A Mixed Integer Linear Programming Model for the Optimal Operation of a Network of Gas Oil Separation Plants

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Abstract

Inspired from a real case study of a Saudi oil company, this work addresses the optimal operation of a regional network of gas-oil separation plants (GOSPs) in Arabian Gulf Coast Area to ultimately achieve higher savings in operating expenditures (OPEX) than those achieved by adopting single-surface facility optimisation. An originally tailored and integrated mixed integer linear programming (MILP) model is proposed to optimise the crude transfer through swing pipelines and equipment utilisation in each GOSP, to minimise the operating costs of a network of GOSPs. The developed model is applied to an existing network of GOSPs in the Ghawar field, Saudi Arabia, by considering 12 different monthly production scenarios developed from real production rates. Compared to rule-based current practice, an average 12.8% cost saving is realised by the developed model.

Keywords: upstream oil and gas industry, gas oil separation plant, operating expenditures, mixed integer programming

1. Introduction

In the upstream oil and gas industry, a surface separation facility is called a gas-oil separation plant (GOSP). Every GOSP receives its feed from several wells located municipally around the GOSP (Abdel-Aal et al., 2003). Some of these wells are dry and some are wet (contain associated water). Figure 1 shows a holistic view of a complete single upstream field where the GOSP is located in the middle, and crude wells are connected to it through pipelines. Also, the GOSP is connected to disposal wells, which receive treated gas and/or water from the GOSP to boost up the reservoir pressure and enhance oil production and sweep in the subject area (Raju et al., 2005).

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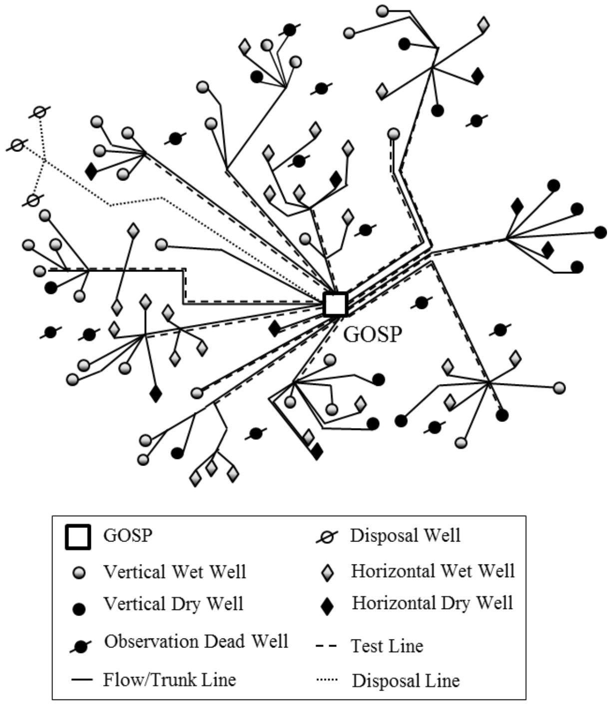


Figure 1. Schematic Layout of a GOSP and its Wells

In rich oil areas, such as the Arabian Gulf coast countries, large numbers of GOSPs exist near each other within the same geological area to serve the high demands of production. Typically, each well serves only one GOSP due to the high cost of pipelines that would be required to connect the wells to more than one GOSP. Some of these GOSPs are connected together laterally through swing pipelines, which allow the transfer of production from GOSP wells to be treated in another GOSP. The purpose of these swing pipelines is to provide a backup route of production from all wells in case of any breakdown or during the planned or unplanned shutdown of a GOSP to avoid any intermittent production. These pipelines are constructed only between nearby GOSPs where wells can free flow naturally based on excess reservoir pressure without the need to use any artificial surface boosting or subsurface lifting. Thus, no pump is required and no cost occurs for the production transfer. Figure 2 shows an example of a network of GOSPs connected by swing pipelines. The production from the wells of a GOSP can be produced through the same GOSP or diverted partially/completely to one of the connected GOSPs for processing. It is worth noting that the existence of these swing pipelines is rare and they are found in only a few applications, as shown in the case study of this paper. Consideration of these swing pipelines for new projects is increasing due to their added flexibilities and tangible benefits in many aspects.

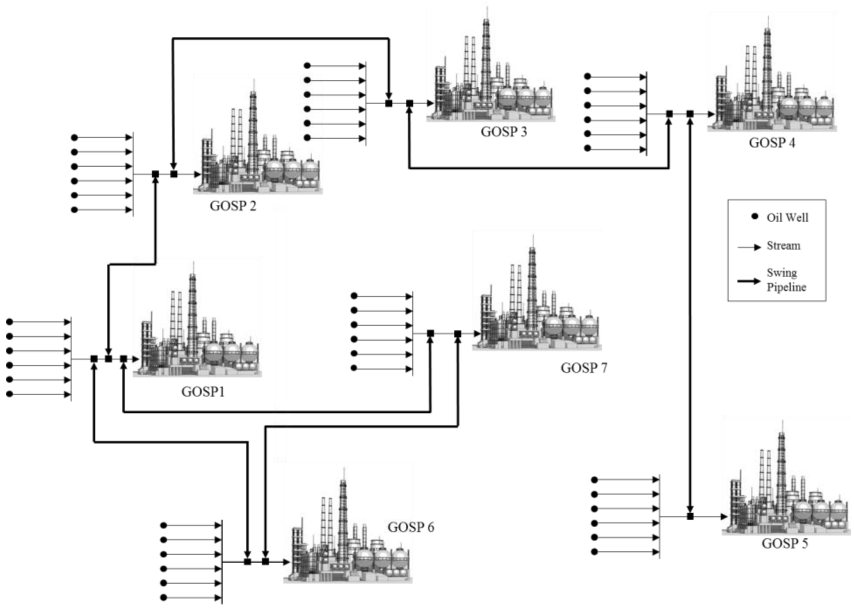


Figure 2. Example of a network of GOSPs

At an area containing several GOSPs, the network of swing pipelines may be used for an additional purpose, which is integrating production rates laterally between the facilities to optimise chemicals consumption and equipment power consumption, while maintaining the assets in their best mode of operation. Finding the optimum allocation strategy utilising the swing pipelines is very complicated and requires the careful consideration of thousands of variables. These GOSPs contain hundreds of equipment with different flow vs. power curves and different chemicals consumption relationships and costs, not to mention the various constraints from all aspects. An opportunity was spotted for the potential optimisation of the whole network as a single node by developing an integrated optimisation model with an objective function targeting a combined reduced operating expenditure (OPEX) of GOSPs.

The OPEX of the upstream sector in the oil and gas industry has been consistently rising over the past years, and will continue to rise in a trend (HIS, 2012). In addition, the fluctuation and uncertainty of oil prices put more pressure on the upstream sector to find effective means to cut down their OPEX and increase their profit margin. Power and chemical consumption costs of GOSPs are considered one of the major cost contributors to the upstream OPEX. A saving of even 1% of these costs could represent a 7 figure USD value for a company as big as the one considered for this paper's case study. Therefore, it is very critical for the upstream sector to find innovative approaches such as the model presented by this paper, and adapt them to face their challenges. In order to accurately calculate the OPEX, especially the power consumption cost, it is important to consider the details of individual equipment, such as pumps and compressors. Given that each equipment has its own unique power vs. flow curve, and the flow rate for each equipment is not only determined by production transfer decisions, but also by the number of selected running equipment units, it is critical to consider equipment specific details to achieve the optimal power consumption.

The aim of this work is to develop an original and integrated mathematical model for the optimal operation of an existing network of GOSPs in Arabian Gulf Coast Area to minimise its OPEX. To the best of our knowledge, it is the first work focuses on the optimisation of operational decisions with the lateral integration among multiple upstream surface separation facilities to achieve the minimum OPEX.

The structure of this paper is organised as follows: Section 2 discusses the major optimisation work on the oil and gas upstream sector with a focus on GOSPs optimisation. Section 3 presents a mixed integer linear programming (MILP) model. Then a case study of a production area in Saudi Arabia is presented in Section 4, followed by the results presentation and discussion in Section 5. Finally, the conclusion is given in Section 6.

2. Literature Review

The petroleum industry has been given huge attention academically and industrially for its dominance and effect on the global economy. The optimisation literature covers a wide range of subjects, from short-term scheduling to strategic supply chain planning (Shah, 1996; Moro and Pinto, 2004; Neiro and Pinto, 2004; Relvas et al., 2006; Fernandes et al., 2013; Tavallali and Karimi, 2014; Sahebi et al., 2014). Given the maturity of the industry, applications of mathematical programming have been employed since 1940s (Bodington and Baker, 1990). Schlumberger (2005) classified the optimisation problems in the upstream sector to four groups, including operator optimisation, production optimisation, field optimisation and reservoir recovery optimisation, with time scales from seconds to years. This work will address the production optimisation for one day to a few months, which is also called real-time production optimisation (RTPO) (Gunnerud and Foss, 2010). Another grouping, based on the scope and function, was suggested by Wang (2003). The author reviewed optimisation problems in the upstream sector and classified them into three main categories: lift gas and production rate allocation; optimisation of production system design and operations; and optimisation of reservoir development and planning. Ulstein et al. (2007) divided the upstream optimisation planning problems to operational, tactical and strategic problems, which, to a certain degree, is also compatible with that of Wang (2003) and Schlumberger (2005).

