Engineering Standard

SAES-L-410 26 November 2012

Design of Pipelines

Document Responsibility: Piping Standards Committee

Saudi Aramco DeskTop Standards

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1 Scope

1.1 This standard covers the additional requirements for designing onshore and near shore pipelines including cross-country pipelines, flowlines and trunklines.

1.2 This standard supplements ASME B31.4 and ASME B31.8 requirements for designing pipelines.

1.3 This standard is also applicable to submarine and offshore pipelines with exclusion of requirements that are technically not applicable.

1.4 This standard is applicable to existing pipelines that will be converted from one specific service to another type of service. Examples of pipelines in this category included, but are not limited to, pipelines converted from stabilized oil to sales gas, from sales gas to NGL and so on.

2 Conflicts and Deviations

2.1 Any conflicts between this standard and other applicable Saudi Aramco Engineering Standards (SAESs), Materials System Specifications (SAMSSs), Standard Drawings (SASDs), or industry standards, codes, and forms shall be resolved in writing by the Company or Buyer Representative through the Manager, Consulting Services Department of Saudi Aramco, Dhahran.

2.2 Direct all requests to deviate from this standard in writing to the Company or Buyer Representative, who shall follow internal company procedure SAEP-302 and forward such requests to the Manager, Consulting Services Department of Saudi Aramco, Dhahran.

3 References

The selection of material and equipment, and the design, construction, maintenance, and repair of equipment and facilities covered by this standard shall comply with the latest edition (at the project cut off date) of the references listed below, unless otherwise noted.

3.1 Saudi Aramco References

Saudi Aramco Engineering Procedures

SAEP-13	*Environmental Assessment*
SAEP-14	*Project Proposal*
SAEP-122	*Project Records*

SAEP-302	*Instructions for Obtaining a Waiver of a Mandatory Saudi Aramco Engineering Requirement*
SAEP-334	*Retrieval, Certification and Submittal of Saudi Aramco Engineering & Vendor Drawings*
SAEP-354	*High Integrity Protective Systems Design Requirements*
SAEP-363	*Pipelines Simulation Model Development and Support*

Saudi Aramco Engineering Standards

SAES-A-004	*General Requirements for Pressure Testing*
SAES-B-062	*Onshore Wellsite Safety*
SAES-B-064	*Onshore and Nearshore Pipeline Safety*
SAES-H-101	*Approved Protective Coating Systems*
SAES-J-600	*Pressure Relief Devices*
SAES-J-601	*Emergency Shutdown and Isolation Systems*
SAES-J-605	*Surge Relief Protection Systems*
SAES-L-100	*Applicable Codes & Standards for Pressure Piping Systems*
SAES-L-101	*Regulated Vendor List for Pipes, Fittings and Gaskets*
SAES-L-102	*Regulated Vendor List for Valves*
SAES-L-105	*Piping Materials Specifications*
SAES-L-108	*Selection of Valves*
SAES-L-109	*Flanges, Bolts and Gaskets*
SAES-L-110	*Limitation on Piping Components & Joints*
SAES-L-120	*Piping Flexibility*
SAES-L-125	*Safety Instruction Sheet for Piping and Pipelines*
SAES-L-131	*Fracture Control of Line Pipe*
SAES-L-132	*Material Selection of Piping Systems*
SAES-L-133	*Corrosion Protection Requirements for Pipelines/Piping*
SAES-L-136	*Pipe Selection and Restrictions*

SAES-L-140	*Thermal Expansion Relief in Piping*
SAES-L-150	*Pressure Testing of Plant Piping and Pipelines*
SAES-L-420	*Scraper Trap Station Piping and Appurtenances*
SAES-L-440	*Anchors for Buried Pipelines*
SAES-L-450	*Construction of On-Land and Near Shore Pipelines*
SAES-L-460	*Pipeline Crossings under Roads and Railroads*
SAES-L-850	*Design of Submarine Pipelines and Risers*
SAES-X-400	*Cathodic Protection of Buried Pipelines*

Saudi Aramco Standard Drawings

AB-036907	*Cathodic Protection, Pipeline KM Marker and Test Station*
AD-036973	*Marker Plates for Pipeline Kilometer Marker*

Saudi Aramco Forms and Smart Data Sheets

SDS-L-100	*Carbon Steel Line Pipe Requisition*

Saudi Aramco Engineering Reports

EPR-1714 / EPI 151-41	*Wind Induced Vibration of Pipelines (1960)*
SAER-6078	*Analysis of Buried Pipelines*

3.2 Industry Codes and Standards

American Society of Mechanical Engineers

ASME B31.3	*Process Piping*
ASME B31.4	*Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*
ASME B31.8	*Gas Transmission and Distribution Piping Systems*

3.3 Saudi Government

SSD-29	*Saudi Security and Safety Directives*

4 Definitions

All definitions listed in SAES-L-100 shall apply to this standard, including the following:

- Cross Country Pipelines
- Design Factor

- Flowlines (including trunklines and testlines)
- MAOP
- Production Pipelines
- Wellhead Piping

SMYS: Specified minimum yield strength.

5 Applicable Code and Standards

5.1 In addition to referenced Codes and Standards in this standard, the applicable Codes and standards in accordance with SAES-L-100 shall apply.

5.2 Piping systems designed and constructed in accordance with ASME B31.3 are acceptable within the scope of ASME B31.4 or ASME B31.8 subject to the approval of the Chairman of the Piping Standards Committee.

5.3 Wellhead Piping Layout

5.3.1 The wellhead piping layout and components shall be approved by the assigned specialist through coordination with Production and Facilities Development Department in the Petroleum Engineering Organization to suit the well configuration and the drilling site. Available typical installation drawings for wellhead piping shall be used as far as applicable. Refer to SAES-B-062 for safety requirements.

5.3.2 The design of the wellhead piping, based on drilling requirements including well killing and acidizing shall be provided by Area Production Engineers.

5.3.3 For new oil or gas fields and for water wells, the design basis shall be developed and approved jointly by the Chairman of Piping Standards Committee and Production and Facilities Development Department.

5.4 For submarine pipelines and risers, the additional requirements of SAES-L-850 shall apply.

6 Design Package and Project Records

The pipeline design shall include, as a minimum, the preparation of the documents listed below and shall be given Saudi Aramco engineering drawing numbers per SAEP-122. These documents shall be prepared in accordance with SAEP-334 and will become permanent plant records:

- Piping and Instrument Diagram (P&ID).

- Process Flow Diagram (PFD).
- Calculation sheets supporting flow and pressure drop data, surge analysis in liquid services, stress analysis of restrained and unrestrained pipelines, anchor design, supports for above ground and minimum cover for buried pipelines, etc., as applicable, (calculation sheets are not required for flowlines).
- Safety Instruction Sheets (SIS) per SAES-L-125.
- Pipeline route/corridor drawing.
- Piping detail drawings for end connections, branches, crossings, etc.
- Hydrostatic Test Diagram and pressure testing plans per SAES-A-004 and SAES-L-150.
- Pipe support and anchor detail drawings.
- Project Scope of Work or Project Specifications covering the installation and highlighting any special features or precautions, tie-in temperature range, procedures for testing, lay-up, and commissioning as applicable.
- As-built pipeline Plan and Profile drawings including pipeline data and appurtenance information such as topography, area classification and design factors, MAOP, station location of all accessories along the pipeline presented in a tabular form along the route of pipeline.

