accommodated in one of the spare lines. The exact quantity of the various chemicals that may be required will be determined when water production characteristics are determined, after start up.

4.1.6 OFFSHORE PIPELINE

4.1.6.1 Routing

A common feature of all the development concepts considered in detail for Corrib was the requirement for an offshore gas export pipeline. To this end, preliminary offshore and onshore surveys were carried out in 1999 as reconnaissance for possible pipeline routes.

The potential offshore pipeline routes and landfalls under consideration at this time covered the north west coast to the east of Corrib from Donoughmore bay to Killala Bay.

Results of the 1999 offshore survey indicated significant areas of rocky seabed for all the routes south of (and including) Blacksod Bay, through which there was no obvious pipeline corridor without the need for substantial seabed construction works (e.g. rock-dumping, cutting and/or blasting). Subsequent feasibility study work therefore concentrated on the northern landfalls comprising, Broadhaven Bay, Bunatrahir Bay, and Killala Bay with a preference for Broadhaven Bay due principally to:

- The shorter length of the offshore pipeline (thus minimising the liquid handling problems associated with multiphase flow);
- The shorter length of the offshore controls umbilical (thus minimising the need for potentially unreliable joints and maximising the range of vessels capable of carrying out installation);
- The identification of a suitable location behind Broadhaven to site the required on-shore gas processing plant;
- The result of an extensive offshore route survey carried out in the summer of 2000 confirmed the viability of a pipeline route between the Corrib infield facilities and Broadhaven Bay. The proposed route is shown in Figure 4.4 and extends some 83.2km to 87.5km (dependent on the selected path around Erris Head) to the landfall at Dooncarton.

4.1.6.2 Landfall and onshore section

The preferred landfall location for the offshore gas export pipeline is a sandy beach area at Dooncarton requiring the construction of a conventional trench and cofferdam configuration to allow the pipeline to be pulled ashore. An alternative location at Brandy Point (a cliff located a few kilometres west of Dooncarton) reduces the length of the offshore pipeline but requires either directional drilling or tunnelling to effect a landfall.
From the landfall, a further 8.7km section of pipeline is required onshore to complete the offshore pipeline system and tie-in to the gas terminal facilities. This short onshore section of the pipeline is routed via the north bank of the Sruwaddacon estuary and makes two river crossings.

4.1.6.3 Bathymetry and soils

The bathymetry of the pipeline along the proposed pipeline route is shown in Figure 4.5. The route features an area between KP 7 and KP 21 which is characterised by iceberg scours. The resulting uneven seabed requires careful routing of the pipe combined with remedial measures to ensure pipeline spanning is minimised.

Along the pipeline route, three main types of seabed have been identified:

- Very soft to soft clay
- Firm to hard clay
- Sands and gravels (locally cobbles and boulders)

4.1.6.4 Mechanical design

The selected pipeline sizing for the offshore gas pipeline is 20" in diameter. The 20" diameter was chosen over smaller diameter and twin pipelines (14", 16" and 18") despite its greater cost. This was done for several reasons:

a) It improves pipeline system operability (including turndown and peak flow capacity)

b) It increases the available drawdown and hence allows accelerated production as the pressure drop for a given flowrate is reduced in the 20" line compared to the smaller diameter lines.

c) It will allow daily production rate changes to largely be achieved using onshore control valves, rather than individual well chokes, thus increasing the anticipated reliability of the subsea system.

No tie-ins or tees are currently planned in the offshore pipeline. Our current view is that the risked potential does not justify such upfront expenditure. However, this issue is subject to review.

The pipeline design pressure will be set at or close to the maximum wellhead shut in pressure of 345barg while maximum normal system operating pressures will be in the region of 150 barg. Initial material selection studies indicate that the pipe will be fabricated in API 5L grade X-70 carbon steel with a pipe wall thickness of 28.2mm. However, this may be revised during the detail design phase. This design pressure will also apply to the short (7km) onshore section of pipeline from the landfall to the terminal. This is a significant design input into the routing of this section of line for which a detailed risk assessment will be
undertaken. As part of this risk assessment, consideration will be given to installation of a pipeline isolation valve at the landfall.

To provide protection from external corrosion, the pipe will be coated and provided with anodes as a back-up in case of coating breakdown or damage. Internal corrosion protection will be provided in the form of a corrosion inhibitor which is mixed with the methanol and constantly injected into the flowing pipeline system to form a protective barrier on the internal wall of the pipe.

Periodic internal inspection by “intelligent pig” run from a temporary subsea launcher will enable the integrity of the pipeline system to be verified. No requirement for regular operational pigging (e.g. liquid removal runs) is envisaged.

Pipeline stability will be assured by the provision of between approximately 40mm and 70mm thickness of dense concrete coating on the sealine pipe, with the greater thickness of concrete being used closer to the shore in shallower water where waves action has a greater influence on the seabed installed pipe. In the water depths approaching the shore, further measures are required to ensure pipeline stability and in this area the pipe will be trenched.

