

Chapter 2

Project Description

2.1 Project Background

The RJ-ON-90/1 Production Sharing Contract was executed between the Government of India, ONGC and Shell India Production and Development (SIPD) on 15th May 1995. The Contract Area covered was approximately 11,108km². CEIL farmed into the block in three stages, initially taking a 10% interest from SIPD in 1997 and increasing that interest to 50% in further stages in 1998 and 1999. In 2003 Cairn Energy Hydrocarbons Ltd (CEHL) acquired SIPD's equity in the block and the Contractor under the PSC is now constituted of ONGC, CEIL and CEHL. CEIL and CEHL are wholly owned subsidiaries of Cairn Energy PLC. The Government of India (GoI) extended the Exploration Period for a period of three years, from 15th May 2002 to 14th May 2005. Following the relinquishments at the end of PSC Exploration Phases I, II and III the Contract Area comprised of 4970 km². The Government Of India (GoI) – Ministry of Petroleum & Gas (MoPG) accorded approval in July 2004 for the extension of the Phase-III block retention area by 852 km² to carry out exploratory drilling to the north of the N-C oil discovery well. Thus the current total area of the block is about 5820 km².

CEIL participated with Shell in the drilling of the onshore Guda-1 and Guda-2 wells, in the block in early 1999 resulting in the successful Guda-2 oil discovery. In

November 2001, CEIL made a second oil discovery on the block with an exploration well on Prospect-H (Saraswati) located towards the basin flank. In February 2003, CEIL announced discovery of oil and gas from the exploratory well drilled in the Prospect-E, near village Nagarka in Barmer district and now called the “Raageswari Field”. This was followed by the discovery of the Kaameshwari field and the GR-F field.

CEIL has drilled about 40 exploratory and appraisal wells in the block and has carried out extensive 2D (over 6000 line km) & 3D (over 1000 km²) seismic surveys to identify leads and prospects, explore and delineate the extent of the various hydrocarbon reserves of the hydrocarbon discoveries and to better understand the intricacies of the complex structures within the discovered fields in the RJ-ON-90/1 block so as to provide adequate information to prepare an appropriate hydrocarbon production development plan.

2.2 Recent Development

CEIL persistence and aggressive exploration policy yielded phenomenal success when from the beginning of 2004 significant hydrocarbon discoveries have been made in the northern portion of the block. A discovery was made in the N-B prospect (Mangala Field) near village Jogassaria, (Baytoo tehsil) in early January 2004. This was followed by the find in the N-A prospect (Aishwariya Field) near village Kawas, (Baytoo tehsil) in March 2004, discovery in the N-C prospect (Shakti Field) near village Jhetaniyon-Ki-Dhani (Barmer tehsil) and the most recent one the hydrocarbon discovery in the N-V prospect (Bhagyam Field) near village Bothia (Barmer tehsil). The appraisals of the Mangala & the Aishwariya field have been substantially completed while the appraisals of the Shakti & Bhagyam fields are in progress.

2.3 Estimated Oil Reserves in the Area

The initial estimate of oil reserve of the Mangala discovery is in the range of 450 – 1100 million barrels and N-A is in the range of 130 – 470 million barrels. The recoverable reserves are estimated to be 120 – 335 million barrels for the Mangala field and 20 – 80 million barrels for the Aishwariya field. These figures have been independently assessed by the international experts *DeGolyer and MacNaughton*.

The southern fields are much smaller in terms of the estimated reserves. The oil reserves estimated for Saraswati & Raageswari field are approximately 6.5 million barrels and 3.9 million barrels respectively.

Recent discoveries such as the Shakti & Bhagyam are yet to be appraised, however based on the results of the ongoing seismic and exploratory drilling program, it is

reasonable to assume that the cumulative oil reserves in the RJ-ON-90/1 block as a whole is expected to be substantial and the discoveries are seen to be commercially viable for further development. The discoveries to date has the potential to augment by upto 10% India's current hydrocarbon production volume and thereby substantially contribute to the energy demand of the country.

2.4 Overview of Proposed Hydrocarbon Development Project

This project proposal addresses the **development of five fields** viz. Mangala and Aishwariya oil fields in the Northern Zone of the block, Saraswati and Raageshwari oil fields and Raageshwari gas field in Central Zone of the block. All the above fields are located in the Barmer district, Rajasthan. The overall map of the RJ-ON-90/1 block showing the discovered fields is given in **Fig. 2.1**.

CEIL proposes to develop all the above fields concurrently and the projects are expected to be completed by October 2007. It is likely that some of the smaller fields may be targeted for early production and may start commercial production before the completion of the larger field development.

The development of the block can be done in many ways. The various options for development are dictated by the variation in the quality of oil & its treatment requirements, logistics & infrastructure requirements, in-field constraints etc. Briefly, the development concept will be to have single or multi well pads, from where the well fluid flow lines will be connected to a common flow line. The well fluid will be routed to one or more Group Gathering Stations (GGS) where the crude will be processed. The well fluid which is a combination of oil, produced water and natural gas will be phase separated and the stabilized crude oil from Central Processing Facility (CPF) will be sent to the crude storage facility known as Central Tank Farm (CTF). The formation water will be treated and re-injected into the oil reservoir strata to aid in maintaining the reservoir pressure to ensure enhanced oil recovery by water polymer flooding. The natural gas will be compressed and utilised for meeting the energy requirements for process heating, power generation and for gas lift of the well fluid. The processed oil is stored in tank farm and transfer of custody to the buyer is done at the outlet flange of the tank farm / metering device. The Government of India has nominated Indian Oil Corporation Limited (IOCL) as the buyer and the processed crude will be sold to the buyer at the outlet flange of the CTF/ Crude oil storage tanks as applicable. The crude oil from the Raageshwari / Saraswati fields may also be transported to the CTF in the Mangala field through tankers so as to enable transfer of custody to IOCL from one central location.

The Mangala & Aishwariya fields will have a dedicated central Captive Power Plant (CPP) to cater to the power requirements for operation of the fields. The CPP would be fuelled either by crude oil and / or natural gas. The natural gas for the CPP operation will be supplied through a dedicated gas pipeline from the Raageswari gas field located in the southern portion of the block. The power plant would be rated for a 50 MW of electrical power generation. Power will be distributed either through a network of transmission towers or underground cables or a combination thereof.

The Mangala & Aishwariya field reservoirs would require maintenance of pressure to achieve enhanced crude recovery with water injection. The injection water would essentially be required to replace the volume of oil removed. This injection water will be sourced mainly from the produced water separated from crude and the balance makeup requirement will be met from a near by saline groundwater deep aquifer. A large saline groundwater aquifer (well-field) has been identified to source the supply of makeup water. The saline well field will supply upto 25,000 m³ /day of saline water through a network of abstraction well and pipeline network. The aquifer water will be commingled with the treated produced water, prior to desalination in a dedicated desalination plant (Reverse Osmosis (RO) plant). It will be desalinated prior to injection in the formation. There will be about 15,000 – 18,000 m³/day of RO reject water produced which will be routed through pipeline for injection below the deep underground hydrocarbon formation to assist in reservoir pressure support. This will be done through deep injection dump wells located in the identified injection well field.

Interconnecting pipelines will connect the well pads and the processing facilities within the various hydrocarbon fields. There will also be interconnecting pipeline from the southern field to the northern field and a dedicated gas pipeline from the gas field in the south to the facilities in the north. Similarly there will be crude oil / natural gas pipeline feeding the captive power plant. In addition to the above there will be pipelines from the saline water well field to the Mangala CPF and RO reject stream pipeline from the Mangala CPF to the injection field.

The field and the surface facilities will be interconnected by suitable roads and pipeline corridors for operational flexibility. The surface facilities will be installed as per applicable codes & standards, international practices and applicable local regulations.

2.5 Location Details

It is proposed to develop the following five fields in the block:

Zone	Field Name	Tehsil	District
Northern	Mangala	Baytoo & Barmer	Barmer
	N-A	Baytoo	Barmer
Central	Saraswati	Gudha Malani	Barmer
	Raageswari	Gudha Malani	Barmer
	Raageswari Gas	Gudha Malani	Barmer

2.5.1 Mangala Field

The locations of Well Pads, GGS, CPF and CTF are shown in **Figs 2.2 & 2.3**. In the Oil & Gas Development, the exact locations can only be finalised and refined based on the on-going sub-surface investigation and the test results of the exploratory and appraisal program. Hence their locations are tentative, till the sub-surface investigations are substantially completed. **It is therefore expected that the final Well Pad locations may be within 1 km radius of the location shown in the maps and the final locations of GGS, CPF and CTF may be within 500 m radius of the given location.** There are eight (8) alternative locations shown for 4 Nos. GGS proposed and the final location will be any of the four out of 8 locations. Similarly two (2) alternative locations are shown in the layouts for one CPF and one CTF. The final location of CPF and CTF will be any one of the two.

2.5.2 Aishwariya Field

The locations of Well Pads, & GGS are shown in **Figs 2.4 & 2.5**. The Aishwariya Field will share the common facility of CPF & CTF with the Mangala Field. **As explained earlier the final Well Pad locations may be within 1 km radius of the location shown in the maps and the final locations of GGS may be within 500 m radius of the given location.** The Aishwariya field will have upto 8 well pads and the GGS will be placed within the vicinity (located with-in radius of 1-3 km) of Well Pads. Group of Well Pads will be connected to the nearest GGS. Two locations out of the four GGS locations proposed will be finally selected for the development.

2.5.3 Saraswati Field

The locations of Well Pads, & GGS are shown in **Figs. 2.6 & 2.7**. The Saraswati & Raageswari field will share a common GGS & CTF. The Saraswati field will have upto four (4) well pads and one (1) GGS. One out of the two GGS locations proposed will be finally selected for the development. **As explained earlier the final Well Pad locations may**

be within 1 km radius of the location shown in the maps and the final locations of GGS may be within 500 m radius of the given location.

2.5.4 Raageswari Field

The locations of Well Pads are shown in **Fig. 2.8**. The Saraswati & Raageswari oil field will share a common GGS & CTF. The Raageswari oil field will have upto six (6) well pads. **As explained earlier the final Well Pad locations may be within 1 km radius of the location shown in the maps.**

2.5.5 Raageswari Gas Field

The Raageswari gas field is an integral part of the Raageswari oil field. The locations of Well Pads & GGS are shown in **Fig. 2.8**. The Raageswari gas field will have upto two well pads. The Gas Collection & Processing Facility will be located at the Raageswari oil well pad location WP2. **As explained earlier the final Well Pad locations may be within 1 km radius of the location shown in the figure.**

2.5.6 Captive Power Plant

The captive power plant is located approx. 5 km west of the proposed CPF1 / CTF location proposed for the Mangala field development. This has been necessitated due to consideration of locating the power plant stacks away from the flight path of air force station operations. The proposed location is in *Bandra* village and is shown in **Fig. 2.9** and the tentative location coordinates are Longitude 71° 32' 06.68" and Latitude 25° 56' 02.93". **The exact location may undergo minor change due to technical and other considerations after the completion of the detailed engineering.**

2.5.7 Saline Water Well Field

The Mangala & Aishwariya hydrocarbon reservoir conditions require **pressure support** to achieve optimum exploitation of the reservoir. This is proposed to be achieved by a combination of water polymer flooding and saline water injection to maintain the reservoir pressure. The project proposes to set up a saline water abstraction well field near the village *Madpura Barwala* about 20 km south west of the Mangala CPF. The well field will consist of a network of 24 bore-wells of approximate depth 300 – 500 m, at a minimum spacing of 1 km. The locations of bore-wells and the interconnecting piping are shown in **Fig. 2.10**. The depth and location are tentative and the actual bore-well location may be within 1 km radius of the given location.

2.5.8 Saline Water Injection Well Field

Due to the stringent requirement of quality in the injection water to enable effective polymer flooding, it is proposed to set up a desalination plant (Reverse Osmosis Technology) at the CPF. The desalination plant will desalinate the produced water and the make-up saline water and in the process it is envisaged that about 15,000 – 18,000 m³/day (25 – 30 % input water volume) of high salinity reject water stream will be generated. This reject water will be piped to an injection well field for disposal below the hydrocarbon formation (>. 1500 m deep). This will be done through upto six (6) deep injection dump wells. The location of the injection field (Wastewater Disposal Facility) is shown in **Figs. 2.11 to 2.12.**

2.5.9 Interconnecting Pipeline Corridor

There will be number of pipelines connecting Well Pads, GGS, CPF, CTF and CPP for carrying well fluids, produced water, gas, stabilised oil, injection water, lift gas, hot oil, fuel gas, etc. The pipelines will be buried and generally laid alongside the roads connecting the facilities, as given in the layout maps.

CEIL commissioned SECONS Surveys Pvt Ltd to carry out a reconnaissance survey to determine the suitability of the proposed pipeline corridor, identify important features such as rail and road crossing, and modify the proposed routing based on existing physical and social features. The pipeline corridor generally traverses open arid land, which are largely cultivated only during the rainy season (*Kharif*). The proposed pipeline corridor routing is shown in the respective field development maps. The total length of the various pipeline corridors will be about 300 km.

2.6 Hydrocarbon Production – Facilities Description & Operational Details

It is proposed to develop under this project hydrocarbon development plan four oil fields and one gas field in the block. The total crude oil production capacity from the four fields will be upto 128,000 barrels of oil per day and 30 million standard cubic feet per day of associated gas. Additionally the Raageswari gas field will be developed to supply natural gas to meet the energy demands of the northern field (Mangala & Aishwariya fields) and will be designed to produce and process 20 MMSCFD.

While the general unit processes are similar in all the scenarios, the differences or variations mainly revolve around grouping of and location of some of these facilities and the type of equipment and production capacities.

The overall hydrocarbon production facilities proposed under this project will broadly consist of the following elements / operations:

- Hydrocarbon Production & Water Injection wells
- Mangala field oil production facilities (Well pads, GGS, CPF & CTF)
- Aishwariya field oil production facilities (Well pads & GGS)
- Saraswati & Raageswari field oil production facilities (Well heads & GGS)
- Raageswari Gas field production facilities (Well pads, Gas processing and transfer)
- Facilities for processing associated gas and lift gas
- Central Captive Power Plant of 50 MW capacity in the northern block
- Saline water well field facilities to supply 25,000 m³/day of saline groundwater
- Injection (Dump) wells for rejected saline water from Reverse Osmosis desalination Plant
- In-field hydrocarbon pipeline
- Infrastructure facilities required for the development project

The details of each of the above elements / operations are described below.

2.6.1 Drilling - Production & Injection Wells

The overall development plan envisages the drilling of a total of 568 wells comprising of 303 hydrocarbon production wells, 235 injection wells, 24 saline water borewells for the abstraction of saline water and 6 injection (dump) wells for the disposal for rejected saline water from Reverse Osmosis desalination Plant.

CEIL has drilled several exploratory and appraisal wells in the various hydrocarbon field location in the RJ-ON-90/1 block as part of the exploratory and appraisal program. These exploratory and appraisal wells may also be converted into production or injection wells. The wells so converted will be in addition to the total wells stated above.

The development plan conceives multi-pad drilling, which enables several wells to be drilled from a single drilling pad location. The maximum well depths (hydrocarbon target zones) in the northern zone would be around 1500-2000 m. The well depths progressively increases towards the central zone – Saraswati field wells would be around

2000 – 2500 m in depth and the Raageswari wells would be in the range of 3000 – 4000 m total depth. Several wells will be drilled either vertical or deviated from a single well pad location. Slim hole well designs will be adopted where appropriate depending on the deviation and individual technical considerations. **Table 2.1** shows the details of the number of well pads, production and injection wells per pad and the total estimated number of wells required for the exploitation of each individual field.

The well pad arrangements and operations are similar for Mangala, Aishwariya, Saraswati & Raageswari oil fields, except that the equipment sizing and internal arrangements would be to suit individual field crude quality and production capacity.

2.6.1.1 Drill Site Preparation

The site preparation involves land acquisition and clearance prior to civil works. The site needs to be graded and suitably elevated above the local flood level. Suitable foundations will be constructed to hold the heavy drilling rig equipment. Water, drilling mud and pits and cuttings storage pits etc will be prepared before the rig is mobilized. Septic tanks and soak pits will be provided to dispose off the domestic wastewater at the drill site. Prior to rig mobilization, the adequacy and strength of approach will be checked and wherever required they will be widened and strengthened.

2.6.1.2 Rig Mobilization

The rig mobilization and assembling stage invite deployment of several trucks, heavy lifting and earth moving equipment in addition to deployment of manpower.

Land based detachable modular rigs will be used for drilling on land. The rig can be detached into individual components and road transported to the location and assembled. The mobilization of the drill site involves transportation of drilling rig in modules and erected by means of mobile cranes. The drill site equipments are designed as modular / skid mounted type, which facilitates quick demobilization and remobilization. The installation of the drill site equipment / facilities involves about 80 trailer loads spread over 10 days. Once the site is prepared, drilling equipment, supplies and drilling personnel will be mobilized and the drilling rig will be erected and the statutory licenses obtained.

2.6.1.3 Drilling Operation

The drilling process involves drilling of the well hole across various ground layers to a predetermined depth. CEIL proposes to use mobile land drilling rigs to achieve the above desired objective. Drilling operations would commence after getting necessary clearances from the MoEF & RSPCB for the project and well in advance to the completion of the

production facilities. The drilling operation would commence at the various individual field locations with multiple rigs operating concurrently and would also involves simultaneous data logging of the stratigraphy and carrying out well tests and test flaring. Typically the drilling of a well would take 15-30 days depending on the target depth and the type of rig deployed.

Well spudding is the start of drilling activity. Top-hole section will be drilled to a desired depth based on well design. After drilling top-hole section, it will be cased with a pipe called "Casing". "Casing" provides support to hole wall and secures hole section. Other than that it isolates problematic hole sections such as loss zones, shale sections, over pressurized formations etc. After running casing, space between hole wall and "Casing" (annulus) will be cemented. This process of drilling and casing the hole section continues until the final well depth (target) is achieved.

While drilling, if the formation pressure exceeds the hydrostatic pressure exerted by the drilling fluid, formation fluids break out in to the well bore. This is called kick. Primary means of well control is to have sufficient over-balance over formation pressure. For some reason if an unexpected over-pressurized formation is encountered while drilling and if the well control situation arises, rig is equipped with equipment to control this situation. These are set of equipments is called "Blowout Preventers" Blowout Preventer consists of, "Annular Preventer" (closes the annular space between drill string and casing) and or "Ram Preventer" (Pipe Rams or Shear Rams). The preventers are stacked in a sequence and this assembly of preventers is termed as "BOP Stack". Blowout prevention equipment will be installed, tested and operated according to the Well Control Manual for Drilling Operations. The BOP stack in use will be pressure tested initially before drilling out of the casing shoe and thereafter weekly.

2.6.1.4 Testing Operations

At the end of the drilling of the production wells will be tested for various parameters including flowing the wells for an extended period. The crude oil from the testing operations will either be flared (over several days) or disposed to nominated buyer / recycler. CEIL will obtain necessary approval from the applicable regulatory organisation in case of offsite disposal.

Crude oil test flaring facilities will be provided at the production well drilling locations for burning of hydrocarbons during testing. The test flare pit will be located within the drill site location with adequate safety distance considerations. The residual oily wastes if any after completion of testing phase will be totally removed and sent to the authorized waste

disposal site or oil handling installations for resource conservation.

The setting out of the flare pit will be done in a manner to direct the flame away from any pockets of cultivation / existing green cover. In case unavoidable firewall will be erected to prevent any scorching of the vegetation.

2.6.1.5 Well Suspension

After completing the well drilling and well completion, the wells will be capped and closed with fencing around it to prevent unauthorized man entry or stray entry of cattle.

2.6.1.6 Drilling Mud

Drilling of wells require specially formulated muds which basically comprises of inert earth materials like bentonite, barite in water with several additives to give fluidity and filter cake characteristics while drilling. The drilling muds have several functions like lubrication and cooling of the drill bit, bring out the drill cuttings from the well bore, thixotropic property to hold cuttings during non-operations, formation of thin cake to prevent liquid loss along well bore etc. Several additives are mixed into the mud system to give the required properties. Water based and synthetic based mud systems will be used in this project.

The drilling mud is circulated during the drilling process and between the drilling of subsequent wells. In the case of WBM some spent drilling mud will be generated which will be stored in lined pits. In the case of SBM almost no spent mud will be generated as the entire SBM is re-circulated in the drilling of several wells.

2.6.1.7 Resources & Utilities for Drilling Operations

2.6.1.7.1 Water

The water requirement in a drilling rig is mainly meant for preparation of drilling mud apart from washings and domestic use. While the former consumes the majority of water requirement, the water requirement for domestic and wash use is very less. Based on land rig drilling experience, the daily water consumption will be in the range of 40 to 50 m³/day. The water will be procured through water tankers from registered water suppliers. Saline water wherever appropriate will be used since it is also suitable for drilling mud preparation.

2.6.1.7.2 Power

The drilling process requires movement of drill bit through the draw works which require power. Power requirement for drilling operations would be through modular/mobile DG sets. The combined power requirement during active drilling would be approximately 3000 - 3500 KVA with a diesel consumption of 6-7 KL/day. The individual DG sets will have a capacity of approximately 500 - 1000 KVA. Typically there will be 3-4 DG in operation and 1-2 DG sets as standby per drilling rig. The lean power requirement is about 500 KVA for meeting utility requirements on the rig. The exhaust stacks of the DG sets of land based rigs vent the emissions at an approximate height of 5-6 m from the ground level. The DG sets are enclosed in acoustic control enclosures.

2.6.1.8 Drilling Site Facilities

2.6.1.8.1 Camp Site

In remote operating areas where there is no acceptable local accommodation, it is necessary to provide camp facilities to house operations staff, crew and other contractor personnel. Mobile campsite will be set up on temporary leased land. Typically for each drilling campaign (consisting of drilling of several wells) a temporary campsite will be set up. The approximate area requirement will be about 1 Ha (10,000 m².)