7 Pipeline Optimization Study

7.1 Each new pipeline shall be thoroughly studied to evaluate its technical and economical feasibility. The economic analysis shall include a Life Cycle Cost Analysis. The study shall be conducted no later than the Project Proposal stage and shall address the following as a minimum:

a) Pipe diameter, wall thickness and material type and grade.

b) Pipeline routing, construction method (i.e., aboveground or buried) and their impact on initial capital, operation, and maintenance expense.

c) Pipeline area classification.

d) The maximum allowable operating pressure, the available inlet pressure and the minimum required delivery pressure.

e) Requirements for future expansion.

f) Constructability of the pipelines.

g) Design flow rate (and future needs), velocity limitations (upper and lower) imposed by the fluid composition and flow pattern for multi-phase fluid.

h) Pipeline material selection, with regard to potential corrosion and erosion affects (See SAES-L-133).

7.2 Production pipelines in gas or crude may not require detailed pipeline optimization study. For pipelines in this category, consult the Production & Facilities Development Department of E&P which is the responsible organization for the development of these pipelines.

7.3 Pipeline hydraulic studies should be conducted as needed and in accordance with SAEP-363.

8 Limitations on Design Factor and Stress Level

8.1 Each pipeline shall have an area classification per SAES-B-064. The design factors specified by this Standard, shall overrule those stipulated in ASME B31.4 and/or ASME B31.8.

8.2. Pipelines in Hydrocarbon

8.2.1 For onshore pipelines in hydrocarbon service, the design factors, F shall not exceed values listed in Table 1.

8.2.2 For offshore pipelines in hydrocarbon service, the design factor shall be 0.72. The design factor for the riser (as defined in ASME B31.4, paragraph A400.2), shall be 0.5. If the 0.5 design factor results in a wall thickness beyond the capabilities of the available In Line Inspection (ILI) tools, a design factor of 0.6 may be used for the riser subject to the approval of the Chairman of the Piping Standards Committee.

Table 1 – Design Factor for Pipelines in Hydrocarbon, Toxic and Flammable Services

Pipeline Type	Service	Class 1	Class 2	Class 3	Class 4
Cross country pipelines	Gas	0.72	0.60	0.50	0.40
Cross-country pipelines	NGL, LPG	0.72	0.60	0.50	0.40
Cross country pipelines	Crude Oil sour	0.72	0.60	0.50	0.40
Cross country pipelines	Crude Oil sweet	0.72	0.60	0.50	0.40
Cross country pipelines	Refined products	0.72	0.60	0.50	0.40
Production Pipelines	Gas Sour, & sweet	0.72	0.60	0.50	0.40
Production Pipelines	Sour crude oil	0.72	0.60	0.50	0.40
Production Pipelines	Sweet crude oil	0.72	0.72	0.50	0.40
Well head piping	all services	0.50	0.50	0.50	0.40
Pipelines over Open Water	all services	0.60	0.60	0.50	0.40

8.3 For pipelines in non-hydrocarbon, nontoxic and non-flammable services, the design factor, F shall not exceed values listed in Table 2.

Table 2 – Design Factor for Pipelines In-Services other than Hydrocarbon

Service	Class 1	Class 2	Class 3	Class 4
Sea Water	0.72	0.72	0.72	0.72
Water disposal	0.72	0.72	0.72	0.72

These design factors shall extend all the way to the break spec within the plant area.

8.4 Any buried pipeline in hydrocarbon or flammable service and within 150 m of process plant SSD fence, the design factor, F, shall not exceed 0.50.

For flowlines, testlines and trunklines in hydrocarbon service the distance is 50 m from the GOSP SSD fence but not less than 150 m from the inlet manifold header.

8.5 Piping Assemblies

8.5.1 For piping assemblies (such as jump-overs between pipelines or laterals, and main line valve bypasses) of cross country pipelines falling under paragraph 8.2 above, the design factor, F, shall be shall be in accordance with Table 1 but not more than F = 0.60.

Commentary Note:

The requirement for the lower design factor is per paragraph 841.121 of ASME B31.8 code to take into consideration the additional mechanical stresses due to fabrication and operation.

8.5.2 For piping assemblies (such as jump-overs between pipelines or laterals, and main line valve bypasses) of cross country pipelines falling under paragraph 8.3 above, the design factor, F, shall be in accordance with Table 2.

8.6 Scraper Trap Piping:

8.6.1 For on land facilities the design factor for scraper trap piping shall not exceed 0.5.

8.6.2 For offshore facilities scraper piping excluding the incoming/outgoing mainline including the scraper launcher/ receiver barrel shall not exceed 0.5.

8.7 Limitations on Stresses

8.7.1 Crude Oil Service Lines

In calculating the combined stress in production pipelines in crude oil service designed to shut-in wellhead pressure requirements, the following metal temperatures shall be assumed: 38°C for buried lines, 27°C for underwater lines, and 65°C for above ground lines.

8.7.2 For liquefied hydrocarbon gas services, the nominal hoop stress calculated for the vapor pressure of the liquid at flowing design conditions shall not exceed 25% of SMYS, unless the pipe material has adequate crack arrest capability at a higher hoop stress caused by the vapor pressure of the liquid. (Refer to SAES-L-131).

8.7.3 Welded Attachments

If the piping is designed to operate at a hoop stress in excess of 50% of the SMYS of the pipe material, all structural attachments which transfer loads to the pipe through welds, shall be welded to full encirclement sleeves or saddle pads of at least 90 degrees with rounded corners. All welds to the pipe shall be specified as continuous welds. Internally coated piping system may be exempted from the welded attachments requirements. Un-welded structural attachments may be used for the internally coated pipe.

ASME B31.4 paragraph 421.1(d) and ASME B31.8 paragraph 834.5(b), if applicable, shall not be waived.

8.7.4 Stresses Due to Soil Overburden

The sum of the hoop stress due to internal pressure and the calculated circumferential bending stress due to external loading by soil overburden shall not exceed the maximum value provided by the applicable Code for hoop stress excluding joint, quality or other derating factors (E = 1).

9 Limitations on Materials

The following limitations shall apply to the line pipes and piping components:

9.1 Procured material for pipes, pipe fittings and gaskets shall be in accordance with SAES-L-101.

9.2 Procured material for valves shall be in accordance with SAES-L-102.

9.3 Material specifications shall be in accordance with SAES-L-105.

9.4 Selection of valves shall be in accordance with SAES-L-108.

9.5 Selection of pipe flanges shall be in accordance with SAES-L-109.

9.6 Limitations on pipe joint per SAES-L-110 shall apply.

9.7 Carbon steel line pipe shall comply with SAES-L-131 for fracture control requirement.

9.8 Selection of the basic material shall be in compliance with SAES-L-132.

9.9 SAES-L-136 shall apply for pipe material selection and restrictions

9.10 The smart data sheet SDS-L-100 “Carbon Steel Line Pipe Requisition” should utilized for material requisition of carbon steel line pipe.

10 Design Temperature

10.1 The design temperature shall be selected based on the maximum anticipated flowing conditions.

Commentary Note:

This is to avoid arbitrary selection of design temperature. Design temperature has significant cost impact on pipeline thickness, thrust anchor block and construction requirements.

10.2 Tie-In Temperature

For fully restrained pipelines (buried and above-ground), a tie-in temperature shall be specified during the Project Proposal stage. The construction location and expected ambient conditions during construction activities are major factors for defining the tie-in temperature.

10.3 Temperature for Coating Consideration

For the purpose to specify the coating type, the temperature may be specified higher than that for design temperature. This higher temperature shall be used as the design temperature for the piping system. Such higher temperature could cause by excursions.

