APPLICATION OF NUMERICAL OPTIMIZATION OF SEAWATER PUMPING SYSTEMS

by

Joseph M. Thorp

Engineering Specialist

Aramco Services Company

Houston, Texas

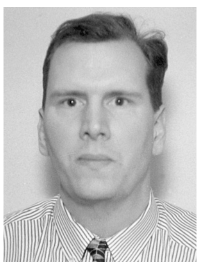
and

Jeffrey A. Olsen

Vice President, Software Architecture

Applied Flow Technology Corporation

Woodland Park, Colorado



Joseph M. Thorp is an Engineering Specialist within the Technical Services Department of Aramco Services Company (ASC), in Houston, Texas. He has provided technical support for Saudi Arabian Oil Company (Saudi Aramco) projects in Europe and North America, along with supporting field activities during interim assignments in Saudi Arabia as part of the Consulting Services Department. Mr. Thorp is Saudi Aramco's designated representative to the American Petroleum Institute Subcommittee on Mechanical Equipment that includes Vice Chairmanship of API 610 (Centrifugal Pump) and Chairmanship of API 682 (Seals). He is the API mechanical equipment representative to the International Standards Coordinating Committee who interfaces with ISO, headquartered in Europe. Prior to joining ASC, he worked with Phillips Petroleum Company.

Mr. Thorp holds a B.S. degree (Mechanical Engineering) from Michigan State University and an MBA from the University of St. Thomas. Mr. Thorp is a registered Professional Engineer in the State of Texas.

Jeffrey A. Olsen joined Applied Flow Technology in 1996 and as Vice President is primarily responsible for the architecture and development of their globally marketed software for pipe system analysis. He has contributed to software development and consulting in the areas of incompressible and compressible pipe flow; waterhammer analysis; pipe and pump systems optimization; and application deployment, protection, and training. Previously, he developed computational models of mechanical systems that were used in training simulators for the power industry. In the Thermodynamics group at General Dynamics Space Systems Division, he did engineering and research in cryogenic rocket design.

Mr. Olsen received a B.S. degree (Mechanical Engineering, 1988) and an M.S. degree (Mechanical Engineering, 1989) from Brigham Young University.

ABSTRACT

A new project to increase the oil produced at Khurais, Saudi Arabia, was the focus of a study to determine the optimal pipeline size and pump combination for a 90.4 mile (145.5 km) long, treated-seawater transfer line between Ain Dar and Khurais. The study evaluated the supply pumps at Ain Dar, operations with and without booster pumps at Khurais, and the injection pump configuration at Khurais. The entire system was optimally designed to provide the required seawater flow of 2.14 million barrels per day (62,400 gpm) for initial operations prior to 2009 with the ability to be scaled up to the planned increased flow of 3.0 million barrels per day (87,500 gpm) 10 years later.

Both first costs and life-cycle costs over 20 years were evaluated. The tradeoff of increasing initial costs to reduce life-cycle costs was examined during the study. The pipeline material considered was X-70 steel with sections welded together to form the 56 inch, 60 inch, or 64 inch diameter pipe. The study assumed the pipeline could have a maximum of two unique wall thicknesses along its entire length.

The study started from a well-engineered design and through optimization techniques realized a first cost savings of $37 million (5 percent) and life-cycle cost savings of $104 million (12 percent). This cost savings could have been greater except that part of the cost reduction was used to allow the possibility for the system to be operated at a 17 percent increased capacity without any additional expenditure for construction.

INTRODUCTION AND BACKGROUND

The design and operating variables that most impact pipeline pump life-cycle costs have been presented in the literature (Thorp, 2001). Users continue to rely on new and innovative approaches to satisfy consumer needs for reliable, low cost, and environmentally friendly oil supply. Opportunities for achieving these requirements have been necessitated through larger economies of scale stemming from burgeoning world oil demand. To that end, Saudi Aramco is implementing a historically-significant project to increase future production by increasing the total amount that can be extracted from existing fields. One method to increase the amount of oil that can be extracted from an oil field is through enhanced recovery using water injection. This is accomplished by injecting high-pressure water into the reservoir thereby forcing more oil out of the field. Many of the Saudi Arabian oil fields are located in the hot, dry, sandy desert on the eastern portion of the country. In the desert, water is a scarce commodity; however, there are vast amounts of water in the seas that border the country. A large technical hurdle that must be overcome is transporting the seawater to the oil fields over a variety of terrains using a network of pipelines and pumping stations.

As new oil fields are developed and old ones brought back into production, an ever growing network of seawater pipelines is pushed farther and farther inland. This can be a costly operation, but is also a good candidate to use optimization to find cost-cutting opportunities.

The design study described in the paper was focused on determining the best configuration of pipeline material and sizes, pumps, and pumping stations to meet both the current seawater requirements and to have the flexibility to scale to accommodate the increased demands in the future.

Optimization techniques have been used for many years on structural applications (Schmit, 1960; Vanderplaats, 1999a) but their use on pumping systems design is relatively new. Combining both systemwide flow analysis and optimization techniques provides a powerful new approach to lower costs and increase performance during system design (Hodgson and Walters, 2002; Walters, 2002).

The existing Qurayyah seawater treatment plant, located on the Persian Gulf, south of Ad Dammam and Dhahran, will send treated water westward to Ain Dar located on the north portion of the Ghawar oil field (Figure 1). The Ghawar oil field is the world's largest, producing about 4.5 million barrels per day, roughly 5.5 percent of the world's daily production, and has the highest sustained oil production rate achieved by any single oil field in world history (Croft, 2005). It stretches 174 miles from north to south and 16 miles across to encompass 1.3 million acres (Durham, 2005). There have been 3400 wells drilled into this reservoir since the field was brought online in 1951.

