Submission to Oral Hearing by Edward Moran

re

Objection to Proposed Determination To Grant An IPPC Licence To

Shell E & P Ireland Ltd To Operate A Refinery At Ballinaboy, Co. Mayo

by FRIENDS OF ROSSPORT LTD

Withholding of information and requirements of BAT

Submission / Objection To Proposed Determination To Grant An IPPC Licence To Shell E & P Ireland Ltd To Operate A Refinery At Ballinaboy, Co. Mayo by FRIENDS OF ROSSPORT LTD & IMELDA MORAN

Withholding of information and requirements of BAT

EU Dir 85/337

Preamble

... the best environmental policy consists in ***preventing the creation of pollution or nuisances at source***, rather than subsequently trying to counteract their effects

... they affirm the need to take effects on the environment into account a***t the earliest possible stage in all the technical planning and decision-making processes***

EU Dir 97/11

Preamble

... Community policy on the environment is based on ***the precautionary principle*** and on ***the principle that preventive action should be taken***, that environmental damage ***should as a priority be rectified at source*** and that ***the polluter should pay***;

EU Dir 96/61

Preamble

14. ... ***full coordination of the authorization procedure and conditions between competent authorities*** will make it possible to achieve the highest practicable level of protection for the environment as a whole

17. ... emission limit values, parameters or equivalent technical measures ***should be based on the best available techniques***, without prescribing the use of one specific technique or technology and taking into consideration the technical characteristics of the installation concerned, its ***geographical location*** and ***local environmental conditions***

20. ... because best available techniques will change with time, particularly in the light of technical advances, ***the competent authorities must monitor or be informed of such progress***.

Article 7 Integrated approach to issuing permits

Member States shall take the measures necessary ***to ensure that the conditions of, and procedure for the grant of, the permit are fully coordinated where more than one competent authority is involved***, in order to guarantee an effective integrated approach by all authorities competent for this procedure.

'***Project-splitting***' happens in many and diverse ways in regard to obtaining planning permissions and licences. It is a most insidious process whereby large projects are split into smaller parts for which permissions are then sought in a manner gauged to exert utmost pressure on the respective Competent Authorities to accede to the application. It turns planning permits into a game, a test of strength, where influence and power on one side are pitted against authority and integrity on the other.

Masquerading under the guise of efficiency and expeditiousness '***project-splitting***' frequently shows little regard for either but displays all the hallmarks of leveraging and coercion. Where an investment is of mega proportions and a significant part of it has obtained permissions, dare any authority refuse it the remaining permission or licence? This is evident in the current instance in that permissions already obtained represent potential investment commitments of enormous proportions and so the prospect of refusal of a licence is, for many, people unthinkable. The law fails to provide against this abuse.

Article 7 requires that "*Member States shall take the measures necessary to ensure that .... procedure for the grant of, the permit are fully coordinated where more than one competent authority is involved...*" In the current case that would require that the planning permission and IPPC licence applications should have been applied for concurrently, especially since any consideration of pollution issues is specifically excluded by law from being adjudicated by the planning authority. In fact the applicant did not apply for the IPPC licence until the planning permission had been secured. Why was this so since at all times expeditiousness was a primary concern of the applicant?

While this questionable practice is permitted by our national legislation as it stands, it is clearly contrary to the intention and spirit of Directive 96/61. Consequently, exceptional responsibility is placed on the EPA to ensure that the application does in fact merit grant of a licence despite the general perception of it being a *fait accompli*. It is regrettable that any planning authority should be placed in this invidious position as, if they succumb to the pressure of *fait accompli* and fail to uphold the spirit of the Directives, they fuel cynicism and undermine the fabric of public life.

The preamble to each of the above listed Directives comprises numerous references to previous initiatives commencing with **Article 130** of the founding Treaty of the European Union. Against this background of previous enactments intended to protect the local, national and global environment, Directive 96/61 consistently and repeatedly emphasises the importance of integration of responsibility and care. However, the transposing of those principles into national legislation has, by dividing responsibility among different agencies, created gaps, loopholes and grey areas whereby the essential spirit of the Directive is undermined, diluted or even betrayed. Our legislators have failed us and in the process have made the task of our administrators singularly difficult.

It is for these compelling reasons that it is necessary to refer back at all points to the precise wording of the Directive when following the letter of national law. A Reasoned Opinion of the EU in 2002, addressed to the Irish government, noted that corporations are entitled under current Irish legislation to employ '***project-splitting***' methods in obtaining various planning licences and permissions but it resolutely called into question whether this latitude is acceptable. However, the wheels of justice grind slowly and the issue has not yet been brought to adjudication. In the meantime corporations seek advantage in fixing on these gaps, loopholes and grey areas between the jurisdiction of those agencies and use them blatantly to short-circuit, evade or derive leveraging advantage in respect to obtaining licences and permissions.

The issue of **project-splitting** is therefore particularly relevant to the matter before this Oral Hearing. The applicant secured the inland pipeline route at a very early stage, long before the implications of its unique dangers became known. About the same time the government announced the Bord Gais Craughwell-Bellanaboy export pipeline to service the applicant. In this way a certainty was already being established in people's minds that the applicant's project would be established - even before the planning permission process for the so-called gas terminal was commenced. No effort to obtain the IPPC licence process was made until several years later, despite the fact that without such a licence all other authorisations and permissions would be useless. Then within weeks of the proposed refinery licence being granted, the IPPC licence application process was commenced. With three major permissions representing several hundred million Euro investment apparently secured, was it ever a credible scenario that an IPPC licence would be refused so long as seemingly 'adequate' proposals were presented?

This is the nub of the matter: we, the indigenous people, are entitled to retain our quality of life and environment against threat from remote, faceless shareholders whose sole concern is profit and self-interest. Yet devious means are employed to usher through this project whereby disclosure of crucial information is denied to us by use of those gaps, loopholes and grey areas which are such a consistent feature of our legislation. We have literally spent years trying to pin down precisely how these defects in the legislation are used to facilitate the short-cuts, evasions and surreptitious intentions of developers and we find that the failure to require competent authorities and protective agencies to consult with each other in a proactive way is at the root of these defects (See attached correspondence with Duchas from 2001). The manner in which the upstream pipeline was presented for years as a normal downstream pipeline best illustrates this point. Ironically this section of the project has proven to be a most damaging mistake for the developer, though it required years of effort on our part to uncover its well concealed dangers. The current IPPC licence application has has followed a similar pattern of concealment and misrepresentation.

The issue of cold venting of gas from the proposed refinery is one such instance and it has become a focal point of concern regarding the practices employed by the applicant. In line with the requirements of the EU Environmental Impact Assessment Directive this aspect of the process was required to be explained and evaluated in the EIS and stated in the Planning Permission application documents. Had it been, its implications would most certainly have been teased out during that process, especially so during the An Bord Pleanala Oral Hearing at which a Principal Officer of the National Authority for Occupational Safety and Health was questioned at very considerable length, and in detail, as to the consequences of possible hazards arising from operation of such a refinery in the very particular circumstance of Bellanaboy's unique environment. This opportunity was denied to concerned appellants.

The particular importance of this denial is that it the proposed refinery is designated a SEVASO site as thousands of tons of hazardous substances will be stored there (up to 4,000 tones of methanol and several more thousand tons of condensate). Consequently the Health and Safety Authority are required to evaluate risks to the public in regard to such sites in the course of the Planning Permission application process. This did not happen in respect to cold-venting as SEPIL had not indicated its intention to cold-vent at that stage. We contend that withholding of such essential information either invalidates the Planning Permission granted, or precludes the sanctioning of that particular process entirely.

In that light we contend that '**project-splitting**' is tantamount to '**self-inflicted jeopardy**'. That is to say, where a developer enters into contracts or premature expenditure in respect to a project for which necessary permissions or licences have not been secured, then that developer is necessarily taking a risk which can only be considered as reckless and does not merit sympathy or consideration in respect to loss arising from such recklessness. Otherwise, as indeed appears to be the case, the door is opened to calculated, emboldened and brazen use of such tactics to circumvent mandatory requirements at all levels.