In the literature, there are lots of literature work focusing on the optimisation of design and planning of production networks in oil fields, including subsurface and/or surface facilities. Iyer et al. (1998) developed an mixed integer nonlinear programming (MINLP) model for the planning and scheduling of investment and operation in offshore oil field facilities, including the selection of reservoirs, well sites, well drilling, and platform installation schedule and capacities of well and production platforms. van den Heever et al. (2001) proposed an MINLP optimisation model for the design and planning of offshore hydrocarbon field infrastructures and developed a Lagrangean decomposition solution procedure. Goel and Grossmann (2004) addressed the optimal investment and operational planning of gas field developments under uncertainty in gas reserves using stochastic programming. Cullick et al. (2004) developed an framework for the optimal reservoir planning and management under the uncertainty of associated risks. Kosmidis et al. (2005) proposed an MINLP optimisation model and a solution procedure for the well scheduling problem considering the optimal connectivity of wells to manifolds and separators, as well as the optimal well operation and gas lift allocation. Foss et al. (2009) proposed a Lagrangian decomposition method for a well allocation and routing optimisation problem. Gunnerud and Foss (2010) presented an MILP model for the real-time optimisation of process systems with a decentralized structure, which was solved using Lagrangian decomposition and Dantzig-Wolfe decomposition. These work was extended to the use of parallelization of Dantzig-Wolfe decomposition (Gunnerud et al., 2010; Torgnes et al., 2012) and Brach & Price decomposition (Gunnerud et al., 2014). Rahmawati et al. (2012) addressed the integrated field operation and optimisation by developing an optimisation framework integrating reservoir, well vertical-flow, surface-pipeline and surface-process, thermodynamic and economic models. Codas et al. (2012) used piecewise linearisation to develop an MILP model integrating simplified well deliverability models, vertical lift performance relations, and the flowing pressure behavior of the surface gathering system. Tavallali et al. (2013) developed an optimisation model for the optimal producer well placement and production planning in an oil reservoir, and extended for multireservior oil fields with surface facility networks (Tavallali et al., 2014). Silva and Camponogara (2014) developed an integrated production optimisation model for complex oil fields, considering the production network structure.

However, in the literature, the operational decisions of GOSP network, as focused in this work, was given little attention, possibly due to the unconventional nature of the project, as surface facilities usually stand solo with no connections or integration with nearby similar purpose facilities. Figure 3 shows the common boundaries in the upstream real-time optimisation problems related to surface facilities (dash line). The objective of the literature model is either oil production maximisation, single facility OPEX minimisation, or NPV maximisation. None of the literature work has considered multiple production trains in a single model to optimise combined OPEX. The optimisation boundary targeted by this work is illustrated by the solid line. It is important to highlight that this boundary does not overlap with existing upstream real-time optimisation models. On the contrary, the proposed optimisation model in this work could be applied sequentially after the optimisation within any other boundaries in a complementary manner.

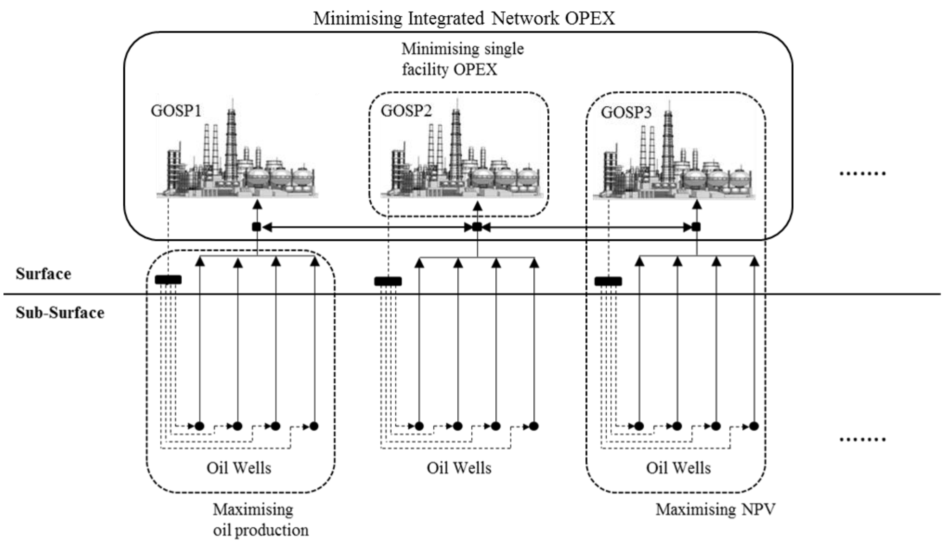


Figure 3. Research boundary comparison between this work and the literature work on the upstream real-time production optimisation

3. Problem Statement

In this work, we address the optimal operation of a network of GOSP's, considering the crude transfer via swing pipelines and operation mode of the equipment in the process of each

GOSP. A GOSP is considered to be the first crude treatment process to provide preliminary separation of the crude to gas, oil and water. Its objective is mainly to separate gas, water and contaminants from the oil and treat the three products to the required specifications. Then, oil and gas are streamed to oil refineries and gas processing plants, respectively, for further processing. Water, and sometimes part of the gas, is injected back in the reservoir, depending on the oil recovery enhancement strategy of the production field. The main operations within a GOSP can be summarised as follows:

- Separation; separating the gas, oil and water from produced wellhead streams through multiple tasks
- Dehydration; removing water droplets emulsified within the oil
- Desalting; reducing the salt content of the crude by diluting associated water and then dehydrating

Beside the crude received from the wells, GOSPs consume chemicals as raw materials for different purposes. The main chemicals consumed are:

- Demulsifier; to enhance the separation between oil and water in highly emulsified mixtures
- Corrosion inhibitor; mainly to prevent corrosion development in metal pipelines
- Scale inhibitor; to prevent any scale build-up in the containers.

GOSP capacities vary greatly from approximately 20 thousand barrels per day (kbd) to 400 kbd of oil. The capacity of a GOSP is designed based on the the forecasted production rates for the associated field wells. A standard GOSP size in our case study is around 330 kbd. These facilities require intensive power supply to run the various rotating equipment contained. The major sets of power equipment are:

- Charge pumps (two-phase pumps, oil and water)
- Injection pumps (water)
- Boosting pumps (oil)
- Shipper pumps (oil)
- High pressure (HP) compressors (gas)
- Low pressure (LP) compressors (gas)

Every GOSP has the same set of equipment but varies greatly when it comes to capacity, efficiency and number of equipment items depending on the age, design parameters and philosophy. In each GOSP, the number of operating equipment items and their operation modes has significant effects on power consumption, which can represent a large portion of the OPEX in the upstream.

The GOSPs considered here are connected by swing pipelines. Although the production rates of each GOSP are originally determined by its wells' production, its actual production rates can be reallocated by transferring crude to the nearby GOSPs through swing pipelines. The final inlet feed of each GOSP, after crude transfer, can determine the amount of chemicals for the separation and the flow rates of operating equipment. Therefore, in this work, we aim to find the optimal production transfer between GOSPs and the equipment operation modes within each GOSP, with a minimum total OPEX of the network of GOSPs considered.

There are some assumptions made for the optimisation problem in this work, as listed below:

- Crude can be transferred from selected wells of one GOSP to another using the swing pipelines without any back-effect on well productivity.
- Temperature drops in the crude when it is transferred from one GOSP to another are ignored here due to the fact that all transfer pipelines are internally coated and buried underground, which preserves the temperature with very minimal loss.
- Given that all nearby GOSPs have very similar crude characteristics, the effect of crude mixing on the chemicals consumption was ignored.
- Component separation fractions from the vessels were assumed to be constant. For gas-oil separation, it is highly dependent on separator pressure, which is fixed. For water-oil separation, the automated demulsifier injection system at these GOSPs maintains the separation of water and oil at steady fractions.
- The flow vs. power curve of each equipment item can be represented by quadratic polynomials.
- All parallel equipment for the same task has identical characteristics.
- Equipment serving the same task shares a common suction and so the load is equally shared among the operated ones.
- Discharge pressure requirements are not considered directly. The equipment minimum and maximum flow rates take into account the system required pressure,

and ensure that the equipment can always overcome the discharge pressure if it operates within a certain window of flow rates.

- A recycle mode of operations is not allowed. The assigned minimum flow rate for each piece of equipment is actually its minimum recycle flow rate to avoid any recycle operations.
- The reservoir effects in terms of variations in GOSP injected water are ignored. The GOSP injected water serves as a secondary source of the injected water in the reservoir, while the main source comes from treated seawater plants.
- Only power consumption costs of the liquid pumps and gas compressors are considered, as they contribute most of the operating cost. Common and trivial power consuming items, such as air conditioning and lighting, are ignored in power cost, and are considered under fixed operating cost, which also includes the manpower cost and maintenance and service cost.
- As demulsifier accounts for over 90% of the total chemicals cost; other chemicals cost is ignored in this problem.
- The added freshwater and salty water are mixed and considered as water, one of the final products.