The campsite will provide accommodation to all operational crew and the contractor personnel. At any point of time, it is anticipated that about 90 personnel will be housed in the campsite during the production well drilling campaign. The site will be self-contained with the captive power supply and water treatment and sewage treatment system. Toilet facilities are in build as part of the accommodation unit. The sewage lines from the units are connected through a pipeline system to a septic tank and soak pit system. Food and other organic waste will be subjected to bio-degradation through organic composting and / or vermi-composting.

2.6.1.8.2 Drill Site

Drill site construction would typically involve the construction of impermeable layer lined pits for the temporary storage of drilling fluid, drill cuttings, water storage, foundations for the drilling rig and accessories, inter-connecting drains, paved secure storage provision for chemical, HSD, lubricating oil and waste oil, drill site office and communication facilities and a sewage treatment system (septic tank and soak away pits and piping) for disposal of the domestic waste. A ground level flare arrangement comprising of a recessed concrete flare pit would be constructed to flare any hydrocarbons during well testing. The approximate area required for the drill site would be approximately 20,000 m².

2.6.2 Mangala Field Development

The general facility details for the Mangala field development are described in this section.

The proposed Mangala oil development facility in the block would be adequately sized and infrastructure provided to produce upto 100,000 barrels of oil per day (~ 13,500 T of crude oil). As described earlier the development plan consists of developing well-head facilities to extract the well fluid from the sub-surface reservoir, and processing the well fluid to separate the crude oil, produce water and associated gas phases at the GGS. The crude oil will be routed through pipeline to the crude storage tanks at the CTF.

The produced water will be routed to the produce water treatment plant located in the Central Processing Facility (CPF) for pretreatment, primarily oil removal and then commingling with saline water abstracted from the saline water well field and treated at the injection water pretreatment plant and subsequently in a desalination unit. Finally it would be re-injected back into the hydrocarbon reservoir through injection wells located at the well-pads. The reject stream from the desalination unit will be injected below the oil-water-contact through deep dump wells.

The associated gas will be treated for Carbon dioxide (CO₂) removal, gas dehydrated and compressed and piped to CPF. A minimal amount of gas from the low pressure separator would need to be flared. The associated gas generation is expected to be only 17 million standard cubic feet per day due to the low GoR (Gas Oil Ratio) of the Mangala crude. The associate gas will be used to augment the gas requirement for heating, power generation and lift gas purposes.

The transfer of custody of the produced crude to the Government of India nominated buyer will be done at the outlet flange of the CTF. It is also envisaged that due to the waxy, high pour point characteristic of the crude mixing suitable diluent (naphtha / diesel) with the crude before pumping may be required.

The nature of the reservoir crude and the reservoir characteristics require reservoir pressure maintenance and artificial lifting of the crude for optimal crude recovery. Three options have been considered for lifting of crude from the reservoir, they are as follows:

1. Water injection
2. Water injection using surfactant (soaps) and polymers additives
3. Gas lift

Each of these schemes is briefly described below.

Water Injection: The Mangala & Aishwariya field reservoirs would require maintenance of pressure to achieve enhanced crude recovery with water injection. The injection water would essentially be required to replace the volume of oil removed.

Water injection using surfactant (soaps) and polymers additives: Both additives are biodegradable. These additions have the large potential to raise the recovery from the combined Mangala and Aishwariya fields by a further 5-20% of the oil in place. Techniques such as these are already applied world-wide in countries such as Canada, USA and Brazil and also in India, in oilfields located in Assam and Gujarat States.

Gas Lift: It has been found to be beneficial to use gas lift of well fluid from the reservoir. In order to facilitate this artificial lifting, it is estimated that around 100 MMSCFD lift gas is required with a Gas to Liquid Ratio (GLR) of 300 scf/bbl. This gas along with the associated gas will be recovered in the GGS and transported to CPF, Where it will be compressed from 60 psig to 750 psig (minimum) before being sent back to the wellheads for gas lift.

The proposed Mangala field development plan is given in **Table 2.2**. The Mangala Field Architecture is given in **Fig. 2.14**. The Mangala field development facilities would broadly consist of the following facilities:

- Upto Fifteen (15) Well Pads with each well pad connected to upto thirteen (13) production wells and thirteen (13) injection wells;
- Upto Four (4) Group Gathering Stations each capable of producing upto 25,000 barrels of oil per day (~ 3,380 T per day) with following main processing units:
 - Oil/Gas/Water HP-Separator (3 phase separator)
 - Two Stage Oil Dehydrators/ Desalters
 - Degassing facility of produce water and pumping system
 - LP Separator
 - Oil upgradation unit (such as visbreaker unit for greater flow assurance of the waxy crude)
 - Oil Buffer Storage and Pumping station

- CO₂ Removal System
- Gas Dehydration System
- Associated Gas Compressor Package
- Chemical Injection Package
- Utilities Systems
- Electrical & Instrumentation System
- Communication System
- Fire Fighting Systems
- Material & Waste Storage facilities
- Administrative office
- One common Central Processing Facility (CPF) for Mangala & Aishwariya field development capable of treating 380,000 barrels of water for re-injection and lift gas compression of upto 100 MMSCFD. The CPF will contain the following facilities:
 - Produced water storage & treatment system
 - Raw water receipt/storage
 - Injection water treatment and desalination plant
 - Storage of desalinated injection water and injection pumping
 - Potable water generation systems
 - Lift Gas Compressor Package
 - Utilities Systems
 - Electrical & Instrumentation System
 - Communication System
 - Fire Fighting Systems
 - Material & Waste Storage Facilities
 - Secure Landfill Facilities

- Incinerator
- Helipad
- Administrative office
- One common Central Tank Farm (CTF) for Mangala & N-A field development with crude oil storage capacity of 706,680 barrels of crude oil and 588,400 barrels of diluent (naphtha, diesel or equivalent) storage. The CTF may be integrated as part of the CPF and will contain the following facilities:
 - Crude oil storage tanks
 - Diluent Storage tanks
 - Crude & Diluent booster / export pumps
 - Custody transfer meter & transfer to export pipeline
 - Custody transfer meter and road tanker loading / unloading system
 - Fire Fighting System

The well pad arrangements and operations, crude processing, gas compression and conditioning, lift gas compression and operations of utility systems are similar for Mangala, Aishwariya, Saraswati & Raageswari oil fields, except that the equipment sizing would be varied and minor process modifications done to suit the individual field crude quality and production capacity. The main process operations are described below. **The details for the other oil fields would be similar and hence has not been separately discussed.**

The **Rajasthan Field development Project Report** provides further technical details on the individual equipment sizing, operating conditions and the process flow diagram.

2.6.2.1 Well Pads & Well Head Facilities

2.6.2.1.1 Well Pads

The well pad basically comprise of Christmas tree with flow lines with suitable piping and valves. The well pads could be single or multi well pads. Multi well pads would comprise of many well heads at one location and the flow lines from each well head will be brought to a common manifold before flowing to treatment facility. As the pressures from different wells could be at different levels, artificial lift pumps / lift gas shall be used for pumping well fluid to surface facilities.

2.6.2.1.2 Artificial Lift

The wells which do not self flow would require alternative recovery methods to lift the oil. Considering the quality of oil, artificial lift is expected to be required in the Mangala development area from the beginning of field life. The artificial lift can be achieved through the use of Sucker Rod Pumps, Electrically Submersible Pumps, Progressive Cavity Pumps or Gas Lift. Some or all of these are expected to be deployed in this field development. It is estimated around 100 MMSCFD of lift gas would be required to work the Mangala & Aishwariya field. This lift gas along with the associated gas will be recovered in the GGS and transported to CPF, where it will be compressed from 60 psig to 750 psig (minimum) before being sent back to the well-heads for gas lift. Thus the lift gas will essentially be in a closed loop circulation.

2.6.2.1.3 Well Fluid Heat Exchangers

The well fluid temperature at the down stream of choke is estimated at 47°C. The fluid would need to be heated to ensure fluid flow to the GGS. Shell and Tube type hot oil heat exchanger will be installed in the well head facility to heat the well fluid to 80°C. The hot oil system (thermic fluid) will be installed at the GGS and circulated through a closed loop system. As an alternative, an option for electric heater could also be deployed.

2.6.2.1.4 Chemical Injection Skid

A skid mounted chemical injection package unit will be provided for injection of pour point dispersant chemicals. This is done to prevent the well fluid to clog within the pipeline and maintain good flow characteristics. The skid mounted system will have facility for pour point chemical storage and dispensing. The system would consist of PPD tank, PPD dosing pump, demulsifier storage and dosing system, corrosion inhibitor storage and dosing system, scale inhibitor storage and dosing system and any other chemicals required for field operations.

2.6.2.1.5 Well Fluid Pipelines

The well fluid will be transported to the GGS through buried carbon steel pipeline. The pipeline diameter would vary from 3-inch to 6-inch depending on the duty conditions. Pipelines for transport of well fluid, lift gas, injection water and hot oil circulation will be laid within the pipeline corridor connecting to the GGS. The consolidated details of pipeline is given in section 2.6.8.

2.6.2.2 Group Gathering Station

The Group Gathering Stations are meant for Oil/Gas/Water separation, Oil treatment and stabilisation and associated gas treatment and compression. The key sub systems are briefly explained below. Typical layout of Group Gathering Station is shown in Fig. 2.15.

2.6.2.2.1 Oil/Gas/Water HP Separator (3-Phase Separator)

The heated Well fluids (70 °C) enter the HP-Stage separators for initial separation of Oil, Gas and Water. The separator is a spill over weir type three-phase separator and operates at 150# pressure rating. It consists of a horizontal carbon steel vessel where gravity separation of the gas, oil and water phase occurs. Provision for nitrogen blanking is provided. The separated crude is routed to the electrostatic dehydrator for further processing. The associated gas flows to the CO₂ removal system. The produce water is sent for produce water treatment via degasser.

2.6.2.2.2 Two Stage Oil Dehydrator / Desalter

The oil from HP separator is pumped to Two-stage dehydration/desalted. Crude oil De-hydrator/ De-Salter are used for treating crude oil emulsions. The dehydration and desalting action are performed in two stage operation. The essential parts of system are Coalescing pad and electric grids. Coalescing pads are provided to help small dispersed water-in-oil or oil-in-water droplets to combine into larger droplets which are easier to separate by gravity. The electric grid establishes the electric field which enhances coalescing of the water droplets. The desalting action is achieved by mixing of fresh water into the feed emulsion to dilute the brine phase and thereby lower the salt content of the treated crude.

2.6.2.2.3 LP Separator

The LP Separator is a polishing unit to remove the residual portion of associated gas from the crude. This is done by flashing the liquid at Low pressure. The stabilised oil is stored in buffer oil storage tank and pumped through pipeline to CTF. for storage before metering and custody transfer. The gas from the LP separator is routed for flaring.

2.6.2.2.4 Oil Buffer Storage / Pumping System

The oil buffer storage tank is meant to provide intermediate storage of the processed crude oil before being pumped to the CTF. The crude oil storage tank consists of fixed roof type with heating coil arrangement with hot oil circulation. Crude transfer pumps are installed for evacuation of the tanks. Alternative electrical heating is also being considered.

2.6.2.2.5 Carbon Dioxide (CO₂) Removal System

The associated gas in the Mangala & Aishwariya reservoirs has high Carbon dioxide (CO₂) content. The CO₂ in the gas can be corrosive to the equipment in the presence of water and would therefore need to be removed. The CO₂ removal may be done by physical membrane process or DEA/MDEA (Di-Ethanol amine or Methyl Di Ethanol amine process) contacting process. The amine systems consist of air coolers which cool the gas to make it suitable for the process and then taken through contactor column, where it contacts the lean amine solution flowing down from the top the column. The process gas is in counter flow with lean amine. The CO₂ is absorbed by the lean amine. The rich amine leaving the contactor column is then regenerated in regeneration column by stripping of CO₂ and cold vented to atmosphere. The sweet gas from contactor is then routed to HP gas scrubber to knock off any liquid particles before entering the Compressor System. The gas compressors will compress the gas to suitable pressures as required for internal fuel gas service etc.

2.6.2.2.6 Gas Dehydration System

The combination of Carbon dioxide with water practically ensures that corrosive conditions will exist in plant. To avoid the corrosive environment, either CO₂ or water is required to be removed from the process gas. Water removal /gas dehydration can be done by many process viz, Glycol dehydration and Pressure Swing Adsorption process. The dry gas from dehydration system is routed to the Compressor System. The gas compressors will compress the gas to suitable pressures as required for internal fuel gas service etc.

2.6.2.2.7 Associated and Lift Gas Treatment & Compression

The associated gas from the crude along with the lift gas, separated out from the separators is routed to the compression unit. This is to transport all gases at medium pressure level to the CPF and lift a part of the gas to the lift gas pressure level and send it back to the wellhead.

2.6.2.2.8 Oil Upgradation Unit at Mangala and N-A field

Oil upgradation units are required to upgrade the flow assurance properties and achieve the desired pour point and wax content in the product crude so that it is suitable for cross country transportation via. pipeline to the refineries from the oil field.

The conceptual process flow diagram of oil upgradation unit is shown in **Fig. 2.16**.

There are several possible alternative options are available for this section. They are viz. visbreaking, visbreaking combined with thermal cracker heater, aquaconversion and

residual fluid catalytic cracking- RFCC. This process selection is a subject of detailed study to check the requirement from technical and commercial point of view. However basically all the process will use a moderate to high temperature conversion of higher molecular weight paraffinic hydrocarbons to lower molecular weight hydrocarbons. This conversion achieves the desired pour point and reduces the wax content in the crude as well.

Basically in the visbreaking process the crude is distilled for lighter end separation and then heated at medium temperature upto 500°C, based on the process selection, to start the reaction for breaking up higher paraffin. The operation is carried out at 10~15barg pressure. At medium temperature the conversion efficiency in the furnace is low; however a soaker drum is installed, downstream, to achieve higher conversion efficiency. Quenching is also done to arrest the uncontrolled conversion and reduction of coke formation. Finally the product from unit is separated for gas, distillate and residue. The upgraded product can be used as diluents and mixed with the crude to achieve the pour point of 18°C or lower.

2.6.2.2.9 Flare System

The flare system caters to the need of flaring of associated gas from shut-down / emergency and normal operations. The normal operation flaring would primarily be the separated gas from the LP separator and produce water degasser. Flares are equipped with gas pilots and igniters with purge gas. The flare system consists of knock-out drum (KOD), flare pump and header. Liquids from the flare knock-out-drum are routed to the oil buffer tank. The flare stack would be of 30 m height.

2.6.2.2.10 Interconnecting Pipelines

The stabilised oil from the GGS will be pumped to the CTF through buried carbon steel pipeline laid within the pipeline corridor connecting to the CPF. Interconnecting plant pipelines for transport of crude oil, hot oil, water, associated gas, closed drain, instrument air, potable water, fire water, etc. will be laid. In-plant pipeline may consist of elevated pipeline on pipe-racks or buried underground.

2.6.2.2.11 Chemical Injection

The chemical injection system will be similar to the details described in earlier section.

2.6.2.2.12 Drainage and Sewage Disposal

The plant area will be provided with a network of surface drains to cater to the 20-year maximum intensity of rainfall expected in the area. The process drains will be closed

type and will be kept segregated from the storm water flows. The rain-water flows from area that has a potential for contamination due to the facility operation will be routed to the process drain through suitable valve / isolation gate control. A check oil trap will be provided near the outlet of the storm water drain. Arrangements will be made to divert the storm water for rain water harvesting.

Sewage from the toilets of the buildings will be connected to either septic tanks / soak-away system or provided treatment in a package sewage treatment plant. The treated sewage will be used for greenbelt development.

2.6.2.3 Central Processing Facility (CPF) & Central Tank Farm (CTF)

The CPF / CTF will be preferably integrated into one common facility. The facility would be deigned to meet the requirements of both the Mangala & Aishwariya field development.

The key sub systems comprising the CPF / CTF are briefly explained below. Typical layout of CPF /CTF is shown in **Fig. 2.17**.

2.6.2.3.1 Produced Water Storage & Treatment System

The produced water separated and degassed in the GGS is routed to the Central Processing Facility for further treatment. The produced water is planned to be treated and made suitable for water injection. The maximum quantity of produced water estimated to be produced during the life of the field is estimated to be 306,000 barrels of water per day (~ 48,600 m³/day). The capacity of the produce water treatment plant would be approximately 336,000 barrels / day (~53,500 m³/day). The produce water treatment will consist of degassing, oil removal through IGF, sand / sediment removal through hydro-cyclone and sand and dual media filtration. The treated produced water will be routed to the injection water treatment system raw water tank and commingled with treated make up saline water required for re-injection to maintain the reservoir pressure. The treated produced water will be stored in a closed fixed roof tank with provision for inert gas blanking (nitrogen blanking). The treated produce water will be pumped to the injection water treatment system.

In the case of Saraswati & Raageswari field the produced water will be treated in treatment plant located at the common CPF to meet deep well discharge standards and pumped into deep dump wells (at least 1000 m deep).

2.6.2.3.2 Raw Water Storage

Fixed roof raw water storage tanks will be provided to store the saline water received from the saline water well field. Provision for inert gas blanking (Nitrogen blanking) will be made. The saline raw water will be pumped to the injection water treatment system.

2.6.2.3.3 Injection Water Treatment & Injection Water Pumping

Water injection is an important requirement in the Oil & Gas Industry and is a critical requirement for the Mangala & Aishwariya field development. Water injection as a recovery method is expected from the beginning of field life to provide for reservoir pressure and mobility. The total injection water requirement would comprise of the quantity of produced water and the additional quantity made up from the saline water source. The maximum injection water requirement is estimated to be 380,000 barrels of water per day (~ 60,000 m³/day). The injection water treatment plant will have a design capacity of 66,500 m³/day. The injection water will meet the RSPCB standard for deep well disposal.

The quantum of injection and thus injection rate per well shall be dependant on the reservoir management philosophy. The injection system would comprise of

- Injection wells (for injection into the reservoir)
- Injection water treatment
- Injection pumping system

The source of additional injection water would be from the saline water aquifer located south east of Aishwariya field at about 9 Km away near the village *Madpura-Barwala*. A comprehensive study has been carried out to ensure that the water sourced from this locational has minimal impact on any existing fresh water source. The saline water aquifer and the saline well-field details are detailed in earlier section.

The injection water will be treated to meet the reservoir quality requirements. There are three sections in the injection water treatment. The three sections are closed units with provision for fuel gas blanketing. Blanketing gas will be provided from the plant fuel gas header, in order to avoid oxygen ingress in water. For water injection, in the oil reservoir, it is required to maintain practically nil oxygen content in the injection water.

Section-1 (Pre-Treatment)

Pre-treatment block is the first stage treatment and consist of removal of suspended particulate matters and residual oil along with associated BOD and COD. This section shall have chlorination and dual media filters along with the associated facilities such

as feed pumps, backwash pumps and fuel gas scouring system. Optional installation of de-sanders shall be provided for the ground water stream in case the water wells produce large quantity of sand along with water.

This feed water received in a tank, wherein chlorine is added to control the biological growth. The water from the tank is pumped through horizontal, centrifugal Filter feed pumps to Dual Media filters operating in parallel. Coagulant (FeCl_3) solution (10%) is dosed at upstream of Dual Media filters as flocculent. The dual media filters have sand and anthracite bed to filter out the suspended solids and adsorb the residual oil, BOD/COD. Backwashing operation for each of the above mentioned filters is carried out, using filtered water from pretreatment section stored in the backwash tank and through the filter backwash pumps for 10-15 minutes. A fuel gas scouring system will be provided for the scouring operation of all the filters for 5 minutes.

Section-II (Reverse Osmosis)

This unit is mainly responsible for reduction of TDS from inlet concentration of 8000 ppm to outlet concentration of 1000 ppm. However in course of this, a highly saline reject water stream will be generated from the RO units. This stream is typically around 25% of the inlet water quantity. This RO reject water between 15,000 – 18,000 m³/day with a total dissolved solids concentration of approximately 30,000 mg/l will be routed through pipeline and disposed into the deep saline aquifer below the oil-water-contact through injection wells located in the injection field. The depth of disposal will be greater than 1500 m.

The Reverse Osmosis unit essentially works on molecular level. It separates the molecular impurities from the water thus making one stream rich in salt molecules and other stream lean in salts thus reducing the TDS of the water.

The filtered water is pumped to Reverse Osmosis System through 5 micron cartridge filters using R.O. filter feed pumps. There shall be on-line dosing of the HCL, sodium bi-sulphite, scale inhibitor chemicals, upstream of a static mixer, for trouble free and efficient operation of the Reverse Osmosis System.

Reverse Osmosis is a cross-flow filtration, high pressure spiral-wound membrane process which produces permeate (product water) stream low in TDS and a reject stream high in TDS for disposal. The transport of water through the membrane is through the physical pores present in the membrane (porosity), or by diffusion from one bonding site to another within the membrane. The chemical nature of the membrane is such that it will absorb and pass water preferentially to dissolved salts at the solid/liquid interface. This may occur by weak chemical bonding of the water to the membrane surface or by dissolution of the water

within the membrane structure. The chemical and physical nature of the membrane determines its ability to allow for preferential transport of solvent (water) over solute (salt ions).

The RO reject water consisting of high TDS stream will be injected into rejection wells located 3-4 kms down dip of the reservoir in deeper aquifer, typically 500 m below the Oil Water Contact.

Further detailing such as blending a part of saline water with RO permeate water to get the desired TDS of 1000 mg/l in the injection water shall be decided during the process design stage.

