PROCESS DESCRIPTION

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1 INTRODUCTION

Iranian Offshore Oil Company (IOOC) owns Hengam Oil Field and operates oil production facilities in the Persian Gulf. Associated gas from Hengam Oil Production Facilities is presently being flared. According to IOOC policies, associated gases shall be recovered to control air pollutions, preserve energy and use in market and potential industries. Hence, Hengam Gas Treatment Project has been initiated.

Considering above, it is planned to gather all associated gases from the Separators and Stripping Column, treat, compress and export to the National Iranian Gas Company (NIGC).

According to Hengam Oil Field MDP Report, in the first years of production, rate of associated gas will be 40 MMSCFD. This rate will be increased to 80 MMSCFD of treated gas after approximately 5 years of production; so the gas gathering, compression and treating facilities shall be designed for 80 MMSCFD. Transmission facilities of treated compressed gas are not in this PROJECT Scope of Work.

The Hengam Gas Treatment Plant is a grass roots development and will include of the simultaneous development of the following units:

- Gas Gathering and Compression Unit
- Gas Sweetening Unit
- Gas Dehydration and Dew Point Control Unit
- Sulfur Recovery Unit
- Utilities
- Flare System

2 DOCUMENT SCOPE

This document describes the processes plants of Hengam Gas Treatment System Project.

3 DEFINITIONS

For the purposes of this document, the following definitions SHALL apply:

PROJECT

The Hengam Gas Treatment Project

COMPANY

The Iranian Offshore Oil Company (IOOC)

CONTRACTOR

EPC Contractor, the Jondishapour Industrial Co.

CONCESSION REQUEST

A deviation request by the SUBCONTRACTOR or VENDOR, is usually made after receiving the contract package or purchase order. Often, it refers to an authorization to use, repair, recondition, reclaim, or release materials, components or equipment already in progress or completely manufactured but which does not meet or comply with COMPANY requirements. A CONCESSION REQUEST is subject to COMPANY approval.

SUBCONTRACTOR(S)

Any third party to whom CONTRACTOR has subcontracted any part of the services or from whom CONTRACTOR has purchased any materials.

VENDOR(S)/ SUPPLIER(S)

The person, firm, company or corporation to whom the purchase order is placed including their assignees.

SERVICES

All and any work performed by CONTRACTOR, pursuant to CONTRACT.

SHALL

Indicates a mandatory requirement.

MAY

Is used in a permissive sense to state authority or permission to do the act prescribed or provide the function being defined in the prescribed manner. The words “no person may” or “a person may not” mean that no person is required, authorized, or permitted to do the act prescribed, and the words “may not” mean that the item being described is not required, authorized, or permitted in the prescribed manner.

INCLUDE

Means “include but not limited to”

4 PROCESS DESCRIPTION

4.1 Gas Gathering and Compression Unit (Unit 100)

Reference PFD	QSM2-100-PR-PF-0001	Gas Gathering and Compression Unit
Reference PFD	QSM2-100-PR-PF-0002	HP Gas Compressor
Reference BFD	QSM2-000-PR-BD-0001	Process Overall Block diagram

Gas Gathering and Compression Unit comprises of two sections:

1- Gas Gathering and LP Compression

2- HP Gas Compressor

The duty of Gas Gathering and LP Compression Section is gathering and compressing the sour associated gas coming from the existing Stripper Column (T-101) along with vapors from existing 2nd and 3rd Stage Oil Separators (respectively V-102 and V-103) at Hengam Oil Plant. Then, the outlet compressed gas sent to Gas Sweetening Unit (Unit 200) and mixed with the flashed associated gas coming from the existing 1st Stage Oil Separator (V-101) and routed to Gas Sweetening Inlet Separator (200-V-01).

The duty of HP Gas Compressor section of this unit is pressurizing of Sweet Gas Products from Gas Dehydration and Dew Point Control Unit (Unit 300) to gas export facilities.

Table 4.1 provides the characteristics of the total sour associated gas feedstock at plant design capacity to Gas Gathering and Compression Unit battery limit.