Based on the above assumptions, the considered optimisation problem is described as follows:
Given are:

- A network between GOSPs with swing pipeline connections;
- GOSP capacities for each component;
- daily initial designated flow rate for each GOSP;
- capacities of the swing pipelines connecting any two GOSPs;
- fixed operating cost and operating time of each GOSP;
- process flow sheet within each GOSP;
- available equipment, their minimum/maximum capacities, power consumption curves, and the separation fractions of all components;
- chemicals consumption equations based on treated production rates; and
- chemical and electricity prices;

to determine:

- GOSP selection;
- swing pipeline selection;

- transferred flow rates through swing pipelines;
- final inlet crude flow rates of each component; and
- equipment selection and operating rates;

so as to

- minimise the total OPEX, including power and chemicals consumption costs, and fixed operating cost.

4. Mathematical Formulation

In this section, we present a static MILP model for the OPEX minimisation of a network of GOSPs in a fixed planning horizon. The notation used in the model is presented below:

Indices

g, g'	Gas-oil separation plant, GOSP
c	Component = {oil, water, gas, demulsifier, freshwater}
j	Operating equipment/unit
i	Task
s	Produced and consumed states
k	Break point in piecewise linearisation

Sets

J_{gi}	Equipment performing the task *i* in GOSP g
I^R	Tasks by rotating equipment (pumps + compressors)
I^P	Tasks by pumps
G_g	GOSPs connecting GOSP g through swing pipelines
S_i	State produced or consumed by task *i*
S^{IN}	Intermediate state
S^{RM}	Raw material state
S^P	Product state

Parameters

a_{gi}	second order coefficient in flow vs. power curve for task *i* in GOSP g
b_{gi}	first order coefficient in flow vs. power curve for task *i* in GOSP g
c_{gi}	constant coefficient in flow vs. power curve for task *i* in GOSP g
CC_{gc}^{max}	Maximum component capacity in GOSP g
CC_{gc}^{min}	Minimum component capacity in GOSP g
$ChemC_g$	Chemicals market price for GOSP g
FOC_g	Fixed operating cost for GOSP g
FW_g	Freshwater consumption in GOSP g
IF_{gc}	Initial designated flow rate of component *c* for GOSP g
OT	Operating time
Pc	Power market price
Pik_{gik}	Power at breakpoint *k* for task *i* in GOSP g

Pj_{gij}^{max}	Maximum power consumption of equipment *j* for task *i* in GOSP g
Rj_{gj}^{max}	Maximum capacity rate for equipment *j* in GOSP g
Rj_{gj}^{min}	Minimum capacity rate for equipment *j* in GOSP g
Rik_{gik}	Operating rate at breakpoint *k* for task *i* in GOSP g
$SPC_{gg'}^{max}$	Maximum swing pipeline capacity from GOSP g to g'
$SPC_{gg'}^{min}$	Minimum swing pipeline capacity from GOSP g to g'
ψ_{gsic}^{+}	Fraction of components in each produced state *s* for task *i* in GOSP g
ψ_{gsic}^{-}	Fraction of components in each consumed state *s* for task *i* in GOSP g

Continuous Variables

CC	Chemicals consumption cost
FC	Fixed operating cost
FF_{gc}	Final inlet flow rate of component *c* in GOSP g
$OPEX$	Total OPEX for all GOSPs
P_{gs}	Final products (gas, oil and water) for GOSP g
PC	Power consumption cost
Pi_{gi}	Power consumption for a single unit for task *i* in GOSP g
Pj_{gij}	Power consumption for equipment *j* for task *i* in GOSP g
$Q_{gg'}$	Total transferred flow rate from GOSP g to g'
R_{gic}	Rate of component *c* for task *i* in GOSP g
Ri_{gi}	Processing rate for a single unit for task *i* in GOSP g
Rj_{gij}	Processing rate for equipment *j* for task *i* in GOSP g
RMR_{gsc}	Inlet rate of component *c* for raw materials state s for GOSP g
W_{gik}	SOS2 variable at break point *k* for task *i* in GOSP g

Binary Variables

X_g	1 if GOSP g is selected for process; 0 otherwise
$Y_{gg'}$	1 if transfer from GOSP g to g' is selected; 0 otherwise
Z_{gij}	1 if equipment *j* is selected to perform task *i* at equipment g; 0 otherwise

In the MILP model presented below, the gas flow rates in = (mscfd) are converted to thousand barrels per day of oil equivalent (kbdoe) to improve numerical stability.

4.1 Production Designation through GOSPs

The crude production is initially designated for the wells connected to a GOSP based on the reservoir strategy and production demands. This gives us the initial production flow rates for each GOSP. By utilising the swing pipelines, the crude can be reallocated to other GOSPs for process. Therefore, the mass balance for determining the final inlet component flow rates entering the GOSPs can be expressed as:

$$FF_{gc} = IF_{gc} + \sum_{g' \in G_g} CF_{cg'} \cdot Q_{g'g} - \sum_{g' \in G_g} CF_{cg} \cdot Q_{gg'}\ , \ \forall g, c \tag{1}$$

where IF_{gc} and FF_{gc} are the initial designated and final inlet rates of component c for GOSP g, respectively; $Q_{g'g}$ is the combined flow rate from GOSP g' to g; CF_{cg} is the component fraction based on the initial designation for each g; and G_g is the set of GOSPs connecting g through swing pipelines. Note that to avoid the difficulty in tracking the components in the crude through transfer, it is assumed that the crude can only be transferred to the GOSPs directly connected to its originally designated ones for processing, and cannot go to further GOSPs. Therefore, for each GOSP, its total flow rate transferred to other GOSPs cannot exceed its originally designated flow rate.

The transfers between GOSPs are constrained by the capacities of the swing pipelines connecting them. Therefore, Eq. (2) is introduced to maintain the transferred flow rates between the maximum and minimum capacities of the pipelines accordingly:

$$TPC_{gg'}^{min} \cdot Y_{gg'} \leq Q_{gg'} \leq \; TPC_{gg'}^{max} \cdot Y_{gg'}, \quad \forall g, g' \in G_g \tag{2}$$

where $TPC_{gg'}^{min}$ and $TPC_{gg'}^{max}$ are the minimum and maximum swing pipeline capacities between g and g', respectively; and $Y_{gg'}$ is a binary variable to indicate whether the transfer from g to g' is selected.

Physically, there is only a single swing pipeline connecting any two GOSPs; therefore, the transfers through any swing pipeline should be limited to one direction, if both directions are available, as defined by the constraint below:

$$Y_{gg'} + Y_{g'g} \leq 1, \quad \forall g \in G_{g'}, g' \in G_g, g < g' \tag{3}$$

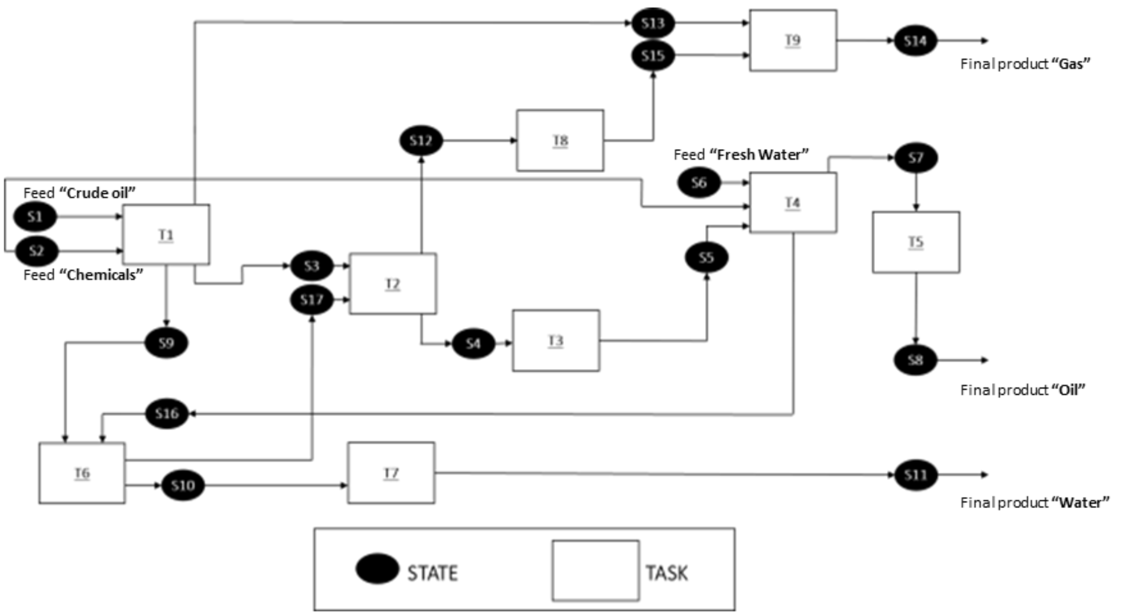
For each GOSP, its final inlet component flow rates must be maintained within the minimum and maximum capacities, if the GOSP is selected (binary variable $X_g = 1$):

$$SPC_{gc}^{min} \cdot X_g \leq FF_{gc} \leq SPC_{gc}^{max} \cdot X_g, \quad \forall g, c \tag{4}$$