Figure 1. General Area Overview of Saudi Arabia Showing the Ghawar, Ain Dar, and Khurais Oil Fields.

Located west of Ghawar are the Khurais, Abu Jifan and Mazalij oil fields (Figure 2). Khurais is the closest and by far the largest being 78.9 miles (127 km) long and covering 1116 sq miles (2890 sq km) (Saudi Aramco, 2007). It is about 155 miles (250 km) southwest of Dhahran and 186 miles (300 km) northeast of Riyadh, the Saudi capital. Khurais is of similar structure and lies parallel to Ghawar, but is smaller in size. Saudi Aramco has initiated a major project aimed at increasing the production at Khurais from 300,000 to 1.2 million barrels per day by 2009 (Croft, 2005; Oil and Gas, 2006), which would make it the largest incremental increase in world oil supply in the 75 year history of Aramco.

Figure 2. Details of the Ghawar and Khurais Oil Fields.

Meeting increasing oil demand from China, India, and other developing countries is the fundamental purpose of this project. To accomplish this at the lowest possible life-cycle, cost numerical optimization methods were used.

SCOPE OF STUDY

General Overview

Existing operations currently use treated seawater pumped from the Persian Gulf to Ain Dar on the northern side of the Ghawar oil field. The idea is to use this source and pump it an additional 90.4 miles (145.5 km) westward to Khurais. The general system guidelines called for two supply pumps at Ain Dar that would send the seawater though a single, terrain-following pipeline. Pipe was delivered to the site in 80 foot sections where welding of the pipe sections and bending were performed in-situ as required by the terrain.

When the seawater arrived at Khurais, booster pumps would increase the pressure to meet the suction requirements of the high-pressure injections pump. The tradeoff of incorporating booster pumps and operating at a lower pipeline pressure versus operating the pipeline at a higher pressure and eliminating the booster pumps was a major design consideration.

Original Design

The study started from a well-engineered design, which will be referred to as the Original Case. This called for two supply pumps, three booster pumps and five water-injection pumps. The pipeline was specified using X-60 steel with a 64 inch inner diameter and a constant wall thickness of 0.562 inches throughout. Figure 3 shows an overview of the original system.

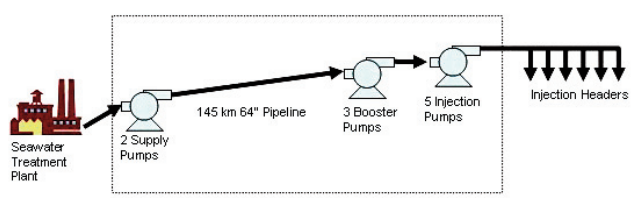


Figure 3. Original Design with Booster Pumps.

The input data used in the development of the numerical model were based on the performance curves for two API type BB2, 20 × 40, single-stage pumps running at 1800 rpm each having an assumed impeller diameter of 38.07 inches (967 mm). These gas turbine driven units were each selected to provide a rated capacity of 31,200 gpm (7086 m^3/hr).

The performance and cost data for three booster pumps at Khurais (two operating and one spare) were entered into the model and were assumed to be API type BB1, 30 × 28 single-stage, double-suction, motor-driven pumps, also having a rated capacity of 31,200 gpm (7086 m^3/hr) at 1780 rpm.

The five injection pumps are gas turbine driven, API type BB5, 20 × 20 × 21 radially split, multistage barrel pumps running at 4134 rpm. Each is rated at 12,500 gpm (2844 m^3/hr). These injection pumps were used in each of the cases studied.

Optimized Design Configurations

Various pump combinations and configurations were examined during the study to find the one that would supply the flow demands and be the most cost-efficient. Tradeoffs between operating pressures, number of pumps needed, pipeline diameter, and pipeline wall thickness were evaluated. The system was designed to handle a continuous flowrate of 2.14 Mbbl/day (million barrels per day), or approximately 62,400 gpm, under normal operating conditions. Figure 4 shows a typical system with the booster pumps eliminated.

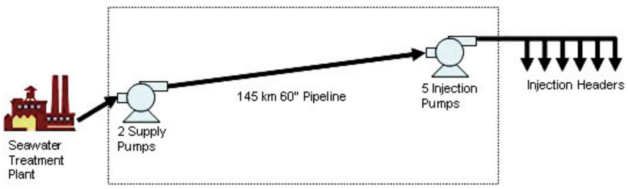


Figure 4. Optimized Design Case without Booster Pumps.

The seawater supply pump requirements called for a rated capacity of 31,200 gpm (7086 m^3/hr) with a rated suction pressure of 97.0 psig (6.69 bar). The required head developed depended on the pump and pipeline configuration. Several candidate pumps were evaluated. These included an API type BB3, 20 × 26, two-stage, double-suction with an impeller trimmed to 25.35 inches (644 mm) running at 2300 rpm; an API type BB2, 20 × 40, single-stage with a 38.07 inch (967 mm) impeller running at 1800 rpm; and an API type BB3, (20 × 20) × 24 × 28, two-stage, dual-suction using a 29.0 inch (737 mm) impeller running at 1965 rpm. These are all gas-turbine driven through a gearbox with two pumps operating in parallel.

Depending on the supply pump selected and the pressure loss through the pipeline, booster pumps may be required to raise the available suction pressure at the inlet of the injection pumps above the minimum requirement to avoid cavitation and other problems. The single-stage booster pump candidates were an API type BB1, 30 × 38, dual-suction with a 36 inch (914 mm) impeller running at 1180 rpm; an API type BB1, 30 × 28, dual-suction with a 24.25 inch (616 mm) impeller running at 1780 rpm; an API type OH2, 14 × 16 × 24, end suction with a 21.97 inch (558 mm) impeller running at 1780 rpm; and an API type BB1 16 × 32, single-stage, dual-suction with a 30.66 inch (779 mm) impeller running at 1175 rpm. The design specified three motor-driven booster pumps in parallel with two running and one spare.