4.1.1 Gas Gathering and LP Gas Compression

Sour associated gas stream from the Stripping Column (T-101) sent to Low Low Pressure (LLP) Compressor Suction Scrubber (100-V-01) of this Unit. Operating condition of sour associated gas stream at Stripping Column is 11.6°C temperature, 1.8 barg pressures and about 4.8 MMSCFD flowrate. Totally, 0.8 bar Pressure drop considered for transmission pipeline (about 593 meter length and 10" diameter), Gas Flowmeter and Control Valve installed on associated gas stream from Stripping Column at Hengam Oil Plant to Gas Gathering and Compression Unit battery limit.

Finally sour associated gas at approximately 9.9°C temperature and 1 barg pressure delivered to Low Low Pressure Compressor Suction Scrubber. The scrubber is considered in order to separate liquid droplets from sour gas stream to minimize oil carryover to downstream gas compressor. The liquid that may be present is collected in the H/C closed drain header. Then the gas is routed to the Low

Low Pressure (LLP) Compressor (100-C-01) and pressurized up to 3.7 barg and then enters into the Low Low Pressure (LLP) Compressor After Cooler (100-A-01) to be cooled down to 55°C.

Then the outlet compressed sour gas, mixed with the sour associated gas coming from existing 3rd Stage Oil Separator (V-103). Operating condition of sour associated gas stream at 3rd Stage Oil Separator is 14.0°C temperature, 3.8 barg pressures and about 1.6 MMSCFD flowrate. Totally, 0.8 bar Pressure drop considered for transmission pipeline (about 584 meter length and 6" diameter), Gas Flowmeter and Control Valve installed on associated gas stream from 3rd Stage Oil Separator at Hengam Oil Plant to Gas Gathering and Compression Unit battery limit. Finally sour associated gas at approximately 12.9°C temperature and 3 barg pressure delivered to Low Pressure Compressor Suction Scrubber (100-V-02), to remove the possible condensate present in the gas stream, before entering the following compression stage. The condensate present is collected and sent to the H/C closed drain header. The sour gas stream is then routed to the Low Pressure (LP) Compressor (100-C-02) and pressurized up to 11.5 barg and then enters into the Low Pressure (LP) Compressor After Cooler (100-A-02) to be cooled down at 55°C.

Finally, compressed sour gas from Low Pressure Compressor After Cooler mixed with the sour associated gas stream coming from the existing 2nd Stage Oil Separator (V-102). Operating condition of sour associated gas stream at 2nd Stage Oil Separator is 16.0°C temperature, 11.8 barg pressures and about 5.4 MMSCFD flowrate. Totally, 0.9 bar Pressure drop considered for transmission pipeline (about 578 meter length and 6" diameter), Gas Flowmeter and Control Valve installed on associated gas stream from 2nd Stage Oil Separator at Hengam Oil Plant to Gas Gathering and Compression Unit battery limit. Finally sour associated gas at approximately 15.3°C temperature and 10.9 barg pressure delivered to Low Pressure Compressor Suction Scrubber (100-V-03), to remove the possible condensate present in the gas stream. The condensate that may be present is collected and sent to the H/C closed drain header. Downstream the gas is routed to the Medium Pressure (MP) Compressor (100-C-03) and pressurized up to 42.7 barg and then enters into the Medium Pressure (MP) Compressor After Cooler (100-A-03) to be cooled down at 55°C.

Hydrogen sulfide is the primary corrosive agent in Hengam Gas Treatment System Project feedstock and frequently carbon dioxide is present as well. The presence of various iron sulfides in the corrosive products at different concentrations of hydrogen sulfide has been identified.

One of the most used technical methods to control corrosion phenomena and protect the surfaces is injection of corrosion inhibitors. Inhibitors often work by adsorbing themselves on the metallic surface, protecting the metallic surface by forming a film. Inhibitors are normally distributed from a solution or dispersion. Some are included in a protective coating formulation.