4.1.6.5 Protection

The required thickness of steel for design pressure containment plus the concrete coating give the proposed pipeline sufficient strength to resist environmental and fishing loads without trenching in deeper waters, while the line will be trench in shallower inshore waters. Rock-dumping may also be used in areas where span correction is required; this will be determined following post lay survey.

The subsea umbilical and the sea outfall pipe from the terminal will be trenched for their entire length (or protected by rock-dumping where trenching is not possible).

Strict marine operational procedures including the provision of anchor exclusion zones in the vicinity of the pipeline will be applied, to minimise the possibility of interaction with marine vessels in the field area.
4.1.7 TERMINAL

4.1.7.1 Overview

Natural gas from the Corrib field is received from the offshore pipeline at a peak rate of 350 MMscf/d, reducing over the lifetime of the field as the reservoir is depleted. Pipeline fluids include natural gas, aquifer water, condensed water, condensate, methanol and corrosion inhibitor. Methanol is injected to provide hydrate inhibition.

The gas, aqueous and hydrocarbon phases undergo primary separation in the slug-catcher, which then feeds the three main process routes of gas treatment, condensate recovery and methanol regeneration.

The subsea facility provides the necessary methanol injection, control and power requirements via an umbilical. Details are given in Section 4.1.5.4.

The location of the terminal and the onshore portion of the pipeline are shown in Figure 4.6. A schematic layout of the terminal is shown in Figure 4.7.

4.1.7.2 Inlet facilities

Production fluids enter the terminal at up to 135 barg and between 2 and 14°C, dependent upon subsea wellhead flowing conditions, gas rate and ambient conditions.

Provision is made for a temporary pig receiver for pipeline testing / commissioning and monitoring using on-line intelligent pigs. Process isolation of the terminal from the pipeline is available from the plant inlet valve and the terminal is electrically isolated from the pipeline.

The fluids first enter the slugcatcher where the liquid phases are removed. A High Integrity Protection System (HIPS) set at 143 barg isolates the slugcatcher from the pipeline in the event of overpressure, with operator intervention required to initiate blowdown. The liquid hydrocarbons (condensate) and water/methanol that separate out from the gas in the slugcatcher pass to the condensate recovery and methanol regeneration systems respectively.

Gas from the slugcatcher passes, via an inlet heater, to the Inlet Filter Separator. The heater, which is by-passed in normal operation, is used to heat the inlet gas during plant start-up operations hence avoiding low temperature excursions in the downstream equipment. A HIPS system set at 110 barg isolates the Inlet Filter Separator from the slugcatcher in the event of overpressure, with operator intervention required to initiate blowdown. The Inlet Filter Separator provides secondary separation of the gas from any carryover condensate and water. The separator contains a vane pack or equivalent to enhance liquid removal and also a de-mister at the gas outlet nozzle to ensure that the liquid carry-over in the final gas stream is less than 0.01 US gallon/MMscf.
4.1.7.3 Gas treatment

Gas from the inlet filter separator is expanded across the Joule-Thomson (J-T) valve. The effect of expanding the gas chills it and condenses out heavier hydrocarbons, methanol and water resulting in a gas composition that satisfies the export gas quality specification.

As the reservoir is depleted, the arrival pressure to the terminal falls. In about the ninth year of operation, it may become necessary to include a propane refrigeration unit upstream of the J-T valve to satisfy the export gas specification.

4.1.7.4 Sales Gas – compression, metering and export

The gas is then compressed to export pressure by the sales gas compressors. Two discrete compression trains are provided, with each train rated for the plant full flow of 350 MMscfd. Each compressor is driven by a gas-fuelled turbine driver. The compressors will be re-wheeled at various stages in field life to meet the changing operating conditions.

The gas is then cooled and passes to the Sales Gas Metering Package. This consists of 2 x 100% metering runs, where the gas flowrate is fiscally measured. Gas quality measurement is performed by on-line gas chromatograph with data reported to the operator. The metered gas is flow controlled within the package to meet the daily nomination set by the operator.

Fiscal metering facilities will be provided together with online measuring facilities providing automatic determination of gross caloric value, Wobbe Index, relative density and water content/dewpoint as well as hydrocarbon dewpoint. The defined export gas specification also sets limits on H₂S, total sulphur and other components e.g. oxygen and nitrogen. Whilst some of these components are expected to be absent from the gas, clarification is required as to which components require online monitoring.

The metered gas is finally injected with odourant and is discharged from the terminal to the export pipeline. The terminal discharge pressure is a maximum of 100 barg.

4.1.7.5 Condensate system

Condensate received from the offshore pipeline and separated in the process is stabilised by a series of pressure reductions and heating. It is then cooled and transferred to storage tanks via a mercury removal bed to reduce the mercury content of the condensate to less than 0.05 parts per million (ppm) weight percentage. Produced condensate is used as fuel in the terminal or, if in excess, transferred to road tankers for offsite disposal.