Section-III (Chemical Solutions Dosing)

An integrated system is envisaged for chemical solutions preparation and dosing in the chemical house for desalination plant and chemical conditioning.

2.6.2.3.4 Potable Water Generation

The potable and process water required for the operation of the Mangala & Aishwariya fields will be met by desalination of the saline water obtained from the saline water well field. It is estimated that approximately 1000 - 1500 m³/day of fresh water would need to be produced to cater to the process, domestic and greenbelt requirement. The package desalination plant, based on Reverse-Osmosis (RO) or thermal process (utilizing waste heat) would be located in the CPF. The reject water from the desalination process will be commingled with the injection water desalination plant reject stream for disposal through the dump wells. The desalinated potable water would meet the World Health Organisation (WHO) standards.

2.6.2.3.5 Lift Gas Compression

Gas Lift system is a secondary recovery system employed in low energy reservoir, wherein the wells cannot flow on their own pressure. Lift gas is sent through the annulus between well tubing and casing to lift the oil column through the tubing. The lift gas flows along with the wellfluids and separated in the surface processing facilities.

The gas separated in the processing facilities is a mixture of the lift gas that is sent through the annulus and the associated gas dissolved in the oil which is released in the separator. The gas thus separated is compressed and used as fuel gas for process heating requirements and also as fuel for power generation.

The lift gas requirement is met directly from an independent gas well located

within the block. . The gas from the well is compressed in a compressor train to the desired pressure for gas lifting. As explained earlier it is estimated around 100 MMSCFD of lift gas would be required to work the Mangala & Aishwariya field. This lift gas along with the associated gas will be recovered in the GGS and transported to CPF, where it will be compressed from 60 psig to 750 psig (minimum) before being sent back to the well-heads for gas lift. Thus the lift gas will essentially be in a closed loop circulation

2.6.2.3.6 Oil Storage Tanks

The capacity of crude oil storage shall be suitable to cater to store about five days of production during maintenance of facilities. The tanks will be installed within a paved and dyked area. It will comprise of fixed roof carbon steel tanks and will be designed as per applicable codes and standard and international practices. The total maximum crude oil storage capacity will be approximately 700,000 barrels of oil per day (~ 112,000 T). Each tank will be provided with hot oil heating coil arrangements. Crude oil booster pumps will be installed to boost and maintain adequate operating pressure in the system.

The dyked tank area with containment provisions will be provided with water sprinkler system and other fire fighting provisions as described in **Section 2.6.6**. The tanks will be grouped so as to provide optimum containment arrangement and prevent any spills and leaks to spread through out the tank farm area. A network of process drain will be laid within the paved area and routed to an oil water separator.

It is intended to have one or more Central Tank Farms in the total development area. The tank farms at North and Central areas may be interconnected for operational flexibility.

2.6.2.3.7 Diluent Storage Tanks

In order to improve the flow characteristics of the crude, it is also planned to mix the crude with suitable diluents like naphtha, diesel, or any lighter crude before dispatching though the Buyer's export pipeline. The storage capacities for the diluents will be suitable for 1 to 2 days requirements. The diluent tanks will be installed within a paved and dyked area and will comprise of fixed roof carbon steel tanks. The total maximum diluent storage capacity will be about 588,000 barrels of oil (~ 79,500 T).

The diluent will be supplied by the buyer (IOC) through pipeline and received at the diluent tank farm. Diluent booster pumps (6 no. each of 480 m³/hr capacity) will be installed to boost and maintain adequate operating pressure in the system.

2.6.2.3.8 Oil Export Custody Transfer System

The Buyers pipeline may be routed through the CTF facilities or the export pumping shall extend up to the Buyer's pipeline injection point. Export pumps shall be designed suitably for loading into tankers or pipeline. Dedicated export pumps for crude oil will be provided. The diluent and the crude will be co-mingled in the export pipeline. Custody transfer metering arrangement will be provided to measure and record the crude oil exported. It is to be understood that the diluent is being used only as a means to assist the flow of the crude in the export pipeline and is not to be included in the crude oil production quantity from the Mangala & Aishwariya fields. The diluent will be mixed with the crude oil produced after the custody transfer meter.

The installation of the export pipeline to the buyer's (IOC) refining facility is the responsibility of the buyer and approvals regarding the same will be obtained by the buyer.

2.6.2.3.9 Tanker Loading System

In addition to the export pipeline arrangement it is proposed to have tanker loading gantry system of a capacity upto 5,000 barrels of oil per day (~ 675 T) to enable road transport of limited amount of crude oil. The gantry arrangement will be able to cater to 4-6 tankers at a time. The gantry will have water sprinkler system as required. The loading bay will be paved with spill collection system.

2.6.2.3.10 Flare System

The flare arrangements will be similar to that described in earlier **section**.

2.6.2.3.11 Incinerator

A high temperature incinerator will be installed at the CPF for the incineration of oily wastes / oily sands / oil contaminated drill cuttings. **The incinerator will serve as a common incineration facility for all the fields described under the development plan.** The incinerator will be designed with appropriate residence time and will be provided with two chambers to ensure complete combustion. The incinerator will be rated at a capacity of 100 kg/hr. The ash from the incinerator is expected to be suitable for use as landfill / road base. Tests will be conducted on the residue to ensure that it is within the permitted limits for use as landfill / road base, etc.

2.6.2.3.12 Waste Storage Facility

The layout of the CPF will incorporate a well-designed secure landfill site for the storage and disposal of those wastes that require secure disposal or may need to be stored in a

secure place till such time as required for bio-remediation, solar drying, etc. In additions high salinity solid wastes will also need to be disposed in a secure manner to ensure no adverse impact on the groundwater / top soil.

The landfill site will be deigned to meet the storage requirements for the wastes requiring landfill disposal over the 20 year period of the field life. The landfill site will be designed and constructed based on the guidelines issued by the Ministry of Environment & Forest (MoEF) - Criteria for Hazardous Waste landfill'. The landfill site will be provided with leachate collection system and monitoring well provisions. The landfill design and other details are explained in **Chapter 4** of this report.

The waste storage facility would also include a high-temperature twin chamber incinerator of about 100 kg/hr capacity for incineration of oily wastes that cannot be recycled. The incinerator will be provided with a 30 m stack.

2.6.2.3.13 Helipad

The project envisages construction of one helipad at the CPF facility at Mangala to serve the northern zone and a helipad at Saraswati field GGS to serve the central zone. The helipad would be approximately 40 m x 40 m in size with hard standing and concrete paved area. The design and installations will be as per the requirement of DGCA and in complete compliance to all safety requirements. Sufficient buffer distance would be provided from the operational areas. A paved tank area will be constructed for storage of aviation fuel. If deemed necessary pre-fabricated hanger arrangements will be made for parking. Necessary approvals from the concerned regulatory authorities will be obtained.

2.6.2.3.14 Supporting Facilities

The GGS & CPF will have an administrative and operating office block, which will house facilities like control room, stores, offices, canteen, toilet facilities, medical centre and other administrative functional areas. Communication towers and telemetric control systems will be installed. The facility will be enclosed with safety boundary walls and security watch towers installed. The entry to the facilities will be restricted and round the clock security guards provided.

2.6.3 Aishwariya Field – Facilities Description & Operational Details

The development plan for the Aishwariya field is similar to the plan and process scheme described for the Mangala Field (**Refer section–2.6.2**). As explained earlier the Aishwariya field will share common facility (CPF / CTF) set up for the Mangala & Aishwariya field for the processes to be carried out in the CPF / CTF, which mainly are

produce water treatment, injection water treatment and re-injection water pumping, crude and diluent storage and waste management facilities. Thus the Aishwariya field development essentially comprises of installation and operation of well-pads, flowing the well-fluid to Group Gathering Stations to carry out phase separation, pumping the crude to the CTF, and associated gas treatment and compression and routing the produced water to the common CPF for produce water treatment. Depending on GOR of the well fluids, the gas may be flared locally (low GOR), or compressed in GGS and transported to CPF for further utilization (High GOR, Low Carbon Dioxide) or sent through CO₂ removal facility/Gas dehydration facility before being compressed and utilised as fuel.

The proposed Aishwariya field oil development facility would be adequately sized and infrastructure provided to produce upto 20,000 barrels of oil per day (~ 2,700 T of crude oil). The associated gas generation is expected to be only 3.4 million standard cubic feet per day. As stated earlier, the Group Gathering Stations (GGS) shall be placed within the vicinity (located with-in radius of 1-3 km) of Well Pads. Artificial Lift pumps are proposed to pump the oil all the way from sub-surface to GGS. Group of Well Pads will be connected to the nearest GGS.

The Aishwariya field development facility would broadly consist of the following facilities:

- Upto Eight (8) Well Pads with each well pad connected to upto five (5) production wells and five (5) injection wells.;
- Upto Two (2) Group Gathering Stations each capable of producing upto 10,000 BOPD (~ 1,350 T per day).

The proposed Aishwariya field development plan is given in **Table-2.3**. The Aishwariya Field Architecture is given in **Fig. 2.18**. The Process Flow Diagrams for this development are similar to Mangala field. Typical architecture of Aishwariya development is shown in **Fig. 2.18** and the typical Layout for GGS are shown in **Fig. 2.19**. The facilities proposed to be installed in the N-A field GGS will be similar to that described for the Mangala field GGS. The **Rajasthan Field Development Project Report** provides further details on equipment sizing and related technical specifications.

2.6.4 Saraswati and Raageshwari Field - Facilities Description & Operational Details

The Saraswati & Raageshwari fields will have much smaller rate of oil production than the Mangala field. The development plan proposed for these fields vary in terms of the

facilities and the capacity of the well pads required for their exploitation. However, the process of well fluid processing and gas compression remains the same. The development concept is to design minimum necessary facility, mainly to cater to small capacity well pads. Importantly these fields may not require artificial lift or water re-injection due to the reservoir characteristics. Under this option the oil is degassed in the well pad itself. Thus the facilities at well head will include single well/multi well pads and (oil and water)/gas separation shall be done. The oil along with produced water will be piped / trucked to GGS wherein the water is removed and the oil is processed for meeting the specification. Produced water is treated and disposed of in a dump well. Both Saraswati and Raageshwari fields will have a common GGS. Saraswati and Raageshwari field development architecture is shown in **Fig. 2.20**.

One common Central Tank Farm (CTF) will be provided which will be located adjacent to the GGS. The stabilized crude from the GGS will be piped to the CTF. Oil will be exported from CTF. Oil will be exported from CTF for high GOR fields, the associated gases will be used for power generation / flared.

The proposed Saraswati & Raageswari field development plan is given in **Table 2.4**.

The envisaged combined crude oil production capacity from Saraswati & Raageswari field would be upto maximum 8,000 BOPD and maximum associated gas production of 0.35 MMSCFD. The Saraswati & Raageswari field development facility would broadly consist of the following facilities:

- Upto Four (4) Well Pads with each well pad connected to upto six (6) production wells for the Saraswati field;
- Upto Six (6) Well Pads with each well pad connected to upto six (6) production wells for the Raageswari field;
- Each Well Pad will be capable of producing upto 2000 BOPD (Saraswati) & 700 BOPD (Raageswari) and will have the following facilities
 - Artificial Lift
 - Oil+Water / Gas Separator
 - Fuel Gas Filter System
 - Oil+Water Storage Tank
 - Truck Loading System

- Crude / DG / Gas based Power Generator Set
- Flare System
- Fire Fighting System
- Utilities Systems
- Electrical & Instrumentation System
- Communication System
- Material & Waste Storage facilities
- One common Group Gathering Stations capable of producing upto 8,000 barrels of oil per day (~ 1,100 T per day) & Central tank Farm capable of storing 40,000 barrels of crude oil. The GGS / CTF will have the following facilities:
 - Oil/Gas/Water HP-Separator (3 phase separator)
 - Two Stage Oil Dehydrators/ Desalters
 - Crude / Hot Oil Heat Exchanger
 - Chemical Injection Skid
 - Oil Buffer Storage and Pumping station
 - Crude Oil Storage Tank
 - Crude Oil Custody Transfer System
 - Crude Oil Export System
 - Produce Water Treatment Plant
 - Flaring System
 - Fire Fighting System
 - Utilities Systems
 - Electrical & Instrumentation System
 - Communication System

- Material & Waste Storage facilities
- Helipad
- Warehouse
- Administrative office

The process and operational details are generally similar to that described earlier. The **Rajasthan Field Development Project Report** provides the technical details such as the PFD, equipment specification and sizing and operational parameters.

2.6.5 Gas Field Development

Raageshwari Gas Field Development is intended to meet the Fuel gas requirements of Rajasthan field development. The Raageshwari Gas Field development architecture is given in **Fig. 2.21**.

The gas is compressed, dehydrated and then sent to Mangala CPF / Power Plant to meet the fuel gas requirements for Power Generation and heating. The stabilised condensate is sent to Raageshwari Oil Field GGS for spiking into crude Oil. Facility is also provided to evacuate the condensate by road trucks.

The typical Layout for the Gas Collection System (GCS) is given in **Fig. 2.22**. The capacities of various facilities proposed for Raageshwari Gas Field development are given in **Table 2.5**.

2.6.5.1 Well Pads and Well Head Facilities

The well pad basically comprise of Christmas tree with flow lines with suitable piping and valves. Multi well pads would comprise of many well heads at one location and the flow lines from each well head will be brought to a common manifold before flowing to treatment facility.

The Gas Well Head Facilities primarily consist of Well heads, gas flow meters in each flow line Production manifold, a pig launcher and utility distribution systems. Provision is kept for methanol injection during start up to tackle gas hydrate problems.

2.6.5.2 Gas Collection Station

The Gas Collecting Station is intended for Gas/Water/Condensate separation, Gas dehydration and Condensate stabilisation.

The key sub systems in the Gas Collecting Station (GCS) are listed below and

briefly explained further.

- Inlet Separator (2 phase separator)
- Suction Gas Scrubbers.
- Gas Compressors Trains (2 Working + 1 Standby)
- TEG (Tri-ethylene Glycol) contactor for Dehydrating the Gas.
- TEG (Tri-ethylene Glycol) regenerator.
- Condensate Flash Drum
- Condensate Stabilizer, Reboiler, Condensate Cooler
- Condensate Storage
- Condensate Pumping and tanker Loading System
- Local power generation using gas
- Gas metering system.
- Pig Launchers / Receivers.

2.6.5.2.1 Inlet Separator

The Well fluids enter the Inlet separators for separation of Gas and liquids comprising of condensate and water. The gas is then sent to suction gas scrubbers for removal of entrained liquid particle before the gas enters the gas Compressors. The liquids from the Inlet Separator and suction scrubbers are sent to Condensate flash drum for separation of water and condensate.

2.6.5.2.2 Gas Compressors

The gas from Inlet Separator enters a manifold and then passes through the suction gas scrubbers before being routed to the compressors. The compressors would be reciprocating type. The gas is compressed to an estimated pressure of about 500 psig for transporting it to Central Processing Facilities in N-A / Mangala field by pipeline. The gas from the Compressor is cooled by air fin coolers to near ambient temperature before entering the TEG dehydrator.

It is envisaged to install three trains of Suction Scrubber, Compressor and after cooler configuration. Each compressor will have recycle valves and capacity control. Normally two trains will be working with one train as stand by. The compressed and cooled gas from each compressor is routed to a manifold before entering the TEG contactor.

2.6.5.2.3 Gas Dehydration System

To avoid corrosion to long distance pipeline to CPP, water is required to be

removed from the natural gas. Water removal known as gas dehydration can be done by many processes viz, Glycol dehydration and Pressure Swing Adsorption process. The gas from the compressors is passed through TEG contactor where the gas comes into contact with TEG. TEG absorbs the water at lower temperatures and lets out at higher temperatures. The dry gas from the contactor tower is then passed through the metering skid and then to the pipeline which delivers the gas to CPP. The wet TEG from the contactor is then regenerated in a regenerator skid and re-circulated.

2.6.5.2.4 Condensate System.

The liquids consisting water and condensate from Inlet separator, Suction scrubber and TEG Contactor are routed to Condensate flash drum where water and condensate are separated. The water, being small in quantities, is then degassed and sent to solar pond for natural evaporation. The condensate is then stabilized by removing the light hydrocarbons by heating to required temperature in the reboiler and circulating through the stabilizer. The stabilized condensate is then cooled and sent to storage tanks. The condensate from the tanks can be sent to nearby Raageshwari Oil GGS for spiking in the crude or can be dispatched by road tankers for operational requirements.

2.6.6 Fire Protection System

The typical fire fighting system for the various facilities described under this project is outlined in this section. The exact details of the fire fighting systems and capabilities to be installed and developed will be finalised after the completion of detailed engineering in consultation with the concerned process and equipment vendors and fire. It is also to be understood that not all facilities described below will be applicable for every installation. The outline of the fire system proposed is described below.

Fire protection system shall be deigned in accordance with the requirements of OISD, Tariff Advisory Committee (TAC) of India, NFPA standards, design requirements and safe engineering practices and will have full capability for early detection and suppression of fire. The system will primarily consist of:

- Hydrant system.
- Foam protection system
- Deluge sprinkler system.
- Portable fire extinguisher.
- Fire detection and alarm system.

Hydrant System: The system will essentially consists of firewater storage, pumping, system pressurisation and all inter connected pipe work and auxiliary fire fighting appliances. The water storage & pumping capacity and other features of this system will be finalised considering TAC recommendations.

Adequate number of engine driven/ electric motor driven fire water pumps will be provided. The pumps will be started automatically in the event of drop in header pressure. The actuation will be through pressure switches, the setting of which will be staggered to achieve sequential starting of the pumps to meet the system demand. When power supply is available, the electric motor driven pump will start first and in case of further pressure drop the engine driven pump will start. However when electric power is not available, the engine driven pump will cut-in depending on the system demand. The pumping capacity would meet the simultaneous water demand for foam protection of one oil tank, and supplementary foam hose stream in the oil dyke area, which is the maximum water demand in a single occurrence of fire. The pumping capacity should also meet the guidelines of TAC for this size of plant, considering ordinary hazard occupancy.

The fire water system will be kept pressurised by the hydro-pneumatic tank, which will take care of small leakages from the fire water system. A jockey pump, sized as per the TAC guidelines will, automatically replenish the water level in the hydro-pneumatic tank at periodic intervals. Air required for pressurising the hydro-pneumatic tank will be supplied by an electric motor driven compressor.

The outdoor hydrant system will be provided all over the plant for exterior protection. The hydrant mains will be laid underground. Hose houses, complete with all accessories, will be provided at suitable intervals. The overall plant will be divided in several fire zones, where the fire fighting action can be pursued effectively. The pressurised main will also be connected to Sprinkler/ emulsifier System for protection of transformers & Fuel Oil storage tanks.

Foam protection system: Fuel oil storage tanks and the surrounding dyke areas will be protected with low expansion foam system, using fluoro-protein. The storage tanks will be provided with sub-surface foam injection system and the dyke area will be provided with supplementary foam hose stream for combating spill fires. The foam protection system will be designed as per the requirements of NFPA, OISD and TAC. A central foam preparation unit consisting of at least foam storage tank, proportionating devices etc. shall be provided, to supply foam solution to the foam protection system. Pressurised water for foam system will be tapped from the outdoor main hydrant.

Sprinkler system: Automatic deluge sprinkler system will be provided for the protection of power transformer. An array of spray nozzles will be provided all around the protected area. The nozzles will be connected to the automatic deluge valve. A set of heat or smoke detectors, located in the area will sense the fire. Deluge valve will automatically open once two independent detectors sense fire.

Manually initiated water spray system will be provided for exposure protection of oil storage tanks, so that when one tank is on fire, the other tank can be cooled to guard against exposure heating. Pressurized water supply to all sprinkler systems will be tapped from the outdoor hydrant main.

Portable Fire Extinguishers: Besides, fire hydrant arrangement, portable fire extinguishers of suitable categories will be placed at control rooms, electrical switchgear room & various utility buildings for immediate use in the event of fire. Three different kinds of extinguishers i.e. foam, CO₂ and multipurpose dry chemical (MPDC) will be provided. Each type of extinguisher has its own characteristic to fight a particular class of fire. The size and type of extinguishers will be decided as per recommendations of NFPA and relevant Indian Standard and will be placed in convenient accessible locations.

2.6.7 Supporting Facilities

Infrastructure in such development is quite substantial and critical for effective operations management. Some of the key infrastructure requirements are:

- Ware House
- Support Services
- Work shops
- Laboratory
- Communication Centre
- Living Quarters
- Helipad / Air strip

The Infrastructure may be provided in a central location closer to the Northern facilities. This could be annexed to CTF or CPF as suitable. This is dependant on various factors including logistics requirements etc.

Ware House management shall be central to the development area and shall cater

to all facilities in both North and Central zones. However there could be minimal store houses in each facility to cater for immediate needs. Works shops will be for maintenance of plant equipment, electrical and instrumentation. This will have necessary carnage and other tools & tackles as required. Laboratory services are essential to maintain the quality of products, production operations related to chemical injection etc. Latest equipment and technologies shall be provided for such services.

2.6.8 Pipeline Corridor

As explained earlier there will be number of pipelines connecting Well Pads, GGS, CPF and CTF carrying well fluids, produced water, gas, stabilised oil, injection water, lift gas, hot oil supply and return etc. The pipelines will be generally laid alongside the roads connecting the facilities, as given in the layout maps. The pipeline corridor will be about 30-m wide. The pipelines will be designed to meet the OISD standards in terms of material selection, design, installation and will be corrosion protected. The pipelines will be buried and the required Right-of-way will be acquired.

The pipelines sizes may vary and will range from 3” to 28” and the number of lines within the corridor will be upto 8 lines. The total length of the various pipeline corridors will be about 300 km.

