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PROJECT TITLE:

SAGASCO RESOURCES
YOLLA FIELD DEVELOPMENT

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YOLLA FIELD DEVELOPMENT
FACILITIES STUDY

OR-414

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1.0 SUMMARY

The Yolla field is a rich gas condensate field approximately midway between Melbourne and Tasmania. This development study concerns screening of options relating to the type of offshore facilities and processing options.

Offshore facilities can range from totally subsea to a full processing platform with many variations such as jackups, semisubmersibles, and FPSO's. The processing options primarily relate to the location, offshore versus onshore, where various processing steps take place. Eight cases were studied in more detail. The descriptions are detailed in Sections 4 and 5.

The costs for the eight cases evaluated are summarised below:

CASE	1	2	3	4	5	6	7	8
FIELD CONFIGURATION	Subsea	Jackup	Drilling Platform	Process Platform	Process Platform	Process Platform	Subsea/ FPSO	Drilling Platform /FPSO
PROCESSING SCHEME	3 Phase	3 Phase	3 Phase	2 Phase	Dew Pt Control	Membrane	Dew Pt Control	Dew Pt Control
Offshore Facilities	79.6	133.9	38.3	84.7	117.2	136.8	134.4	134.2
Pipeline to Plant	101.3	101.3	92.3	67.6	84.9	74.9	76.6	67.6
Slug Catcher	21.5	21.5	21.5	17.5	0.0	0.0	0.0	0.0
Gas Plant	57.4	57.4	57.4	44.2	45.4	34.0	45.4	45.4
Onshore Storage	9.6	9.6	9.6	9.6	6.8	6.8	6.8	6.8
Cond. & Sales Gas Pipelines	7.4	7.4	7.4	7.4	3.7	3.7	3.7	3.7
Sub Total	276.8	331.1	226.5	231.0	258.0	256.2	266.9	257.7
Drilling Phase 1	51.6	41.7	49.1	49.6	49.6	49.6	52.2	49.6
Drilling Phase 2	39.7	31.3	34.8	38.2	38.2	38.2	40.2	38.2
TOTAL CAPEX US$M	**368**	**404**	**310**	**319**	**346**	**344**	**459**	**346**
YEARLY OPEX US$M	**22**	**32**	**18**	**25**	**32**	**33**	**31**	**31**

All costs are in US$ millions current at 1/1/95 and have an accuracy of +/- 30%.

Costs for the facilities are based on supply and fabrication from the Far East Region for cost minimisation.

A sketch representation of each of the eight cases is provided in Figures 5.1 to 5.3 together with the pro's and con's of each option in brief.

The favoured option from the development study is Case 4, "Process Platform - 2 Phase Pipeline" at an estimated development cost of US$ 319 million. Case 4 includes a fixed platform with base processing facilities of compression, pumping, and water removal from the gas. The platform is assumed to be manned with accommodation for 20 personnel. Topside deck weight is around 2400 tonne with deck dimensions of 30 x 46 metres. A single 12 inch pipeline to shore delivers the gas and condensate as a 2-phase mixture. The onshore plant has a slug catcher to accept the 2-phase production. The gas plant provides sales gas, propane, butane and condensate as sales products. Onshore storage is provided for the liquid products. A 4 inch pipeline delivers the condensate from Blackrock to the Shell Geelong refinery. A 12 inch pipeline delivers sales gas from Blackrock to the Geelong gas gate. Future major capital items that will add to the US$ 319 million are booster compression (US$ 6.1 million) around year 8 and abandonment cost (US$12.8 million).

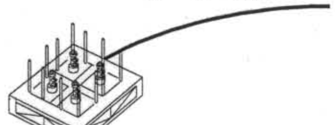
Case 3 offers a marginally lower initial capital cost and a lower operating cost in the summary table. However it has the significant drawbacks of early production decline and lower reserves recovery without major future investment for compression. A new process platform would have to be added to provide compression. Hence, future investment in Case 3 will be significantly greater than Case 4 to match the production profile and reserves recovery of Case 4.

SAGASCO Resources

YOLLA OPTIONS 1 TO 3

FIGURE I.

CASE 1
SUBSEA - 3 PHASE



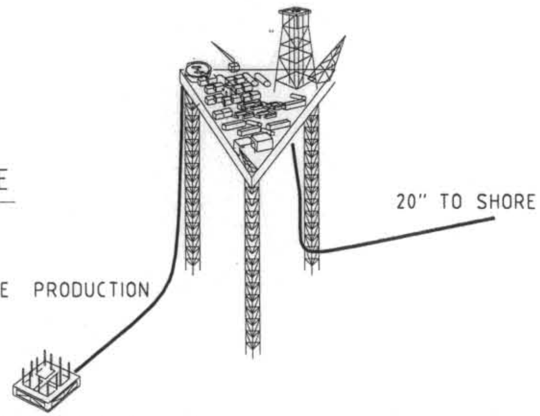
PRO'S

- MID-RANGE OPEX

CON'S

- HIGH CAPEX
- LOWER RESERVES RECOVERY
- HIGH RISK
- NO WELL TESTING
- VERY LARGE SLUG CATCHER REQUIRED

CASE 2
JACKUP - 3 PHASE



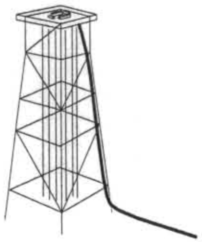
PRO'S

- DRILLING CAPABILITY ON LOCATION

CON'S

- HIGH CAPEX
- HIGH OPEX
- VERY LIMITED SPACE FOR FUTURE COMPRESSION
- VERY LARGE SLUG CATCHER REQUIRED

CASE 3
DRILLING PLATFORM - 3 PHASE



PRO'S

- LOWEST INITIAL CAPEX
- LOWEST OPEX
- ECONOMIC POTENTIAL IF LOWER RESERVES RECOVERY ACCCEPTABLE WITHOUT COMPRESSION

CON'S

- MAJOR CAPEX FOR FUTURE PROCESSING PLATFORM TO PROVIDE COMPRESSION
- VERY LARGE SLUG CATCHER REQUIRED

5 cm

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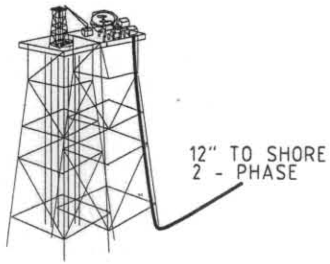
YOLLA OPTIONS 4 TO 6

FIGURE 2.

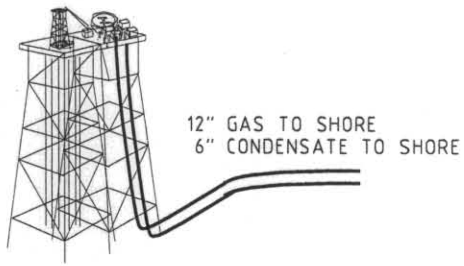
CASE 4
PROCESS PLATFORM
- 2 PHASE



PRO'S
- MOST ECONOMIC
- LOWEST CAPEX FOR INCLUSION OF COMPRESSION
- MID RANGE OPEX
- FULL RESERVES RECOVERY

CON'S
- OFFSHORE MANNING
- LARGE SLUG CATCHER REGUIRED

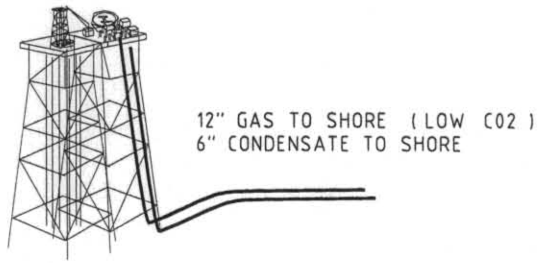
CASE 5
PROCESS PLATFORM
- DEW POINT CONTROL



PRO'S
- ELIMINATES SLUG CATCHER
- FULL RESERVES RECOVERY

CON'S
- MORE CAPEX AND OPEX THAN CASE 4
- OFFSHORE MANNING

CASE 5
PROCESS PLATFORM
- MEMBRANE



PRO'S
- ELIMINATES SLUG CATCHER
- FULL RESERVES RECOVERY

CON'S
- MORE CAPEX AND OPEX THAN CASE 4
- OFFSHORE MANNING

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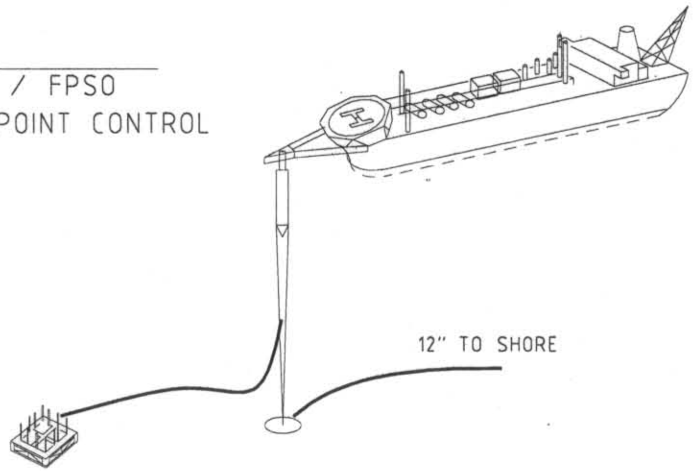
SAGASCO Resources

YOLLA OPTIONS 7 AND 8

FIGURE 3

CASE 7
SUBSEA / FPSO
- DEW POINT CONTROL



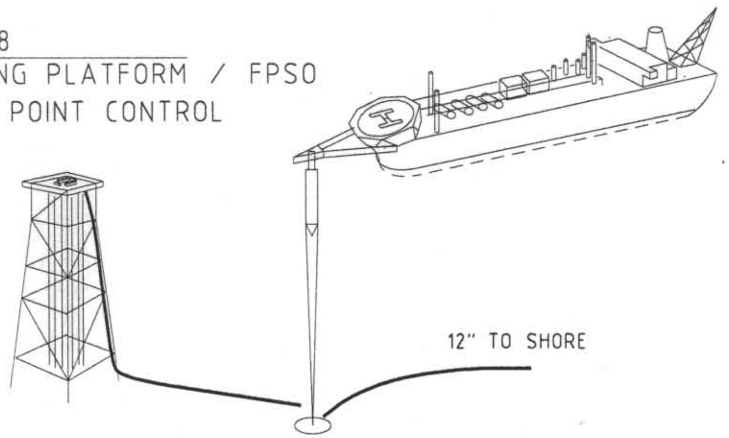
PRO'S

- INSTALLATION EFFORT AT OFFSHORE YOLLA SITE MINIMIISED
- ELIMINATES SLUG CATCHER

CON'S

- HIGH CAPEX AND OPEX
- FPSO DRY DOCK WILL INTERRUPT GAS DELIVERY
- WEATHER MAY INTERRUPT PRODUCTION
- WELL MAINTENANCE REQUIRES RIG MOBILISATION

CASE 8
DRILLING PLATFORM / FPSO
-DEW POINT CONTROL



PRO'S

- GOOD ACCESS TO WELL HEADS
- ELIMINATES SLUG CATCHER

CON'S

- HIGH CAPEX AND OPEX
- FPSO DRY DOCK WILL INTERRUPT GAS DELIVERY
- WEATHER MAY INTERRUPT PRODUCTION

5 cm

2.0 INTRODUCTION

SAGASCO has commissioned Dawson Brown & Root to perform a concept and feasibility study for the Yolla field development. This report documents the findings of the study.

The starting point for this study is an understanding that the offshore facilities are totally open to available options. The onshore facilities can be located at either Geelong or Long Island Point. Production targets have been set at 89 MMSCF/D wellhead gas average and design capacity of 100 MMSCF/D. Within this framework, the study has identified and looked at the available options. Costing has been developed in sufficient detail to identify the most cost effective development approaches.

A number of concepts and issues have been identified by SAGASCO for the study to address. These concepts and issues were communicated in the main via the letter dated 28 February 1995 and titled "Initial Data Package to DBR for use in the Yolla Facilities Study", together with some follow-on communications. This study report covers the concepts and issues raised.

3.0 BASIC DATA AND ASSUMPTIONS

The basic data used in this study is compiled in Appendix C. The base data is largely from information provided by SAGASCO. Where specific assumptions have been made by DBR they are marked. The base data has been used for deriving/estimating indicative process, equipment and structural sizes.

4.0 DEVELOPMENT OPTIONS

4.1 Onshore Plant Site

Two onshore plant sites have been identified. One at Blackrock near Geelong and the second at Long Island Point. Schematic maps showing the two site alternatives are given in Figures 4.1.1 and 4.1.2.

For the Blackrock location, the pipeline from offshore has only a short land crossing of 1 kilometre before arrival at the plant. Delivery of products from the plant is by a 28 kilometre, 4 inch pipeline for the condensate and by truck loadout for the propane and butane. Gas will be sold at the Geelong gas gate to the utility company.

For the Long Island Point site, the pipeline from offshore has 30 kilometres of land crossing before arrival at the plant. Delivery of condensate and LPG would be to the near-by Esso plant via pipelines. Gas will be sold at the plant gate to the utility company.

The plant facilities at both locations would be similar. The Long Island Point plant site could exclude the process of separating LPG into separate propane and butane streams. Esso would need to have spare processing capacity and be willing to offer a reasonable price for the LPG mix. A more likely outcome is that economics and marketing leverage will dictate that the LPG is split in SAGASCO's plant and marketed as separate propane and butane.

The most significant facility difference between the two locations comes down to the feed pipeline from offshore. The length of feed pipeline to the Blackrock site is 225 km. The length of pipeline to the Long Island Point plant is 206 km, with 30 km of the length being onshore. The cost of the two alternative routes is expected to be very similar. While the pipeline length to Long Island Point is shorter, the onshore pipe routing will face difficulties and balance out the cost of the two options.

In overview, cost estimates for the two onshore sites will be similar. The site selection basis should therefore not focus on the minor cost differences of the two sites. Instead, the selection should be based on the indirect cost issues of best market location, community and authorities support, and complexity of environmental issues.

On the basis of the indirect cost issues, the Blackrock site is the best choice. For the detailed costing in this study we have therefore focused on the Blackrock site option.

FIGURE 4.

SAGASCO
Resources

YOLLA DEVELOPMENT
BASE CASE

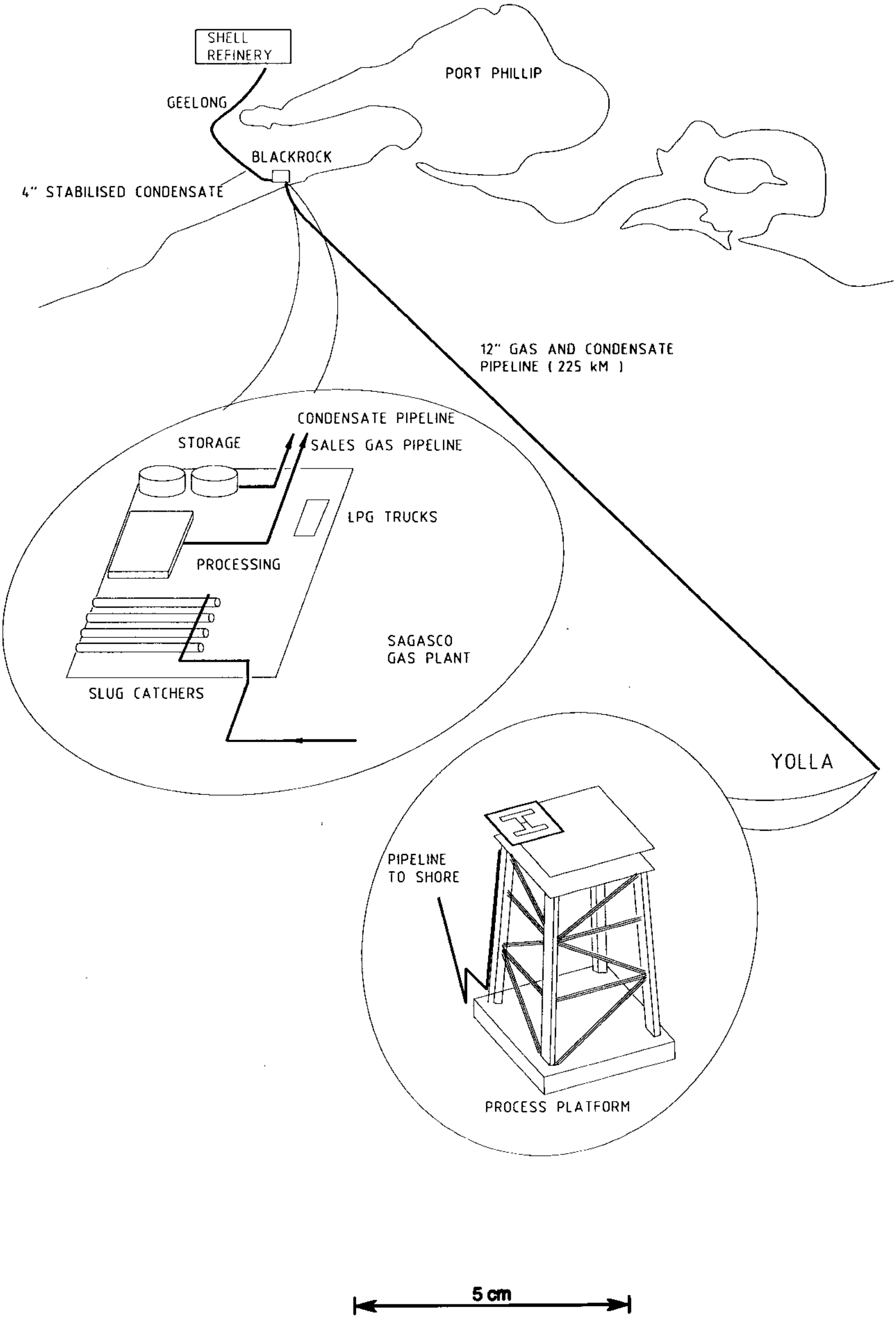


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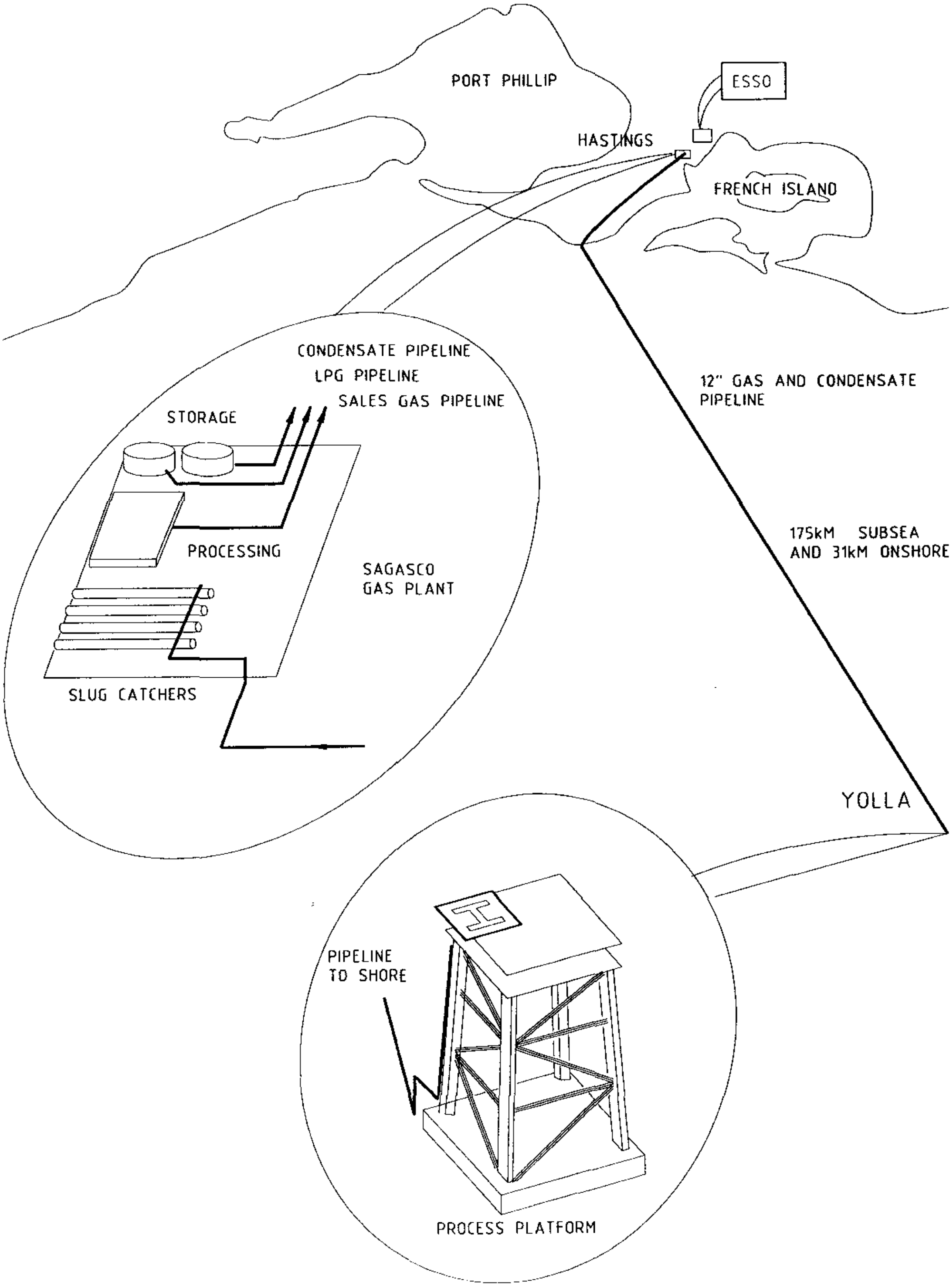
FIGURE 5.

SAGASCO Resources

YOLLA DEVELOPMENT

LONG ISLAND POINT - HASTINGS SITE



4.2 Process Flow Schemes and Descriptions

CASE 1 Subsea - 3 Phase

Case 1 is a Subsea development that would use a subsea manifold to commingle production for delivery to shore via a 3-phase pipeline. Pipeline diameter selected is 20 inch. All control communications would be via an umbilical from the onshore plant base. Glycol and corrosion inhibitor for hydrate and corrosion control would be supplied via the umbilical.

The onshore plant is assumed to be at Blackrock. The 3-phase production is received into a very large slug catcher - around 30,000 barrels at the plant. Gas off the slug catcher is first compressed and then processed for LPG recovery. The products are sales gas, propane, butane and stabilised condensate. Gas is sold at the Geelong gas gate via a 12 inch 27.7 kilometre pipeline owned by SAGASCO. Propane and butane are sold individually and transported from site by trucks. Condensate is delivered by 4 inch pipeline to the Shell Geelong refinery. The condensate pipeline is installed alongside the sales gas pipeline.

CASE 2 Jackup - 3 Phase

Case 2 is a jackup rig development. A subsea template is provided with individual flexible risers for each well. Production manifolding is provided on the jackup rig together with well testing, glycol and corrosion inhibitor storage and injection facilities. All production is exported via a flexible riser and 20 inch pipeline. The required well head control communications are provided from the jackup via an umbilical.