There are two condensate storage tanks; one used to collect stabilised condensate from the process and the other used to supply the users. Whenever feasible, the condensate is used in the heating system to minimise export.

An off-specification condensate tank is also provided.
4.1.7.6 Methanol system

Hydrate inhibition in the onshore terminal, subsea facilities and offshore pipeline is achieved by the injection of methanol.

The terminal is serviced by a number of strategically located methanol injection points whilst delivery offshore is via an umbilical. The onshore terminal includes a regeneration facility which regenerates the raw (water-rich) methanol that is returned, via the pipeline, from the subsea facilities, and also stores product (water-lean) methanol prior to re-injection into the offshore facilities.

Three raw methanol storage tanks provide seven days capacity in the event of a regeneration system failure / shutdown.

Raw (water-rich) methanol solution is treated in the regeneration system where the methanol still produces an overhead product (98% methanol) and a column effluent water containing 50pppm methanol or less. The still consists of a multi-tray column with heat input provided by a kettle re-boiler. The re-boiler is serviced by the heating medium system.

The product methanol from storage is pumped to the desired location by the terminal, wellhead or pipeline injection pumps. Corrosion inhibitor is injected into the methanol stream downstream of the export filters.

4.1.7.7 Utilities

The following utility systems are provided at the terminal.

4.1.7.7.1 Fuel gas system

The primary source of fuel gas is taken from the discharge of the sales gas compression system (at 103 barg, 35°C) whilst a secondary, start-up source is available directly from the inlet heater (at 110 barg, 2°C). The high pressure source gas is pre-heated to 50 °C and is then let-down to a pressure of 40 barg, prior to feeding the independent HP and LP fuel gas systems.

The high pressure (HP) fuel gas system supplies a dedicated fuel source to the sales gas compressor turbine. The pre-conditioned source gas is let-down to the HP system operating pressure as it enters the HP fuel gas knock out drum where liquids are removed. The gas stream is routed to the electric HP Fuel Gas Heater which provides 20 °C superheat. Further conditioning is provided within the vendor scope as necessary.

The low pressure (LP) fuel gas system, which has multiple feed streams, feeds a variety of LP fuel users. The system is directly analogous with the HP system with an equivalent pressure let down to the LP fuel gas knock out drum. This vessel is provided for liquid dropout removal with a dedicated electric heater again supplying 20 °C of superheat prior to gas distribution. Further conditioning is provided within the vendor scope as necessary.
4.1.7.7.2 Flare

The plant has two discrete flare systems, from HP and LP sources. The flare systems have separate collection headers, stacks and flare tips, but the stacks utilise a common structure.

No flaring occurs from either system during normal operation. The HP flare system is sized for a flow of 350 MMscf/d, providing full flow relief of the gas export system, while the LP flare system is sized for a flow of approximately 8 MMscf/d. Both flare systems will utilise pilot-less ignition system.

4.1.7.7.3 Closed drainage system

Operational and maintenance drainage from the Process and Utilities areas of the terminal could be contaminated with hydrocarbons. It is collected via a dedicated piped closed drain collection network. This collects all operational and maintenance drainage associated with process and utility items.

The fluids so collected are transferred to the Closed Drains Drum. Pumps are then used to transfer the aqueous or hydrocarbon phase back to the process.

4.1.7.7.4 Oily water sewer system (open drains)

Water that could be contaminated with oil is designated as oily water. Typically this includes wash down water, accidental oil spills and the storm water run off from paved areas in the process areas. Rainwater or firewater falling on the associated open paved areas run via drains to the oily water sewer.

Bunded areas drain away from the tanks and equipment. A bund contains the greater of 110% of a single tank or 25% of the total tankage within the bund. The bund contents are isolated using valves outside the bund wall to contain any spillages and to control the discharge to the oily water sewer.

All fluids flow to a tilted plate separator where any oil is removed. Clean water overflows into a storage sump which also contains treated water from the produced water treatment facilities. Once the water has been tested and shown to meet emission limits, it can be discharged to the offshore outfall.

4.1.7.7.5 Produced water treatment and disposal

The aqueous phase recovered from the methanol still is sent to the Effluent Feed Sump where its quality and composition can be assessed. If the levels of methanol and / or other substances are within the required emission limits, the water can be pumped directly to the treated water sump for discharge with other treated water.

The produced water is kept separate from other wastewater so that it can be further treated if necessary in a self-contained facility. If the levels of contaminants are too high, produced water treatment facilities (i.e. a dissolved air floatation (DAF) unit with sludge treatment) will
be hired to provide the necessary treatment until an optimised permanent replacement can be installed. Sufficient storage capacity has been allowed in the terminal to ensure that water can be stored until appropriate treatment facilities are available.