Best Available Technology:

Item 17 of the preamble EU Directive 96/61 asserts that "*emission limit values, parameters or equivalent technical measures should be based on best available techniques, without prescribing the use of one specific technique or technology, and taking into account the technical characteristics of the installation concerned, its geopraphical location and local environmental conditions..*" and these are embodied as requirements in **Article 9.4** and **Article 10 item 20** which asserts that "*because the best available techniques will change with time, particularly in the light of technical advances, the competent authorities must monitor or be informed of such progress..*"

Article 3(a) requires that "*all the appropriate preventative measures are taken against pollution, in particular through application of the best available techniques*: and

Article 8 requires that "*the competent authority shall grant a permit containing conditions guaranteeing that the installation complies with the requirements of this Directive or, if it does not, shall refuse to grant the permit.*."

All of these are effectively elaborations of Item 1 which in turn refers back to the Treaty as the originating authority which established that "*the objectives and principles of the Community's environment policy, as set out in Article 130r of the Treaty, consist in particular of* ***preventing, reducing and as far as possible, eliminating*** *pollution by giving priority to* ***intervention at source*** *and ensuring prudent management of natural resources, in compliance with "he polluter pays"principle and the principle of "pollution prevention*"

In light of the individual and cumulative requirements of these principles and directions we contend that SEPIL is not employing the best available technology; and, particularly, that it has failed in its obligation to inform the competent authority regarding development in respect to best available technology. The fact is that a Shell companies have developed technologies which it variously describes as revolutionary or 'step-up' technologies and which have already gained widespread recognition as such within the off-shore production sector of the gas industry. Yet they have never imparted such information to the Competent authority and have mislead us, the concerned public repeatedly and consistently in this regard.

One such technology is supersonic gas processing. This technology has no moving parts; has no need for injection of hydrate or corrosion inhibitors; eliminates the need for decompression of the gas; and is capable of operation on an unmanned, small-scale platform. It not only complies to a much higher degree with the objectives of Directive 96/61 but also meets SEPIL's own objectives of safety in respect to off-shore production, as well as reduced capital and servicing costs off-shore.

This technology has been commercially commissioned and operated by another Shell company in Malaysia in circumstances so demanding and so fraught with danger that no conventional technology could cope. The gas field in question is off-shore, well beyond attainable tie-back distance and contains exceptional amounts of water, condensate and, most seriously, sulphur which made a manned platform entirely untenable with respect to danger to workers lives. Yet the developing company was so confident of its new technology that it gave an unprecedented guarantee of >98% up-time; and the production company was likewise so confident that it in turn commissioned an installation capable of processing twice the expected daily output of the Corrib field without awaiting final outcome of the field tests.

We acknowledge that the Directive prohibits the Competent Authority from specifying a particular technology, however we hold that the EPA must set standards for SEPIL in respect to pollutants which approximate to those which could be attained by the use of supersonic processing technology. In short, there are no grounds for permitting emissions to air of the order of 40,000 tonnes p.a. and particularly the releases of pernicious VOC's and cold-vented methane; likewise, there are no grounds for noxious emissions to water, and especially the 3,000+ tonnes of methanol lost without trace but presumed to be in the production water effluent to Broadhaven Bay; furthermore in respect to **Article 3(d)** that "*energy is used efficiently*" there are no grounds for permitting the use of massive turbines as proposed for generating 50MW of electricity to re-compress the gas for export since the pressure from the well can be retained for this purpose; and, finally, there are no grounds for permitting an enormous slug catcher on-shore at the proposed refinery since both the water and condensate can be removed at source thus precluding the possibility of slugs.

We call upon the EPA in light of these compelling considerations to withdraw its Proposed Permission for an IPPC licence in this instance.

Appendices

1. **EU Reasoned Opinion**

2. **Letter to Duchas - with attachments**

3. **Offshore Gas Industry Awards**

4. **EU & Irish Legislation – various excerpts**

5. **International Gas Union Report - various excerpts**

6. **Supersonic and other Offshore Processing Technology**

1. EU Reasoned Opinion

COMMISSION OF THE EUROPEAN COMMUNITIES

Brussels, 25 07 2001
1997/4703 and 1999/4449
C(2001)2253

REASONED OPINION

addressed to Ireland under Article 226 of the Treaty establishing the European Community, on account of its failure to fulfill obligations under Council Directive 85/337/EEC of 27 June 1985 on the assessment of the effects of certain public and private projects on the environment and Council Directive 97/11/EC of 3 March 1997 amending Directive 85/337/EEC, 2.8. Complaints, P2000/4190 (relating to a new cement works at Kinnegad, County Meath) and P2000/4455 (relating to a gas-fired power plant beside the River Boyne, County Meath) raised the issue of compliance with the Impact Assessment Directive in cases where decision-making is split between Irish local planning authorities and the Irish Environmental Protection Agency. In particular, it was claimed that, in such cases, the environmental information provided during the EIA was not properly taken into account in the decision-making process. The same issue arose in relation to complaints P2000/4002 and P2000/4799 concerning a pig-rearing installation at Stradbally, County Waterford. This last-mentioned complaint *inter alia* argued that the potential environmental impact of a proposed pig-rearing installation at Stradbally, County Waterford radically changed during the decision-making procedure for the installation. In particular, the developer applied for planning permission (i.e. the consent allowing physical development to proceed) on 12 March 1998, and, as part of an EIA, presented information on the environmental impact of the development by way of an environmental impact statement (EIS). The latter indicated that there were 1,507 hectares of suitable lands for spreading wastes from the installation. However, approximately 70% of this land-bank was withdrawn before a decision was made on the project by the relevant Irish local planning authority. The local planning authority gave planning permission on 24 March 1999 without requiring any information from the developer on the environmental impact of waste disposal on the spread-lands to be substituted for this withdrawn land-bank. The matter was administratively appealed to Ireland's Planning Appeals Board, which sought information from the developer on the substitute spread-lands. However, the request for and provision of this information fell outside the public consultation period (i.e. the period during which the public was invited to respond to the developer information), with the result that the public concerned by the potential impact of waste disposal on the substitute lands had no opportunity to express an opinion. The Board granted planning permission on 21 January 2000. In response to Commission enquiries, the Irish authorities confirmed that the pig-rearing installation was subject to an integrated pollution control licence, and was thus subject to two regulatory regimes, one on planning control involving the relevant Irish local planning authority (and, on appeal, the Irish Planning Appeals Board), and the other on pollution control involving Ireland's Environmental Protection Agency. The Irish authorities confirmed that there had been a substitution of spread-lands, and also confirmed that additional information on substitute spread-lands had been sought by the Irish Planning Appeals Board after the public consultation period had closed.

2.9. Complaint P1998/4307 concerned the environmental impact of a motorway project in County Kildare ("the Kildare Bypass"), which was given development consent on 22 January 1996, following an EIA. The project involves constructing a motorway below the level of the surrounding land. This in turn requires constant removal of large amounts of water from an aquifer (i.e. natural underground water reservoir) beneath the motorway in order to keep the motorway dry. During the impact assessment procedure, Ireland's competent nature conservation authority expressed serious concerns about the impact of this water removal[7], fearing that it would interfere with natural flows of water to a nearby internationally important wetland, Pollardstown Fen[8]. They advised that the

Pollardstown

[7] These concerns are reflected in a report, "Assessment of the Environmental Impact Study on the Kildare By-Pass, in particular an Assessment of the County Council's Proposal to De-water the Mid-Kildare Aquifer and the impact on the Pollardstown Fen and the Grand Canal," David Ball and others, Office of Public Works (OPW), November, 1993.

[8] Pollardstown Fen is intended to be protected as a site covered by Directive 92/43/EEC on the conservation of natural habitats and of wild flora and fauna ("the Habitats Directive")

2. Letter to Duchas - with attachments

(20)

Phone:097 81225

Chapel Street,
Belmullet,
Co. Mayo.

