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Optimal Design of a Multi-Period Natural Gas Transmission Network

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Abstract

Natural gas is increasingly adopted as an energy source due to its cleanliness and high efficiency. Transmission pipelines play a vital role in transporting large volumes of natural gas over long distances, typically operating at high pressures and using compressors at regular intervals to maintain flow. In this context, a model was developed for the eastern part of the Egyptian gas network, with Zohr Gas Field as the supply source. The objective of this paper is to optimize this network model to minimize transportation costs under varying supply conditions represented by a nonlinear function dependent on flow rates and pressures. At first period, the supply source is Zohr field. And the second period is after the decrease of production of Zohr field supply source so additional supply sources are added. To maintain the required minimum pressure levels, three strategies were evaluated and compared: increasing the pipeline diameter, adding compressor stations, or applying both methods. The PipeSim software was utilized to support the solution process. The output of this model is the optimum diameter, the number of compressors and its location and the total cost.

Keywords: *Natural gas; Pipeline network; Optimization; Minimum cost; Multi-period; PipeSim.*

1. Introduction

Over the past two decades, global primary energy consumption has risen by approximately 50%. This growth in demand presents significant technological and economic challenges in meeting the needs of energy markets (OECD, 2013)[24]. In this context, natural gas (NG) has become an important alternative of energy supply in the global energy matrix. Moreover, the consumption of natural gas is growing faster than that of any other fossil fuel [1]. The demand for natural gas is expected to continue rising in the future, as it plays a crucial role in achieving two major energy objectives for the 21st century: ensuring sustainable energy supplies for social and economic development and mitigating the negative impacts on global climate and the environment [2]. The Energy Market Regulatory Authority (EMRA, 2011) [25] predicts that natural gas demand will keep increasing through 2035, driven by environmental considerations and its ease of use [3].

Gas transportation includes both transmission and distribution. Transmission refers to the movement of large volumes of gas at high pressures over long distances, from production sources to distribution centers. Gas distribution, on the other hand, is delivering the gas to individual consumers [4]. Natural gas (NG) is transported through large pipeline networks that operate under fluctuating conditions such as temperature changes, varying customer demands, and gas composition. These pipeline networks generally consist of supply nodes, demand nodes, compressor stations, and pipelines of different diameters and lengths [5].

The pressure drop that occurs in these pipelines can impact both the quantity and quality of the transported gas, as well as the overall safety and reliability of the system. To minimize the effects of pressure drop, engineers and operators must account for various factors, including pipeline diameter, length, surface roughness, gas flow rate, and the properties of the gas. Additionally, using materials compatible with H_2 gas, efficient fittings and valves, and precise calculations to predict pressure drop are essential for optimizing the system's performance [6]. The following methods can help minimize pressure drop in gas transportation [7]: i) Transport natural gas at lower flow line temperatures; ii) install a compressor if gas is required to be transported over a very long distance. The longer the pipeline, the greater the pressure drop; iii) for very large diameter pipes, initial transport pressure must be very large, pressure drop increases with decreasing pipe diameter; iv) Heavier gases tend to cause a higher pressure drop; v) Pressure drop is greater at bends and valve locations.

The flow capacity of a pipeline is directly influenced by its inlet and outlet pressures. As the inlet pressure increases, the flow capacity rises, while a decrease in outlet pressure reduces it. Without compressors along the flow path, the pressure will gradually drop. Since the pressure at distribution centers is usually fixed, this drop could eventually lead to an unsustainable flow capacity. To maintain adequate flow capacity, compressors are installed at the entry points of selected pipelines to boost pressure. Operating these compressors incurs costs, which depend on the flow rate and the pressures at their inlet and outlet [8].

When designing and expanding natural gas (NG) transportation networks, it is essential to carefully consider their long-term benefits. These networks are meant to operate for extended periods and must be capable of adapting to varying demands over time. A well-planned network allows NG companies to minimize both strategic and operational costs while improving customer service levels [9].

In natural gas (NG) network design optimization problems, the goal is often to either minimize investment costs or maximize net profit. The model's output helps determine the optimal number and location of compressor stations, as well as the ideal pipe sizes. Key design variables include the locations and types of compressor stations, possible pipeline locations, lengths, diameters, and the allowable operating pressure levels for the system. The primary aim of NG network flow problems is to minimize costs while meeting demand. To achieve this, decision variables are determined to control the gas flow through the pipeline network. Operating costs for NG transmission systems are heavily influenced by compressor station operations, as these stations set the amount of gas in the system. Therefore, selecting the optimal locations and capacities for compressors is a crucial decision [10].

For NG flow in long pipelines, the Weymouth, Panhandle A, and Panhandle B equations are commonly used. The Panhandle B equation, also known as the Modified Panhandle equation, is used for even larger pipe diameters and high-pressure transmission pipelines [11]. In this research we used the Panhandle B equation.

The purpose of this paper is to optimize the solution to the problem of compensating for a supply drop of existing gas supplier/suppliers maintaining the required gas quantity and minimum end pressure for each gas consumer. The study addressed several sub-problems in optimizing natural gas pipeline networks including:

1) determining the quantity of gas supplied by available sources,
2) establishing the required gas pressures and flow rates throughout the network,
3) identifying the optimal locations and capacities of compressor stations,
4) deciding on the lengths and diameters of the pipelines to be installed,
5) minimizing the combined capital and operational costs.

The paper proposed, tested, and compared three different strategies: increasing pipeline diameter, adding a compressor station, or implementing a combination of both methods to achieve the objective of minimizing total costs.

2. Literature review

Regarding the design and development of pipeline networks aimed at minimizing costs, several researchers have proposed optimization models to improve natural gas transmission networks. Kabirian and Hemmati [13] introduced an integrated nonlinear optimization model for designing and developing natural gas transmission pipeline networks. This model aimed to provide the best development plan for an existing network over a long-run planning horizon with least discounted operating and capital costs. They also applied a heuristic random search optimization method to solve the model. Borraz-Sánchez and Haugland [8] proposed a nonlinear mathematical model that considered gas flow and pressure. Their objective was to minimize fuel costs in gas transmission networks, using dynamic programming and adaptive discretization techniques [12].