All treated water is sent to the Treated Water Sump where it is discharged to the offshore outfall with rainwater. An outfall pipe (8" in diameter) will be laid from the terminal to the landfall and beyond into the Bay. The pipe will terminate subsea with a diffuser that will be designed to be snag free and protected from dropped objects such as anchors. The outfall will be used to disperse the discharged water from the terminal. The emission limits for the effluent will be set in the Integrated Pollution Prevention and Control Licence for the terminal. Special processes and controls will be used within the terminal to ensure any discharge meets these standards. The volume of produced water to be discharged is not expected to exceed 100 m$^3$ per day (Tables 3.14 and 3.15) although the actual volumes will only be known after production has commenced.

4.1.7.7.6 Power generation

The plant is self-sufficient in power generation, and the three power generators, each rated at 1020 kW, operating as 3 x 50% units to meet the maximum continuous duty over the lifetime of the plant. An emergency generator is rated at 650 kW is included to provide emergency power to critical users on loss of the normal power supply, or to meet black-start demands.

The power generators run on LP fuel gas. The emergency generator runs on diesel and is provided with its own day tank to ensure security of supply.

4.1.7.7.7 Firewater protection

The firewater protection system comprises water deluge systems, foam systems, hydrants, hose reels and monitors. The capacity of the firewater system (1200 m$^3$/hr) is based on the worst case scenario of a fire in the process area with simultaneous deluge of the area on fire and the adjacent areas provided by 4 x 50% firewater pumps. Two jockey pumps are provided sized at 5% of fire pump capacity and sufficient for one hydrant.

Due to the remote location of the terminal from the nearest emergency services, a total of six hours storage of firewater is provided in a pond. The pond is sized for 6 hours plus allowances for evaporation, freezing conditions and firewater jockey pump supply. Make-up water is from the local fresh water supplies.

The fire mains is a 16" grid system to provide a minimum discharge pressure of 7.0 barg at the furthest monitor or hydrant and the pressure range requirements for the worst case nozzles of deluge/foam systems. The fire main contains sectionalising valves capable of isolating various sections of the fire main for maintenance purposes.

Fixed roof tanks, with or without internal floating roof, containing condensate or methanol, have fixed foam chambers designed to pour foam solution onto the liquid surface.
Fixed firewater deluge system are provided for the protection of hydrocarbon tanks, pumps, compressors, vessels and tanker loading areas. Each deluge system is capable of local remote manual operation at the skid and at the control room.

Hydrants provide a source of firewater for the fire hose, portable monitors, mobile foam units, mobile foam trailers and fire fighting vehicles. Water monitors provide a source of firewater for extinguishing and cooling vulnerable parts of equipment, storage tanks and structure throughout the terminal. An operator who is remote from the monitor location operates the monitors.

4.1.7.7.8 Chemicals

The Corrosion Inhibitor Package stores and injects inhibitor into the methanol system for transfer to the offshore facilities.

A scale inhibitor injection system will be provided to inject inhibitor into the methanol still feed line. This will prevent the formation of scale on the column plates and also reduce the frequency of acid washing.

The Odourisation Package stores and injects odourant into the sales gas stream to onshore pipeline. The odourant is as specified by BGE.

4.1.7.7.9 Other utilities

Other utilities provided at the terminal include:

- Heating medium system. Provides heat for methanol re-boiler, condensate heater and start-up heater.
- Instrument air system. This supplies clean, dry, compressed air at 10 barg for Instrument and Plant Air users.
- Nitrogen generation system. A bottled back-up is provided for loss of the nitrogen generator.
- Potable and service water system. Service water is supplied from a mains water supply. The water supplies the potable and service water system, and is also used to top up the firewater pond.
- Diesel storage. Diesel is used for the emergency generator, vehicle filling, and for the diesel drivers on the firewater pumps.

4.1.7.8 Terminal protection system

The subsea pipeline and terminal inlet line will be designed for 345 barg, the slugcatcher and the inlet heater will be designed for 150 barg and the downstream gas dewpointing and sales gas will be designed for 116 barg.
Shut down of the onshore terminal will cause the pressure in the pipeline feeding the slugcatcher to rise as the flow reduces to zero and the pipeline pressure settles out, to a pressure below wellhead flowing pressure.

With the slugcatcher design pressure set at 150 barg, a High Integrity Protection System (HIPS) is included for safeguarding the slugcatcher against over pressure under blocked outlet conditions.

It is anticipated that in early life the slugcatcher operating pressure will be in the range 110 to 135 barg.

An instrument based shutdown system is included to protect against overfill of the slugcatcher. High level detection will automatically result in closure of the inlet isolation valves.

The design pressure of the gas export pipeline is expected to be lower than the compressor discharge pressure. A HIPS system will be provided to protect the onshore pipeline against overpressure from the terminal.

