TECHNICAL REPORT

SYNOPSIS

My Technical report comprises of mainly the Concept Study Report and some of the Sample Calculations carried out by me:-

1) Concept Study Report for xxxx well flowlines Rationalisation Project along with Simulation input data and configuration
2) Operating Philosophy & Control Narrative for xxxx well flowlines Rationalisation Project
3) Safeguarding Narrative for xxxx Well flowlines Rationalisation Project
4) Calculations for PVV & Blow-off Hatch for Crude Storage Tanks
5) Calculations for sizing of Relief valve.

1. CONCEPT STUDY REPORT FOR XXXX WELL FLOWLINES RATIONALISATION PROJECT

I had started working on this project since its inception. The project was initiated mainly to avoid congestion of well flowlines in XXXX Production station corridor.

The oil producing wells are free-flowing and two-phase flow with no solids but some amount of water present in aqueous phase. So I had to simulate the model using PIPESIM 2006 Edition-2 software to calculate the pressure drop for the line size selected. The idea was to get together a cluster of wells based on the proximity to a Remote manifold OR MSV and run a single bulk header to the station. Fluid mechanics engineering design was considered for carrying out the hydraulics. Considering the number of bends and pipe fittings in addition to actual length, the equivalent length was calculated. Further, the limitation on continuous flow of liquid in pipe to avoid static charges build-up and erosion velocity of liquid was taken into consideration. In addition, a test header from each of the Remote manifold OR MSV for well testing mainly through a Multi-Phase flow meter (MPFM), was considered to measure the total flow.

My first priority was to build the simulation model for the existing wells. The production from the existing wells is routed to the 6” manifold at the station via individual 4” well flowlines. Configuring the flow of fluid through well downhole upto the choke valve was a challenging task. Relevant inputs were taken from the reservoir team. The ID and length of the well downhole upto the total depth was fed into the simulation model.
Further, the equivalent length of the flowlines downstream of the wing valve was calculated.
The simulation was carried out and verified.
Various Options were considered as stated in the report.
Finally, a cluster of seven new well flowlines routed to remote manifold was considered as the best option.

The MPFM (MultiPhase flow meter) has Venturi meter for liquid measurement, single Gamma source for GVF% measurement and Dual Gamma source for WC%.

For standard oil/gas calculations

$Q_{VOS}= Q_{VO}$ * Shrinkage factor

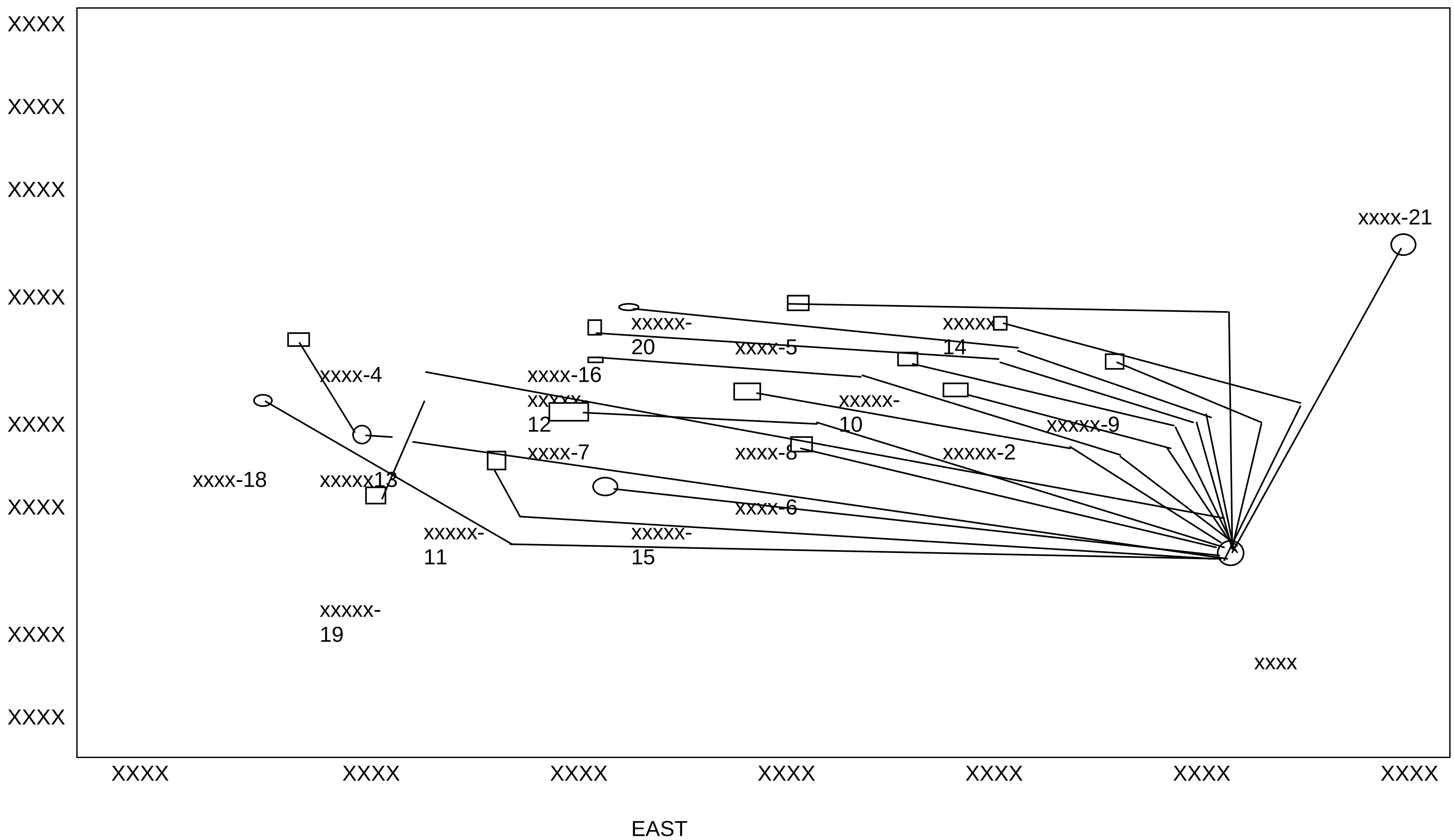
where

Q_{VOS} – Oil flow rate at actual condition, m3/d
Q_{VO} – Oil flow rate at standard condition, Sm3/d
Shrinkage factor – Crude Oil shrinkage coefficient

Qgs= Qg * P_1* Tn/ Pn* T_1/Z Factor+ Q_{vos}* Solution GOR

where

Qgs – Gas flow rate, Standard, Sm3/day
Qg - Gas flow rate, actual, m3/day
P_1 - Absolute pressure,actual
Tn – Standard temperature (K)
Pn - Absolute pressure,standard
T_1 - Actual temperature (K)
Z Factor – Nature gas volume compressibility
Q_{vos}- Oil flow rate, standard condition, Sm3/d