The Coating Specialist of CSD shall be consulted for detail and proper coating specification.

11 Design Pressure and Wall Thickness

11.1 General Requirements

11.1.1 The general Saudi Aramco philosophy for protection pipeline systems is that the pipeline system shall be mechanically capable to withstand design condition within the applicable Code requirement.

11.1.2 With the condition that paragraph 11.4 is adhered to, High Integrity Protection Systems (HIPS) may be used to protect pipeline systems with lower wall thickness and/or lower class rating required to meet requirements of paragraph 11.1.1 above.

It shall be understood that there is potential of pipeline leakage and or ruptures in case of failure of HIPS while the pipeline system become subject to overpressure beyond its mechanical strength.

Commentary Note:

HIPS will protect the line as long as they are well designed, contracted properly, inspected and commissioned rigorously and more importantly they are maintained and tested periodically.

11.2 Design Pressure

11.2.1 General Rule

The design pressure of the pipelines required to achieve design through put capacity should be equal to the MAOP of the pipeline.

Exception:

Exception to this is that when the diameter to wall thickness or minimum wall thickness requirements are the limiting factors where selected pipe wall thickness may dictate higher MAOP than required design pressure.

Commentary Note:

This is to avoid arbitrary or over-conservative selection of design pressure. Design pressure has significant cost impact on pipeline thickness and construction requirements.

11.2.2 Liquid Service Cross-Country Pipelines

11.2.2.1 The design pressure shall be equal to or greater than the maximum steady state operating pressure as defined in ASME B-31.4 Section 400.2.

11.2.2.2 Surge and hydraulic calculations shall be made to determine the maximum pressure due to surge and other variations.

11.2.2.3 Mechanical relief or surge system (s) as required by SAES-J-600 and SAES-J-605 shall be provided if the pressure due to surge or other variations exceed the maximum design pressure of the piping system by more than 10%.

Commentary Note:

Based on the economical analysis, the design wall thickness may be increased to overcome the overpressure due to static overpressure such as the closer of class one valve.

11.2.3 Gas Pipelines

For cross-country pipelines in gas service, the design pressure shall not be less than the compressor shut off pressure, unless the piping system is protected by full process relief system.

11.2.4 Crude Oil Production Pipelines

Crude oil production pipelines such as flowlines, trunklines and testlines the design pressure shall be based on the calculated or estimated most severe condition at the wellhead during shut-in.

Typical data about oil fields is available in Appendix-A, however, Production and Facilities Development Department shall be consulted to provide the latest data.

11.2.5 Gas Production Pipelines

For gas production pipelines such as gas flowlines, trunklines and transmission lines the design pressure shall be based on the calculated or estimated most severe condition at the wellhead during shut-in.

Typical data about gas fields is available in Appendix-A, however, Production and Facilities Development Department shall be consulted to provide the latest data.

11.3 Line Pipe Wall Thickness

11.3.1 It is the responsibility of the designer to select the wall thickness at the most economical value which meets design pressure requirements per this Standard and the applicable Code. The designer shall avoid over conservatism particularly for long and large diameter pipelines.

11.3.2 For carbon steel piping, the minimum nominal wall thickness shall not be less than the values listed in Table 3.

Table 3 – Limitation on Wall Thickness of Carbon Steel Line Pipe

Nominal Size (Inches)	Hydrocarbon Service	Water Service
2 and smaller	SCH 80	SCH 40
3 through 5	SCH 40	SCH 40
6 through 32	6.35 mm (0.25 inch)	6.35 mm (0.25 inch)
34 and larger	Diameter/135	Diameter/135

11.3.3 Wall thickness calculations should be submitted to CSD for review by the Piping Specialist at the early stage of project development and prior to placing purchase orders for line pipes.

11.3.4 Violations to the wall thickness requirements shall be resolved by the Chairman of the Piping Standards Committee. To the discretion of the Chairman, a waiver may be required or not.

11.4 Conditions for Application of HIPS

11.4.1 HIPS may be used only for flowlines and trunklines where meeting the requirement of paragraph 11.1.1 is impractical such as that the pipe thickness could not be achieved or involves serious constructability problems.

11.4.2 For new oil or gas field development, HIPS shall be approved on a case by case basis by Proponent, Process & Control Systems and Loss Prevention.

11.4.3 HIPS shall not be used for cross country pipelines.

11.4.4 The HIPS shall be evaluated, designed, installed and tested in compliance with requirements of SAES-J-601 and SAEP-354.

12 Construction Types

12.1 General

Unless it is limited by this standard or the governing code and SSD-29 requirements, an economic feasibility study shall be conducted to determine the most cost effective type of construction; whether it should be buried or above ground where all construction options should be evaluated.

12.2 Buried Pipelines

12.2.1 Buried cross-country pipelines shall have the original ground surface restored by using suitable fill, or graded to suit the surrounding terrain (e.g., sand dune areas) in accordance with SAES-L-450.

If requested by the Proponent, a bermed over construction may be used for pipeline demarcation and restriction of vehicular crossing.

12.2.2 Berm Cover

The minimum height of the berm shall be 900 mm measured from top of the pipeline regardless of service.

12.2.3 Pipe Cover for Bends

The required height of berm shall be calculated using acceptable company software such as ADBP or PIPECOVR at locations where the 900 mm may not be sufficient to keep the line from bow out of the ground.

Commentary Note:

> *The potential for line bow out is higher in 20 inches diameter pipelines and smaller pipelines with pipe wall thickness of 0.375 inches and higher, at the same time operating at temperature higher than 170°F. More details are available in SAER-6078 "Analysis of Buried Pipelines".*

12.2.4 The top of the pipeline shall be buried at a minimum depth of 450 mm below finished grade.

12.3 Bermed-Over Pipelines

Where, because of the soil conditions, it is not feasible or economical to restore the original grade, such as in rocky areas and in landfill in subkhas or tidal flats, buried cross-country pipelines shall have a stabilized berm per SAES-L-450.

12.4 Above-Ground Restrained Pipelines

Where the terrain or other considerations, such as cost of construction, or corrosion preclude burial, the pipeline should be designed for above ground installation.

These lines shall be fully restrained by means of ring girders and end anchors as detailed in Section 14 below. The pipeline shall be supported off the natural or graded ground surface per SAES-L-450.

12.5 Above-Ground Non-Restrained Pipelines

12.5.1 This construction type is recommended for production pipelines in crude oil service and water injection pipelines up to 16” sizes. This is due to the simplicity of the design, construction, and cost effectiveness and availability of construction contractors.

12.5.2 Above-Ground Non-Restrained construction may also be a cost effective alternative for services other than that specified in 12.5.1, subject to the approval of the Chairman of Piping Standards Committee.

12.5.3 Above-ground non-restrained pipelines shall have expansion loops or offsets to accommodate for thermal expansion. Stress analysis shall be performed for these lines per SAES-L-120.

13 Corridors and Pipelines Layout

13.1 Corridors

Parallel lines shall be routed within a common corridor. Pipelines serving an onshore plant shall make the approach within one or more designated corridors or pipeways.

Parallel pipelines with scraper traps shall terminate in a common scraper trap area and have tie-lines to the plant placed in a pipeway.

13.2 Vehicle Crossings

Above-ground pipelines and bermed over pipelines shall have crossings, at selected locations, suitable for the passage of people, vehicles and animals as dictated by local conditions. These road crossings shall be in accordance with SAES-L-460. When both feasible and practical, the location of new crossings should match with those installed on existing parallel pipelines.