According to above mentioned description, a Corrosion Inhibitor Package (100-X-02) considered to injection of corrosion inhibitor agents into the following points at Gas Gathering and Compression Unit (Unit 100):

1- Into Sour Associated Gas Stream from 3rd Stage Oil Separator

2- Into Sour Associated Gas Stream from 2nd Stage Oil Separator

3- Upstream of Low Low Pressure Compressor After Cooler (100-A-01)

4- Upstream of Low Pressure Compressor After Cooler (100-A-02)

5- Upstream of Medium Pressure Compressor After Cooler (100-A-03)

Table 4.1: Gas Compression Unit Feedstock Characteristics

COMPOSITION (Mole Fraction)	Sour Gas from Stripping Column (T-101)	Sour Gas from 2nd Stage Oil Separator (V-102)	Sour Gas from 3rd Stage Oil Separator (V-103)
Water	0.0075	0.0014	0.0038
Nitrogen	0.0609	0.0190	0.0050
Carbon dioxide	0.0217	0.1718	0.2192
Hydrogen sulfide	0.0296	0.0399	0.0797
Methane	0.6426	0.5951	0.3865
Ethane	0.0580	0.1019	0.1474
Propane	0.0949	0.0471	0.1042
i-Butane	0.0256	0.0081	0.0183
n-Butane	0.0367	0.0106	0.0239
i-Pentane	0.0090	0.0025	0.0053
n-Pentane	0.0075	0.0019	0.0040
Hexane	0.0038	0.0004	0.0011
Heptane	0.0016	0.0003	0.0011
Octane	0.0005	0.0000	0.0005
Nonane	0.0001	0.0000	0.0000
C_{10}^{+}	0.0000	0.0000	0.0000
Temperature	9.9 °C	15.3 °C	12.9 °C
Pressure	1.0 Barg	10.9 Barg	3.0 Barg
Molecular Weight	25.4	25.6	31.2
Total Mass Flowrate	6077 kg/hr	6920 kg/hr	2443 kg/hr

4.1.2 HP Gas Compressor

HP Gas Compressor section delivers sweetened and dehydrated gas coming from Gas Dehydration and Dew Point Control Unit (Unit 300) at 24°C Temperature, 34.2 barg and 68.3 MMSCFD flowrate. Dry sweet gas is sent to High Pressure Compressor (100-C-04) via High Pressure Compressor Suction Scrubber (100-V-04) for removing liquid condensate. At High Pressure Compressor outlet, dry sweet gas with 112.8°C and 90.4 barg sent to High Pressure Compressor After Cooler (100-A-04) for cooling down to 55°C and then sent to Gas Export Pipeline.

The dry, pressurized and sweet gas enters the battery limits of Hengam Gas Treatment System. Pig Launcher (100-X-01) at this section considered for pipeline maintenance and cleaning.

4.2 Gas Sweetening Unit (Unit 200)

Reference PFD	QSM2-200-PR-PF-0001	Gas Sweetening Unit
Reference PFD	QSM2-200-PR-PF-0002	Amine Regeneration System
Reference PFD	QSM2-200-PR-PF-0003	Solvent Storage Tanks
Reference BFD	QSM2-000-PR-BD-0001	Process Overall Block Diagram

The Gas Sweetening Unit shall remove the H_2S and CO_2 content of sour gas stream down to the PROJECT specification.

Table 4.2 provides the desirable specification of the H_2S and CO_2 content in the product of Gas Sweetening Unit.

Table 4.2: H_2S and CO_2 Content at the Outlet Stream of Gas Sweetening Unit

Specification	Value
H_2S Content at the outlet of Amine Contactor Column	4 ppmv
CO_2 Content at the outlet of Amine Contactor Column	<1 mol%

Compressed sour gas from the Medium Pressure Gas Compressor After Cooler (100-A-03) of Gas Gathering and Compression Unit (Unit 100) mixed with sour associated gas stream coming from 1st Stage Oil Separator (V-101) of Hengam Oil Plant and flows to the Amine Contactor Column (200-V-07) via Gas Sweetening Inlet Separator (200-V-01) and Gas Inlet Filter Separator (200-F-01).