LOCATION OF WELLS AS PER CO-ORDINATES

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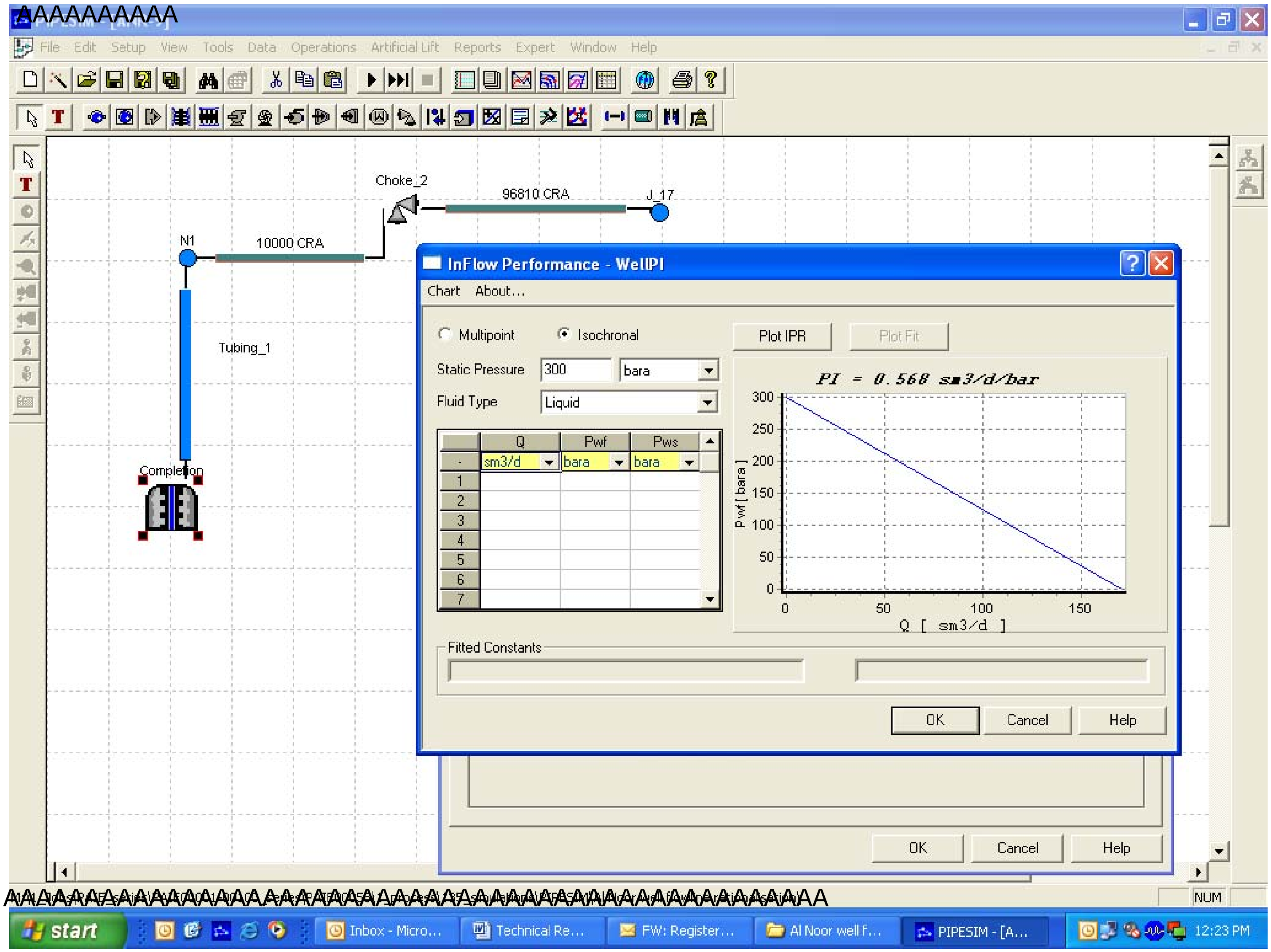
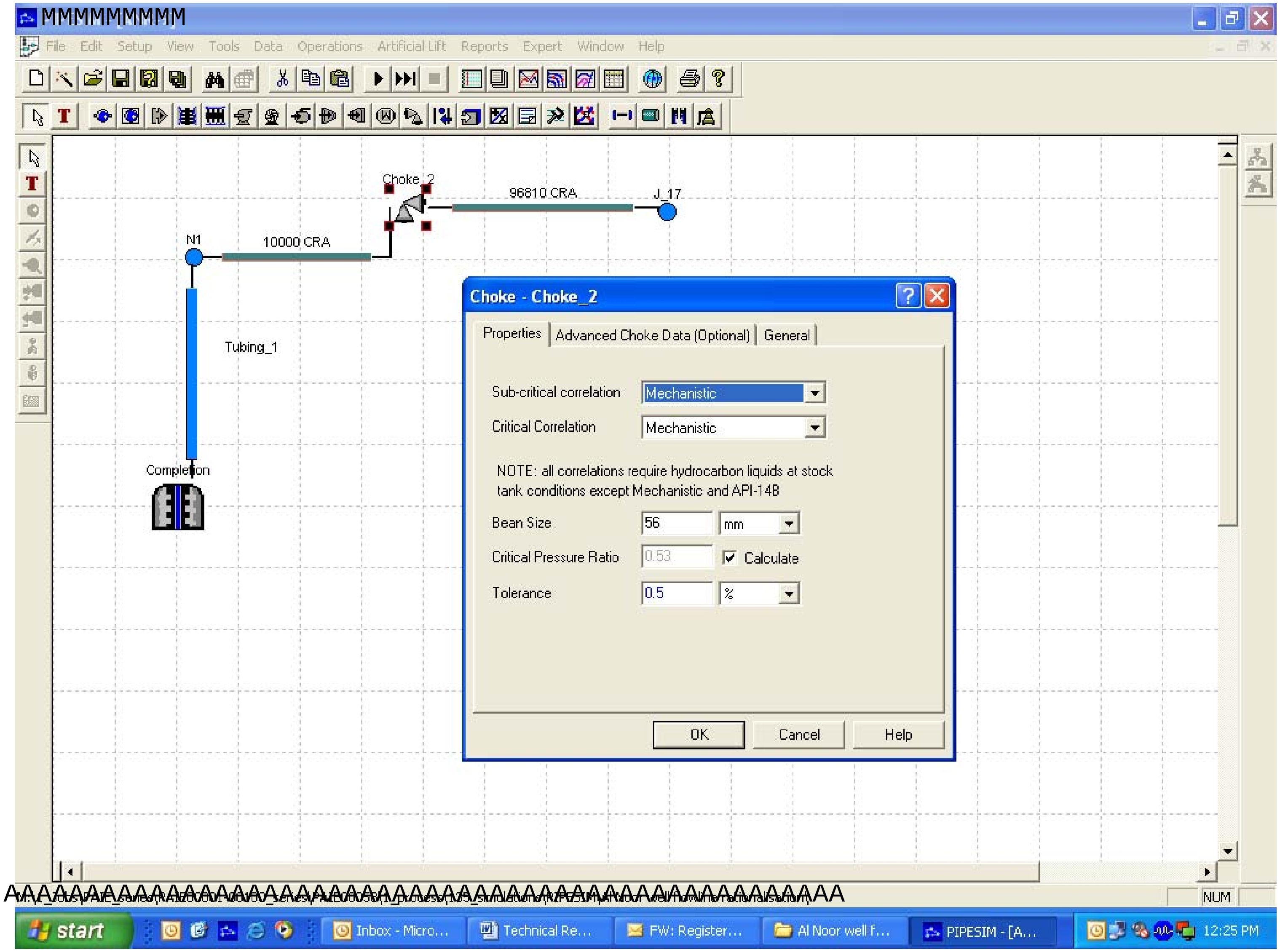
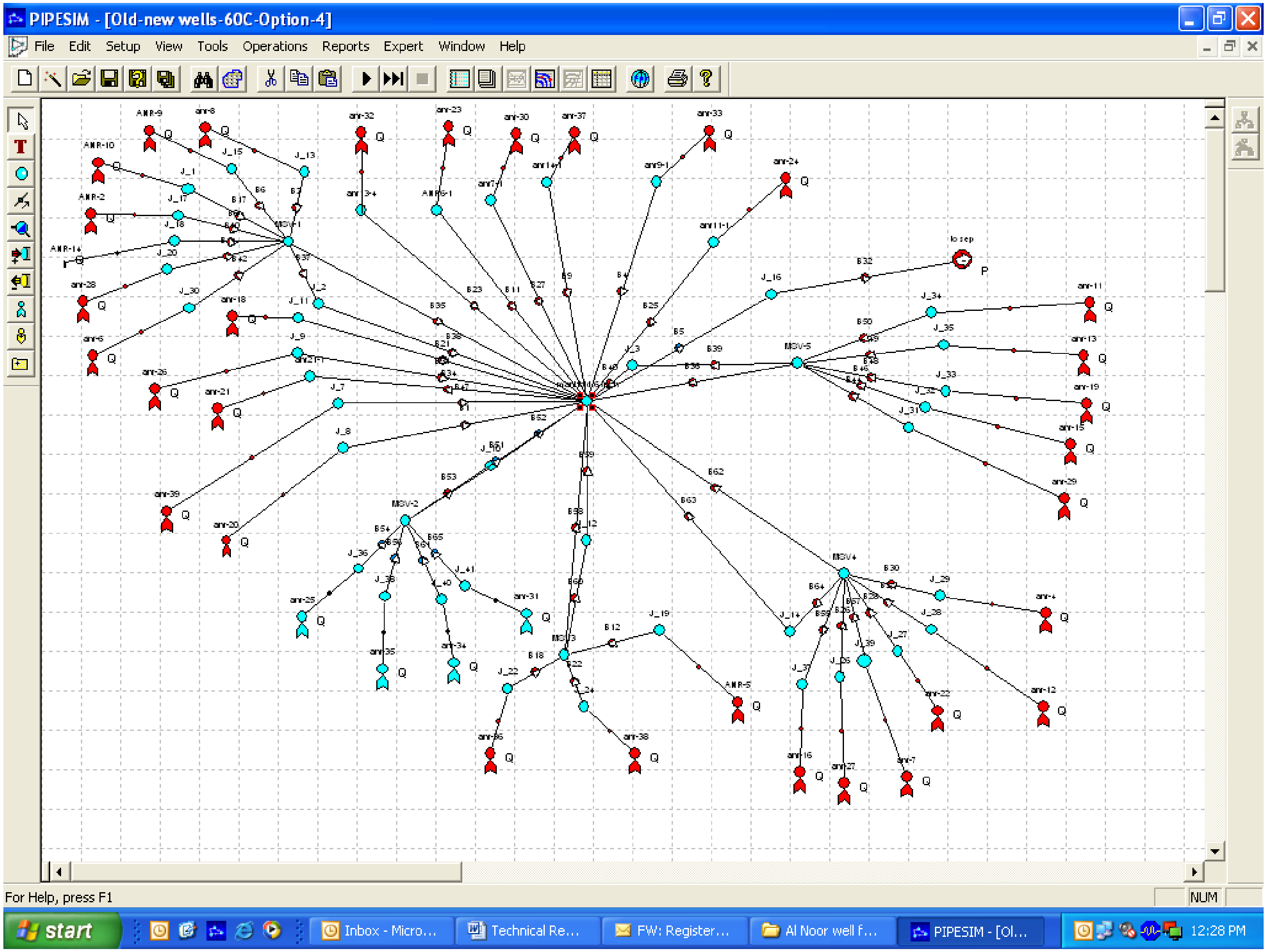