The onshore plant is the same as for Case 1.

CASE 3 Drilling Platform - 3 Phase

Case 3 is a Drilling platform development. This is a permanent steel structure for supporting the individual well conductors and wellheads. Drilling would be provided by a visiting jackup rig. Production manifolding is provided on the drilling platform together with well testing, glycol and corrosion inhibitor storage and injection facilities. All production is exported via a 20 inch pipeline.

The drilling platform costed in Case 3 is sized for minimum facilities. For future compression a new separate process platform would need to be provided.

The onshore plant is the same as for Case 1.

CASE 4 Process Platform - 2 Phase

Case 4 is a Process Platform delivering gas and condensate production via a 2-phase pipeline to shore.

A process flow scheme for the platform is presented in Appendix B, Drawing No. SAGA-3. Facilities include gas, condensate and water separation. The gas is filtered, contacted with glycol for water removal, then compressed for export. The water removal is for corrosion protection of the pipeline and to prevent hydrate formation. Compression is required to allow efficient pipeline delivery to shore. The line size can be taken down to 12 inch diameter by providing a platform discharge pressure of 1740 psia. At 1740 psia discharge piping on the platform remains within ANSI 900 class to keep costs down. Corresponding gas arrival pressure at the plant is 622 psia for a flow rate of 89 MMSCF/D. Separated condensate is passed through a filter coalescer for water removal and then pumped into the export pipeline.

Water handling is provided by hydrocyclone separator. Treated water is dumped overboard.

The reservoir is predicted to pressure deplete as the gas reserves are produced. Hence, compression is required to sustain gas delivery rates and for enhanced recovery of reserves. Pipeline compression would be provided with the initial facilities. Booster compression is a future requirement for when separator pressure can no longer be maintained around 710 psi by the available reservoir pressure.

A large onshore slug catcher is required to receive the 2-phase pipeline production. For the 12 inch pipeline selection, a 22,000 barrel slug catcher is required.

The onshore plant, provides processing to produce sales gas, propane, butane and stabilised condensate. Process flow diagrams have been prepared for the facility. Refer Appendix B, Drawing Nos. SAGA-3 and SAGA-4.

As shown in the process flow diagrams a pig receiving facility is provided ahead of the slug catcher. Normal flow will by-pass the pig receiver and go direct to the slug catcher. Gas off the slug catcher is first treated for CO_2 removal. An amine plant is selected for the CO_2 removal rather than a membrane system on the basis of lower cost. The amine plant includes an amine contactor tower for stripping the CO_2 from the gas and a heater system for regeneration of the CO_2 rich amine solution.

The gas stream then goes through a cooling process for drop out of LPG and heavier components. Initial cooling of the feed gas is provided by the gas-gas exchanger. Liquids are separated and then the gas is further cooled by expansion via the turbo expander. Temperature of the gas is reduced to around -50 ^{o}C for liquids recovery in the down stream cold separator. Pressure in the cold separator is set at 300 psia. This lean cold gas then goes to the gas-gas exchanger for warming and onto the compressor side of the turbo expander compressor for initial compression. Final compression to 1000 psig is provided by the pipeline compressor. A compressor after cooler is provided to maintain a delivery temperature specification. This process generates sales quality gas, ready for delivery to the utility company.

Liquids handling starts from the slug catcher. Slug catcher liquids go to the de-ethaniser for stripping of ethane and any other lighter components. Gas off the de-ethaniser is compressed and directed to the front end of the gas process. Liquids from the de-ethaniser go to the stabiliser column. Overheads from the stabiliser column is LPG and the bottoms product is stabilised condensate. The stabilised condensate is cooled and rundown to storage. From storage, the condensate is pumped for delivery down the 4 inch export pipeline.

Overheads from the stabiliser is directed to the depropaniser. The depropaniser provides fractionation of the LPG into an overhead propane stream and a bottoms butane stream. The butane stream is cooled before rundown to storage. Export of the propane and butane is via a truck loading facility.

CASE 5 Process Platform - Dew Point Control

Case 5 is a Process Platform providing dew point controlled gas for single phase pipeline delivery to shore. Condensate is delivered by a 6 inch pipeline to shore.

To support separate handling of gas and condensate, the platform facilities need to provide dew point control on the gas, plus condensate stabilisation. A process flow diagram for the platform is provided in Appendix B, Drawing No. SAGA-1.

Dew point control for the gas is provided by low temperature separation. The low temperature is achieved with a turbo expander-compressor in combination with a gas-gas exchanger. The low temperature separation process ensures enough recovery of liquids to provide a dew point specification of 40 ^{O}F.

Recovered condensate is stabilised to meet an RVP specification. The stabiliser column is the main element of condensate processing. Feed to the stabiliser column is pre-heated by a feed-bottoms exchanger. A bottoms reboiler is provided. Reflux to the stabiliser column is provided by the cool liquids separated from the gas stream. Overhead vapour from the stabiliser column is compressed for return to the main gas stream.

In the SAGA-1 process scheme, there is no provision of a glycol contactor. Instead, most of the moisture will drop-out in the dew point control process. A continuous injection of glycol or methanol into the turbo expander inlet and outlet provides sufficient protection against hydrate formation.

Water handling is provided by hydrocyclone separator. Treated water is dumped overboard.

Utility systems required include cooling water and hot oil, in addition to the base utilities of power generation, drains and vents.

Included in the SAGA-1 process scheme is booster compression, positioned down stream of the production separator. The booster compression may be installed in later years of the field life. The Capex total presented for Case 5 does not include the future cost of this compression.

A slugcatcher is not required onshore in this case as the dew point control ensures that condensate does not drop out of the gas along the pipeline.

A process flow diagram for the onshore plant is given in Appendix B, Drawing No. SAGA-2.

The onshore process as described for Case 4 in most aspects is very similar for Case 5. Only the noteable differences will be described.

In Case 5 there is no slug catcher. Instead, the gas pipeline production is received into the pipeline receiver vessel. In Case 5, condensate is delivered by separate pipeline. The condensate is already stabilised and goes direct to the sales pipeline.

Cases 4 and 5 both have three distillation columns, but there is a marked difference in their duties. In Case 5 there is comparatively little condensate to be recovered from the gas plant feed, as most of the condensate has been recovered offshore. Hence, the process sequence for Case 5 liquids is de-ethaniser, depropaniser then debutaniser. Stabilised condensate is the bottoms stream off the debutaniser.

BOOSTER COMPRESSION FOR CASES 4 & 5

The production separator will initially operate at 710 to 1000 psi. Reservoir pressure will remain sufficiently high to maintain 710 to 1000 psi in the separator in the early years of production. The reservoir pressure will progressively decline and in time will no longer support 710 psi separator pressure. To maintain production in the later years, booster compression will be required. In this study, it has been assumed that separator pressure will be allowed to decline to 300 psi while still maintaining 89 MMSCF/D production rate. The booster compression power required to support this operating scenario is 5100 Hp, together with a pipeline compressor power of 5900 Hp. This level of compression power is the maximum expectation of what may be justified. Acceptance of a reduced production rate, or operation with a higher minimum separator pressure will reduce the required compression power.

For Case 5, the flow diagram in Appendix B, Drawing No. SAGA-1 shows booster compression included as a future option. For Case 4, the flow diagram in Appendix B, Drawing No. SAGA-3 does not show booster compression. Booster compression would be positioned immediately downstream of the production separator, similar to Case 5.

CASE 6 Process Platform - Membrane

Case 6 is a process platform providing CO_2 removal and dew point control of the gas. The 12 inch gas pipeline will operate in single phase to shore. Condensate is delivered by a separate 6 inch pipeline to shore.

This scheme is similar to Case 5, with the exception that CO_2 removal is performed on the platform rather than onshore. CO_2 removal on the platfrom is provided by a membrane system. Two stages of membrane separation are required with intermediate compression.

A lower gas flow to the pipeline is provided by the CO_2 removal offshore. This reduces the pressure rating required for the 12 inch pipeline and hence reduces its cost relative to Case 5.

The onshore plant will be the same as for Case 5 with the exception that CO_2 removal via the amine plant is not required.

CASE 7 Subsea / FPSO - Dew Point Control

Case 7 is a subsea facility feeding to an FPSO. The FPSO provides process facilities for dew point control of the gas and condensate stabilisation. Gas production is delivered to shore by a 12 inch pipeline operating in single phase. Condensate is stored in the FPSO tanker and off-loaded by shuttle tanker.

The subsea facility is a satellite system located on the sea floor. All wells are drilled from the one template. Production from the wells is manifolded at the satellite and flows to the FPSO via a rigid riser integral with the mooring. A separate flowline riser, again integral with the mooring is provided for well testing on the FPSO. Control of the satellite facility is from the FPSO via an electro-hydraulic multiplex umbilical.

The FPSO is assumed to be a 50,000 DWT converted tanker. The process facilities as described for the Case 5 process platform are provided on the tanker. Export of the processed gas is via a 12 inch rigid riser integral with the mooring.

Gas plant facilities for Case 7 are tha same as for Case 5.

CASE 8 Drilling Platform / FPSO - Dew Point Control

Case 8 is a drilling platform facility delivering to an FPSO. The FPSO provides process facilities for dew point control of the gas and condensate stabilisation. Gas production is delivered to shore by a 12 inch pipeline operating in single phase. Condensate is stored in the FPSO tanker and off-loaded by shuttle tanker.

The drilling platform is a fixed platform with minimum facilities. All the well heads are on the platform. Manifolding is provided for total production to be delivered to the FPSO via a single production flowline. A separate test flowline is also provided for well testing on the FPSO.

4.3 Platform Equipment Layouts

Deck layouts for the process platform have been developed. Two layouts are presented in Appendix F. The layouts are preliminary and have been used to size the total deck for costing purposes. The deck layouts shown are for Cases 4 and 5.

The platform has a main deck and cellar deck. Most of the process equipment is located on the cellar deck. The main deck has space allocation for future compression.

For Case 4 the cellar deck area is 100 X 150 ft (30 X 46 m). Weight of the topsides deck is around 2400 tonne.

For Case 5 the cellar dimensions are 100 X 200 ft. Weight of the topsides deck is around 3000 tonne.

5.0 REVIEW OF DEVELOPMENT OPTIONS

5.1 Evaluation of Options

Our aim in this study is to find the most economic facilities option for development of the Yolla field. The options available are broad. Appendix A provides an outline of the full array of options in a chart form. From the full array, a short list of options has been selected for detailed consideration. The 8 options were selected as having the most potential. For this report, the economic assessment of the options has been limited to review of capex and opex data. Table 5.1 provides a cost summary for the 8 short listed options.

The main pro's and con's are also given the Figures 5.1, 5.2 and 5.3 for each of the 8 cases. The main driver for selection is project economics, as indicated by the capex and opex of the options.

The high capex and opex combinations are easily eliminated. The options with lowest capex and opex are Cases 3 and 4. A simplistic selection between Cases 3 and 4 can be made if it is assumed that reserves recovery must be similar for the two cases. With future investment in compression included to allow full reserves recovery, Case 4 becomes the clear choice.

Case 3 with 3 phase pipeline operation has the added complexities of hydrate control and corrosion control. Wet gas production is exposed to hydrate formation and will require hydrate inhibitor injection. The base case free water assumption is 200 bpd, which may need up to 60 bpd glycol to be injected. If water production rises to the sensitivity case of 2000 bpd, glycol supply and recovery becomes a major burden.

The 3 phase pipeline requires internal corrosion protection. Since the gas has about 20 percent CO_2 , wet CO_2 corrosion would be very severe. So for this case corrosion inhibitor would have to be added. Chemical consumption cost is around US$ 50,000 per year for the base case water production, but if high water production is seen then this cost will increase dramatically.

Provision of future compression is very different for Cases 3 and 4. For Case 4, booster compression can be added at a reasonable cost of US$6.1 million (current dollar cost) when required. Case 3 would require major investment in a new processing platform to support the separation and compression facilities, which almost certainly could not be justified.

While Case 3 is not economic with a future compression platform, it may still be a good development approach. The reserves recovery will be less than Case 4 , but may be acceptable. The 20 inch pipeline in Case 3 allows target production to be maintained down to a separator pressure of 600 psia which extends to around year 8 or 9. A decline in production rate would then have to be accepted. Further consideration of Case 3 is therefore recommended with the acceptance of a lower reserves recovery.

TABLE 5.1 Cost Summary

CASE	1	2	3	4	5	6	7	8
FIELD CONFIGURATION	Subsea	Jackup	Drilling Platform	Process Platform	Process Platform	Process Platform	Subsea/ FPSO	Drilling Platform /FPSO
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TOTAL CAPEX US$M	**364**	**404**	**310**	**319**	**346**	**344**	**359**	**346**
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All costs are in US$ millions current at 1/1/95 and have an accuracy of +/- 30%.

5.2 Sensitivity Studies

NGL Recovery Cases

In Cases 1 to 8, gas has been assumed to be processed by a simple expander plant. Propane recovery achieved is around 60%. Butane recovery achieved is around 95%.

LPG recovery is subject to optimisation. The alternatives range from nil recovery of LPG through to over 95% recovery of propane. The alternatives are summarised in Table 5.2.1.

Case OSDPC (Onshore Dew Point Control) is dew point control for the gas, stabilisation for the condensate and produces no LPG products. Instead, it rejects propane and most of the butane to the sales gas. CO_2 content in the sales gas would be around 10% to maintain the wobbe index specification. Condensate is stabilised by stripping out propane and butane as necessary to meet an RVP specification. Capital investment for Case OSDPC is lowest at US$ 37 million for the onshore plant facilities. The payback stream is represented as product revenue less utility power and fuel. For Case OSDPC the payback is US$ 79.03 million per year.

Case MOSGP (Minimum Offshore Gas Plant) is a simple expander process for LPG recovery. Case MOSGP specifically aligns with Case 4 of this study. The plant produces the four products: sales gas, propane, butane and stabilised condensate. Investment for Case MOSGP is US$ 54 million and payback is US$ 82.54 million per year. Relative to Case OSDPC, the additional investment of US$ 17 million provides an additional payback of US$ 3.51 million. Return on the incremental investment is therefore not strong.

Case HIGHC3 and Case REFEXP are alternatives for improved propane recovery. Review of the payback and investment for these also show low payback for the incremental investment.

In conclusion, the sensitivities presented in Table 5.2.1 indicate the most economic development option to be Case OSDPC, provision of dew point control and no LPG recovery.

TABLE 5.2.1
SENSITIVITY: NGL RECOVERY CASES

CASE	US$ per Unit	OSDPC	MOSGP (Case 4)	HIGHC3	REFEXP
DESCRIPTION		Dew Point Control Only	Simple Expander Process	Low Pressure Expansion	Refrigerated Expander Process
PERFORMANCE					
Propane Recovery, %		0	63.2	87.0	96.6
Propane, tonne/d	185.00	0	106.1	147.3	163.4
Butane, tonne/d	185.00	0	58.1	60.5	60.5
Condensate, BPD	18.00	4566	4800	4813	4814
Sales Gas, MMSCFD	2.00	76.7	66.9	65.6	64.8
UTILITIES					
Electric Power, kW	0.06	910	1640	1660	4840
Fuel Gas, MMBTU/hr	2.00	88.3	129.0	173.0	168.0
CAPEX, MMUS$					
Gas Plant		34.6	44.2	54.8	50.2
Onshore Storage		2.4	9.6	10.9	10.9
TOTAL		37	54	66	61
OPEX, MMUS$/YR					
Electric Power		0.46	0.83	0.84	2.44
Fuel Gas		1.48	2.17	2.91	2.82
TOTAL		1.94	2.99	3.74	5.26
PRODUCT VALUE, MMUS$/yr					
Sales Gas		52.21	44.66	43.01	42.54
Propane		0.00	6.87	9.54	10.58
Butane		0.00	3.76	3.92	3.92
Condensate		28.77	30.24	30.32	30.33
TOTAL		80.97	85.54	86.79	87.37
PAYBACK, MMUS$/YR		79.03	82.54	83.05	82.10

NOTES:

1 350 Operating days per year

160 MMSCF/D Peak Flowrate

For increased reliability of supply, an option for consideration is a facility that will allow peak production of 160 MMSCF/D. The required facilities have been costed and compared to Case 4 in Table 5.2.2.

The cost growth is significant for the platform, the pipeline, the slug catcher and the gas plant. Total investment is increased from US$ 319 million to US$ 384 million. This increase in investment is significant and would not be justified.

TABLE 5.2.2
SENSITIVITY : 160 MMSCFD PEAK FLOWRATE CASE

	CASE 4	SENSITIVITY	
PEAK FLOWRATE, MMSCF/D	**100**	**160**	**REMARKS**
FIELD CONFIGURATION	**Process Platform**	**Process Platform**	
PROCESSING SCHEME	**2 Phase**	**2 Phase**	
Offshore Facilities	84.7	107.0	
Pipeline to Plant	67.6	87.2	From 12 to 16 in.
Slug Catcher	17.5	20.8	
Gas Plant	44.2	66.0	
Onshore Storage	9.6	9.6	
Cond. & Sales Gas Pipelines	7.4	7.4	
SubTotal	231.0	298.0	
Drilling Phase 1	49.6	86.0	From 8 Wells to 14 Wells
Drilling Phase 2	38.2		
TOTAL CAPEX US $M	**319**	**384**	

CO_2 Removal Facilities

Offshore CO_2 removal has been presented in Case 6. CO_2 removal is by a 2 stage membrane system with intermediate compression.

A lower gas flow to the pipeline is provided by CO_2 removal offshore. A consequent saving of about US$ 10 million is made on the pipeline, but the cost of the membranes and the associated recycle compression system balance this out.

Case 6 capex of US$ 344 million and opex of US$ 33 million make this option unattractive relative to Case 4.

For onshore CO_2 removal, an amine system was selected. This is a lower cost system for the final gas purity of 3 percent CO_2.

Water Handling Capacity

Sensitivity to water handling capacity has been considered. The high water case is 2000 bpd versus the base case of 200 bpd. Water handling facilities are not sensitive to capacity in the range 200 to 2000 bpd. The high water case adds an estimated US$ 0.2 million capex.

Concrete Gravity Structure

A steel jacket has been assumed for the platforms in Cases 3 to 6. An alternative is a concrete gravity base structure (CGS). For Case 4, a CGS has been costed and found to add approximately US$12 million to the installed cost. On this basis a CGS is not recommended.

Field Life

A 20 year life has been assumed for the facilities. Sensitivity to a change to 30 year projected life has been considered. Up to US$ 5 million is estimated to be the incremental capex for a 30 year life.

The additional investment is for example required in anodes for external protection of the offshore pipeline and the platform jacket. Additional investment would also be required for additional corrosion allowance for vessels in the process.

Opex costs already account for ongoing maintenance and component replacements. An extension of the field life does not change the estimates of annual opex.

If the process needs to be modified to extend the field life, then the additional facilities would add to the field life extension costs. For example, larger compression capacity would be a separate additional capital expenditure item.

Slug Catchers

The slug catchers predicted for the three and two phase cases are very large and costly. The pricing is for harp type slug catchers which would also take up a lot of space. In these sizes, it would probably be less costly to use a combination harp and hairpin system. (The hairpin is a looped length of offshore pipeline which would store most of the pigging slug volume. The harp then could be made smaller to handle random slugs.) Such a system would be more complex to operate.

An alternative is to use a regular pigging program to avoid excessive liquid holdup in the pipeline. This does add to operating cost and is not compatible with a subsea system.

6.0 PRODUCTION YIELDS

Presented in Table 6.1 are the product yields for the two well production compositions provided (see Appendix C for the well compositions). The base composition is richer in heavier hydrocarbon components than the alternate composition and consequently yields more propane, butane and condensate.

Propane recovery provided by the onshore facilities is around 60% in all cases where the Simple Expander Process is used. This level of recovery is modest and consistent with a mid range investment level. More investment in plant allows greater recovery. Yields can be increased to 163 tonne/d of propane and 60 tonne/d butane by expanding to lower pressures or adding refrigeration.

Alternatively less investment can be considered by not recovering LPG. Propane and butane can be rejected to the sales gas. The onshore process would simplify to dew point control for the gas and condensate stabilisation. To meet wobbe index, CO_2 would have to be slipped to the sales gas to a level of around 10%.

These onshore processing plant alternatives are discussed further in section 5.2, Sensitivity Studies.

TABLE 6.1 PRODUCT YIELDS

Stream	Flow Base Composition	Flow Alternate Composition	UNITS
Platform Gas	89	89	MMSCF/D
Sales Gas	66.9	67.4	MMSCF/D
Sales Gas (GHV)	77.4	78.0	TJ/d
Propane	106.1	104.7	tonne/d
Butane	58.1	55.2	tonne/d
Condensate	4800	4180	bbl/d

7.0 COST ESTIMATION

Cost estimation for this study has been developed using a number of sources. Vendors have been consulted for major equipment items. Reference has been made to similar previous projects. Market data has been incorporated. And the estimating packages SEAPLAN for offshore costs and EQ for onshore costs have been applied.

Process definition and equipment sizing form the basis of the estimating work. The process schemes have been discussed in section 4. The equipment sizing is summarised in the equipment lists included in Appendix D.

Cost estimates for the case studies have been summarised in Table 5.1 with breakdowns provided for the main components. Some further cost breakdowns have been provided for the offshore facilities in Appendix E.

Opex costs have been based on SEAPLAN estimates together with broad input from Operating company contacts that we have. A breakdown of the opex costs is also provided in Appendix E.

Abandonment costs for the offshore facilities have been estimated. These costs are presented with the operating costs in Appendix E.

8.0 SCHEDULE

For Case 4, time to first production is estimated to be 35 months from the start of detailed design.

Figure 8.1 provides the schedule details.