4.2 Process in a GOSP

The representation of a process can either be aggregated, short-cut or rigorous depending on the complexity and details included. Adding too much detail may result in computational challenges and rigidness to find the optimal solution. Simplifying the flow sheet could result in overlooking critical details that could render the model unpractical. In this work, the process within the GOSPs was formulated by the state-task network (STN) framework

(Kondili et al., 1993), due to its capability to cover all the process features and the modelling requirements. The component fractions for the separation tasks (T1, T2, T4 and T6) are assumed to be known parameters. Figure 4 shows the developed STN representation for a standard GOSP in the oil and gas industry. In this framework, we represent all GOSP processes in a unified representation that segregate the states, tasks and units so that they can be easily utilised for the required purposes in the model. Every state consists of five components: gas, oil, salty water associated with crude, chemicals demulsifier and added freshwater. The fraction of these components is different from state to another and from a GOSP to another. The tasks represent the different separation, pumping and compressing tasks within the GOSP. All equipment is linked to one specific task only and there is no multitasking equipment in our problem. In each GOSP g, we have $\psi^{+}_{gsic}(> 0)/\psi^{-}_{gsic}(< 0)$ for the fraction of component c that is produced/consumed in state s for the processing task i within GOSP g.



State				Task	
S1	Crude feed	S10	Water separated from T6	T1	Three phase (Gas/Oil/Water) high pressure separation
S2	Chemicals injection	S11	Final Product "Water" pumped by T7	T2	Two phase (Gas/Oil) low pressure separation
S3	Oil separated from T1 plus remaining gas and water	S12	Gas separated from T2	T3	Two phase (Oil/Water) pumping
S4	Oil separated from T2 plus remaining water	S13	Gas separated from T1	T4	Two phase (Oil/Water) dehydration + desalting
S5	Oil & remaining water pumped by T4	S14	Final Product "Gas" compressed by T9	T5	Oil product pumping
S6	Fresh water injection	S15	Gas compressed from T8	T6	Two Phase (Water/Oil) low pressure separation
S7	Oil separated from T4	S16	Water separated from T4	T7	Water product pumping
S8	Final Product "Oil" pumped by T5	S17	Oil separated from T6	T8	Low pressure gas compression
S9	Water separated from T1 and emulsified oil			T9	High pressure gas compression

Figure 4. STN representation of a GOSP

The STN process flow is initiated by linking the raw materials RMR_{gsc} to the task rates R_{gic}, so that the consumed task rate is equal to the raw materials added.

$$RMR_{gsc} + \sum_{i \in S_i} \left(\psi_{gsic}^{-} \cdot R_{gic} \right) = 0, \quad \forall g, c, s \in S^{RM} \tag{5}$$

In the GOSP operation, usually there are five raw materials that enter the GOSP (oil, gas and salty water from the crude received from the wells, chemicals and added freshwater). Eqs. (6)-(8) define the five raw materials.

Eq. (6) bridges the network outside the GOSPs with the internal process flow sheets by equating the GOSPs final inlet component flow rate, FF_{gc}, with the state of STN crude raw materials.

$$RMR_{gsc} = FF_{gc}, \quad \forall g, c \in \{oil, gas, water\}, s = s1 \tag{6}$$

The demulsifer is the main chemical raw material considered, and its consumption is determined by the inlet oil and water rates:

$$RMR_{gs,demulsifer} = ChemR_g \cdot \left(FF_{g,oil} + FF_{g,water} \right) \quad \forall g, s = s2 \tag{7}$$

where chemicals consumption rate, $ChemR_g$, is a function of the crude temperature, liquid flow rate and GOSP characteristics obtained experimentally.

The consumed freshwater for each GOSP is assumed to be a fixed value.

$$RMR_{gs,freshwater} = FW_g \cdot X_g, \quad \forall g, s = s6 \tag{8}$$

The intermediate states and tasks are modelled in the STN in the following format:

$$\sum_{i \in I_s} \left(\psi_{gsic}^{+} + \psi_{gsic}^{-} \right) \cdot R_{gic} = 0, \quad \forall g, c, s \in S^{IN} \tag{9}$$

Then, the mass balance for the final products is formulated as follows:

$$\sum_{i \in I_s} \sum_{c} \psi_{gsic}^{+} \cdot R_{gic} = P_{gs}, \quad \forall g, s \in S^{P} \tag{10}$$

where P_{gs} denotes the final products (gas, oil and water) production from GOSP g treated for the targeted specifications, noting that fresh water and salty water are combined as produced water in the final product. Demulsifier will be dissolved in the oil and therefore it is added to the oil rate in the final quantity. Therefore, we have five raw materials but three final products.

So far, the process flow rates are defined through tasks. For the tasks that involve rotating equipment, i.e., pumps and compressors (T3, T5, T7, T8 and T9 in Figure 4), the flow rates must also be associated with the equipment rates to calculate power consumption. For example, if a task is coupled to multiple pumps, the number of pumps would be required to process the task rate and the flow rate for each pump need to be optimised. As a result, Eq. (11) is defined to link the task flow rates with their associated equipment flow rates, in which the total rate for all equipment is equal to the summation of all components and streams produced from a task.

$$\sum_c \sum_s \psi^+_{gsic} \cdot R_{gic} = \sum_{j \in J_{gi}} Rj_{gij}, \quad \forall g, i \in I^R \tag{11}$$

where Rj_{gij} is the processing flow rate of equipment j for task i within GOSP g. The above equation is valid in our case given that all pumping and compression tasks are modelled through the STN independently with only a single state consumed and a single state produced. If there are multiple produced states and only one goes to the set of equipment associated, then this equation needs to be modified accordingly.

Every equipment has an upper and lower operating range that must be maintained. So, the equipment rates are limited within given bounds, if it is selected within their specific operating windows:

$$Rj^{min}_{gj} \cdot Z_{gij} \leq Rj_{gij} \leq Rj^{max}_{gj} \cdot Z_{gij}, \quad \forall g, i \in I^R, j \in J_{gi} \tag{12}$$

where Rj^{min}_{gj} and Rj^{max}_{gj} are the minimum and maximum rate of equipment j within GOSP g, respectively; and Z_{gij} is a binary variable to indicate whether equimpent j is selected to perform task i within GOSP g.

If GOSP g is not selected for operation, then no equipment inside this GOSP should operate:

$$Z_{gij} \leq Y_g, \quad \forall g, i \in I^R, j \in J_{gi} \tag{13}$$

Typically, all equipment within the same set shares a common suction pipeline and a common discharge pipeline, as shown in Figure 5. Therefore, the flow rates of each pump within one set must stay the same to prevent the pumps from affecting the performance of the other pumps. The compressors can be allowed to have variable equipment flow rates, but the current practice in the industry shares also the load equally to maintain a similar distance for all compressors from their minimum flow rate limit (known as a surge line).

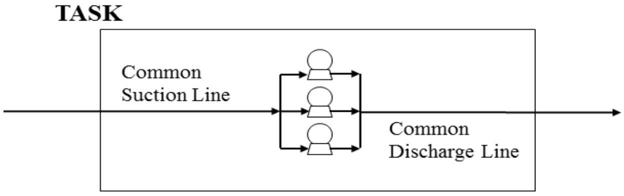


Figure 5. Common suction and discharge pipelines for a set of pumps

Since all equipment in a set is linked to a single task, a unified rate can be enforced for all running equipment by equating their rates to a single auxiliary variable associated with the containing task, Ri_{gi}. To avoid enforcing all equipment to have a positive value, the flow rate of each running equipment *j* must be equal to Ri_{gi}. .

$$Rj_{gij} \leq Ri_{gi}, \quad \forall\, g, i \in I^R, j \in J_{gi} \tag{14}$$

$$Rj_{gij} \geq Ri_{gi} - Rj_{gj}^{max} \cdot \left(1 - Z_{gij}\right), \quad \forall\, g, i \in I^R, j \in J_{gi} \tag{15}$$

Note that if different operating flow rates for the parallel compressors are allowed, the above equations can be only valid for tasks by pumps, i.e., $i \in I^P$.