Well flow v/s FTHP



CHOKE VALVE DETAILS



TOTAL SIMULATED MODEL

INPUTS FOR CALCULATIONS AND MODELLING

GRE details- Refer document No. 1561-DP-01

6”-120 bar(g)- ID-xxx mm
Wall thickness – xxx mm
Conductivity- 0.346 W/m deg K
4”-120 bar(g)- ID- xxxxx mm
Wall thickness-7.061 mm.

Ground conductivity- 0.6400999 W/m/K
Steel pipe conductivity– 50 W/m/K.

4 ½”-xxx-10000# - I.D-97.18 mm
Thickness-17.12 mm
4’-xxxx- I.D-108.28 mm
Thickness- 6.02 mm
6”-xxxxx I.D-161.19 mm
Thickness-7.11 mm.

GRE Roughness factor- 0.001524

Equivalent length of 4” pipeline before choke valve – (actual length – 12.950 m) – 42 metres.
Equivalent length of 4” pipeline after choke valve- (actual length- 39.500 m) – 51 metres.

Reservoir data considered

Pressure – xxx bar(g)-New wells
xxx bar(g)-Old wells
Temp.- 89 degC
Well PI - Liquid Pi -xxx sm3/day/bar.

Tubing- Datum MD-0
Ambient temp- 5/60 degC
SSSV MD-71 m
ID-xx mm Perforations- xxxx m MD
xxxx m TVD

Tubing #1 – 0	xxxxx	99
Tubing#2 - xxxxx	xxxxx	75
Tubing#3 - xxxx	xxxxx	160

6 inch production header considered- 30 metres from Station manifold upto HP Separator
4 inch flowline from each well – 2 kms.

Pressure at XXXX manifold-86 bar (a).
Criteria constraints for manifold- xxxx m3/day oil stn.
Capacity GOR - xxxx.

APPROACH TO CALCULATIONS

For single well (4-inch flowline)

1) Equivalent length calculated for pipe length upstream of choke valve.
2) Equivalent length calculated for pipe length downstream of choke valve upto well –pad battery limit.
3) Flowline from well-pad battery limit upto Remote manifold

For Bulk header sizing from Remote manifold to Station manifold

The preliminary size considered was 6-inch identical to the Production header at the Station manifold.

Another challenge was the flow of oil from individual wells which is gradually decreasing. So a table was developed by me in Excel to evaluate the maximum oil flow from the wells to the station in particular year. The basis as provided by the reservoir team was that the new well will start producing 380 m^3/day in the first month, 200 m^3/day after 2 months and 150 m^3/day after 3 months of commencement of production. The wells would be hooked up one at a time
Also, the production from existing wells will gradually decrease at an average rate of 35% from the flow rate for the previous year.

Since the flow was primarily two-phase flow, PIPESIM simulation was carried out for all the cases considered. I used API-14E equation for calculation of erosion velocity and cross-check with the output from the PIPESIM model. It was matching.

In order to avoid erosion damage and associated problems in two-phase flow systems, API RP14E recommends limiting the maximum production velocity to a value defined by the following empirical equation:

$$V_e = C/\sqrt{\rho}$$

where

V_e = the maximum allowable erosional velocity in ft/sec
ρ = the density of fluid in lb/cu ft at flowing conditions of temperature and pressure
C = a constant generally known as the C factor, is in the range of 100 to 125

For a sand-free, two-phase flow situation, the C factor is limited to 100 for continuous flow and 125 for intermittent flow. The API RP14E recommends the use of a lower unspecified C factor for fluids containing sand.

Based on the Pressure drop for Multiphase fluid flow as per Perry, Chapter 6
as reproduced below:-

MULTIPHASE FLOW

Multiphase flows, even when restricted to simple pipeline geometry, are in general quite complex, and several features may be identified which make them more complicated than single-phase flow. Flow pattern description is not merely an identification of laminar or turbulent flow. The relative quantities of the phases and the topology of the interfaces must be described. Because of phase density differences, vertical flow patterns are different from horizontal flow patterns, and horizontal flows are not generally axisymmetric. Even when phase equilibrium is achieved by good mixing in two-phase flow, the changing equilibrium state as pressure drops with distance, or as heat is added or lost, may require that interphase mass transfer, and changes in the relative amounts of the phases, be considered.

Wallis (*One-dimensional Two-phase Flow*, McGraw-Hill, New York, 1969) and Govier and Aziz present mass, momentum, mechanical energy, and total energy balance equations for two-phase flows. These equations are based on one-dimensional behavior for each phase. Such equations, for the most part, are used as a framework in which to interpret experimental data. Reliable prediction of multiphase flow behavior generally requires use of data or correlations. **Two-fluid modeling**, in which the full three-dimensional microscopic (partial differential) equations of motion are written for each phase, treating each as a continuum, occupying a volume fraction which is a continuous function of position, is a rapidly developing technique made possible by improved computational methods. For some relatively simple examples not requiring numerical computation, see Pearson (*Chem. Engr. Sci.*, **49**, 727–732 [1994]). Constitutive equations for two-fluid models are not yet sufficiently robust for accurate general-purpose two-phase flow computation, but may be quite good for particular classes of flows.

I therefore developed PIPESIM simulation model to calculate the pressure drop and the pressure to be maintained downstream of the individual well choke valve.
I counterchecked the simulation output with Flowline design calculations as per API-14E for two phase flowline calculations.

Attached herewith is a copy of the original report along with the results for your consideration.

XXXX WELL FLOWLINES RATIONALISATION

CONCEPT SELECTION REPORT

		:

TABLE OF CONTENTS

1 MANAGEMENT SUMMARY

The report on Flowline Rationalisation study is contemplated to avoid criss crossing of the flowlines, optimally utilising the available slots at manifolds taking into account identified low producers that would be abandoned in future and minimise the extensive need of CRA manifold extensions which will restrict future field developments. It also aims at addressing the main issue of flowline routing to optimise the flowline lengths, reduce the demand on the space already occupied by flowlines, achieve more operational flexibility and minimise the hook up costs.