Üster and Dilaveroglu [9] tackled the problem of designing a new natural gas transmission network or expanding an existing one while minimizing both total investment and operating costs. They developed a large-scale mixed-integer nonlinear optimization model (MINLP) to determine the optimal locations for pipelines and compressor stations in the network. The model was solved using the advanced Bonmin MINLP solver. Alves *et al.* [26] proposed a multi-objective optimization model for designing natural gas transmission pipelines, aiming to minimize transportation costs and maximize the transported gas volume, considering the increasing demand for natural gas. They incorporated constraints for gas flow and compressor stations, solving the model using the Generalized Reduced Gradient (GRG) method. Mikolajková *et al.* [27] developed a multi-period MINLP model that also considered the possibility of expanding the pipeline network to new locations for gas distribution. They took into account constraints related to mass and balance equations, pressure drop, and gas compression [12].

In their study of the performance and location of gas compressors in pipeline networks, Larson and Wong [28] focused on determining the steady-state optimal operating conditions for a straight natural gas pipeline with compressors in series. They used dynamic programming to find the optimal suction and discharge pressures. Due to the limitations of dynamic programming, the length and diameter of the pipeline segment were assumed to remain constant. Martch and McCall [29] extended this work by introducing branches into the pipeline segments, modifying the original problem. Cheesman [30] further enhanced this model by introducing a computer optimization code, which complemented the work of Martch and McCall. This modification allowed the lengths and diameters of the pipeline segments to be treated as variables. Olorunniwo [31] and Olorunniwo and Jensen [32] made further advancements by optimizing a complete gas transmission network, taking into account the type and location of both pipelines and compressor stations [13].

3. Methods

3.1. Software programs used

The most common simulation software programs that are used in natural gas network models: PipeSim, OLGA and HYSIS. Simulator tools are not flawless, and their predictions could be different from reality. Therefore, the strengths and weaknesses of prediction tools in different conditions should be considered. Employing proper simulating software which has a good match with field data and nature of the issue leads to a reliable prediction and gives an accurate sense of multiphase behavior [14]. In this study, the program used for simulation is PipeSim. It is an engineering tool that covers a wide range of applications within oil and gas field.

Figure 1 shows the PipeSim workflow for both the single branch and the network [15]. In this research, it is a simulation for network model. The network model is several single branch models connected by nodes. Single branch model only has one supply node and one consumer node.

The main centrifugal compressor equations used are as follows: Adiabatic Route, Polytropic Route and Mollier Route (compositional cases only) [15]. There are several different methods available for calculating the friction factor (f). The most famous single phase flow correlations used are as following: Moody, AGA (for gas only), Panhandle 'A' (for gas only), Panhandle 'B' (for gas only), Hazen-Williams (for liquid water only) and Weymouth (for gas only) [15]. In this study, panhandle B equation is used as the flow equation as it is the most suitable one for the pipe diameters and pressures ranges used in our study. And the compressor used is adiabatic with efficiency 80%.

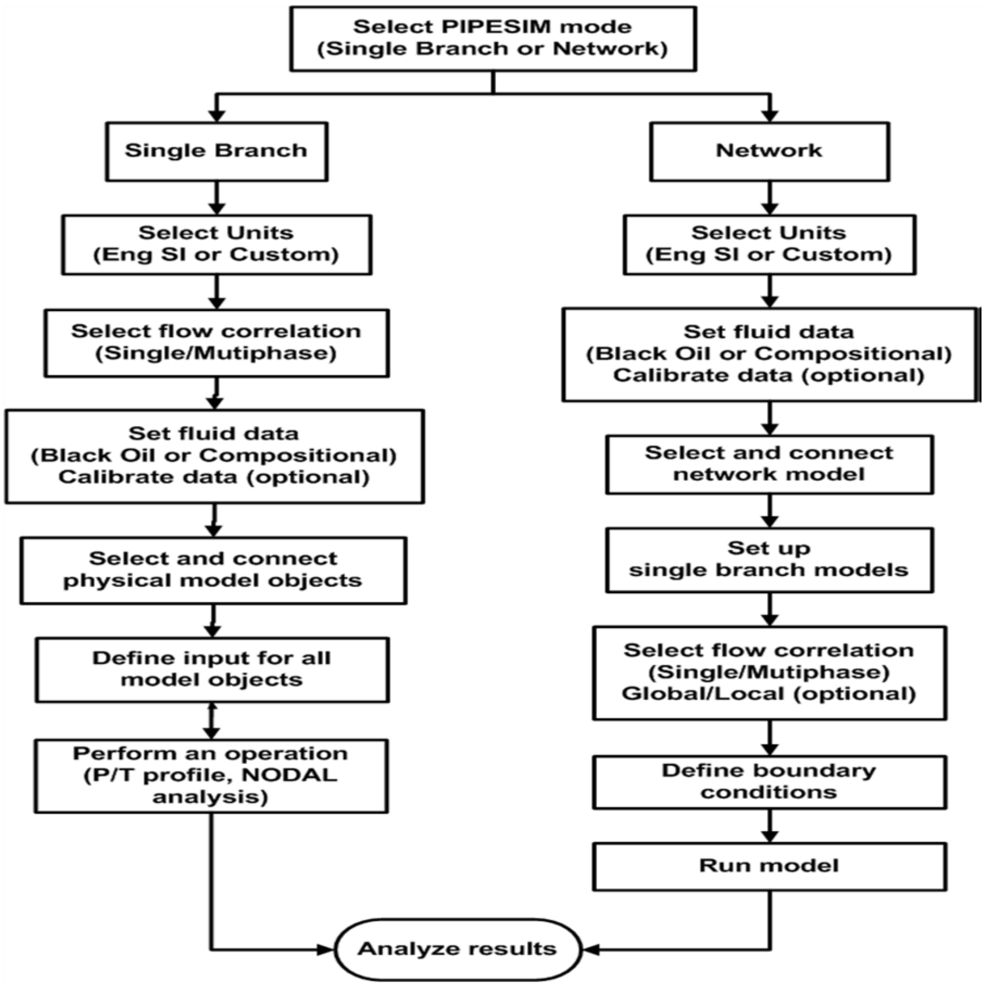

Figure 1. PipeSim workflow.