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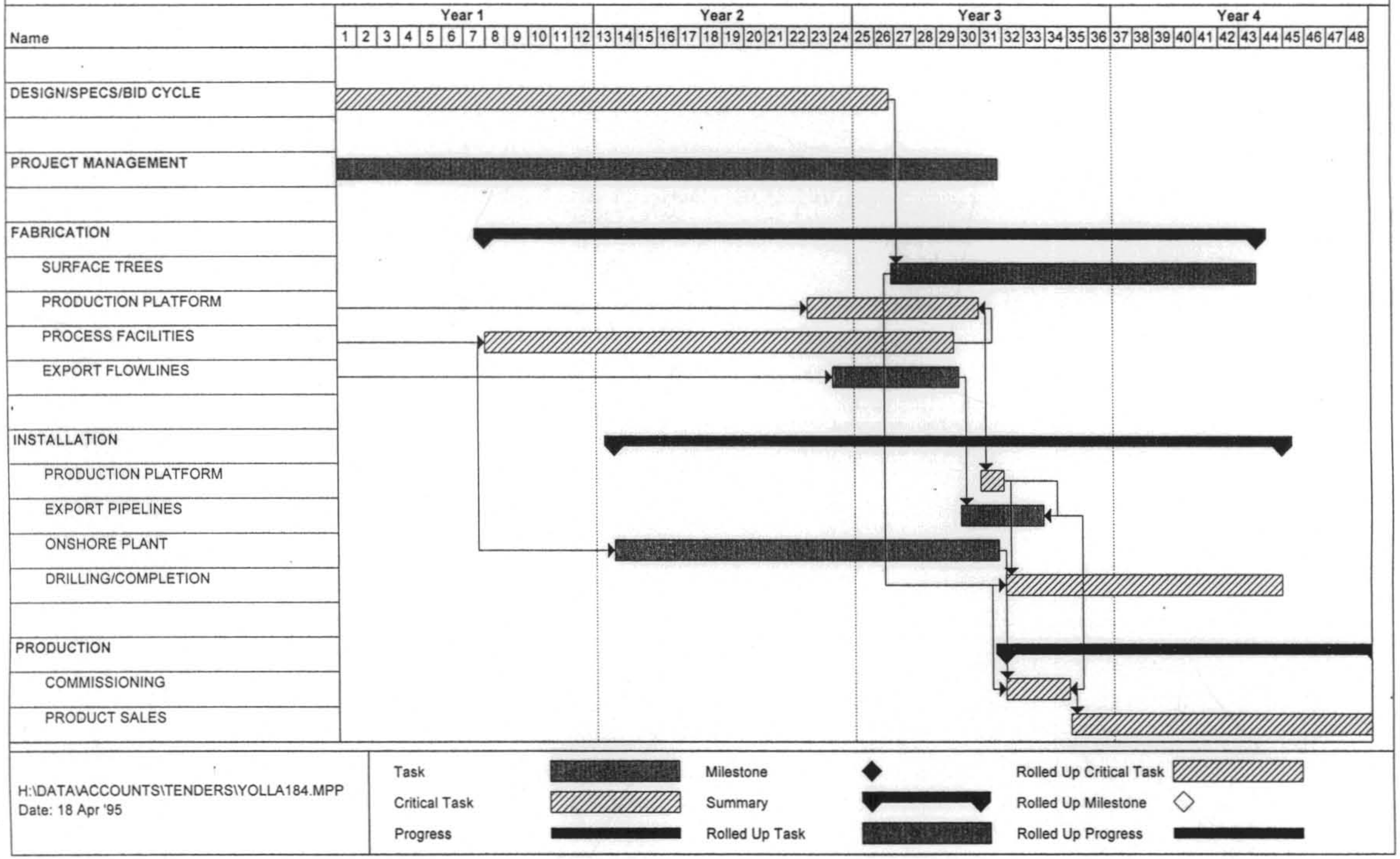
FIGURE 8.1

YOLLA - CASE 4 PROCESS PLATFORM - 2 PHASE

EJ/PCM



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9.0 ALTERNATIVE CONTRACTING STRATEGIES

Introduction

The following is an analysis and example of various contracting strategies that could be used on the Yolla Gas Field Development. The strategies that we discuss below are by no means all ways to develop a field, however, they are in our opinion commercially innovative and could provide an opportunity to potentially reduce the cost of the Yolla project.

There are many variations of contracting methods available to SAGASCO, however, in reviewing the development of a contracting strategy Sagasco should consider three critical areas, those are:

- price determination
- risk allocation
- compensation

Price Determination

The stage of the project at which prices are determined (either target or fixed) has effect on the accuracy and consequently the risks associated with those prices. Differing contracting strategies will determine the price at different stages and therefore have an impact on the risk distribution.

Open book price determination allows the contractor and SAGASCO to work together to estimate the costs of the field development. The contractor exposes his costs, overhead allocation and contingencies and negotiates an appropriate profit margin with the SAGASCO.

In a closed book scenario SAGASCO would receive the development price structure from the contractor with little or no information on the cost structure. Typically, closed book methods are employed in traditional bidding situations and are not conducive to a trust based relationship.

Risk Allocation

We believe that the best way to manage the risk associated with the development is to set up a contracting structure that permits those risks to be assumed by the party who is in the best position to control the particular risk. Further it is important that an equitable risk and reward balance are maintained.

It is assumed that significant development risks such as those associated with reservoir management and the sales price of the product will be held by the operator and as such these risks are not addressed. The risks addressed are those associated with the design and construction of the facilities, tie back and completion of the wells and the operations and maintenance of the completed facility. At a high level these risks include the capex cost of the facility, the completion date of the facility, the opex cost to run the facility and the risk associated with the performance of the facility.

The risks can be absorbed by either the contractor or the client or be shared by structuring a gain sharing relationship.

Compensation

Various alternative payment compensation structures are available in a contracting strategy and such structures can include but are not limited to the following concepts:

- progress payments
- milestone payments
- neutral funding
- production funded payments

These payment structures are not discussed further as they are equally applicable to each of the following contracting strategy examples discussed.

Alternative Contracting Strategies

We have successfully contracted in any combination of the above and would like to give SAGASCO a broad range of examples of how they could contract on the Yolla project as follows:

- Open book, single alliance contractor price determination, leading to fixed price EPC
- Open book, single alliance contractor price determination leading to target price
- Open book, SAGASCO chosen alliance group price determination leading to target price with gain sharing in proportion to risk
- Life of field partner
- Contract to produce

Open Book Single Alliance Contractor Price Determination Leading to Fixed Price EPC

Under this scenario the contractor would effectively be the sole alliance contractor for SAGASCO and would hold the majority of the price and completion risk on the project. The intention would be to work with SAGASCO on an open book basis during the project definition stage to develop an estimate for the Yolla development. At the end of this stage the contractor would be able to offer SAGASCO a fixed price for design and construction of the facilities and the subsea completions. The contractor would expose their cost base, overhead, material costs, subcontract costs and agree contingencies and profit margins with SAGASCO. The intent would be during the project definition stage - where the concept is defined and the basic engineering is completed to be able to confidently estimate a fixed price with which the contractor can satisfactorily accept the risks associated with sufficient completion, process and price guarantees.

The major scope items for which the contractor could be responsible are as follows:

- Concept development
- Basic and detailed engineering
- Procurement
- Fabrication
- Offshore facilities and pipeline installation
- Hook-up and commissioning
- Subsea facilities
- Onshore plant construction and commissioning
- Well completion and testing

Under this scenario the contractor would assume the following risks:

• Development price risk	Fixed price
• Schedule completion risk	Guarantee through liquidated damages
• Performance risk	Guarantee provided
• Materials	Warranty provided
• Workmanship	Warranty provided

Open Book Single Alliance Contractor Price Determination Leading to Target Price

Under this scenario, SAGASCO would contract with a single alliance contractor to develop the Yolla Gas Field. The contractor would share, with SAGASCO, the price and completion risk, through incentive provisions related to achieving these targets and other objectives set for the project.

In this case, the contractor would work with SAGASCO throughout the project on an open book basis. The contractor and SAGASCO would jointly develop the target budget for the Yolla Gas Project during the project definition stage. The target budget would be used to establish a gain sharing structure in which the contractor would share and be rewarded for under expenditure of the agreed target budget. Conversely we would be penalised for not achieving the objectives. Establishing the target budget during the project definition phase would provide an incentive for innovative ideas during the basic engineering works when the project is still at a significant cost influence stage.

The gain sharing would be structured to reflect the contractor's ability to influence the total cost of the development. The contractor would pass on this gain sharing philosophy to major subcontractors that it considers could significantly influence the success of the development.

With the open book approach the contractor would expose their cost structure throughout the life of the project. This would include details of overhead allocations, labour costs, material costs, subcontract costs and alliance partner costs. This cost would be applied against their estimate of material quantities, labour productivity and applicable contingencies to determine a base cost and to this base cost would be allocated an agreed profit margin to determine the target budget. The profit margins would be determined at an early stage in the relationship with SAGASCO.

This approach provides SAGASCO with the advantages of containing their risk using a target budget for the design and construction works. This containment is achieved by insuring strong incentives are in place for the parties' work on an integrated basis and reduce the target budget. It has further advantages concerning the project schedule such as a lengthy bidding period is not required for the detailed design and construction phases. Also, this concept will allow SAGASCO to maintain control of the project without having to establish a major project team.

We would suggest using an integrated project management team staffed with both the contractor personnel and SAGASCO personnel. This would eliminate duplication between the client and contractor and allow them to work in a true partnering configuration.

Under this scenario the contractor would assume the following risks:

• Development price risk	Guarantee through incentive scheme
• Schedule completion risk	Guarantee through incentive scheme
• Performance risk	Guarantee provided
• Materials	Warranty provided
• Workmanship	Warranty provided

Open Book Client Chosen Alliance Consortium Price Determination Leading to Target Price

Under this concept SAGASCO would select contractors and form an alliance group responsible for the Yolla Gas Project. The Alliance group would be made up of the appropriate contractors and SAGASCO.

The alliance would operate in a similar manner to that described above in so much as a Target Budget would be determined at an early stage in the development. The alliance would be governed through the establishment of an Alliance board made up of representatives of all the alliance members.

The alliance members would be charged with common goals and an incentive structure again based upon improving the target budget and schedule. However in this case as the alliance is made up of multiple parties the gain sharing structure would reflect each contractor's ability to the influence the total cost of the development. The formula for the final over or under expenditure of the Target Budget will be pre- determined from a detailed analysis of each Alliance member's ability to influence the final cost

For example the design engineer has a large influence on the final cost although his actual cost regarding the total development cost is relatively small. Therefore his risk reward factor would be larger than the percentage of his actual cost of the total development budget.

Under this scenario and acting as the management and design contractor would limit its maximum risk to the value of its normal profit.

Life of Field Business Partner

The concept of a Life of Field business partner is where the contractor would commit to provide the following services in conjunction with a small SAGASCO team:

- Concept development
- Basic and detail design up to a fit for purpose functional design covering onshore, surface, subsea and subsurface facilities;
- Project management services through life of field;
- Document /image/data management
- Selection of contractors and suppliers
- Facilities operation and maintenance
- Integrated logistics and support through life of field
- Continuity from basic engineering to abandonment for engineering, procurement spares, logistics

The entire process would be managed by an integrated team with people selected for each position from within SAGASCO the LOF partner or from external sources. The positions would remain for the life of the field that would give a continuity of philosophy and strategy throughout the life of field.

Other contractors would be invited to join the business partnership in an alliance for the scope items as follows:

- Fabrication
- Installation of facilities and pipeline
- Hook-up and commissioning
- Onshore plant construction and commissioning
- Subsea facilities and subsea maintenance
- Well completion and maintenance

These additional contractors would join and leave the alliance at different phases. The alliance would be dynamic in nature. Some elements would continue throughout the field life such major equipment suppliers who have an interest in supplying and maintaining their equipment and retaining ownership of its performance.

Contract to Produce

The contractor could under two contracts take responsibility for the development of the field through to production and could be compensated for performance of the contract on a dollar per unit of gas basis. Furthermore, this can be structured so as it could be financed on a limited recourse basis if that were required. Under this example the contractor would bear many of the risks associated with the Yolla development. Effectively the only risks that the contractor would not bear are those associated with gas price and the size and performance of the reservoir. Risks would be transferred to the contractor by means of a Turnkey Construction contract and an Operations and Maintenance contract that will provide for fixed price services and technical performance of the facilities- topsides, subsea and onshore.

The intention would be to work with SAGASCO on an open book basis during the project definition stage to develop an estimate for the Yolla development. At the end of this stage the contractor would be able to offer SAGASCO a single point, fixed price EPC Turnkey construction contract for all the engineering and construction works required to bring the field into full production. This will involve the following:

- fixed price, non-inflatable contract
- guaranteed completion date
- guaranteed performance levels
- liquidated damages to support the above guarantees
- single point "umbrella protection" whereby the contractor themselves directly take responsibility for all the guarantees and thereby support the obligations of all sub-contractors who will be involved with the development

This contract will transfer all the principal engineering and construction phase risks to the contractor.

The contractor can also provide the development with an Operations and Maintenance (O&M) contract that will become effective once the contractors have discharged their obligations under the Turnkey Construction contract. The O&M contract would oblige the contractor to provide ongoing O&M services and in return the contractor could, for example, receive a fixed price per unit of gas payment.

The overall production contract would be overseen by an integrated executive committee with people selected from both SAGASCO and the contractor.

10.0 ALLIANCING

Introduction

Regardless of the type of contract relationships, we believe that the contracting philosophy should be based upon alliance principles, with a high degree of trust, aligned objectives, measurement, performance indicators, teamwork and shared risk and reward. Alliancing is essentially a co-operative arrangement that brings together the skills of different parties into a project with the express purpose of minimising expenditure, allowing cross fertilisation of ideas on design and construction, as well as enhancing the achievement of financial and schedule targets.

Benefits

The benefits of working on an alliance premise are multi faceted with the two principal gains being reduced cost and reduced time. These two key elements are derived by developing an alliance team that is dedicated, focused on the project objectives, built on trust and based on the best person for the job.

The benefits are derived by the structure of the alliance relationship, driven by the leadership commitment and direction given by the alliance board to the project team. It is fundamental that the alliance board must be proactive, be committed and work as a team, such that the project team has visual demonstration behind the concept of the alliance contract.

At project initiation, the Alliance Board will develop the objectives and parameters for the project and will identify what key benefits the SAGASCO alliance wants to realise from the project.

Besides the specific benefits and objective the alliance board may want to realise, the following subjects should be derived from working in an alliance relationship:

Reduced capital costs achieved by:

- Reduction of interfaces and better communication
- Streamlining management structure to reduce response time, providing a better quality answer
- Uninhibited team approach for selection of vendor standard products and fit for purpose application
- Contracting premise with the principal alliance partners, suballiance partners and aligned vendors for incentives to reduce the total project cost
- A team based environment to create a win win situation
- Informed decision making
- Reduced inspection and expediting by using alliance vendors

Reduced construction schedule

- Is achieved by the adoption of the points highlighted in reduced capital costs above.

Reduced Ongoing Operating Costs achieved by:

- Operations people are incorporated into the alliance team providing the ability to input and assess through all stages of the design, construction and operation.

- Use of vendor standard products, facilitates ease of supply of technical support, back up spares and replacement.

- Integrated team ensuring common utilisation of equipment and specification of items across all parts of the development.

- Reduced ongoing management and technical resources by having alliance vendors being capable and responsible for supporting their equipment or product.

In addition to the substantial savings that will be achieved by the elimination of the man marking which is traditional in conventional contracting structures, savings will be achieved by the incorporation of the subordinate expertise into the integrated team from the contractor, subcontractor, client and vendor .

Contractor Supplier Alliances

Contractors have transformed long term relationships with suppliers into supplier alliances. These relationships are based on the same principles as described above, i.e. long term relationships, trust, aligned objectives, quality and continuous improvement. As a result, a fit for purpose product is supplied at a lower cost and a better schedule than would have been achieved via traditional supplier and customer relationships.

We have found that our alliances with suppliers that have met the prerequisite alliance features are "critical" to success of our projects.

Our alliance suppliers normally work as part of our integrated team. The benefits of supplier alliances include:

- Elimination of duplication of resources
- Application of the latest technology
- Supplier "buy in" for product application
- Elimination of over specification or preferential engineering
- Reduced cost
- Reduced expediting and inspection
- Greater assurance of receiving timely documentation and prerequisite interface information
- Supply of products which can be serviced and supported through life

Risk Management

The basic premise for alliance contracting is that the entity best suited to manage the risk should be responsible for the risk. This philosophy ensures that the entity has the appropriate authority and responsibilities, and therefore contingency plans in place to minimise the impact on the project when unforeseen situations that would create risk arise.

We would strongly recommend that one of the prime drivers for the alliance be the elimination of potential risk, and the determination of contingency plans should an item that could cause cost or schedule impacts on the project arises. This philosophy would be created by the Alliance Board with setting the objectives, contracting philosophy, and targets for the project.

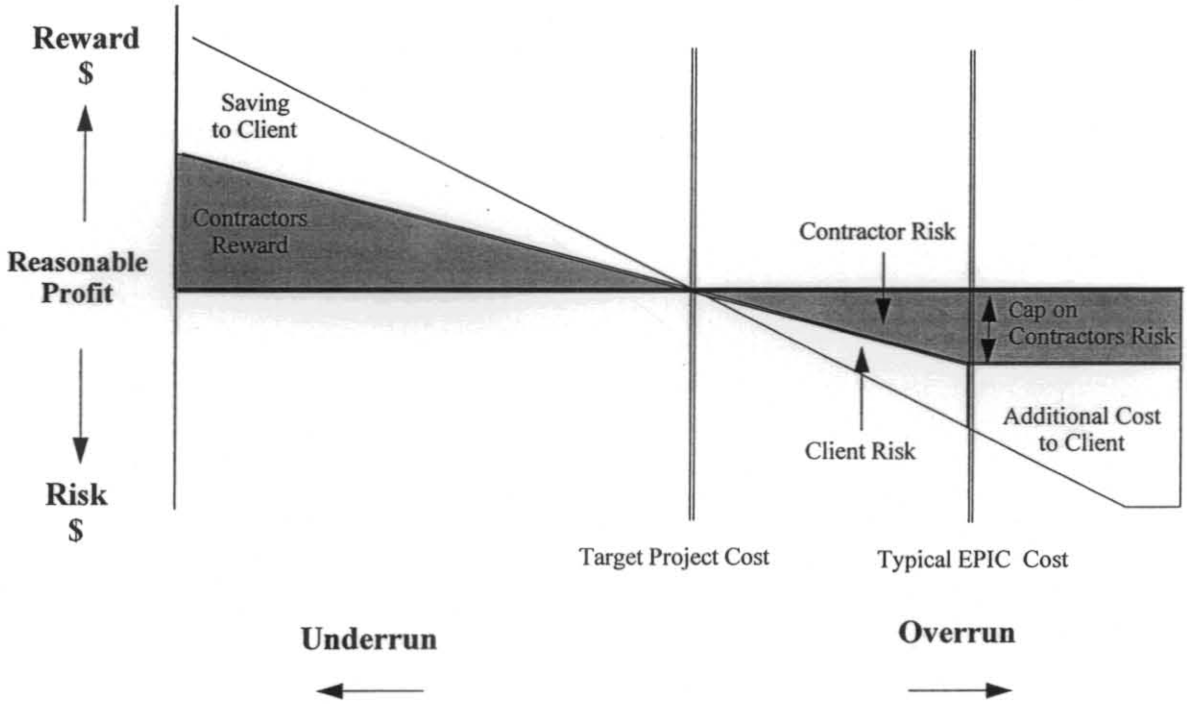
Gain Sharing Structures

The following are some basic principles that should be included or reviewed before developing a gain share structure.

- sharing of risk and reward is proportional to influence of cost
- utilisation of uncertainty allowance to be controlled by the Alliance
- no finger pointing - success or failure is a joint responsibility irrespective of who caused it
- the cap on total risk be equal to profit
- target budget to be jointly agreed
- provides incentive for all to achieve completion under target
- provides possibility to gain extraordinary benefits
- gain sharing is linked to joint performance of the Alliance - win or lose together
- parties participate in gain sharing dependent on final project cost
- gain sharing based on balanced risk and reward

The following example is a typical gain share structure for the Capex portion of a field development currently used by the contractor in Australia and the North Sea. A target budget for the facility's design and construction is agreed by the Alliance before sanction of the project. The price determination is made up of input from selected alliance contractors on their traditional basis and assumes that they will receive normal profit. An example of this would be lump sums from installation contractors, man-hour rates from the engineering contractors and a mixture of lump sum and rates from the fabricators. A risk and reward structure is then set up whereby if the final project cost goes over the target budget, the overrun is spread out among the alliance members at an agreed percentage until the cost overrun reaches the gain share total capped cost whereby any cost overruns after the caps are borne by the client.

Risk and Reward Schematic



APPENDIX A

DEVELOPMENT OPTIONS SHEET

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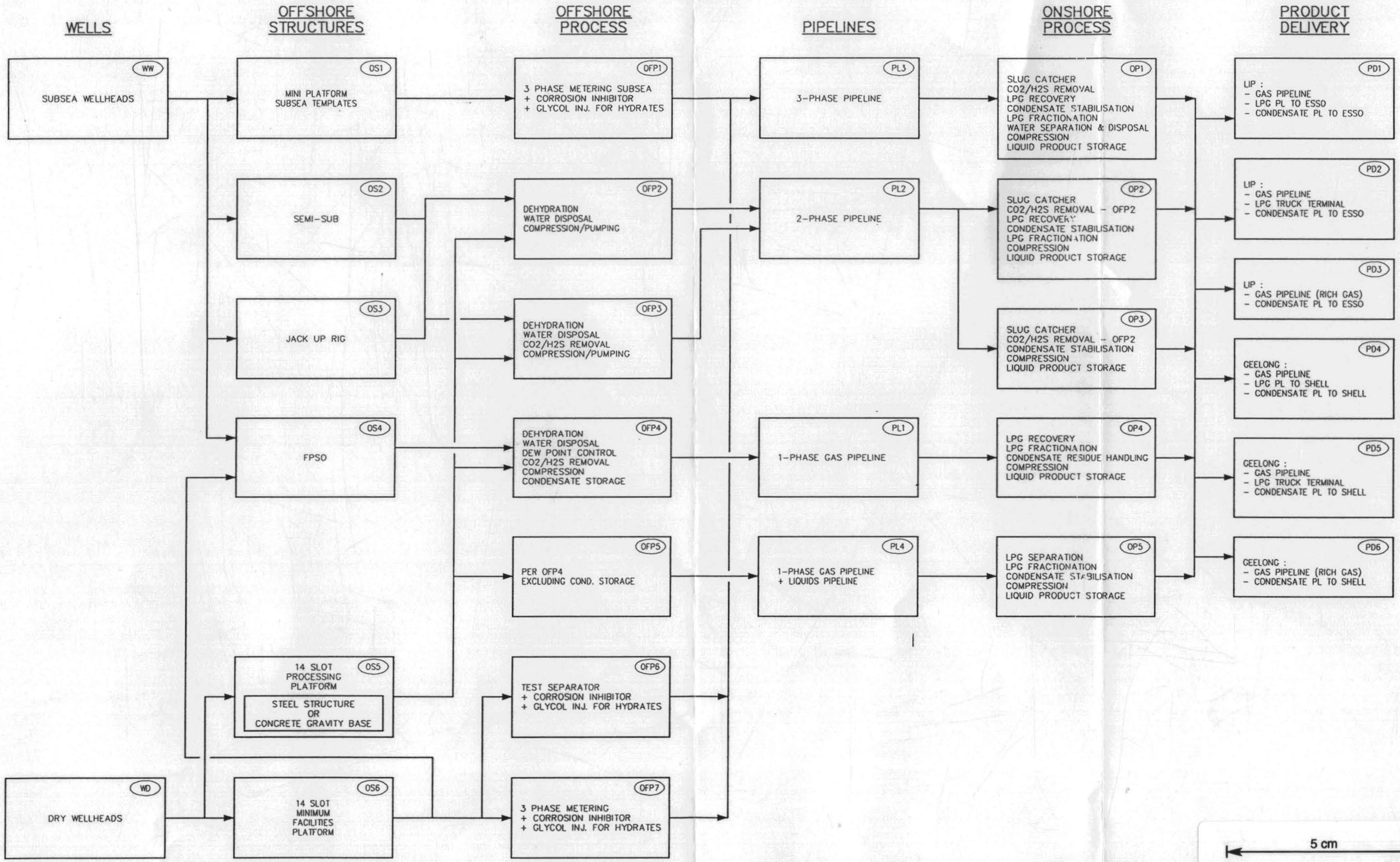
SAGASCO – YOLLA STUDY
FACILITY OPTIONS



