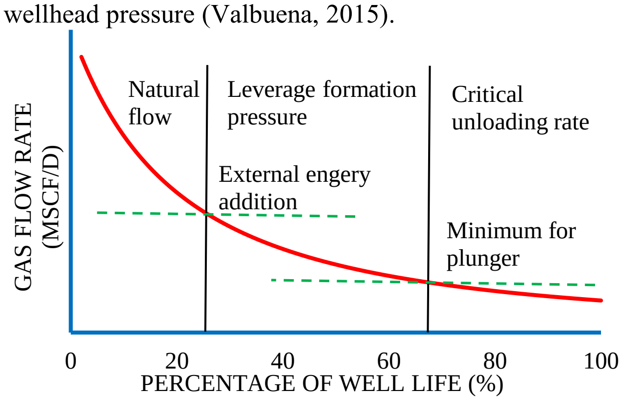

Figure 1. Typical lifetime of a horizontal well

There are several guidelines and expert systems designed for ALM selection in the literature. They mainly use parameters specifying well characteristics, operation envelopes of the ALM methods, and economic criteria to recommend suitable ALMs. In an early example, Clegg (1988) recommended using three economic factors, income, operating cost, and capital cost, in that order as a basis for the selection of ALMs for vertical wells. The first expert systems for ALM selection was introduced by Heinze et al. (1989), and it considered a limited set of well characteristics, and recommended one of the four ALMs based on these characteristics and ALM design requirements. The latest expert system was developed by Valbuena (2015). It first eliminates ALMs using guidelines developed based on the well characteristics, field experience and the operation envelopes of the ALMs. Then, the remaining ALMs are ranked by twenty-four attributes, which are weighted in a scale from 1 to 10 defined by the operators. Finally, an economic evaluation is performed to make the final recommendations. All methods and expert systems, in general, consider the well characteristics at a single point in time and assess the suitability of the ALMs for the well at that point in time. Some of the well characteristics change over the lifetime of the well due to production. Therefore, a systematic approach is needed to incorporate changing well characteristics, consider the interaction of the ALMs with the well and each other, and produce an artificial lift infrastructure plan for the lifetime of the well. The artificial lift infrastructure planning problem is further complicated by uncertain model parameters. Uncertainties in economic parameters and demand are exogenous uncertain parameters. The production performance of the well depends on the selected ALMs. This dependence is currently not well-understood, and its uncertainty is only resolved once the ALM starts operation making it an endogenous uncertainty.

This paper presents mathematical programming approaches to artificial lift infrastructure planning problem for horizontal shale gas producing wells. A discrete-time large-scale nonconvex MINLP is developed to select the optimum ALMs and their installation plan for a given well. Exploiting the special structure of the nonlinear terms in the MINLP, an equivalent MILP is constructed. Finally, we extend the model by incorporating the ALM-dependent production rates. This yields a multistage SMILP with endogenous uncertainty.

Problem Statement

Givens are the characteristics of a candidate horizontal shale-gas well such as its geometry, operating conditions and production performance to date, and the economical parameters such as gas price, natural gas liquid price, and the ALMs' equipment, installation, and operating costs. The goal is to determine the optimal ALM(s) and their installation plan that yield the maximum economic performance for the well. The economic performance is assessed using net present value (NPV) for the MINLP and MILP, and expected NPV (ENPV) for the multistage SMILP.

The Artificial Lift Infrastructure Planning Model

The deterministic MINLP model is given in Figure 2. The planning horizon is discretized into $|T|$ equal time periods (in this case months). The objective is to maximize the NPV that takes into account the costs and financial gains due to production over the life of the well as stated in Eq. (1). Equation (2) estimate the gross income in each month r by deducting local taxes, royalties, and operating and maintenance cost. The binary variable $y_{i,t,p}$ in Eq. (2) becomes one if ALM i is installed at month p and uninstalled at month t. The revenue from gas, oil and natural gas liquids sales are calculated in Eq. (3). Equations (4) – (6) are used to calculate the taxable income. The binary variable x_r, which becomes one if taxable income is negative at month r, avoids deducting federal taxes for months with negative taxable income (Eqns. (1), (5) and (6)). The straight-line n-year depreciation model used in the NPV calculations is given in Eq. (7), and the capital cost is calculated by Eq. (8).