Table 4.3 provides the characteristics of the total sour gas feedstock from Gas Gathering and Compression Unit and 1st Stage Oil Separator to Gas Sweetening Unit.

Table 4.3: Gas Sweetening Unit Feedstock Characteristics

COMPOSITION (Mole Fraction)	Sour Associated Gas from 1st Stage Oil Separator (V-101)	Sour Gas from Gas Compression Unit (Unit 100)
Water	0.0005	0.0036
Nitrogen	0.0720	0.0342
Carbon dioxide	0.1119	0.1171
Hydrogen sulfide	0.0150	0.0410
Methane	0.7176	0.5869
Ethane	0.0500	0.0901
Propane	0.0214	0.0742
i-Butane	0.0037	0.0166
n-Butane	0.0051	0.0230
i-Pentane	0.0013	0.0055
n-Pentane	0.0010	0.0045
Hexane	0.0003	0.0019
Heptane	0.0002	0.0009
Octane	0.0000	0.0003
Nonane	0.0000	0.0000
C_{10}^{+}	0.0000	0.0000
Temperature	17.5 °C	55 °C
Pressure	42 Barg	42 Barg
Molecular Weight	22.1	26.3
Total Mass Flowrate	74995 kg/hr	15434 kg/hr

Gas Inlet Filter Separator is designed to remove any liquid hydrocarbon carry-over and extraneous material which could promote foaming in the Amine Contactor Column. The filtered gas enters the bottoms of the Amine Contactor Column with 23°C temperature, 41.2 barg pressure and 79.8 MMSCFD flowrate, which is a tray type column, where it is brought into countercurrent contact with the circulating 25 wt% Diethanolamine Solution (DEA) flowing down the column with the 55°C temperature, 41 barg pressure and 450 m^3/hr flowrate.

The sweet gas from top of Amine Contactor Column will enter the Gas Sweetening Outlet Separator (200-V-02) where any entrained amine will be separated and returned to the Rich Amine Flash Drum (200-V-03); sweet gas will leave the Gas Sweetening Outlet Separator to the Gas Dehydration and Dew Point Control Unit (Unit 300). CO_2 and H_2S analyzers considered at this stream to monitor sweet gas product specification. A split range control system considered on this stream for controlling

pressure of sweet gas to Gas Dehydration and Dew Point Control Unit (Unit 300). While pressure of sweet gas stream increasing from normal condition up to design pressure of Gas Sweetening Outlet Separator, control valve installed on flare header will be opened and then a portion of sweet gas stream sent to HP Flare until pressure decreases down to normal condition.

Table 4.4 provides the characteristics of the Sweet Gas Product leaving Gas Sweetening Unit to feed Gas Dehydration and Dew Point Control Unit.

A branch of sweet and wet gas stream from Gas Sweetening Outlet Separator is sent to Fuel Gas System as backup 1 fuel gas.

The rich amine is withdrawn from the bottom of the Amine Contactor Column with 70.2°C temperature, 41.2 barg pressure and 460 m^3/hr flowrate under level control and flows to the Rich Amine Flash Drum (200-V-03).

Most of the hydrocarbon co-absorbed in the rich amine stream is flashed off in the Rich Amine Flash Drum which operates at 5.0 barg.

The Rich Amine Flash Drum is a three phase separator and designed to separate acid gas, hydrocarbon condensate and rich amine.

Separated Hydrocarbon droplets sent to H/C closed Drain Header under level controller and the rich amine stream separated is heated in the Lean/Rich Amine Heat Exchanger (200-E-01) up to 96°C temperature against lean amine from the Amine Regenerator Column (200-V-08).