3.2. Mathematical model

In this study, the problem is modeling the Egyptian Eastern gas network for optimal design. It is to be solved by PipeSim simulation package. As shown in figure (2), this is a representation for the problem goal objective and the data needed to solve it. And in our case the goal objective is the minimum cost to achieve the flow and pressure requirements [16].

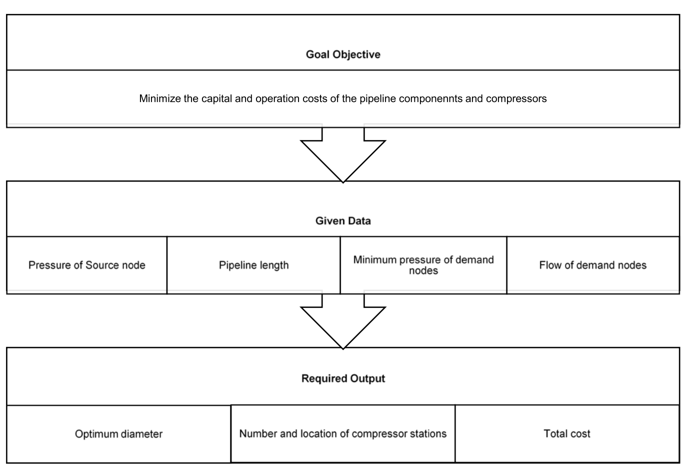

Figure 2. Representation of a problem under study.

The objective function is formulated as the total annual cost, which includes both the operating and maintenance costs of the compressors, as well as the capital costs associated with the pipeline segments and compressor stations. The annualized costs for each pipeline segment take into account the diameter and length of the pipes. In the model, each compressor is assumed to operate adiabatically, with its inlet temperature equal to the ambient temperature.

The flow correlation used is the Panhandle B equation. The calculated flow (Q) in equation (1) is used to calculate the work (W) for a compressor by equation (2) [11]. The pipeline set is indicated as (I) and the compressor set is indicated as (J).

$$Q(I) = 737 \times EP \times \frac{Tb}{Pb} \times D(I)^{2.53} \times [(\frac{PD(I)^2 - PS(I)^2}{L(I) \times T \times Z \times (G)^{0.961}})^{0.51}] \quad (1)$$

where: Q = flow rate (SCFD); D = pipeline diameter (inch); D = pipeline length (mile); Pb = base pressure (psia); Tb = base temperature (R); T = suction temperature (R); PS =suction pressure (psia); PD = discharge pressure (psia); EP = pipeline efficiency (decimal value); Z = compressibility factor (dimensionless); G = specific gravity (dimensionless).

$$W(J) = 0.0857 \times Q(I) \times T \times \frac{K}{K-1} \times Z \times \frac{1}{EC} [(\frac{PD(I)}{PS(I)})^{\frac{Z(K-1)}{K}} - 1] \quad (2)$$

where: W = compressor work (HP); K = suction condition (the ratio of specific heats of gas (dimensionless)); Q = flow rate (MMSCFD); T = suction temperature (R);
PS =suction pressure (psia); PD = discharge pressure (psia); Z = compressibility factor (dimensionless); EC = compressor adiabatic (isentropic) efficiency (decimal value).

The objective function is minimizing the total cost. The total cost is calculated by equation (3) includes the sum of the investment cost over 10 years and the operating annual cost for all arcs [17].

$$ATC = MIN\,(ICP + OCP + ICS + OCS) \times AF \quad (3)$$

where: ATC = total cost ($/year); ICP = investment cost of pipelines capital cost ($/year); OCP = operating cost of pipeline operating cost ($/year); ICS = investment cost of compressor stations ($/year); OCS=operating cost of compressor stations ($/year); AF=annuality factor (4.75).

The compressor costs are classified into operating and maintenance costs and capital costs which are calculated in equations (4) and (5) respectively.

$$OCS = \sum_{J=1} CO \times W(J) \times 1.1 \quad (4)$$

where: OCS = operating cost of compressor stations ($/year); CO = compressor operating cost constant (8.2 €/kW year); W = compressor work (kW).

$$ICS = \sum_{J=1} (CC \times W(J) + CS \times B(J)) \times 1.1 \quad (5)$$

where: ICS = investment cost of compressor stations ($/yr); CC = compressors variable capital cost constant (70 €/kW year); W = compression horsepower (kW); CS = compressor station fixed capital cost constant (7410 €/year); B = compressor decision (if a compressor is present, B= 1).

The pipeline costs are classified into capital costs and operating costs which are calculated in equations (6) and (7) respectively.

$$ICP = \sum_{I=1} (CP \times L(I) \times D(I)) \times 1.1 \quad (6)$$

where: ICP = investment cost of pipelines capital cost ($/year); CP = pipeline capital cost constant (15778 €/kM M year); L = pipeline length (kM); D = pipeline diameter (M).

$$OCP = \sum_{I=1} (CF \times L(I) + CV \times (D(I) - 16) \times L(I)) \times 1.1 \quad (7)$$

where: OCP = operating cost of pipeline operating cost ($/year); CF = pipeline fixed cost constant (600 €/kM year); CV pipeline variable cost constant (20 €/inch kM year); D = pipeline diameter (inch); L pipeline length (kM).