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NOTES	REVISIONS • BY • DATE	REVISIONS • BY • DATE	Brown & Root FAR EAST ENGINEERS PTE. LTD. Engineers • Constructors	DRAWN BY: PHILIP CHUA DATE 9 MAR 1995 CHECKED BY: – DATE – SCALE: NONE	APPROVED APPROVED SEAL	TITLE OF DRAWING: SAGASCO – YOLLA STUDY FACILITY OPTIONS NAME OF OWNER: DAWSON BROWN & ROOT LOCATION OF PROJECT:	CONTRACT NO. 1601-002 DRAWING NO. 1601-1 SHEET 1 OF 1

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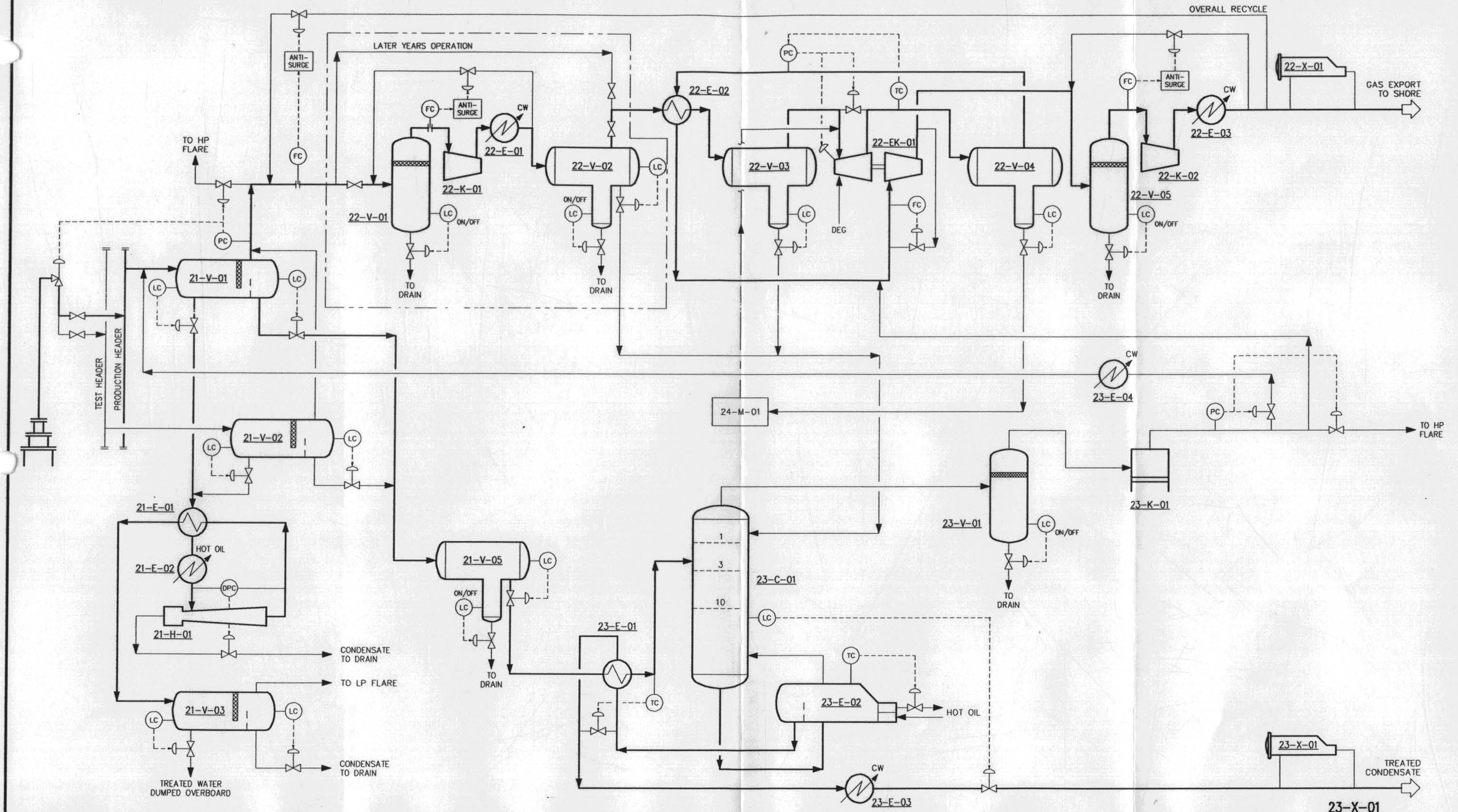
APPENDIX B

PROCESS FLOW DIAGRAMS

ITEM TAG NO. :	21-V-01	21-V-02	22-V-01	22-K-01	22-E-01	22-V-02	22-E-02	22-V-03	22-EK-01	22-V-04	22-V-05	22-K-02	22-E-03	22-X-01
DESCRIPTION :	PRODUCTION SEPARATOR	TEST SEPARATOR	BOOSTER SUCTION K.O.D.	BOOSTER COMPRESSOR	BOOSTER COMPRESSOR AFTER COOLER	BOOSTER DISCH. K.O.D.	GAS-GAS EXCHANGER	EXPANDER SUCTION K.O.D.	EXPANDER COMPRESSOR	COLD SEPARATOR	PIPELINE COMPRESSOR K.O.D.	PIPELINE COMPRESSOR	PIPELINE COMPRESSOR AFTER COOLER	GAS P/L PIG LAUNCHER



ITEM TAG NO. :	21-E-01	21-E-02	21-H-01	21-V-03	21-V-05	23-E-01	24-M-01	23-C-01	23-E-02	23-E-03	23-V-01	23-E-04	23-K-01	23-X-01
DESCRIPTION :	WATER-WATER EXCHANGER	WATER HEATER	HYDROCYCLONE	DEGASSER	CONDENSATE SURGE DRUM	FEED-EFFLUENT EXCHANGER	GLYCOL REGENERATOR	CONDENSATE STABILISER	STABILISER REBOILER	CONDENSATE COOLER	OVERHEAD SUCTION K.O.D.	OVERHEAD COMPRESSOR AFTERCOOLER	OVERHEAD COMPRESSOR	CONDENSATE PIG LAUNCHER

CASE : WEND

NOTES

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Brown & Root
FAR EAST ENGINEERS PTE. LTD.
Engineers • Constructors

DRAWN BY: PHILIP
DATE 15 MAR 1995
CHECKED BY: EJ
DATE 10-4-95
SCALE: NONE

APPROVED

APPROVED

SEAL

TITLE OF DRAWING : OFFSHORE FACILITIES
YOLLA FIELD DEVELOPMENT
NAME OF OWNER : SAGASCO
LOCATION OF PROJECT :

CONTRACT NO. 1601-02
DRAWING NO. SAGA-1
SHEET 1 OF 1

Filename J:\6024\PIDS\SAGA-1 Last Update 07-04-1995 2:18p By PHILIPC

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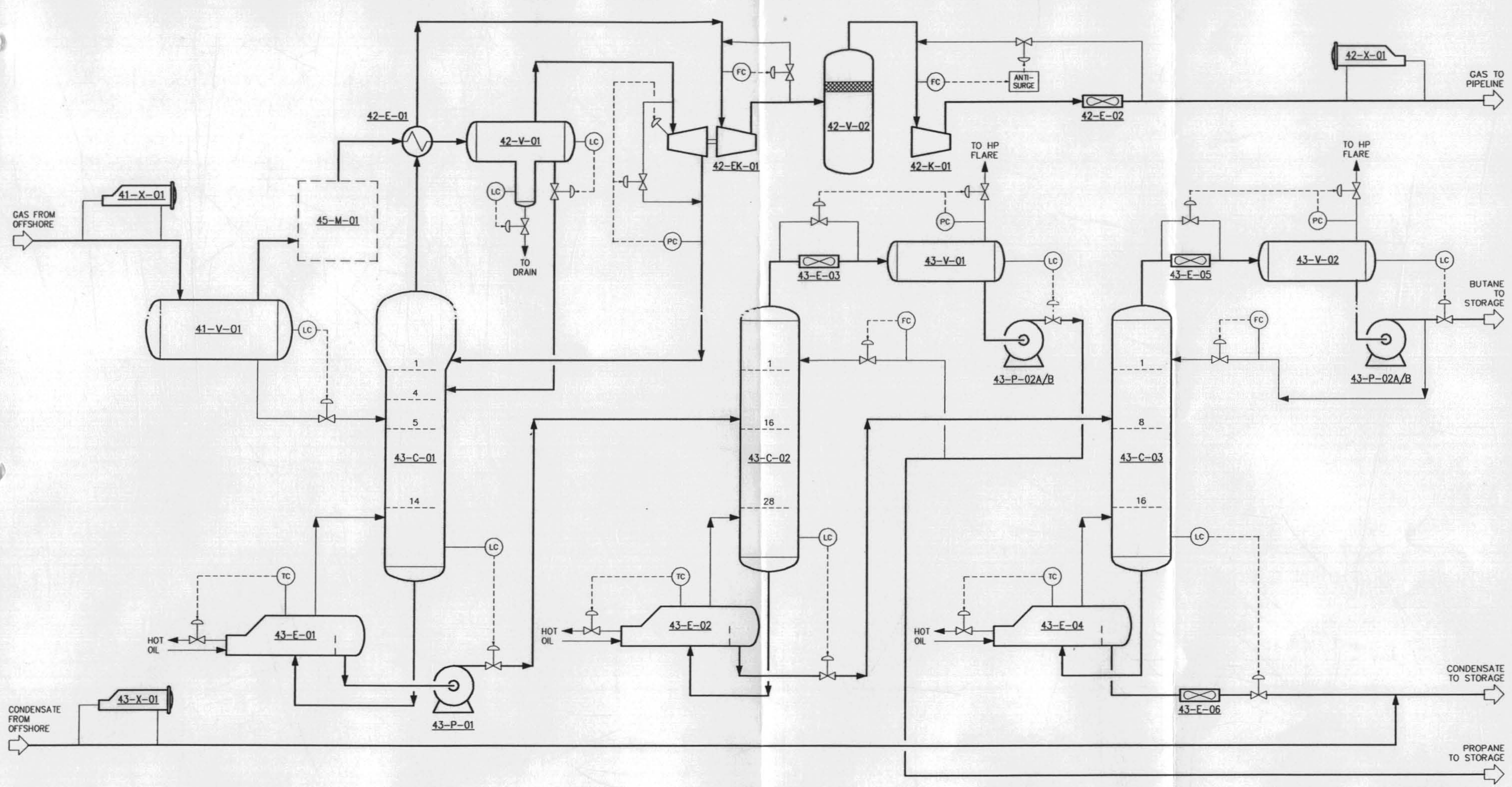
ITEM TAG NO. :	41-X-01	41-V-01	45-M-01	42-E-01	42-V-01	42-EK-01	42-V-02	42-K-01	42-E-02	42-X-01
DESCRIPTION	PIG RECEIVER	PIPELINE RECEIVER	GAS SWEETENING & DEHYDRATION UNIT	GAS-GAS EXCHANGER	EXPANDER SUCTION K.O.D.	EXPANDER-COMPRESSOR	PIPELINE COMPRESSOR K.O.D.	PIPELINE COMPRESSOR	PIPELINE COMPRESSOR AFTER COOLER	GAS P/L PIG LAUNCHER



ITEM TAG NO. :
DESCRIPTION

- 43-V-01 DEPROPANISER REFLUX ACCUMULATOR
- 43-C-01 DE-ETHANISER
- 43-C-02 DEPROPANISER
- 43-P-02A/B DEPROPANISER REFLUX PUMPS
- 43-C-03 DEBUTANISER
- 43-V-02 DEBUTANISER REFLUX ACCUMULATOR
- 43-P-03A/B DEBUTANISER REFLUX PUMPS
- 43-X-01 PIG RECEIVER
- 43-E-01 DE-ETHANISER REBOILER
- 43-P-01 DE-ETHANISER BOTTOMS PUMP
- 43-E-02 DEPROPANISER REBOILER
- 43-E-03 REFLUX CONDENSER
- 43-E-04 DEBUTANISER REBOILER
- 43-E-05 REFLUX CONDENSER
- 43-E-06 CONDENSATE COOLER

CASE : DPCGP

NOTES

5 cm

REVISIONS • BY • DATE

REVISIONS • BY • DATE

Brown & Root
FAR EAST ENGINEERS PTE. LTD.
Engineers • Constructors

DRAWN BY: PHILIP
DATE 15 MAR 1995
CHECKED BY: EJ
DATE 10-4-95
SCALE: NONE

APPROVED

APPROVED

SEAL

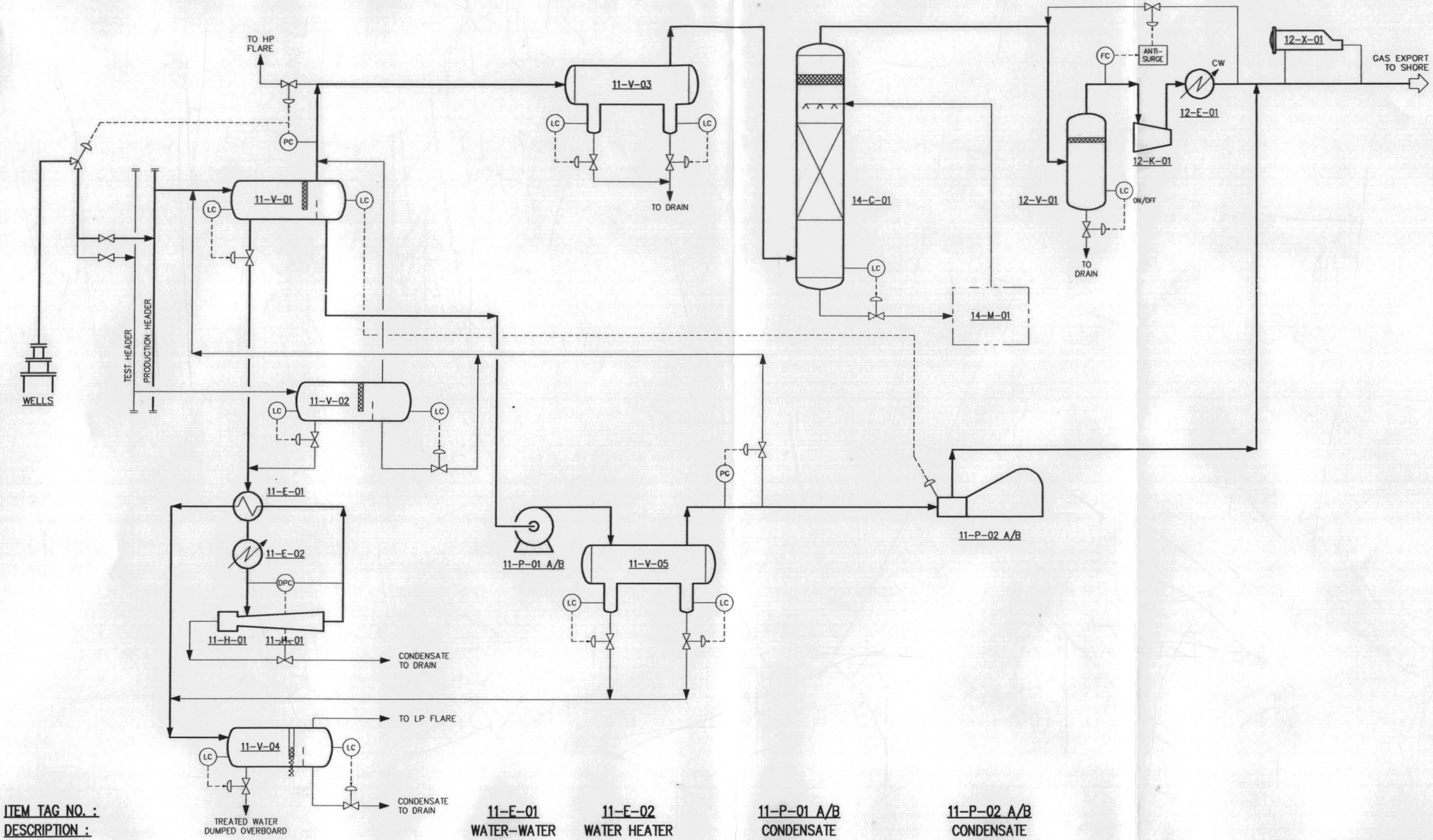
TITLE OF DRAWING : ONSHORE FACILITIES
YOLLA FIELD DEVELOPMENT
NAME OF OWNER : SAGASCO
LOCATION OF PROJECT :

CONTRACT NO. 1601-02
DRAWING NO. SAGA-2
SHEET 1 OF 1

Filename J:\6024\PIDS\SAGA-2 Last Update 06-04-1995 08:11a By PHILIPC

514051

ITEM TAG NO. :	11-V-01	11-V-02	11-V-03	11-V-04	11-H-01	11-V-05	14-C-01	14-M-01	12-V-01	12-K-01	12-E-01	12-X-01
DESCRIPTION :	PRODUCTION SEPARATOR	TEST SEPARATOR	GAS FILTER SEPARATOR	DEGASSER	HYDROCYCLONE	CONDENSATE COALESCER	GLYCOL CONTACTOR	GLYCOL REGENERATOR	PIPELINE COMPRESSOR K.O.D.	PIPELINE COMPRESSOR	COMPRESSOR AFTER COOLER	PIG LAUNCHER



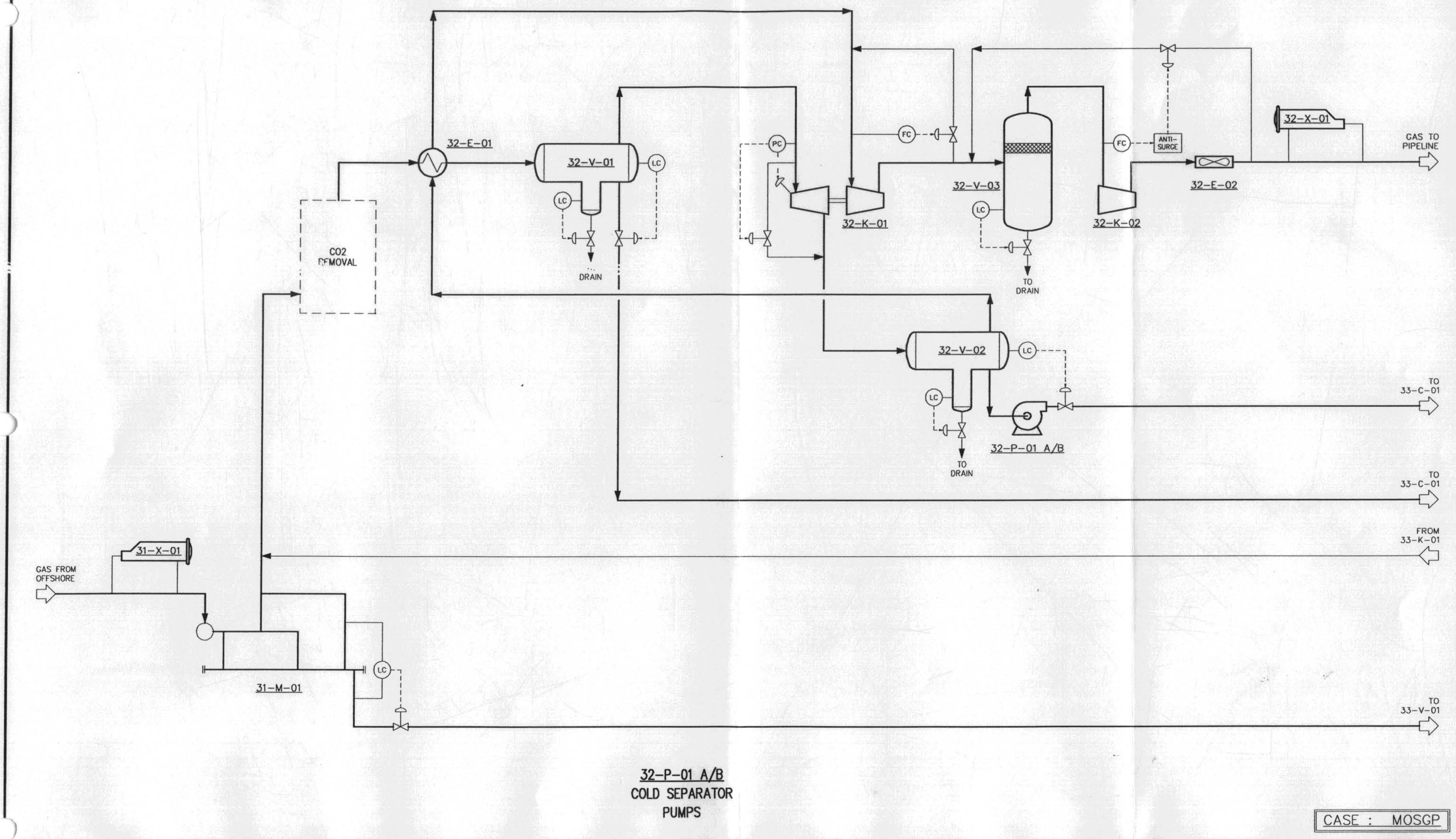
ITEM TAG NO. :	11-E-01	11-E-02	11-P-01 A/B	11-P-02 A/B
DESCRIPTION :	WATER-WATER EXCHANGER	WATER HEATER	CONDENSATE BOOSTER PUMPS	CONDENSATE PIPELINE PUMPS

CASE : MINOS

NOTES	REVISIONS • BY • DATE	REVISIONS • BY • DATE	Brown & Root FAR EAST ENGINEERS PTE. LTD.	DRAWN BY: PHILIP	APPROVED	TITLE OF DRAWING : OFFSHORE FACILITIES	CONTRACT NO. 1601-02
5 cm			Engineers • Constructors	DATE 15 MAR 1995	APPROVED	YOLLA FIELD DEVELOPMENT	DRAWING NO. SAGA-3
				CHECKED BY: EJ		NAME OF OWNER : SAGASCO	
				DATE 10-4-95	SEAL	LOCATION OF PROJECT :	SHEET 1 OF 1
				SCALE: NONE			

Filename J:\6024\PIDS\SAGA-3 Last Update 07-04-1995 2:07p By PHILIPC

ITEM TAG NO. :	31-X-01	31-M-01	35-M-01	32-E-01	32-V-01	32-V-02	32-K-01	32-V-03	32-K-02	32-E-02	32-X-01
DESCRIPTION :	PIG RECEIVER	SLUG CATCHER	GAS SWEETENING & DEHYDRATION UNIT	GAS-GAS EXCHANGER	EXPANDER SUCTION K.O.D.	COLD SEPARATOR	EXPANDER COMPRESSOR	PIPELINE COMPRESSOR K.O.D.	PIPELINE COMPRESSOR	COMPRESSOR AFTER COOLER	PIG LAUNCHER