CEIL commissioned SECONS Surveys Pvt Ltd to carry out a reconnaissance survey to determine the suitability of the proposed pipeline corridor alignment, identify important features such as rail and road crossing, and modify the proposed routing based on existing physical and social features. The pipeline corridor largely traverses open arid land, which are largely cultivated only during the rainy season (*Kharif*). The proposed pipeline corridor routing is shown in the respective field development maps. Details of the pipeline corridor are presented in **Table 2.6**.

It is to be noted that the routing and pipeline corridor length shown are tentative and may be subject to change due to site constraints. **The exact pipeline corridor alignment will be finalised after completion of the detailed engineering and detailed routing survey.**

2.7 Infrastructure Requirements

2.7.1 Land

The approximate area required for the various facilities proposed for the oil field development is shown in **Table 2.7**. The layout of the facilities is shown under the respective sections. It is to be noted that the land areas shown are tentative and may require to be

modified. The exact areas required will be finalised after the detail engineering and finalization of the layout of the facilities.

The total land requirement for the proposed development plan would be approximately 290 Ha. It is to be noted that the land requirement is spread over several locations as detailed in table below. The land will be acquired from private / government lands after obtaining due statutory approvals. Crop and land compensation will be paid as determined by the revenue officials.

In addition to the above there would be land required for access roads, to be constructed wherever there are no existing roads.

2.7.2 Power

A key feature of the Rajasthan oil development project is that it is expected to have a high electrical demand because of the requirements for artificial lift wells (ESPs, PCPs), water injection, transfer of high viscosity fluids and the large distance between facilities. The power requirement for the Northern zone fields will be met by captive generation at a centralised power plant using either crude oil or natural gas or a combination as fuel. **(Refer Section on Captive Power Plant for details).**

The energy demands of the central zone fields will be met by captive generation at individual facility location by generating sets fuelled by HSD / Crude oil / Natural Gas.

In general all facilities will have the necessary electrical energy receiving, distribution, earthing and control systems. The systems will be designed and operated to international safety norms for oil field installations. The initial estimates of power requirements for the project are given in **Table 2.8**. It is to be understood that these figures are subject to change based on the detailed engineering and actual equipment selection and facility layout.

2.7.3 Water

The major water requirement for the project is for re-injection purpose for secondary recovery from the northern zone fields (Mangala & Aishwariya). It is estimated approximately 25,000 KL/day would be required. It is assumed that this quantity will be required for the full life of the field, though in actual practice as the field enters the production decline phase, the re-injection water requirement would also correspondingly decrease. This major source of water will be saline water sourced from the extensive saline deep ground water aquifer in the area.

The actual oil & gas processing operations do not require much water and the water requirements are limited to cooling water, wash water and potable water. The fire water requirements are only for make up for evaporation losses after initial filling is done and hence not considered.

CEIL proposes to install a desalination plant of about 1,500 – 2,000 m³/day product water capacity to cater to the needs of the Mangala & Aishwariya field operation. **This is in addition to the desalination unit required as part of the injection water treatment process.** The desalination plant would also meet the cooling water requirements of the captive power plant. Fresh water for greenbelt development and maintenance will be met from recycling the treated effluent / sewage and or fresh water from the desalination plant.

In the case of the central zone facilities, the fresh water requirements are less as compared to the northern field and will be sourced from local registered water suppliers. In case it is found feasible and suitable source of saline water exists, CEIL may install a desalination plant in the Saraswati CPF or the Raageswari GCS and distribute the fresh water to the central zone facilities through

The preliminary estimates of sweet water requirement required for the operation of the various facilities are indicated in **Table 2.9**.

2.8 Captive Power Plant

The power requirement for the Mangala and Aishwariya development is proposed to be generated in a dedicated centralised captive power plant of 50 MW capacity. The sources of fuel for this purpose are Associated Gas and or Non-Associated Gas from Raageshwari Gas Field or Crude oil. The power may be produced using either of the following units:

- Gas turbine driven Generator (Gas based)
- Gas engine driven Generator (Gas based)
- Liquid fuel fired Engine driven Generator (Crude oil or diesel based)

The crude oil will be supplied through pipelines via the nearest GGS of Mangala Field and the natural gas, will be supplied from Raageshwari field through pipelines.

The power generation will be centralised for Mangala and Aishwariya fields and distributed to different load centres / facilities. The tentative location of the Power Plant is

shown in **Fig. 2.9**.

The power generation may be at 11 KV or 33 KV level which is the optimal level for transport to long distances to reduce transmission losses. The voltage level will be stepped down to 6600/415/240V levels at the facilities as per the specific facility requirements. Suitable systems shall be provided for Emergency power, DC power systems, Sub stations for distribution, Un Interrupted Power Supply, Control power etc. The systems shall meet DGMS, Hazardous Area Classification and other standards applicable.

2.8.1 Technology Options

The project proposes to use any of the three options namely, Gas turbines, Crude oil fired I.C Engines and Gas fired I.C Engines for power generation. Each option is elaborated hereunder.

Option – I Gas Turbine Based CPP: Gas Turbines are widely accepted machines for power generation. These are rotating machines and work on Brayton Cycle. These machines are compact, lightweight and are supplied as completely packaged units within weather proof acoustic enclosures, ready to be installed outdoors.

Option – II Gas Engine Based CPP: Reciprocating engines working on gas are in operation as they have higher efficiencies of about 40 to 42% with lower effect on performance due to site conditions. These gas engines are spark ignition engines, low or medium speeds having proven operating experience.

Option – III Crude Oil Engine Based CPP: Reciprocating engines working on Crude Oil are in operation as they have higher efficiencies of about 40 to 42% with lower effect on performance due to site conditions. These crude oil engines are compression ignition engines, low or medium speeds having proven operating experience.

The following options have been considered for finalisation of Power Plant configuration.

- **Option – I:** Power Plant with eight (8) Nos. Fuel Gas Fired Gas turbines (7W + 1S).
- **Option – II:** Power Plant with eight (8) Nos. Fuel Gas Fired I.C Engines (7W + 1S).
- **Option – III:** Power Plant with eight (8) Nos. Crude oil fired I.C Engines (7W + 1S).

It is to be noted that the options have not been listed in order of ranking and any one or combination of the options to generate the required power of 50 MW.

The technical specifications, configuration and layout and operational details are provided in the **Power Generation Study Report prepared by Engineers India Limited** for Rajasthan Oil development project report.

2.8.1.1 Crude Oil Engine Option

The crude oil engine option consists of eight crude oil fired (7W + 1S) I.C Engine sets of Wartsila model no. 18V32 or equivalent, each having site electrical output of 7.93 MWe. The exhaust gases from the engine are utilised for Thermic fluid hot oil heating in a Heat Recovery Unit (HRU), and this hot oil is in turn utilised for maintaining crude oil temperature within pump able range. The Net power output of the plant (assuming 4% internal auxiliary power consumption) is 53.29 MW. The total Crude oil requirement for the power plant considering seven (7) engines in operation at 100% base load will be approx. 272 MT/day. The waste heat recovery possible from the turbine is 16.9 million kcal/h.

The engine will be provided with electronic-hydraulic governor, a motor driven turning gear device, turbo-charger and engine protective devices. The lubricating system will consist of main and cylinder lube oil system crude oil storage, treatment, circulation, light fuel oil start-up system, compressed air system, cooling system, utility air and exhaust gas system. The various units will be housed in enclosed building and equipments will be provided with noise control measures so as to ensure that the noise limit of 85 db(A) at 1 m from the equipment is not exceeded.

The electrical system and instrumentation and control system that will be provided are discussed in the **Power Generation Study Report**.

Each engine will be provided with **independent steel stack of approximately 75 m height**. The height of the chimney has been estimated assuming the concentration of SO₂ in the crude oil to be 1% sulphur. The crude oil analysis from the Mangala field indicates that the sulphur content is less than 1%.

2.8.1.2 Gas Engine Option

Consisting of Eight fuel gas fired (7W + 1S) I.C Engine sets of model no. 20V34SG or equivalent, each having site electrical output of 7.89 MWe. The exhaust gases from the engine are utilised for Thermic fluid hot oil heating in a Heat Recovery Unit (HRU), and this hot oil is in turn utilised for maintaining crude oil temperature within pump able

range. The Net power output of the plant (assuming 4% internal auxiliary power consumption) is 53.02 MW. The total fuel gas requirement for the power plant considering seven (7) engines in operation at 100% base load will be approx. 238MT/day. The waste heat recovery possible from the turbine is 19.3 million kcal/h.

The engine will be provided with electronic-hydraulic governor, a motor driven turning gear device, turbo-charger and engine protective devices. The lubricating system will consist of main and cylinder lube oil system including lube oil cleaning system. The auxiliary systems include fuel gas system, compressed air system, cooling system, utility air and exhaust gas system. The various units will be housed in enclosed building and equipments will be provided with noise control measures so as to ensure that the noise limit of 85 db(A) at 1 m from the equipment is not exceeded.

The electrical system and instrumentation and control system that will be provided are discussed in the ***Power Generation Study Report***.

Each engine will be provided with independent **steel stack of approximately 30 m height**. The analysis of the natural gas proposed to be used has no sulphur dioxide.

2.8.1.3 Gas Turbine Option

The Gas Turbine option consists of seven (7) fuel gas fired (6 Working + 1 Standby) Gas turbines sets of Siemens make Cyclone model or equivalent, each having site electrical output of 9.5 MWe at generator terminals. The exhaust gases from gas turbine are utilised for Thermic fluid hot oil heating in a Heat Recovery Unit (HRU), and this hot oil is in turn utilised for heating the crude oil.

The packaged Gas Turbine Generator (GTG) will be installed outdoors in a weatherproof acoustic enclosure, which will limit the sound pressure level to 85 dB(A) at 1 meter from the enclosure. GTG enclosure will be designed as standalone equipment for outdoors installation, which is a standard feature of such turbines. The Net power output of the plant (assuming 3% internal auxiliary power consumption) is 55.29MW. The total fuel gas requirement for the power plant considering six (6) turbines in operation at 100% base load will be approx. 329 MT/day. The waste heat recovery possible from the turbine is 69.96 million kcal/h.

The GTG will have a lube oil system, cooling system, speed-reducing gear box between the turbine and the generator, exhaust system will have exhaust gas ducts, expansion bellow, exhaust gas diffuser and exhaust gas silencer to limit the exhaust noise contribution

to maintain an overall noise level to 80 dB(A).

Each engine will be provided with **independent steel stack of approximately 15 m height**. The analysis of the natural gas proposed to be used has no sulphur dioxide.

2.8.2 Effluent Treatment & Disposal System

The effluents generated from the power plant operation are oil contaminated wastewater. It is estimated approx. 100 – 120 m³ /day of oily wastewater will be generated from the power plant operation. In case of gas based power plant option, the effluent generation will be significantly less.

The oily wastewater will be collected through process drains into a central holding pit for uniform volumetric loading into an oil/water separator. The floating oil will be skimmed and the dissolved oil will be removed by aid of chemical flocculation / dissolved air floatation systems. The oily sludge will be collected in a sump and periodically transferred to the CPF at Mangala field. The deoiled water will be subjected to activated sludge treatment, followed by filtration through dual media filter. The treated effluent will meet the land discharge standards stipulated by RSPCB and will be used for greenbelt development.

The domestic sewage from the plant operation will either be treated in septic tank-soak pit system or combined with the biological treatment stage of the oily water ETP.

2.9 Injection Water Sourcing & Saline Water Well Field

2.9.1 Need for Water Injection

In addition to the normal ‘domestic’ requirements for water for staff and site facilities, the project needs large quantities of brackish or saline water for injection into the oil reservoir formations after suitable treatment to improve oil recovery.

When oil wells are drilled into an oil reservoir, the oil will normally be pushed out by the pressure of water underlying the oil and the gas that comes out of solution as the pressure of the oil drops immediately around the well. These pressures are usually sufficient to force the oil to flow to the surface, and this method of production is called primary production.

However, in many cases the pressure declines rapidly with production, and the recovery of oil is poor – more than 90 per cent is often left in the reservoir. This will be the case in the Fatehgarh reservoir (Barmer basin), where the oil is relatively viscous, the natural water pressure is low and there is relatively little gas in the oil to expand and drive the oil out.

In cases like these, it is preferable to provide some form of pressure support to the production process. This usually consists of injecting water into the reservoir beneath the oil (**Figure 2.22 & 2.23**). This water injection maintains the reservoir pressure, helping to force the oil out to the surface; the flow of water through the reservoir also enhances production by helping to ‘sweep’ the oil from the pore spaces in the reservoir rock, a process known as secondary recovery. This greatly increases the production efficiency, enabling recovery of up to three times as much oil as would be possible with primary production.

2.9.2 Saline Injection Water Requirement

CEIL estimates that maximum saline water demand will be about 25 ML/day (25 000 m³/day) for injection (pressure support) and other purposes for its Mangala & Aishwariya field operations. This is the maximum peak demand that is likely to arise during oilfield operation and includes water for site use. **Over the period during which the fields will be operating, it is expected that the average demand will be much less than 25,000 m³/day.**

The Mangala & Aishwariya hydrocarbon reservoir conditions require **pressure support** to achieve optimum exploitation of the reservoir. This is proposed to be achieved by a combination of water polymer flooding and saline water injection to maintain the reservoir pressure. The fresh water for polymer flooding will be obtained by desalinating the saline groundwater. It is important that the injection water should be free of suspended particles, which would clog up the pores in the reservoir and prevent the injected water from entering it easily. It must also be free of microbes, which can reproduce very rapidly and form colonies that can block up pore space or lead to precipitation of minerals in pipelines, reservoir pores or in the injection wells. It is also essential that there is very little dissolved oxygen.

CEIL commissioned a study by **Water Management Consultants Limited (WMC)**, UK - an international water consultancy group to study and recommend a suitable source of supply of upto 25 ML/day (25 000 m³/day) of saline water, sustainable for at least 25 years, **without adverse effects on local water supplies or communities**. The consultants (WMC) scope of work included detailed groundwater data collection from various organisations operating within the area (GWD, CGWB, IMD, PHED, RRSSC), data from the Census and on land use, and field investigations, Construction of a database and geographical information system (GIS), integration of CEIL seismic and well-log data, preparation of a hydrogeological conceptual model, construction of an investigative ground-water flow model, selection of potential wellfield sites, modelling of the effects of abstraction and production of a conceptual design for the proposed saline wellfield.

WMC has presented their findings and recommendation in their report **Cairn Energy – Oil Field Development – Water Resources Study - Phase-I**. The findings of the studies are that saline ground water was expected to be a suitable source, **and ample renewable saline water resources were available within the Mangala & Aishwariya field development area within the RJ-ON-90/1 block**. The study also identified other possible sources and carried out a techno-commercial and availability risk evaluation.

The identified source of saline water resources suitable for abstraction for injection water purposes is located in the extensive Tertiary sandstone formation (Thumbli Formation) in the northern portion of the block. The Thumbli Formation is a laterally extensive sandstone and claystone unit. It consists of sands and semi-consolidated sandstones, with occasional shales, underlain in part of the basin by a shale sequence called the Thumbli Shale. The Thumbli Sands are largely coincident with the GWD-designated Tertiary Sandstone ground-water zone. The seismic surveys carried out for oil exploration have allowed the lithostratigraphic units to be correlated throughout the basin and the geological structures to be mapped. The techniques used for oil exploration have been used to map the aquifer units. In this way the Thumbli Sand has been mapped from its outcrop at the northern limit of the licence block for over 100 km to the south where it is oil-bearing in the Raageshwari Oilfield. **(Refer Figure 2.24 & 2.25)**

Hydraulically, the aquifer is predominantly confined or semi-confined, becoming unconfined to the north and west. **The aquifer covers an area of approximately 2800 km² and has saturated thicknesses of the order of 400 m**. Data from pumping tests suggest that significant permeability (hydraulic conductivities of up to 100 m/day) is present in the north east; seismic and other data imply that permeability decreases towards the west and south. Average recharge, based on the water-table fluctuation method, is estimated to be about 30 mm/year based on data for 1994-2003.

The volume of the Thumbli aquifer (excluding the shales) is estimated from geophysical data to be 9.5×10^{11} m³ (WMC, 2004, Appendix B). Assuming an average porosity of 20 per cent, this would imply a pore volume of 1.9×10^{11} m³. With an abstraction rate of 25,000 m³/day for 25 years, the volume of water required for the oilfield would be 228×10^6 m³. This volume – probably far more than is likely to be needed – therefore represents only 0.12 per cent of the volume of water in storage in the aquifer **(Refer Figure 2.26)..**

The WMC assessment at the conclusion of the Phase 1 Study (WMC, 2004) agrees with GWD and CGWB that a considerable, currently undeveloped, saline ground-

water resource is present in the southern two-thirds of the Thumbli aquifer. It appears that this resource could be abstracted from a well field south and east of the existing fresh-water fields using bore-wells with yields estimated at 1000-1500 m³/day at 500 to 1000-metre spacing.

2.9.3 Saline Water Well Field Design

The conceptual design for the well field is a network of 24 bore-wells, at a minimum spacing of 1 km. These would be arranged in two rows, each with 12 bore-wells. The tentative layout of the saline well field is shown in **Figure 2.10**.

If all 24 bore-wells were connected to a single line, then there would be a risk of interference and backflow, especially if any reflux valves failed. Therefore, groups of three bore-wells would be connected together, and pump to a central reservoir. There will therefore be 8 groups of 3 bore-wells. Within each group, 200 mm diameter pipe would be required from each bore-well to the junction point, then 300 mm diameter pipe to the reservoir. It is estimated that the pumping head for each submersible pump would be 110 m, discharging at 18.94 l/s, requiring 41 kW power at 440 V. Each bore-well would be equipped with individual pump control valves, reflux valves, flow meter and sampling tap. The collection reservoir would have a storage capacity of 2-hours pumping (about 2620 m³), from where the water would be boosted to Mangala through a 700 mm diameter pipeline 12.9 km long plus a 600 mm diameter pipeline 6.5 km long. This would require a pumping head of 50 m, discharging at 363 l/s, requiring 300 kW power at 33 kV. Other provisions are 24 switch rooms at bore-well sites, and one main booster pump room at the collection tank site.

Table 2.1

Details of Number of Well Pads, Production & Injection Wells

Field Description	Max. No. of well Pads	Max. No. of Production Well /Pad	Max. No. of Production well	Max No. of Injection Wells/Pad	Max. No. of Injection Wells	Max. No. of Wells
Mangala	15	13	195	13	195	390
Aishwariya	8	5	40	5	40	80
Saraswati	4	6	24	-	-	24
Raageswari	6	6	36	-	-	36
Raageswari Gas	2	4	8	-	-	8
Saline water Abstraction well	Wells to abstract saline water from the Thumbli aquifer (300 – 500 m deep)					24
Reject Water Injection (Dump)	Disposal of RO reject water (> 1500 m deep)					6
Total	35		303		235	568

Table 2.2

Mangala Field Development Plan

A		WELL PAD
No. of Well Pads		15
Max. Capacity of Each Well Pad (BOPD)		25,000
Max. No. of Production Wells/Pad		13
Max. No. of Water Injection Wells /Pad		13
Injection Water / Injection Well		263 m ³ /well
B		GGS
No. of GGS		4
Max. Capacity of each GGS (BOPD)		25,00,0
Total Field Production (BOPD)		100,000
C		CPF
No.ofCPF	1 (Common for Mangala & NA)	
Max. Produced water (BWPD)		306,000
Min. External (raw water) water (BWPD)		144,000
Max. Injection water (BWPD)		380,000
Max. Associated Gas (MMSCFD)		17
Max. Lift Gas (MMSCFD)		100
D		CTF
No. of CTF	1 (Common for Mangala & NA)	
Storage Capacity (BBLs)		600,000

Table 2.3
Aishwariya Field Development Plan

A	WELL PAD
No. of Well Pads	8
Max. Capacity of Each Well Pad (BOPD)	5,000
Max. No. of Production Wells/Pad	5
Max. No. of Water Injection Wells /Pad	5
Injection Water / Injection Well	318 m ³ /well
B	GGS
No. of GGS	2
Max. Capacity of each GGS (BOPD)	10,00,0
Total Field Production (BOPD)	20,000
C	CPF
No. of CPF	Mangala CPF will be used
Max. Produced water (BWPD)	306,000
Max. External (raw water) water (BWPD)	144,000
Max. Injection water (BWPD)	380,000
Max. Associated Gas (MMSCFD)	3.4
Max. Lift Gas (MMSCFD)	2
D	CTF
No. of CTF	Mangala CTF will be used
Storage Capacity (BBLs)	600,000

Table 2.4
Saraswati & Raageswari Field Development Plan

	SARASWATI	RAAGESHWARI
A	WELLPAD	
No. of Well Pads	4	6
Max. Capacity of Each Well Pad (BOPD)	2,000	700
Max. No. of Production Wells/Pad	6	6
Max. Produced water (BWPD)	400	140
Max. Associated Gas (MMSCFD)	0.07	0.28
B	GGS (Common for Saraswati & Raageshwari)	
No. of GGS	1	
Max. Capacity of GGS (BOPD)	8,000	
Max. Capacity of Produced Water Treatment (BWPD)	1,600	
C	CTF (Common for Saraswati & Raageshwari)	
No. of CTF	1	
Storage Capacity (BBLs)	40,000	

Table 2.5

Raageshwari Gas Field Development Plan

Raageshwari Gas Field	
A	WELL PAD
No. of Well Pads	2
Max. Capacity of Each Well Pad MMSCFD	10
Max. No. of Gas Wells/Pad	4
B	GCS
No. of Gas Collection Station (GCS)	1
Max. Capacity of GCS (MMSCFD)	20