The commonly used standard diameters in the Egyptian network are given in constrain equation (8).

$$16 \le D(I) \le 42 \quad (8)$$

where: D = pipeline diameter (inch).

The maximum pressure in the Egyptian network is given in constrain equations (9) and (10).

$$PS \le 70 \quad (9)$$

where: PS =suction pressure (bar).

$$PD \le 70 \quad (10)$$

where: PD = discharge pressure (bar).

3.3. Problem statement

Concerning the expansion problems, the most common methods to increase the transportation capacity of an existing gas pipeline is to install a compressor or to increase the pipeline diameter or to apply both previous methods. Comparing the first two methods as the following:

3.3.1. Adding a compressor

A compressor unit is a device used to elevate the pressure of natural gas by compressing its volume. This pressure boost enables the gas to overcome frictional losses in the pipeline and maintain the necessary flow and pressure levels as it moves toward the next compressor station or the end users [18]. The main criteria for selecting compressor units include reliability, energy efficiency, initial investment costs, and ongoing maintenance expenses [19]. Other considerations are operability, site location and environmental impact.

The main advantages of this method are as following [20]: i) Energy efficiency: Compressors can be strategically placed to maintain optimal pressure throughout the pipeline; ii) Reliability: They can be adjusted or upgraded to meet changing demand and pressure requirements; iii) Site location: Compressors do not require significant changes to the existing pipeline infrastructure. On the other hand, the main disadvantages are as following [20]: i) Cost: High initial investment and ongoing operational costs, including maintenance and energy consumption; ii) Operability: Requires skilled personnel for operation and maintenance; iii) Environmental Impact: Potential for noise and emissions.

3.3.2. Increasing pipeline diameter

A gas pipeline is to be designed to transport a fixed amount of gas from one point to others. Given the known initial and final conditions of the gas, it is required to determine the number of compressor stations, length of the pipeline segments, diameter of pipeline segments and suction and discharge pressures at each station to satisfy the required flow and final pressure [13]. For modeling flow behavior and pressure drop in the pipeline, the Panhandle B equation is considered the most suitable due to its accuracy in representing high-pressure, long-distance gas transmission systems.

The main advantages of this method are as following [21]: i) Lower Friction: Larger diameter reduces friction, leading to lower pressure drops and improved flow efficiency; ii) Energy Savings: Less energy is required to move gas through a larger pipeline, reducing operational costs; iii) Longevity: Larger pipelines can handle higher volumes and may have a longer lifespan due to reduced wear and tear. On the other hand, the main disadvantages are as following [21]: i) Cost: Significant capital investment for materials and construction to replace or upgrade existing pipelines; ii) Disruption: Construction and installation can be disruptive to existing operations and the environment; iii) Inflexibility: Once installed, the pipeline diameter cannot be easily changed to adapt to future demand.

In brief, adding a compressor is generally more flexible and can be tailored to specific pressure needs, but comes with higher operational costs and environmental considerations. Increasing Pipeline Diameter offers long-term efficiency and lower operational costs but requires substantial initial investment and can be disruptive during installation. There is no solution fit for all, but the best choice depends on the specific needs, budget, and long-term plans for the natural gas network.

3.4. Case study

The case we studied in this research is a field case study about the Eastern Gas Network at Egypt. It is a multiperiod case study which is classified into two periods. At first period, the supply source is Zohr field. And the second period is after the decrease of production of Zohr field supply source so additional supply sources are added.

As shown in Figure 3, the study layout for the Eastern Gas Network is explained. It is classified into:

1) First period, the network with the main supply source from Zohr field.

A) The initial network study to check if the required parameters are achieved.
B) A modified network study to achieve the required flow and pressure by the following methods:
   B1) Method 1: increasing pipeline diameters.
   B2) Method 2: adding a compressor.
      B2.1) Compressor is added at Port Said
      B2.2) Compressor is added at Ismailia
   B3) Method 3: increasing pipeline diameters plus adding a compressor.
      B3.1) Compressor is added at Port Said
      B3.2) Compressor is added at Ismailia

2) Second period, a network with additional new supply sources is established after the production decrease of Zohr source.
   C) New sources network study to compensate for the quantity decreased while keeping the pressures above the minimum required pressure by the following method.
      C1) Method 1: adding new sources and increasing pipeline diameters.
         C1.1) Adding Mediterranean Sea source and increasing its diameter.
         C1.2) Adding Red Sea source and increasing its diameter.
         C1.3) Adding Red Sea and Mediterranean Sea sources and increasing their diameters.
      C2) Method 2: adding Mediterranean Sea source with a compressor on it.
      C3) Method 3: adding Red Sea source and Mediterranean Sea source with a compressor on it.