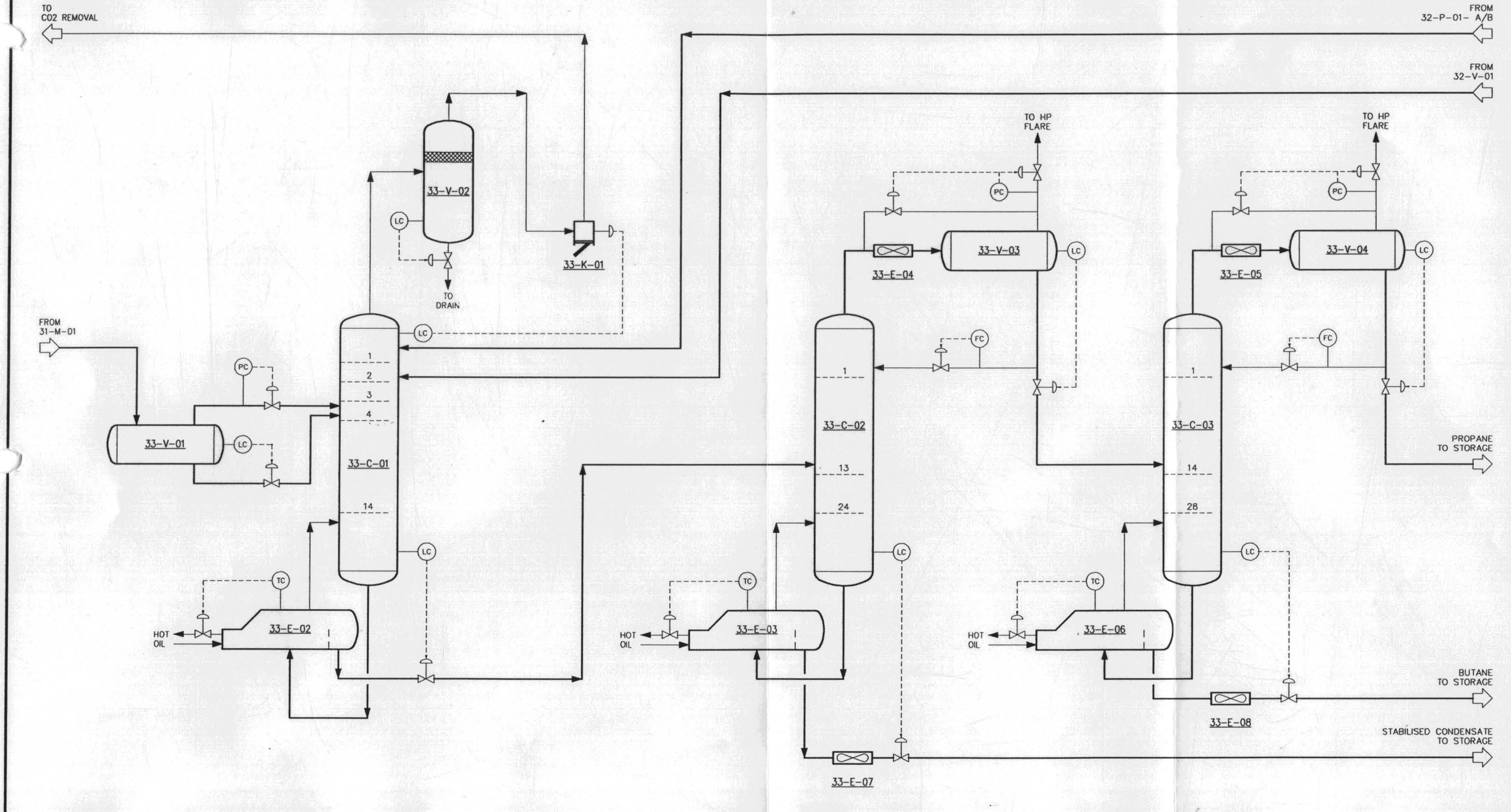
CASE : MOSGP

NOTES	REVISIONS • BY • DATE	REVISIONS • BY • DATE						
5 cm			Brown & Root FAR EAST ENGINEERS PTE. LTD. Engineers • Constructors	DRAWN BY: PHILIP DATE 15 MAR 1995 CHECKED BY: EJ DATE 10-4-95 SCALE: NONE	APPROVED APPROVED	SEAL	TITLE OF DRAWING : ONSHORE FACILITIES YOLLA FIELD DEVELOPMENT NAME OF OWNER : SAGASCO LOCATION OF PROJECT :	CONTRACT NO. 1601-02 DRAWING NO. SAGA-4 SHEET 1 OF 1

Filename J:\6024\PIDS\SAGA-4 Last Update 06-04-1995 4:40p By PHILIPC

514053

ITEM TAG NO. :	33-V-01	33-C-01	33-V-02	33-K-01	33-C-02	33-E-04	33-V-03	33-C-03	33-E-05	33-V-04
DESCRIPTION :	DE-ETHANISER FEED DRUM	DE-ETHANISER	DE-ETHANISER OVERHEAD DRUM	DE-ETHANISER OVERHEAD COMPRESSOR	STABILISER	STABILISER CONDENSER	STABILISER REFLUX ACCUMULATOR	DEPROPANISER	DEPROPANISER CONDENSER	DEPROPANISER REFLUX ACCUMULATOR



ITEM TAG NO. :	33-E-02	33-E-03	33-E-07	33-E-06	33-E-08
DESCRIPTION :	DE-ETHANISER REBOILER	STABILISER REBOILER	CONDENSATE COOLER	DEPROPANISER REBOILER	BUTANE COOLER

CASE : MOSGP

NOTES

5 cm

REVISIONS • BY • DATE

REVISIONS • BY • DATE

Brown & Root
FAR EAST ENGINEERS PTE. LTD.
Engineers • Constructors

DRAWN BY: PATRICK
DATE 23 MAR 1995
CHECKED BY: EJ
DATE 10-4-95
SCALE: NONE

APPROVED

APPROVED

SEAL

TITLE OF DRAWING : ONSHORE FACILITIES
YOLLA FIELD DEVELOPMENT
NAME OF OWNER : SAGASCO
LOCATION OF PROJECT :

CONTRACT NO. 1601-02
DRAWING NO. SAGA-5
SHEET 1 OF 1

Filename J:\6024\PIDS\SAGA-5 Last Update 06-04-1995 4:44p By PHILIPC

APPENDIX C

BASE DATA

APPENDIX C

YOLLA FIELD DEVELOPMENT

SAGASCO RESOURCE LIMITED, AUSTRALIA

BASIC DESIGN DATA

FOR

OFFSHORE AND ONSHORE PLANT

DAWSON BROWN & ROOT
MAR 1995

1.0 Introduction

Sagasco Resource Limited, Australia are considering the development of the Yolla Gas Field. The Yolla gas resource was discovered in 1985 and is located in Bass Strait. Gas from the reservoir contains approximately 19% CO_2 and is rich with heavier hydrocarbons. The field has a limited amount of data available as Sagasco has drilled only one test well. Before proceeding with any further appraisal drilling Sagasco wants the development options to be assessed. Sagasco has appointed Dawson-Brown & Root to perform a feasibility study for this development. This design basis is prepared based on the information given by Sagasco.

2.0 Site and Environmental Data

2.1 Plant Location		
Offshore	Bass Strait, Australia	
Onshore	Near Melbourne	
2.2 Ambient Temperature		
a) Offshore		
Maximum Design Temperature	90 deg F	(32.2 deg C)
Minimum Design Temperature	32 deg F	(0 deg C)
b) Onshore		
Maximum Design Temperature	100 deg F	(37.8 deg C)
Minimum Design Temperature	32 deg F	(0 deg C)
2.3 Relative Humidity		
Maximum Relative Humidity	*90 %	
2.4 Wind Velocity		
One Minute Average	*170 ft/s	(186 km/hr)
100 Minute Average	*85 ft/s	(93 km/hr)
2.5 Seabed Temperature		
Maximum Seabed Temperature	*58 deg F	(14.4 deg C)
Minimum Seabed Temperature	*50 deg F	(10 deg C)
2.6 Wave Data		
Significant Wave Height	26.2 ft (8 m)	
2.7 Distance to Shore		
Distance from Offshore to Black Rock Plant Site	*225 KM	
Distance from Offshore to Long Island Plant Site	*206 KM	
2.8 Water Depth		
Water Depth at Offshore	262.4 ft	(80 m)

** Assumed by DBR*

3.0 Wellfluid Specification

3.1 Wellfluid Stream Composition (Mol%) - Dry Basis

	BASE	ALTERNATE
C1	63.87	64.40
C2	7.64	7.63
C3	3.75	3.72
i-C4	0.65	0.59
n-C4	1.04	0.99
i-C5	0.38	0.35
n-C5	0.39	0.36
C6	0.54	0.51
C7+	2.68	2.32
CO2	18.86	18.91
N2	0.20	0.22
H2S	20 ppm	20 ppm

3.2 Properties of C7+

Mol Weight	137
Sp. Gr. @ 60 deg F	0.793

3.3 Water Production

NormalProduction	2 BBL/ MMSCF of Gas
Maximum Production	20 BBL/ MMSCF of Gas

4.0 Number of Wells

Final Nos of Producing Wells on Platfm/ Facilities	14
Number of Gas Injection Wells	0
Number of Water Injection Wells	0

5.0 Production Forecast

Refer to Attachment-1

** Assumed by DBR*

4.0 Product Specification

Stabilised Condensate , LPG and Sales Gas production are envisaged.

4.1 Stabilised Condensate Spec

Reid Vapor Pressure	*12 Psia (Max) @ 100 deg F
BS&W	*1 % (Vol) Maximum

4.2 Sales Gas Spec

Water Dew Point Spec	112 mg/ m3 (Max)
HC Dew Point Spec	36 deg F
CO2 Content	3% (vol) (Max)
Total Sulphur	115 mg/ m3 (Max)
H2S Content	11.5 mg/ m3 (Max)
Mercaptan Sulphur	23 mg/ m3 (Max)
Free Oxygen	0.2% (Max)
Gross Heating Value	36 - 42 MJ/ m3
Wobbe Index	46 to 50.8 MJ/ m3
Supply Temperature	71 deg C (Max)
Supply Pressure	*1000 Psig

4.3 Propane Spec

Vapor Pressure @ 100 deg F	**200 Psig (Max)
C4+	**2.5% (Vol) (Max)
Volatile Sulfur	**15 grains/ 100 ft3 (Max)

4.4 Butane Spec

Vapor Pressure @ 100 Psig	**70 Psig (Max)
C5+	**2.0 % (Vol) (Max)
Volatile Sulfur	**15 grains/ 100 ft3 (Max)

5.0 Product Storage Requirement at Onshore

Stabilised Condensate	*10 days
LPG	*10 days

** Assumed by DBR*
*** GPSA Standard*

6.0 Produced Water Treatment

To be designed for maximum water production.

Performance	*30 ppm oil (Max) content in the treated water

7.0 Flare System

The flare system shall be designed at offshore & onshore to meet the requirement.

Normal Radiation Level	*500 BTU/hr ft2 (Max)
Peak Radiation Level	*1500 BTU/hr ft2 (Max)

8.0 Fuel Gas System

The source of fuel gas is process gas. Offshore and Onshore both the facilities should be self sufficient in fuel gas.

9.0 Control System

Control , Alarm & Data Monitoring system shall be provided

21.0 Power Generation and Distribution

Offshore facilities

*Offshore facilities will generate it's own power.

Onshore Plant

*Onshore Plant will generate it's own power.

22.0 Utilities

Offshore Facilities

*Offshore facilities will generate it's own utilities.

Onshore Plant

*Raw water will be supplied at onshore plant. Other utilities will be generated at the plant.

** Assumed by DBR*

<u>23.0 Product Prices</u> (Assumed constant through out the field life)

Sales Gas Price	US$ 2.00 / 1000 SCF
Condensate Price	US$ 18.00 / BBL
Propane Price	*US$ 185 / Tonne
Butane Price	*US$ 185 / Tonne

<u>24.0 Utilities Prices</u>(Assumed constant through out the field life)

Raw Water (Avialable at Onshore Plant)	US$ 2.00 / 1000 Gal
Electricity	US$ 0.06/kwh

* *Assumed by DBR*

APPENDIX C

ATTACHMENT 1.

TABLE 5.1

FORECASTS OF GAS PRODUCTION AND WELLHEAD PRESSURE FOR CASES WITH 100 MMscf/d PEAK RATE AND LAST 6 WELLS ON LINE FROM YEAR 8

Year	Raw Gas Production in Year (bcf)	Av. Daily Raw Gas in Year (MMscf/d)	Cum Gas Production (year end) (bcf)	Gas in Reservoir (year end) (bcf)	Reservoir Pressure (year end) (psia)	No. of production wells at year end	Typical peak well rate at year end (MMscf/d)	Typical WHP at year end (psia)
1	32.47	89.0	32.5	567.5	4001.1	8	14	2290
2	32.47	89.0	64.9	535.1	3772.2	8	14	2083
3	32.47	89.0	97.4	502.6	3543.3	8	14	1873
4	32.47	89.0	129.9	470.1	3314.3	8	14	1658
5	32.47	89.0	162.4	437.7	3085.4	8	14	1432
6	32.47	89.0	194.8	405.2	2856.5	8	14	1190
7	32.47	89.0	227.3	372.7	2627.6	8	14	915
8	32.47	89.0	259.8	340.2	2398.7	14	8	1321
9	32.47	89.0	292.2	307.8	2169.8	14	8	1118
10	32.47	89.0	324.7	275.3	1940.9	14	8	898
11	28.57	78.3	353.3	246.7	1739.4	14	then	then
12	25.97	71.2	379.2	220.8	1556.3	14	declining	declining

TABLE 5.2

FORECASTS OF GAS PRODUCTION AND WELLHEAD PRESSURE FOR CASES WITH 100 MMscf/d PEAK RATE AND LAST 6 WELLS ON LINE FROM YEAR 9

Year	Raw Gas Production in Year (bcf)	Av. Daily Raw Gas in Year (MMscf/d)	Cum Gas Production (year end) (bcf)	Gas in Reservoir (year end) (bcf)	Reservoir Pressure (year end) (psia)	No. of production wells at year end	Typical peak well rate at year end (MMscf/d)	Typical WHP at year end (psia)
1	32.47	89.0	32.5	567.5	4001.1	8	14	2290
2	32.47	89.0	64.9	535.1	3772.2	8	14	2083
3	32.47	89.0	97.4	502.6	3543.3	8	14	1873
4	32.47	89.0	129.9	470.1	3314.3	8	14	1658
5	32.47	89.0	162.4	437.7	3085.4	8	14	1432
6	32.47	89.0	194.8	405.2	2856.5	8	14	1190
7	32.47	89.0	227.3	372.7	2627.6	8	14	915
8	32.47	89.0	259.8	340.2	2398.7	8	14	540
9	32.47	89.0	292.2	307.8	2169.8	14	8	1118
10	32.47	89.0	324.7	275.3	1940.9	14	8	898
11	31.17	85.4	355.9	244.1	1721.1	14	8	658
12	27.27	74.7	383.1	216.9	1528.9	14	then	then
13	24.81	68.0	407.9	192.1	1354.0	14	declining	declining

TABLE 5.3

FORECASTS OF GAS PRODUCTION AND WHP FOR CASES WITH 160 MMscf/d PEAK RATE

Year	Raw Gas Production in Year (bcf)	Av. Daily Raw Gas in Year (MMscf/d)	Cum Gas Production (year end) (bcf)	Gas in Reservoir (year end) (bcf)	Reservoir Pressure (year end) (psia)	No. of production wells at year end	Typical peak well rate at year end (MMscf/d)	Typical WHP at year end (psia)
1	32.47	89.0	32.5	567.5	4001.1	14	12.3	2421
2	32.47	89.0	64.9	535.1	3772.2	14	12.3	2219
3	32.47	89.0	97.4	502.6	3543.3	14	12.3	2015
4	32.47	89.0	129.9	470.1	3314.3	14	12.3	1808
5	32.47	89.0	162.4	437.7	3085.4	14	12.3	1596
6	32.47	89.0	194.8	405.2	2856.5	14	12.3	1374
7	32.47	89.0	227.3	372.7	2627.6	14	12.3	1136
8	32.47	89.0	259.8	340.2	2398.7	14	12.3	867
9	32.47	89.0	292.2	307.8	2169.8	14	12.3	526
10	32.47	89.0	324.7	275.3	1940.9	14	then	then
11	31.17	85.4	355.9	244.1	1721.1	14	declining	declining

APPENDIX D

EQUIPMENT LISTS

EQUIPMENT LIST - CASE : MINOS

TAG NO.	SIM NAME	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (psig)	DESIGN TEMP. (deg F)	DIMENSIONS	TYPE V/H, S & T/ AIR CLR	DIFF HEAD (psi)	POWER (KW)	HEAT TRANSFER AREA SQ. FT	HEAT/ COOL MEDIUM	MOC	FOOT PRINT AREA SQ FT	DRY WEIGHT (LBS)	OPTG WEIGHT (LBS)	COST (US$)	REMARKS
WELLHEAD		14	PRODUCER WELL HEADS															
11-V-01	HPSEP	1	PRODUCTION SEPARATOR		1200	160	9' ID x 22' L	H	-	-	-	-	DSS Clad	198	150,000	249,340	600,000	
11-V-02		1	TEST SEPARATOR		1200	160	4' ID x 12' L	H	-	-	-	-	DSS Clad	48	17,000	27,483	76,500	
11-H-01		1	HYDROCYCLONE	2000 BWPD	300	220	4' ID x 15' L	H	-	-	-	-	CS	60	1,000	1,750	20,000	
11-V-03		1	GAS FILTER SEPARATOR		1200	160	9' ID x 22' L	H	-	-	-	-	SS Clad	66	150,000	249,340	450,000	
11-V-04		1	HYDROCYCLONE DEGASSER		50	160	4' ID x 10' L	H	-	-	-	-	CS	40	2,300	11,219	5,800	
11-V-05		1	CONDENSATE COALESCER		1200	160	4' ID x 12' L	H	-	-	-	-	SS Clad	48	18,000	28,483	63,000	
11-P-01 A/B		2	CONDENSATE BOOSTER PUMPS	170 GPM	1200	160	3' W x 4' L	CF	50	5	-	-	CS	12	1,400	2,450	27,000	
11-P-02 A/B	CND-PMP	2	CONDENSATE PIPELINE PUMPS	170 GPM	1950	160	5' ID x 6' L	RECIP	1400	148	-	-	CS	30	9,800	17,150	195,000	
11-E-01		1	WATER-WATER EXCHANGER	1.452 MMBTU/HR	300	220	17" ID x 20' L	H	-	-	-	WATER/WATER	CS	340	7,700	13,475	24,300	
11-E-02		1	WATER HEATER	0.29 MMBTU/HR	300	220	6" ID x 10'L	H	-	84	-	ELECTRIC	CS	60	500	875	15,000	
12-K-01	BOOSTER	1	PIPELINE COMPRESSOR	GT DRIVE	1950	280	35'L x 8.5' W x 9' H	CF	-	GT	-	-	CS	298	80,000	100,000	3,315,000	
12-V-01		1	PIPELINE COMPRESSOR KOD		1200	160	5' ID x 12' H	V	-	-	-	-	CS	60	27,000	16,785	67,500	
12-E-01	BKAC	1	PIPELINE COMPRESSOR AFTERCOOLER	12.892 MMBTU/HR	1950	280	16'W x 20' L	AIR CLR	-	55	35600	AIR	CS	320	47,800	71,700	119,000	
12-X-01		1	PIPELINE PIG LAUNCHER		1950	160	14"ID x 20'L	-	-	-	-	-	CS	280	5,600	9,800	13,500	
12-K-02	LPK(MINEND)	1	FUTURE BOOSTER COMPRESSOR	GT DRIVE	800	280	25'L x 8'W x 9'H	-	-	GT	-	-	-	200	65,000	81,250	0	FUTURE
12-V-02		1	FUTURE BOOSTER SUCTION KOD		800	160	7'ID x 12'H	V	-	-	-	-	-	84	36,000	70,448	0	FUTURE
12-V-03		1	FUTURE BOOSTER DISCH KOD		800	160	4'ID x 10'L	H	-	-	-	-	-	40	10,000	18,923	0	FUTURE
		1	FUTURE BOOSTER AFTERCOOLER		800	160	15'W x 24'L	AIRCLR	-	36	-	AIR	-	360	42,300	63,450	0	FUTURE
14-C-01	DEHYD	1	GLYCOL CONTACTOR	100 MMSCFD	1200	160	4.5' ID x 20.5' H	V	-	-	-	-	SS Clad	92	42,000	60,520	146,000	Structured Packing
14-M-01		1	GLYCOL REGENERATOR PACKAGE		-	-	15'W x 30'L		-	-	-	FUEL FIRED	-	450	80,000	120,000	850,000	
16-SK-01		1	FUEL GAS SKID		350	160	10'W x 15' L	-	-			Electric	-	150	20,000	30,000	50,000	
16-SK-02		1	AIR COMPRESSORS/ DRIER SKID	150 SCFM	200		20'L x 8'W x 12' H	-		-	-	-		160	22,000	30,000	150,000	
16-V-01		1	INST. AIR RECEIVER		200	160	6' ID X 12' H	V	-	-	-	-	-	72	7,200	31,910	18,000	
16-V-02		1	UTILITY AIR RECEIVER		200	160	6' ID X 12' H	V	-	-	-	-	-	72	7,200	31,910	18,000	
16-P-01 A/B		2	SERVICE WATER PUMPS	50 GPM	200	160	3'W x 6'L	-	150	5	-	-	-	18	4,000	6,000	10,000	
16-M-02		2	WATER MAKER	1 GPM	-	-	6'W x 6'L	-	-	-	-	-	-	36	6,600	13,200	100,000	
16-T-01		1	POTABLE WATER DAY TANK	1000 USG	LIQ. FULL	160	4' ID X 11' H	V	-	-	-	-	-	44	3,000	11,342	6,900	
16-T-02		1	POTABLE WATER STORAGE TANK	9,800 USG	LIQ. FULL	160	10' ID X 17' H	V	-	-	-	-	-	170	7,500	89,254	37,200	
16-P-02 A/B		2	POTABLE WATER PUMPS	20 GPM	-	-	3'W x 5' L	-	50	1	-	-	-	15	250	500	7,700	
16-F-03 A/B		2	POTABLE WATER FILTERS	1 GPM	-	-	4'W x6' L	-	-	-	-	-	-	24	2,000	4,000	6,000	
16-P-03		1	DIESEL FIRE WATER PUMP	1500 GPM	200	160	11'L x 5'W	-	-	-	-	-	-	55	24,000	42,000	185,000	
16-P-04		1	ELECTRICAL F W PUMP	1500 GPM	200	160	3'L x 3'W	-	-	185	-	-	-	9	7,000	12,250	75,000	
16-V-03		1	F.W. PUMP STARTING AIR RECEIVERS		200	160	3.5' ID x 12' H	V	-	-	-	-	-	42	4,600	8,050	9,600	
16-V-05		1	H.P. FLARE K.O. DRUM		100	160	8' ID x 20' L	H	-	-	-	-	-	160	12,300	83,436	30,700	
16-V-06		1	L.P. FLARE K.O. DRUM		50	160	4' ID x 10' H	V	-	-	-	-	-	40	2,500	11,423	6,300	
16-M-03		1	HP/LP FLARE TIP & IGNITION PANEL		-	-	3'W x 13'L	-	-	-	-	-	-	39	1,300	2,275	40,000	
16-P-05A/B/C/D		4	HP/LP FLARE PUMPS	30 GPM EACH	200	160	3'W x 6'L	-	-	10	-	-	-	18	2,400	4,200	60,000	
16-V-07		1	SUMP DRUM		50	160	5'ID x 12'L	H	-	-	-	-	-	60	4,400	21,185	10,900	
16-P-06 A/B		2	SUMP PUMP	10 GPM	1200	160	3'W x 4'L	-	1000	6	-	-	-	12	1,000	1,750	22,600	
16-M-05		1	SKIM PILE		10	160	30" ID	-	-	-	-	-	-	5	-	-	-	
16-P-07 A/B		2	SKIM PILE PUMPS	10 GPM	50	160	-	-	50	0.3	-	-	-	-	50	100	4,500	
16-T-03 A/B		2	DIESEL STORAGE (CRANE PEDESTAL)		6"WC+LIQ	160	-	-	-	-	-	-	-	-	-	-	-	