Use of Multi-Port Selector Valves or Remote Manifold assists a lot in achieving these objectives. This study covers all the wells upto 20XX (currently flowing wells as new wells).

‘Remote manifold (7-slots) - 2 nos.’ Option-2B is considered as the best option. The flowlines from the new wells would be routed to two remote manifolds located in field at strategic locations. The bulk header and test header from each of the Remote manifolds located in field would be hooked up to the manifold at XXXX. Depending on the constructability constraints, priority will be given to hook-up of new wells to Remote manifold, due to deferrment issues for the loss of oil production from the old wells, if the old well flowlines will be utilised as per Option-2A.

The well testing frequency is met by three MFM’s which are proposed to be installed at XXXX station manifold to cater to the testing requirement of all producing wells upto 20XX.
The outcome of the flow line rationalisation would be applicable for the wells during the year 200X to 20XX.
The CAPEX for ‘Two remote manifold – 7 slots’ Option-2A is estimated as US $ XXXX as against ‘Two-MSV’s – 7-slots’ which is estimated as US $ XXXXX mln. However, the remote manifold concept is selected as the preferred option due to the following:-

i. MSV performance not proven for similar service (high pressure and high H_2S) in SSS or elsewhere

ii. Limited vendor capability, only 1 vendor responded to our preliminary requests.

iii. High risk to project, no fall back in case MSV’s don’t perform

2 BACKGROUND AND OBJECTIVES

Laying of independent flowlines in field and extension of the manifold within XXXX posed engineering complications and is not a preferred option. This approach would make the area congested and may impact road lay-out in the station. The concept of flowline rationalisation in the field is economically justified due to availability of Remote manifold suitable for XXXX fields.
Flowline co-mingling of two old wells is perceived to be compromising WRM objectives and hence generally not supported.

The objective of the study is to carry out XXXX wells flowline rationalisation to avoid criss crossing of the flowlines, reduce the risks of working very close to high risk live flowlines, minimise the extensive need of CRA manifold extensions and reduce the possible restrictions for further development in future, if required.
This study would cover currently all the wells up-to 20XX (currently flowing wells as new wells).
The main objectives of the study are as follows:-

1) Flowline routing to optimise the flowline lengths.
2) Reduce demand on the space already occupied by flowlines.
3) Achieve more operational flexibility for testing through MFM's and minimise on hook-up costs.
4) Meeting the well testing frequency by installing appropriate well test meters.
5) Optimal utilisation of the available slots at manifolds by taking into account low producers that would be abandoned in future.

Use of MSV's/Remote manifolds in place of on-plot manifold extension will achieve these objectives.
The outcome of this report on flowline rationalisation would be applicable for the wells during the year 200X and beyond.

3 SCOPE

The Scope of Work for the Concept Study is based on the following:-

- Gather all necessary information as required.
- Maximum capacity utilisation of the station.
- Due consideration of the production decline from the existing wells.
- Study the various options for installation of Multi-port Selector Valves / Remote manifolds and routing of individual well flowlines to MSV's /Remote manifolds.
- Routing of Bulk header and test header to manifold
- Investigate the capital and operating costs associated with the options.

4 EXISTING ARRANGEMENTS

4.1 Existing Facilities

4.2 Well Details

4.3 On Pad Well Piping and Flowline Details

The CITHP of the wells is xxx bar(a), and FTHP ranges from xxx bar(a) to xxx bar(a).

On-pad hook-up piping(4 ½", 10000# API), ESD valve, choke valve, piping (4", 900#) from the choke valve, connected to a GRE (4",120 bar(g)) line to the existing manifold at inlet to Production Station.

The existing wells are hooked up to the manifold by individual well flowlines, shown in the sketch below:

4.4 Manifolds

Two manifolds, A-8XXXX and A-XXXX (extended manifold) exist at xxxx, providing 16 slots and no spare available slots. There are two existing MFMs. One new 4-slot manifold, A-81XX and one MFM will be added during the year 20XX.

4.5 Well fluid Properties

At the well-head, fluid temperature is in the range of xx deg C. The bubble point pressure of the fluids from these wells is typically xxx bar(g) at reservoir temperature of 90 deg C.

Following is a typical composition of the well fluid from XXXX listed in Table 4.5 below:

Component		% Mole
NITROGEN	N2	
CARBON DIOXIDE	CO2	
HYDROGEN SULFIDE	H2S	
METHANE	C1	
ETHANE	C2	
PROPANE	C3	
IBUTANE	C4	
PENTANE	C4	
IPENTANE	C5	
PENTANE	C5	
PSEUDO HEXANE	C6	
PSEUDO HEPTANE	C7	
PSEUDO OCTANE	C8	
PSEUDO NONANE	C9	
PSEUDO DECANE	C10	
PSEUDO UNDECANE	C11	
PSEUDO DODECANE	C12	
PSEUDO TRIDECANE	C13	
PSEUDO TETRADECANE	C14	
PSEUDO PENTADECANE	C15	
PSEUDO HEXADECANE	C16	
PSEUDO HEPTADECANE	C17	
PSEUDO OCTADECANE	C18	
PSEUDO NONADECANE	C19	
HEAVY END	C20+	
_CP3A*		
_CP3B*		
_CP3C*		
_CP3D*		
_CP3E*		
_CP3F*		
_CP3G*		
_CP3H*		
_CP3I*		
_CP3J*		

4.5.1 Solid Co-Production

Solid proppant is injected initially to assist in well drainage by maintaining well fracs. While most of the proppant is held in the formation, some of it is co-produced during well clean out through well test unit. There is no evidence of sand co-production so far from any of the xxxxx wells.

4.5.2 Water Production

The analysis in Table 4.5 above is on dry basis, i.e. without water. Water would be co-produced in small amount during initial phases which would be mostly recovered water (injected during well clean-out). This would cease within a few weeks or months of first production.

As the field matures, more and more wells would be drilled towards flank area, increasing the probability of water breakthrough and water co production on continuous basis. Should this occur, the impact would be more on the station side, requiring careful monitoring. No significant impact is expected on flow lines for the wells under reference.

5 DESIGN PARAMETERS

5.1 Flowline Routing

5.1.1 Flowlines length for calculations

The equivalent length of pipelines used for calculation of back-pressure on the choke valve outlet for various options are attached in Appendix-4.

The hydraulic calculations using PIPESIM were carried out for the existing wells/ new wells flowlines.

5.1.2 Design Basis

Minimum inlet pressure at xxxx	86 bar (a)
GRE line Design Pressure	120 bar (g)
Temperature at well-head tap-off point	35-55^{O}C
Flowline Installation	Buried
Off-Plot flowline	GRE
On-Plot flowlines	

5.2 Civil Considerations

- Fencing/area requirements for MSV's and associated instrumentation required.
- Relocation of existing equipments for flowline corridor development.
- Canopy shade for instruments located in field.
- Any other Civil structure.

5.3 Capex of Individual Process systems/ Elements

The installed material cost, as estimated by ---, has been used for Cost Comparison between various Options considered for this study.

Material Description	Installed cost, k US$/unit
Well pad hook-up	
7-slot Remote Manifold	
7-slot MSV	
GRE Flowlines, 4"- 120 bar(g) /km	
GRE Flowlines, 6"- 120 bar(g)/km	
Flare and vent stack, 30 m,4"	
Closed Drain Vessel, 10 m3	

6 WELL HOOK-UP STRATEGY & STUDY DRIVERS

The wells to be hooked up after year 200X require special attention in view of the following:

1) Congestion in field due to more Flowlines with longer lengths.
2) Higher hook up costs.
3) Construction Risk.
4) Bigger footprint area for Manifold in the XXXX.
5) Relocation of installed Equipment at XXXX.
6) Inadequate well testing

7 PLANNING BASIS

7.1 Key Assumptions

Assumptions and basic information are as follows:

- The new well will start producing 380 m^3/day in the first month, 200 m^3/day after 2 months and 150 m^3/day after 3 months of commencement of production. The wells would be hooked up one at a time

8 CONCEPT IDENTIFICATION

8.1 Key considerations

- **Well Location**

Since the new wells are located over a wide area, it is not possible to hook up all new wells with new MSV or new manifolds without extensive criss-crossing and excessive use of materials.