9th September, 2001

Mr. Gerry McDonnell
Asst. Principal Officer,
Duchas.

Dear Mr. McDonnell,

Re: <u>**Gas Terminal Appeal**</u>

Further to your phone call Thursday (7th Sept) re the Duchas 'gas terminal' Planning Permission Appeal to An Bord Pleanala, I wish to record my views, as stated then, that Duchas has a broader mandate than the severely curtailed grounds for appeal adopted.

On 16th August last in my letter to Dr. Craig, Director, Duchas, I pointed out which **Sections** of the enabling legislation (ie **Sections** 27, 28, 31 & 32, S.I. 94/1997) invest responsibility for a proactive approach in Duchas. (The Environmental Protection Agency and the Health and Safety Authority have like responsibility, though not as explicitly stated in their respective enabling legislation.)

My previous letter to you (dated 25th Aug. '01) quoted in highlighted detail the **sub-sections** of S.I. 94/1997 which delegate such responsibility to Duchas. Your response, during yesterday's phone call, that the Planning Authority is restricted to basing its Decision upon exclusively Planning considerations is misleading in that the Planning legislation does not specify ***<u>any</u>*** Planning criteria, other than general guidelines. Also, your interpretation does not distinguish between primary and secondary considerations in determining Planning Decisions. As such it is overly simplistic and excessively narrow. In short, I submit it is an inadequate and deficient interpretation of the legislation.

The crucial fact is that collectively all legislation comprises a single unified expression of the Constitution; and collectively all Departments comprise a single governmental entity. It follows that ***<u>individual</u>*** responsibility delegated to each Authority/Agency is necessarily to be exercised in an interactive and ***<u>collective</u>*** manner, as S.I. 94/1997 Sect. 27, 31 & 32 clearly indicate. Additionally, it follows that there is overall ***<u>cumulative</u>*** interdepartmental responsibility, as Sect. 31 (7) singularly attests.

The relevant legislation in regard to each of the statutory Authorities/Agencies ***reserves to each*** the full integrity of its primary function while ***delegating to each*** the responsibility to promote and protect its special area of competence interactively in regard to others. For a protective agency to interpret the legislation governing its functions in a narrow and constricted manner, ***and in isolation from the complementary legislation governing fellow agencies/authorities***, is tantamount to evasion of collective responsibility.

I can appreciate that there are elements of practice, procedure and precedent which give rise to the above distortions and that defective precedent can eclipse the underlying legislative reality. However there is currently a climate of opinion which requires clarification and re-assessment of the role of statutory Authorities/Agencies, and a proactive role is the necessary response. In such light, the withdrawal by Duchas of its Appeal on narrow grounds would compound its original failure immeasurably.

Yours faithfully,

Edward Moran

Enc.

Abbreviated excerpts from S.I. 94/1997

Obligations of *Local Authorities* and *An Bord Pleanála* in granting planning permission.
27. (1) A local authority … or the Board when duly considering an appeal on a application for planning permission, …. that is not directly connected with…. a ***European site*** but likely to have ***a significant effect*** thereon …. shall ensure that an appropriate assessment of ***the implications*** for the site in view of the site's conservation objectives is undertaken.

(3) …. a local authority or the Board …. shall …. decide to grant permission for the proposed development ***only*** after having ascertained that it ***will not*** adversely affect the ***integrity*** of ***the European site*** concerned.

(5) A local authority or the Board, …. may …. decide to grant planning permission for a proposed development where such development ***has*** to be carried out for ***imperative*** reasons of ***overriding*** public interest

Requirement for discharge by *certain Ministers* of the Government functions under certain enactments
31. (1) Where an operation or activity to which any of the enactments set out in Part I of the Second Schedule applies is neither directly connected with nor necessary to the management of a ***European site*** but likely to have ***a significant effect*** thereon, …. and such operation or activity …. requires the … approval …. of any Minister of the Government, then that Minister shall ensure that an appropriate assessment ***of the implications*** for the site in view of the site's conservation objectives is undertaken

(3) A Minister of the Government in carrying out powers and functions under any of the enactments set out in Part I of the Second Schedule shall …. approve of the operation or activity …. ***only*** after having ascertained that the operation or activity ***will not*** adversely affect ***the integrity*** of the site concerned

(5) …. where a Minister of the Government is satisfied that there are ***no alternative*** solutions that Minister may …. approve of, an operation or activity where such operation or activity ***has*** to be carried out for ***imperative*** reasons of overriding public interest.

(7) Before exercising any function to which this Regulation relates under any of the enactments set out in Part I of the Second Schedule, ***the Minister of the Government concerned shall consult the Minister***

Obligations of *Local Authorities, An Bord Pleanála* or the *Environmental Protection Agency* in the discharge of their powers and functions under certain enactments.
32. (1) Where an operation or activity …. to which an application for a licence …. under any of the enactments set out in Part II of the Second Schedule applies is neither directly connected with nor necessary to the management of ***a European site*** but likely to have ***a significant effect*** …. the Board or the ***Environmental Protection Agency*** shall ensure that an appropriate assessment of the environmental implications for the site in view of the site's conservation objectives is undertaken

(3) The local authority, the Board or the Environmental Protection Agency …. shall grant the licence ***only*** after having ascertained that the operation or activity ***will not*** adversely affect ***the integrity*** of the European site concerned

(5) A local authority, the Board or the Environmental Protection Agency, …. may …. where they are satisfied that there are ***no alternative solutions***, decide to grant a licence …. where such operation or activity ***has*** to be carried out for ***imperative*** reasons of ***overriding*** public interest.

Paragraph 6, as follows, applies *equally* to *each* of the above Regulations:
(6) (*a*) Subject to subparagraph (*b*), ***imperative reasons*** of ***overriding*** public interest shall include reasons of a ***social*** or ***economic*** nature:
(*b*) If the site concerned hosts ***a priority natural habitat*** type of or ***priority species*** the ***only*** considerations of ***overriding public*** interest shall be—
(i) those relating to human ***health*** or public ***safety***, or
(ii) the ***beneficial*** consequences of ***primary*** importance ***for the environment***, or
(iii) further to an opinion from the Commission to other imperative reasons of overriding public interest

1992 13 52 **Functions generally**

52.—(1) The functions of the Agency shall, subject to the provisions of this Act, include—

(c) the provision of support and advisory services for the purposes of environmental protection to local authorities and other public authorities in relation to the performance of any function of those authorities,

(f) such other functions in relation to environmental protection as may be assigned or transferred to it by the Minister under section 53 or 54 including functions arising from any obligations under any treaty governing the European Communities or an act adopted by the institutions of those Communities or other international convention or agreement to which the State is, or becomes, a party

1992 13 55 **Advisory functions in relation to Ministers of the Government**

55.—(1) *The Agency may, of its own volition, and shall when requested by a Minister of the Government, give information or advice or make recommendations for the purposes of environmental protection to any such Minister on any matter relating to his functions or responsibilities and that Minister shall have regard to any such information or advice given or recommendations made.*

(b) may, and shall when requested by the Minister, make recommendations to the Minister in relation to any modification or extension of the functions of the Agency which it considers appropriate.