Table 2.6
Details of Pipeline Corridor

Field	P/L From	P/L To	Number of Lines	Size
Mangala	Each Well Pad	GGs	8	3" to 16"
	GGs	CPF/CTF	8	3" to 24"
Aishwariya	Each Well Pad	GGs	8	3" to 10"
	GGs	CPF/CTF	8	3" to 8"
Saraswati	Each Well Pad	GGs/CTF	3	3" to 10"
Raageswari	Each Well Pad	GGs/CTF	3	3" to 10"
Water Wells	Water Field	GGs/NA	1	3" to 10"
Mangala	CPF/ CTF	Captive Power Plant	4	6" to 12"
Raageshwari Gas Field	Raageshwari GCS	Mangala CPF/CTF	2	6" to 12"
Water Injection Lines	CPF/ CTF	Each Well Pad	TBD	8" to 28"
Injection (dump) Waste water disposal lines	CPF	Injection (Dump) Wells Field	1	18"

Table 2.7

Estimated Land Requirement

Field	Facility	No. of Facilities	Area / Facility (Ha.)	Total Approx. Area (Ha.)
Mangala	Well-Pad	15	2.5	37.5
	GGS	4	15	60
	CPF & CTF	1	50	50
	Power Plant	1	30	30
N-A	Well-Pad	8	2.5	20
	GGS	2	12	24
Saline Water	Water-Well	24	0.50	12
	Reservoir	1	1	1
Reject Stream Injection	Dump Well Field	6	0.50	3
Saraswati	Well-Pad	4	2.5	10
	CPF&CTF	1	7.5	7.5
Raageswari	Well-Pad	6	2.5	15
Raageswari Gas	Well-Pad	2	2.5	5
	GCS	1	13.5	13.5

Table 2.8
Estimated Power Requirement

Field	Facility	Installed Power (KW)	Operating Power (KW)	Total Operating Power (KW)	Source
Mangala	Well-Pad	840	810	12,150	Common Captive Power Plant
	GGs	2,900	2,000	8,000	Common Captive Power Plant
	CPF/CTF	31,750	20,250	20,250	Common Captive Power Plant
	Desalination	7,500	5,000	5,000	Common Captive Power Plant
Aishwariya	Well-Pad	185	160	1,280	Common Captive Power Plant
	GGs	1,500	1,050	2,100	Common Captive Power Plant
Saline Water Well	Bore-wells	75	50	1,200	Common Captive Power Plant
	Reservoir	400	300	300	Common Captive Power Plant
Saraswati	Well-Pad	480	410	2,460	Onsite 500 KW Genset (Crude / HSD / Natural Gas)
	CPF	1265	930	930	Onsite 1500 KW Genset (Crude / HSD / Natural Gas)
Raageswari	Well-Pad	430	380	2,280	Onsite 500 KW Genset (Crude / HSD / Natural Gas)
Raageswari Gas	Well-Pad	55	35	70	Supplied from Raageswari GCS
	GCS	4000	3000	3,000	Generated at location by 2 No.-2 MW Gas Fired Engine Driven Genset

Table 2.9

Estimated Fresh Water Requirement

Field	Facility	Water Requirement (KL/day)				No. of Facility	Total Water Requirement (KL/day)
		Process Water	Domestic Water	Greenbelt Development	Total / Facility		
Mangala	Well-Pad	10	1	4	15	15	225
	GGS	100	5	45	150	4	600
	CPF/CTF	100	15	95	210	1	210
N-A	Well-Pad	5	1	4	10	8	80
	GGS	50	5	20	75	2	150
Saline Water Well	Bore-wells	0.5	-	1.5	2	24	48
	Reservoir	0.5	0.5	4.5	5	1	5
Saraswati	Well-Pad	5	2	13	20	4	80
	CPF	50	10	30	90	1	90
Raageswari	Well-Pad	5	2	13	20	6	120
Raageswari Gas	Well-Pad	5	2	13	20	2	40
	GCS	50	10	40	100	1	100
Captive Power Plant		125	5	20	150	1	150
Total Water Requirement							1898

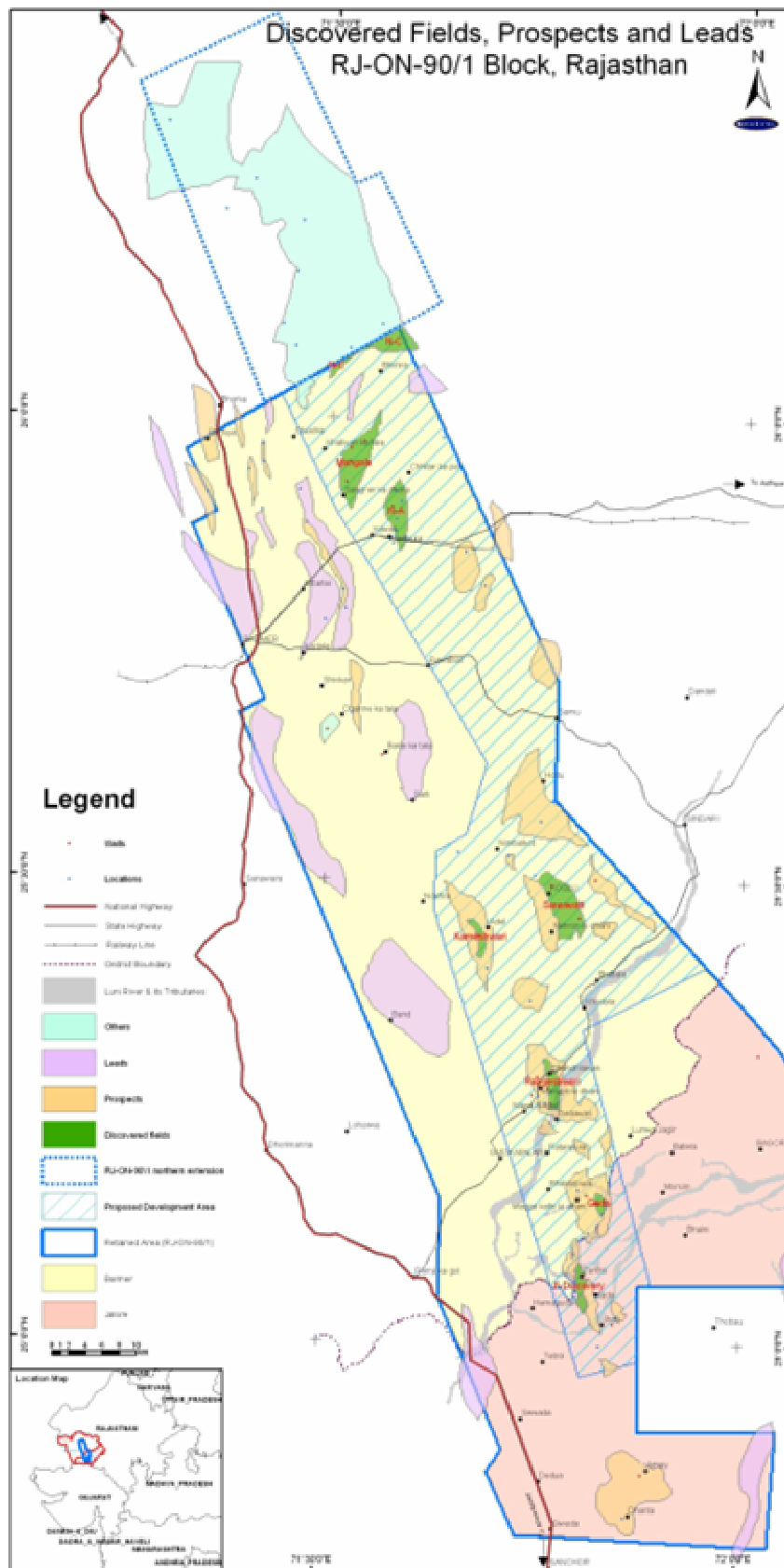


Fig. 2.1: RJ-ON-90/1 Block with Discovered Fields

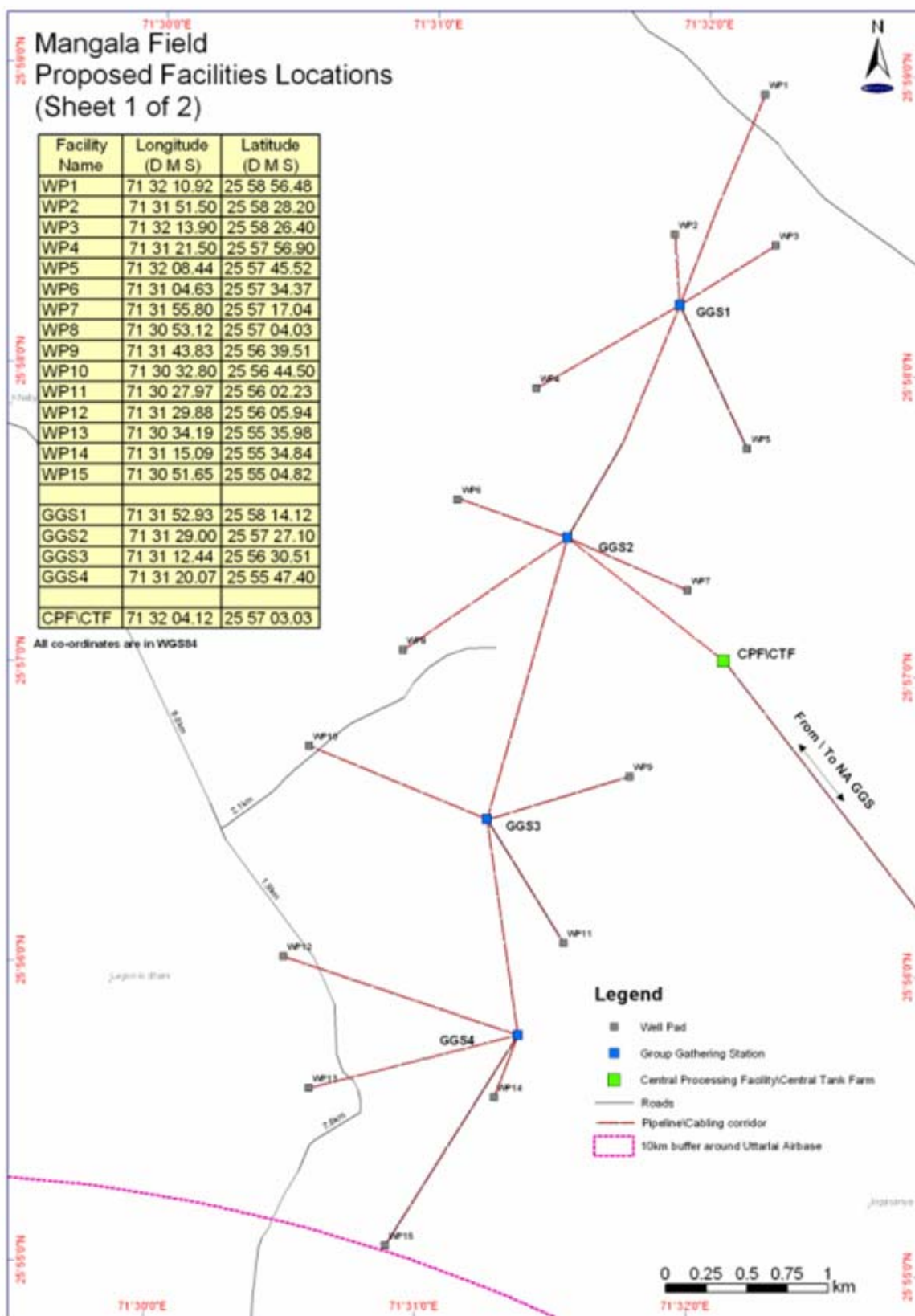


Fig. 2.2: Mangala Field - Locations of Well Pads, GGS, CPF and CTF (Sheet 1 of 2)

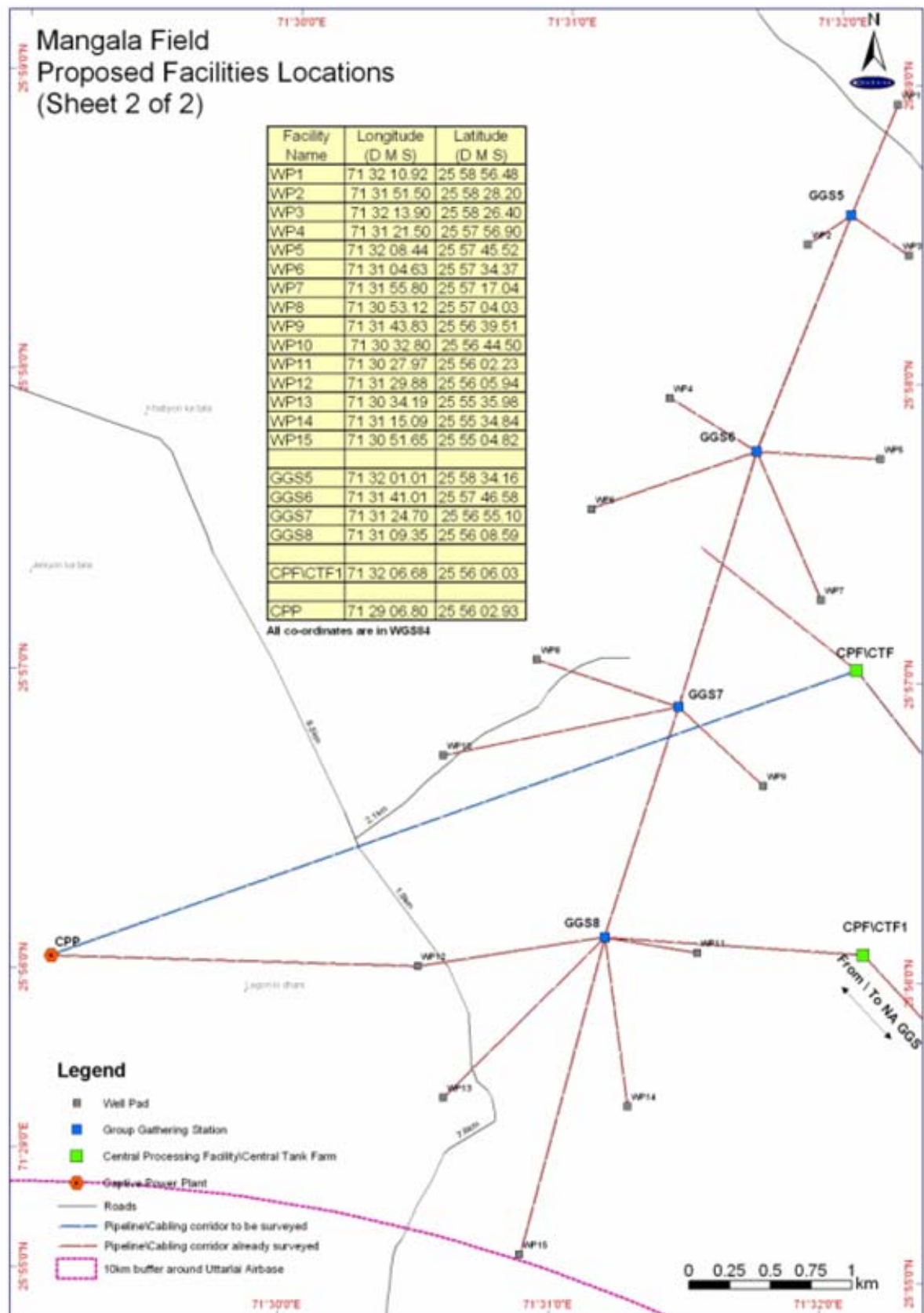


Fig. 2.3: Mangala Field - Locations of Well Pads, GGS, CPF and CTF (Sheet 2 of 2)