- **Manifold Slots Availability at xxxx**

14 new slots are required to hook up 14 new wells at xxxx between year 200X to 20XX.
The existing available 20 slots at manifold are part of one 10 slot manifold, another 6 slot manifold and one new four slot manifold (being executed). These are considered as occupied by 22 wells (upto year 200X).

- **Flowline Capacity**

The maximum fluid handling capacity of the flow line capacity would be based on:

- Available pressure difference
- Maximum permissible fluid velocity
- Erosion velocity

The pressure at well pad is regulated by choke valve (upstream or downstream). The minimum pressure upstream of choke valve is considered as xx bar(g) and downstream of choke valve may vary between xx bar(g) to xx bar(g).
The pressure at manifold inlet is determined by HP separator operating pressure, set at xx bar(g). The maximum manifold inlet pressure is considered as xx bar(g) to accommodate flow through MFM during well testing.
Thus the line capacity would be determined by a maximum permissible differential pressure of xx bar(g).

- **Production Gathering**

Production from each well has so far been routed to station through individual 4” line. However, several flowlines can be joined together and flow as single line to xxxx to achieve study drivers listed in section 6.0 above. The flowlines can be grouped using conventional type remote manifold or Multiport Selector Valves (Reference:-Literature from Framo). A combination of MSV’s and manifold is also considered to examine, if it leads to more savings.

- **Comparison of MSV's with Manifold**

MSV	Conventional manifold	
	Remote Manifold (In Field)	At XXXX
Seven wells can be hooked up to single MSV	Any no. of wells can be routed by designing required slots	Extension of existing manifold may not be possible. Further expansion constrained by space & pipelines. Requires relocation of existing equipment, microwave tower.
Compact dimensions- by routing of single production header and test header to manifold avoiding congestion of flowlines	Larger dimensions - Individual flow lines from each well thereby congestion and associated construction problems	Larger dimensions - Individual flow lines from each well thereby congestion and associated construction problems
Less number of valves	More number of valves	More number of valves
Lower installed cost	Higher costs	Higher costs
Instrument assisted remote operation from DCS	Manual operation (located far away from station thereby travel involved)	Manual operation, no travel involved
Single vendor	Many fabricators	Many fabricators
New draining and venting systems required in field.	New draining and venting systems required in field	New draining and venting systems not required
Maintenance issues and well testing needs to be looked into to avoid deferment in case of failure.	No known maintenance issues.	No maintenance issues.
No prior experience in operation of MSVs	Operator experienced to handle manifold operation	Operator experienced to handle manifold operation

- **Location of MSVs or Remote Manifold**

Proximity to wells and routing of the flowlines is the key consideration in fixing the location of the MSVs or Remote Manifolds.

- **Foot Print Area of Flowlines at XXXX Entrance**

To lay 14 new GRE lines, only 5.7 metres of space is available at entrance corridor against minimum 20 metres additional space required.

- **Well Testing and MFM location**

A total of three MFM's will be required for all the wells (new and existing). The two existing MFM's shall be replaced by new type and one new MFM will be installed. The MFM's for well testing can be installed in field or at xxxx.
MFM's are delicate instrument and require routine operator attention and protection from intrusion. Supervising the instruments like MFM's at remote locations is not convenient.
In the event of non-availability of a particular MFM, the piping flexibility can be provided inside XXXX.
In most likelihood, one of the existing GRE lines would be used as test header.
Above advantages far outweigh the cost of laying a new test header from MFM to Station.
Therefore, MFM installation at XXXX is preferred.
Refer Appendix-5, justifying the need of three MFMS, along with well co-ordinates. It is to be noted that the co-ordinates of new wells are tentative and may vary by ± 500 m.

8.2 Proposed Configuration for Well flowlines

Four options have been considered to hook up new wells:-

Option	Concept
1	INDIVIDUAL FLOWLINES
2A	CONVENTIONAL REMOTE MANIFOLD (existing wells hook-up)
2B	CONVENTIONAL REMOTE MANIFOLD (new wells hook-up)
3	TWO MSV's, 7 Slots
4	FIVE MSV's, 7 Slots

Option 1 – 'Individual Flowlines'

Continue to route the individual flowlines from the (new) wellheads upto the manifold in xxxx. This will lead to congestion in well flowline corridor and relocation of equipment / Radio Antenna post in the corridor.

Option 2A – 'Conventional Remote Manifold' –old/existing wells hook-up

This concept considers co-mingling of well flowlines and well testing at xxxx. It does not consider further drilling of new wells beyond 20XX.The table below shows the arrangement of Remote manifold to accommodate all the wells up-to 20XX

Well Routing to	Up-to 200X		200X-20XX	
	No. of wells	Flow Lines	No. of Wells	Flow Lines
To Remote Manifold	15	New Flow Lines	1	New Flow Line
XXXX Manifold	6	use dedicated, existing flowline	14	12 wells use Old flowlines released by other wells 2 wells use new flow lines
Total	21		15	

One new 6”-120 bar(g) bulk header and one 4”- 120 bar(g) test header would have to be provided from each of the remote manifold. The arrangement for venting and evacuation on remote site using a vacuum truck are considered necessary. Please refer Typical PEFS for Remote manifold with venting/drain arrangement attached in Appendix-3.

Option 2B – ‘Conventional Remote Manifold’ New wells hook-up

This concept considers routing of new well flowlines to Conventional remote manifold. It does not consider further drilling of new wells beyond
One new 6”-120 bar(g) bulk header and one 4”- 120 bar(g) test header would have to be provided from each of the remote manifold. The arrangement for venting and evacuation on remote site using a vacuum truck are considered necessary. Please refer Typical PEFS for Remote manifold with venting/drain arrangement attached in Appendix-3.

Option 3 – ‘Two MSVs’

This Option is similar to option 2A above, except that the remote manifold is replaced by MSV.

Option 4 – ‘Five MSVs’

This concept considers possibility of drilling of more wells beyond 201X nd therefore requires provision to accommodate new wells which are not yet firmed up. This concept would avoid hook up of more wells without having to install new remote manifold or MSV’s. The table below shows the arrangement of MSVs to accommodate all the wells up-to 20XX

Well Routing to	Up-to 200X		200X-20XX	
	No. of wells	Flow Lines	No. of Wells	Flow Lines
To MSV	16	New Flow Lines	10	New Flow Lines
xxxxx Manifold	5	use dedicated, existing flowline	5	5 wells use Old flowlines released by other wells
Total	21		15	

9 CONCEPT SELECTION

9.1 Comparison of Options

The primary difference between Option 1/2 and Option 3/4 is segregation of the old/new well flowlines to MSV's.

PARAMETERS	OPTION-1	OPTION-2A*	OPTION-3	OPTION-4
	INDIVIDUAL FLOWLINES	REMOTE MANIFOLD	2-MSVs	5-MSVs
New GRE flowlines				
No. of Joints in field (New-Old GRE flowlines)	None	30	30	20
No. of new GRE flowlines crossing old GRE flowlines	456	128	128	117
No. of locations for above crossings	35	24	24	20
No. of Road crossings for new GRE flowlines	84	49	49	112
Station corridor expansion, metres	20	6	6	6.6
Equipments to be relocated	1)Radio Antenna Post 2)Amine Storage Tank T-X	NIL	NIL	Radio Antenna Post

* Option-2B comprises of hook-up of flowlines from new wells to Remote Manifold.

** The tank is located in plant area and relocation is not easy, as it would impact other equipment and piping, requiring further study and investigations.

9.2 Selection Criteria

The criteria used to select the optimum concept are as follows:

- Minimise subsurface risk.
- Technically robust.
- Minimise initial Capex exposure
- Economically robust
- Comply with corporate HSE policy.

9.3 Selected Concept

Option-2B with “TWO REMOTE MANIFOLD’s- 7 slots” is the most suitable option due to the following:-

- MSV performance not proven for similar service (high pressure and high H_2S) in XXX elsewhere
- The number of Road crossings & “criss crossing” between existing and new flowlines is less than for Option 1 and Option 4.
- The station corridor (width) for incoming flowlines is less than in Option-1.
- No deferment issues due to loss of oil production is envisaged.