4.1.7.9 Emergency shutdown and blowdown

An emergency shutdown (ESD) system for protection of individual systems will be provided as well as a depressurisation system which will allow for controlled emergency blowdown of the high pressure processing equipment. There are three levels of emergency shutdown:

Level 1 - shuts down terminal facilities.
Level 2 - shuts down a discrete system.
Level 3 - shuts down individual item of equipment.

4.1.8 BGE EXPORT PIPELINE

The construction, installation, commissioning and operation of the gas export pipeline from the terminal to the BGE ring main at Galway is the responsibility of BGE.

4.1.9 LIMITATIONS ON RECOVERY DUE TO CHOICE OF FACILITIES OR PRODUCTION TECHNOLOGY

It is currently anticipated that about seven wells will be required to develop the field (Section 4.3.4). The design of the southern well is being reviewed at present. Issues being considered include fracture stimulation and multi-laterals. If successful such techniques could be applied to well 18/20-4.

The number, location and design of subsequent wells will depend on:
a) Actual well and reservoir performance;
b) Actual gas sales and sales contracts;

c) The success or otherwise of any stimulation techniques employed on the southern well and on well 18/20-4;

d) The ability of the subsea system and terminal to cope with proppant production and our ability to control or prevent the same through 'fracpac' completions;

e) System reliability; and

f) Economic support for the well being considered.

The subsea facilities provide for up to eight wells tied directly to the manifold and are designed such that additional wells can be 'daisy-chained' to the existing wells (Section 4.1.11.1).

The development of Corrib using a subsea tieback to an onshore terminal, rather than using a floating or fixed platform with processing equipment located above the field, will impact the acquisition of data from the field. In particular flow from all the wells will be co-mingled offshore. It therefore will not be possible to divert production from a single well through a test separator. However the development of the field has been designed to maximise the data that is collected on well and reservoir performance. Details are given in Section 6.1.4. Further, in addition to the data collected from the wells and subsea system, it will be possible to gain information on the performance of individual wells, and of their effect on one another, by differencing at the terminal.

The pipeline diameter selected will allow both effective and economically efficient drainage of the reservoir and the ability to operate the field with maximum reliability (Section 4.1.6.4).

Offshore compression would have allowed a slightly lower abandonment pressure than that that will be achieved with onshore compression since there is inevitably some pressure loss in the pipeline to shore. However Corrib is only viable economically if it is developed in the manner proposed in this Plan (Section 4.1.1.3), which does not allow installation of compression offshore.

Overall, no significant limitations on recovery due to choice of facilities or production technology are recognised.

4.1.10 SPARE CAPACITY

The capacity of the system is 350 MMscfpd. Early in field life there is no spare capacity in the system; production is constrained by the terminal capacity. This is particularly true of the $P_{10}$ model. No speculative extra capacity is included in the pipeline due to the marginal economics of the development.

The spare capacity available in the pipeline and terminal later in field life is a function of:
a) Production levels from and reservoir pressures in Corrib and
b) The arrival pressure, composition and volume of third party gas to be transported through
   the Corrib pipeline and processed in the terminal.

Without this information it is not possible to state what spare capacity will be available in the
Corrib pipeline and terminal. In any event, it should be recognised that the transportation
and processing of gas from a further discovery in the area will backout gas from Corrib, the
degree to which this occurs being determined by the above factors.

The terminal layout is such that an eventual expansion of the facilities can be
accommodated.

4.1.11 SCOPE FOR MODIFICATIONS AND EXPANSION FOR UPSIDE, SATELLITE
FIELD DEVELOPMENT AND THIRD PARTY TIE-INS

4.1.11.1 Subsea

The design of the subsea production system’s central manifold features one spare “slot”.
This could be used for an eighth well should this be required to drain the field effectively. If
necessary, further wells can be connected in a ‘daisy-chain’ manner to the manifold via the
proposed cluster or satellite well flowbases.

In addition, the manifold design allows the potential connection of a second manifold (should
this be required for a future satellite field) or, alternatively, a third party tie-in to the export
pipeline can be made at the manifold.

4.1.11.2 Terminal

Space for increasing the capacity of the slugcatcher or for installing a new slug catcher is
allowed local to the slugcatcher. Space is also provided for installing additional gas
processing capacity adjacent to the existing process train.
4.2 PROJECT MANAGEMENT: ORGANISATION AND LOCATION

4.2.1 ENTERPRISE ENERGY IRELAND LIMITED

The Corrib Project is being undertaken by Enterprise Energy Ireland Limited whose high-level organisation is shown in Figure 4.8.

4.2.2 CORRIB PROJECT ORGANISATION

The Corrib Project organisation is shown in Figure 4.9. The Project Team is composed of 100% dedicated members plus support from services that are common to and available in the Dublin Office i.e. Drilling, HSEQ, Legal, Commercial and IS Management.

Personnel requirements are defined and monitored via the Project Personnel Schedule.