(4) *The Agency may, for any Minister of the Government or any public authority designated by order under subsection (5) or for any other person or body, organise and promote, or assist in organising and promoting, conferences, seminars, lectures, demonstrations, training courses or publications for persons involved in environmental protection*

1992 13 56 **Advisory functions in relation to local authorities.**

56.—*(1) The Agency may, and shall when requested by the Minister, give information or advice or make recommendations for the purposes of environmental protection, to a local authority or to local authorities generally in relation to the performance of any of its or their functions and the authority or authorities shall have regard to any such information or advice given or recommendations made.*

(c) the standards, conditions or criteria to be applied, or the guidelines, codes of practice or procedures to be followed, for the purposes of environmental protection in relation to any development, process or practice either generally or of a particular class,

1992 13 57 **Assistance to local authorities**

57.—(1) *The Agency shall provide such general support and assistance for the purposes of environmental protection to local authorities in relation to the performance of any of their functions as it considers necessary and feasible.*

1992 13 63 **Performance of statutory functions by local authorities**

63.—(1) *Where the Agency is of opinion that a local authority has failed to perform a statutory function of that authority in relation to environmental protection, or has performed that function in an unsatisfactory manner, the Agency may request a report*

(2) *The Agency, having considered any report of the local authority may, with a view to ensuring the satisfactory performance of the function in question—*

(a) issue such advice and recommendations to the local authority as it considers necessary, or

(3) (a) Where the Agency is of the opinion that the response of the local authority to advice or recommendations issued or assistance or support offered under subsection (2) is inadequate for the purposes of environmental protection it may, without prejudice to any of its powers under this Act or any other enactment, direct the local authority to carry out, cause to be carried out, or arrange for, such action related to the function in question as the Agency considers necessary for the purposes of environmental protection within such period as may be specified.

(4) *Nothing in this section shall be construed as enabling the Agency to exercise any power or control under this section in relation to the making of a decision on an application for a permission under Part IV of the Act of 1963*

1992 13 81 **Consultation with the Agency.**

81.—*The Agency shall be consulted by such public authorities prior to the discharge of such functions related to the environment as the Minister, following consultation with any other Minister of the Government who in the opinion of the Minister is concerned, may, by regulations, specify and such public authorities shall have regard to the views of the Agency prior to carrying out the functions specified*

1992 13 98 **Application of other Acts.**

98.—*(1) Notwithstanding section 26 of the Act of 1963, or any other provision of the Local Government (Planning and Development) Acts, 1963 to 1991, where a licence or revised licence under this Part has been granted or is or will be required in relation to an activity, a planning authority or An Bord Pleanála shall not, in respect of any development comprising or for the purposes of the activity—*

(a) decide to refuse a permission or an approval under Part IV of the Act of 1963 for the reason that the development would cause environmental pollution, or

and, accordingly—

(i) *a planning authority in dealing with an application for a permission or for an approval for any such development shall not consider any matters relating to the risk of environmental pollution from the activity;*

(ii) *An Bord Pleanála shall not consider any appeal made to it against a decision of a planning authority in respect of such an application, or any submissions or observations made to it in relation to any such appeal, so far as the appeal, or the submissions or observations, as the case may be, relates or relate to the risk of environmental pollution from the activity.*

(2) *Notwithstanding the provisions of the Minerals Development Acts, 1940 to 1979, where a licence or revised licence under this Part has been granted or is or will be required in relation to an activity, a lease granted by the Minister for Energy under the said Acts in respect of the same activity shall not contain conditions which are for the purpose of the prevention, limitation, elimination, abatement or reduction of environmental pollution from the activity.*

3. Offshore Gas Industry Awards

OTC Distinguished Achievement Awards for Companies, Organizations, and Institutions

1971 Shell Oil Co. In recognition of the distinguished achievements of Shell Oil Co. in the field of offshore technology during the period of 1955 through 1967, when techniques and equipment were developed for floating, diverless ocean-floor well drilling and completion operations that resulted **in the first all-weather column stabilized floating drilling rig, the first diverless underwater completion, the first floating drilling rig, the first submersible robot-supported drilling system for deepwater floating operations** and the development of **an automatic, dynamically positioned, deepwater drilling vessel**.

1973 Global Marine, Inc. For the design and operation of the Glomar Challenger, which represents an efficient and cost-effective extension of oil industry ocean drilling technology to serve basic science. As **the first drillship to core the world's deep ocean basins**, the Glomar Challenger is credited with many technological firsts, including operating continuously in a dynamically positioned mode, deepwater hold reentry, and **drilling in more than 20,000 feet of water**.

1975 Chicago Bridge and Iron Co. In recognition of outstanding achievement in the design, construction, and installation of **large seafloor crude oil storage units** in 1969 through 1972 in the Arabian Gulf. These 500,000 bbl structures of unique design contributed significantly to the subsea technology related to membrane structure, their placement, anchoring, and operation on the seafloor. In coupling and as an extended application, the second and third units were pioneers in adding large surface platforms integral to the storage units, permitting contemporary construction and simultaneous placement.

1977 Phillips Petroleum Co. To Phillips Petroleum Co. for its distinguished contributions to offshore technology in the development of the Ekofisk Field and, particularly, for its pioneering achievement in employing a **concrete gravity structure for oil storage**, the design, construction, and installation of which established the feasibility of using concrete gravity structures in other areas of the North Sea.

1980 Exxon Co., U.S.A. In recognition of the contribution to offshore technology in the design, construction, and testing of a **deepwater, diverless submerged production system**. This highly innovative approach to deepwater offshore production and the experience and knowledge gained in testing techniques and equipment are major contributions to the development and production not only of petroleum but of other mineral resources.

1982 Shell Oil Co. In recognition of the distinguished achievements of Shell Oil Co. in the innovative design, construction, and installation of COGNAC--**the world's deepest (1,025 feet) and heaviest (50,000 tons) bottom-founded steel drilling and production platform**. Construction and installation of this platform involved the first application of an underwater pile-driving hammer, the use of a record number of deep saturation-diving team days for installation support, and the innovative application of **state-of-the-art technology in the use of remote control techniques for platform positioning, alignment, and joining of the three-part platform**.

1984 Exxon Co., U.S.A. For distinguished achievements in **the design, construction, and installation of the world's first commercial guyed-tower drilling and production platform**, which has contributed significantly to deepwater construction technology and to industry's capabilities for producing hydrocarbon reserves in deeper offshore waters.

Conoco, Inc. For distinguished contributions to offshore technology through the design, construction, installation, and operation of **the world's first commercial drilling and production tension leg platform** in the Hutton Field, U.K.; and especially for **design innovations in the tension leg platform concept that have advanced deepwater oil and gas production technology**.

1988 Norwegian Contractors For enhancements of the design and successful fabrication and deployment of concrete drilling, production, and storage facilities in the North Sea, and especially for pioneering offshore applications of the slip-form method of concrete construction, **extending oil and gas production to deeper and more harsh offshore areas**.

1989 Placid Oil Co. For distinguished achievements in **the design, construction, and installation of a floating production system for deep water** and especially for completion of a well in **2,300 feet of water** and for **design innovations in the production riser and pipeline connection techniques**.

1991 Heerema Offshore Construction Group, Inc. For significant achievements in offshore technology over a period of many years, especially for the conception, design, and successful operation of the first semi-submersible twin crane vessels that revolutionized offshore construction by **permitting continuous operations in severe weather**, making possible lifts substantially larger than previous generations of derrick barges.

1992 Petroleo Brasileiro S.A. (Petrobras) For outstanding technical achievements related to the **development of deepwater production systems**, including guidelineless lay-away wet Christmas trees with flexible pipe **in water depths exceeding 700 meters**, installation of the world's deepest monobuoy at a depth of 405 meters, **floating production systems moored in water depth exceeding 600 meters**; and for establishing, with participating scientific and technical communities, development programs directed toward enhancing deepwater systems.

1993 Freeport-McMoRan Resource Partners For technological excellence in the **design and construction of the world's largest offshore system of interconnected and stand-alone structures** for simultaneous mining of sulfur and production of **oil and gas**; and in recognition of the innovative design elements and overall project management to anticipate and accommodate **the significant subsidence effects of offshore mining operations.**

1996 Conoco, Inc. For design, construction, installation and start up operation of **the world's first concrete tension leg platform hull**. Developed **in 345 meters water depth** in **one of the world's most harsh operating environments**, the Heidrun Project represents a significant extension of offshore technology, including less than five years from detailed engineering to first production.