As part of defining the configurations, the issue of eliminating the booster pumps altogether played an important role. Eliminating the pumps would reduce the first and life-cycle costs and increase reliability. However, this would require higher pipeline pressures, stronger pipe and larger supply pumps to ensure the injection pumps have the necessary net positive suction head (NPSH). This tradeoff was assessed in this study.

The pipeline will be constructed by welding the pipe sections at the installation site. The Original Design called for a 64 inch diameter pipeline with a 0.562 inch wall along the entire length constructed from X-60 steel, which has a yield strength of 60,000 psi.

The optimized cases used X-70 steel, which has a yield strength of 70,000 psi. The increased steel cost was offset by the higher strength and reduced required wall thickness. The study considered only pipeline diameters of 56, 60, and 64 inches. The smaller diameters required less steel and are less costly to fabricate. This came at the expense of higher fluid velocities, greater pressure drops, and increased required hydraulic horsepower.

Another change from the original design examined in the study is to allow varying wall thicknesses along the length of the pipeline. In general the highest pressure the pipeline would experience is at the discharge of the supply pumps—from there the pressure tended to decrease. To meet the operating pressure requirements the entire pipeline must be constructed with a wall thickness dictated by the supply pump discharge pressure. To minimize construction and maintenance costs a maximum of two wall thicknesses was allowed for the optimized designs. Significant cost savings were realized by determining what wall thicknesses should be used and at what point this change should take place.

Future Operations

Another important consideration in the design was the ability to increase the seawater flowrate to 3.0 Mbbl/day after 10 years. This required the pipeline to withstand higher pressures because the pumps needed to overcome increased frictional losses. One option to minimize this pressure requirement was to construct a parallel loop of pipeline for a specified length, which then recombined with the main line at some point downstream of the supply pumps. This decreased the flowrate in the main line and reduced the pumping requirements due to pressure loss. Figure 5 shows a typical system using the expansion loop.

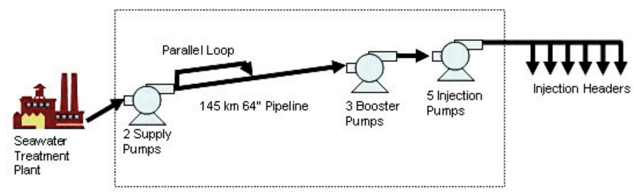


Figure 5. Optimized Design Using Parallel Loop for Increased Flowrate.

The parallel loop would be fabricated using the same size and type of steel from which the main line is constructed. The location of where the loop reconnects into the main line was determined by the operating conditions of the supply pumps. Since the wall thickness of the main line was sized to withstand the supply pump discharge pressure at the initial design flowrate, the loop line needed to carry enough of the additional flow so that this discharge pressure was not increased. The higher flowrate increased the pressure loss in the pipeline, which resulted in a lower pressure at the end of the pipeline, so booster pumps were required to be added to the system.

The original design did not have any additional flow capacity built in so an additional parallel loop would be required if the system flowrate was increased. One of the goals in this study was to build in some expansion capability while reducing the overall cost of the system. This would allow some changes in the operation over time before another major construction project must be initiated to build a parallel loop.

Additional study cases were run at an increased design flow of 2.5 Mbbl/day to investigate the cost-benefit of building into the initial design this additional capacity. This required increased first costs for thicker-walled pipe to withstand the higher pressures required for the higher flowrate. However, it provided the flexibility to vary the flow without incurring the much greater costs of pipeline and pump modifications.

System Constraints and Parameters

The maximum allowable operating pressure (MAOP) can be determined by Equation (1), which results in the original design (60 inch, X-60 steel) having a MAOP of 758.7 psig.

$$P = \frac{2SFt}{D} \quad \textbf{(1)}$$

where:
P = Maximum pressure or MAOP, psig
S = Pipe minimum yield strength, psi
F = Design factor = 0.72
t = Pipe wall thickness, inches
D = Nominal outside pipe diameter, inches

Based on system safety requirements, the maximum design operating pressure (MOP) cannot exceed 95 percent of the MAOP for the specific pipe diameter and wall thickness. Therefore, Equation (1) can be written in terms of the design pressure and wall thickness as shown in Equation (2), which was used as a constraint of the optimization.

$$MOP = 0.95 * \frac{2SFt}{D} \quad \textbf{(2)}$$

Additionally, the wall thickness must satisfy a minimum project design requirement shown in Equation (3).

$$\frac{D}{t} < 120 \quad \textbf{(3)}$$

where:
D = Nominal outside pipe diameter, inches
t = Pipe wall thickness, inches

The wall thickness transition location was determined using both Equations (2) and (3). The minimum wall thickness for a given pipe diameter based on Equation (3) was substituted into Equation (2) to determine the maximum pressure for the minimum wall thickness. Then, based on the results, the point along the pipeline at which this pressure was never exceeded farther downstream was where the wall thickness was transitioned. Note that the pressure used is based solely on the pipe geometry; however, the transition point is based on the system configuration and operation.

It is important to design the system with all operating conditions in mind. The pipeline must not only withstand the pressure under flow conditions but also the static pressure that results when the pumps are tripped. This shutoff column head is based on the supply pump shutoff head less the elevation difference to any point in along the pipeline. In general, the pipeline traveled uphill from the supply pumps; however, it did follow the contours of the land.