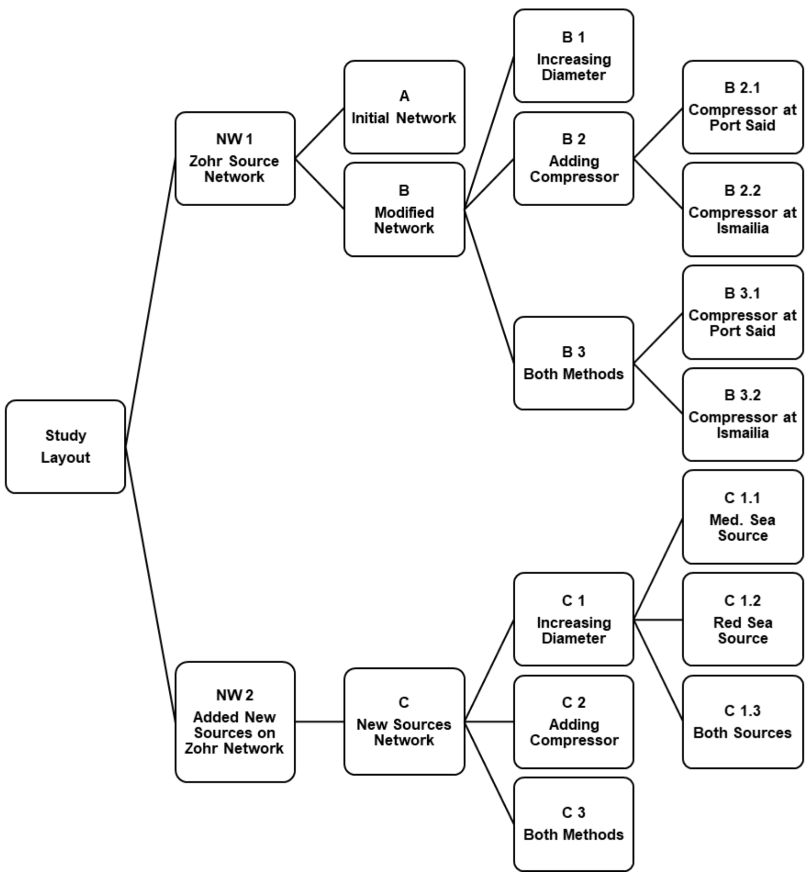

Figure 3. Study layout.

Period (1): Eastern gas network (NW1):

Zohr is an Egyptian natural gas offshore field in the Mediterranean Sea. For the network under study and as shown in figure (4). The only natural gas source, Zohr Gas Field (70 bar), feeds 3 branches including 5 large consumers: Damietta in the first branch, El-Shabab in the second branch and Port Said, Ismailia and Suez in the third branch.

As shown in figure (4), it illustrates the configuration of the Eastern Gas Network (NW 1) first period from Zohr source indicating:

1. The supply source.
2. The consumers.
3. The required flow rate for each consumer.
4. The minimum required pressure for each consumer.
5. The supply source pressure.
6. The pipelines length.

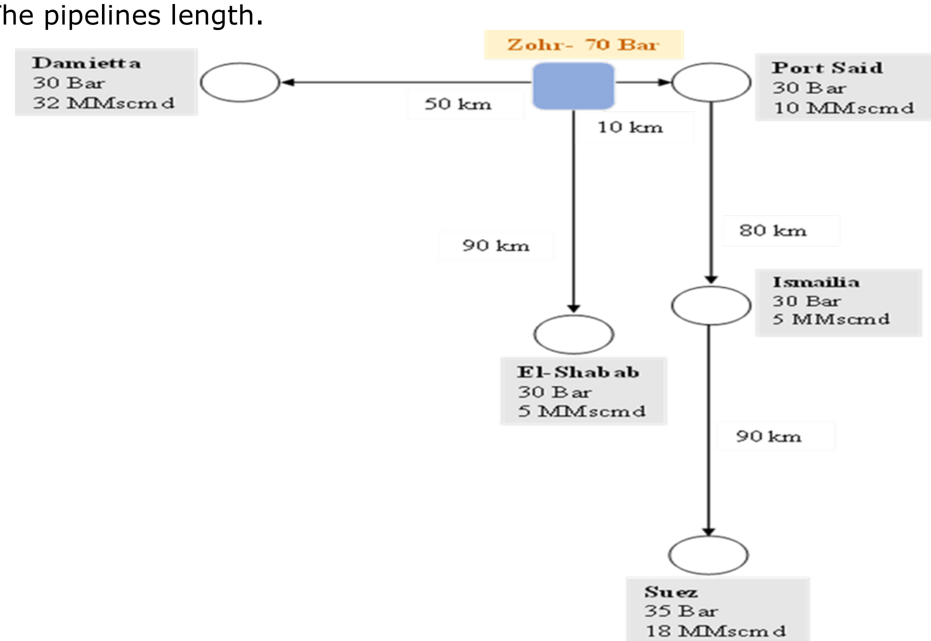

Figure 4. Eastern gas network (NW 1) first period.

Table 1 shows the required minimum pressure, the required flow for each consumer and the length of the network pipelines.

Table 1. The Eastern gas network (NW1) data.

Pipeline	Required minimum pressure Prm [bar]	Diameter [Inch]	Length [km]	Flow [MMscmd]
Zohr / Damietta	35	32	50	32
Zohr / El-Shabab	30	16	90	5
Zohr / Port Said	30	32	10	10
Port Said / Ismailia	30	30	80	5
Ismailia / Suez	35	30	90	18

4. Results and discussion

4.1. Initial network

First, we calculated the initial case (NW1) without any modification and checked for the required flow rates and minimum pressures. The cost of this initial network is calculated by cost equation from equation (3) to equation (7) and equals $ 19067278. As shown in Table 2, the minimum pressure values for the initial network are obtained for each consumer except for Suez. So, this network needs modification until the pressure in Suez (Psz) be greater than the minimum pressure required in it (Psz-rm) by at least 1 bar.

Table 2. The initial network results.

Pipeline	Pressure [Bar]	Flow [MMscmd]
Zohr / Damietta	52.01	32
Zohr / El-Shabab	34.34	5
Zohr / Port Said	66.65	10
Port Said / Ismailia	44.97	5
Ismailia / Suez	8.74	18

4.2. Modified network

There are three methods to increase the pressure value to the required minimum pressure: by increasing the pipeline diameter, by adding a compressor or combination of the two previously mentioned methods.

4.2.1. Method (b1): increasing pipeline diameter

As shown in Table 3, we made trials for method (b1) by increasing the pipeline diameters till we obtained the required minimum pressures for this network in the 5th trial. Trials are done by changing each segment alone or combination of two segments or all segments at same time.

Table 3. Method (b1) trials (increasing pipeline diameters).