The production flow rate of a horizontal shale-gas well can be described using a modified hyperbolic decline curve function (Fetkovich et al., 1996). These functions are given in Eqns. (9) - (11) for predicting gas (Qg), oil (Qo), and natural gas liquids (Qng) flowrates, respectively, after the well is loaded. The gas production flow rate for month r, Qg_r, depends on the gas flowrate at month (p-1) (i.e., the month prior to the installation of ALM i), Qg_{p-1}, and the flowrate change ratio of the installed method i, Qrc_i. In the current model, it is assumed that the ALMs do not impact the decline curve parameters, b and D (Eqns. (9) – (11)).

Equations (12) - (16) define the ALM installation and removal plan constraints. Equation (12) states that each method can be installed at most once. Equations (13) and

Objective Function
Max: Net Present Value

$$NPV = \sum_r \left\{ (GI_r - TI_r \cdot x_r \cdot FT) \left(\frac{1}{(1+MARR)^r} \right) \right\} - CC(1 - FT) \quad \forall r \in T \tag{1}$$

Subject to
Gross Income

$$GI_r = \left(Rev_r(1-RT)(1-LT) - \sum_{i,t\geq r,p\leq r} \left(Cm_i y_{i,t,p} \right) \right) WI \quad \forall r \in T \tag{2}$$

Revenue

$$Rev_r = P_g Qg_r + P_o Qo_r + P_{ng} Qng_r \quad \forall r \in T \tag{3}$$

Taxable Income

$$TI_r = GI_r - Dep_r \quad \forall r \in T \tag{4}$$

$$TI_r \leq x_r M \quad \forall r \in T \tag{5}$$

$$TI_r > (x_r - 1)M \quad \forall r \in T \tag{6}$$

Depreciation

$$Dep_r = \sum_{i,t\geq r,p\geq r-n+1}^{p\leq r} \left(\frac{Ce_i}{n} y_{i,t,p} \right) \quad \forall t,p,r \in T, i \in I \tag{7}$$

Capital Cost

$$CC = \sum_{i,t,p} \left(Co_i y_{i,t,p} \frac{1}{(1+MARR)^p} \right) \quad \forall t,p \in T, i \in I \tag{8}$$

Decline Curve Function

$$Qg_r = \sum_{i,t,p} \left\{ y_{i,t,p} Qg_{p-1} Qrc_i \left(1 + bD(r-p+1) \right)^{-\frac{1}{b}} \right\} \tag{9}$$

$$Qo_r = \sum_{i,t,p} \left\{ y_{i,t,p} Qo_{p-1} Qrc_i \left(1 + bD(r-p+1) \right)^{-\frac{1}{b}} \right\} \tag{10}$$

$$Qng_r = \sum_{i,t,p} \left\{ y_{i,t,p} Qng_{p-1} Qrc_i \left(1 + bD(r-p+1) \right)^{-\frac{1}{b}} \right\} \tag{11}$$

$\forall t,p,r \in T, i \in I, p \leq r \leq t$

Planning Constraints

$$\sum_{t,p} y_{i,t,p} \leq 1 \quad \forall t,p,r \in T, i \in I \tag{12}$$

$$\sum_{i,t} y_{i,t,p} \leq 1 \quad \forall t,p,r \in T, i \in I \tag{13}$$

$$\sum_{i,p} y_{i,t,p} \leq 1 \quad \forall t,p,r \in T, i \in I \tag{14}$$

$$y_{i,t,p} = 0 \quad \forall t,p \in T, i \in I, t \leq p \tag{15}$$

$$y_{i,t,p} + y_{j,k,l} \leq 1 \quad \forall j \neq i, p+1 \leq l \leq t, t+1 \leq k \leq T \tag{16}$$