514064

EQUIPMENT LIST - CASE : MINOS

TAG NO.	SIM NAME	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (psig)	DESIGN TEMP. (deg F)	DIMENSIONS	TYPE V/H, S & T/ AIR CLR	DIFF HEAD (psi)	POWER (KW)	HEAT TRANSFER AREA SQ. FT	HEAT/ COOL MEDIUM	MOC	FOOT PRINT AREA SQ FT	DRY WEIGHT (LBS)	OPTG WEIGHT (LBS)	COST (US$)	REMARKS
16-P-08 A/B		2	DIESEL TRANSFER PUMP	30 GPM	150	160	3'W x 4' L	GEAR	50	1	-	-	-	12	800	1,400	5,500	
16-F-04		1	DIESEL CENTRIFUGE/FILTER COALESCER		150	160	2'ID x 5'L	-	-	-	-	-	-	10	500	875	54,000	
16-T-04		1	GLYCOL STORAGE TANK	1000 USG	ATM	160	4'ID x 11'L	-	-	-	-	-	-	44	3,000	11,342	6,900	
16-P-09		1	GLYCOL PUMP	20 GPM	50	160	3'W x 4'L	-	100	1.2	-	-	-	12	500	825	7,750	
16-G-01 A		1	POWER GENERATOR-1	800 KW	-	-	10'W x 15'L	-	-	-	-	-	-	150	20,000	25,000	1,000,000	
16-G-01 B		1	POWER GENERATOR-2	800 KW	-	-	10'W x 15'L	-	-	-	-	-	-	150	20,000	25,000	1,000,000	
16-G-02		1	EMERGENCY GENERATOR	100KW	-	-	10'W x 10' L	-	-	-	-	-	-	100	10,000	12,500	50,000	
16-M-06		1	HELICOPTER REFUELING SKID		-	-	5'W x 7'L x 4'H	-	-	5	-	-	-	35	4,000	7,000	135,000	
16-M-07		2	PEDESTAL CRANES	30 TONS	-	-	-							-	80,000	80,000	360,000	
16-M-08		1	HVAC AIR HANDLING UNIT		-	-	10'W x 10'L							100	6,000	7,200	40,000	
16-M-09			SURVIVAL CRAFT/DAVIT	20 MEN	-	-	-								10,000	15,000	100,000	
16-M-10		1	SEWAGE TREATMENT UNIT	20 MEN	-	-	3'W x 10'L							30	1,500	5,000	12,000	
16-M-11		1	FOAM SYSTEM		-	-	5'W x 7'L							35	7,000	12,250	30,000	
16-M-12		1	INERT GAS SYSTEM		-	-	5'W x 6'L							30	1,000	1,750	5,000	
16-M-13		1	HYPOCHLORINATOR PACKAGE		-	-	6'W x 8'L							36	10,000	17,500	100,000	
16-M-14		1	SWITCHGEAR/MCC		-	-	15'W x 20'L							300	40,000	40,000	200,000	
16-LQ-01		1	ACCOMODATION MODULE	20 MEN			50'W x 30'L							1,500	-	-	-	
SUB TOTAL			PROCESS & UTILITIES							543				6,831	1,147,000	1,911,868	9,942,150	
			BULK ITEMS	COST---40% OF TOTAL PROCESS & UTILITIES (ELECTRICAL 2% + INST/CONTROL/SAFETY ETC 19% + PIPING FITTINGS 19%)										1,708	286,750	477,967	3,976,860	
				WT & AREA ----- 25% OF TOTAL PROCESS & UTILITIES (ELECTRICAL 1% + PIPING FITTINGS 20%+ INST/CONTROL 4%)														
TOTAL			TOP SIDE (EXCLUDING STRUCTURE)											8,538	1,433,750	2,389,835	13,919,010	

EQUIPMENT LIST - CASE : WEND

TAG NO.	SIM NAME	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (psig)	DESIGN TEMP. (deg F)	DIMENSIONS	TYPE V/H, S & T/ AIR CLR	DIFF HEAD (psi)	POWER (KW)	HEAT TRANSFER AREA SQ. FT	HEAT/COOL MEDIUM	MOC	FOOT PRINT AREA SQ FT	DRY WEIGHT (LBS)	OPTG WEIGHT (LBS)	COST (US$)	REMARKS
WELLHEAD		14	PRODUCER WELL HEADS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
21-V-01	SEP	1	PRODUCTION SEPARATOR		1200	160	9' ID x 22'L	H	-	-	-	-	DSS Clad	198	150,000	249,340	600,000	
21-V-02		1	TEST SEPARATOR		1200	160	4' ID x 12' L	H	-	-	-	-	DSS Clad	48	17,000	27,483	76,500	
21-H-01		1	HYDROCYCLONE	2000 BWPD	300	220	4' ID x 15' L	H	-	-	-	-	CS	60	1,000	1,750	20,000	
21-V-03		1	HYDROCYCLONE DEGASSER		50	160	4' ID x 10' L	H	-	-	-	-	CS	40	2,300	11,219	8,100	
21-V-05		1	CONDENSATE SURGE DRUM		350	160	4' ID x 10' L	H	-	-	-	-	SS Clad	40	4,800	12,641	16,900	BOOT: 1' IDx 2.5 ' H
21-E-01		1	WATER-WATER EXCHANGER	1.452 MMBTU/HR	300	220	17" ID x 20'L	H	-	-	-	WATER/WATER	CS	28	7,700	13,475	24,300	
21-E-02		1	WATER HEATER	0.29 MMBTU/HR	300	220	8" ID x 10'L	H	-	-	-	HOT OIL	CS	7	500	875	5,000	
22-V-01		1	BOOSTER SUCTION KOD		800	160	7' ID x 12' H	V	-	-	-	-	SS CLAD	84	36,000	70,448	126,000	
22-V-02	HPKD	1	BOOSTER DISCH KOD		800	160	4' ID x 10' L	H	-	-	-	-	SS CLAD	40	10,000	18,923	35,000	BOOT: 1' ID x 3' H
22-V-03	WSEP	1	EXPANDER SUCTION KOD		1200	160	7' ID x 16' L	H	-	-	-	-	SS CLAD	112	73,000	111,423	255,000	BOOT: 1' ID x 3' H
22-V-04	CSEP	1	COLD SEPARATOR		600	160/ 20	4' ID x 12' L	H	-	-	-	-	SS CLAD	48	9,700	119,110	33,800	BOOT: 1' ID x 2.5' H
22-V-05		1	PIPELINE COMPRESSOR KOD		650	160	6' ID x 12' H	V	-	-	-	-	CS	72	23,500	44,672	58,750	
22-K-01	LPK	1	BOOSTER COMPRESSOR		800	300	25' L x 8' W x 9' H			GT			-	200	65,000	81,250	3,320,000	
22-EK-01	EXP/XPK	1	EXPANDER COMPRESSOR		1200/600	160/20	10'W x 18'L	-	-	-	-	-	-	180	33,000	41,250	750,000	
22-K-02	BOOSTER	1	PIPELINE COMPRESSOR		1900	320	35' L x 8.5' W x 9' H			GT			-	298	80,000	100,000	3,315,000	
22-E-01	HPAC	1	BOOSTER COMPRESSOR AFTERCOOLER	2.03 MMBTU/ HR	800	290	31" ID x 20' L	S & T	-	-	2700	WATER		52	26,400	46,200	83,000	
22-E-02	GGX	1	GAS-GAS EXCHANGER	4.993 MMBTU/HR	1200/600	160/20	33" ID x 20' L	S & T	-	-	3300	GAS/GAS		55	32,300	56,525	101,000	
22-E-03	BKAC	1	PIPELINE COMPRESSOR AFTERCOOLER	18.472 MMBTU/HR	1900	160	27" ID x 20' L	S & T	-	-	2000	WATER		45	19,600	34,300	61,500	
22-X-01		1	PIPELINE PIG LAUNCHER		1900	160	14" ID x 20' L	-	-	-	-	-	CS	23	5,600	6,934	13,500	
23-C-01	STAB	1	CONDENSATE STABILISER		350	480	4' ID x 32' H	V	-	-	-	-	SS Clad	128	25,000	43,750	126,000	
23-E-01	FD-BTMS	1	FEED EFFLUENT EXCHANGER	1.843 MMBTU/HR	350	480	8" ID x 12' L	S & T	-	-	76	CRUDE/CRUDE		8	1,000	1,750	3,000	
23-E-02		1	STABILISER REBOILER	7.869 MMBTU/HR	350	480	38" ID x 25' L	KETTLE	-	-	1870	HOT OIL		79	22,000	38,500	69,000	
23-E-03	BTM-COOL	1	CONDENSATE COOLER	6.504 MMBTU/HR	350	410	17" ID x 20' L	S & T	-	-	655	WATER		28	6,400	11,200	20,100	
23-E-04		1	OVHD COMPRESSOR AFTERCOOLER	0.4 MMBTU/HR	800	270	8"ID x 12' L	S & T	-	-		WATER		8	1,000	1,750	3,000	
23-V-01		1	STABILISER OVHD COMPR SUCTION KOD		350	160	2'ID x 6' H	V	-	-	-	-	CS	12	2,500	3,676	6,000	
23-K-01	STK	1	STABILISER OVHD COMPRESSOR		800	270	26' L x 12' W x 11' H	-	-	58			-	312	60,000	75,000	200,000	
23-X-01		1	CONDENSATE P/L PIG LAUNCHER		350	160	8"ID x 20' L	-	-	-	-	-	CS	13	1,300	1,736	4,000	
24-M-01		1	GLYCOL REGENERATOR PACKAGE		-	-	15'W x 20'L x 15' H	-	-	-	-	HOT OIL	-	300	50,000	75,000	250,000	
26-SK-01		1	FUEL GAS SKID		350	160	10'W x 15'L	-	-	-	-	HOT OIL	-	150	20,000	30,000	50,000	
26-SK-02		1	AIR COMPRESSORS/ DRIER SKID	150 SCFM EACH	200		20' L x 8' W x 12' H	-	-	40	-	-	-	160	22,000	30,000	150,000	
26-V-02		1	INST. AIR RECEIVER		200	160	6' ID x 12' H	V	-	-	-	-	CS	72	7,200	31,910	18,000	
26-V-03		1	UTILITY AIR RECEIVER		200	160	6' ID x 12' H	V	-	-	-	-	CS	72	7,200	31,910	18,000	
26-P-01 A/B		2	SEA WATER LIFT PUMPS	2200 GPM	200	160	4'W x 6'L	-	-	55	-	-	-	24	7,000	14,000	68,000	
26-E-01		1	S.W. PLATE EXCHANGER & STRAINER		200	150	3'W x 6' L x 5'H	-	-	-	-	-	-	18	5,000	10,000	112,000	
26-M-02		2	WATER MAKER	2 GPM	-	-	8'W x 8'L	RO TYPE	-	-	-	-	-	64	10,000	20,000	150,000	
26-T-01		1	POTABLE WATER DAY TANK	2000 USG	LIQ. FULL	160	5' ID X 14' H	V	-	-	-	-	-	70	4,400	21,085	9,350	
26-T-02		1	POTABLE WATER STORAGE TANK	19,600 USG	LIQ. FULL	160	14' ID X 17' H	V	-	-	-	-	-	238	11,400	174,908	44,900	
26-P-02 A/B		2	POTABLE WATER PUMPS	50 GPM EACH	-	-	5' W x 5' L	-	50	1.5	-	-	-	25	320	640	7,800	
26-F-03 A/B		2	POTABLE WATER FILTERS	2 GPM	-	-	5' W x 5' L	-	-	-	-	-	-	25	3,300	6,600	9,600	
26-P-03 A		1	DIESEL FIRE WATER PUMP-1	2000 GPM	200	160	11' L x 5' W	-	-	-	-	-	-	55	28,000	49,000	220,000	
26-P-03 B		1	DIESEL FIRE WATER PUMP-2	2000 GPM	200	160	11' L x 5' W	-	-	-	-	-	-	55	28,000	49,000	220,000	
26-P-04		1	ELECTRICAL FW PUMP	2000 GPM	200	160	3' L x 3' W	-	-	250	-	-	-	9	8,300	14,525	90,000	
26-V-03		1	F.W. PUMP STARTING AIR RECEIVER		200	160	3.5' ID x 12' H	V	-	-	-	-	CS	42	4,600	8,050	9,600	
26-V-04		1	F.W. PUMP STARTING AIR RECEIVER		200	160	3.5' ID x 12' H	V	-	-	-	-	CS	42	4,600	8,050	9,600	
26-V-05		1	H.P. FLARE K.O. DRUM		100	160	8' ID x 20' L	H	-	-	-	-	CS	160	12,300	83,436	30,700	

514066

EQUIPMENT LIST - CASE : WEND

TAG NO.	SIM NAME	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (psig)	DESIGN TEMP. (deg F)	DIMENSIONS	TYPE V/H, S & T/ AIR CLR	DIFF HEAD (psi)	POWER (KW)	HEAT TRANSFER AREA SQ. FT	HEAT/COOL MEDIUM	MOC	FOOT PRINT AREA SQ FT	DRY WEIGHT (LBS)	OPTG WEIGHT (LBS)	COST (US$)	REMARKS
26-V-06		1	L.P. FLARE K.O. DRUM		50	160	4' ID x 10' H	V	-	-	-	-	CS	40	2,500	11,423	6,300	
26-M-03		1	HP/LP FLARE TIP & IGNITION PANEL		-	-	3'W x 13'L	-	-	-	-	-	-	39	1,300	2,275	40,000	
26-P-05 A/B/C/D		4	HP/LP FLARE PUMPS	30 GPM EACH	200	160	3'W x 6'L	-	50	10	-	-	-	18	2,400	4,200	60,000	
26-V-07		1	SUMP DRUM		50	160	5'ID x 12'L	H						60	4,400	21,185	10,900	
26-P-04 A/B		2	SUMP PUMP	10 GPM	1200	160	3'W x 4'L	-	1000	6	-	-	-	12	1,000	1,750	22,600	
26-M-05		1	SKIM PILE		10	160	48" ID	-	-	-	-	-	-	13	-		-	
26-P-05 A/B		2	SKIM PILE PUMPS	10 GPM	50	160	-	-	50	0.3	-	-	-	-	50	100	4,500	
26-T-03 A/B		2	DIESEL STORAGE (CRANE PEDESTAL)		6"WC+LIQ	160	-	-	-	-	-	-	-	-	-		-	
26-P-06 A/B		2	DIESEL TRANSFER PUMP	30 GPM	150	160	3'W x 4'L	GEAR	50	1.2	-	-	-	12	800	1,400	5,500	
26-F-04		1	DIESEL CENTRIFUGE/FILTER COALESCER		150	160	2'ID x 5' L	-	-	-	-	-	-	10	500	875	54,000	
26-T-04		1	GLYCOL STORAGE TANK	1000 USG	ATM	160	4'ID x 11'H	V	-	-	-	-	CS	44	3,000	11,342	6,900	
26-P-07		1	GLYCOL PUMP	20 GPM	50	160	3'W x 4'L	-	-	-	-	-	-	12	500	825	7,750	
26-WH-01A/B		1	HOT OIL WASTE HEAT RECOVERY				DUCT										300,000	
26-V-08		1	HOT OIL EXPANSION VESSEL		50/ FV	600	5'ID x 15'L	H	-	-	-	-	CS	75	5,400	23,778	11,600	
26-P-08 A/B		2	HOT OIL CIRCULATION PUMPS	350 GPM	150	600	3'W x 5'L	-	-	20	-	-	CS/SS IMP	15	2,000	3,500	30,000	
26-F-01A		2	HOT OIL FILTERS	35 GPM	150	600	3'W x 5'L	-	-	-	-	-	CS	15	4,900	8,575	14,200	
26-T-05		1	COOLING WATER SUPPLY TANK	8800 USG	50	160	10'ID x 15'L	V	-	-	-	-	CS	150	6,900	80,311	36,000	
26-P-08 A/B/C		3	COOLING WATER CIRCULATION PUMPS	1400 GPM EACH	100	160	3'W x 8'L	-	-	90	-	-	CS	24	3,600	6,300	20,000	
26-G-01 A		1	POWER GENERATOR 1	1.0 MW	-	-	10'W x 15'L	-	-	-	-	-	-	150	25,000	31,250	1,200,000	
26-G-01 B		1	POWER GENERATOR 2	1.0 MW	-	-	10'W x 15'L	-	-	-	-	-	-	150	25,000	31,250	1,200,000	
26-G-02		1	EMERGENCY GENERATOR	100 KW	-	-	10'W x 10'L	-	-	-	-	-	-	100	10,000	12,500	50,000	
26-M-06		1	HELICOPTER REFUELING SKID		-	-	5'W x 7'L x 4'H	-	-	5	-	-	-	35	4,000	7,000	135,000	
26-M-07		2	PEDESTAL CRANES	30 TONS	-	-	-								80,000	80,000	360,000	
26-M-08		1	HVAC AIR HANDLING UNITS		-	-	10'W x 10'L							100	6,000	7,200	40,000	
26-M-09		-	SURVIVAL CRAFT/DAVIT	40 MEN	-	-	-								15,000	22,500	140,000	
26-M-10		1	SEWAGE TREATMENT UNIT	40 MEN	-	-	4'W x 10'L							40	2,000	7,000	18,000	
26-M-11		1	FOAM SYSTEM		-	-	5'W x 7'L							35	7,000	12,250	30,000	
26-M-12		1	INERT GAS SYSTEM		-	-	5'W x 6'L							30	1,000	1,750	5,000	
26-M-13		1	HYPOCHLORINATOR PACKAGE		-	-	6'W x 8'L							48	20,000	35,000	200,000	
26-M-14		1	SWITCHGEAR / MCC		-	-	15'W x 20'L							300	40,000	40,000	250,000	
26-LQ-01		1	ACCOMODATION MODULE	40 MEN	-	-	70'W x 30'L	-	-	100	-	-	-	2,100	-	-	-	INCLUDED IN
																		STRUCTURE
SUBTOTAL			PROCESS & UTILITIES							637				7,426	1,224,470	2,348,833	15,060,250	
			BULK	COST---- 40 % OF TOTAL PROCES & UTILITIES(ELECTRICAL 2% + INST/CONTROL/SAFETY 19% + PIPING/FITTINGS/ MANUAL VALVES 19%)										1,856	306,118	587,208	6,024,100	
				WT & AREA ------- 25 % OF TOTAL PROCESS & UTILITIES (ELECTRICAL 1% + INST / CONTROL/ SAFETY 4% + PIPING/FITTINGS 20 %)														
TOTAL			TOP SIDE (EXCLUDING TOP SIDE)							637				9,282	1,530,588	2,936,041	21,084,350	