1998 The Mensa Project, Shell Deepwater Development Inc. For major advancements in the economic recovery of deep water, remote petroleum reserves through the development, installation and successful operation of the Mensa project, **which established new records for water depth and tieback distance.**

2000 Kerr-McGee Corporation - FPS Neptune Project
For the **Neptune Spar Project** and specifically for the foresight and vision in the commitment to the design, fabrication, installation and subsequent operation of **the first Spar production platform**. This innovative technology has resulted in **a new generation of floating production systems** that offer a **viable alternative to existing platforms for deepwater drilling, production, processing and operations.**

2001 Petroleo Brasileiro S.A. (Petrobras) For outstanding advancements to deepwater technology and economics in the development of the Roncador Field; a timeline of 27 months from discovery to first oil production **in a water depth of more than 1800 meters**; made possible by the use of a dynamically positioned early production system, and a dedicated production system using **steel catenary exporting risers, taut-leg polyester mooring**, and subsea production hardware.

2003 TotalFinaElf for the Girassol Project For its technical innovations, its demanding project schedule, and its ability to overcome major challenges. Technical innovations include application of **unique free-standing towers**, deepest adaptation of the hinge-over subsea template, the largest FPSO in the water depth including the largest module for sulfate removal, industry-first midwater flowlines, largest catenary leg mooring buoy, to name a few.

2004 Shell and BP for the Na Kika Project
For outstanding application in the design, construction and installation of the Na Kika floating development and **production system in 6,350 feet of water**, and the **associated subsea infrastructure** that ties together six dispersed fields.

2005 Kerr-McGee Oil and Gas Corp. and Technip
For their successful global relationship that has pioneered and delivered three generations **of spar floating production systems** in nine years. Application of the third generation cell spar at **Red Hawk** has **significantly reduced the economical industry reserve threshold for stand alone deepwater field developments.**

2006 DORIS Engineering
For its sustained and pioneering innovations in the design and construction of offshore facilities for nearly four decades. DORIS **has addressed special and difficult problems in frontier areas, including harsh environments, remote locations and very deep waters**. DORIS has participated in important advancements in technologies for concrete platforms, subsea facilities, floating production/storage systems and living quarters that have reduced risk and costs.

4. EU & Irish Legislation – various excerpts

(A)

Environmental Assessment

Council Directive 85/337/EEC of 27 June 1985

on the assessment of the effects of certain public and private projects on the environment

Reference: Official Journal NO. L 175 , 05/07/1985 P. 0040 - 0048

THE COUNCIL OF THE EUROPEAN COMMUNITIES,

Having regard to the Treaty establishing the European Economic Community, and in particular Articles 100 and 235 thereof,

Having regard to the proposal from the Commission (1),

Having regard to the opinion of the European Parliament (2),

Having regard to the opinion of the Economic and Social Committee (3),

Whereas the 1973 (4) and 1977 (5) action programmes of the European Communities on the environment, as well as the 1983 (6) action programme, the main outlines of which have been approved by the Council of the European Communities and the representatives of the Governments of the Member States, stress that the best environmental policy consists in preventing the creation of pollution or nuisances at source, rather than subsequently trying to counteract their effects; whereas they affirm the need to take effects on the environment into account at the earliest possible stage in all the technical planning and decision-making processes; whereas to that end, they provide for the implementation of procedures to evaluate such effects;

Whereas the disparities between the laws in force in the various Member States with regard to the assessment of the environmental effects of public and private projects may create unfavourable competitive conditions and thereby directly affect the functioning of the common market; whereas, therefore, it is necessary to approximate national laws in this field pursuant to Article 100 of the Treaty;

Whereas, in addition, it is necessary to achieve one of the Community's objectives in the sphere of the protection of the environment and the quality of life;

Whereas, since the Treaty has not provided the powers required for this end, recourse should be had to Article 235 of the Treaty;

Whereas general principles for the assessment of environmental effects should be introduced with a view to supplementing and coordinating development consent procedures governing public and private projects likely to have a major effect on the environment;

B

Environmental Assessment

Council Directive 97/11/EC of 3 March 1997

amending Directive 85/337/EEC on the assessment of the effects of certain public and private projects on the environment

OFFICIAL JOURNAL NO. L 073 , 14/03/1997 P. 0005

THE COUNCIL OF THE EUROPEAN UNION,

Having regard to the Treaty establishing the European Community, and in particular Article 130s (1) thereof,

Having regard to the proposal from the Commission (1),

Having regard to the opinion of the Economic and Social Committee (2),

Having regard to the opinion of the Committee of the Regions (3),

Acting in accordance with the procedure laid down in Article 189c of the Treaty (4),

(1) Whereas Council Directive 85/337/EEC of 27 June 1985 on the assessment of the effects of certain public and private projects on the environment (5) aims at providing the competent authorities with relevant information to enable them to take a decision on a specific project in full knowledge of the project's likely significant impact on the environment; whereas the assessment procedure is a fundamental instrument of environmental policy as defined in Article 130r of the Treaty and of the Fifth Community Programme of policy and action in relation to the environment and sustainable development;

(2) Whereas, pursuant to Article 130r (2) of the Treaty, Community policy on the environment is based on the precautionary principle and on the principle that preventive action should be taken, that environmental damage should as a priority be rectified at source and that the polluter should pay;

(3) Whereas the main principles of the assessment of environmental effects should be harmonized and whereas the Member States may lay down stricter rules to protect the environment;

(4) Whereas experience acquired in environmental impact assessment, as recorded in the report on the implementation of Directive 85/337/EEC, adopted by the Commission on 2 April 1993, shows that it is necessary to introduce provisions designed to clarify, supplement and improve the rules on the assessment procedure, in order to ensure that the Directive is applied in an increasingly harmonized and efficient manner;

(5) Whereas projects for which an assessment is required should be subject to a requirement for development consent; whereas the assessment should be carried out before such consent is granted;

C

Integrated Pollution Prevention and Control

COUNCIL DIRECTIVE 96/61/EC of 24 September 1996 concerning integrated pollution prevention and control

THE COUNCIL OF THE EUROPEAN UNION,

Having regard to the Treaty establishing the European Community, and in particular Article 130s (1) thereof,

Having regard to the proposal from the Commission (1),

Having regard to the opinion of the Economic and Social Committee (2),

Acting in accordance with the procedure laid down in Article 189c of the Treaty (3),

1. Whereas the *objectives and principles* of the Community's environment policy, as set out in **Article 130r** of the Treaty, consist in particular of preventing, reducing and as far as possible eliminating pollution by giving priority to intervention at source and ensuring prudent management of natural resources, in compliance with the 'polluter pays' principle and the principle of pollution prevention;

2. Whereas the ***Fifth Environmental Action Programme***, the broad outline of which was approved by the Council and the Representatives of the Governments of the Member States, meeting within the Council, in the resolution of 1 February 1993 on a Community programme of policy and action in relation to the environment and sustainable development (4), accords priority to integrated pollution control as an important part of the move towards a more sustainable balance between human activity and socio-economic development, on the one hand, and the resources and regenerative capacity of nature, on the other;

3. Whereas the implementation of an integrated approach to reduce pollution requires action at Community level in order to modify and supplement existing Community legislation concerning the prevention and control of pollution from industrial plants;

4. Whereas Council Directive **84/360/EEC** of 28 June 1984 on the combating of air pollution from industrial plants (5) introduced a general framework requiring authorization prior to any operation or substantial modification of industrial installations which may cause air pollution;

5. Whereas Council Directive **76/464/EEC** of 4 May 1976 on pollution caused by certain dangerous substances discharged into the aquatic environment of the Community (6) introduced an authorization requirement for the discharge of those substances;..................................

****

14. Whereas full coordination of the authorization procedure and conditions between competent authorities will make it possible to achieve the highest practicable level of protection for the environment as a whole;..

****

17. Whereas emission limit values, parameters or equivalent technical measures should be based on the best available techniques, without prescribing the use of one specific technique or technology and taking into consideration the technical characteristics of the installation concerned, its geographical location and local environmental conditions; ....