13.3 Spacing of Parallel Pipelines

13.3.1 The clear distance (OD to OD) between parallel pipelines shall be such that the installation and eventual repairs can be done with minimum risk of damage to or interference with the operation of adjacent pipelines. Consideration shall be given to requirements for future pipelines in corridors and above grade pipeways with limited space.

13.3.2 Cross Country Buried Pipeline

The minimum centerline spacing of buried parallel pipelines, each built at different times, shall be 15 m to allow access for construction or maintenance equipment. The minimum clear distance between two parallel buried pipelines, built at the same time, shall be minimum 3 m, except where this clearance cannot be provided over a relatively short length (such as in a road crossing) not to exceed a maximum of 150 m. Vehicles and equipment access to each pipeline needs to be made from only one side.

If the minimum spacing requirements cannot be achieved or there is economical incentive for the deviation a concurrence letter shall be signed by PMT, Proponent representative and CSD Piping Specialist.

13.3.3 Cross-Country Above-Ground Pipelines

The minimum centerline spacing of above-ground, restrained, parallel pipelines on individual supports shall be 3 m with 15 m access for maintenance equipment from one side.

13.3.4 Production Pipelines

The following shall apply:

a) For 24” pipe sizes and smaller, the minimum parallel spacing shall be 5 m on one side for maintenance vehicle access.

b) For larger than 24” pipe sizes, the parallel spacing requirements shall be reviewed and approved by the Operating Department.

13.3.5 In all cases where the minimum required spacing can not be provided, the routing alternatives shall be presented to Operating Departments during the DBSP Review.

13.4 Clearances between Pipelines and Others

13.4.1 The minimum clearance between pipelines and any adjacent structure shall be as follows:

a) Minimum of 1 m (3 ft) for cross-country pipelines.

b) Minimum of 0.6 m (2 ft) for production pipelines, water supply lines, water injection lines, and GOSP water disposal lines.

13.4.2 Buried pipelines crossing each other shall have a minimum clearance of 0.6 m (2 ft) and shall be increased as practical as achievable. Also, for areas where pipeline settlement is expected the two lines shall be separated by sand bags or any other means to insure that the two lines will not be in contact with time.

13.4.3 If for any reason this clearance can not be provided or not addressed in this section, approval must be obtained from the Manager of Operating Department and Chairman of Piping Standards Committee.

13.5 Pipeline Markers

In addition to the requirements of ASME B31.4, Section 434.18 and SAES-B-064 for markers in populated areas, kilometer markers similar to those illustrated on Standard Drawings AB-036907 and AD-036973 shall be installed at every kilometer station of the pipeline, at road crossings (within 10 meters of the road on both sides of the road), and near appurtenances, deflections, junctions and transitions where needed to identify the approximate location of such features. Additional markers are not required for appurtenances at the end points of the pipeline.

Commentary Notes:

For example, a block valve can be referred to as the block valve at KM 18.6 with the name of the pipeline.

Kilometer markers, per Standard Drawing AB-036907 referred to above, do not require a cathodic protection one-pin test station, other than at every kilometer station, or at those locations listed in SAES-X-400.

14 Anchors and Pipe Supports

14.1 End Anchors

14.1.1 Above-ground fully restrained pipelines shall be provided with end anchors designed to withstand the full thrust and pull forces due to thermal expansion and contraction and due to internal fluid pressure considering Poisson's ratio, with a maximum anchor deflection of 6 mm unless it can be shown that larger movement be accommodated by the piping system.

14.1.2 All buried cross-country pipelines shall be provided with a full thrust or drag anchor at each end of the pipelines under the following conditions:

- The pipelines length is 1.5 km and longer.
- The pipelines thrust force or their end movements are detrimental to the terminating point such as scraper trap area, manifolds, etc.
- It is the designer responsibility to optimize the anchor size and to determine whether it is needed depending on design parameters with concurrence from the Chairman.

14.1.3 A full thrust anchor shall be provided at the onshore end and close to the shoreline at the transition points between onshore and subsea offshore pipelines.

14.1.4 The end anchor shall be designed per SAES-L-440. The flowing design temperature should be used in calculating the thrust force.

14.2 Deflection Anchors

Any change in direction in the horizontal and/or vertical plane of above-ground restrained pipelines shall require one or more deflection anchors designed to resist the resultant force of the full thrust forces.

Deflection anchors may be required on buried pipelines if the passive soil restraint against the pipe is not sufficient to fully restrain the line.

14.3 Intermediate Anchors

Differential thrust anchors shall be provided for above ground restrained pipelines where there is a change in thrust, e.g., due to a change in pipe diameter or wall thickness. This requirement is exempted if the associated local axial movement of the line can be shown to be less than 6 mm.

Intermediate anchors or axial line stops shall be provided for above-ground unrestrained pipelines between and/or at the center of expansion loops or offsets. The design load for such intermediate anchors shall include the effect of friction forces.

14.4 Camel Crossings

Camel crossings are considered as equalizing anchors between expansion loops or offsets and shall not be considered as end anchors without appropriate design analysis.

Commentary Note:

> *Equalizing anchors usually will be subjected to minimal thrust force. In fact calculation could show that the may be under zero axial loads.*

14.5 Ring Girders Pipe Supports

14.5.1 Above ground restrained pipelines shall be supported on ring girders, or 180-degree saddles with top strap, designed to prevent lateral buckling of the pipeline. Suitable electrical insulation strips shall be provided between the pipe and the support if required to prevent dissipation of cathodic protection current.

14.5.2 If the ring girder supports of the above ground piping sections interfere with the cathodic protection of the buried sections (if some sections of the line are buried), electrical insulation between the pipe and the supports is required per SAES-X-400.

14.5.3 The pipe surface covered by the ring girder or saddle and top strap shall be coated with a SAES-H-101 approved epoxy coating such as APCS-26 to prevent corrosion of the pipe. Coating is not required if a fiberglass insulating spacer is epoxy bonded to the pipe after abrasive blasting the pipe surface to Sa 2-½ (near white metal blast).

14.6 Clearance from Grade

For above-grade pipelines the clearance between bottom of the pipe and the finished grade shall not be less than the following:

a)	Inside plant areas and where the grade under the pipe is hard surfaced	300 mm
b)	Outside plant areas with nearby stabilized sand dunes	450 mm
c)	In areas with moving sand dunes	900 mm

14.7 Support Spacing (Restrained)

To mitigate wind-induced resonance vibration of the above-ground cross-country pipelines with diameters larger than 12 inch that are supported at regular intervals, every seventh span length shall be reduced by 20%. The basic support spacing shall be selected so that the natural frequency of the pipeline in operating condition is outside the range of wind induced frequencies plus or minus 10% for wind speed above 9 m/s (20 MPH) which will cause vortex shedding.

Commentary Note:

The Saudi Aramco Engineering Report EPR-1714 "Wind Induced Vibration of Pipelines" or any other reliable engineering source could be used to perform these calculations.

14.8 Guides and Stops

The free movement of unrestrained piping, both in axial and lateral directions, shall be controlled and limited by properly located guides and anchoring points to within acceptable bounds. The restraints shall be designed to withstand any shock loads which may occur due to start-up, surges or slug flow. The design force due to liquid slugs shall be conservatively estimated (density times the square of the maximum expected velocity times the cross-sectional flow area of the pipe) and applied at all changes in direction of the pipe.