EQUIPMENT LIS. CASE : MOSGP

TAG NO.	SIM NAME	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (psig)	DESIGN TEMP. (deg F)	Widh/ Dia. (ft)	Length (ft)	Height (ft)	TYPE V/H, S&T/ AIR CLR	DIFF HEAD (psi)	POWER (KW)	HEAT TRANSFER AREA SQ. FT	FUEL (MMBTU/hr)	MOC	WEIGHT (LBS)	COST (US$)	AREA (FT2)	REMARKS
31-X-01		1	PIG RECEIVER		1950	150	2	10								5600	13500	128.00	
31-M-01		1	SLUG CATCHER	22000 BBL	1950	160				H	-	-	-		CS		17500000	0.00	
32-E-01		1	GAS-GAS EXCHANGER	7.275 MMBTU/hr	700	150	3	35		S&T			2300		CS	26160	54900	369.00	
32-V-01		1	EXPANDER SUCTION KOD		700	160/-30	6	15		H	-	-	-		NCS	37633	75200	252.00	BOOT
32-V-02		1	COLD SEPARATOR		250	160/-80	5	12.5		H					316SS	8410	45700	203.50	
32-P-01 A/B		2	COLD SEPARATOR PUMPS	60 GPM							200						12900		
32-EK-01		1	EXPANDER /COMPRESSOR				8.5	16.5									550000	326.25	
32-V-03		1	PIPELINE COMPRESSOR SUCTION KOD		400	160	6	10		V	-	-	-		CS	18000	27388	192.00	
32-K-02		1	PIPELINE COMPRESSOR				8.5	32	9			4769				75000	3090000	551.00	
32-GT-02		1	GAS TURBINE DRIVE FOR COMPR.											43.42			incl		
32-E-02		1	PIPELINE COMPRESSOR AFTERCOOLER	12.471 MMBTU/hr	1100	325	12	28		AC		18	30335		CS		82400	612.00	
32-X-01		1	PIPELINE PIG LAUNCHER		1100	190	2	10								5600	13500	128.00	
33-V-01		1	DE-ETHANISER FEED DRUM		375	160	6	12.5		H					CS	19200	31600	222.00	
33-V-02		1	DE-ETHANISER OVHD DRUM		375	160/-20	2		8	V					CS	2900	6700	64.00	
33-V-03		1	STABILISER REFLUX ACCUMULATOR		300	160	4	10		H	-	-	-		CS	6600	12700	160.00	
33-V-04		1	DEPROPANISER REFLUX ACCUMULATOR		150	180	4	10		H	-	-	-		CS	4200	9700	160.00	
33-C-01		1	DE-ETHANISER COLUMN		375	350	5.5		62	V					CS	59900	150000	132.25	
33-C-02		1	STABILISER COLUMN		250	425	3		60	V					CS	20000	70300	81.00	
33-C-03		1	DEPROPANISER COLUMN		275	275	4		70	V					CS	22000	68300	100.00	
33-K-01		1	DE-ETHANISER OVERHEAD COMPRESSOR				12	26	11			151.82				60000	250000	576.00	
33-E-02		1	DE-ETHANISER REBOILER	11.839 MMBTU/hr	375	350	2	20		Kettle			650		CS	6800	18700	208.00	
33-E-03		1	STABILISER REBOILER	5.923 MMBTU/hr	275	275	2	20		Kettle			575		CS	5500	16900	208.00	
33-E-04		1	STABILISER CONDENSER	4.679 MMBTU/hr	275	160	12	32		AC		23	36171		CS		87400	684.00	
33-E-05		1	DEPROPANISER REBOILER	3.985 MMBTU/hr	250	425	2	20		Kettle			165		CS	2300	11200	208.00	
33-E-06		1	DEPROPANISER CONDENSER	3.631 MMBTU/hr	250	180	12	32		AC		14	38854		CS		91700	684.00	
33-E-07		1	CONDENSATE COOLER	7.064 MMBTU/hr	275	275	12	20		AC		11	23901		CS		65500	468.00	
33-E-08		1	BUTANE COOLER	0.299 MMBTU/hr	250	425	7	14		AC		0.20	3057		CS		28200	260.00	
33-P-01 A/B		2	STABILISER REFLUX PUMP	100 GPM			2	2			50	3.65				690	16590	64.00	
33-P-02 A/B		2	DEPROPANISER REFLUX PUMP	110 GPM			2	2			50	4.01				690	16590	64.00	
34-C-01		1	AMINE CONTACTOR		700	200	9		65							350000	571300	225.00	
34-V-01		1	AMINE FLASH VESSEL		50	200	11		35							69000	116800	289.00	
34-E-01		1	AMINE HEATER	46.68 MMBTU/hr	700	200	3	35		S&T			3200			38850	51800	369.00	
34-E-02		1	AMINE COOLER	34.92 MMBTU/hr	700	200	40	40		AC		60	182200				406900	2116.00	
34-E-03		1	AMINE GAS/GAS EXCHANGER	7.97 MMBTU/hr	700		6	40		S&T			10620			116300	177900	552.00	
34-P-01 A/B/C		3	AMINE PUMPS	1425 GPM			4	6			700	581.97					250000	360.00	SWAG
35-M-01		1	METHANOL REGENERATION PACKAGE		-	-	15	30								80000	850000	756.00	
36-SK-01		1	FUEL GAS SKID		350	160	10	15								20000	50000	336.00	
36-SK-02		2	AIR COMPRESSORS/ DRIER SKID	400 SCFM EACH	200											40000	270000	0.00	
36-V-02		1	INST. AIR RECEIVER		200	160				V						13000	33000	0.00	
36-V-03		1	UTILITY AIR RECEIVER		200	160				V						13000	33000	0.00	
36-P-03		1	FIRE WATER PUMP	1500 GPM	200	160	3	3				185				7000	75000	81.00	Electrical
36-P-03		1	FIRE WATER PUMP	1500 GPM	200	160	11	5								24000	370000	187.00	Diesel
36-TK-01		1	FIREWATER TANK	18000 BBL			24		40							135650	178800	900.00	
36-V-05		1	FLARE K.O. DRUM		100	160	8	20		H						12300	30700	364.00	
36-M-03		1	FLARE TIP														40000	10000.00	
36-V-07		1	CONTAMINATED STORM WATER POND				50	50									20000	3136.00	

EQUIPMENT LIS CASE : MOSGP

TAG NO.	SIM NAME	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (psig)	DESIGN TEMP. (deg F)	Widh/ Dia. (ft)	Length (ft)	Height (ft)	TYPE V/H, S&T/ AIR CLR	DIFF HEAD (psi)	POWER (KW)	HEAT TRANSFER AREA SQ. FT	FUEL (MMBTU/hr)	MOC	WEIGHT (LBS)	COST (US$)	AREA (FT2)	REMARKS
36-M-04		1	CPI SEPARATOR				10	10									10000	256.00	
16-02		1	EMERGENCY GENERATOR				10	10								10000	40000	256.00	
36-H-01		1	HOT OIL HEATER	68.43 MMBTU/hr		550	10			V				85.53375			170500	256.00	
36-P-05 A/B		2	HOT OIL CIRCULATION PUMPS	9635.03 GPM		550	5	10			100	562.14					100000	176.00	SWAG
36-V-08		1	HOT OIL SURGE DRUM		50	550	5		10	V							8900	121.00	
51-TK-01 A/B		2	PROPANE STORAGE	10000 BBL	275	160	48			SPHERE						1568550	1982000	13824	
51-TK-02 A/B		2	BUTANE STORAGE	5000 BBL	150	180	38			SPHERE						476296	748000	8664	
51-TK-03		1	CONDENSATE STORAGE	35000 BBL	ATM	165	78		41	FLOATING ROOF						478656	717600	24336	
51-P-01 A/B		2	PROPANE LOADING PUMPS	200 GPM			2	2			50	7.29				1400	27080	64.00	
51-P-02 A/B		2	BUTANE LOADING PUMPS	200 GPM			2	2			50	7.29				1400	27080	64.00	
51-P-03 A/B		2	CONDENSATE LOADING PUMPS	200 GPM			2	2			50	7.29				1400	27080	64.00	
			TOTALS									1636.7		128.955495		3843985	29801008	74857	

TOTAL HORIZ VESSELS	232600
TOTAL VERTICAL VESSELS	108988
TOTAL COLUMNS	976700
TOTAL S&T EXCH	331400
TOTAL AC EXCH	762100
TOTAL HEATERS	170500

514069

EQUIPMENT LIST

PROJECT : SAGASCO YOLLA FIELD STUDY

CASE : DPCGP

BY : T.K.DAS
REV. : A
DATE : 24.3.95

TAG NO.	SIM NAME	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (psig)	DESIGN TEMP. (deg F)	Widh/ Dia. (ft)	Length (ft)	Height (ft)	TYPE V/H, S&T/ AIR CLR	DIFF HEAD (psi)	POWER (KW)	HEAT TRANSFER AREA SQ. FT	FUEL (MMBTU/hr)	MOC	WEIGHT (LBS)	COST (US$)	AREA (FT2)	REMARKS
41-X-01		1	PIG RECEIVER		1200	150	2	10								5600	13500	128.00	
41-V-01		1	PIPELINE RECEIVER		800	160	7	18		H	-	-	-		CS	67855	94758	312.00	
42-E-01		1	GAS-GAS EXCHANGER	6.909 MMBTU/hr	800	150	3	35		S&T			2300		CS	26160	54900	369.00	
42-V-01		1	EXPANDER SUCTION KOD		800	160	5	12		H	-	-	-		CS	25990	49821	198.00	BOOT
42-EK-01		1	EXPANDER /COMPRESSOR				8.5	16.5									550000	326.25	
42-V-02		1	PIPELINE COMPRESSOR SUCTION KOD		400	160	6	10		V	-	-	-		CS	18000	27388	192.00	
42-K-02		1	PIPELINE COMPRESSOR				8.5	30	9							75000	3090000	522.00	
42-GT-02		1	GAS TURBINE DRIVE FOR COMPR.											38.609					
42-E-02		1	PIPELINE COMPRESSOR AFTERCOOLER	10.893 MMBTU/hr	1100	325	10	35		AC		21	33654			33660	88660	656.00	
42-X-01		1	PIPELINE PIG LAUNCHER		1100	190	2	10								5600	13500	128.00	
43-V-01		1	DEPROPANISER REFLUX ACCUMULATOR		275	160	4	10		H	-	-	-		CS	6100	13110	160.00	
43-V-02		1	DEBUTANISER REFLUX ACCUMULATOR		150	180	4	10		H	-	-	-		CS	4200	9700	160.00	
43-C-01		1	DE-ETHANISER COLUMN		275	250	3.5		62	V						36000	94674	90.25	
43-C-02		1	DEPROPANISER COLUMN		275	275	3		50	V						16000	54255	81.00	
43-C-03		1	DEBUTANISER COLUMN		150	325	3		44	V						7700	23908	81.00	
43-E-01		1	DE-ETHANISER REBOILER	4.01 MMBTU/hr	275	250	3	12		Kettle			150			2150	12730	162.00	
43-E-02		1	DEPROPANISER REBOILER	3.056 MMBTU/hr	275	275	3	12		Kettle			150			2150	11030	162.00	
43-E-03		1	DEPROPANISER REFLUX CONDENSER	2.826 MMBTU/hr	275	160	12	35		AC		23	36696			36700	88320	738.00	
43-E-04		1	DEBUTANISER REBOILER	2.915 MMBTU/hr	150	325	3	12		Kettle			150			1800	10700	162.00	
43-E-05		1	DEBTANANISER CONDENSER	3.268 MMBTU/hr	150	180	8	35		AC		14	21888			21900	57400	574.00	
43-E-06		1	CONDENSATE COOLER	0.312 MMBTU/hr	150	325	5	5		AC		1	1122			1122	18250	121.00	
43-P-01 A/B		2	DE-ETHANISER BOTTOMS PUMP	90 GPM			2	2			50	3.28				690	16590	64.00	
43-P-02 A/B		2	DEPROPANISER REFLUX PUMP	100 GPM			2	2			50	3.65				690	16590	64.00	
43-P-03 A/B		2	DEBUTANISER REFLUX PUMP	90 GPM			2	2			50	3.28				690	16590	64.00	
44-C-01		1	AMINE CONTACTOR		800	200	9		65							350000	571300	225.00	
44-V-01		1	AMINE FLASH VESSEL		50	200	11		35							69000	116800	289.00	
44-E-01		1	AMINE HEATER	46.68 MMBTU/hr	1000	200	3	35		S&T			3200			38850	51800	369.00	
44-E-02		1	AMINE COOLER	34.92 MMBTU/hr	1000	200	40	40		AC		60	182200				406900	2116.00	
44-P-01 A/B/C		3	AMINE PUMPS	1425 GPM			4	6			700	581.97					250000	360.00	SWAG
45-C-01	DEHYD	1	GLYCOL CONTACTOR		800	160	4.5		20.5	V					SS Clad	42000	146000	110.25	
45-M-01		1	GLYCOL REGENERATOR PACKAGE	0.1 MMBTU/hr	-	-	15	30								80000	850000	756.00	
36-SK-01		1	FUEL GAS SKID		350	160	10	15								20000	50000	336.00	
36-SK-02		2	AIR COMPRESSORS/ DRIER SKID	400 SCFM EACH	200											40000	270000	0.00	
36-V-02		1	INST. AIR RECEIVER		200	160				V						13000	33000	0.00	
36-V-03		1	UTILITY AIR RECEIVER		200	160				V						13000	33000	0.00	
36-P-03		1	FIRE WATER PUMP	1500 GPM	200	160	3	3				185				7000	75000	81.00	Electrical
36-P-04		1	FIRE WATER PUMP	1500 GPM	200	160	11	5								24000	370000	187.00	Diesel
36-TK-01		1	FIREWATER TANK	18000 BBL			24		40							135650	178800	900.00	
36-V-05		1	FLARE K.O. DRUM		100	160	8	20		H						12300	30700	364.00	
36-M-03		1	FLARE TIP														40000	10000.00	

EQUIPMENT LIST

PROJECT : SAGASCO YOLLA FIELD STUDY

CASE : DPCGP

BY : T.K.DAS
REV. : A
DATE : 24.3.95

TAG NO.	SIM NAME	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (psig)	DESIGN TEMP. (deg F)	Widh/ Dia. (ft)	Length (ft)	Height (ft)	TYPE V/H, S&T/ AIR CLR	DIFF HEAD (psi)	POWER (KW)	HEAT TRANSFER AREA SQ. FT	FUEL (MMBTU/hr)	MOC	WEIGHT (LBS)	COST (US$)	AREA (FT2)	REMARKS
36-V-07		1	CONTAMINATED STORM WATER POND				50	50									20000	3136.00	
36-M-04		1	CPI SEPARATOR				10	10									10000	256.00	
16-02		1	EMERGENCY GENERATOR				10	10								10000	40000	256.00	
36-H-01		1	HOT OIL HEATER	56.761 MMBTU/hr		550	10			V				70.95125			170500	256.00	
36-P-05 A/B		2	HOT OIL CIRCULATION PUMPS	7992.37 GPM		550	5	10			100	466.30					100000	176.00	SWAG
36-V-08		1	HOT OIL SURGE DRUM		50	550	5		10	V							8900	121.00	
51-TK-01 A/B		2	PROPANE STORAGE	7000 BBL	275	160	42			SPHERE						1130100	1515100	10584.00	
51-TK-02 A/B		2	BUTANE STORAGE	7000 BBL	150	180	42			SPHERE						464330	958620	10584.00	
51-TK-03		1	CONDENSATE STORAGE	6000 BBL	ATM	165	38			FLOATING ROOF						62050	122630	5776.00	
51-P-01 A/B		2	PROPANE LOADING PUMPS	200 GPM			2	2			50	7.29				1400	27080	64.00	
51-P-02 A/B		2	BUTANE LOADING PUMPS	200 GPM			2	2			50	7.29				1400	27080	64.00	
51-P-03 A/B		2	CONDENSATE LOADING PUMPS	200 GPM			2	2			50	7.29				1400	27080	64.00	
			TOTALS									1384.4		109.56025		2911237	10926664	52944.8	

EQUIPMENT LIST

MEMBRANE UNIT

TAG NO.	SIM NAME	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (psig)	DESIGN TEMP. (deg F)	Widh/ Dia. (ft)	Length (ft)	Height (ft)	TYPE V/H, S&T/ AIR CLR	DIFF HEAD (psi)	POWER (KW)	HEAT TRANSFER AREA SQ. FT	FUEL (MMBTU/hr)	MOC	WEIGHT (LBS)	COST (US$)	AREA (FT2)	REMARKS
ME-01		1	1ST STAGE PRETREATMENT				25	14	16							120000		620	
ME-02		1	1ST STAGE MEMBRANES				30	14	14							125000		720	
ME-03		1	2ND STAGE PRETREATMENT				25	10	6							75000		496	
ME-04		1	2ND STAGE MEMBRANES				30	12	12							80000	5800000	648	
K-01		1	RECYCLE COMPRESSOR				8.5	35	9			4340				80000	3500000	594.5	
V-01		1	1ST STAGE SUCTION SCRUBBER		75		2		6							1616	4305	64	
V-02		1	2ND STAGE SUCTION SCRUBBER		175		4.5		9							5446	10929	110.25	
V-03		1	3RD STAGE SUCTION SCRUBBER		350		3.5		7							5231	10597	90.25	
E-01		1	1ST STAGE DISCHARGE COOLER	5.04 MMBTU/HR	175		12	20									62367	468	
E-02		1	2ND STAGE DISCHARGE COOLER	5.26 MMBTU/HR	350		12	20									63257	468	
E-03		1	3RD STAGE DISCHARGE COOLER	5.78 MMBTU/HR	800		12	20									71914	468	
												4340		0		492293	9523369	4747	

APPENDIX E
COST ESTIMATE DETAILS

514073

SAGASCO RESOURCE LTD
YOLLA FIELD DEVELOPMENT STUDY

Concept Option Cost Summary
1-May-95

Option Number	Description
CASE 1 (Offshore Component)	Subsea, 3 Phase Trunkline Remote Well System, 1 Template, Subsea Manifolding 20" Wellfluid Trunkline to Shore Process Facilities---- Nil

Cost Summary

Offshore Capital Cost	79.6 $Mil
Trunkline Cost	101.3 $Mil
Drilling/ Completion Cost (Phase 1)	51.6 $Mil

Total Capital Cost Breakdown		Engineer/ Design/PMT $M	Procure/ Fabricate $M	Transport/ Install $M	Total $M
Engineering/Design/ Project Management		7.241			7.241
Facilities					
	Process & Utilities		0.000		
	Well Templates/ Manifolds		10.374	6.29	
	Trees		5.276		
	Wellheads		2.099		
	Control System		48.366		
	Sub Total		66.115	6.290	72.405
Intrafield Flowlines			0.000	0.000	0.000
Total Offshore Capital Cost		7.241	66.115	6.290	79.646
Trunkline	Material	3.378	53.944		
	Installation Cost			35.000	
	Installation Vessel Mob/Demob			9.000	
Total Trunkline Cost		3.378	53.944	44.000	101.322
Drilling Platform Wells (8)	Materials		17.822		
	Ship Cost		33.795		
Total Drilling/ Completion Cost			51.617		51.617

SAGASCO RESOURCE LTD | **Concept Option Cost Summary**
YOLLA FIELD DEVELOPMENT STUDY | **1-May-95**

Option Number	Description
CASE 2	All Satellite Wells Type 3 Convereted Jackup 20" Trunkline to Shore Process Facilities---- Test Separator, Flare Etc

Cost Summary

Offshore Capital Cost	133.9 $Mil
Trunkline Cost	101.3 $Mil
Drilling/ Completion Cost	41.7 $Mil

Total Capital Cost Breakdown		Engineer/ Design/PMT $M	Procure/ Fabricate $M	Transport/ Install $M	Total $M
Engineering/Design/ Project Management		12.177			12.177
Jackup					
	Purchase Cost		35.000		
	Conversion Cost		37.800	2.396	
	Sub Total		72.800	2.396	75.196
Facilities					
	Process & Utilities		3.259		
	Trees		4.635		
	Wellheads		2.542		
	Production/Export Risers		5.473	13.766	
	Control System		6.205		
	Sub Total		22.114	13.766	35.880
Intrafield Flowlines			6.963	3.726	10.689
Total Offshore Capital Cost		12.177	101.877	19.888	133.942
Trunkline	Material	3.378	53.944		
	Installation Cost			35.000	
	Installation Vessel Mob/Demob			9.000	
Total Trunkline Cost		3.378	53.944	44.000	101.322
Drilling Platform Wells (8)	Materials		13.863		
	Ship Cost		27.840		
Total Drilling/ Completion Cost			41.703		41.703

SAGASCO RESOURCE LTD — **Concept Option Cost Summary**
YOLLA FIELD DEVELOPMENT STUDY — **1-May-95**

Option Number	Description
CASE 3 (Offshore Component)	Remote 2800 Ton Well Platform, 1 Template, Light WO/ Wire Line System 20" Trunkline to Shore, 3 Phase Flow Process Facilities ---Test Separator, Hydraulic Pack, Flare

Cost Summary

Offshore Capital Cost	38.3 $Mil
Trunkline Cost	92.3 $Mil
Drilling/ Completion Cost (Phase 1)	49.1 $Mil

Total Capital Cost Breakdown			Engineer/ Design/PMT $M	Procure/ Fabricate $M	Transport/ Install $M	Total $M
Engineering/Design/ Project Management			3.481			3.481
Drilling Platform	Deck	358 S Ton		3.229		
	Jacket	1146 S Ton		4.298		
	Piles	1359 S Ton		2.311		
	Sub Total			9.838	20.000	29.838
Facilities						
	Process & Utilities			4.328		
	Trees			0.550		
	Production/ Export Riser			0.094		
	Sub Total			4.972	0.000	4.972
Intrafield Flowlines				0.000	0.000	0.000
Total Offshore Capital Cost			3.481	14.810	20.000	38.291
Trunkline	Material		3.378	53.944		
	Installation Cost				35.000	
	Installation Vessel Mob/Demob				0.000	
Total Trunkline Cost			3.378	53.944	35.000	92.322
Drilling Platform Wells (8)	Materials			17.575		
	Ship Cost			31.535		
Total Drilling/ Completion Cost				49.110		49.110

SAGASCO RESOURCE LTD — **Concept Option Cost Summary**

YOLLA FIELD DEVELOPMENT STUDY — **1-May-95**

Option Number	Description
CASE 4 (Offshore Component)	Drilling, Production, Accomodation Platform 12" Trunkline to Shore, 2 Phase Flow One Template Integrated with Jacket 20 Men Living Quarter Process Facilities "MINOS" Case Light Workover/ Wireline System

Cost Summary

Offshore Capital Cost	84.7 $Mil
Trunkline Cost	67.6 $Mil
Drilling/ Completion Cost (Phase 1)	49.6 $Mil

Total Capital Cost Breakdown			Engineer/ Design/PMT $M	Procure/ Fabricate $M	Transport/ Install $M	Total $M
Engineering/Design/ Project Management			7.700			7.700
Structural						
	DECK	2621 S Ton		19.658		
	JACKET	2256 S Ton		8.459		
	PILES	2675 S Ton		4.549		
	TEMPLATE			0.000		
	Sub Total			32.666	25.000	57.666
Facilities						
	Process & Utilities			13.919		
	Accomodations			4.590		
	Production/Export Risers			0.065		
	Trees			0.756		
	Sub Total			19.330		19.330
Intrafield Flowlines				0.000	0.000	0.000
Total Offshore Capital Cost			7.700	51.996	25.000	84.696
Trunkline	Material		1.918	30.648		
	Installation Cost				35	
	Installation Vessel Mob/Demob				0	
Total Trunkline Cost			1.918	30.648	35	67.566
Drilling Platform Wells (8)	Materials			18.058		
	Ship Cost			31.535		
Total Drilling/ Completion Cost				49.593		49.593

SAGASCO RESOURCE LTD **Concept Option Cost Summary**
YOLLA FIELD DEVELOPMENT STUDY **1-May-95**

Option Number	Description
CASE 5 (Offshore Component)	Drilling, Production, Accomodation Platform 12" Gas & 6" Condensate Trunkline to Shore One Template Integrated with Jacket 40 Men Living Quarter Process Facilities "WEND" Case Light Workover/ Wireline System

Cost Summary

Offshore Capital Cost	117.2 $Mil
Trunkline Cost	84.9 $Mil
Drilling/ Completion Cost (Phase 1)	49.6 $Mil

Total Capital Cost Breakdown			Engineer/ Design/PMT $M	Procure/ Fabricate $M	Transport/ Install $M	Total $M
Engineering/Design/ Project Management			10.654			10.654
Structural						
	DECK	3249 S Ton		33.139		
	JACKET	3059 S Ton		11.469		
	PILES	3628 S Ton		6.168		
	TEMPLATE			0.000		
	Sub Total			50.776	25.000	75.776
Facilities						
	Process & Utilities			21.084		
	Accomodations			8.840		
	Production/Export Risers			0.085		
	Trees			0.756		
	Sub Total			30.765		30.765
Intrafield Flowlines				0.000	0.000	0.000
Total Offshore Capital Cost			10.654	81.541	25.000	117.195
Trunkline	Material		2.581	41.301		
	Installation Cost				41.000	
	Installation Vessel Mob/Demob				0	
Total Trunkline Cost			2.581	41.301	41.000	84.882
Drilling Platform Wells (8)	Materials			18.058		
	Ship Cost			31.535		
Total Drilling/ Completion Cost				49.593		49.593

SAGASCO RESOURCE LTD | **Concept Option Cost Summary**
YOLLA FIELD DEVELOPMENT STUDY | **1-May-95**

Option Number	**Description**
CASE 6 (Offshore Component)	Drilling, Production, Accomodation Platform 10" Gas & 6" Condensate Trunkline to Shore One Template Integrated with Jacket 40 Men Living Quarter Process Facilities Dehydration, Dew Point Control & CO2 Removal] Light Workover/ Wireline System