Article 2

Definitions

For the purposes of this Directive:

11. **'best available techniques'** shall mean the most effective and advanced stage in the development of activities and their methods of operation which indicate the practical suitability of particular techniques for providing in principle the basis for emission limit values designed to prevent and, where that is not practicable, generally to reduce emissions and the impact on the environment as a whole:

— **'techniques'** shall include both the technology used and the way in which the installation is designed, built, maintained, operated and decommissioned,

— **'available'** techniques shall mean those developed on a scale which allows implementation in the relevant industrial sector, under economically and technically viable conditions, taking into consideration the costs and advantages, whether or not the techniques are used or produced inside the Member State in question, as long as they are reasonably accessible to the operator,

— **'best'** shall mean most effective in achieving a high general level of protection of the environment as a whole. In determining the best available techniques, special consideration should be given to the items listed in Annex IV;

Article 7 Integrated approach to issuing permits

Member States shall take the measures necessary to ensure that the conditions of, and procedure for the grant of, the permit are fully coordinated where more than one competent authority is involved, in order to guarantee an effective integrated approach by all authorities competent for this procedure.

Article 8 Decisions

Without prejudice to other requirements laid down in national or Community legislation, the competent authority shall grant a permit containing conditions guaranteeing that the installation complies with the requirements of this Directive or, if it does not, shall refuse to grant the permit.

All permits granted and modified permits must include details of the arrangements made for air, water and land protection as referred to in this Directive.

****

Article 11 Developments in best available techniques

Member States shall ensure that the competent authority follows or is informed of developments in best available techniques.

****

D

ENVIRONMENTAL PROTECTION AGENCY ACT, 1992

Environmental protection, environmental pollution and environmental medium.

4.—(1) In this Act "environmental protection" includes—

(*a*) the prevention, limitation, elimination, abatement or reduction of environmental pollution, and

(*b*) the preservation of the quality of the environment...................

Best available technology not entailing excessive costs.

5.—(1) Subject to *subsection (3)*, a reference in this Act to the use of the best available technology not entailing excessive costs to prevent or eliminate, or where that is not practicable, to limit, abate or reduce an emission from an activity, shall be construed as meaning the provision and proper maintenance, use, operation and supervision of facilities which, having regard to all the circumstances, are the most suitable for the purposes.

(2) For the purposes of *subsection (1)*, regard shall be had to—

(*a*) in the case of an activity other than an established activity—

(i) the current state of technical knowledge,

(ii) the requirements of environmental protection, and

(iii) the application of measures for these purposes, which do not entail excessive costs, having regard to the risk of significant environmental pollution which, in the opinion of the Agency, or any other licensing authority in relation to *section 111*, exists;

(*b*) in any other case, in addition to the matters specified in *paragraph (a)*—

(i) the nature, extent and effect of the emission concerned,

(ii) the nature and age of the existing facilities connected with the activity and the period during which the facilities are likely to be used or to continue in operation, and

(iii) the costs which would be incurred in improving or replacing the facilities referred to in *subparagraph (ii)* in relation to the economic situation of activities of the class concerned. .....

****

76.— Codes of practice.

(1) The Agency may—

(*a*) prepare and publish codes of practice, or

(*b*) approve of a code of practice or any part of a code of practice drawn up by any other body,

for the purpose of providing practical guidance with respect to compliance with any enactment or otherwise for the purposes of environmental protection. ....

****

87.— Regulations regarding licences.

((**3**) (***a***) A person who in relation to an application for a licence, or to a review of a licence or revised licence, under this Part, makes a statement in writing which to his knowledge is false or misleading in a material respect, shall be guilty of an offence.

(*b*) Where a person is convicted of an offence under this subsection, any licence or revised licence granted to that person, or to some other person on whose behalf the convicted person was authorised to act, consequent on the application or review in relation to which the information was furnished, shall stand revoked from the date of the conviction.

E

S.I. No. 85/1994:

ENVIRONMENTAL PROTECTION AGENCY (LICENSING) REGULATIONS, 1994.

Procedure at oral hearings.

35. (1) A person appointed to conduct an oral hearing shall have discretion as to the conduct of the hearing and in particular shall—

(*a*) conduct the hearing without undue formality,

(*b*) permit any party to the objection, the planning authority in whose functional area the activity to which the licence application or review relates, is or will be situate, or such employee of the Agency as the Agency may decide, to appear in person or to be represented by another person,

(*c*) decide the order of appearance of persons to be heard.

(2) Where the Agency has given notice in accordance with article 39 (2) of its intention to take into account matters other than those raised by the parties to the objection, the parties shall be permitted, if present, to make submissions in relation to the said matters to the person conducting the oral hearing.

(3) A person appointed by the Agency to conduct an oral hearing shall be appointed in writing by the Agency to be an authorised person for the purposes of section 13 of the Act.

Power to require attendance at oral hearings.

36 (1) Subject to sub-article (2), the person appointed to conduct an oral hearing may, by giving notice in that behalf in writing to any party to the objection, such employee of the Agency as the Agency may decide or the planning authority in whose functional area the activity is or will be situate, require that party, employee or authority to attend at such time and place as is specified in the notice and to produce any documents, particulars, or other information in his or its possession, custody or control.

****

(3) A person to whom a notice under sub-article (1) has been given shall not refuse or wilfully neglect to attend in accordance with the notice or shall not wilfully alter, suppress, conceal or destroy any documents, particulars or other information to which the notice relates or having so attended, shall not refuse or wilfully fail to produce any documents, particulars or other information to which the notice relates.

(4) A person appointed to conduct an oral hearing may require an officer of a local authority, sanitary authority or planning authority concerned to provide any information which that person reasonably requires for the purpose of the hearing, and it shall be the duty of the officer concerned to comply with the requirement.

F

Public Participation and Access to Justice

(Århus Convention)

Directive 2003/35/EC of the European Parliament

and of the Council of 26 May 2003

providing for public participation in respect of the drawing up of certain plans and programmes relating to the environment and amending with regard to public participation and access to justice Council Directives **85/337/EEC** and **96/61/EC**

THE EUROPEAN PARLIAMENT AND THE COUNCIL OF THE EUROPEAN UNION,

Having regard to the **Treaty establishing the European Community**, and in particular **Article 175** thereof,

Having regard to the proposal from the Commission(1),

Having regard to the opinion of the European Economic and Social Committee(2),

Having regard to the opinion of the Committee of the Regions(3),

Acting in accordance with the procedure laid down in Article 251 of the Treaty(4), in the light of the joint text approved by the Conciliation Committee on 15 January 2003,

Whereas:

(1) Community legislation in the field of the environment aims to contribute to preserving, protecting and improving the quality of the environment and protecting human health.

(2) Community environmental legislation includes provisions for public authorities and other bodies to take decisions which may have a significant effect on the environment as well as on personal health and well-being.

(3) Effective public participation in the taking of decisions enables the public to express, and the decision-maker to take account of, opinions and concerns which may be relevant to those decisions, thereby increasing the accountability and transparency of the decision-making process and contributing to public awareness of environmental issues and support for the decisions taken.

(4) Participation, including participation by associations, organisations and groups, in particular non-governmental organisations promoting environmental protection, should accordingly be fostered, including inter alia by promoting environmental education of the public.

(5) On 25 June 1998 the Community signed the **UN/ECE** Convention on Access to Information, Public Participation in Decision-Making and Access to Justice in Environmental Matters (**the Århus Convention**). Community law should be properly aligned with that Convention with a view to its ratification by the Community.

(6) Among the objectives of the Århus Convention is the desire to guarantee rights of public participation in decision-making in environmental matters in order to contribute to the protection of the right to live in an environment which is adequate for personal health and well-being.

Article 3 Amendment of Directive 85/337/EEC

Directive 85/337/EEC is hereby amended as follows:

7. the following Article shall be inserted:

"Article 10a

Member States shall ensure that, in accordance with the relevant national legal system, members of the public concerned:

(a) having a sufficient interest, or alternatively,

(b) maintaining the impairment of a right, where administrative procedural law of a Member State requires this as a precondition,

have access to a review procedure before a court of law or another independent and impartial body established by law to challenge the substantive or procedural legality of decisions, acts or omissions subject to the public participation provisions of this Directive.