Trial No. >	1st	2nd	3rd	4th	5th
Zohr / Damietta (D.)	32	32	32	32	32
Zohr / El-Shabab (D.)	16	16	16	16	16
Zohr / Port Said (D.)	32	34	34	32	34
Port Said / Ismailia (D.)	32	30	32	32	32
Ismailia / Suez (D.)	30	30	30	32	32
Pressure at Suez (Psz)	28.77	10.01	30.48	35.14	38.3
Remarks	Psz < Psz-rm	Psz < Psz-rm	Psz < Psz-rm	Psz ≡ Psz-rm	Psz > Psz-rm

4.2.2. Method (b2): (adding a compressor)

As shown in Table 4, we made trials for method (b2.1) by adding a compressor at Port Said and increasing the compression ratio till we obtained the required minimum pressures for this network in the 2nd trial.

Table 4. Method (b2.1) trials (adding a compressor at Port Said).

Trial No. >	1st	2nd
Compressor at Port Said (C.R.)	1.1	1.15
Pressure at Suez (Psz)	33.31	36.73
Remarks	Psz < Psz-rm	Psz > Psz-rm

As shown in Table 5, we made trials for method (b2.2) by adding a compressor at Ismailia and increasing the compression ratio till we obtained the required minimum pressures for this network in the 2nd trial.

Table 5. Method (b2.2) trials (adding a compressor at Ismailia).

Trial No. >	1st	2nd
Compressor at Port Said (C.R.)	1.3	1.35
Pressure at Suez (Psz)	33.27	36.66
Remarks	Psz < Psz-rm	Psz > Psz-rm

4.2.3. Method (b3): (adding a compressor plus increasing pipeline diameter)

As shown in Table 6, we made trials for method (b3.1) by adding a compressor at Ismailia and increasing the compression ratio plus increasing the pipeline diameters till we obtained the required minimum pressures for this network in the 2nd, 4th, 5th and 7th trials.

Table 6. Method (b3.1) trials (adding compressor at Ismailia plus increasing pipeline diameters).

Trial No. >	1st	2nd	3rd	4th	5th	6th	7th
Zohr/Damietta (D.)	32	32	32	32	32	32	32
Zohr/El-Shabab (D.)	16	16	16	16	16	16	16
Zohr/Port Said (D.)	32	32	34	34	32	34	34
Port Said/Ismailia (D.)	32	32	32	32	32	30	30
Ismailia/Suez (D.)	30	30	30	30	32	30	30
Compressor at Ismailia (C.R.)	1.1	1.15	1.05	1.1	1.05	1.25	1.3
Pressure at Suez (Psz)	34.98	38.84	34.8	38.83	38.67	33.31	36.81
Remarks	Psz < Psz-rm	Psz > Psz-rm	Psz < Psz-rm	Psz > Psz-rm	Psz > Psz-rm	Psz < Psz-rm	Psz > Psz-rm

As shown in Table 7, we made trials for method (b3.2) by adding a compressor at Port Said and increasing the compression ratio plus increasing the pipeline diameters till we obtained the required minimum pressures for this network in the 2nd, 3rd, 4th and 6th trials.

Table 7. Method (b3.2) trials (adding compressor at Port Said plus increasing pipeline diameters).

Trial No. >	1st	2nd	3rd	4th	5th	6th
Zohr/Damietta (D.)	32	32	32	32	32	32
Zohr/El-Shabab (D.)	16	16	16	16	16	16
Zohr/Port Said (D.)	34	34	34	32	32	32
Port Said/Ismailia (D.)	30	30	32	32	32	32
Ismailia/Suez (D.)	30	30	30	32	30	30
Compressor at Ismailia (C.R.)	1.1	1.15	1.05	1.05	1.05	1.1
Pressure at Suez (Psz)	33.86	40.75	37.44	42.66	35.86	42.01
Remarks	Psz < Psz-rm	Psz > Psz-rm	Psz > Psz-rm	Psz > Psz-rm	Psz ≡ Psz-rm	Psz > Psz-rm

To obtain the least cost feasible acceptable solution, we collected all acceptable solutions at which all the parameters are achieved from methods b1, b2.1, b2.2, b3.1 and b3.2 and compared their total costs with reference to the cost of the initial case to choose the least one as shown in Table 8. It was found that trial 5th of method no. b1 is the least cost method to obtain the required minimum pressure for the transportation network NW 1. In addition, the increasing diameter method is the least cost due to the addition of the capital cost of the compressor and its operating cost.

Table 8. Comparison of the total cost among all acceptable trials for NW 1.

Method No.	Accepted trial No.	Total cost [10^6 $]	Difference to initial case cost [10^6 $]
b1	5	19.86	0.79
b2.1	2	21.87	2.8
b2.2	2	20.62	1.55
b3.1	2	20.7	1.63
	4	20.34	1.27
	5	20.28	1.21
	7	21.54	2.48
b3.2	2	20.66	1.59
	3	20.02	0.96
	4	20.38	1.31
	6	20.49	1.42

4.3. Period (2): Extended Eastern gas network (NW2)

Natural gas produced at Egypt's largest field, Zohr, continued to decline over the course of 2023, according to reporting by the Middle East Economic Survey (MEES) [22]. So, due to the drop in the natural gas production from Zohr Field, it is needed to add another source of natural gas. The flow of Zohr source decreased by more than 20 million, so we needed to compensate for the quantity decreased while keeping the pressures above the minimum required pressure.

As shown in Figure 5, it illustrates the configuration of the Extended Eastern Gas Network (NW 2) second period from Zohr source and additional new sources (Mediterranean Sea source and Red Sea source) indicating:

1. The supply sources.
2. The consumers.
3. The required flow rate for each consumer.
4. The minimum required pressure for each consumer.
5. The supply sources pressure.
6. The pipelines length.