Both first costs and life-cycle costs were taken into account. The system was expected to operate for 20 years using a discount rate of 8.5 percent to equate all costs to present value.

OPTIMIZATION METHODS

Throughout history people have tried to optimize their environment—whether it was a farmer trying to harvest the largest yield from his crops or a traveling salesman trying to visit customers in the most efficient way. The advent of numerical computers has allowed such problems to be formulated and solved in a rigorous manner. Continued research in this field has led to better and more robust methods capable of solving increasingly complex problems. The details of the optimization methods are beyond the scope of this paper; however, a basic understanding of the fundamentals will help clarify the process used in designing the pipeline.

In all optimization problems there is an objective, $F\left(\vec{X}\right)$, which is either minimized (e.g., cost) or maximized (e.g., performance). In the case of this project the objective was to minimize the cost of the pipeline. There are several factors that make up this objective: cost of the pipeline and coating, cost of the pumps, cost of operation and maintenance, etc. The objective value is changed by changing the design variables. In this case the design variables are the diameter and thickness of the pipeline and which pumps are being used. As these design variables are changed the model is rerun to determine the new objective value or cost of the project. This process is repeated until the best design with the lowest cost is found.

Now, clearly the smallest diameter and thinnest pipe would result in the lowest cost. But there are several limits, or constraints, on the selection that the optimization must follow. These constraints include the maximum operating pressure from Equation (2), minimum wall thickness from Equation (3), pump performance characteristics, etc. Any violation of any of the constraints results in an infeasible solution and the design is discarded.

There are many methods of solving a constrained optimization problem and there is continuing research in developing even better and faster methods. Some of the more common ones are either gradient-based methods or genetic algorithms methods. One of the simplest and best known is the first-order, steepest decent method, which is a gradient-based method. This method uses the partial derivative of the objective function with respect to each design variable to determine the search direction that will result in the greatest change in the objective function. It then moves in that direction to a point by changing the design variables. Finally the objection function and partial derivatives are recalculated using the new values of the design variables. This process of sequential steps continues until the objective is optimized.

This procedure can be generalized by Equation (4), which shows the progression of the set of design variables, $\vec{X}$, from step q to $q + 1$.

$$\vec{X}^{q+1} = \vec{X}^{q} - \alpha\vec{\nabla}F\left(\vec{X}^{q}\right) \quad \textbf{(4)}$$

The steepest-decent method determines the search direction as the negative of the gradient of the objective function, as shown in Equation (5) for step q.

$$\vec{S}^{q} = -\vec{\nabla}F\left(\vec{X}^{q}\right) \quad \textbf{(5)}$$

Typically the gradient is found numerically by perturbing each of the design variables, one at a time, and calculating the partial derivative of the objective function with respect to that design variable. By substituting Equation (5) into Equation (4) one gets the steepest-decent formula, Equation (6).

$$\vec{X}^{q+1} = \vec{X}^{q} - \alpha\vec{S}^{q} \quad \textbf{(6)}$$

Once one has the search direction $\vec{S}^{q}$ one now needs to find how far to go in that direction. The move parameter α is a scalar and determines the distance along $\vec{S}^{q}$ to be traveled. There are several ways to find an α*, the distance that will yield the maximum change. The simplest is to guess two values for α, determine the objective at these points, then interpolate and iterate until α* is found. This will give a new set of design variables $\vec{X}^{q+1}$ from which one can use Equations (4, 5, and 6) for the next optimization step. This procedure is repeated until an optimum is found.

The optimization software tool used in this project incorporated several advanced methods, both gradient-based and genetic, to optimize nonlinear, constrained problems as well as perform hydraulic and cost calculations. As the optimizer engine perturbed the design variables, the hydraulic solver was run and returned the new objective function value so the gradients could be determined. This process was automatically repeated until the best design case was found. Additional details on optimization methods in general and specific to piping networks can be found in the literature (Applied Flow Technology, 2004; Hodgson and Walters, 2002; Vanderplaats, 1999b).

MODEL DEVELOPMENT

Since the various components of the system are interdependent, the most benefit can be obtained by optimizing the system as a whole. The first step was to lay out a model of the system with actual pump performance data and pipe material specifications. The hydraulic system was modeled using a leading, commercially available network pipe and pumping system optimization tool (Hodgson and Walters, 2002; Walters, 2002). This allowed for rapid development and analysis of the several cases listed above. The several pump candidates were evaluated by adding them to a database of pump curves and impeller diameter combinations. Then these were swapped into the model to be evaluated.

The model was built to follow the general terrain of the 90.4 mile (145.5 km) pipeline, which allowed for the calculation of the hydrostatic pressure at the peaks and valleys throughout the pipeline. The optimization software tool was able to calculate the hoop stress and give warnings when the allowable limit was exceeded. There was an elevation gain of 889 ft (301 m) from the supply pumps at Ain Dar (561 ft [171 m] above sea level) to the booster/injection pumps at Khurais (1450 ft [442 m] above sea level). The pipeline profile used is shown in Figure 6.

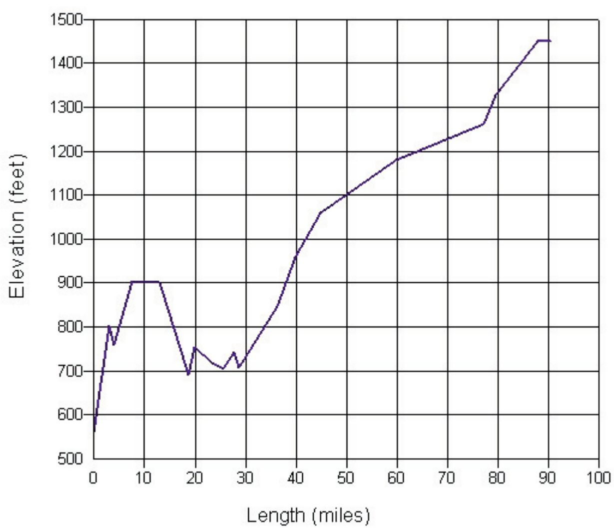


Figure 6. Elevation Change along the Pipeline from Ain Dar to Khurais.