14.9 Low Friction Supports

Low friction supports by use of Teflon sheets or equivalent should be avoided. In case they are not avoided, low friction supports shall be designed such that sand or other debris cannot accumulate on sliding surfaces (by making the top surface larger than the bottom surface). Sliding surfaces shall be protected during all construction activities including painting and sandblasting.

15 Sectionalizing Valves

15.1 Sectionalizing Valves

In addition to the requirements of Section 434.15 of ASME B31.4 and Section 846 of ASME B31.8, the maximum spacing between sectionalizing block valves shall be as follows:

a) Table 4 as a function of service and class locations, as defined in SAES-B-064.

b) Additional valves for emergency isolation shall be provided as required by SAES-B-064. A sectionalizing valve may be used as an emergency isolation valve if the valve complies with the requirements of SAES-B-064.

c) Additional operational valves may be required by the Operating Department in order to operate and maintain the pipeline, associated equipment, and facilities.

Table 4 – Sectionalizing Valve Spacing

	Class 1	Class 2	Class 3	Class 4
Hydrocarbon and Flammable Pipelines				
Abs. vapor pres. >450 kPa (65 psia)	Note 1	Note 1	16 km	8 km
Abs. vapor pres. <450 kPa (65 psia)	Note 1	Note 1	16 km	16 km
Gas	32 km	24 km	16 km	8 km
Non-Hydrocarbon Pipelines				
Note 2	32 km	24 km	16 km	16 km
Other than Note 2	Note 3	Note 3	32 km	32 km

Notes:

1. Install valves upstream and downstream of environmentally sensitive areas as identified in the Environmental Assessment portion of the Project Proposal. See SAEP-13 and SAEP-14.
2. Sour water, seawater, brine, and other contaminated or chemically treated water.
3. Install valves only as required by the operating department.

Exception:

If the proposed spacing exceeds these limits, the valve locations shall be jointly reviewed and approved by a committee consisting of the General Supervisor as designated by the Manager of the Operating Department, the Chairman of the Piping Standards Committee, CSD, the Chief Environmental Engineer, Environmental Engineering Division, EPD, and the Chief Fire Prevention Engineer, Loss Prevention Department.

15.2 For production pipelines in crude oil service, an additional block valve shall be provided in each flowline and trunkline at the approach to the onshore GOSP unless remotely controlled or automatic safety valves are provided at the wellhead piping. This valve shall be located outside the plant security fence, close to the patrol road, unless the Operating Department specifies that it be located inside the GOSP.

16 Check Valves

16.1 General Requirement

A check valve shall be installed in each branch near the intersection point, and near the upstream end of cross-country pipelines in hazardous service, such that backflow is prevented in case of an upstream line rupture or emergency in the plant which feeds the pipeline.

16.2 Bi-directional Scrapable Pipelines

If the pipeline is designed for bi-directional flow service, a check valve and a parallel block valve shall be installed. If a check valve was installed on an existing outgoing pipeline which will be converted to bi-directional flow, the block valve can be installed on the by-pass and the check valve left on the main line. For the design of a new pipeline in bi-directional flow, the check valve shall be installed on the by-pass.

16.3 Production Lines

Each flowline and testline segment shall have a check valve near the downstream end of the segment to prevent one well from injecting into another well, and to prevent backflow from the trunkline in case of a flowline rupture. Bypasses around the check valves shall be installed where there is a requirement for eventual pumping of water or other liquids from the GOSP to a well site at any time while the wells are shut in. Bypasses shall contain block valves and shall be self-draining.

17 System Appurtenances

17.1 Vents and Drains

Permanent vents and drains with plugged or blinded valves, or other appurtenances provided for the blow-down of pipeline sections at selected locations, shall be installed only as required by the Operating Department for emergency conditions. Temporary vent valves, if required during the initial filling of the pipeline for hydrostatic test, shall be removed and the connection plugged and seal welded after the test.

17.2 Instruments and Control

Pressure gauges, thermowells, and any controlling or recording instruments, surge protection equipment, telemetry and other remote monitoring and control shall be provided as required by the Operating Department and be installed per applicable instrumentation standards.

17.3 Other Appurtenances

Pipeline appurtenances covered by other SAESs include the following:

- Vessels such as for separation of liquid slugs from gas lines and for sand removal at water supply wells per applicable vessel standards;
- Devices for internal pipeline corrosion monitoring and control, injection of inhibitors and other chemicals, gas blanketing of water wells, etc., per SAES-L-133;
- Cathodic protection equipment, test and bonding stations, insulating joints or flanges, etc., per SAES-X-400;
- Thermal relief valves on lines in liquid service per SAES-L-140;
- Scraper traps and associated piping per SAES-L-420;
- Concrete anchors for buried pipelines shall comply to SAES-L-440; and
- Roads and railroad crossings per SAES-L-460.

18 Pipelines Scraping Requirements

18.1 Responsibilities

18.1.1 Deviations and/or alterations to the requirements of this section shall be approved by Chairman of the Materials and Corrosion Control Standards Committee and the Chairman of the Piping Standards Committee.

18.1.2 In addition to Paragraph 18.1.1 the approval of the Operating Organization shall be obtained through a concurrence letter to deviate from the requirements during projects development.

18.2 Unless specifically identified below, designing pipelines to allow the passage of scraper and the installation of permanent scraping facilities that are capable of accepting instrument scraping tools should be evaluated for its economical and operational justification. Following are general guidelines that could be used to justify such installation:

a) For corrosion control and monitoring of the pipeline,

b) Pipelines passing through populated areas classified as area class,

c) For removal of liquid build-up in gas lines,

d) When routine hydrostatic revalidation tests must be made (onshore oil and gas flowlines are excluded),

e) When required and justified by the Operating Organization.

18.3 Cross Country Pipelines

All new cross country pipelines shall be designed to allow passage of instrument scraper tool and should have permanent scraping facilities.

18.4 Subsea Production Pipelines

All new subsea production pipelines shall be designed to allow for the passage of ILI tools and shall have permanent scraping facilities that are capable of accepting ILI tools.

18.5 Onshore Production Pipelines

Install permanent scraping facilities that are capable of accepting ILI tools in all new onshore hydrocarbon pipelines. The following are exempted:

- Single well pipelines (flowlines) upstream of a GOSP, or the Khuff Gas Manifold
- Short branches such as jumpovers
- In case the Operating organization exempted the production pipelines within their jurisdiction.

18.6 Onshore Water Injection Pipelines

For onshore water supply and injection headers, the need for ILI capability shall be determined by the Chairman of the Materials and Corrosion Control

Standards Committee and the Operating Organization.

18.7 Design Requirements

The following requirements shall apply for pipelines designed to allow passage of scrapers, instrumented type as well as cleaning type.

18.7.1 The Project Proposal should identify the specific type of scrapers to be used to assess in designing scraper trap size and minimum bend radius.

18.7.2 Additional design requirements for permanent scraping facilities, including the scraper traps, appurtenances and associated piping shall be in accordance with SAES-L-420.

18.7.3 Pipeline Bends

Long radius bends shall be used in pipelines with permanent scraping facilities. The bend radius shall be not less than eight diameters (8D) for lines up to 8-inch NPS, 5D for lines of 10-inch NPS through 14-inch NPS, and 3D (either bends or forged elbows) for lines of 16-inch NPS and larger if 5D cannot be used because of space limitation, or difficulty in procurement, subject to review and approval by the Chairman of Piping Standards Committee.