The Subsurface and Drilling teams are located in Enterprise’s main Dublin office in Ballsbridge. The remainder of the Project Team is currently located in a separate Enterprise office in Blackrock but is expected to move to Enterprise’s Ballsbridge office in Q2 2001.

All team members are connected by voice, fax and data communications with access to an overall project Electronic Document Management System (EDMS). Team building events are held at regular intervals to ensure awareness, develop relationships and promote communications.

4.2.3 COMMITTEES

A number of corporate committees have been established to support the Corrib Project including:

Advisory Board to:

- Provide timely advice and support to the General Manager and Project Director;
- Facilitate input from disciplines not represented on the Project;
- Augment existing corporate assurance processes; and
- Facilitate knowledge management input to the project.

Bid Committee to:

- Ensure that the procurement process is carried out in accordance with law and good commercial practice;
- Verify that Enterprise’s procurement policy, principles and procedures as set out in the Procurement manual have been observed; and
- Ensure compliance with EU procurement directives.

**IS Steering Committee** to:

- Provide overall guidance and support to the project on IS matters and ensure facilities and services are provided as required.
4.3 PROCUREMENT, CONSTRUCTION, INSTALLATION AND COMMISSIONING

4.3.1 PROCUREMENT, CONSTRUCTION AND INSTALLATION

4.3.1.1 Wells and completions

The Corrib Field is in a remote location and is in an area characterised by extreme weather conditions. Enterprise’s objective with regard to completion equipment and services is to get the completion appropriately designed and installed first time without any long term problems. It is therefore a requirement that field proven equipment is used where possible and that offshore service personnel have previous experience with the particular equipment being utilised.

It should be noted that the installation of the subsea equipment will be conducted in parallel with the completion operations. It is anticipated that about three wells will be drilled and completed after production start-up. The completion design used in the latter wells may be modified based on the results of the first four wells. The plan is therefore to purchase completion equipment for the initial wells in 2001. All additional equipment, including back-up, will be owned by the successful contractor and purchased by Enterprise as required.

4.3.1.2 Subsea

It is intended that EPC (engineering, procurement, and construction) contracts for the offshore pipeline and infield facilities will be awarded shortly after the project is sanctioned. The offshore pipeline and infield facilities will be provided via two contracts. The first will provide for provision of a subsea hardware facilities system (including christmas trees, manifold and control system). The second will allow for the provision of a pipeline and umbilical system, and the installation of all the subsea production equipment with the exception of the christmas trees.

Following onshore fabrication of the principal subsea system components, offshore installation will be scheduled for the working “weather window” of summer 2002. During this period the first four wells will be completed and the christmas trees installed by the selected drilling rig.

Installation and tie-in of the remaining subsea equipment packages will generally be achieved by dynamically positioned, construction class, monohull vessels. Due to the prevailing water depth, all installation operations will adopt remote (diver-less) installation techniques and much use will be made of ROV (Remotely Operated Vehicle) mediated intervention. Depending on the final lift weight of the manifold structure, a separate specialised heavy lift crane vessel may be required to deploy, install, level and anchor the manifold.

The predicted weight and volume of the required main control umbilical is such that a
specialised cable or reel lay vessel will be required for this task. The selected vessel will load the umbilical from the vendors quay side manufacturing facility, and transport it to the proposed landfall site at Broad Haven Bay. The umbilical lay operation will be initiated by pulling the first end of the umbilical ashore. Once secure, the vessel will commence umbilical lay by paying out umbilical onto the seabed while steaming to the Corrib field. The umbilical will subsequently be protected by the use of trenching equipment, which will jet or plough a narrow trench for the umbilical.

The offshore gas export line will be installed by a specialised pipelay vessel which may be an anchored semi-submersible or DP monohull vessel. Installation will be undertaken in the summer season of 2002 and can be initiated at the beach and laid towards the Corrib field or visa versa. In either case, careful co-ordination of pipelay with the other installation activities occurring in the field will be required (see also Section 4.1.6.5).

4.3.1.3 Terminal

It is intended that an EPC (engineering, procurement and construction) contract for the onshore reception and processing terminal will be awarded shortly after the project is sanctioned.

The EPC contractor is expected to commence peat removal and ground preparation work soon after award to ensure civil work can commence as early as possible and aim to complete before the onset of winter of 2001. Requisitions for long lead items will be prepared and issued to the successful EPC bidder for his use. Due to the availability of substantial accommodation within travelling distance of the Terminal site, a construction camp is not envisaged although there will be site offices etc.

Due to the remoteness of the site, lack of port facilities nearby and lack of infra-structure that can used to transport heavy loads (such as modules) a 'stick-build' approach is envisaged. Main mechanical, electrical and instrumentation work is expected during 2002. The mechanical completion is expected during late 2002 with pre-commission and commissioning activities to follow with first commercial gas during first quarter of 2003.