Technical Limitation Constraints

$$f_{i,t,p,r}\left(LFR_r, y_{i,t,p} \right) \leq 0 \quad \forall t,p,r \in T, p \leq r \leq t \tag{17}$$

$$g_{i,t,p}\left(y_{i,t,p} \right) \leq 0 \quad \forall t,p,r \in T \tag{18}$$

Nomenclature

Sets

$i, j \in I$ = Set of ALMS
$r, t, p, l, k \in T$ = Sets of operating months

Parameters

Pg = Price of gas
Po = Price of oil
Png = Price of natural gas liquid
Cm_i = Operating cost of method *i*
Co_i = Equipment and installation cost of method *i*
Ce_i = Equipment cost of method *i*
$MARR$ = Minimum acceptable rate of return
b = Decline exponent constant
D = Nominal decline rate
LT = Local tax rate
RT = Royalty tax rate
FT = Federal tax rate
WI = Working interest
Qrc_i = Flowrate change ratio when ALM i is installed
M = Upper bound of the taxable income at month r

Variables

Qg_r = Gas flow rate at month r
Qo_r = Oil flow rate at month r
Qng_r = Natural gas liquid flow rate at month r
LFR_r = Liquid flow rate, depends on oil flow rate and natural gas liquid flow rate at month r
TI_r = Taxable income at month r
GI_r = Gross income at period r
Dep_r = Depreciation at period r
CC = Total equipment and installation cost

Binary Variables

$$y_{i,t,p} = \begin{cases} 1 \text{ if method } i \text{ installed at month } p \\ \quad \text{and uninstalled at month } t \\ 0 \qquad\qquad otherwise \end{cases}$$

$$x_r = \begin{cases} 1 \text{ if taxable income is negative} \\ \qquad\qquad \text{at month } t \\ 0 \qquad\qquad otherwise \end{cases}$$

Figure 2 The MINLP of the Horizontal shale gas model

(14) limit the number of ALMs that can be installed at any given month to a maximum of one. Equation (15) ensures that an ALM is installed before its removal. The last constraint, Eq. (16), prevents the overlap of two ALMs.

Each ALM has defined design and operational limitations such as the Artificial Lift R&D Council guidelines, and limitations stated in typical attribute tables (e.g., Weatherford, 2013). These limitations are incorporated as technical limitation constraints in the model. The most common limitation deals with the liquid flow rate ranges that an ALM can be operated (Eq. (17)). For example, the Weatherford (2013) attribute table sets the maximum flow rate a plunger lift can operate as 200 barrels per day (BPD). Therefore, one of the constraints in Eq. (17) set is Eq. (19), where $i = 1$ for plunger lift.

$$y_{1,t,p} LFR_r \leq 200 \qquad \forall t,p,r \in T, p \leq r \leq t \tag{19}$$

The remainder of the technical limitation constraints can be expressed using the binary decision variable $y_{i,t,p}$ and relevant well or ALM parameters as stated in Eq. (18). For example, Donald et al. (2014) recommends that candidate wells for well head compression should have less than 1100 psi (80 bar) closed-in tubing head pressure ($CITHP$) and less than 175 psi (12 bars) flowing tubing head pressure ($FTHP$). Equations (20) and (21) formulate these statements for wellhead compression where $i = 3$.

$$y_{3,t,p} FTHP \leq 175 \qquad \forall t,p \in T \tag{20}$$

$$y_{3,t,p} CITHP \leq 1100 \qquad \forall t,p \in T \tag{21}$$

Equations (1) through (18) form the large-scale non-convex MINLP model of the artificial lift problem.

Reformulated MILP model

The nonlinear terms of the MINLP model are in the decline curve constraints (Eqns. (9) -(11)), in the objective function (Eq. (1)), and in technical limitation constraints (Eqns. (18) and (19)). They have a special structure, and are the multiplications of a binary variable with a continuous variable (such as ($y_{i,t,p}Qg_{p-1}$), ($y_{i,t,p}LFR_r$), and ($TI_r x_r$)). We use exact linearization for replacing these nonlinear terms with linear equivalents (Oral et al., 1990).