9.4 Concept Definition and Optimisation

9.4.1 Line Capacity

Qualifications:
GRE Line is from MSV to manifold at XXXX/CRA-6" Manifold piping/CRA-4" Well-pad piping.
Ambient Temperature- 60 deg C
Average Flowing Fluid Temperature -55 Deg C
The maximum flow rates for well fluids based on liquid velocity criteria are as follows:-

Flowline Material	Size	Maximum Permitted Liquid Velocity (Ref DEP 31.40.00.10 & GRE Vendor)	At Liquid Velocity of 4.0 m/s (As predicted by PIPESIM)					Flow Pattern
			At Operating Conditions			At Standard Conditions		
			Superficial Liquid Velocity	Erosion Velocity	Fluid Mean Velocity (Oil+gas)	Liquid	Associated Gas	
		** m/s	m/s	m/s	m/s	sm3/d	sm3/d	
GRE	6"							
GRE	4"							
CRA	6"							
CRA	4"							

Considering the erosion velocity, as predicted by PIPESIM, as the limit for fluid mean velocity considering two-phase flow, the maximum flow rates at Standard conditions for well fluid (Stock Tank Conditions) are as follows:

Flowline Material	Size	At Fluid mean Velocity near to Erosion Velocity (As predicted by Pipesim)					Flow Pattern
		At Operating Conditions			At Standard Conditions		
		Superficial Liquid Velocity	Erosion Velocity	Fluid Mean Velocity (Oil+gas)	Liquid	Associated Gas	
		m/s	* m/s	m/s	sm3/d	sm3/d	
GRE	6"						
GRE	4"						
CRA	6"						
CRA	4"						

10 SCOPE OF SELECTED OPTION

The two Remote manifold's will be located based on the proximity to new wells based on the co-ordinates as provided by the Reservoir Engineering group and new flowlines will be routed to individual Remote Manifold's. One 6" bulk header and one 4" Test header will be routed from each of the two remote manifold's located in the field to the manifold located at xxxx.
Venting and draining facilities are to be provided adjacent to the Remote manifold installation for maintenance purposes.

11 OVERALL ECONOMICS

The cost estimates (k US$) for each of the options are summarised in the table below: These are based on the estimates received from XXX.

		Options			
Description	**Capex**	**1**	**2A**	**3**	**4**
Well pad hook-up, for 15 wells	on Pad CRA, k US$				
7-slot 'Remote Manifold for 14 wells/ MSVs	Two Nos., k US$				
GRE Flowlines	4" & 6"- 120 bar(g), k US$				
TOTAL	**k US$**				

Note:- The cost for relocation of equipments in Option-1 and Option-4 is not included in total estimate.

The overall cost in Option 4 will be still more due to routing of new and old well flowlines to MSV's and number of road crossings.

12 PROJECT COST ESTIMATE (CURRENT SCOPE)

Out of the total scope of rationalisation project (Option-2B) including well hook-up scope till 20XX, current scope of the project comprises of installation of remote manifold along with drain/vent facilities (2 sets) and the 6" / 4" bulk/test headers from each of the remote manifold to station. Cost estimate for the current scope as worked out by XX is as below :-

Description of facilities	**CAPEX cost, kUS$**	**Cost allocated in PEEP, kUS$**
7-slot manifold & associated drain / vent facilities (2 sets)		
6" & 4" GRE headers (2 nos. per manifold)		
TOTAL		

13 RISK MANAGEMENT PLAN

Mitigation plans for all surface related risks & uncertainties are given below:

No.	Impact / Likelihood	Risks / Uncertainity	Consequence	Mitigation
1	M/M	Leaks in flanges of Remote manifolds	more maintenance, shutdown, deferment	Proper preventive maintenance and good constructability. Each of the well flowlines to manifold can be isolated to avoid disruption of total flow.
2	M/M	Cost escalation	Impact on Project Cost and schedule	Current steel price + 15-30% future mark-up considered for each item
3	M/M	Poor well field performance	No need to install Remote manifolds	Sub-surface uncertainities minimised due to extensive work

14 PROJECT EXECUTION PLAN

Contracting, Procurement & Construction Strategy

Project schedule

In order to optimise overall project schedule, FEED and DD have been shown as separate activities in the schedule. However, respective FEED & DD activities shall proceed seamlessly without waiting for a formal FEED closure. Successful FEED completion is a key success factor for the project and hence utmost care must be taken to ensure it's competition in totality within schedule duration.

This schedule will be developed further and optimised during the FEED stage of the project as the scope of work is firmed up, resources are allocated to the project, and commitments made. Specific schedules developed by the individual vendors and contractors will be summarised based on their CTR catalogues and interfaced with the overall project schedule.

It is apparent from the schedule that no new wells can be hooked up thru' the remote manifold facilities till 2000. Therefore, first 2 wells of 20XX may be hooked up to the free slots of new station manifold being installed under another project. Schedule for hook-up of further wells shall be developed based on completion of rationalisation project scope.

Design Integrity, Safety & HSE Reviews

Design integrity shall be managed by compliance with the Project Engineering Code of Practice, and through the application of the relevant design guidelines, procedures and specifications. HAZOP, IPF and Design Reviews will be conducted throughout the FEED and DD stages of this project.

The project will implement a process of Hazard and Effects Management (HEMP) throughout the design, construction and commissioning phases consistent with PDO's corporate policy. The necessary HEMP reviews studies and audits shall be integrated into the overall planning to ensure that these requirements are met.

15 FEED & DD SCOPE OF WORK

Refer to Appendix 6 for FEED SOW

16 REFERENCES

16.1 Acronyms and Abbreviations

AG	Above Ground
BFD	Basis for Design
BG	Below Ground
BS&W	Basic Sediment & Water
CA	Corrosion Allowance
CITHP	Closed In Tubing Head Pressure
CP	Cathodic protection
CS	Carbon Steel
CSR	Concept Selection Report
DCS	Distributed Control System
DD	Detailed Design
DEP	Design and Engineering Practice
ESDV	Emergency Shutdown Valve
ESD	Emergency shutdown
FBE	Fusion Bonded Epoxy
FDP	Field Development Plan
FED	Front End Design
FTHP	Flowing Tubing Head Pressure
GRE	Glass Reinforced Epoxy
HAZOP	Hazard and Operability (Study)
HIC	Hydrogen Induced Cracking
MAOP	Maximum Allowable Operating Pressure
MAIP	Maximum Allowable Incidental Pressure
MF	Manifold
MFM	Multi-Phase Flow Meter
MOC	Material of Construction
MOL	Main Oil Line
MSV	Multi-Selector Valve
NB	Nominal Bore
PE	Polyethylene
PFS	Process Flow Scheme
PEEP	Petroleum Economic Evaluation Programme
PEFS	Process Engineering Flow Scheme
PL	Pipeline
PLC	Programmable Logic Controller
RTU	Remote Telemetry Unit
RV	Relief Valve
SCADA	System Control and Data Acquisition
SSC	Sulphide Stress Cracking
TSS	Total suspended solids

17 APPENDICES

Appendix 1 - **Correspondences(Not attached)**
Appendix 2 - **Cost Estimates (Not attached)**
Appendix 3 - **Drawings**
Appendix 4 - **Inputs to Option for Concept Study (Not attached-included in synopsis)**
Appendix 5 - **Well hook-up plan and MFM availability**
Appendix 6 - **FEED & DD Scope of work (Not attached)**

Appendix 3 – Drawings

Sketch-001: Well flowlines from old wells hooked up to manifold
Sketch-002: Well flow lines from New wells hooked up to manifold
Sketch-003: Well flowlines from old/new wells hooked up to manifold (Option-1) & Plot Plan
Sketch-004: Proposed hook up of old/new wells to Remote manifold and new well flowlines to be hooked up to old well flowlines and routed to manifold (Option-2A) & Plot Plan
Sketch-005: Proposed hook up of old/new wells to MSV's and new well flowlines to be hooked up to old well flowlines and routed to manifold (Option-3) & Plot Plan
Sketch-006: Proposed hook-up of old/new wells to MSV's (Option-4) & Plot Plan

Typical Remote Manifold PEFS and Accessories
Schematic diagram for selected concept – Option 2B

Appendix 4 – Inputs to Options for Concept Study

A) Well Production flowrates
B) Well Data for Calculations and PIPESIM modelling
C) Well Production – Projected Profile
D) Additional Flowline lengths for each Option
E) Flowline Construction criteria
F) Typical Well Pad hook-up PEFS

Appendix 5 – Well Hook-up and MFM availability

OPERATING PHILOSOPHY & PROCESS CONTROL NARRATIVE

TABLE OF CONTENTS

1.0. OBJECTIVE

2.0. INTRODUCTION

3.0. OPERATING PHILOSOPHY & PROCESS CONTROL NARRATIVE

3.1. Wells/ Remote Manifold facilities / XXXX manifold operation

XXXX Wells

The wells are provided with a Surface Safety Valve (SSV) and a Surface Controlled Subsurface Safety Valve (SSSV). These valves are operated by a hydraulic panel located at the well head. The wells can be operated from the well head through well hydraulic panel thereby ensuring the safeguarding of the flow line. However, wells can also be closed from the XXXX control room.