Cost Summary

Offshore Capital Cost	136.8 $Mil
Trunkline Cost	74.9 $Mil
Drilling/ Completion Cost (Phase 1)	49.6 $Mil

Total Capital Cost Breakdown			Engineer/ Design/PMT $M	Procure/ Fabricate $M	Transport/ Install $M	Total $M
Engineering/Design/ Project Management			12.433			12.433
Structural						
	DECK	3470 S Ton		40.368		
	JACKET	3240 S Ton		12.145		
	PILES	3842 S Ton		6.532		
	TEMPLATE			0.000		
	Sub Total			59.045	25.000	84.045
Facilities						
	Process & Utilities			30.607		
	Accomodations			8.840		
	Production/Export Risers			0.085		
	Trees			0.756		
	Sub Total			40.288		40.288
Intrafield Flowlines				0.000	0.000	0.000
Total Offshore Capital Cost			12.433	99.333	25.000	136.766
Trunkline	Material		2.099	33.624		
	Installation Cost				39.200	
	Installation Vessel Mob/Demob				0	
Total Trunkline Cost			2.099	33.624	39.200	74.923
Drilling Platform Wells (8)	Materials			18.058		
	Ship Cost			31.535		
Total Drilling/ Completion Cost				49.593		49.593

SAGASCO RESOURCE LTD
YOLLA FIELD DEVELOPMENT STUDY

Concept Option Cost Summary
1-May-95

Option Number	Description
CASE 7	Remote Well System, 1 Template, Subsea Manifolding 50,000 DWT FPSO 12" Gas Trunkline to Shore Process Facilities Dehydration, Dew Point Control

Cost Summary

Offshore Capital Cost	134.4 $Mil
Trunkline Cost	76.6 $Mil
Drilling/ Completion Cost	52.2 $Mil

Total Capital Cost Breakdown		Engineer/ Design/PMT $M	Procure/ Fabricate $M	Transport/ Install $M	Total $M
Engineering/Design/ Project Management		12.215			12.215
FPSO					
	Purchase Cost		20.000		
	Conversion Cost		22.050	1.794	
	Mooring System Cost		18.071	5.262	
	Sub Total		60.121	7.056	67.177
Facilities					
	Process & Utilities		17.839		
	Well Templates/ Manifolds		10.193	6.297	
	Trees		6.216		
	Wellheads		2.099		
	Accomodations		Incl		
	Production/Export Risers		1.873		
	Control System		6.367		
	Sub Total		44.587	6.297	50.884
Intrafield Flowlines			0.935	3.157	4.092
Total Offshore Capital Cost		12.215	105.643	16.510	134.368
Trunkline	Material	1.918	30.648		
	Installation Cost			35.000	
	Installation Vessel Mob/Demob			9.000	
Total Trunkline Cost		1.918	30.648	44.000	76.566
Drilling Platform Wells (8)	Materials		18.381		
	Ship Cost		33.795		
Total Drilling/ Completion Cost			52.176		52.176

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SAGASCO RESOURCE LTD | **Concept Option Cost Summary**
YOLLA FIELD DEVELOPMENT STUDY | **1-May-95**

Option Number	Description
CASE 8	Remote 2800 Ton Well Platform, 1 Template, Light WO/ Wire Line System 50,000 DWT FPSO 12" Gas Trunkline to Shore Process Facilities Dehydration, Dew Point Control

Cost Summary

Offshore Capital Cost	134.2 $Mil
Trunkline Cost	67.6 $Mil
Drilling/ Completion Cost	49.6 $Mil

Total Capital Cost Breakdown			Engineer/ Design/PMT $M	Procure/ Fabricate $M	Transport/ Install $M	Total $M
Engineering/Design/ Project Management			12.201			12.201
Drilling Platform	Deck	302 S Ton		2.497		
	Jacket	1137 S Ton		4.263		
	Piles	1348 S Ton		2.293		
	Sub Total			9.053	20.000	29.053
FPSO						
	Purchase Cost			20.000		
	Conversion Cost			22.050	1.794	
	Mooring System Cost			18.071	5.262	
	Sub Total			60.121	7.056	67.177
Facilities						
	Process & Utilities			20.487		
	Trees			0.756		
	Accomodations			Incl		
	Production/Export Risers			1.344		
	Sub Total			22.587	0.000	22.587
Intrafield Flowlines				0.175	3.020	3.195
Total Offshore Capital Cost			12.201	91.936	30.076	134.213
Trunkline	Material		1.918	30.648		
	Installation Cost				35.000	
	Installation Vessel Mob/Demob				0.000	
Total Trunkline Cost			1.918	30.648	35.000	67.566
Drilling Platform Wells (8)	Materials			18.058		
	Ship Cost			31.535		
Total Drilling/ Completion Cost				49.593		49.593

OPERATING COST ESTIMATES & ABANDONMENT COSTS

CASE	1	2	3	4	5	6	7	8
	US$mil	US$mil	US$mil	US$mil	US$mil	US$mil	US$mil	US$mil
FIELD CONFIGURATION	SubSea	Jackup	Drilling Platf	Process Platf	Process Platf	Process Platf	SubSea/FPSO	DP/FPSO
PROCESSING SCHEME	3 Phase	3 Phase	3 Phase	2 Phase	Dew Pt Control	Membrane	Dew Pt Control	Dew Pt Control
Subsea Maint	0.27	0.06	0	0	0	0	0	0
Platform Maint.	0	3.86	0.42	2.22	4.04	4.1	5.3	5.26
Process Fac Maint	0	5.84	0.44	3.24	6.33	6.52	5.7	5.66
Flowlines/Pipelines Maint	1.23	1.11	0.2	0.83	1.03	1.03	1.03	1.03
Well Maintenance per SAGASCO	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22
Local Office & Warehouse	1.97	1.32	0.3	0.93	1.29	1.46	0.93	0.99
Helicopter & Supply Boat	0.2	3.43	3.43	3.43	3.43	3.43	3.43	3.43
Quarters & Catering	0	0.75	0.2	0.42	0.89	0.89	0.91	0.91
Mooring System Maint	0	0	0	0	0	0	0.15	0.15
Insurance	6.6	4.4	1.06	3.1	4.29	4.88	3.09	3.07
Onshore Plant Opex	7	7	7	6	6	6	6	6
Head Office	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
TOTAL OPEX	22 (note 1)	32	18	25	32	33	31	31
Abandonment Cost	23.2	18.2	12.1	12.8	17.8	20	13.3	13.3

Notes:
1. For Case 1 add US$5.4 mil at 10 yr interval for Well system replacement.

APPENDIX F

PLATFORM EQUIPMENT LAYOUTS

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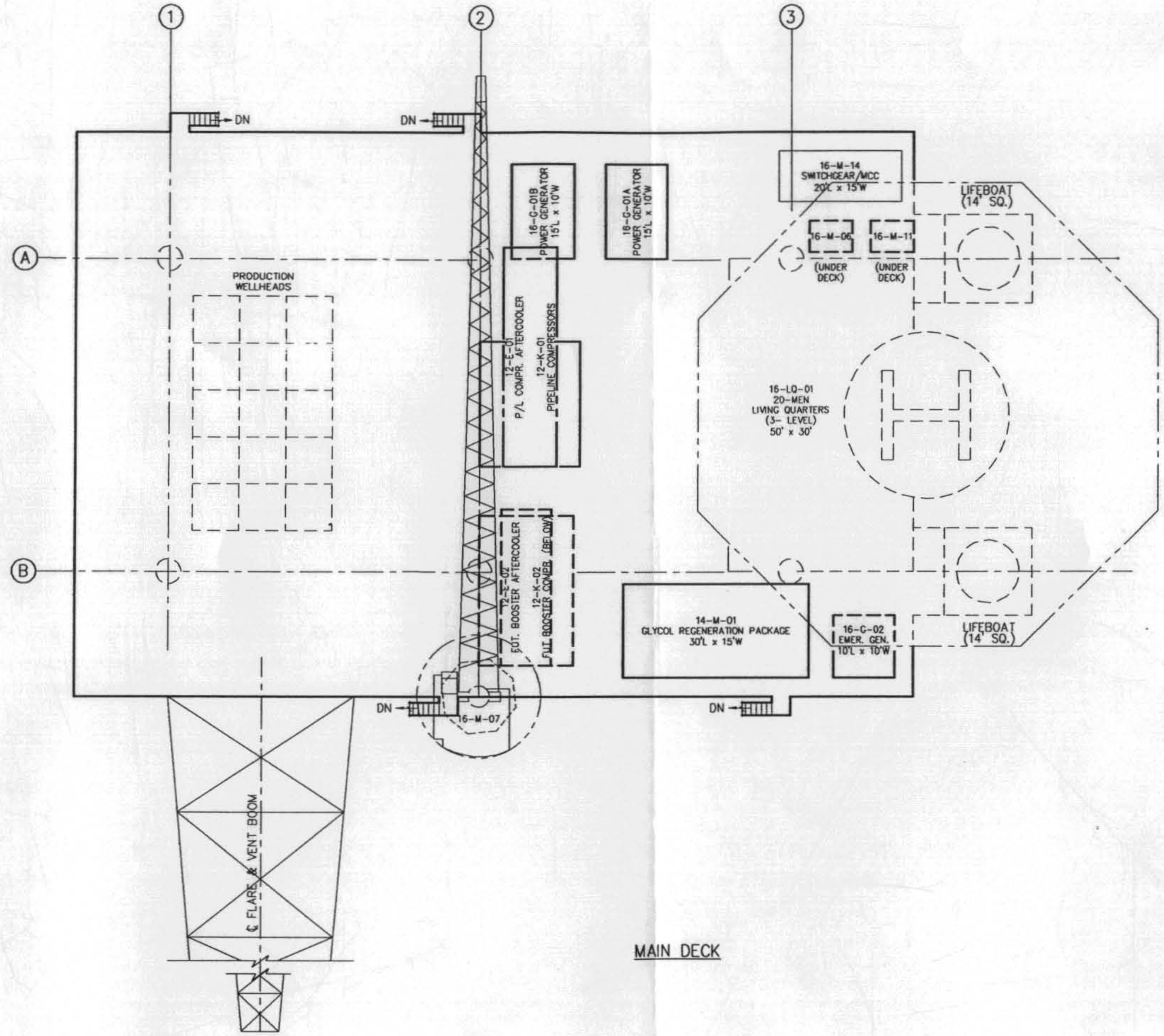

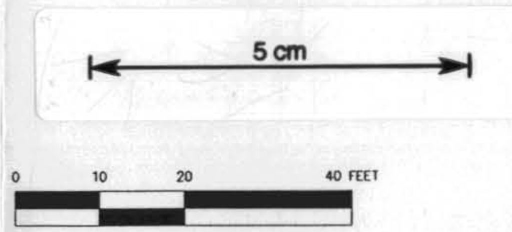

NOTES	REVISIONS • BY • DATE	REVISIONS • BY • DATE					
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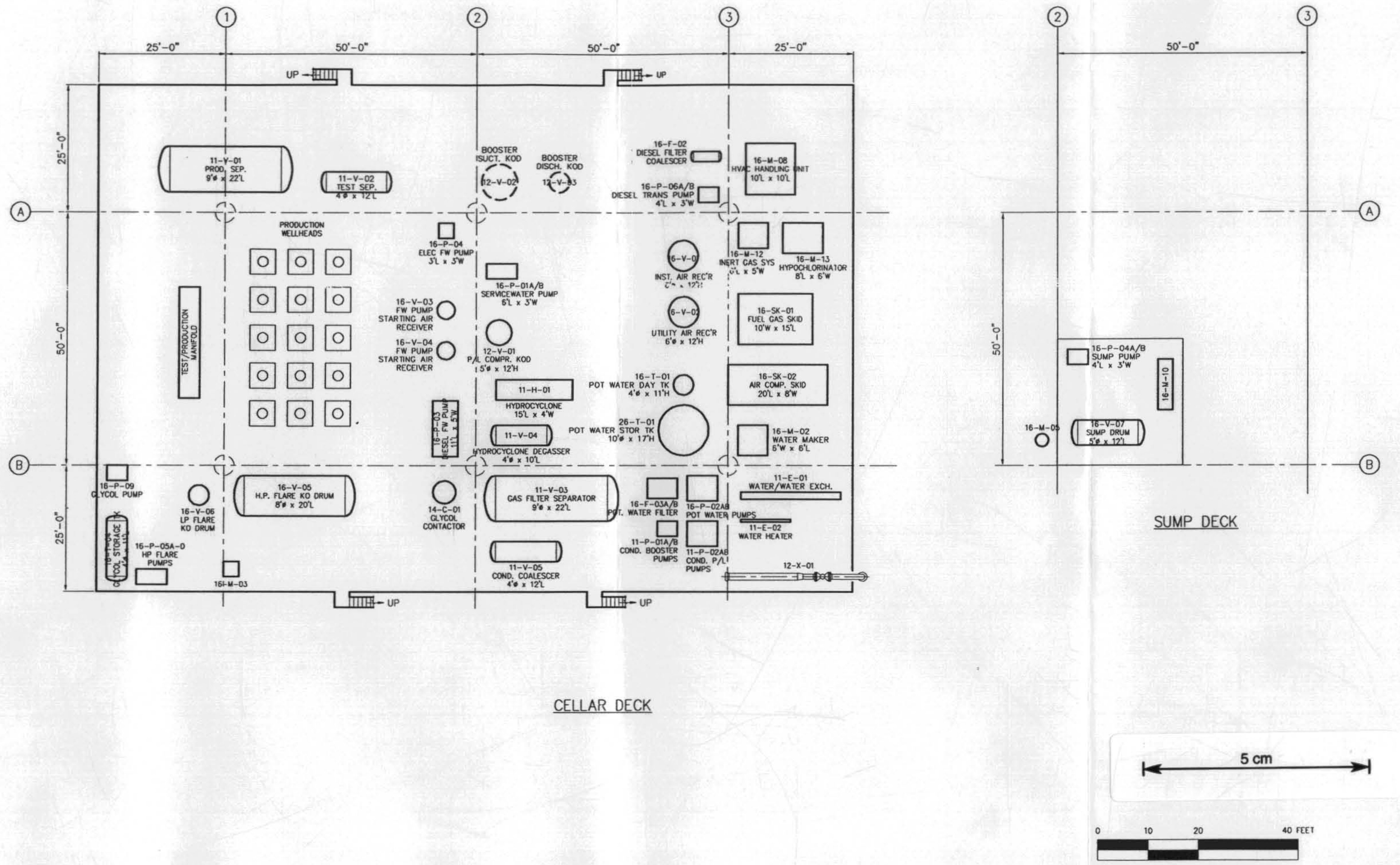

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				DATE 4 APR 95			NAME OF OWNER: SAGASCO	DRAWING NO. MINOL02A
				CHECKED BY: EJ	APPROVED		LOCATION OF PROJECT: YOLLA FIELD DEVELOPMENT	SHEET 1 OF 1
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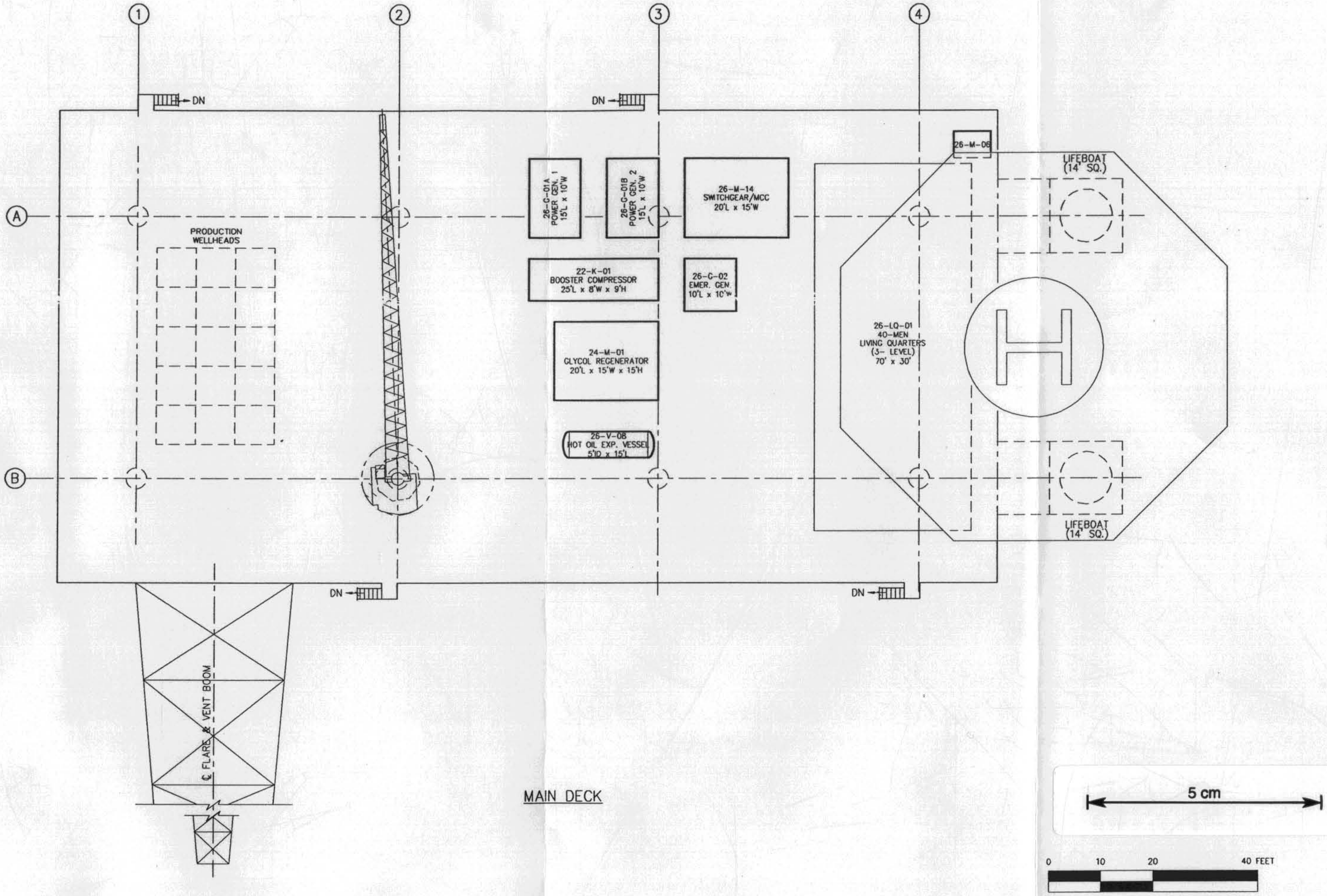

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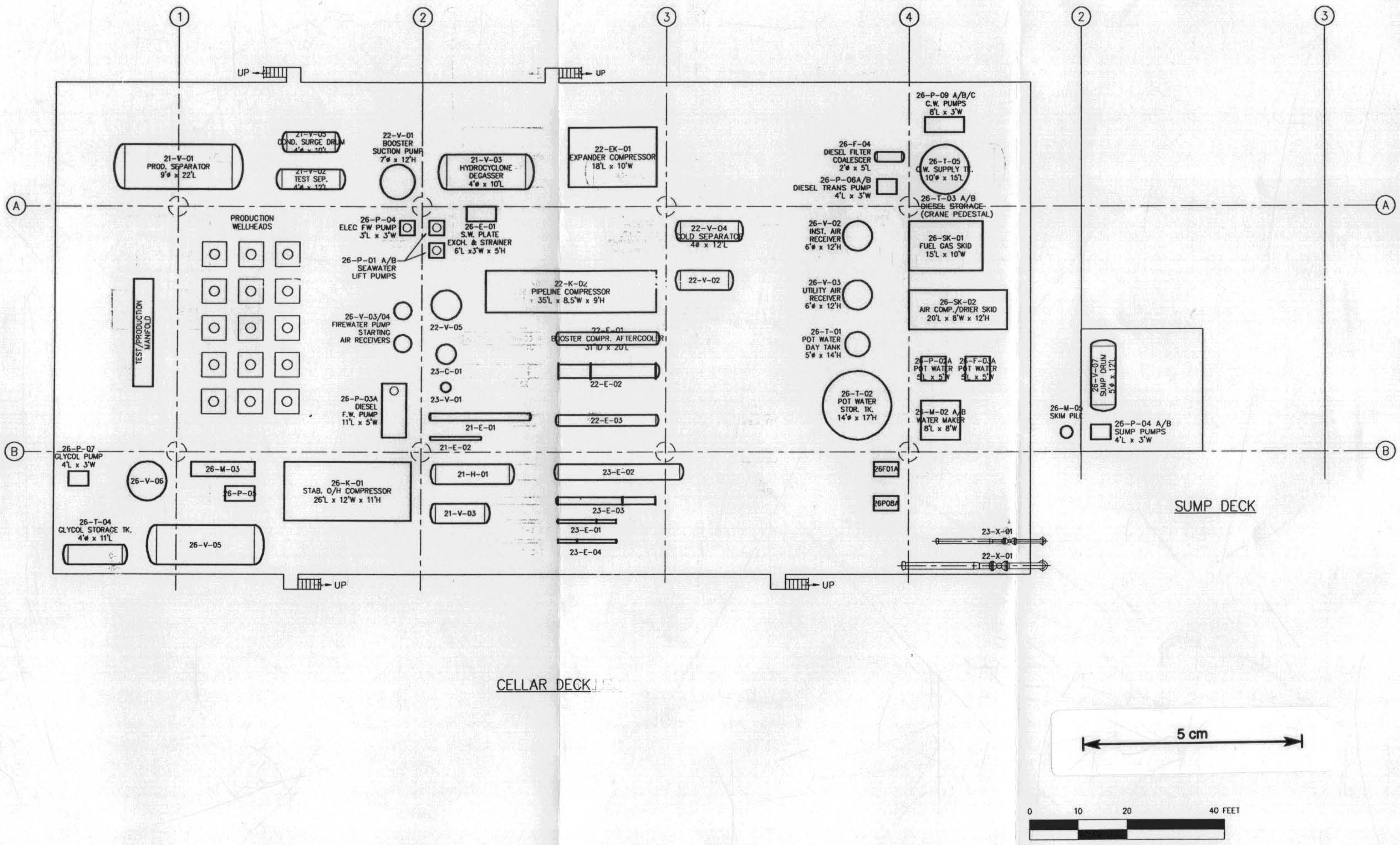

NOTES	REVISIONS • BY • DATE	REVISIONS • BY • DATE			APPROVED	SEAL		
			Brown & Root **FAR EAST ENGINEERS PTE. LTD.** Engineers • Constructors	DRAWN BY: Patrick DATE 4 APR 95 CHECKED BY: EJ DATE 10-4-95 SCALE: 1:120	APPROVED APPROVED	SEAL	TITLE OF DRAWING: EQUIPMENT LAYOUT CELLAR DECK (CASE 5) NAME OF OWNER: SAGASCO LOCATION OF PROJECT: YOLLA FIELD DEVELOPMENT	CONTRACT NO. 1601-02 DRAWING NO. WENDL02 SHEET 1 OF 1

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