Member States shall determine at what stage the decisions, acts or omissions may be challenged.

What constitutes a sufficient interest and impairment of a right shall be determined by the Member States, consistently with the objective of giving the public concerned wide access to justice. To this end, the interest of any non-governmental organisation meeting the requirements referred to in Article 1(2), shall be deemed sufficient for the purpose of subparagraph (a) of this Article. Such organisations shall also be deemed to have rights capable of being impaired for the purpose of subparagraph (b) of this Article.

The provisions of this Article shall not exclude the possibility of a preliminary review procedure before an administrative authority and shall not affect the requirement of exhaustion of administrative review procedures prior to recourse to judicial review procedures, where such a requirement exists under national law.

Any such procedure shall be fair, equitable, timely and not prohibitively expensive.

In order to further the effectiveness of the provisions of this article, Member States shall ensure that practical information is made available to the public on access to administrative and judicial review procedures.";

Article 6 Implementation

Member States shall bring into force the laws, regulations and administrative provisions necessary to comply with this Directive by 25 June 2005 at the latest. They shall forthwith inform the Commission thereof.

When Member States adopt these measures, they shall contain a reference to this Directive or shall be accompanied by such a reference on the occasion of their official publication. The methods of making such reference shall be laid down by Member States.

5. International Gas Union Report - various excerpts

EXPLORATION, PRODUCTION AND TREATMENT OF NATURAL GAS

APPENDIX 1: Members of the Committee

Chairman: Colin Lyle, Gas Market Insights Ltd, UK
Vice Chairman: Vladimir Yakushev, VNIIGAZ, OAO Gazprom, RUSSIA
Secretary: Adam Hinds, Centrica, UK

Members:

Anatoliy Andriyevskyy, NaftoGaz, UKRAINE
Arata Nakamura, Japan National Oil Company, JAPAN
Barry Jones, Australian Petroleum, AUSTRALIA
Branislav Tomovic, NIS-Naftagas, YUGOSLAVIA
Boris Vrbanac, INA – Petroleum Industry of Croatia, CROATIA
Djaouid Bencherif, Sonatrach, ALGERIA
Dominique Copin, Total, FRANCE
Eduardo Abriata, Repsol, ARGENTINA
Eike Benke, Ruhrgas, GERMANY
Esmaeel Bakhtyar, NIGC, IRAN
Francois Labaune, Gaz de France, FRANCE
Homayoon Saremi, NIGC, IRAN
Ivan Pagac, Moravske Naftovedoly a.s, CZECH REPUBLIC
Ivica Brkic, NIS-Naftagas, YUGOSLAVIA
Jeong-Hwan Lee, Korea Gas Corporation, KOREA
Jozef Levoca, Nafta a.s., SLOVAK REPUBLIC
Jozef Pagac, Nafta a.s., SLOVAK REPUBLIC
Joon Kim, ChevronTexaco, USA
Hwan Park, Korea Gas Union, KOREA
Leonid Serednytsky NaftoGaz, UKRAINE
Leopold Brauer, OMV Aktiengesellschaft, AUSTRIA
Lucian Stancu, Romgaz, ROMANIA
Mahdjouba Belaifa, Sonatrach, ALGERIA
Mansoor Motlagh, NIGC, IRAN
Marie-Francoise Chabrelie, CEDIGAZ, FRANCE
Mark Howard, BP, UK
Mike McAllistair, ChevronTexaco, UK
Mirko Lukic, INA Petroleum Industry of Croatia, CROATIA
Miro Durekovic, INA Petroleum Industry of Croatia, CROATIA
Mohamed Dasri, Petronas, MALAYSIA
Munhie Hwang, SK-Enron, KOREA
Nahum Schneidermann, ChevronTexaco, USA
Naushiev Tanbai, Kaztransgas, KAZAKHSTAN
Peter Reichetseder, E.ON Ruhrgas, GERMANY
Rebecca Hyde, Centrica, UK
Ricardo Morck, Repsol YPF, ARGENTINA
Scott Wieslaw, The Oil and Gas Institute, POLAND
Shinichi Suzuki, Japan Oil, Gas and Metals National Corporation, JAPAN
Stanislaw Rychlicki, University of Mining and Metallurgy, POLAND
Taizo Uchimura, Japan National Oil Corporation, JAPAN
Torsten Hole, Statoil, NORWAY
Yves Tournie, Total, FRANCE
Zul Nurani, ExxonMobil, MALAYSIA

(A)

GAS FIELDS: ACONCAGUA (US)
[GULF OF MEXICO]

Gas Composition and Fluid Data

Dry gas. No H_2S and very limited amounts of CO_2 and inert gases.
Primary produced fluid: gas
Gas gravity: 0.56
Condensate yield: 1 – 3 bbl/MMcf
Calorific value: 1020 Btu/MMscf

Major Development Milestones and Facilities Design

Developed with four wells (2-3 producing intervals per well), the Aconcagua field started producing in September 2002, setting a new world record in deep-water production (7,130 ft). This record was then beaten by Camden Hills (7,209 ft) which began to produce a few weeks later.

As no single field contained sufficient reserves to economically justify development costs - their total gas reserves were estimated at less than 1 trillion cubic feet of gas -, Aconcagua, Camden Hills and King's Peak, were pooled altogether into a multifield deep-water development named Canyon Express, sharing infrastructure to improve the economics of such marginal development, while involving three different operating companies and different field co-owners. The gas accumulations are located in Mississippi Canyon (Blocks 217, 305, and 348) and Desoto Canyon (Block 133), the most distant well location being 57 miles far from the platform.

Intelligent completion technology was used in eight of the nine production wells in all three fields to optimize the subsea development of this marginal reserve base, along with pipeline, platform and subsea system synergies and to maximize production capability and reservoir management efficiency. This technology enables gas production from multiple zones to be commingled, and the well to be reconfigured to shut-off water production without the requirement for well intervention. Because these reservoirs water-out very quickly, once water production begins, this ability to drain the multiple gas sands was key to the completion design which also eventually came to include stacked frac-pack sand control, pressure-operated fluid-loss and well-control devices.

It also allows operators to obtain real-time or near-real-time reservoir data, and then reconfigure the wellbore production-injection architecture to adapt to the information obtained. Data from the downhole pressure and temperature gauges help maximize field potential. The data, processed on surface, are integrated into reservoir models to obtain a better understanding of field depletion, water encroachment, and reservoir extent.

Produced gas and condensate from all wells are conveyed using the dual parallel 12-inch flowlines Canyon Express Gas Gathering Pipeline System, back to the host processing platform, located in Main Pass Block 261 and known as Canyon Station. Canyon Station is a fixed-leg platform installed in 300 feet of water. Commissioned on September 19, 2002 when the well MC 305 N°1 started producing, it is designed to treat, process and handle up to 500 Million cf/d of natural gas. Williams Field Services operates the Canyon Station platform.

Operated by Total, the Canyon Express Gas Gathering Pipeline System was given permit by the Minerals Management Service (Gulf of Mexico region) in September 2001. It comprises 32 pipeline segments and is jointly owned by the Aconcagua owners (45%), King's Peak owners (35%) and the Camden Hills owners (20%).

Flowline sleds laid in-line connect the flowline to the individual wellheads via short conventional inverted U-shaped jumpers with a maximum 80-ft length. As a result, flowline routing is dictated to a large part, by the location of the subsea wells. A wet-gas Venturi multiphase flowmeter, at each well production jumper, is used to allocate production prior to the fluid entering the flowline.

A short jumper that allows for pigging connects the western and eastern flowlines at the termination point in the Camden Hills field. The surface control on Canyon Station employs a common master control station (MCS) for sending and receiving data and emergency shutdown (ESD) signals from the subsea control modules.

GRONINGEN (THE NETHERLANDS) (B)

To avoid hydrocarbon condensation in the gas transmission system, Groningen gas is generally conditioned at cold separator conditions of –12 Deg.C and 74 bars.