The flow control valve in the Rich Amine Flash Drum is located downstream of the exchanger to minimize the amount of flashed vapor produced due to heating. Flashed vapor or separated acid gas will be sent to Sulfur Recovery Unit (Unit 400) under pressure controller of Rich Amine Flash Drum. A split range control system considered on this stream for controlling pressure of acid gas stream to Sulfur Recovery Unit. While pressure of acid gas stream increasing from normal condition up to design pressure of Rich Amine Flash Drum, control valve installed on flare header will be opened and then a portion of acid gas stream sent to Acid Gas Flare until pressure decrease down to normal condition. Process description of SRU shall be described by Sulfur Recovery Unit SUPPLIER.

The rich amine stream after heating at Lean/Rich Amine Heat Exchanger passed through a control valve and reduce its pressure down to 1 barg and finally flows to the top of the Amine Regenerator Column, where the H_2S and CO_2 in the rich amine solution is stripped by counter-current contact with steam generated from rich amine solution in the Amine Regenerator Column Reboiler (200-E-02 A/B). The overhead product from the Amine Regenerator Column is a mixture of steam, H_2S and CO_2. This stream leaves the Amine Regenerator Column with 99.5°C temperature, 1.0 barg pressures and about 21.4 MMSCFD flowrate. The water vapor in this stream is condensed and returned to the column as reflux, while the H_2S/CO_2 rich acid gas stream is fed to the Sulfur Recovery Unit (Unit 400).

Water and CO_2 are inert components which decrease the efficiency of the Sulfur Recovery Unit when they are in excess in acid gas. To minimize the amount of water in the feedstock to the Sulfur Recovery Unit, and to limit the water consumption of the Gas Sweetening Unit, the temperature of Amine Regenerator Column Condenser Flash Drum (200-V-04) must be as low as possible.

For this purpose Amine Regenerator Column Condenser (200-A-02) cools down the temperature to about 55^{o}C. Also a steam condensate stream as a water make-up under flow controller considered to inject into Amine Regenerator Column Condenser Flash Drum.

The Amine Regenerator Column is a tray type column. The Reboilers are of Kettle type Heat Exchanger design, heated by LP Steam.

For providing LP steam; MP stream at 235°C and 20 barg received from steam distribution header is let down and cooled down by a control valve and injection of steam condensate at Desuperheater respectively. LP Steam flowrate to Amine Regenerator Column Reboiler controlled by temperature of 20th tray (stage) of Amine Regenerator Column. LP steam after heating of amine solution to be condensed and routed to Condensate Flash Drum (200-V-05). Steam condensate from Condensate Flash Drum sent to steam condensate collection system under level control via Condensate Return Pump (200-P-02 A/B).

The hot lean amine from the bottom of the Amine Regenerator Column at 126 °C is cooled down to 101°C by heat exchanging with the rich amine coming from Rich Amine Flash Drum in the Lean/Rich Amine Heat Exchanger (200-E-01) before entering the Lean Amine Storage Tank (200-T-01). This tank operates as a surge vessel and has sufficient capacity to contain the liquid inventory of the plant in the event of shutdown.

The tank will be blanketed with nitrogen from Nitrogen Header to prevent ingress of air which can degrade the amine solution. The lean amine is pumped from the Lean Amine Storage Tank to the Amine Contactor Column by the Lean Amine Transfer Pumps (200-P-03 A/B/C).

Most of impurities, held within the gas or generated through corrosion or chemical damage, are found in the solvent. Efficient operation of an Amine Contactor Column is largely dependent on the physical quality of the amine.

Foaming is the most important consequence of the entire unit. It can lead to:

- Decrease of Amine Contactor Column efficiency
- An out of specification treated gas stream
- Amine losses
- Difficulties with amine regeneration

Foaming is due to the presence of solid particles from 1 to 10 microns, such as iron sulfide, iron oxide, dust and pipeline debris. It is increased and stabilized by hydrocarbons and by-products of corrosion inhibitors. These solid impurities can also lead to the plugging of control valves and fouling of heat exchangers. Furthermore fouled amine can accelerate corrosion. Carbon steel is corroded by clean amine but the corrosion products form a protective layer. This layer is destroyed by erosion from the solid particles and the metal is again exposed to corrosion. All these conditions can be reduced by the Lean Amine Filter Package (200-X-01) fed from the Lean Amine Storage Tank. A minimum of 10% of the lean amine circulation rate passes through this package and return to Lean Amine Storage Tank.