The well head alarm and safeguarding signals for the new wells will be hooked up with XXXX control room DCS via FOC through Remote manifold IPS. The well operating parameters are transmitted to XXXX control room.

Remote manifold

There will be two remote manifolds located at two separate locations for gathering the crude from different wells. A typical remote manifold facility is as described below.

The 7-slot remote manifold is designed to facilitate hook-up of flowlines from 7 new wells to route the well fluid flow to the XXXX manifold.

The manifold will comprise the following:-

1) 6-inch Production header hooked upto bulk header.
2) 4-inch test header hooked upto test header.

All operations at the remote manifold locations are manual. The testing of wells is also manual operation. The testing is done manually by diverting (opening appropriate valves) the flow from the well required to be tested to the 4” test header.
Pressure indications are provided on Bulk and test headers, which provide pressure indications at Remote manifold location as well as at XXXX control room.

For venting of hydrocarbon from the new facilities (Remote manifolds) during routine maintenance or shutdown, no drain and vent facilities have been provided. If well flowlines and manifold are to be drained, this will be carried out by flushing via the 4-inch test header to the station manifold.

All operations at XXXX manifold are manual.

3.2. Well Capacity Control / RMF production header / test header routing to XXXX

No separate control systems are provided at Remote manifold location for control of pressure/flow from the individual wells. The wells are provided with the automated choke valves of Mokveld make for regulating the well head pressure.

The choke valve on the well flow line regulates the well head pressure, hence the downhole flowing pressure is regulated/maintained above bubble point pressure. The set points of the pressure controller will be set from XXXX control room through FOC. Set points can also be given locally through a suitable over-ride.

3.3. Well Testing at XXXX

ATTACHMENT – 1

PROCESS FLOW SCHEME

SAFEGUARDING NARRATIVE

TABLE OF CONTENTS

1.0 OBJECTIVE

2.0 INTRODUCTION

3.0 SAFEGUARDING NARRATIVE

The flowlines and manifolds are protected against overpressure through an Instrumented Protective System (IPS) located at the well pad. Each well is provided with a Surface Safety Valve (SSV) and Surface Controlled Subsurface Safety Valve (SSSV). These valves are operated by a hydraulic panel located at the well head. The SSV and SSSV are used for well tripping purpose during the shutdown. At the well head area, three panels are provided. These are well hydraulic panel, Field PAC panel and Instrument Protective System (IPS) panel. Well hydraulic panel is used for the open/close operations of SSV, SSSV and choke valve. Field PAC Panel is used for choke valve control. IPS panel is used for well and flowline safeguarding purpose.

Also an ESD valve is provided on each of the well flowline at the upstream of the choke valve for safeguarding purpose utilising the hydraulic shutdown system by IPS.

The pipeline overpressure protection is classified based on SIL-3 function which closes the SSV valve (in addition to choke valve and ESD valve) on flowline pressure high-high and closes the choke valve and ESD valve on flowline pressure high (2 transmitters- 1oo2 function).

3.1 Flowline and Remote Manifold System

CITHP of the wells is xxx bar(g). The wellhead portion up to choke valve (including choke valve) is fully rated (10000# API) for this CITHP value.
Remote manifold safeguarding logic blocks will be located in IPS at Remote manifold sites, respectively. This will be linked to XXXX DCS via FOC for transmitting Remote ESD signals from XXXX and Pressure indication / trip status signals to XXXX.
The relief valve option is not advisable in this system as the relief valve discharge should go to closed system which is not available and lead to a large sized system, if executed. Also the fluid contains high H_2S (i.e. approximately 1.5 mole %) and it is not feasible to install such type of system at each well head. Therefore, it is decided to provide Instrumented Protective System for safeguarding of the 120 bar (g) GRP flowline and CRA piping / manifold system.

The basis of the trip setting is to protect the pipeline from rupture due to overpressure.

3.2 Manifold Skid at XXXX / MFM unit

The Bulk header and test header from each of the Remote manifolds will be connected to new interface piping skid provided at the XXXX manifold located at XXXX.

3.3 Fire and H_2S gas detection / Shutdown

ATTACHMENT – 1

PSFS

To determine the maximum flow for "G" orifice for conventional carbon steel Relief valve with set-pressure of 1500 kPa(g)

REFERENCES

1 API RP-520, Seventh Edition, January 2000
2 API 526, Fifth Edition, June 2002

DESIGN INPUT DATA :

Rekief valve set-pressure =	1500	kPag
Relief valve over-pressure	10	%

Relief valve will discharge into the atmospheric drain pipe.

Flowing Temperature considered =	5	°C or	278.15	°K
Relief valve flow considered =	960	m3/day		

For an estimate, API-520 equation for liquid relief will be used to determine the size of the RV.

Calculation of the relief area

Calculating the orifice area required to pass the liquid

The following illustrates the calculation of required orifice area for capacity certified valves at 10% over pressure as given in API-520.

US Customary Units

$$A = \frac{Q}{38 K_d K_w K_c K_v} \sqrt{\frac{G}{p_1 - p_2}} \qquad (3.9)$$

SI Units

$$A = \frac{11.78 \times Q}{K_d K_w K_c K_v} \sqrt{\frac{G}{p_1 - p_2}} \qquad (3.9)$$

where

A = required effective discharge area, in.^{2} (mm^2).

Q = flow rate, U.S. gpm (liters/min).

K_d = rated coefficient of discharge that should be obtained from the valve manufacturer. For a preliminary sizing, an effective discharge coefficient can be used as follows:

= 0.65 when a pressure relief valve is installed with or without a rupture disk in combination,

= 0.62 when a pressure relief valve is not installed and sizing is for a rupture disk in accordance with 3.11.1.2.

K_w = correction factor due to back pressure. If the back pressure is atmospheric, use a value for K_w of 1.0. Balanced bellows valves in back pressure service will require the correction factor determined from Figure 31. Conventional and pilot operated valves require no special correction. See 3.3.

K_c = combination correction factor for installations with a rupture disk upstream of the pressure relief valve (see 3.11.2),

= 1.0 when a rupture disk is not installed,

= 0.9 when a rupture disk is installed in combination with a pressure relief valve and the combination does not have a published value.

K_v = correction factor due to viscosity as determined from Figure 36 or from the following equation:

$$= \left(0.9935 + \frac{2.878}{R^{0.5}} + \frac{342.75}{R^{1.5}}\right)^{-1.0}$$

G = specific gravity of the liquid at the flowing temperature referred to water at standard conditions.

p_1 = upstream relieving pressure, psig (kPag). This is the set pressure plus allowable overpressure.

p_2 = back pressure, psig (kPag).

R = Reynold's Number.