18.7.4 Valves and Tees

The valves shall be full bore type to allow for the passage of scrapers. Tee shall be barred-tees type where needed.

18.7.5 The pipeline shall not be multi-diameter.

18.7.6 Markers for Subsea Pipelines

Subsea pipelines shall be equipped with visible markers that will assist in identifying defects location during instrument scraping runs. This could be accomplished by:

a) Installing short pipe joints 20 feet in length with separation distances no greater than 2 kilometers along the pipeline length. These short pipe joints shall be permanently externally marked so as to be visible to the divers. For example, Monel plates may be attached to these pipe joints using a polypropylene rope or Monel banding.

b) Presence of permanent, readily identifiable features, such as line break valves, tees, flanged tie-in risers, etc., are acceptable markers and should be taken into account as placements of pup pieces.

18.8 Instrument Run Baseline

PMT (Project Management Team) shall provide a baseline instrument scraper survey when ILI-capable scraping facilities are required. The baseline survey shall be completed prior to the commissioning or just after that with agreed on schedule with the Operating Organization.

19 Corrosion Control

Internal and external corrosion protection requirements for pipelines within the scope of this standard shall be in accordance with SAES-L-133.

Revision Summary

26 November 2012	"Revised the "Next Planned Update." Reaffirmed the content of the document, and reissued with no other changes.

Appendix A – Oil and Gas Production Well Data

A.1 The following Tables contain typical design information for Saudi Aramco producing fields in the form of data sheets, one for each field area. These data should be used only as guidance and not as design basis. The latest data shall be always verified.

A.2 Production & Facilities Development Department of E&P is the responsible organization for updating these data and further consultations.

Table A1 – Abqaiq Oil Field

FIELD	ABQAIQ
Present SIWHP, Kpa (ga) (psig)	6205-8963 (900-1300) as of 10/2003
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 17250 (2500) 8960 (1300)
Maximum flowing surface temp. °C	91
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 3400-7590 (500-1100 1700-3400 (260-465)
Flowline design pressure, Kpa (ga) (psig)	8963 (1300) for oil wells 18271 (2650) for gas cap or potential gas cap producers
Flowline design temperature °C	91

NOTES:

(1) Reservoir pressure is maintained by water injection.

(2) The data provided is for both Arab-D and Hanifa wells.

(3) A gas cap is present in the Arab-D reservoir at about the 1800 m s.s. (5904 ft. s.s.) Arab-D structural contour. It is not expected that the gas cap will extend below this point during the operating life of the field.

(4) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A2 – Ain Dar Oil Fields

FIELD	AIN DAR
Present SIWHP, Kpa (ga) (psig)	3445-8274 (500-1200) as of 12/89
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 17237 (2500) 8274 (1200)
Maximum flowing surface temp. °C	91
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 1380-2415 (200-350) 1035 (150)
Flowline design pressure, Kpa (ga) (psig)	8963 (1300) for oil wells 18271(2650) for gas cap or potential gas cap producers
Flowline design temperature °C	91

NOTES:

(1) Reservoir pressure is maintained by water injection.

(2) A gas cap is present in parts of the field at about the 1800 m s.s. (5904 ft. s.s.) Arab-D structural contour. It is not expected that the gas cap will extend below this point during the operating life of the field.

(3) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A3 – Ain Dar Gas Fields

	AIN DAR (Gas)	
FIELD	Flowlines	Trunklines
Present SIWHP, Kpa (ga) (psig)	31026-44816 (4500-6500)	
Maximum Expected SIWHP, Kpa (ga) (psig)	44816 (6500)	
Maximum flowing surface temperature °C	110	110
Normal flowing pressure: Well-head, Kpa (ga) (psig) Remote Manifold, Kpa (ga) (psig) Gas Gather. Facility, Kpa (ga) (psig)	 11032 (1600) 9653 (1400)	 9653 (1400) 8618 (1250)
Flowline design pressure, Kpa (ga) (psig)	17926 (2600)	13100 (1900)
Flowline design temperature °C	121	121

NOTES:

(1) Consult with the responsible organization per A.2 above for final design details.

(2) Flowlines/trunklines should not be designed for SIWHP. There shall be a specification break at the wellsite (wellsite piping designed to API 10000).

(3) Piping downstream of specification break shall be protected by the well shutdown system backed up by the flowline pressure relief valve.

Table A4 – Abu Hadriyah Dar Oil Field

FIELD	ABU HADRIYA
Present SIWHP, Kpa (ga) (psig)	
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	
Maximum flowing surface temp. °C	
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	
Flowline design pressure, Kpa (ga) (psig)	
Flowline design temperature °C	

NOTE:

The field will be mothballed for the foreseeable future.

Table A5 – Abu Jifan Oil Field

FIELD	ABU JIFAN
Present SIWHP, Kpa (ga) (psig)	
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	
Maximum flowing surface temp. ºC	
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	
Flowline design pressure, Kpa (ga) (psig)	
Flowline design temperature ºC	

NOTE:

The field will be mothballed for the foreseeable future.

Table A6 – Abu Sa'fah Oil Field

FIELD	ABU SA'FAH
Present SIWHP, Kpa (ga) (psig)	4140 (600) as of 12/97
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 N/A (See Note #1) 5520 (850) with ESP ON
Maximum flowing surface temp. ºC	85
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 966-1800 (140-260) 345-550 (50-80) with ESP ON
Flowline design pressure, Kpa (ga) (psig)	5865 (850)
Flowline design temperature ºC	95ºC

NOTES:

(1) Natural aquifer support maintains reservoir pressure above bubble point pressure. No full gas column is expected.

(2) Maximum anticipated SIWHP will occur when the field is temporarily shutin.

(3) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A7 – Berri Oil Field

FIELD	BERRI
Present SIWHP, Kpa (ga) (psig)	2070-12420 (300-1800) as of 12/97
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 N/A (See Note #1) 12420 (1800)
Maximum flowing surface temp. ºC	91
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 670-8270 (100-1200) 900 (130)
Flowline design pressure, Kpa (ga) (psig)	2420 (1800) See Note #2
Flowline design temperature ºC	91

NOTES:

(1) Peripheral water injection is used to maintain reservoir pressure above bubble point pressure. However, in isolated cases, wells completed in zones with limited pressure support can cause reservoir pressure to drop below bubble point local to the wellbore at high well rates. Full gas column is not expected for any well.

(2) Flowlines for the main development under BI-1212 were designed for 9310 (Kpa) (ga) (1350 psig), with flowline protection provided by platform ESD systems. New flowlines designed for 12420 Kpa (ga) (1800 psig) will be capable of withstanding full well shutin pressures.

(3) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A8 – Dammam Oil Field

FIELD	DAMMAM
Present SIWHP, Kpa (ga) (psig)	
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	
Maximum flowing surface temp. ºC	
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	
Flowline design pressure, Kpa (ga) (psig)	
Flowline design temperature ºC	

NOTE:

The Dammam GOSP is dismantled.

Table A9 – Fadhili Oil Field

FIELD	FADHILI
Present SIWHP, Kpa (ga) (psig)	
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	
Maximum flowing surface temp. ºC	
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	
Flowline design pressure, Kpa (ga) (psig)	
Flowline design temperature ºC	

NOTE:

The Fadhili GOSP is dismantled.

Table A10 – Farzan Oil Field

FIELD	FAZRAN
Present SIWHP, Kpa (ga) (psig)	3445-8274(500-1200) as of 12/89
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 N/A (See Note #1) N/A
Maximum flowing surface temp. ºC	91
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 1725-4826 (250-700) 1035 (150)
Flowline design pressure, Kpa (ga) (psig)	8963 (1300)
Flowline design temperature ºC	91

NOTES:

(1) No full gas column is expected.