The optimization tool was set to have the pipe wall thickness be the design variable and used the modern-penalty method to arrive at the best wall thickness based on the pipeline diameter. The constraints were automatically evaluated during the optimization process. Any wall thickness and pump combination that resulted in a constraint violation was rejected. Two objectives were evaluated and compared: minimize first costs and minimize life-cycle costs of the overall system (materials, installation, and operation).

The cost of the raw steel was based on the weight of steel used. This was independent of the size of the pipeline constructed. The installation costs did vary based on the diameter. To help minimize frictional losses and to reduce maintenance, the pipeline was coated. The coating costs also varied based on diameter. The following was used as the cost of the raw steel, fabrication, and coating:

- Steel for all pipe diameters is $1.50/kg
- 56 inch pipe: Installation = $350/meter, Coating = $58/meter
- 60 inch pipe: Installation = $377/meter, Coating = $62/meter
- 64 inch pipe: Installation = $450/meter, Coating = $66/meter

Other costs were the following:

- Electricity is $0.0267/kW-hr
- Natural gas is $0.75/MMBtu ($0.00256/kW-hr)
- Discount rate is 8.5 percent

Configurations Cases Optimized

The Original Case was modeled as a starting baseline to which the other cases were compared. The various combinations of pipeline diameter and design flowrate were examined. Booster pumps were required at the increased flow cases but were optional at the lower flowrates. Table 1 summarizes the cases that were to be analyzed.

Table 1. Cases Analyzed.

Case	Pipeline Diameter (inch)	Design Flowrate (Mbbl/day)	Include Booster Pumps
Orig	64	2.14	Yes
1	56	2.14	Yes
2	60	2.14	Yes
3	64	2.14	Yes
4	56	2.14	No
5	60	2.14	No
6	64	2.14	No
7	56	2.5	No
8	60	2.5	No
9	64	2.5	No
10	56	3.0	Yes
11	60	3.0	Yes
12	64	3.0	Yes

OPTIMIZATION RESULTS

As the matrix of cases were run it became clear that the 56 inch pipe diameter had more pressure drop for the given flowrates than could reasonably be overcome by the supply and booster pumps. These cases were eliminated altogether. It was also determined that the cost of the installation of the 64 inch pipe was large compared to the other offsetting factors, which made these cases not viable.

Of all cases run the best two will be discussed here. They will be referred to as Case A and Case B. Both used X-70 steel to construct a 60 inch diameter pipeline with a transition point between the two wall thicknesses. The booster pumps were eliminated in both cases based on the predicted NPSH at injection pumps being sufficient at the design flowrate.

Case A was optimized for a 2.14 Mbbl/day operating flowrate, which resulted in a 0.60 inch wall thickness for the first 36.3 miles (58.4 km) then transitioning to a 0.50 inch wall for the remaining 54.1 miles (87.1 km) of the pipeline.

Case B was optimized for a 2.5 Mbbl/day flowrate, which resulted in a wall thickness of 0.68 inches for the first 44.8 miles (72.1 km) and then 0.55 inches for the remaining 45.6 miles (73.4 km).

Table 2 gives a summary of the pump operating conditions for the Original, A and B Cases at the various design flows considered. Both Cases A and B used the same API type BB3, (20 × 20) × 24 × 28, two-stage, dual-suction supply pumps. At the 3.0 Mbbl/day flowrate these cases added an API type BB1, 30 × 38, single-stage, double-suction booster pump to maintain the required NPSH at the injection pumps. Both the NPSH available and required are shown for comparison in Table 2 for the booster and injection pumps.

Table 2. Pump Summary Showing Head, Pressure, and NPSH.

Case	Design Flow (Mbbl/day)	SUPPLY PUMP Total Head (ft)	SUPPLY PUMP Discharge Pressure (psig)	BOOSTER PUMP Inlet Pres (psig)	BOOSTER PUMP NPSH Available — Required (ft)	BOOSTER PUMP Total Head (ft)	INJECTION PUMP Inlet Pres (psig)	INJECTION PUMP NPSH Available — Required (ft)	INJECTION PUMP Total Head (ft)
Orig	2.14	1397	719	55.6	155 81	441	254	596 134	5777
Orig	3.0	1400	721	67.2	181 128	229	171	410 383	5963
A	2.14	1918	954	n/a	n/a	n/a	200	477 133	5896
A	3.0	1926	958	51.7	147 33	411	237	557 457	5816
B	2.14	1947	967	n/a	n/a	n/a	201	477 133	5896
B	2.5	2218	1089	n/a	n/a	n/a	200	476 234	5898
B	3.0	2045	1011	53.0	150 33	411	238	560 473	5813

Table 3 shows the optimized wall thicknesses for the Original, A and B Cases. For Cases A and B the two wall thicknesses used are shown along with their length. A parallel loop of pipe is required at the 3.0 Mbbl/day flowrate and the length of the additional loop is also shown.

Table 3. Pipeline Wall Thickness and Length with Maximum Pressures and Percent MAOP.