4.3 Equipment Power Consumption

The power consumption of each equipment can be calculated from its flow vs. power curve. These curves can be represented by quadratic polynomials. To ease the computational load and speed up the convergence, it is assumed that this curve of each equipment for the same task remains the same. Therefore, the power consumption, considering motor efficiency and gearbox efficiency of each equipment for task i within GOSP g, Pi_{gi}, is calculated by Ri_{gi} as follows:

$$Pi_{gi} = a_{gi} \cdot Ri_{gi}^2 + b_{gi} \cdot Ri_{gi} + c_{gi}, \quad \forall g, i \in I^R \tag{16}$$

Where a_{gi}, b_{gi} and c_{gi} are the polynomial equation parameters. The above nonlinear power consumption curves can be approximated using piecewise linearisation technique. For a reasonable accuracy, the linearisation was based on analytical approximation. If more accuracy is required, Natali and Pinto (2008) provides a scientific linearisation approach that may be followed. Based on Eq. (16), we can obtain the breakpoints of the power consumption TPk_{gik} and the flow rate Rk_{gik}, for each equipment of task *i*. Therefore, the power consumption and flow rate can be formulated as:

$$Ri_{gi} = \sum_k Rik_{gik} \cdot W_{gik}, \quad \forall g, i \in I^R \tag{17}$$

$$Pi_{gi} = \sum_k Pik_{gik} \cdot W_{gik}, \quad \forall g, i \in I^R, j \in J_{gi} \tag{18}$$

where W_{gik} is a SOS2 variable that takes at most two consecutive values to locate Ri_{gi} value in any of the corresponding operating intervals of Rjk_{gik}. Therefore, it follows:

$$\sum_k W_{gik} = 1, \quad \forall g, i \in I^R \tag{19}$$

Thus, the power consumption for each equipment is calculated as follows:

$$Pj_{gij} \leq \ Pj_{gij}^{max} \cdot \ Z_{gij}, \quad \forall g, i \in I^R, j \in J_{gi} \tag{20}$$

$$Pj_{gij} \geq Pi_{gi} - Pj_{gij}^{max} \cdot \left(1 - Z_{gij}\right), \quad \forall g, i \in I^R, j \in J_{gi} \tag{21}$$

$$Pj_{gij} \leq Pi_{gi}, \quad \forall g, i \in I^R, j \in J_{gi} \tag{22}$$

where Pj_{gij} is the power consumption for equipment *j* for a task *i* in GOSP g.

4.4 Objective Function

The objective of the proposed model is to minimise OPEX for the complete network of GOSPs. The three costs considered in this model are power consumption cost, PC, chemicals consumption cost, CC, and fixed operating cost, FC. Therefore, the total OPEX for all GOSPs is calculated below with further detailed calculation for each term:

$$OPEX = PC + CC + FC \tag{23}$$

where PC is the combined power cost for running equipment in all GOSPs; CC is the combined chemicals cost; FC is the total fixed operating cost which is independent of the processed flow rates. It only depends on whether a GOSP is running or not.

Here, as discussed previously, we only focus on the power consumption by liquid pumps and gas compressors in the power consumption calculation, due to their significate contribution, and other small portion power consumption cost is considered in the fixed operation cost. The power consumption cost is considered by the total power multiplied by the operating time, *OT*, and power price, *Pc*.

$$PC = OT \cdot Pc \cdot \left(\sum_g \sum_{i \in I^R} \sum_{j \in J_{gi}} Pj_{gij}\right) \tag{24}$$

The chemicals consumption cost is given by the chemicals cost in each GOSP, $ChemC_g$, and its consumed amount.

$$CC = \sum_g \sum_c ChemC_g \cdot ST0_{g,s2,c} \tag{25}$$

The fixed operating cost of one GOSP, FOC_g, is included in the objective function if the GOSP operates.

$$FC = \sum_g FOC_g \cdot X_g \qquad (26)$$

In summary, the proposed MINLP model consists of Eq. (23) as the objective function and Eqs. (1)-(15), (17)-(22), (24)-(26) as the constraints.

5. Case Study

In this section, we apply the proposed model to a real case study. The Ghawar field in Saudi Arabia is considered by far the largest conventional oil field in the world. We focus on a production area of the Ghawar field containing multiple operating GOSPs. The characteristics of the subject area are:

- It consists of 19 GOSPs extending across a distance of 200 km.
- Total oil production rate varies between 3-3.5 million barrel per day (MBD).
- The total number of wells serving all the GOSPs exceeds 1800 wells, and every GOSP is fed by its own wells separately as a single production train from wells to midstream.
- The GOSPs contain around 200 rotating equipment (liquid pumps and gas compressors) varying in size, capacity, function, age and efficiency.

The inlet feed rates to the GOSPs are altered at monthly intervals in response to production demands, reservoir strategy and other considerations. These rates are controlled and adjusted by the choke valves of the feeding wells at the well pads to ensure that each GOSP receives its targeted production rates. The controlling component in production is oil. Gas and water are produced as associated products. Here, 12 monthly production scenarios for a one year period (January to December) are developed from the actual productions. The initial designated flow rate of each GOSP in January is shown in Table 5.

At the surface level, GOSPs are connected by a long chain of pipelines as illustrated in Figure 6. A total of 20 swing pipelines are available to create the lateral connections between all GOSPs. Every GOSP is connected to at least a nearby GOSP. All swing pipelines allow for bidirectional transfers except for three (GOSP7-GOSP6, GOSP16-GOSP3 and GOSP16-GOSP14). These three swing pipelines are unidirectional due to certain restrictions in well deliverability and receiving GOSP designs. Due to their low production rates and the spare capacity in the receiving GOSPs, it has been decided that GOSP7 and GOSP16 are shut down and their production is transferred to the connected GOSPs. This results in the binary variable X_g for the above two GOSPs being fixed to 0. The minimum ($SPC_{gg'}^{min}$) and maximum ($SPC_{gg'}^{max}$) flow rates allowed in the swing pipelines are 5 and 100 kbode, respectively. The monthly operating time (OT) is 720 hours. Additionally, the maximum capacity (CC_{gc}^{max}) and fixed operating cost (FOC_g) for each GOSP are given in Table 1.

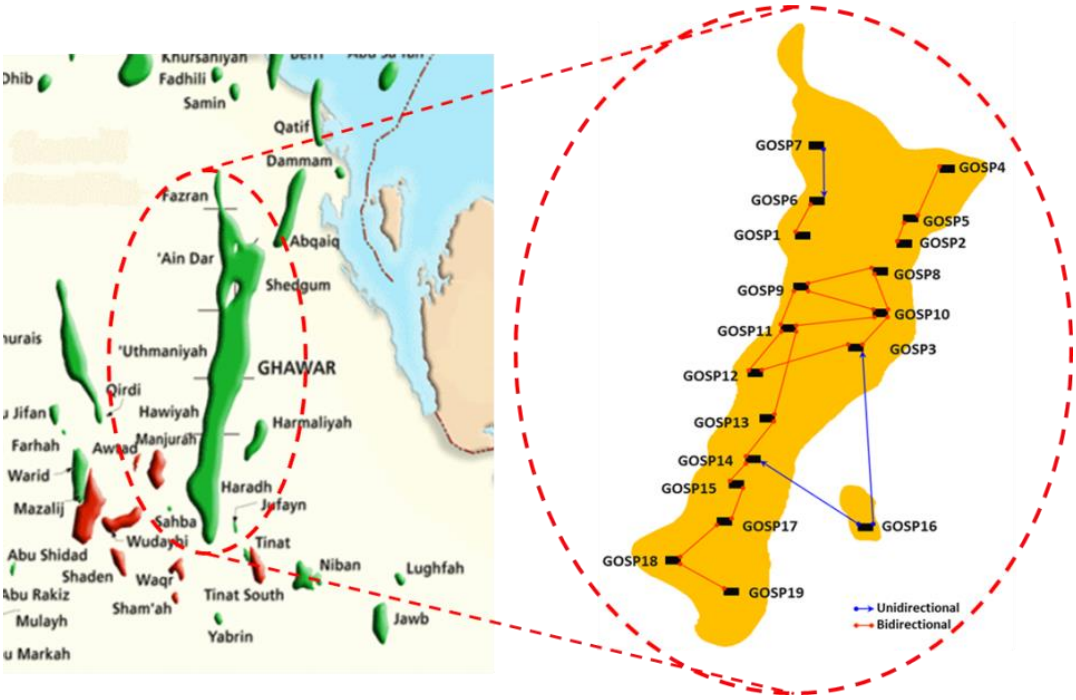


Figure 6. The network of GOSPs case study

Table 1. Capacity of each GOSP and its fixed operating cost

	Oil rate capacity, $CC_{g,Oil}^{max}$ (kbdoe)	Water rate capacity, $CC_{g,Water}^{max}$ (kbdoe)	Gas rate capacity, $CC_{g,Gas}^{max}$ (kbdoe)	Fixed operating cost, FOC_g (million $)
GOSP1	330	150	30	0.024
GOSP2	330	150	30	0.026
GOSP3	330	165	30	0.039
GOSP4	330	150	30	0.024
GOSP5	330	375	30	0.016
GOSP6	330	300	30	0.019
GOSP7	330	300	30	0.019
GOSP8	330	165	30	0.031
GOSP9	330	165	30	0.040
GOSP10	330	375	30	0.040
GOSP11	330	375	30	0.058
GOSP12	330	165	30	0.030
GOSP13	330	165	30	0.046
GOSP14	330	165	30	0.035
GOSP15	330	165	30	0.049
GOSP16	330	165	30	0.019
GOSP17	330	165	30	0.055
GOSP18	330	165	30	0.055
GOSP19	330	165	30	0.055

The GOSPs in our application were built at different periods of time. Their ages, design technologies, efficiencies, parameters and production forecast are different. Due to this, the equipment characteristics (including power curves) are also different. Table 3 lists the number and capacity of the major equipment in each GOSP, including charge pumps for task T3, booster pumps for task T5, shipper pumps for task T5, injection pumps for task T7, LP gas compressors for task T8, and HP gas compressors for task T9, which are the main sources of power consumption. Note T1, T2, T4 and T6 are separation tasks, which are not considered in the power consumption cost in this problem. The variances in characteristics between the equipment provide an opportunity to utilise the developed optimisation models for the optimum power consumptions while meeting the demands.