To remove the nonlinear term $y_{i,t,p}Qg_{p-1}$ in the decline curve constraints, we introduce three new continuous variables, $yQg_{i,t,p,r}$, $yQg1_{i,t,p,r}$, and $Qge_{i,t,p,r}$, and replace Eq. (9) with the constraints given in Eqns. (22) - (27).

$$Qg_r = \sum_{i,t,p} yQg_{i,t,p,r} \tag{22}$$

$$Qg_{i,p,r} = Qg_{p-1} Qrc_i \left(1 + bD(r-p+1)\right)^{-\frac{1}{b}} \tag{23}$$

$$yQg_{i,t,p,r} + yQg1_{i,t,p,r} = Qg_{i,p,r} \tag{24}$$

$$yQg_{i,t,p,r} \leq y_{i,t,p} Qg_0 \tag{25}$$

$$yQg1_{i,t,p,r} \leq (1 - y_{i,t,p}) Qg_0 \tag{26}$$

$$yQg_{i,t,p,r} \geq 0, yQg1_{i,t,p,r} \geq 0 \tag{27}$$

$$\forall t,p,r \in T, i \in I, p \leq r \leq t$$

Equation (22) calculates the gas production flowrate at month r. The variable $Qg_{i,p,r}$ calculated in Eq. (23) is the gas flow rate at month r for ALM i that is installed on month p and uninstalled on month t. Equation (25) ensures that the variable $yQg_{i,t,p,r}$ becomes zero if ALM i is not operational at month r. The parameter Qg_0 is set equal to the maximum possible gas flowrate for the problem.

Incorporating Uncertainty – A Stochastic Programming Model

Let ξ_i represent the random variable associated with the endogenous uncertain parameter Qrc_i (flowrate change ratio when ALM i is installed). It is assumed that ξ_i has two outcomes with equal probabilities, i.e., $\Omega_i = \{\text{High(H)}, \text{Low(L)}\}$. The scenario set, $s \in \boldsymbol{S}$, is generated as the Cartesian product of all possible outcome sets, and given that there are eight ALMs, $|S| = 2^8 = 256$. The deterministic equivalent of the stochastic program is obtained by appending the subscript s to all variables to represent their values under scenario s, and adding non-anticipativity constraints (NACs) explicitly.

To define NACs, we introduce two binary variables, $w_{i,p,s}$ and $z_{i,t,s}$, which satisfy the logical expression:

$$y_{i,\text{t,p},s} \Leftrightarrow w_{i,\text{p,s}} \wedge z_{i,\text{t,s}} \tag{28}$$

Equations (29) - (31) translate the logical expression given in Eq. (28) into constraints. Equation (32) prevents ALMs to be uninstalled without installation.

$$y_{i,\text{t,p},s} \geq z_{i,\text{t,s}} + w_{i,\text{p,s}} - 1 \qquad \forall i \in I, t,p \in T, s \in \boldsymbol{S} \tag{29}$$

$$z_{i,\text{t,s}} \geq y_{i,\text{t,p},s} \qquad \forall i \in I, t,p \in T, s \in \boldsymbol{S} \tag{30}$$

$$w_{i,\text{p,s}} \geq y_{i,\text{t,p,s}} \qquad \forall i \in I, t,p \in T, s \in \boldsymbol{S} \tag{31}$$

$$\sum_p w_{i,p,s} - \sum_t z_{i,t,s} = 0 \qquad \forall i \in I, s \in \boldsymbol{S} \tag{32}$$

The first set of NACs (Eq. (33)) are for $p = 2$, the installation time of the first ALM. Note that our model assumes the well loaded at the first time period, and the first ALM selected is installed at the second time period. At this stage, all scenarios are indistinguishable because none of the ALMs is installed.

$$w_{i,2,s} = w_{i,2,1} \qquad \forall\, i \in I, s \in \boldsymbol{S}/\{1\} \tag{33}$$

We define the subset $\boldsymbol{B} \subset \boldsymbol{S} \times \boldsymbol{S}$ for scenarios s and s' which differ in the outcome of one method**.** The remaining NACs for scenario pairs$(s,s') \in \boldsymbol{B}$ should be active until the differentiating event occurs. After ALM i is uninstalled at period t, the decision variable to install other methods $j \neq i$ after t should be indistinguishable for scenarios s and s'. Thus, the remaining NACs can be expressed with Eq. (34), which is converted to Eqns. (35) and (36).