Case	Design Flow (Mbbl/day)	Pipe Size (in)	Pipe Type	Wall Thickness (in)	MAOP (psi)	Length (km)	Actual Max Pressure (psig)	Max MAOP Ratio (%)
Orig	2.14	64"	X-60	0.562	759	145.5	719	94.7
Orig	3.0	64"	X-60	0.562	759	145.5	721	95.0
				0.562 (loop)	759	98.0	721	95.0
A	2.14	60"	X-70	0.60	1008	58.4	954	94.6
				0.50	840	87.1	678	80.7
A	3.0	60"	X-70	0.60	1008	58.7	958	95.0
				0.50	840	87.1	710	84.5
				0.60 (loop)	1008	46.0	958	95.0
B	2.14	60"	X-70	0.68	1140	72.1	967	84.8
				0.55	925	73.4	559	60.4
B	2.5	60"	X-70	0.68	1140	72.1	1089	95.4
				0.55	925	73.4	619	66.9
B	3.0	60"	X-70	0.68	1140	72.1	1011	88.7
				0.55	925	73.4	571	61.7
				0.68 (loop)	1140	37.5	1011	88.7

Table 3 also shows the maximum pressure in the pipeline for the section of constant wall thickness. The MAOP is based on the pipe material and wall thickness and therefore constant in each section. The ratio of the maximum pressure and MAOP is also shown, which has an upper limit of 95 percent for safety reasons.

Table 4 shows the optimized costs for the three cases presented. It is broken into two parts: the top shows the costs at the 2.14 Mbbl/day configuration and the lower part shows the additional cost required to increase the capability to 3.0 Mbbl/day. The "Total Life Cycle Cost" is the overall cost of the project over the 20-year life including the additional looping construction. The "Supplemental Capacity" is the additional flow beyond the 2.14 Mbbl/day design point that the system is capable of supplying without further modifications. The Original and A Cases do not have any built-in additional capacity, but the Case B configuration allows the flow to increase by 0.36 Mbbl/day (17 percent) without additional modifications.

Table 4. Cost Overview in $Millions.

	Cost Category	Original ($MM)	Case A ($MM)	Case B ($MM)
2.14 Mbbl/day	Pipe Material Type	X-60	X-70	X-70
	Pipe Installation	198	171	190
	Ain Dar Supply Pumps	104	104	104
	Khurais Booster Pumps	20	n/a	n/a
	Khurais Injection Pumps	270	270	270
	20-year Energy	131	127	128
	Failure Maintenance	8	8	8
	Surge Tank	8	n/a	n/a
	Surge Relief / Pond	n/a	2	2
	Supplemental Capacity (Mbbl/day)	0	0	0.36
	Total Cost for Initial Flowrate	**739**	**682**	**702**
3.0 Mbbl/day	New Looping	134	59	52
	New Booster Pumps & Piping	n/a	15	15
	Additional Cost for Future Flowrate	134	74	67
Total Life Cycle Cost ($MM)		**873**	**756**	**769**

For the initial flow requirements of 2.14 Mbbl/day, cost reductions of $57 million (8 percent) and $37 million (5 percent) were realized through optimization as shown for Cases A and B, respectively. In addition to this cost reduction in Case B there is a 17 percent increase in flow capacity prebuilt into the pipeline. The potential savings to bring the system up to 3.0 Mbbl/day capacity required in the future was $117 million (13.5 percent) and $104 million (12 percent) for Cases A and B, respectively.

DISCUSSION OF RESULTS

In this study both first costs and life-cycle costs were reduced. Often one comes at the expense of the other. In this case optimization could reduce both from the Original Design because of several design changes. These were the choice of steel used, reduction of pipeline diameter, elimination of the booster pumps, and allowance of two wall thicknesses along the pipeline. These factors are discussed below.

Using the stronger X-70 steel for the pipeline allowed the supply pumps to increase their discharge pressure and, therefore, the pressure along the entire pipeline. This higher pressure allowed booster pumps to be eliminated in Cases A and B at the 2.14 Mbbl/day flowrate while still maintaining the required NPSH and inlet pressure at the injection pumps. The increased cost of the X-70 steel compared to the X-60 steel used in the Original Case was more than offset by the reduction in the total amount of steel used and the installation costs as the pipeline diameter was reduced from 64 inches to 60 inches. The increased pressures in the pipeline required thicker walls, which increased the cost slightly. The total savings on pipe installation costs was $27 million (13.5 percent) and $8 million (4 percent), respectively for Cases A and B over the Original Case.

The elimination of the booster pumps further reduced the overall system costs. There is a reduction in both first costs for the pumps and life-cycle costs for maintenance and electricity. This saved an additional $24 million over the 20-year life of the project. It is important to note that the amount of energy required to push a quantity of fluid down the pipeline at a certain flowrate is fairly constant. However, the cost of this energy varies on its source. When the electric booster pumps were eliminated, larger gas-driven supply pumps were required. In this situation, there is a net energy cost savings as well because the cost of electricity is about 10 times higher compared to that of natural gas.

This analysis also allowed tradeoff studies to be made addressing the costs associated with building into the original design an increased flow capacity. The design flow point of this expanded system was 2.5 Mbbl/day. At this increased flow the overall system pressure drop increased and, therefore, higher supply pump discharge pressures were required. This, in turn, required thicker pipe walls and an increase in the initial pipeline costs. With the system optimized for this situation the overall initial cost was increased by only 3 percent, from $682 million to $702 million, to achieve a 17 percent increase in system capacity.

To go beyond the design flowrate to meet the expected future demand of 3.0 Mbbl/day, all cases required additional piping to be installed. It was decided that the diameter of the loop would be the same as the main line for ease of maintenance. The length of this additional loop varied with each case. The wall thickness of the loop is the same as the main line because it was driven by the highest pressure the lines experienced, which was at the discharge of the supply pumps. Furthermore, the wall thickness of the main line was based on the supply pump discharge pressure at the lower flowrate. This precluded any increase in the discharge pressure the supply pumps could produce to drive the increased flow.