Table 2. Number and capacity (Rj_{gj}^{max}) of the major equipment in each GOSP

	Charge pump (T3)		Booster pump (T5)		Shipper pump (T5)		Injection pump (T7)		LP gas compressor (T8)		HP gas compressor (T9)	
	No	Capacity (kbdoe)	No	Capacity (kbdoe)	No	Capacity (kbdoe)	No	Capacity (kbdoe)	No	Capacity (kbdoe)	No	Capacity (kbdoe)
GOSP1	2	210	1	210	0	0	2	75	1	6.9	2	15
GOSP2	2	210	1	210	0	0	2	75	1	6.9	2	15
GOSP3	2	210	2	160	0	0	3	55	1	6.9	2	15
GOSP4	2	210	1	210	0	0	2	75	1	6.9	2	15
GOSP5	2	210	2	160	0	0	5	75	1	6.9	2	15
GOSP6	2	210	2	160	0	0	4	75	1	6.9	2	15
GOSP7	2	210	2	160	0	0	4	75	1	6.9	2	15
GOSP8	2	210	2	160	0	0	3	55	1	6.9	2	15
GOSP9	2	210	2	160	0	0	3	55	1	6.9	2	15
GOSP10	2	210	2	160	0	0	5	75	1	6.9	2	15
GOSP11	2	210	2	160	0	0	3	55	1	6.9	2	15
GOSP12	2	210	2	160	0	0	3	55	1	6.9	2	15
GOSP13	2	210	2	160	0	0	3	55	1	6.9	2	15
GOSP14	2	210	2	160	0	0	3	55	1	6.9	2	15
GOSP15	2	210	2	160	0	0	3	55	1	6.9	2	15
GOSP16	2	210	2	160	0	0	3	55	1	6.9	2	15
GOSP17	2	210	0	0	2	200	3	55	1	6.9	2	15
GOSP18	2	210	0	0	2	200	3	55	1	6.9	2	15
GOSP19	2	210	0	0	2	200	3	55	1	6.9	2	15

Compressor power curves of the existing applications were developed based on rated inlet conditions. Some parameters, such as pressure and temperature, have changed greatly since then. Therefore, we considered correction factors for the obtained power (Lapina, 1982). For the pumps, we used Sulzer online database (Sulzer, 2014) to obtain several different curves for the pumps based on similar design parameters. Therefore, we used three different curves for every type of pumping set in the model and then distributed them randomly on the GOSPs.

The proposed model was implemented in GAMS 24.4 (Brooke et al., 2014) on a 64-bit Windows 7 based machine with 3.20 GHz six-core Intel Xeon processor W3670 and 12.0 GB RAM. The computational time limit is 3600 seconds and the optimality gap is 1%.

6. Results and Discussion

In this section, the obtained optimal solutions of the models for the case study in the above section are presented and discussed.

6.1. Model Statistics

We take the January scenario as an example, and the model statistics and computational results are presented in Table 3. To investigate the accuracy of the piecewise linearisation, we fix the variables values obtained by the MILP model, and the post-processed values of variable Pi_{gi} and objective value. The obtained objective values show that the piecewise approximation given by the MILP model provides a OPEX within less than 0.1% of the actual OPEX. Similar results can be found for other scenarios as well.

Table 3. Model statistics for the January production scenario

Model	No of equations	No of continuous variables	No of binary variables	Solver	OPEX (million $)	CPU (s)
MILP	3192	1981	244	CPLEX	7.49[a]/7.50[b]	10

[a]Optimal MILP solution; [b]post-processed without approximation

6.2. Optimal Solutions

In this section, the optimal solution of the January production scenario is presented in details here. Figure 7 shows a schematic map of optimal swing pipelines utilisation between the GOSPs. Out of a total of 20 swing pipelines, 18 ones are utilised, while only the ones between GOSP4 and GOSP5, as well as between GOSP14 and GOSP16, are not utilised. The optimal transfer amount in each pipeline is presented in Table 4.

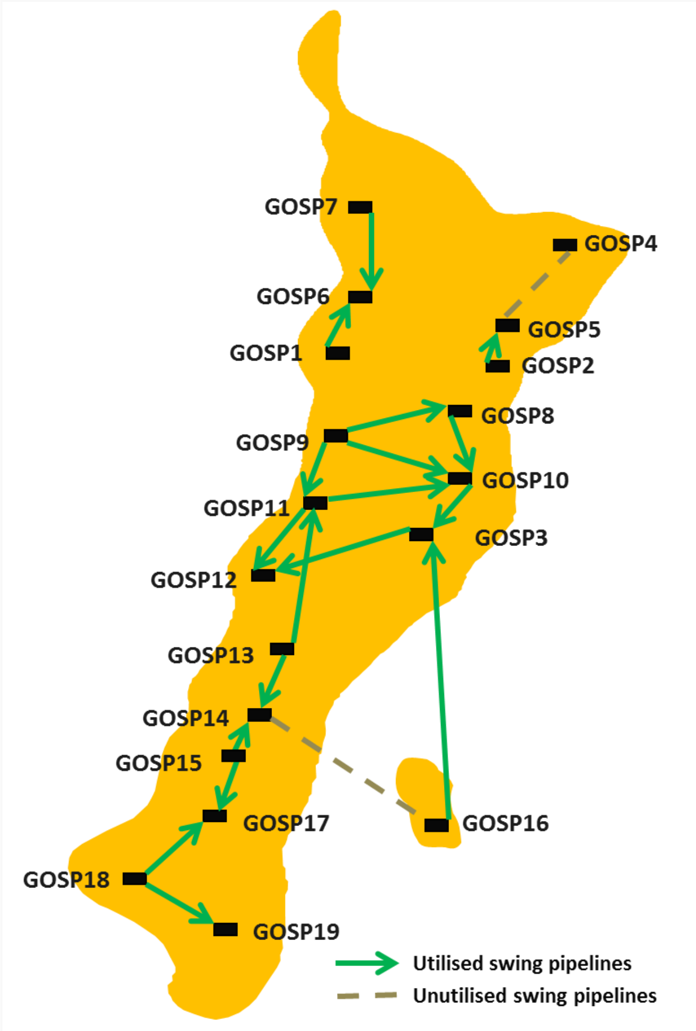


Figure 7. Schematic map of swing pipelines utilization for the January production scenario

Table 4. Optimal transfer through swing pipelines for the January production scenario

From	To	Transfer amount (kbdoe)	Oil (%)	Water (%)	Gas (%)
GOSP1	GOSP6	52.4	60.0	34.4	5.7
GOSP2	GOSP5	39.0	53.9	41.0	5.1
GOSP3	GOSP12	48.0	73.2	19.8	6.9
GOSP7	GOSP6	16.4	91.5	0.0	8.5
GOSP8	GOSP10	39.3	68.2	25.3	6.5
GOSP9	GOSP8	76.9	53.4	41.5	5.0
GOSP9	GOSP10	100	53.4	41.5	5.0
GOSP9	GOSP11	92.7	53.4	41.5	5.0
GOSP10	GOSP3	5.0	55.0	39.8	5.2
GOSP11	GOSP10	100	65.0	28.8	6.2
GOSP11	GOSP12	100	65.0	28.8	6.2
GOSP13	GOSP11	68.5	62.6	31.5	5.9
GOSP13	GOSP14	5.8	62.6	31.5	5.9
GOSP15	GOSP14	81.4	79.8	12.6	7.6
GOSP15	GOSP17	64.8	79.8	12.6	7.6
GOSP16	GOSP3	16.4	91.5	0.0	8.5
GOSP18	GOSP17	100.0	74.4	18.5	7.1
GOSP18	GOSP19	60.4	76.8	15.9	7.3

- Due to their low production rates and the spare capacity in the receiving GOSPs, it has been decided that GOSP7 and GOSP16 are shut down and their production and transferred to the connected GOSPs. This results in FF_{gc} for the two GOSPs being fixed to 0. The minimum and maximum flow rates allowed in the swing pipelines are $SPC_{gg'}^{min}$=5 kbdoe and $SPC_{gg'}^{max}$=100 kbdoe, respectively.

The initial designated and final inlet rates after transfer are given in Table 5. Besides the shutdown GOSP7 and GOSP16, GOSP9 also transfers all its designated rates to other GOSPs, and does not operate in January.