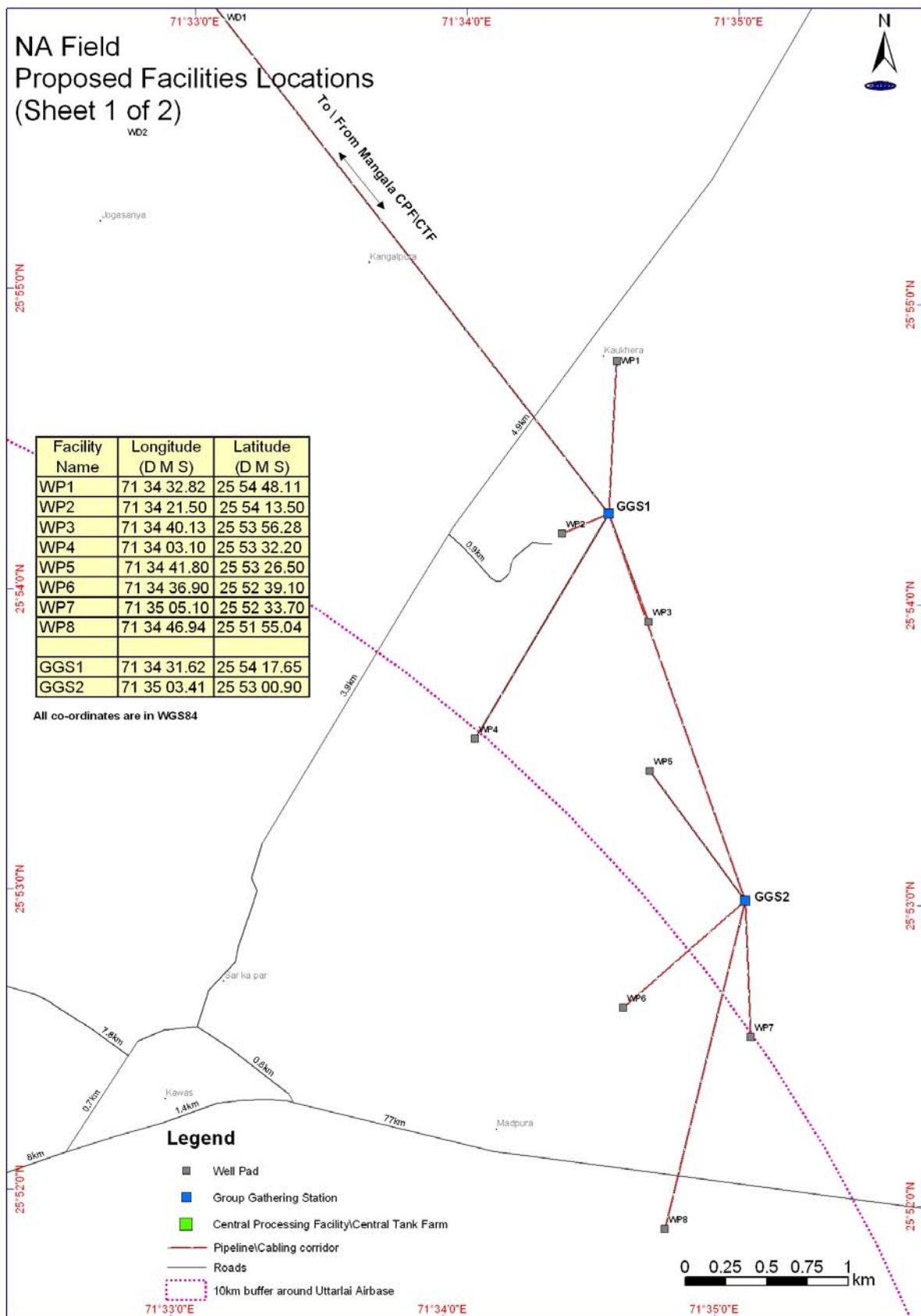


**Fig. 2.4: Aishwariya (N-A) Field - Locations of Well Pads, GGS, CPF and CTF
(Sheet 1 of 2)**

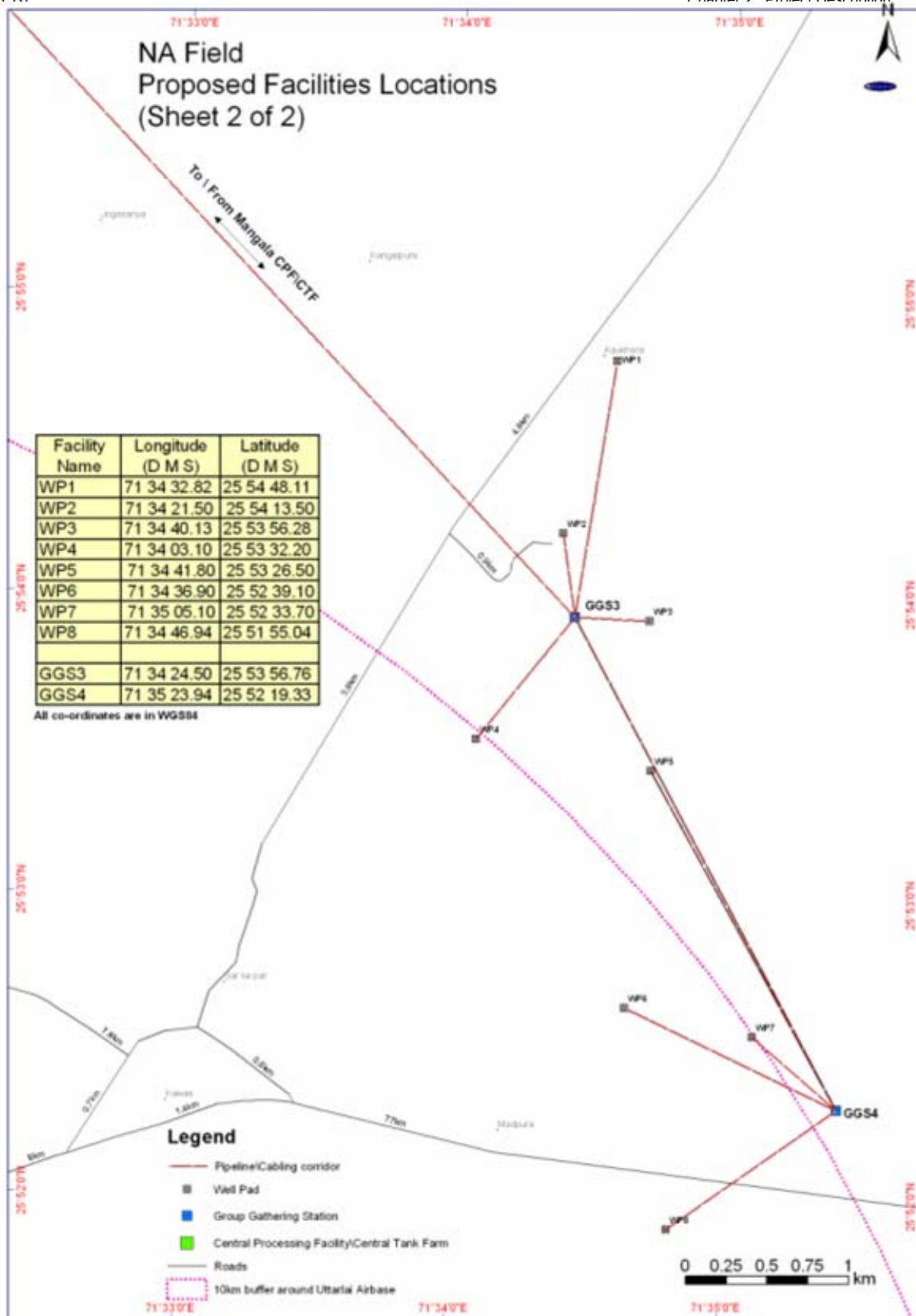


**Fig. 2.5: Aishwariya (N-A) Field - Locations of Well Pads, GGS, CPF and CTF
(Sheet 2 of 2)**

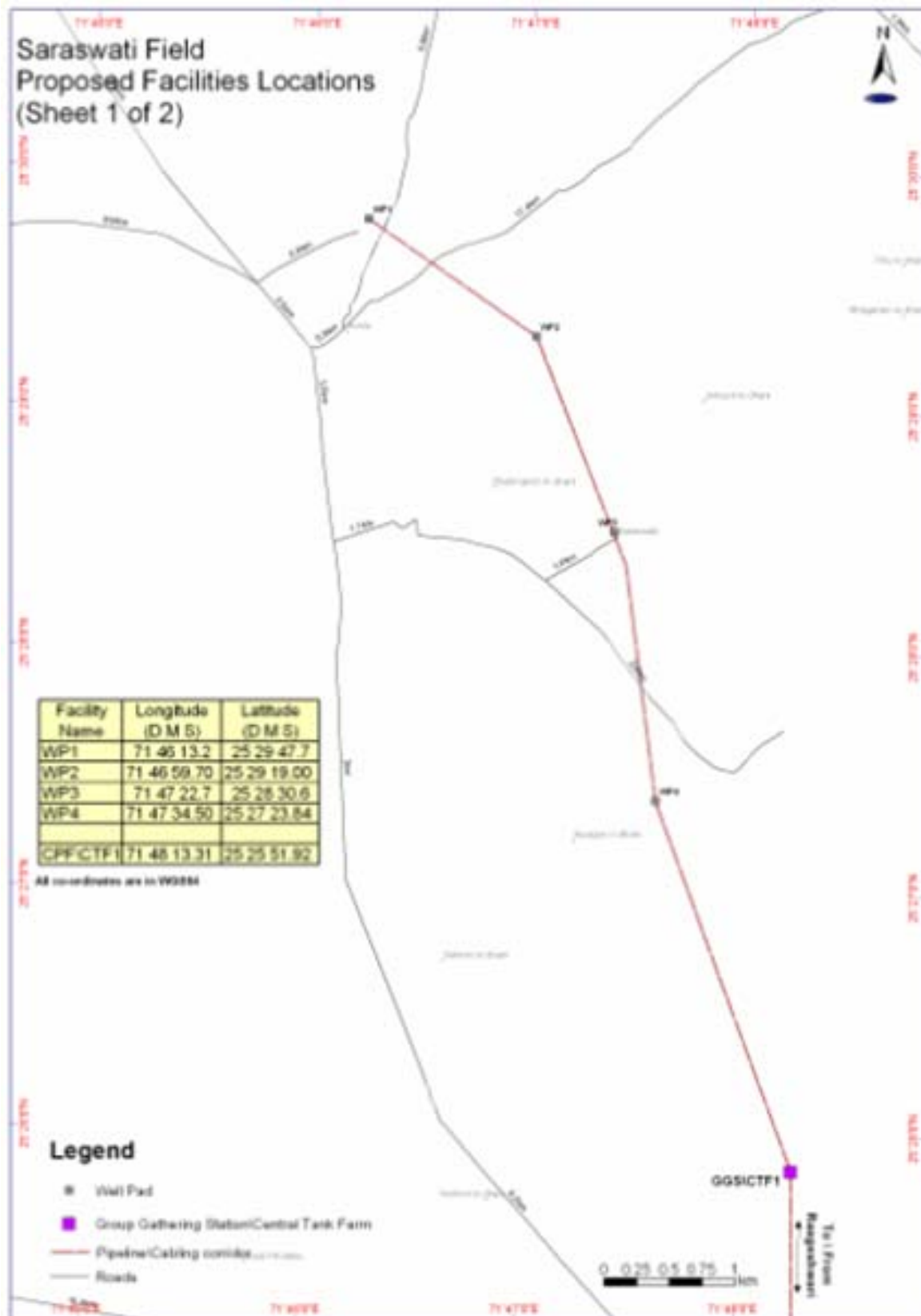


Fig. 2.6: Saraswati Field - Locations of Well Pads, GGS, CPF and CTF (Sheet 1 of 2)

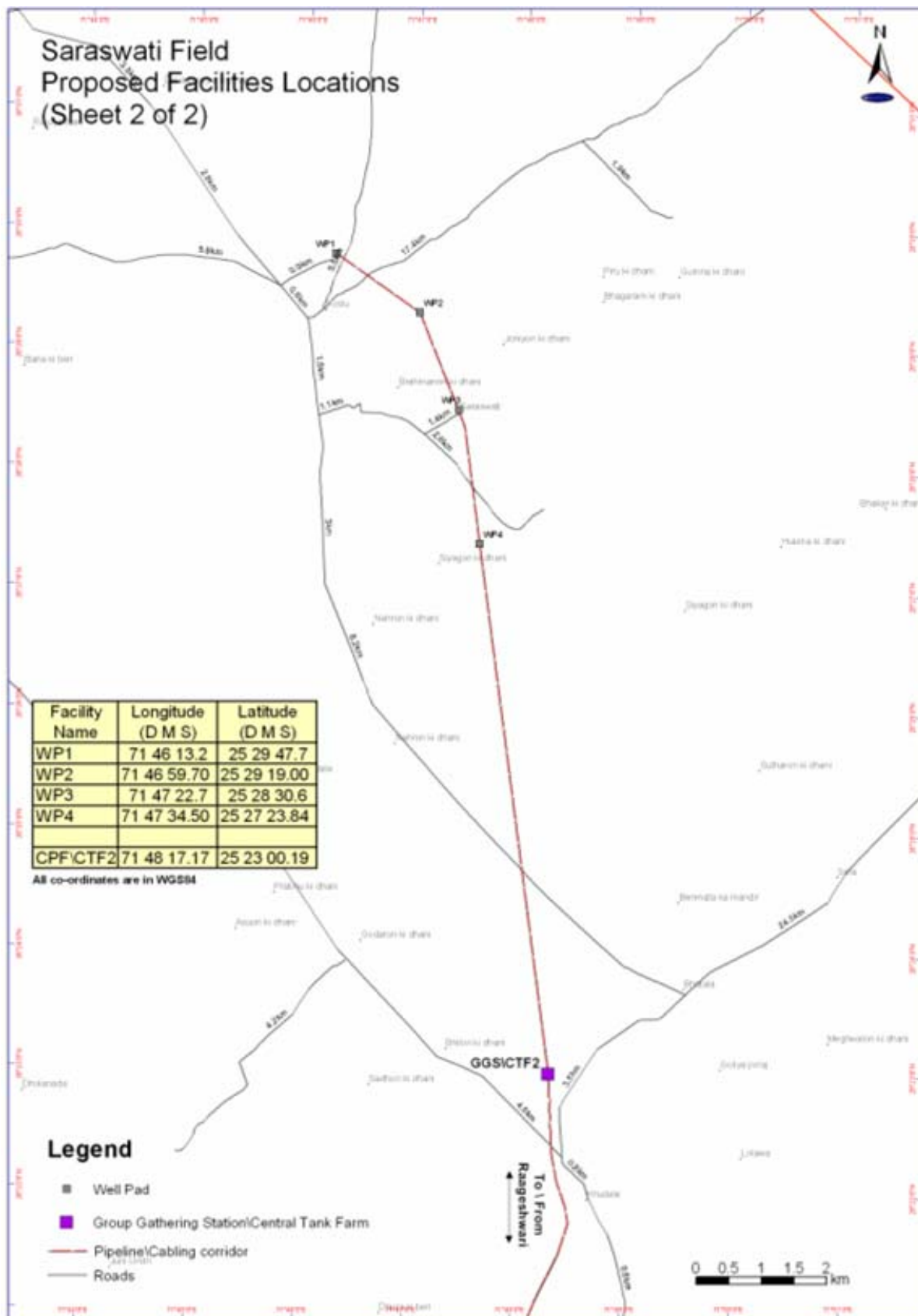


Fig. 2.7: Saraswati Field - Locations of Well Pads, GGS, CPF and CTF (Sheet 1 of 2)

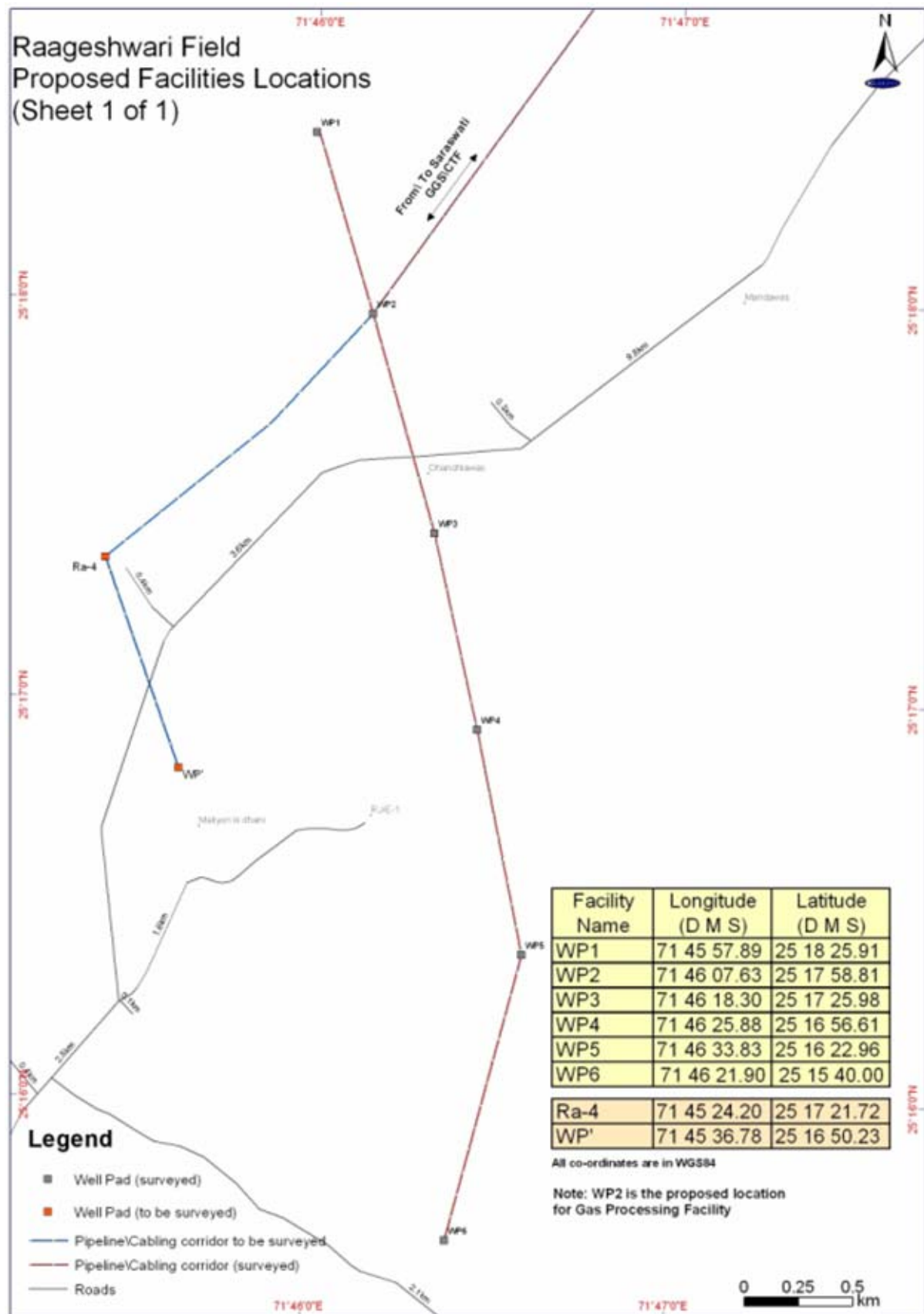


Fig. 2.8 : Raageshwari Oil & Gas Field - Locations of Well Pads, GGS, CPF and CTF

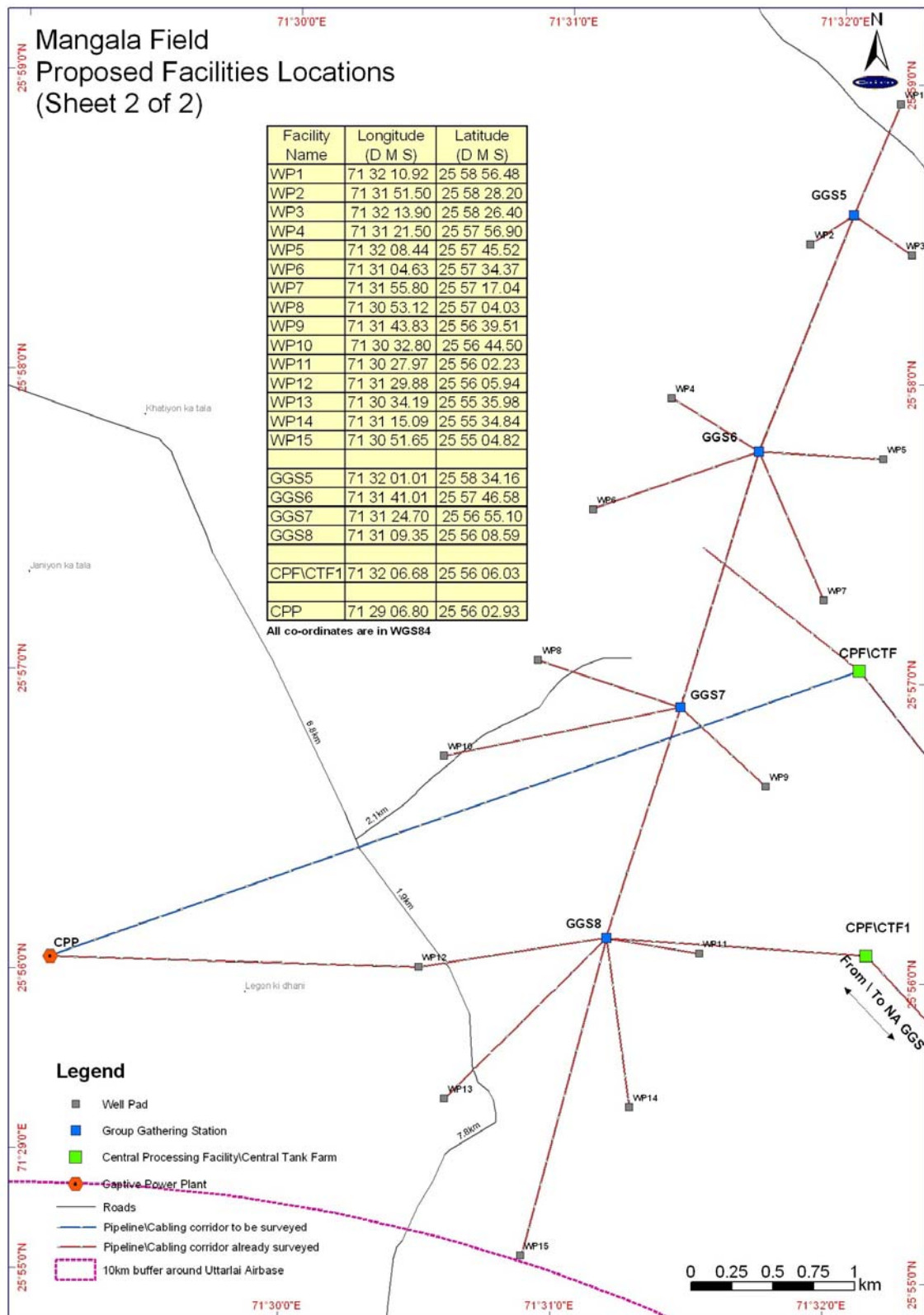


Fig. 2.9: Location of Captive Power Plant & Associated Piping Routing

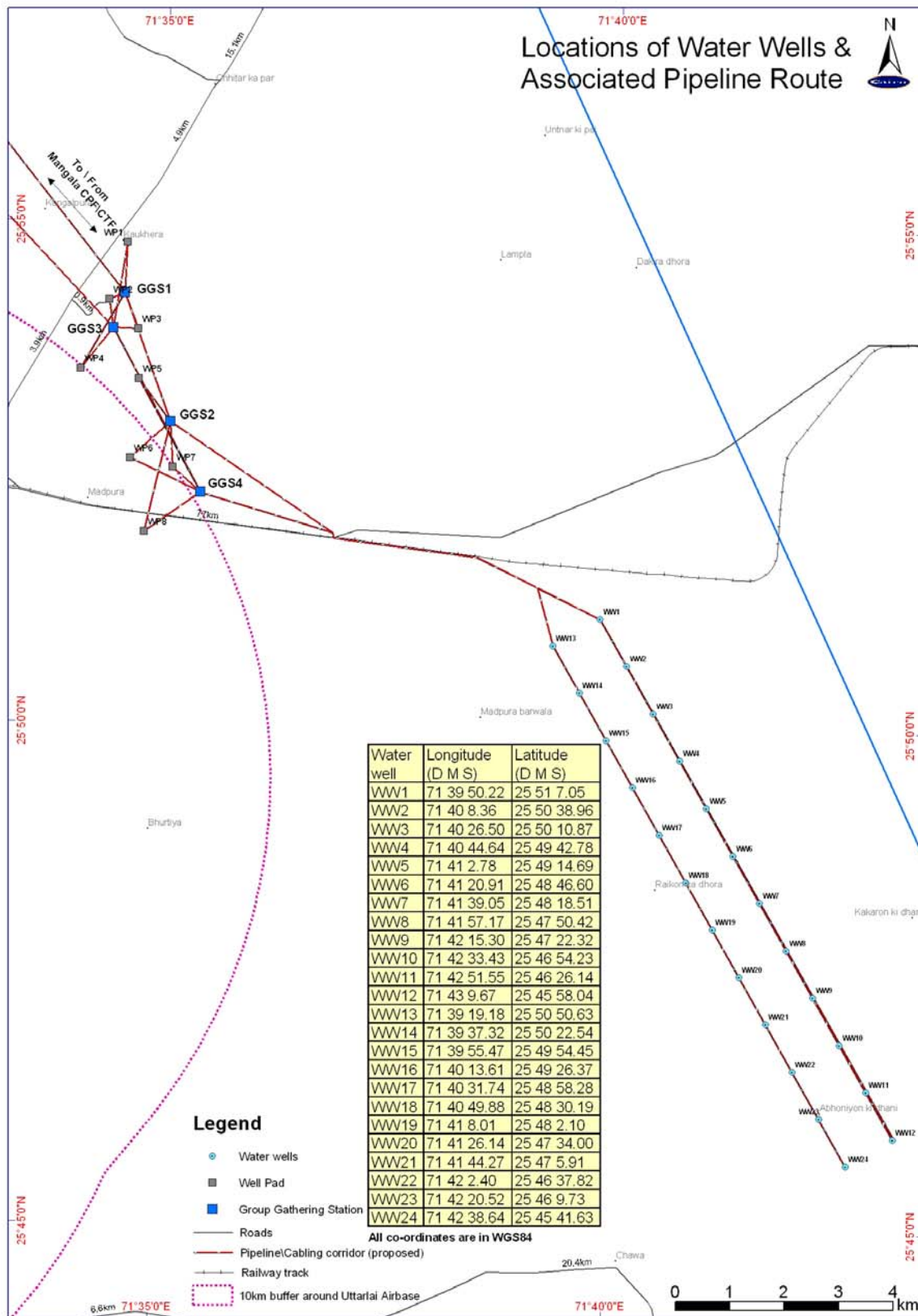


Fig. 2.10: Location of Saline Water Well Field & Piping Routing

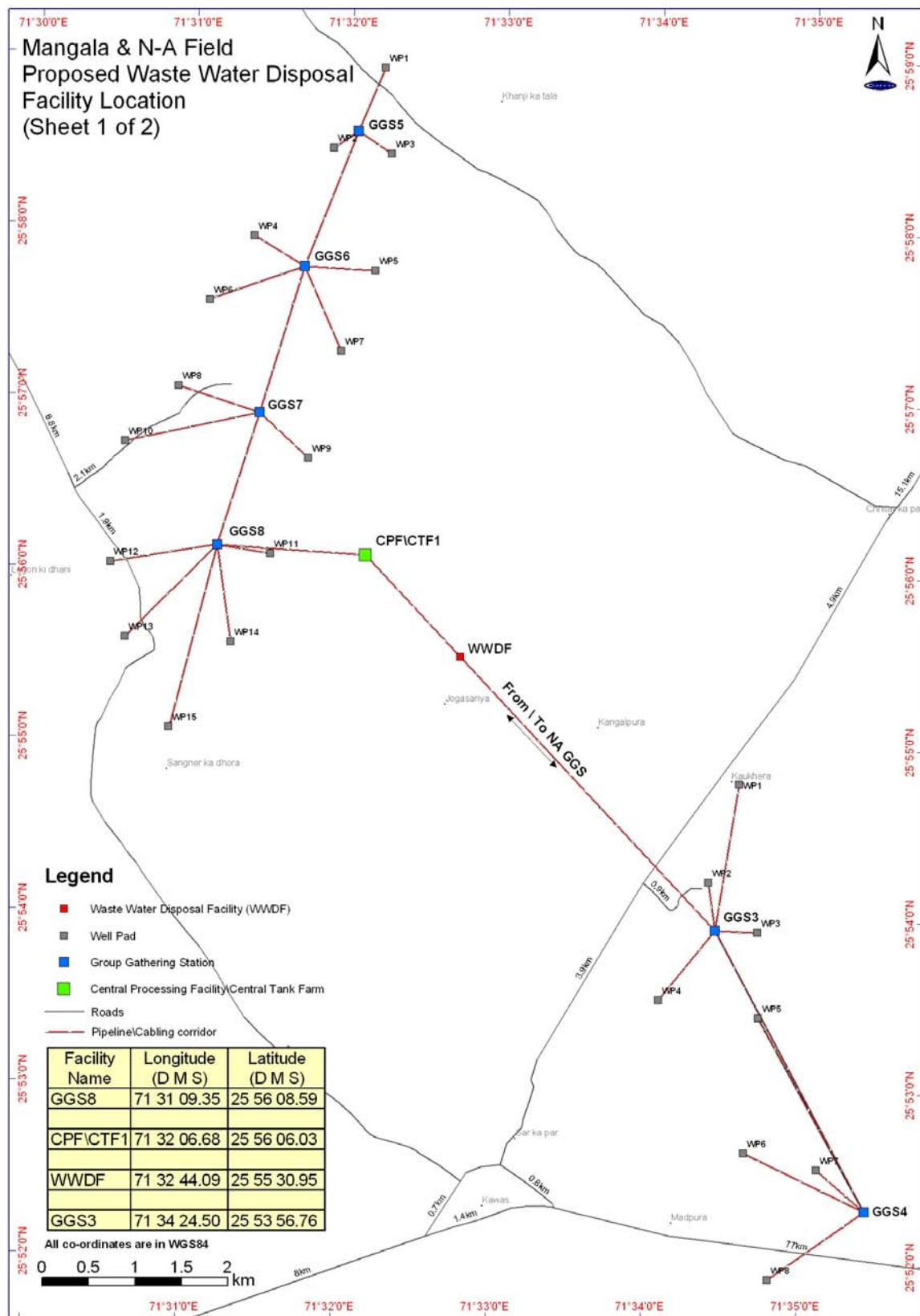


Fig. 2.11: Location of Injection Well Field (Dump Wells)