In a general sense, the new loop was used to reduce pressure drop in the main line, by reducing the flowrate the main pipeline is required to carry for a certain distance. This reduction would balance out the increased pressure drop due to the higher flowrate for the remaining length of the pipeline, which, in turn, would allow the supply pumps to have a constant discharge pressure. Since the main line and the expansion loop were both fed by the same supply pump discharge header and had the same geometry, they had the same pressure drop and flowrate. After the two lines were merged, the main pipeline experienced the full, increased flowrate and, therefore, had a higher pressure drop per length.

An iterative approach was used to determine the required length of loop piping. Since the pressure drop is proportional to the flowrate squared, an estimate of the pressure drop per length of pipe at the higher flowrate could be made. The new loop was the same diameter as the main line with the same wall thickness. This balanced the system and caused the total flow to be roughly split between the main line and the loop. Since the flow is known the pressure drop per length in the loop could also be estimated. Finally, the overall pressure drop from the supply pump discharge to the booster pump inlet was known based on system and pump requirements. Using this information an intelligent estimate of the length for the loop piping can be made. This then had to be adjusted based on the actual elevation of the connection point to ensure the hydrostatic pressure did not exceed the pipe stress limits. The new loop was added to the model of the system. Based on the results the location was adjusted to verify all system parameters were in the required limits.

The length and cost of the new loops needed for Cases A and B were significantly smaller than that required for the Original Case. This is due again to the higher operating pressures the X-70 steel could withstand and the system configuration. The savings for the two cases were $75 million (56 percent) and $82 million (61 percent), respectively. Case B required less loop piping cost because of the built-in additional capacity of the design.

At this higher flowrate the supply pumps cannot maintain a pipeline outlet pressure high enough to meet the injection pumps required NPSH, therefore Cases A and B needed booster pumps installed as well. These added an additional $15 million to the cost of the system expansion. As is common in pipelines, the available NPSH is many, many times the NPSH required of the pumps in order to ensure that the pipeline remains packed. The pump selection replicates pumps that have been installed in the past. Therefore, impeller life calculations were not a major concern in this study.

It is also important to note that part of the reduction in the cost of the pipe materials was the change in design requirements so that two different wall thicknesses could be used. This allowed the pipe in the downstream portion, where the pressures are not as high, to have a thinner wall. The minimum wall thickness is based on the nominal pipe diameter. From Equation (3), for the 60 inch pipe used in Cases A and B the minimum wall thickness is 0.5 inches. Using Equation (2), this translates into a maximum pressure of 798 psig.

The transition point was determined by running the model with a single wall thickness and examining the pressure profile along the length of the pipeline. The point at which the pressure in the pipeline never exceeded this maximum pressure downstream was used as the first guess at an optimal transition point. The model was then rerun using the two wall thicknesses and the pressures were reexamined to verify the pressures in the thinner-walled section still met the maximum pressure requirements. The transition point was then adjusted as necessary. Finally the pump deadhead conditions were examined to ensure the wall thicknesses were also able to withstand this increased pressure. A mitigating factor was that the supply pumps were at the lowest point in the pipeline and, therefore, would see the greatest head pressure.

RECOMMENDED CONFIGURATION

Case B was recommended and is currently under construction. This used a 60 inch diameter pipeline made from X-70 steel with a wall thickness of 0.679 inches until the 44.8 miles (72.1 km) point and then a 0.551 inch wall for the remainder of the line. The maximum pipeline pressure for the 2.14 Mbbl/day design flow was 967 psig at the supply pump discharge, which was 85 percent of the maximum allowable operating pressure.

Figure 7 shows the static pressure along the length of the pipeline for the initial design point flowrate of 2.14 Mbbl/day. The increase in pressure between 15 and 30 miles was due to the pipeline elevation decreasing over this section. The pressure for the Original Case is also shown for comparison.

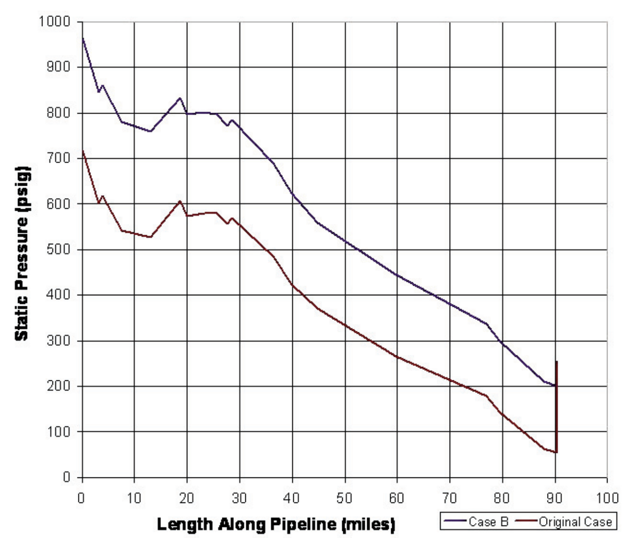


Figure 7. Static Pressure along the Pipeline from Ain Dar to Khurais for a Flowrate of 2.14 Mbbl/day.

The sharp pressure rise at the end of the Original Case curve represents the booster pumps before the injection pump inlets. Case B eliminated the booster pumps and had a higher pipeline pressure. As a result the inlet pressure at the injection pumps was 201 psig with an NPSH available of 477 ft, well in excess of the required 133 ft.

Careful inspection also shows the increased pressure drop per length of pipeline for Case B. This is a result of the smaller pipe diameter and, therefore, higher pressure loss for the given flow rate.