$$\begin{bmatrix} z_{i,t,s} \\ w_{j,l,s} = w_{j,l,s'} \end{bmatrix} \vee \left[\neg z_{i,t,s} \right] \qquad \forall l \geq t+1, (s,s') \in \boldsymbol{B} \quad (34)$$

$$w_{j,l,s} - w_{j,l,s'} \leq 1 - z_{i,t,s} \qquad \forall l \geq t+1, (s,s') \in \boldsymbol{B} \quad (35)$$

$$w_{j,l,s} - w_{j,l,s'} \geq z_{i,t,s} - 1 \qquad \forall l \geq t+1, (s,s') \in \boldsymbol{B} \quad (36)$$

Case Studies

We use the deterministic models for planning ALM infrastructure for two case studies of Woodford Shale Horizontal Well: (I) a high liquid flowrate well, and (II) a low liquid flowrate well (Valbuena, 2015). The planning horizons were up to 48 months. The impact of uncertain production is studied using the high liquid flowrate well. The mathematical programs are modeled in GAMS 24.6.1 and solved using a Lenovo ThinkStation P900 with Intel 2.3 GHz CPU and 24 GB RAM. The MILP are solved using CPLEX 12.6.3, and the MINLP are solved with SCIP 3.2.

Field Application: Woodford Shale Horizontal Well

The horizontal high flowrate well was hydraulically fractured in eight different stages. The average production conditions indicated a gas rate of 800 thousand standard cubic feet per day (Mscf/D), a liquid rate of 520 BPD (of which 500 barrels were water and the remaining oil), a water cut of 96%, a gas-liquid ratio of 1,950 standard cubic foot per stock tank barrel (scf/STB). The well is currently operated with gas lift using a well-site compressor. However, recently the liquid production dropped to around 300 BPD, which may indicate that liquids are being left at the bottom of the well, causing unstable and intermittent production. The low liquid flowrate well is currently operated with a plunger installed at 7,261 ft. measured depth and 68° with a stop collar. The production history shows erratic behavior. It is assumed that the production stopped, and the ALM installation will restore the production from the initial gas production of 200 Mscf/D.

Comparison of MINLP and MILP on Case I

The artificial lift infrastructure planning problem for Case Study I is solved for planning horizons of 12, 18 and 24 months using the MINLP and the MILP models. The maximum CPU time was limited to 10 hours. The results are summarized in Table 1. Both models recommend installing Sucker Rod Pump (SRP) for the overall planning horizon for problems solved to optimality. Due to the large upper bound, the MINLP solution for planning horizon of 24 months has a relative gap of 54.26% at 10 CPU hours. The results in Table 1 reveals that the solution time changes significantly with the length of the planning horizon.

Table 1. Deterministic solution of Case Study I

		Solution time (s)			
Month	NPV ($)	MINLP	MILP	TMINLP	TMILP
12	2805092	24	4	7	1
18	3714696	519	101	138	5
24	4418921	NA	978	741	22

Valid Inequalities Based on Problem Characteristics

The operation envelopes for liquid and gas flowrates of many ALMs are relatively large. For example, Weatherford (2013) indicates that the maximum operating flowrate for rod pumps is 6000 BPD. These envelopes are directly translated to technical limitation constraints in Eqns. (17) and (18). However, at any time period, the production flowrate cannot be larger than the amount dictated by the decline curve obtained assuming that the ALM with the highest Qrc_i is installed. Equations (37) – (40) translate this physical limitation into inequality constraints that bound the liquid, gas, oil and natural-gas-liquids flowrates, respectively. These equations are added to the original MINLP and MILP to tighten their formulations, and the new models are called TMINLP and TMILP.

$$LFR_r \leq LFR_1 Max_{i \in I}\{Qrc_i\}\big(1 + bD(r - p + 1)\big)^{-\frac{1}{b}} \qquad (37)$$

$$Qg_r \leq Qg_1 Max_{i \in I}\{Qrc_i\}\big(1 + bD(r - p + 1)\big)^{-\frac{1}{b}} \qquad (38)$$

$$Qo_r \leq Qo_1 Max_{i \in I}\{Qrc_i\}\big(1 + bD(r - p + 1)\big)^{-\frac{1}{b}} \qquad (39)$$

$$Qng_r \leq Qng_1 Max_{i \in I}\{Qrc_i\}\big(1 + bD(r - p + 1)\big)^{-\frac{1}{b}} \qquad (40)$$