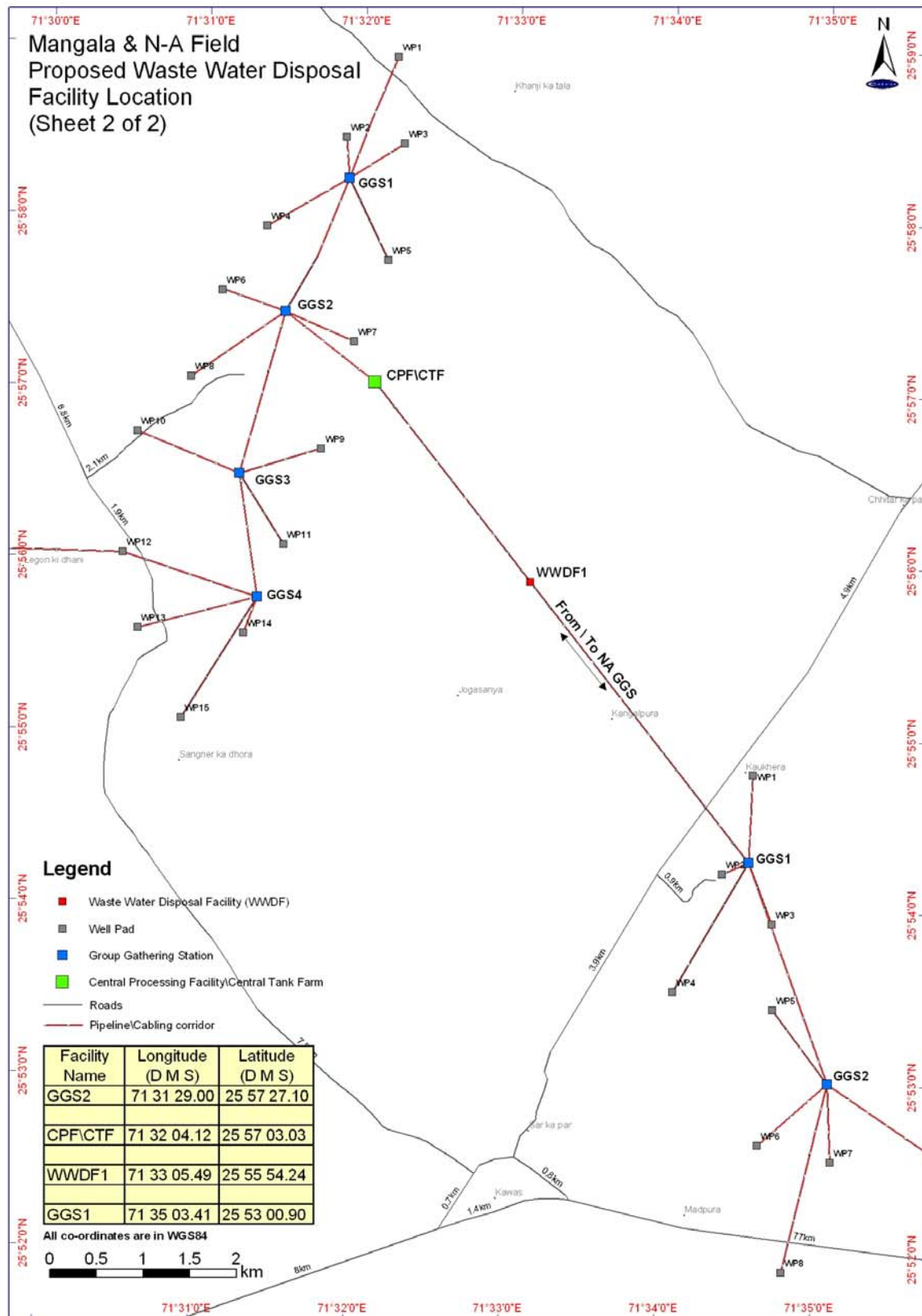


Fig. 2.12: Location of Injection Well Field (Dump Wells)

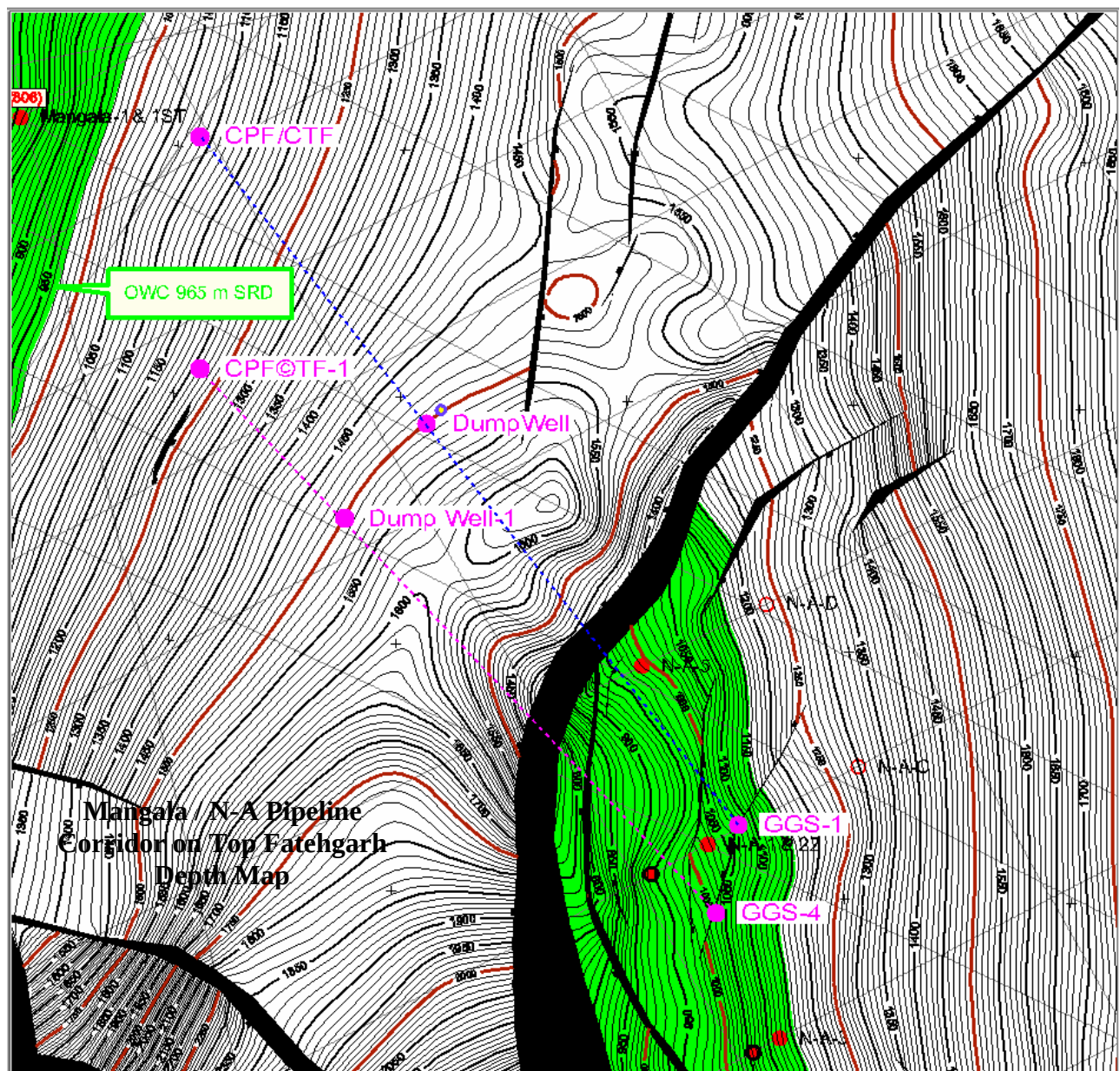


Fig. 2.13 : Location of Injection (Dump Wells)

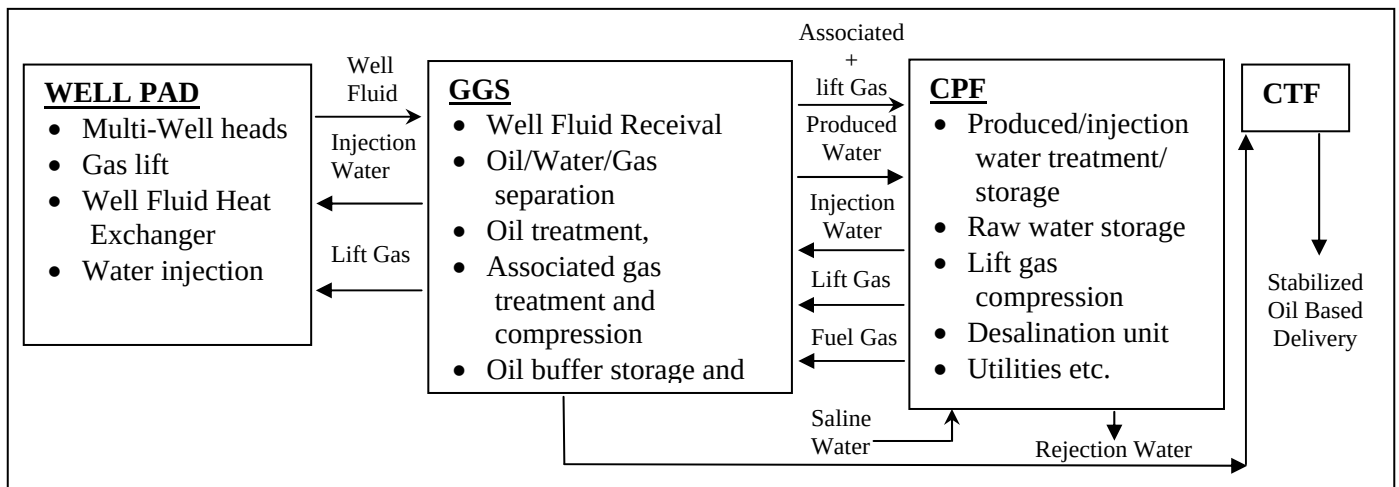


Fig. 2.14 : Mangala Field Architecture

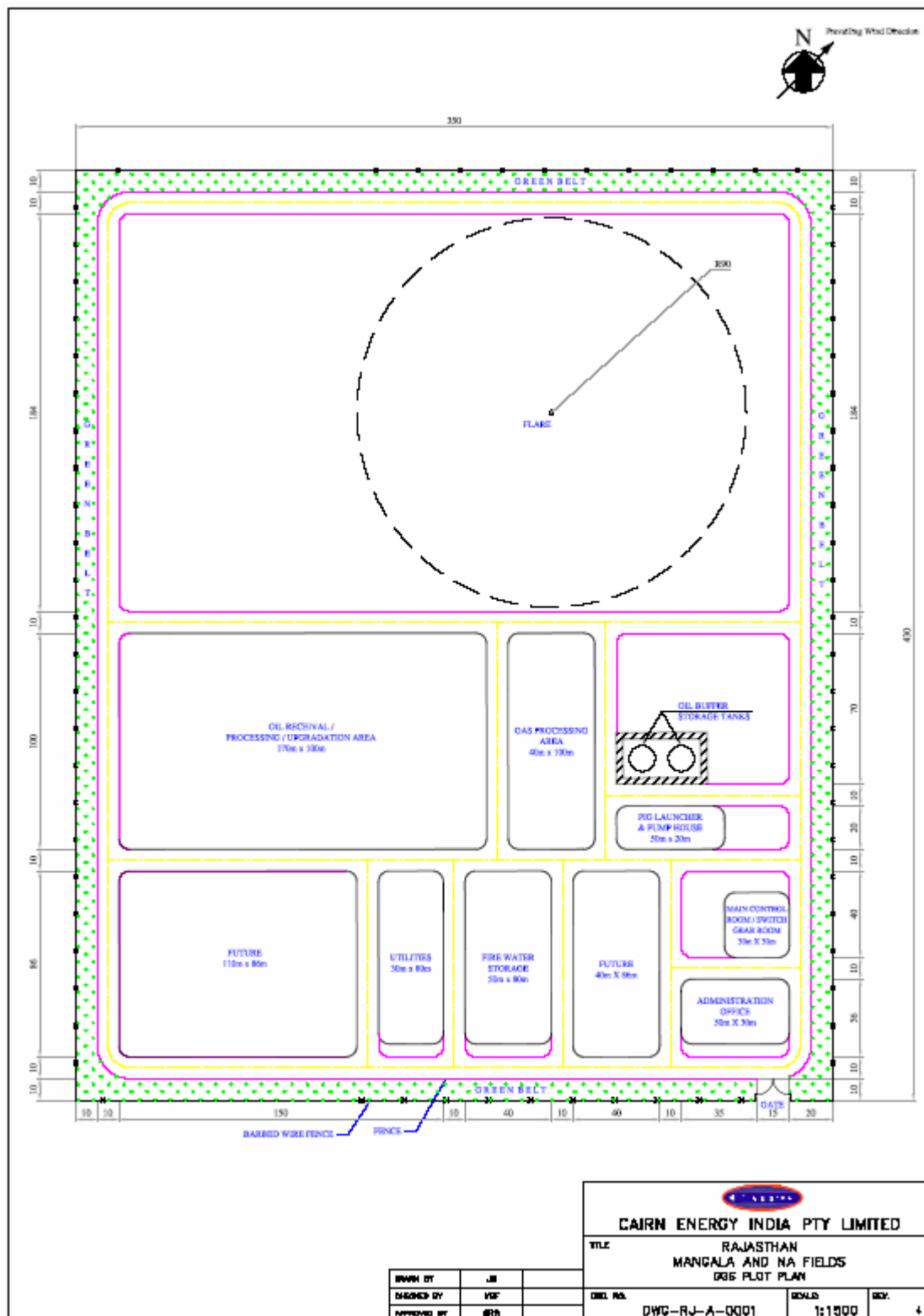
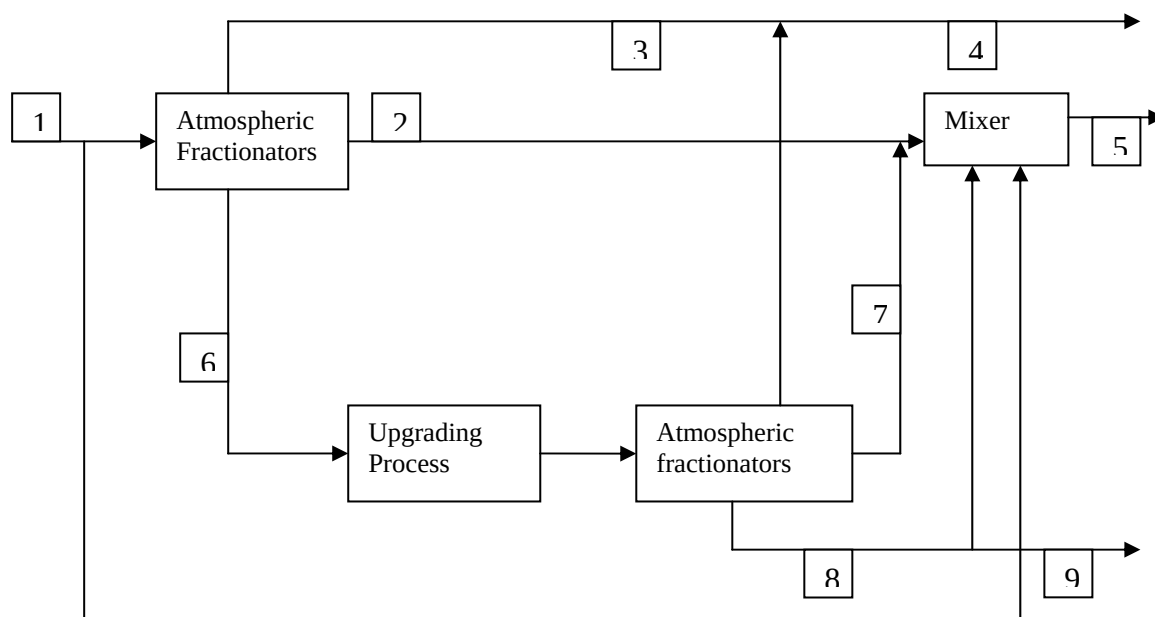


Fig. 2.15 : Typical Layout – Group Gathering Station (GGS)