Figure 8 shows the pressure along the pipeline for the future flowrate of 3.0 Mbbl/day. Both Case B and the Original Case use booster pumps. The resulting pressure rise is shown at the end of each curve.

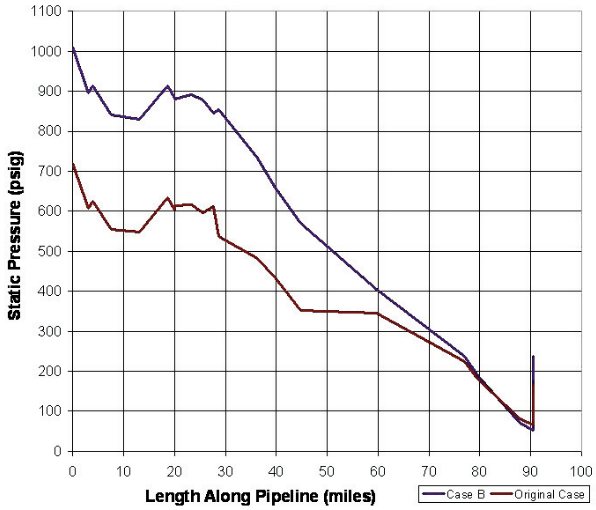


Figure 8. Static Pressure along the Pipeline from Ain Dar to Khurais for a Flowrate of 3.0 Mbbl/day.

Figures 9 and 10 show the pump data for the selected supply pump and the injection pump.

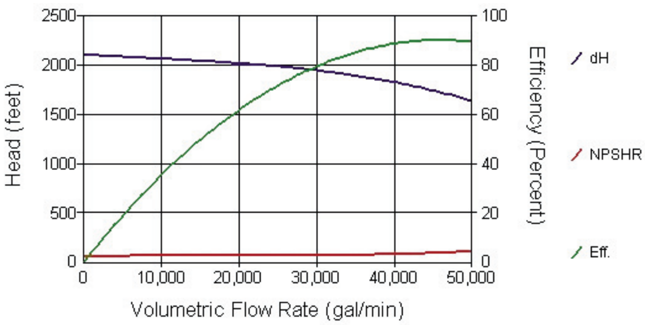


Figure 9. Pump Performance Curve for the Supply Pumps (API Type BB3, (20 × 20) × 24 × 28, Two-Stage, Dual-Suction) at Ain Dar.

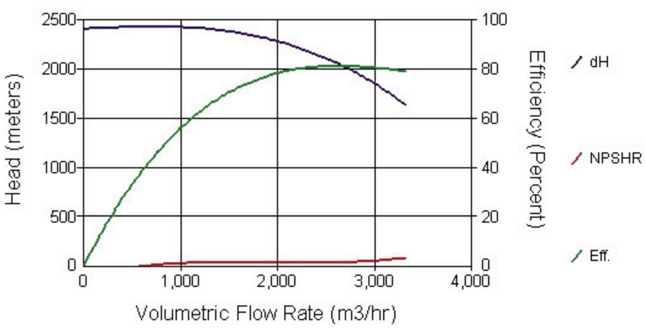


Figure 10. Pump Performance Curve for the Injection Pumps (API Type BB5, 20 × 20 × 21 Radially Split, Multistage Barrel Pumps) at Khurais.

Table 5 gives the supply pump deadhead (shutoff) conditions for the pipeline at the supply pumps and at the transition point for the three flowrates. Since the elevation at the transition point is 500 ft (152 m) above the supply pumps, the local pressure is reduced allowing a thinner wall. Again, the 3.0 Mbbl/day case has an additional loop that rejoins the main pipeline before the wall transition point.

Table 5. Deadhead Conditions at the Supply Pumps and Wall Transition Point.

	2.14 Mbbl/day		2.5 Mbbl/day		3.0 Mbbl/day	
	@ Ain Dar	@ 72.1 km	@ Ain Dar	@ 72.1 km	@ Ain Dar	@ 72.1 km
Elevation (ft)	561	1060.5	561	1060.5	561	1060.5
Pump Shutoff Head (ft)	2117	2117	2447	2447	2377	2377
Shutoff - Column Head (ft)	2117	1618	2447	1948	2377	1878
Shutoff - Column Head (psig)	953	728	1101	876	1070	845
MAOP Required (psig)	1018	766	1159	925	1126	889
0.679" wall MAOP	1140	-	1140	-	1140	-
0.551" wall MAOP	-	925	-	925	-	925

Table 5 shows the local elevation and the head generated by the supply pumps when they are deadheaded. The local head and pressure taking into account the elevation is also shown. This is then related to a required MAOP of the pipe wall based on Equation (2), being 95 percent of the actual operating pressure. Finally, the MAOP of the pipe wall is shown for the two wall thicknesses.

Figure 11 shows the sections of pipe as they are placed in the Saudi Arabian desert in preparation for welding operations. Figure 12 depicts the apparatus used to bend the pipeline. This is necessary to allow the pipeline to follow the terrain.

Figure 11. Pipeline Sections Ready for Welding in Saudi Arabia.

Figure 12. Pipeline Bending Process.

CONCLUSION

It is important to note that this study started from a well-engineered design and that through optimization additional cost savings and increased system capacity were realized. Tradeoffs in first and life-cycle costs were able to be easily examined. Changes to the system were quickly made to the model and the analysis rerun in the optimization software tool. This demonstrated the benefits of using such techniques to lower costs and increase performance during system design.

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ACKNOWLEDGEMENT

The authors would like to thank Aramco Services—Public Affairs for permission in publishing this paper. Special thanks is extended to Mr. Mohammad H. Al-Natour, Project Manager of the Khurais Seawater Pipelines & SHY-1 Expansion Division for his unwavering support and dedication to success.