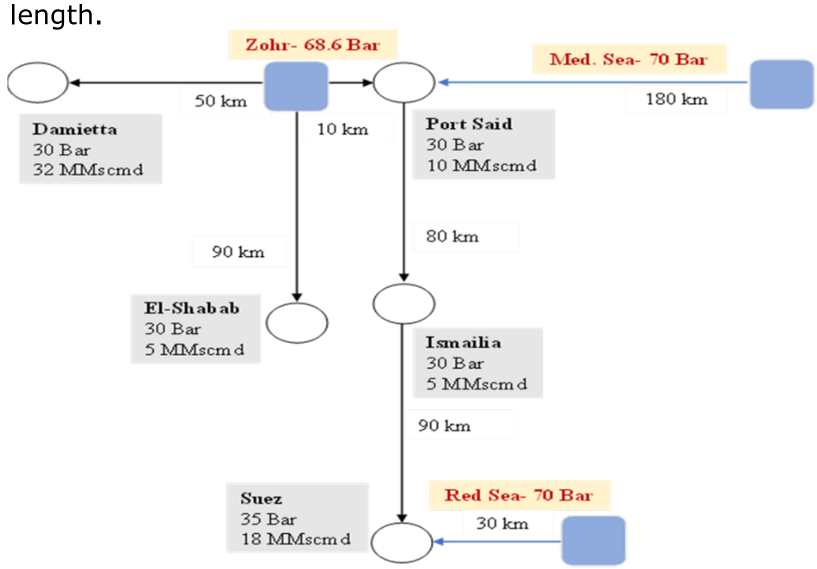

Figure 5. Extended Eastern Gas Network (NW 2) second period.

4.3.1. New sources network

There are two available sources that we can use Mediterranean Sea source and Red Sea source provided that the quantity received from Mediterranean Sea source shouldn't exceed 25 million and quantity received from Red Sea source shouldn't exceed 21 million and the total amount received from both sources shouldn't exceed 35 million.

4.3.1.1. Method (c1): (adding new sources and increasing pipeline diameter)

As shown in Table 9, we made trials for method (c1.1) by adding Mediterranean Sea source and increasing the pipeline diameter till we obtained the maximum allowable flow for this network, but no trial is acceptable.

Table 9. Method (c1.1) trials (adding Mediterranean Sea source).

Trial No. >	1st	2nd
Zohr pressure [bar]	70	70
Zohr flow [MMscmd]	61	57.2
Mediterranean Sea diameter [inch]	36	42
Mediterranean Sea pressure [bar]	68.6	68.6
Mediterranean Sea flow [MMscmd]	9	12.8

As shown in Table 10, we tested method (c1.2) by adding a Red Sea source and increasing the pipeline diameter until we obtained the maximum allowable flow for this network in the second trial.

Table 10. Method (c1.2) trials (adding Red Sea source).

Trial No. >	1st	2nd
Zohr pressure [bar]	70	70
Zohr flow [MMscmd]	51.5	49.2
Red Sea diameter [inch]	32	36
Red Sea pressure [bar]	68.6	68.6
Red Sea flow [MMscmd]	18.5	20.8

As shown in Table 11, we tested method (c1.3) by adding Red Sea and Mediterranean Sea sources and increasing the pipeline diameter until we obtained the maximum allowable flow for this network in the second, third, and fourth trials.

Table 11. Method (c1.3) trials (adding Red Sea and Mediterranean Sea sources).

Trial No. >	1st	2nd	3rd	4th
Zohr pressure [bar]	70	70	70	70
Zohr flow [MMscmd]	51.1	49	45.2	43.3
Mediterranean Sea diameter [inch]	36	36	36	36
Mediterranean Sea pressure [bar]	68.6	68.6	68.6	68.6
Mediterranean Sea flow [MMscmd]	7.6	7	6.9	6.7
Red Sea diameter [inch]	24	28	32	36
Red Sea pressure [bar]	70	70	70	70
Red Sea flow [MMscmd]	11.3	14	17.9	20
Mediterranean and Red Sea total flow [MMscmd]	18.9	21	24.8	26.7

4.3.1.2. Method (c2): (adding a new source with a compressor)

As shown in Table 12, we made trials for method (c2) by adding a pipeline from Mediterranean Sea source with a compressor in the middle of it and increasing the compression ratio till we obtained the maximum allowable flow for this network in the 2nd and 3rd and 4th trials.

Table 12. Method (c2) trials (adding Mediterranean Sea source with a compressor).

Trial No. >	1st	2nd	3rd	4th
Zohr pressure [bar]	70	70	70	70
Zohr flow [MMscmd]	50.9	48.7	46.8	45.2
Mediterranean Sea diameter [inch]	36	36	36	36
Mediterranean Sea line comp. (C.R.)	1.15	1.2	1.25	1.3
Mediterranean Sea pressure [bar]	68.6	68.6	68.6	68.6
Mediterranean Sea flow [MMscmd]	19.1	21.3	23.2	24.8

4.3.1.3. Method (c3): (adding a new source with a compressor plus increasing pipeline diameter)

As shown in Table 13, we made trials for method (c3) by adding a pipeline from Mediterranean Sea source with a compressor in the middle of it and another pipeline from Red Sea source plus increasing the pipeline diameters till we obtained the maximum allowable flow for this network in the 2nd, 3rd, 4th, 5th, 6th and 7th trials.

Table 13. Method (c3) trials (adding Red Sea and Mediterranean Sea sources with a compressor).

Trial No. >	1st	2nd	3rd	4th	5th	6th	7th
Zohr pressure [bar]	70	70	70	70	70	70	70
Zohr flow [MMscmd]	50.9	47.7	48.2	45.3	42.4	40.7	38.3
Mediterranean Sea diameter [inch]	36	36	36	36	36	36	36
Mediterranean Sea line compressor (C.R.)	1.05	1.1	1.05	1.05	1.05	1.05	1.05
Mediterranean Sea pressure [bar]	68.6	68.6	68.6	68.6	68.6	68.6	68.6
Mediterranean Sea flow [MMscmd]	12.9	16.3	12.8	12.4	12.2	12.2	12.3
Red Sea diameter [inch]	16	16	20	24	28	32	36
Red Sea pressure [bar]	70	70	70	70	70	70	70

Trial No. >	1st	2nd	3rd	4th	5th	6th	7th
Red Sea flow [MMscmd]	6.2	6	9	12.3	15.4	17.1	19.4
Mediterranean and Red Sea total flow [MMscmd]	19.1	22.3	21.8	24.7	27.6	29.3	31.7

To obtain the least-cost feasible acceptable solution, we collected all acceptable solutions at which all the parameters are achieved after compensating the decreased flow from Zohr source from methods c1.1, c1.2, c1.3, c2 and c3 and compared their total costs per total flow of each to choose the best as shown in Table 14.