4.3.2 COMMISSIONING

4.3.2.1 Wells and completions

At the end of the completion installation phase, the wells will be left perforated with hydrocarbon gas to the subsea christmas tree. The subsea christmas tree valves and the tubing retrievable safety valve will be closed. Once the wells have been tied in to the subsea production system via production jumpers and controls, the wells will be ready for final commissioning in preparation for gas production once the onshore terminal is completed.
4.3.2.2 Subsea and offshore pipeline

Following installation of the subsea production system, all components will be pressure and function-tested and prepared for production operations. The offshore pipeline system may be de-watered and commissioned by a range of methods depending on the scheduled availability of commissioning gas and the state of readiness of the terminal following completion of subsea equipment installation.

The current envisaged means of pipeline de-watering is by the use of a pigging train consisting of a methanol swab, and nitrogen buffer section driven with compressed air from the onshore section of the pipeline. Once the hydro-test water has been expelled to sea at the Corrib field facilities, the system is sealed and the pressure increased in the pipeline by the continued injection of compressed air from the onshore end. This increase in pipeline pressure reduces extreme cooling effect of hydrocarbon gas expanding downstream of the choke during start up.

The pipeline is initially filled with gas from a single well and is used to reverse the pig train and push the methanol, nitrogen and air back to the terminal. Once the pipeline system is gas-filled, the remaining wells may be brought on line and the normal production flow initiated.

4.3.2.3 Terminal

Following mechanical completion, the pre-commissioning activities will commence on a system by system basis. Once pre-commissioning activities are complete, non-hydrocarbon related systems would be commissioned to be ready for receiving hydrocarbon gas from offshore.

Black start of the terminal will commence with power from emergency generator to provide power for subsea system and essential users. Gas from the pipeline will initially routed to flare via the slug catcher. Once the nitrogen used for 'inerting' the pipeline is reduced to an acceptable level in the gas stream, the inlet facilities will be commissioned first and will provide fuel gas to the power generators. Thereafter, the gas conditioning, compression and metering and export facilities will be commissioned in succession. Enterprise operations staff will be integrated with the EPC contractor staff from early on to enable smooth transfer of operation following performance / test runs.

4.3.3 SCHEDULE

The key elements of the overall schedule are detailed on the Project Level 2 Schedule (Figure 4.10). The following subjects are addressed:

- Regulatory - covers the major consents, permits, licences and approvals required from Government and Regulatory authorities.

In Figure 4.10 it is assumed that the southern well is drilled in 2001 as a vertical well. It is therefore designated 18/25-C.
- Partner agreements - covers the main agreements that are required between Enterprise Energy Ireland Limited and its co-ventures.
- Drilling - details the further wells and well completions to be carried out during the project phase.
- FEED (Front End Engineering and Design)
- Subsea hardware - details the activities for engineering design, procurement and fabrication of the infield subsea facilities.
- Subsea installation - details the activities for engineering, procurement and installation of the infield subsea facilities, subsea pipeline and umbilical.
- Onshore terminal - details the activities associated with the engineering, procurement and construction for the onshore gas terminal.
- Onshore pipeline - details all the activities required to design, procure and construct the onshore pipeline from Broad Haven to Galway, being undertaken by BGE.

The current 'critical path' for the project starts with preparation and submission and approval of the Terminal Planning Application and runs through the onshore terminal activities to commissioning and First Gas Sales.

The target date for commencement of gas sales is 31st January 2003. The achievement of this date is dependent upon the timely receipt of all planning permissions, regulatory consents and approvals, allowing work to commence at the Terminal site at the earliest opportunity. It is also dependent upon completion of a) the offshore subsea installation work during the 2002 summer weather window and b) the onshore pipeline from the terminal to the Galway area and the Ring Main, both being constructed by BGE.
Figure 4.1  Diagram of Corrib production system

NOT TO SCALE

PLEM - Pipeline End Manifold
SDU - Subsea Distribution Unit
UTA - Umbilical Termination Assembly
OTU - Onshore Termination Unit
Figure 4.2  Provisional completion diagram
Figure 4.3  Cross-section through typical control umbilical
Figure 4.4  Map showing alternative routes for the offshore pipeline
natural gas

a3
Figure 4.6  Map showing location of terminal (blue rectangle) and pipeline from landfall to terminal
Figure 4.7  Diagram of terminal process sequence
Figure 4.8  Enterprise Energy Ireland Limited - Organisation Chart (upper level only)
Figure 4.9  Corrib Field Development Project - Organisation Chart
SECTION END
5. DEFERRED DEVELOPMENT AND FUTURE DEVELOPMENT DECISIONS

5.1 DEFERRED DEVELOPMENT

This section is not applicable: there is no deferred development.

5.2 FUTURE DEVELOPMENT DECISIONS

5.2.1 NUMBER OF WELLS AND SUBSEA LAYOUT

It is intended to use the four existing suspended appraisal wells as future producers. A fifth well will be drilled in 2001. The surface location of the fifth well is under consideration (Sections 4.1.3.2 and 4.19), as is the possible stimulation of well 18/20-4 prior its completion. The surface location of the fifth well may impact the layout of the subsea equipment.