(2) Reservoir pressure will remain above bubble point pressure.

(3) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A11 – Haradh Oil Field

FIELD	HARADH
Present SIWHP, Kpa (ga) (psig)	4140 (600)
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 N/A (See Note #2) 6210 (900)
Maximum flowing surface temp. ºC	77
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 2070 (300) 828-1035 (120-150)
Flowline design pressure, Kpa (ga) (psig)	8970 (1300)
Flowline design temperature ºC	82

NOTES:

(1) HRDH GOSP-1 was commissioned in March, 1996. And, HRDH GOSP-2 was commissioned in April, 2003.

(2) No full gas column is expected.

(3) Reservoir pressure is maintained by sea water injection.

(4) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A12 – Haradh Gas Field

	HARADH (Gas)	
FIELD	**Flowlines**	**Trunklines**
Present SIWHP, Kpa (ga) (psig)	44816 (6500)	
Maximum Expected SIWHP, Kpa (ga) (psig)	44816 (6500)	
Maximum flowing surface temperature ºC	107	107
Normal flowing pressure: Well-head, Kpa (ga) (psig) Remote Manifold, Kpa (ga) (psig) Gas Gather. Facility, Kpa (ga) (psig)	 8618 (1250) 7584 (1100)	 7584 (1100) 5860 (850)
Flowline design pressure, Kpa (ga) (psig)	13790 (2000)	11032 (1600)
Flowline design temperature ºC	110	110

NOTES:

(1) Consult with the responsible organization per A.2 above for final design details.

(2) Flowlines piping should not be designed for SIWHP. There shall be a specification break at the wellsite (wellsite piping designed to API 10000 rating).

(3) Piping downstream of specification break shall be protected by the well shutdown system backed up by the flowline pressure relief valve.

(4) The Haradh manifold and Haradh Khuff wells are planned to come onstream mid-year 2001.

Table A13 – Harmaliyah Oil Field

FIELD	HARMALIYAH
Present SIWHP, Kpa (ga) (psig)	
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 16560 (2400)
Maximum flowing surface temp. ºC	82
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 3450 (500) 830 (120)
Flowline design pressure, Kpa (ga) (psig)	8970 (1300)
Flowline design temperature ºC	82

NOTE:

The field is on production since February, 2002 (free-flowing to UTHN GOSP-4)

Table A14 – Hawiyah Oil Field

FIELD	HAWIYAH
Present SIWHP, Kpa (ga) (psig)	5520 (800)
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 N/A (See Note #1) 6895 (1000)
Maximum flowing surface temp. ºC	82
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 1518-2140 (220-310) 828-966 (20-140)
Flowline design pressure, Kpa (ga) (psig)	8970 (1300)
Flowline design temperature ºC	82

NOTES:

(1) No full gas column is expected.

(2) Reservoir pressure is maintained by sea water injection.

(3) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A15 – Hawiyah Gas Field

	HAWIYAH (Gas)	
FIELD	Flowlines	Trunklines
Present SIWHP, Kpa (ga) (psig)	44816-48263 (6500-7000)	
Maximum Expected SIWHP, Kpa (ga) (psig)	44816-48263 (6500-7000)	
Maximum flowing surface temperature ºC	110	107
Normal flowing pressure: Well-head, Kpa (ga) (psig) Remote Manifold, Kpa (ga) (psig) Gas Gather. Facility, Kpa (ga) (psig)	 8618 (1250) 7584 (1100)	 7584 (1100) 5860 (850)
Flowline design pressure, Kpa (ga) (psig)	13790 (2000)	11032 (1600)
Flowline design temperature ºC	121	110

NOTES:

(1) Consult with the responsible organization per A.2 above for final design details.

(2) Flowline piping should not be designed for SIWHP. There shall be a specification break at the wellsite (wellsite piping designed to API 10000).

(3) Piping downstream of specification break shall be protected by the well shutdown system backed up by the flowline pressure relief valve.

(4) The Hawiyah manifold and Hawiyah Khuff wells are planned to come onstream mid-year 2001.

Table A16 – Hawtah Oil Field

FIELD	HAWTAH
Present SIWHP, Kpa (ga) (psig)	0-4826 (0-700) as of 10/2003
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 N/A (See Note #3) Nil (See Note #4)
Maximum flowing surface temp. ºC	54
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	689-6895 (100-1000) with ESP
Flowline design pressure, Kpa (ga) (psig)	9825 (1425)
Flowline design temperature ºC	75

NOTES:

(1) Field came on production on 09/94.

(2) Reservoir pressure is maintained by water injection.

(3) The maximum bubble point pressure of 1170 kPa (155 psig) prevents gas columns from being sustained in wellbores.

(4) Producing wellhead pressures are sustained by electric submersible pumps. With the pumps turned off wells will not flow at the maintained reservoir pressure. However, with pumps turned on, SIWHP can approach flowline design pressure.

(5) Consult with the responsible organization per A.2 above for final design details.

Table A17 – Khurais Oil Field

FIELD	KHURAIS
Present SIWHP, Kpa (ga) (psig)	
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	
Maximum flowing surface temp. ºC	
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	
Flowline design pressure, Kpa (ga) (psig)	
Flowline design temperature ºC	

NOTES:

(1) The field is currently mothballed.

(2) Date will be submitted when the field is demothballed and pressures are well known.

Table A18 – Khursaniyah Oil Field

FIELD	KHURSANIYAH
Present SIWHP, Kpa (ga) (psig)	
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	
Maximum flowing surface temp. ºC	
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	
Flowline design pressure, Kpa (ga) (psig)	
Flowline design temperature ºC	

NOTE:

The field will be mothballed for the foreseeable future.

Table A19 – Marjan Oil Field

FIELD	MARJAN
Present SIWHP, Kpa (ga) (psig)	5685-12420 (850-1800) as of 12/97
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 18975 (2750) N/A
Maximum flowing surface temp. ºC	85
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 4140-8970 (600-1300) 1800 (260)
Flowline design pressure, Kpa (ga) (psig)	19320 (2800) See Note #2
Flowline design temperature ºC	66

NOTES:

(1) Reservoir pressure is at or near the bubble point pressure. There are no plans to introduce pressure maintenance.

(2) The gas cap may expand into all wells.

(3) GOSPs 2 and 3 wells produce sour gas. GOSP-1 wells produce up to 30 ppm H_2S, and crude is handled at GOSP-2.

(4) The SIWHP has been increased due to recent Ratawi development.

(5) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A20 – Mazalij Oil Field

FIELD	MAZALIJ
Present SIWHP, Kpa (ga) (psig)	
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	
Maximum flowing surface temp. ºC	
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	
Flowline design pressure, Kpa (ga) (psig)	
Flowline design temperature ºC	

NOTE:

The field will be mothballed for the foreseeable future.

Table A21 – Nuayyim Gas Field

FIELD	NUAYYIM
Present SIWHP, Kpa (ga) (psig)	11721 (1700) as of 12/95
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 19512 (2830) 11721 (1700)
Maximum flowing surface temp. ºC	55
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 6900-10342 (1000-1500) A sand 3103-6550 (450-950) B sand 345-690 (50-100)
Flowline design pressure, Kpa (ga) (psig)	14370 (2084)
Flowline design temperature ºC	77

NOTES:

(1) Field came on production on 01/97.