$\forall p, r \in T, i \in I, p \leq r$

Table 1 compiles the solutions obtained using TMINLP and TMILP for Case Study I. The optimality gaps of the solutions presented in Table 2 are 0% for both MINLP and MILP models. Comparing the results given in Table 1 reveals that the additional inequality constraints reduces the solution times up to two orders of magnitude both for MINLP and MILP models. The inclusion of MINLP models in this analysis allow the study of inequality constraint impacts on their solution times. The planning problems of Case Studies I and II are solved to optimality using the TMILP formulation for planning horizons up to 48 months. Results are compiled in Table 2. The solutions reveal that a single ALM is installed and operated until the end of the planning horizons for all cases considered. For Case Study I, the optimal ALM is the Sucker Rod Pump. For Case Study II, which has a low liquid flowrate, the optimal ALM is Sucker Rod Pump (SRP) if the planning horizon is 12 months, Well Head Compression (WHC) for the planning horizon of 24 months, and Velocity String (VS) for planning horizons of 36 and 48 months. The flowrate change ratio of SRP is higher than WHC and VC, and it has lower operating costs. However, the liquid flowrate drops below the minimum allowable value for SRP for planning horizons longer than 12 months. Because the production is relatively low from this well, the model favors installation of an ALM that can be operated for the whole planning horizon. For longer planning horizons (36 and 48 months), the VS is preferred over WHC due to its lower operating costs.

Table 2. The solution of Case Studies I and II using TMILP model

	Months	NPV($)	Time(s)	Optimal ALM
Case I	12	2805092	1	SRP
	24	4418921	22	SRP
	36	5424537	154	SRP
	48	6093133	129	SRP
Case II	12	129811	0.8	SRP
	24	203164	12	WHC
	36	257223	82	VS
	48	296336	288	VS

A Hypothetical Case Study of SMILP

The hypothetical case study is generated based on Case Study II, and obtained by changing the operational envelop of SRP from 6000-10 BPD to 6000-260 BPD. There are only three suitable methods for the hypothetical case study (Sucker Rod Pump, Electrical Submersible Pump and Gas Lift), which reduces the number of scenarios to eight: $s_1 = (H,H,H)$; $s_2 = (H,H,L)$; $s_3 = (H,L,H)$; $s_4 = (H,L,L)$; $s_5 = (L,H,H)$; $s_6 = (L,H,L)$; $s_7 = (L,L,H)$; $s_8 = (L,L,L)$. For uncertain parameter Qrc_i, the value of the outcome H is assumed to be 20% above its nominal value, and the value for L 20% below the nominal. The planning horizon is 16 months. The optimum solution is given in Table 3. The ENPV is $3,416,507, and the SMILP was solved in 4659 CPU seconds.

Table 3. The SMILP solution

Months	Scenarios							
	1	3	5	7	2	4	6	8
t=2	SRP							
t=7	SRP				ESP			

The first ALM installed is SRP for all the scenarios. At the 7th month, the ESP is installed under scenarios 2, 4, 6, and 8 while SRP stays operations for the rest. The liquid flow rate drops below the operational envelope of SRP for scenarios with low outcome of Qrc_{SRP}.

Assuming nominal values of Qrc_i, the solution of the deterministic model recommends operating SRP throughout the planning horizon. If the deterministic solution were implemented, the ENPV would have been $3,252,676. The difference between the ENPV of the stochastic and this solution, i.e., , the value of the stochastic solution, is $163,831, a 5% increase.

Conclusions and Future Recommendations

This paper presented three optimization models for artificial lift infrastructure planning of shale gas producing horizontal wells. First, we developed a discrete-time, large-scale, nonconvex, mixed-integer nonlinear programming model (MINLP) considering the possibility of multiple different artificial lift methods installed over the lifespan of a well. The original model incorporates technical limitation constraints such as the operational and design limitations of each ALM, previous expert experience and limitations stated in the typical attribute tables. Then, a mixed-integer linear programming model (MILP) is obtained by linearizing the original MINLP model. A set of valid inequalities are introduced to tighten both MINLP and MILP models, and they reduced the solution times up to two orders of magnitude. Last, a stochastic mixed-integer linear programming model (SMILP) is developed to incorporate the impact of uncertain outcomes of production rates for each artificial lift methods. Future work will focus on studying the impact of exogenous uncertainties.

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