Table 5. Initial designated rates and optimal final inlet rates for the January production scenario

	Initial rate (kbdoe)			GOSP Selection	Final inlet rate (kbdoe)		
	Oil	Water	Gas		Oil	Water	Gas
GOSP1	110	63	10.4	Yes	78.6	45.0	7.4
GOSP2	92	70	8.7	Yes	71.0	54.0	6.7
GOSP3	170	46	16.1	Yes	152.6	38.5	14.4
GOSP4	156	67	14.8	Yes	156.0	67.0	14.8
GOSP5	113	54	10.7	Yes	134.0	70.0	12.7
GOSP6	205	127	19.4	Yes	251.4	145.0	23.8
GOSP7	15	0	1.4	*No*	-	-	-
GOSP8	143	53	13.6	Yes	157.3	75.0	14.9
GOSP9	144	112	13.6	*No*	-	-	-
GOSP10	174	126	16.5	Yes	316.5	204.3	30.0
GOSP11	196	87	18.6	Yes	158.4	89.4	15.0
GOSP12	216	99	20.5	Yes	316.6	154.1	30.0
GOSP13	205	103	19.4	Yes	158.5	79.6	15.0
GOSP14	248	142	23.5	Yes	316.6	154.1	30.0
GOSP15	266	42	25.2	Yes	149.3	23.6	14.1
GOSP16	15	0	1.4	*No*	-	-	-
GOSP17	233	58	22.1	Yes	316.3	72.8	30.0
GOSP18	236	49	22.4	Yes	158.0	32.9	15.0
GOSP19	270	37	25.6	Yes	316.4	46.6	30.0

The optimal OPEX in January production scenario is $7.49 million, in which power consumption cost is $5.99 million (80%); chemicals consumption cost is $0.60 million (12%); and the fixed operating cost is $0.60 million (8%). As a result, most OPEX results from power consumption cost, which can be further analysed. In Figure 8, most of the power is consumed by HP compressors and power injection pumps, which represents a total of 86% of the power consumption cost. The details of the operation of liquid pumps and gas compressors are given in Table 6. There are 109 equipment items out of 190 available items utilised as follows:

- 22/35 charge pumps (oil + water);
- 17/29 booster pumps (oil + injected demulsifier);
- 5/6 shipper pumps (oil + injected demulsifier);
- 27/60 injection pumps (salty water + injected freshwater);
- 16/19 LP gas compressors (gas); and
- 22/38 HP gas compressors (gas).

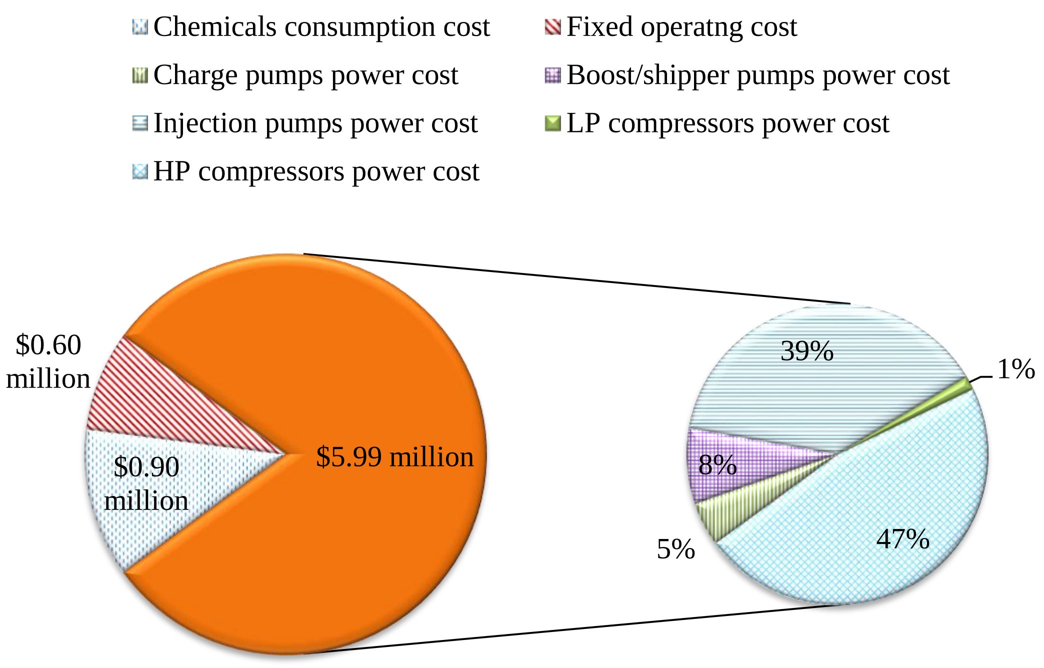


Figure 8. Cost breakdowns of the January production scenario

Table 6. Optimal operation of equipment in the January production scenario

	Charge pumps			Booster pump			Shipper pump			Injection pump			LP gas compressor			HP gas compressor		
	No	Rate (kbdoe)	Power (kW)	No	Rate (kbdoe)	Power (kW)	No	Rate (kbdoe)	Power (kW)	No	Rate (kbdoe)	Power (kW)	No	Rate (kbdoe)	Power (kW)	No	Rate (kbdoe)	Powe r (kW)
GOSP1	1	101	273	1	80	688	-	-	-	1	50	3742	1	0.7	138	1	7	3837
GOSP2	1	98	269	1	71	675	-	-	-	1	59	3977	1	6.7	134	1	7	3431
GOSP3	1	173	380	1	153	513	-	-	-	1	43	1988	1	1.4	176	1	14	4699
GOSP4	1	190	407	1	156	801	-	-	-	1	72	4359	1	1.5	178	1	15	4649
GOSP5	1	170	375	1	135	492	-	-	-	1	75	4448	1	1.3	167	1	13	4933
GOSP6	2	162	364	2	126	481	-	-	-	2	75	4448	1	2.4	225	2	12	4897
GOSP8	1	194	415	1	157	518	-	-	-	2	40	1916	1	1.5	179	1	15	4631
GOSP10	2	210	439	2	159	428	-	-	-	3	70	2532	1	3.0	255	2	15	4622
GOSP11	1	203	429	1	159	520	-	-	-	2	47	2066	1	1.5	180	1	15	4622
GOSP12	2	193	411	2	158	520	-	-	-	3	47	2071	1	3.0	255	2	15	4622
GOSP13	1	199	421	1	159	520	-	-	-	2	42	1964	1	1.5	180	1	15	4622
GOSP14	2	197	419	2	159	520	-	-	-	3	53	2187	1	3.0	255	2	15	4622
GOSP15	1	161	363	1	150	509	-	-	-	1	29	1674	1	1.4	175	1	14	4737
GOSP17	2	177	387	-	-	-	2	159	1035	2	39	1892	1	3.0	255	2	15	4622
GOSP18	1	174	383	-	-	-	1	159	1035	1	38	1870	1	1.5	180	1	15	4622
GOSP19	2	171	377	-	-	-	2	159	1034	1	52	2158	1	3.0	255	2	15	4622

6.3. Optimal Solution vs. Current Practice

To evaluate the optimal solution achieved, we compare the optimal results for all the 12 monthly production scenarios with the current practice, i.e., each GOSP only processes its initial designated rate only, except the shutdown GOSP7 and GOSP16, to get an insight of the added value from the model.

The OPEX between the two solutions for all 12 months are compared in Figure 9, in which the optimal solutions have consistent savings of 8% to 15% in all 12 months. In Figure 10, it can be observed that in some months, the difference in chemicals consumption cost and fixed operating cost is not very significant. In particular, in March and August, the chemicals consumption cost in the current practice is even lower than the optimal solution. The power consumption cost in the optimal solutions, which represents about 80% of the total OPEX, has 10-20% advantage than the current practice. As a result, the total OPEX in the optimal solutions shows significant savings.