(2) Reservoir maint. pressure not yet defined. Above SIWHP data assumes original reservoir pressure. Should be reviewed and possibly revised after initial year of production.

(3) No initial gas cap.

(4) There are tentative plans to gas lift this field in the future.

(5) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A22 – Qatif Oil Field

FIELD	QATIF
Present SIWHP, Kpa (ga) (psig)	
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	
Maximum flowing surface temp. ºC	
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	
Flowline design pressure, Kpa (ga) (psig)	
Flowline design temperature ºC	

NOTES:

(1) The field is planned for production in October, 2004.

(2) Ethane is being injected/reproduced from the South Dome Sulaiy wells.

(3) Naphtha can be injected into the oil zone in the South Dome.

(4) LPG/NG is being injected into the oil zone in the North Dome.

(5) Reservoir pressure will be maintained by water injection in 2004.

(6) No full gas column is expected.

(7) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A23 – Qirdi Oil Field

FIELD	QIRDI
Present SIWHP, Kpa (ga) (psig)	
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	
Maximum flowing surface temp. ºC	
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	
Flowline design pressure, Kpa (ga) (psig)	
Flowline design temperature ºC	

NOTE:

The Qirdi GOSP is dismantled.

Table A24 – Safaniyah Oil Field

FIELD	SAFANIYA
Present SIWHP, Kpa (ga) (psig)	2070-4830 (300-700) as of 12/97. See Note #2
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 N/A (See Note #1) 4658 (675)
Maximum flowing surface temp. °C	66
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 690-3445 (100-500) 345 (50)
Flowline design pressure, Kpa (ga) (psig)	5175 (750)
Flowline design temperature °C	66

NOTES:

(1) No full gas column is expected.

(2) Natural aquifer support maintains Reservoir pressure at or near the bubble point pressure.

(3) Given shutin pressure data excludes Ratawi rsvr wells which currently have SIWHPs as high as 6210 Kpa (ga) (900 psig). No Ratawi producing wells planned to be drilled in the foreseeable future.

(4) The maximum injection pressure of future gas lift system is 12400 Kpa (ga) (1800 psig).

(5) All offshore flowlines and trunklines are protected by ESD systems and a well and tie-in platforms.

(6) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A25 – Shaybah Oil Field

FIELD	SHAYBAH
Present SIWHP, Kpa (ga) (psig)	5520-8280 (800-1200) as of 12/78
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 14317 (2075) See Note #1 N/A
Maximum flowing surface temp. ºC	85
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 4830-6900 (700-1000) 2967 (430)
Flowline design pressure, Kpa (ga) (psig)	14317 (2075)
Flowline design temperature ºC	85

NOTES:

(1) No gas column is expected.

(2) Due to proximity of gas cap flowlines should be designed for shutin of wells with full gas column.

(3) Production support will be provided by gas cap expansion. All separated gas (solution gas) will be reinjected into the gas cap.

(4) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A26 – Shedgum Oil Field

FIELD	SHEDGUM
Present SIWHP, Kpa (ga) (psig)	3445-8274 (500-1200) as of 12/89
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 N/A (See Note #1) 8274 (1200)
Maximum flowing surface temp. ºC	91
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 1170-4482 (170-650) 1035-1655 (150-240)
Flowline design pressure, Kpa (ga) (psig)	8963 (1300)
Flowline design temperature ºC	91

NOTES:

(1) No full gas column is expected.

(2) Reservoir pressure is maintained by water injection.

(3) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A27 – Shedgum Gas Field

FIELD	SHEDGUM (Gas)	
	Flowlines	Trunklines
Present SIWHP, Kpa (ga) (psig)	31026-44816 (4500-6500)	
Maximum Expected SIWHP, Kpa (ga) (psig)	44816 (6500)	
Maximum flowing surface temperature ºC	110	110
Normal flowing pressure: Well-head, Kpa (ga) (psig) Remote Manifold, Kpa (ga) (psig) Gas Gather. Facility, Kpa (ga) (psig)	 11032 (1600) 9653 (1400)	 9653 (1400) 8618 (1250)
Flowline design pressure, Kpa (ga) (psig)	17926 (2600)	13100 (1900)
Flowline design temperature ºC	121	121

NOTES:

(1) Consult With the responsible organization per A.2 above for final design details.

(2) Flowlines/trunklines should not be designed for SIWHP. There shall be a specification break at the wellsite (wellsite piping designed to API 10000).

(3) Piping downstream of specification break shall be protected by the well shutdown system backed up by the flowline pressure relief valve.

Table A28 – Uthmaniyah Oil Field

FIELD	UTHMANIYAH
Present SIWHP, Kpa (ga) (psig)	2070-8280 (300-1200)
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 20700 (3000) 8280 (1200)
Maximum flowing surface temp. ºC	77
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 1240-2345 (180-320) 828 (120)
Flowline design pressure, Kpa (ga) (psig)	8970 (1300)
Flowline design temperature ºC	82

NOTES:

(1) Reservoir pressure is maintained by sea water injection.

(2) Reservoir engineering calculations indicate that the Uthmaniyah gas cap has essentially been produced. However, some wells located at the top of the structure in the GOSP-9 area are still considered to be capable of developing a full gas column during shutin.

(3) Consult with the responsible organization per A.2 above for details of any further updates before final design.

Table A29 – Uthmaniyah Gas Field

FIELD	UTHMANIYAH (Gas)	
	Flowlines	Trunklines
Present SIWHP, Kpa (ga) (psig)	31026-44816 (4500-6500)	
Maximum Expected SIWHP, Kpa (ga) (psig)	44816 (6500)	
Maximum flowing surface temperature ºC	110	110
Normal flowing pressure: Well-head, Kpa (ga) (psig) Remote Manifold, Kpa (ga) (psig) Gas Gather. Facility, Kpa (ga) (psig)	 11032 (1600) 9653 (1400)	 9653 (1400) 8618 (1250)
Flowline design pressure, Kpa (ga) (psig)	17926 (2600)	13100 (1900)
Flowline design temperature ºC	121	121

NOTES:

(1) Consult with the responsible organization per A.2 above for final design details.

(2) Flowlines/trunklines should not be designed for SIWHP. There shall be a specification break at the wellsite (wellsite piping designed to API 10000).

(3) Piping downstream of specification break shall be protected by the well shutdown system backed up by the flowline pressure relief valve.

Table A30 – Zuluf Oil Field

FIELD	ZULUF
Present SIWHP, Kpa (ga) (psig)	2553-14766 (370-2140) as of 10/2003
Maximum Expected SIWHP, Kpa (ga) (psig): With full gas column At reservoir maint. pressure	 16540 (2400) See Note #1 N/A
Maximum flowing surface temp. °C	66
Normal flowing pressure: Well-head, Kpa (ga) (psig) Separator, Kpa (ga) (psig)	 2760-8274 (400-1200) 1725 (250)
Flowline design pressure, Kpa (ga) (psig)	16900 (2450)
Flowline design temperature °C	66

* Dead wells SIWHP, however, active wells minimum SIWHP = 500 psig

NOTES:

(1) The potential for a full column of gas exists in most Zuluf wells.

(2) The Safaniya reservoir pressure will remain above bubble point pressure. There are no plans to introduce reservoir pressure maintenance.

(3) The maximum injection pressure of the future gas lift system is 12400 Kpa (ga) (1800 psig).

(4) Consult with the responsible organization per A.2 above for details of any further updates before final design.