Table 14. Comparison of the total cost among all acceptable methods for NW 2.

Method No.	Accepted trial No.	Total cost [10^6 $]	Cost per flow [10^6 $/MMscmd]
c1.2	2	22.28	1.08
c1.3	2	36.26	1.73
	3	36.52	1.47
	4	36.79	1.38
c2	2	36.26	1.7
	3	36.9	1.59
	4	37.57	1.52
c3	2	36.23	1.63
	3	36.06	1.65
	4	36.33	1.47
	5	36.57	1.33
	6	36.84	1.26
	7	37.1	1.17

It was found that trial 7^{th} of method no. c3 is the second least cost method to obtain the maximum allowable flow for the transportation network NW 2. It is the best solution as the availability of variety of flow as it starts decreasing that we can use Red Sea source alone, both sources and both sources and a compressor.

5. Conclusions

This paper proposes a model for multi period natural gas pipeline network to determine the optimal design of Eastern Gas Network in Egypt using minimum cost as objective function with PipeSim software. First period: trials were made to achieve the required pressure and flow at each consumer by three methods: increasing pipeline diameter, adding a compressor or combination of both methods. It was found that the 5^{th} trial of method no. b1 (increasing pipeline diameter) is the least cost acceptable trial at which all the parameters are achieved.

Generally, increasing pipeline diameter is the least cost due to the high operating and maintenance cost of a compressor compared with that of an equivalent pipeline. As it is a design modification case, increasing the diameter isn't an issue.

Second period: new sources were added to compensate for the drop in natural gas production of Zohr source. It was found that the 7^{th} trial of method no. c3 (adding pipeline from Red Sea source and pipeline from Mediterranean Sea source with a compressor in the middle of it plus increasing pipeline diameters) is the best solution at which all the parameters are achieved after compensating the decreased flow from Zohr source. In this trial according to the flow required, firstly the Red Sea source can be used alone, then both sources and finally both sources with a compressor along the Mediterranean Sea source pipeline and change its compression ratio. So, we don't afford the total cost at the beginning of the second period.

In some cases, adding a compressor is better compared to the increasing diameter method as it has the availability of flow change as it starts decreasing or any fluctuations. Pipeline diameter change causes fixed change, and it is preferred during design not modification of a network with decreasing supply source flow. The compressor can be used with low compression ratio and be increased in case of needing to increase the flow required. So, the operating cost isn't high from the beginning.

6. Recommendations

Natural gas networks have a dynamic nature with respect to supply and demand. So, a thorough study is needed during the design phase to estimate future flow changes and hence consider future transportation capacity. This updated and comprehensive techno-economic study is expected to select the appropriate method to accommodate future flow changes.

The selected method requires flexible measures such as extension connections, loop connections and bypass connections. Pipeline looping is a method used to increase the capacity of an existing pipeline by installing an additional pipeline either of equal or different diameter that runs parallel to the original line, forming a loop. The added loop can be of the same length or shorter than the existing pipeline. Both the original and new pipelines are connected at the beginning and end of the loop, and they may also be linked at intermediate points, depending on operational needs. When operated in synchronous mode, this configuration effectively enhances the overall capacity of the pipeline system.

Also, compressors should be specified to offer adjustable compression ratios to better accommodate changing demand. This approach minimizes capital costs while maintaining the ability to respond dynamically to future variations in gas flow. The above-mentioned approach is expected to alleviate technical difficulties and over cost related to seeking available pipeline route and the construction of additional pipelines and/or compressors.

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Authors' contributions

Omar M. Hussien is responsible for writing original draft, review and editing, visualization, software, resources, investigation, formal analysis, data curation, conceptualization and journals communication. Nasser A. Zoghaib is responsible for field data resources, methodology, investigation, conceptualization, supervision on this paper, contribution in review and editing and writing original draft. Moustafa E. Awad is responsible for validation, supervision, investigation and academic review. All authors read and approved the final manuscript.

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List of abbreviations

AF	*Annuity factor*
ATC	*Annual total cost*
B	*Compressor decision*
CC	*Compressors variable capital cost constant*
CF	*Pipeline fixed cost constant*
CO	*Compressors operating cost constant*
CP	*Pipeline capital cost constant*
CR	*Compression ratio*
CS	*Compressor stations fixed capital cost constant*
CV	*Pipeline variable cost constant*
D	*Pipeline diameter*
EC	*Compressor adiabatic (isentropic) efficiency*
EMRA	*Energy market regulatory authority*
EP	*Pipeline efficiency*
F	*Friction factor*
G	*Specific gravity*
GRG	*Generalized Reduced Gradient*
I	*Pipelines set*
ICP	*Investment cost of pipelines*
ICS	*Investment cost of compressor stations*
J	*Compressor stations set*

K	*Suction condition*
L	*Pipeline length*
MEES	*Middle east economic survey*
MINLP	*Mixed integer nonlinear optimization model*
NG	*Natural gas*
NW	*Network*
OECD	*Organization for economic cooperation and development*
OCP	*Operating cost of pipelines*
OCS	*Operating cost of compressor stations*
PD	*Discharge pressure*
PRM	*Required minimum pressure*
PS	*Suction pressure*
Q	*Flow rate*
T	*Suction temperature*
W	*Work*
Z	*Compressibility factor*

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