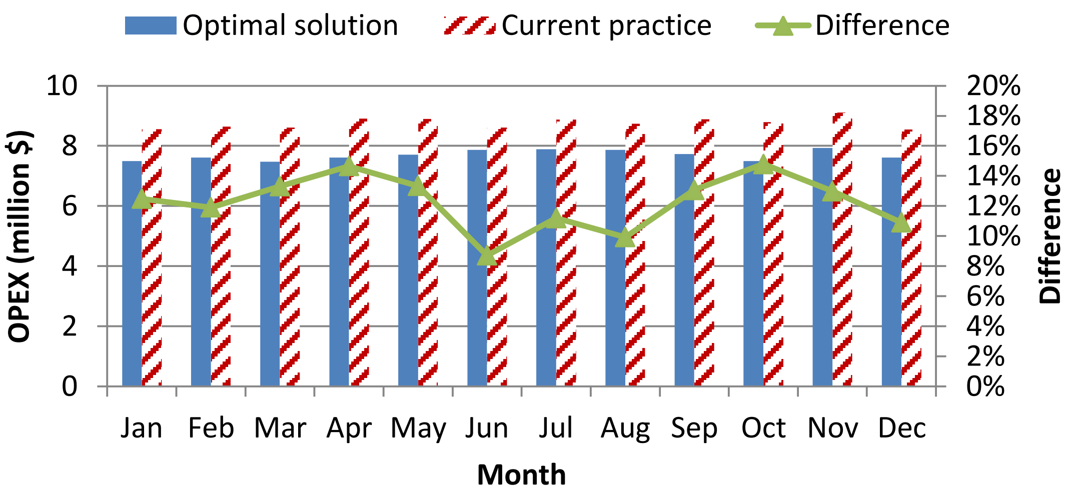


Figure 9. OPEX of the optimal solution and current practice in all monthly production scenarios

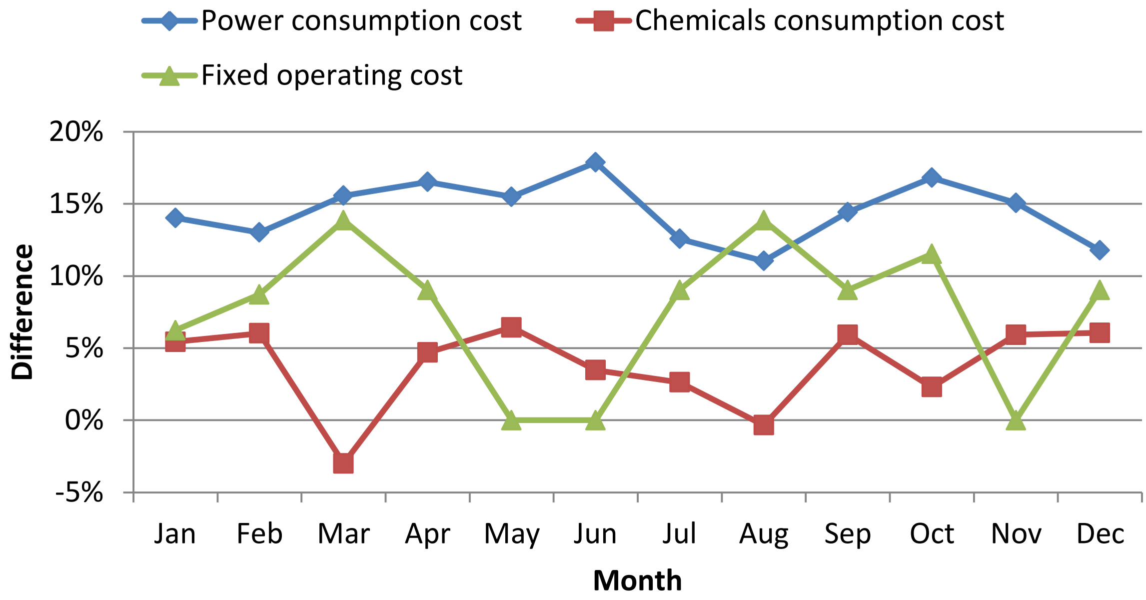


Figure 10. Cost saving of the optimal solution compared to the current practice in all monthly production scenarios

Figure 11 presents the OPEX comparison for each GOSP between optimal solution and current practice in the January production scenario. It shows that the optimal solution cannot guarantee that all GOSP can obtain OPEX savings compared to the current practice. In the January scenario, the OPEX of only nine GOSPs in the optimal solution is lower than that in the current practice, while there are eight GOSPs that have higher OPEX in the optimal solution. The optimisation model considers the whole network of GOSP's and reallocates the process rates among all GOSPs, to achieve a better overall saving rather than the saving of each GOSP. In other words, some GOSPs must experience an increase in their OPEX in order to achieve a better overall OPEX for the whole network.

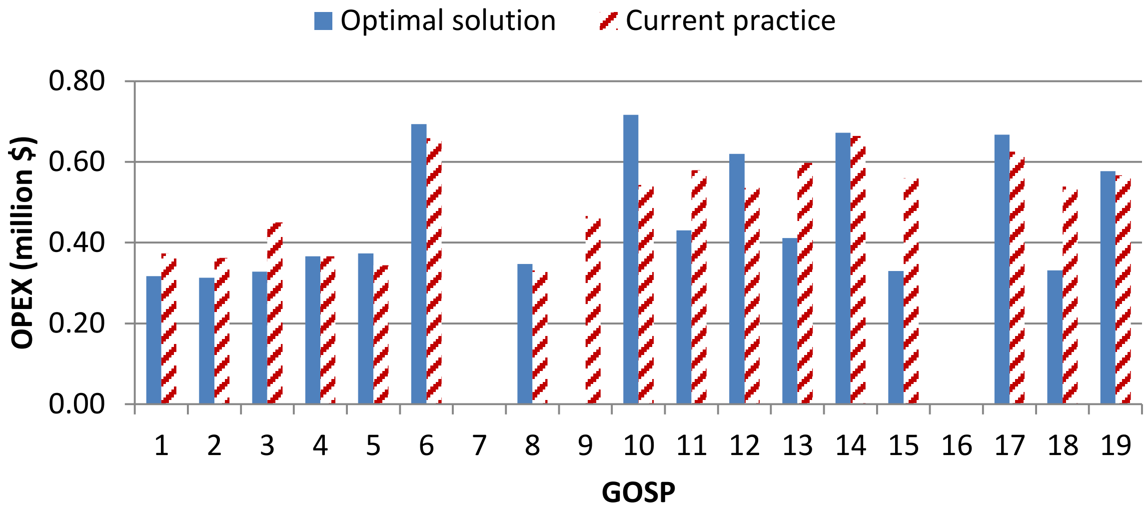


Figure 11. OPEX of the optimal solution and current practice for each GOSP in the January production scenario

Now, we compare the annual total OPEX between the optimal solution and current practice to show the benefit of the proposed optimisation models. Figure 12 shows that a total annual OPEX of $92.28 million in the optimal solution, compared to $105.85 million for the current practice, with a saving of $13.57 million representing 12.8% difference. Most of the savings results from the power consumption cost, which has a 14.5% difference.

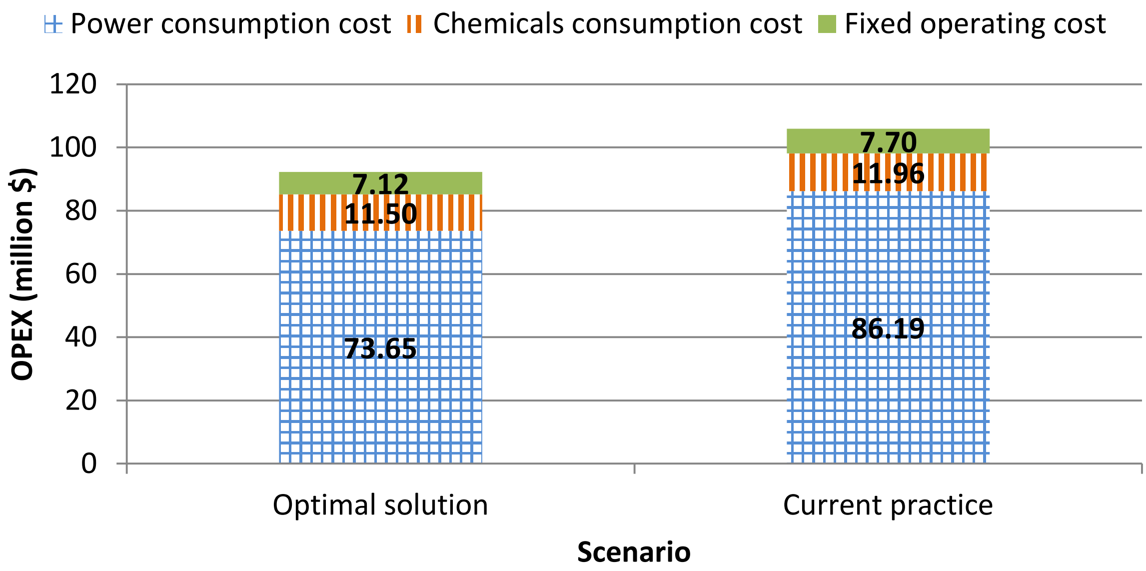


Figure 12. Annual OPEX of the optimal solution and current practice

7. Conclusions

In this work, we have integrated GOSP well production at the surface facilities to achieve a combined optimal OPEX for a network of GOSPs connected laterally through swing pipelines. A MILP model has been developed to optimise the operating costs of these GOSPs while maintaining all equipment in the best mode of operation. The developed models were applied to a real case study in Ghawar field, Saudi Arabia, by considering 12 monthly production scenarios. The benefits of the proposed optimisation model was demonstrated by comparing the optimal solutions with the current practice without swing pipelines transfer. The computational results showed an average of more than 10% OPEX reduction, which leads to an annual OPEX savings of about $14 million.

This work also provides the basis for further optimisation opportunities by possibly coupling the proposed models with existing upstream and downstream sections, to expand the area of interest and obtain even higher combined savings.

Acknowledgements

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