Legend: 1. Desalted and Dewatered Crude

2. Distillate

3. C4 & Lighter

4. Fuel gas

5. To Pipeline

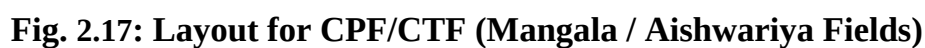
6. Residue

7. Distillate (Diluents)

8. Residue

9. Fuel Oil

Fig. 2.16 : Conceptual Process Flow Diagram for Oil Upgradation Plant





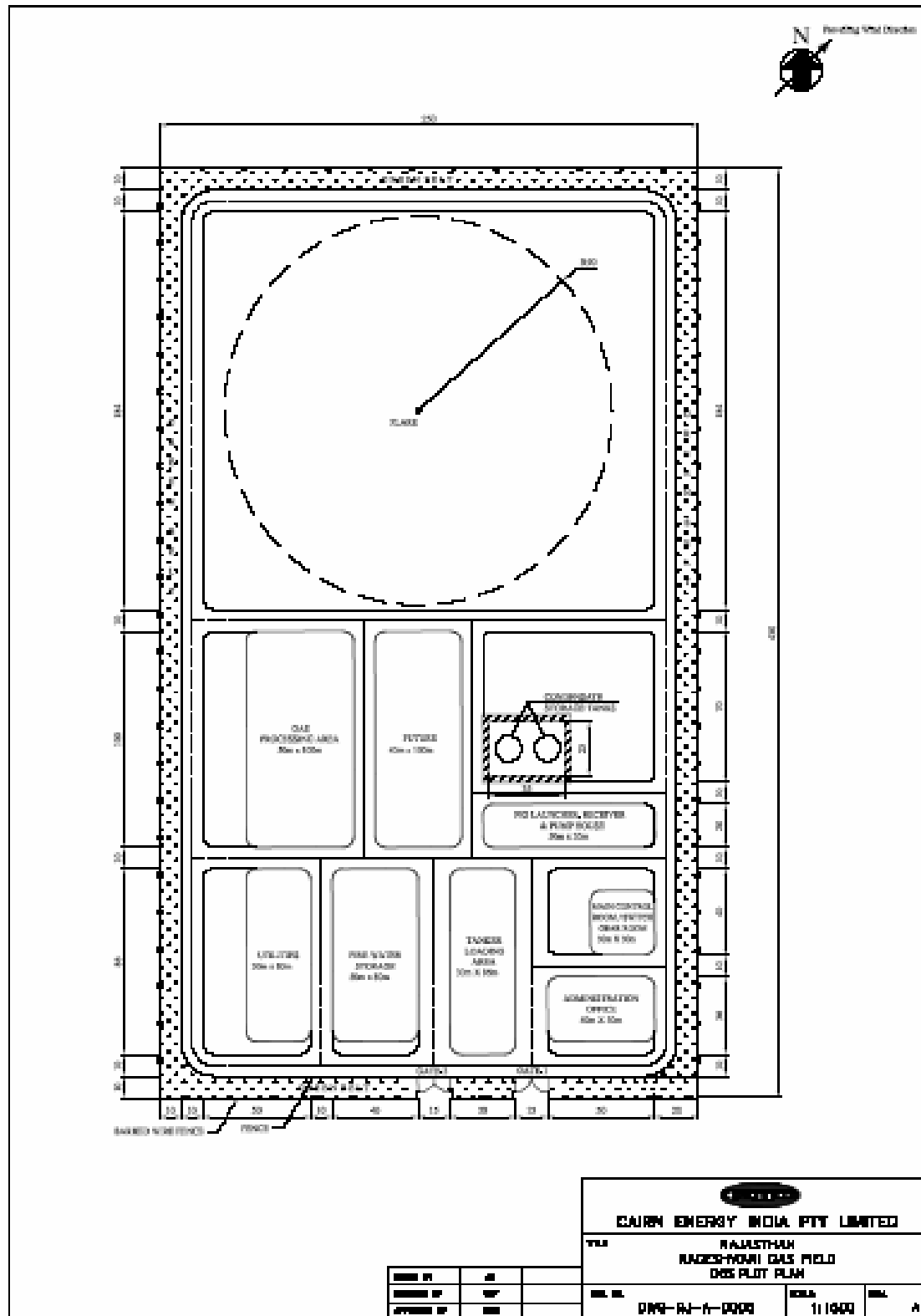


Fig. 2.19: Layout for Raageswari Gas Collection & Processing Station

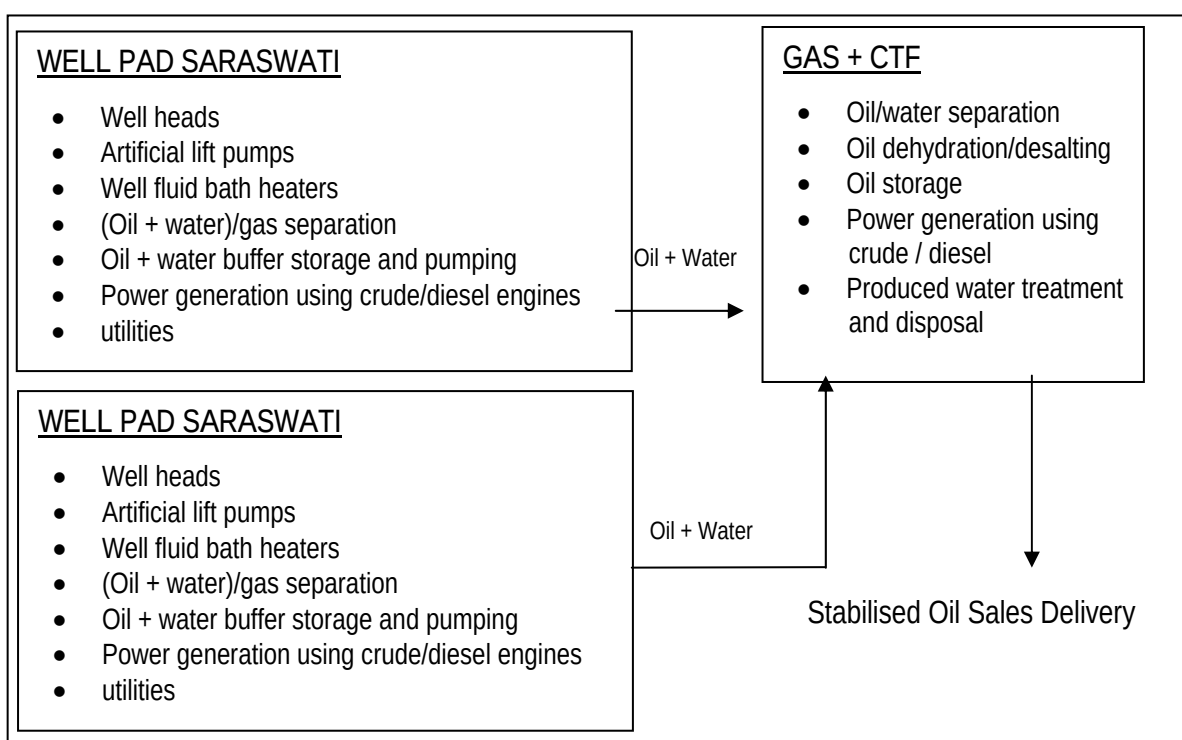


Fig. 2.20 : Saraswati & Raageswari Field Architecture

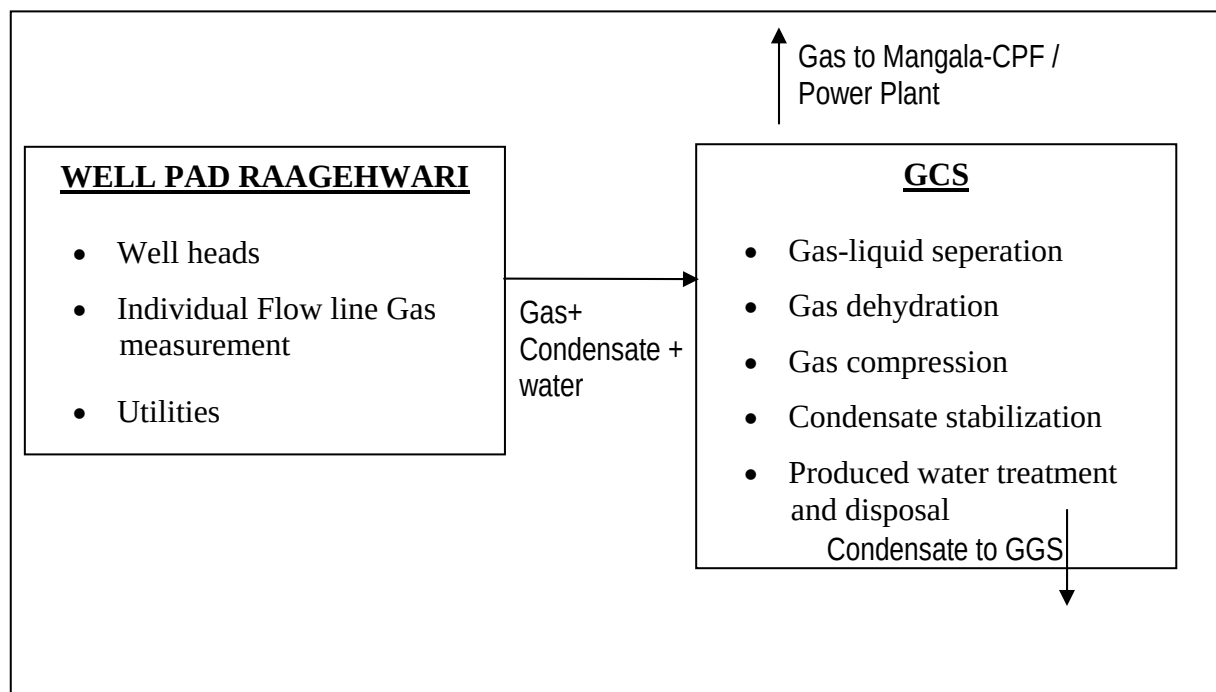


Fig. 2.21 : Raageshwari Gas Field Development Plan

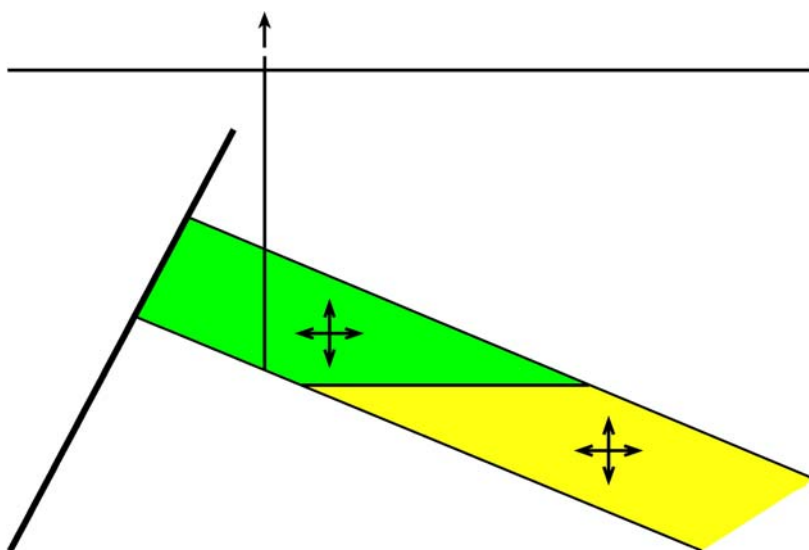


Figure 2.22: Primary production of oil.

(Production depends on expansion of the oil and the water in the reservoir, and gas coming out of solution. Recovery efficiency is low)

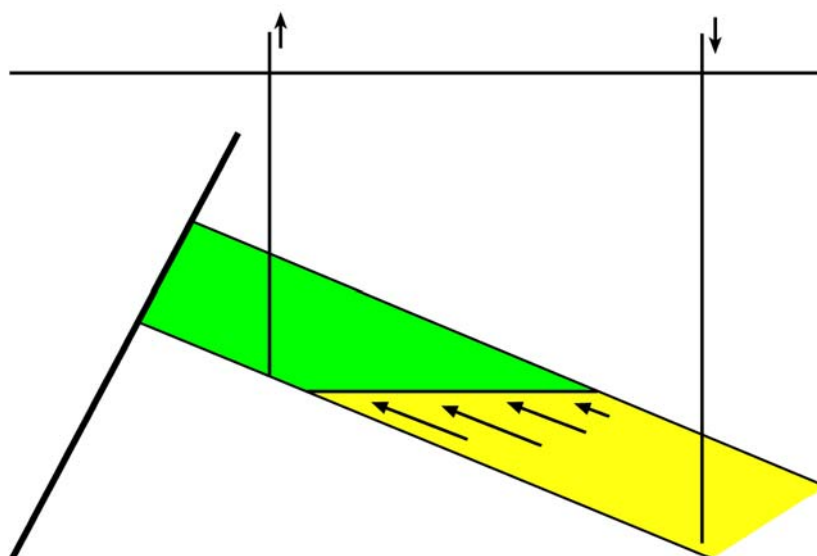


Figure 2.23: Secondary Recovery of Oil Using Water for Pressure Support

(As oil is removed from the oil pool, water is injected into the water body beneath it to maintain pressure and help drive the oil from the reservoir. Recovery efficiency is greatly improved.)

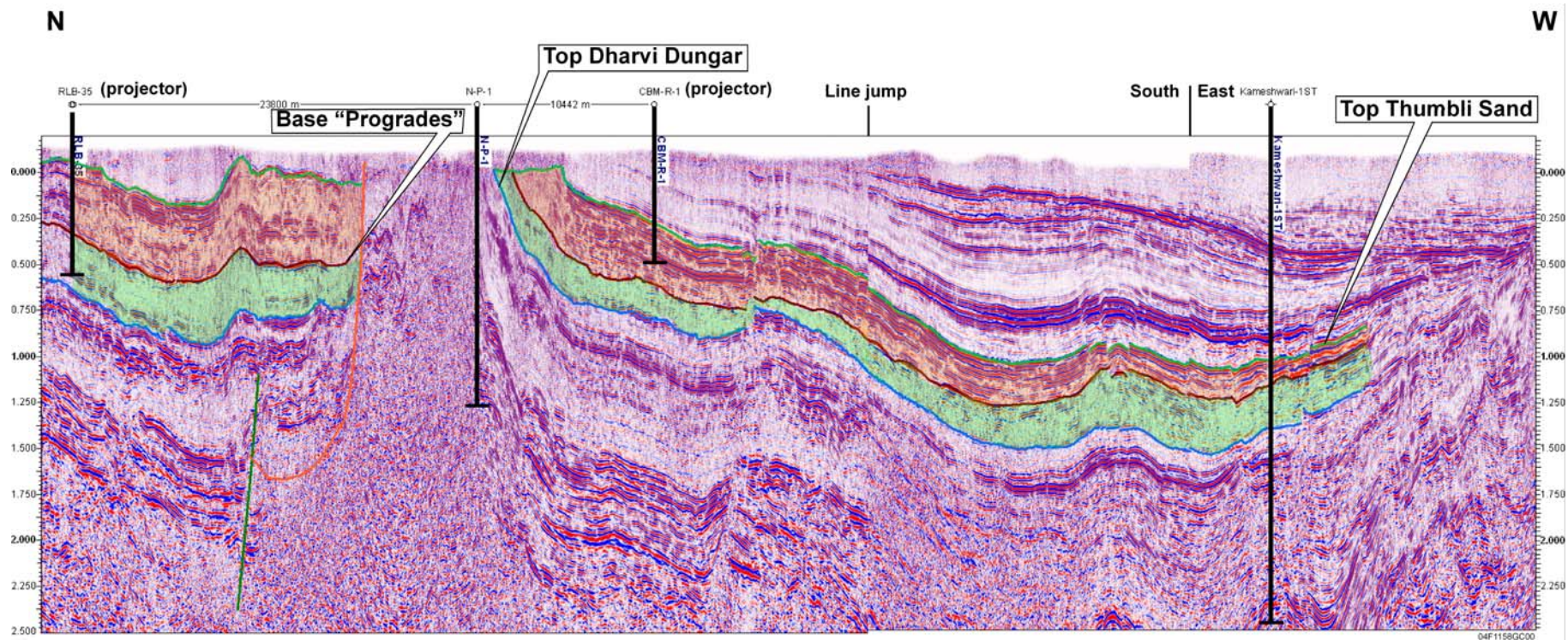


Figure 2.24: Seismic section (approximately N-S) through the Barmer Basin showing the Thumbli Sand (red-orange) as it deepens and thins towards the south

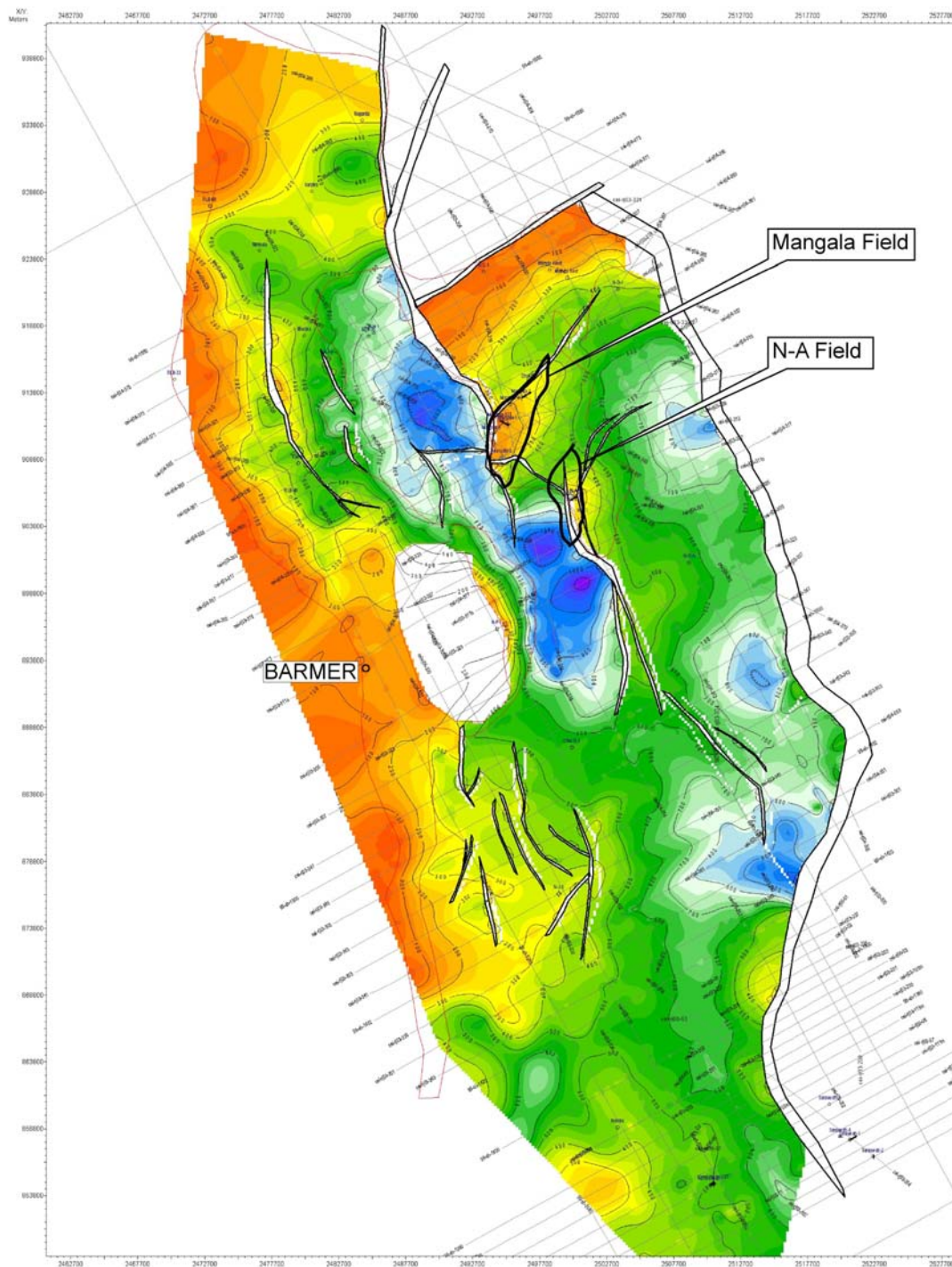


Figure 2.25: Thickness map of Thumbli Sand showing areas of maximum thickness (>700m) in blue

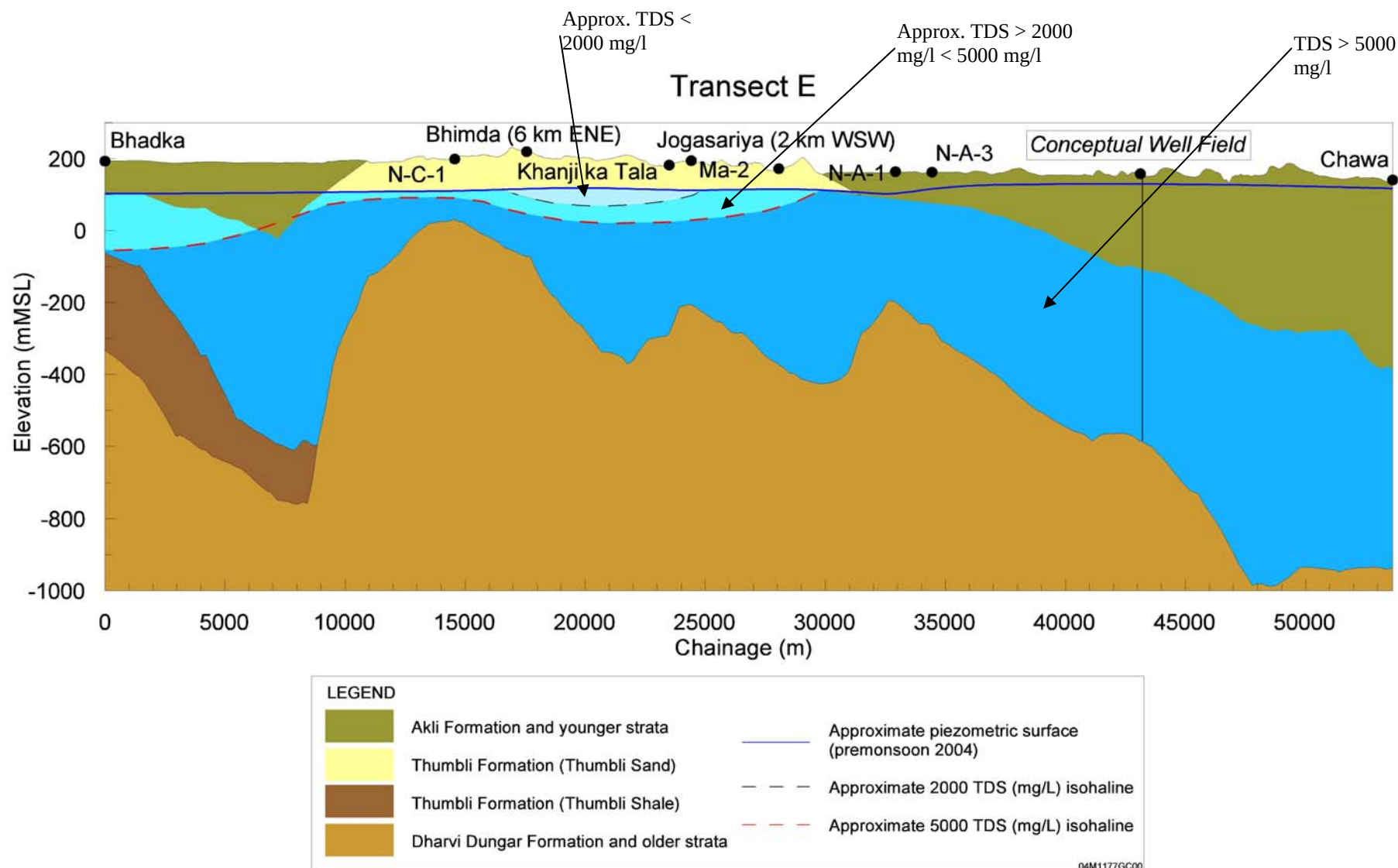


Figure 2.26: Cross-section through the aquifer showing the inferred disposition of fresh and saline water.