Substituting the values,

Q =	40	m3/hr
	0.0111	m3/s
	666.67	lpm

Kd =	0.65	(Relief valve is installed)
Kw =	1	(Conventional valve)
Kc =	1	(Rupture disk not installed)

For preliminary orifice sizing, Kv = 1 (Assumed)

G =	0.908	(Sp. Gr. Of crude oil)	
r =	908	kg/m3	(Density of crude oil)

p1 = Relieving Pressure = (1 + % Over-pressure/100) x the safety valve set-pressure
=(1+ 10/100) * 1500
1650 kPag

p2 = 150 kPag (Max. expected back-pressure as RV discharges to atmosphere)

Substituting the values,

Required orifice area Ari = $11.78 * 666.67 * 0.867^{0.5}$ /[$0.65 * 1 *1 * 1 * (1650\text{-}150)^{0.5}$]
(Initial guess)

Ari = 297.26 mm^2
0.461 in^2

The selected available area for carbon steel conventional valve Asi is 0.503 in^2
324.52 mm^2
3.25E-04 m^2

μ = 50.23 cp

Reynold Number R = Q x (18800 x G) / [μ x $(A)^{0.5}$]

Substituting the values,

R = 666.67 x 18800 x 0.908 / (50.23 x $324.52^{0.5}$)

12576.84

Substituting the value of R to determine Kv,

Kv = 1/(0.9935+2.878/R^0.5+342.75/R^1.5)

0.980964

Required Orifice Area Ar = Ari/Kv

=297.26 / 0.980964

303.03 mm^2

0.470 in^2

The selected available area for carbon steel conventional valve As is 0.503 in^2

(based on Table 1 in API-526) 324.52 mm^2

3.25E-04 m^2

Actual flow expected through relief valve = Q As/Ar

=40 * 0.503 / 0.470

42.84 m3/hr

1028.07 m3/day

Based on API-526, orifice for conventional safety valve is **1 1/2" G 3"**

with safety valve inlet flange rating of **150#** and

safety valve outlet flange rating of **150#**

Table 1—Standard Effective Orifice Areas and Letter Designations

Designation	Effective Orifice Area (square inches)
D	0.110
E	0.196
F	0.307
G	0.503
H	0.785
J	1.287
K	1.838
L	2.853
M	3.60
N	4.34
P	6.38
Q	11.05
R	16.0
T	26.0

1 OBJECTIVE

Sizing of PVV & Blow Hatch for Settling tank (T-XXXX) & Reclaimed fluid tank (T-XXXXX) for XXXX production stati
Following cases are to be considerec

1. Normal inbreathinç
2. Normal outbreathinç
3. Failure of blanket gas control valve
4. Fire case
5. Instrument & power failure case

2 ASSUMPTIONS

I For calculation purpose it is assumed that crude transfer pump & water + solid drain are not carried (simultaneously

II 75 PCV 612 & 75 PCV 614 are pilot operated valve & no instrument air supply is required therefore instrum power failure case is deletec

III PVV sizing is based on PCV failure case where as Blow-off Hatch is sized for fire case or PCV failure ca: whichever is higher

IV For PCV failure case line length of Blanket gas line from Battery limit to Settling / Reclaimed fluid tank assumed to be 250 meter & the same to be confirmed during detail engineerir

3 EVALUATION OF DESIGN CASES

Diameter	6.1	meter
Height	4.16	meter
Set pressure / Vacuum	1.65 / (-) 0.54	

Design pressure of the tank is 2.0 KPa (g) / (-) 0.6 Kpa (g). As per API 620 (clause 9.2.2) & API 520 the accumulat pressure at max load shall not exceed 20 % above design pressurei.e. 2.2 Kpa (g). Therefore with set pressure 1.65 Kpa (g) for PVV, accumulated pressure (with 10 % accumulation) in the tank will be 1.81 Kpa((

Therefore volume of tank	122	m3
	767.4	BBL
Tank operating temperature	26	°C

Set pressure of PVV 1.65 KPa (g) / (-) 0.56 KPa (g)

Set pressure of Blow-off Hatch 1.8 KPa (g)

Evaluation of cases

A) Normal inbreathing

Inbreathing resulting from
1. Maximum flowrate of crude oil from from tank to pump + thermal inbreathi
2 Crude oil flowrate from settling tank to Reclaimed fluid tan
3 (Water + Solid) drain.

Flowrate of drain water from settling / Reclaimed fluid tank through 4" line with 1 m/sec velocity is 28.5 m3 For calculation purpose it is considered as 40 m3/hr. Max flowrate of crude oil from settling to Reclaimed flu is 40 m3/hr as there is no control valve on line from Settling to Reclaimed fluid tank. Pump out rate is 40 m3. For calculation purpose it is assume that crude transfer pump & water +solid drain are not carried (Simultaneously. However crude transfer pump can withdraw crude oil from one tank & water +solid drain fr other tank can be carried out simultaneousl

Pump out rate 40 Nm3/hr
Therefore inbreathing requirements for operating the pumps is equivalent to 0.94 nm3/hr of air for ea cubic meter of liquid withdrawn. However for calculation purpose it is considered to be 1 m3/hr of air each cubic meter of liquid withdrawn. (Refer API 2000 clause 4.3.2.
Therefore amount of inbreathing a 40 Nm3/hr

Inbreathing resulting from thermal expension / contraction is calculated as per API 20

As per table 2B for 122 m3 of tank capacity thermal inbreathing is 20.6 Nm3/hr

Therefore normal inbreathing rate is 40 + 20.6 = 60.6 Nm3/hr = 64.1 sm3/hr = 1538.4 sm3 / day.

B) Normal Outbreathing

Normal outbreathing will result from maximum flowrate of liquid from road tanker into the tar

Tanker unloading rate 40 m3/hr

Therefore outbreathing requirement due to flow of liquid into the tank is 2.02 m3/hr of air per cubic liquid inflow. (Refer API 2000 clause 4.3.2.2

Therefore total air flowrate from tank during outbreathing is 40 x 2.02 = 81 m3/l

Outbreathing resulting from thermal expension / contraction is calculated as per API 20

As per table 2B for 122 m3 of tank capacity thermal outbreathing is 20.6 m3/

Therefore normal outbreathing rate is 81 + 20.6 = 101.6 Nm3/hr = 107.4 sm3/hr = 2577.6 sm3/da

C) Failure of Blanket gas control valve

Battery limit pressure of Blanket gas is 3.51 bar a. This pressure is reduced by using self actuated control val

Pressure drop across self actuated control valve = 2.4 ba

Refer for inlet gas line size

Failure of PCV will cause higher gas flowrate through PVV. Considering sonic velocity through 2" line provic upstream of PCV, maximum flowrate through PVV is 1000 kg / hr. (Refer ESI output, attachment

For estimating the flowrate equivalent length is considered as 250 meter from tie inpoint inside battery l of suwaihat Production ststion.**The same shall be confirmed during detail engineering**

Density = 1 x 18.94 ÷ (0.08206 x 288.6

= 0.7997 kg / sm3

Vol flowrate = 1251.0 sm3 / hr.

Refer Hysis output for viscosity calculation & ESI output for flowrate at sonic velocity (attachment

With 25 % margin on flowrates

Vol flowrate = 1565.0 sm3 / hr.

PCV failure can occure during normal outbreathing also. Therefore outbreathing during PCV failure case

Normal outbreathing + PCV failure case = 1565 + 108 = 1673 sm3 / l

D) FIRE CASE

Set pressure of blow-off Hatch = 1.8 KPa (g). Therefore for fire case with 21 % accumulation, maximum pressu in the tank is 1.8 x 1.21= 2.18 KPa (g) which is less the 2.2 KPa (g

Flowrate through PVV during fire case is calculated as follows

Q = 199300 x F x A^0.566

Surface area of tank A = 3.142 x 6.1 x 4.16

= 79.73 m²

Q = 224200 x 1 x 79.8^0.566

Q = 2674.05 KWatts

As latent heat of vapourization for crude oil = 849.2 Kj / Kg. (refer attachment 2 stream No 43). Theref

L = 849.2 KJ / Kg

T = 34.1°C

T = 307.1°K

M = 26.06 (Refer Hysis output attachment 2

Therefore flowrate through blow-off hatc

Nm3 / hr = 881.55 x (QF÷L) x (T÷M)^0.5

= 881.55 x (2674.05 x 1 ÷ 849.4) x (307.1 ÷ 26.06)^0.5

= 9526.92 Nm3/hr

With 25 % margin on flowrates

= 11908.6 Nm3/hr

= 12000 sm3/hr