Antifoam agent will be injected upstream of the Lean Amine Transfer Pumps and Amine Regenerator Column as required.

A stream of demineralized water as water make-up considered for Lean Amine Storage Tank.

During normal operation, amine drains from process equipment i.e. Amine Contactor Column, Rich Amine Flash Drum, Lean/ Reach Amine Heat Exchanger, Amine Regenerator Column and etc. in Gas Sweetening Unit (Unit 200) will be gathered and drained into Amine Sump Drum (200-V-06) through the Amine Closed Drain Header which is an underground facility. During maintenance, after isolation and depressurization, Amine Drains from the mentioned process equipment are drained to this drum.

Amine Sump Drum is underground horizontal drum, located at the suitable lowest grade elevation of Gas Sweetening Unit (Unit 200) Area in order to maximize the potential for gravity drainage.

Amine Sump Drum is single compartment and one Amine Sump Pump (200-P-06) is installed in this drum. This pump installed inside the Amine Sump Drum vertically suspended and will work under level control.

Based on the analysis of amine liquid collected in Amine Sump Drum, it shall either be pumped to Lean Amine Solution Tank (200-T-03) or disposed by road tanker in case of solvent degradation.

To avoid amine degradation phenomena through air diffusion into amine solution, a nitrogen blanketing considered for this drum.

The Amine Sump Drum provides liquid hold-up and degassing of the liquids. Vapor will be routed to atmosphere at a safe location.

The Fresh Amine Storage Tank (200-T-02) and Solution Amine Storage Tank (200-T-03) considered for the supply of fresh DEA (Diethanolamine) to the Gas Sweetening Unit (Unit 200), and the backup storage of Lean Amine Storage Tank (200-T-01). All tanks for storage of amine are blanketed with nitrogen to prevent degradation due to air contact.

Fresh DEA is added to Fresh Amine Tank using the Fresh Amine Pump (200-P-04) located on the DEA Unloading Facility Yard. The pumps operate using an air supply from plant air header.

Fresh Amine Pump is a barrel pump with the following specification:

Type	Rated Capacity	Differential Pressure	Specific Gravity
Barrel Pump (Compressed Air Driven)	20 lit/min	1 bar	1.09 @ 20°C

The discharge line from the Barrel Pump is connected to the feed line to the Fresh Amine Storage Tank via a flexible connection.

A steam coil considered in Fresh Amine Storage Tank to heat fresh amine up to desired temperature to avoid amine freezing.

Fresh DEA will be sent to the Solution Amine Storage Tank, where it can be mixed with demineralized water, if necessary, to make 25wt% amine solution.

Lean Amine Solution Pumps are fed from Fresh Amine Storage Tank. There are two pumps; one is duty, the other is stand-by. The pumps are designed in such a way that they can either transfer fresh DEA to Solution Amine Storage Tank as Pure DEA (Make-up) to produce lean amine solution, or feed lean amine solution from Solution Storage Tank to Lean Amine Storage Tank.

4.3 Gas Dehydration and Dew Point Control Unit (Unit 300)

Reference PFD	QSM2-300-PR-PF-0001	Gas Dehydration and Dew Point Control Unit
Reference BFD	QSM2-000-PR-BD-0001	Process Overall Block diagram

The characteristics of the sweet gas entering the Gas Dehydration and Dew Point control Unit are as follows:

- Design Treatment Capacity: 68123 kg/hr
- Pressure: 40.3 barg
- Temperature: 54.9 °C
- Composition: Shown in Table 4.4.