The number, location and design of subsequent wells will depend on:

a) Actual well and reservoir performance;
b) Actual gas sales and sales contracts;
c) System reliability;
d) The success or otherwise of the techniques employed on the southern well and on well 18/20-4; and
e) Economic support for the well being considered.

It is currently anticipated that a total of seven wells will be required, but the actual number required may prove to be less or greater than this.

5.2.2 CHRISTMAS TREE CONFIGURATION

The final configuration of the christmas tree to be employed (Section 4.1.4.3) will not be decided until the tenders from the prospective subsea contractors have been fully reviewed and the optimum subsea equipment configuration identified.

5.2.3 METHOD OF PERFORATION

The method of perforating the wells (Section 4.1.4.4) will not be decided until more data are available on actual gun performance in hard reservoir rocks. The
completion method for the southern well and for well 18/20-4 will not be decided until
the data from the former are available (Section 4.19).

5.2.4 ROUTE OF OFFSHORE PIPELINE
The route of the offshore pipeline will be agreed with the contractor awarded the
contract for its construction and installation as it may be impacted by the selection of
installation vessel (Figure 4.4). The possible incorporation of a landfall valve is still to
be determined.
SECTION END
FIELD PRODUCTION

6.1 FIELD MANAGEMENT PLAN

6.1.1 OBJECTIVES

The field management objective is to maximise the value of the Corrib field.

6.1.2 PRINCIPLES

The above objective will be achieved in a manner that is consistent with Enterprise’s policy on health, safety and the environment (Section 8.1.1) and with good and prudent oil and gas industry practice.

6.1.3 MAXIMISATION OF ECONOMIC GAS RECOVERY

The value of the Corrib Field will be maximised by:

a) Maximising economic recovery and accelerating economic production of gas both by effective reservoir management and by careful consideration of the reservoir requirements in the operation of the terminal; and

b) Careful and rigorous control of both capex and opex.

The above will be achieved in a manner that is consistent with the principles described above.

6.1.4 DATA GATHERING AND ANALYSIS

The open-hole logging programme carried out on wells drilled to date is described in Section 3.1.3.1. It is planned to carry out similar open-hole logging programmes over the reservoir interval in future wells. However the amount of log data acquired in the section above the reservoir may be reduced. It is probable that the well to be drilled in 2003 will be cored and tested. It is likely that core will be acquired in subsequent wells and these may be tested.

Operational constraints permitting, it is planned to run a PLT in each well when it is perforated and completed. For reasons of cost, it is not planned to re-enter the Corrib wells once they have been completed: no cased-hole logging is currently anticipated.

The subsea facilities will provide for acquisition of the following data during field life:

- Down-hole temperature and pressure in each well.
- Wellhead temperature and pressure both upstream and downstream of the choke on each well.
- Gas production rate at each wellhead.

The geological model and FFSM will be continually updated during field life using the above data.

6.1.5 RESOLUTION OF EXISTING UNCERTAINTIES

6.1.6 POTENTIAL FOR WORKOVER, RE-COMPLETION OR FURTHER DRILLING
6.1.7 ADDITIONAL PHASES OF APPRAISAL OR DEVELOPMENT

No additional phases of appraisal or development beyond those described in this Plan are currently recognised. The programme of drilling described in this Plan together with the programme of data gathering and analysis described in Section 6.1.4 should provide a full and complete description of the field and allow its effective drainage.
6.2 FIELD OPERATION AND MAINTENANCE

6.2.1 SUBSURFACE AND WELLS
6.2.2 SUBSEA AND OFFSHORE PIPELINE

The operation of the subsea system will be executed by production personnel in the terminal control room utilising the subsea electro-hydraulic multiplex control system to open and close subsea valves and monitor subsea production parameters. In particular, in early years, production from each offshore well will be controlled by a subsea choke. The position of the choke can be set remotely by the onshore operator. In order to reduce wear of chokes, the frequency of movement of the chokes will be minimised by packing/unpacking of the subsea pipeline, however, ultimately the magnitude and timing of changes in gas nominations will dictate choke movements.

The gas composition, predicted water production rate and the careful selection of optimum pipeline diameter and slugcatcher size and design, results in the elimination of the requirement to carry out routine operational pigging. The liquid inventory in the subsea pipeline and the accompanying slug volumes will be accommodated by the system.

The capability to pig the line has however been retained by the provision of a temporary subsea pig-launcher which will be installed subsea periodically in order to run an intelligent inspection pig, to confirm the integrity of the pipeline system.

Similarly a program of regular external inspection of the pipeline system and subsea facilities will be carried out by ROV and survey vessel to determine the state of repair of the system.

The proposed subsea facilities will be designed for field life use and accordingly there is no planned maintenance requirement. However should an active component fail, in addition to