Table 4.4: Sweet Gas Composition to Gas Dehydration and Dew Point Control Unit

COMPOSITION (Mole Fraction)	Sweet Gas from Gas Sweetening Outlet Separator (200-V-02)
Water	0.0040
Nitrogen	0.0764
Carbon dioxide	0.0001 (< 1%)
Hydrogen sulfide	0.0000 (< 3ppmw)
Methane	0.8015
Ethane	0.0642
Propane	0.0336
i-Butane	0.0064
n-Butane	0.0089
i-Pentane	0.0022
n-Pentane	0.0017
Hexane	0.0006
Heptane	0.0004
Octane	0.0000
Nonane	0.0000
C_{10}^{+}	0.0000
DEA	0.0000
Temperature	54.9 °C
Pressure	40.3 Barg
Molecular Weight	19.7
Total Mass Flowrate	68123 kg/hr

Presence of water in the gas pipeline can cause hydrate formation. The hydrate crystals agglomerate to form large solid plugs that can block pipelines and disrupt production. At worst they can cause flow lines to burst.

The Gas Dehydration and Dew Point Control Unit (Unit 300) shall remove the water and hydrocarbon content down to the required specification to avoid hydrate formation.

Table 4.5 presents the desirable dew point of this component in the outlet of Gas Dehydration and Dew Point Control Unit.

Table 4.5: Water and Hydrocarbon Dew Point Specification at the Outlet of Gas Dehydration and Dew Point Control Unit

Specification	Value
Water Dew Point @ 44 barg	-10°C
Hydrocarbon Dew Point @ 55 barg	-10°C

A kind of system for removal of water from gas is Low Temperature Separation (LTS) method. The sweet gas from Gas Sweetening Outlet Separator (200-V-02) with 54.9°C enters to Gas Dehydration and Dew Point Control Unit and sent to Hot Gas/Gas Exchanger (300-E-01) to cool down to 39.4°C.

Cooling process causes partial condensation of hydrocarbon gas at outlet stream of Hot Gas/Gas Exchanger (300-E-01). Water Separator (300-V-01) considered for separation of condensates from sweet gas. Condensate stream from Water Separator sent to hydrocarbon closed drain header and sweet gas sent to Cold Gas/Gas Exchanger (300-E-02) for pre-cooling about to 24.1°C before entering to Chiller (300-E-03).

To prevent hydrate formation and producing desirable cooling process through Cold Gas/Gas Exchanger and Chiller, glycol compound continuously injected at upstream of these equipment at two separate points.

Propane Refrigeration Package (300-X-01) considered for producing required cooling to cool down the sweet gas to about -12°C at Chiller. Through cooling process in Chiller, all of water content in the sweet gas stream at this temperature will be condensed and thereafter this stream sent to Gas-Liquid Separator (300-V-02) to separate glycol compounds and water from sweet gas and Unstabilized Condensate Liquid.

Unstabilized Condensate Liquid separated in Gas-Liquid Separator will be sent to Hengam Oil Production Plant for injection to 2nd Stage Oil Separator under level control to be added to oil product.

Special Attention shall be paid to equalize the temperature and pressure of this stream with the temperature and pressure of 2nd Stage Oil Separator to prevent it from shocking. So a Condensate Heater (300-E-04) and control valve considered in this unit to regulate temperature and pressure respectively.

Water and glycol solution compound or heavy liquid phase separated in Gas-Liquid Separator flow to MEG Regeneration Package (300-X-02) to remove water content under level control and regeneration of glycol compound. Regenerated glycol compound sent to upstream of Cold Gas/Gas Exchanger and Chiller to be reused in Dew Point Control Section.

After dehydration and dew point control processes, cooled sweet gas from top of the Gas-Liquid Separator with -12°C temperature, and 66334 kg/hr flowrate is sent to Cold Gas/Gas Exchanger and Hot Gas/Gas Exchanger respectively to cool down sweet wet gas streams inlet to Gas Dehydration

and Dew Point Control Unit and finally routed to HP Gas Compressor Section of Gas Gathering and Compression Unit (Unit 100) for pressurized up to desired condition suitable for sending to gas export pipeline.