The delivery contract for Groningen gas specified a minimum delivery pressure, a water dew point of -2 Deg.C at 63.8 bar, but no hydrocarbon dew point.

Groningen gas reserves

Original gas in-place in the Slochteren sandstone is 2,840 billion normal cubic meter sales volumes (appr. 100 Tcf). The expected remaining reserves of the Groningen Field as of 1.1.2006 are approximately 1045mrd Nm3 sales volumes, whilst some 20% of these reserves remain to be developed through the finalisation of the current Groningen Long Term investment programme (expected in 2009).

Field development and facilities

The Groningen gas field started producing in 1963. Initial development was limited to the Southern part of the accumulation, where the complete reservoir was not underlain by an aquifer.

On the basis of favourable reservoir properties (high permeability and good reservoir connectivity), it was decided to drain the reservoir by wells grouped together in clusters, thus economizing on surface facilities. Production wells were drilled from one cluster, feeding into a gas-treatment plant that is situated next to the well-location. The first 14 clusters were set up in the structurally high southern part of the field, with each cluster consisting of 8 wells at an initial (total) capacity of appr. 14 million m^3/d. The gathering system consisted of a looped pipeline with three sales manifolds.

Due to rapid market growth and increased off-take from the Southern part of the Field, pressure differences across the field were experienced. At the end of 1969, reservoir simulation studies demonstrated that a restricted off-take from the Southern part of the field would result in considerably lower average wellhead pressures, when compared with development of the entire field (i.e. Central and Northern area). In order to meet capacity requirements, a considerable amount of new wells were drilled in the Central and Northern parts of the field - with the installation of corresponding new cluster treatment facilities. Each cluster had an initial capacity of about 24 million m^3/d (through 11 wells), whilst a newly constructed gathering centre was connected with a pipeline to the Southern loop.

The Groningen field is currently produced through some 300 wells at 29 cluster locations (14 standard size clusters and 15 king size clusters). Some 30 observation wells are also drilled over the peripheral part of the field.

The total nominal (name plate) gas processing capacity of the surface facilities is some 555 millions m^3/d (0 Deg. and 1.01325 bar), although many clusters are now capacity constrained due to reduced well deliverabilities. With an average of around 10 –12 wells, each cluster produces through a common manifold into five low temperature separation units, in which the gas is cooled down to -12 Deg. C (at 74 bar) to meet the required specifications. Cooling is achieved by a Joule Thomson (JT) valve and a gas/gas exchanger. This low temperature is obtained principally by expansion of the gas. Condensate and water are eliminated to prevent build-up of liquid slugs in the delivery pipelines.

Extending the field's operating life

Up to the end of the 1980's, the initial reservoir pressure of 350 bar had been sufficient to meet the required flow at the minimum manifold pressure that was required to operate the low temperature separation plants effectively (about 25 bar higher than the gas delivery pressure).

However, the reservoir pressure soon started to decline some 3 bar. per year, thereby reducing the required production capacity, which urged NAM to develop a framework plan to meet the demand for Groningen gas in the decades to come.

1.1.5 NUGGETS FIELD (UNITED KINGDOM)

Nuggets is a cluster of small hydrocarbon finds located in the Alwyn area, in the UK sector of the North Sea, 160 km east of the Shetlands Islands and 400 kilometres north-east of Aberdeen. It consists of four gas-bearing accumulations stretching over seven blocks (3/19a, 3/19b, 3/20a, 3/18c, 3/24a, 3/24c and 3/25a) of UK Quadrant 3, approximately 40 to 70 km south of Alwyn.

Total Exploration & Production UK plc operates Nuggets N1, N2, N3 and N4 with a 100% working interest, under licenses number P.239, P.118, P.491 and P.090. In 1994, Total and Elf had purchased Shell/Exxon's (block 3/19a) and Mobil's (block 3/19b) respective stakes in Nuggets.

The Nuggets field distinct gas discoveries were made in 1973 (Nuggets N1), 1974 (Nuggets N4), 1989 (Nuggets N2) and 1991 (Nuggets N3). These accumulations lie in an Eocene production horizon.

In 1973, Total drilled exploration well 3/19a-1B in 123m of water, to a depth of 2,468 m. The well tested gas at an initial rate of 12.4 MMscfd. A second well (3/20a-1) drilled in 1989, tested up to 23.4 MMscfd gas at 2,180 m. These two wells discovered and delineated the Nuggets N1 (North Nuggets) accumulation.

In 1974, the Nuggets N4 accumulation was discovered by Total-operated wildcat 3/25a-2 which tested 14.9 MMscfd of gas. A subsequent well (3/24a-3), drilled to the east in 1990, also encountered gas and proved the extension of Nuggets N4 (South Nuggets) into the 3/24a block.

In 1989, Shell drilled exploration well 3/19b-2 in 109 m of water, and predominantly found gas with some oil in this 4,100 m well (drilled to deeper Jurassic objectives). This Eocene accumulation discovered became the Nuggets N2 (West Nuggets) accumulation.

In 1991, Total drilled 3/19a-4 to the west of Shell's find and tested gas at 25.5 MMscfd from the Eocene. This discovery was called Nuggets N3 (Southwest Nuggets).

Gas composition at Nuggets:

- C_1: Approximately 98%
- H_2S: no evidence
- CO_2: 0.15%

The Nuggets reservoirs contain relatively dry gas having a calorific value of 37.6MJ/m3, with a low proportion of condensate and water.

Production

The Nuggets system is designed to produce up to 6 MMscm/d (220 MMscf/d) of gas (peak) with around 150 bbls/day of associated condensate and up to 1000 bbls/day of water.

The field has now been on production for 4 years with current production of around 5.3 MMscm/d (190 MMscf/d) with around 140 bbl/day of condensate.

Field development and production facilities

The completion of the debottlenecking of the gas processing plant and the subsequent increase in treatment capacity at the Alwyn North platform in 1999, enabled the development of the Nuggets gas-bearing accumulations.

In July 2000, the UK authorities gave consent for the development plan for the Nuggets N1 gas accumulation. Less than a year later, in March 2001, development plans for Nuggets N2 and N3 natural gas fields, received approval. The remaining structure, Nuggets N4 was given development approval in April 2003. As Nuggets fields received development approval after 15 March 1993, they are therefore exempt from Petroleum Revenue Tax (PRT).

D

1.1.6 SHTOKMANOVSKOYE (RUSSIAN FEDERATION)

The Shtokmanovskoye gas condensate field was discovered in 1988. It lies on the shelf of the Barents Sea, 290 km west of Novaya Zemplya Island and 650 km northeast of the town of Murmansk, at water depths of 305 to 330 m. Extending over 45 km in length and 35 km in width, the field is located in very harsh physical, as well as fragile environmental, conditions, with temperature ranging from - 25 C in winter to + 25 C in summer. Rough sea-bed conditions are compounded by drifting ice and waves height can reach 17.5 m.

Rosshelf initially controlled the licence for the Shtokman field. In 1995, a consortium comprising Total (France), Conoco (USA), Hydro (Norway) and Fortum (Finland) was formed to develop the accumulation with 50% of the equity. The other 50% plus one share was held by Rosshelf.

In 2000, the Russian government approved a Production Sharing Agreement (PSA) for the field, designed to establish a long-term legal framework for foreign investment in the natural resources sector. In 2002, the 1995 framework agreement expired and the licence for Shtokman was transferred to Sevmorneftegaz, a Gazprom and Rosneft joint venture. At the end of 2004, Gazprom acquired Rosneft's 50% stake in Sevmorneftegaz as well as Rosneft's 26% stake in the Rosshelf company, accordingly securing total control over the offshore fields in the Barents Sea.

Reservoir properties

At the present time commercial gas reserves have been found in the Jurassic deposits and gas accumulations have been revealed in five horizons.

- Initial formation pressure: 200-240 atm
- Temperature: + 40°C

Natural gas reserves

According to the Russian classification of reserves approved by the State Committee on Resources (SCR) in 1996, initial gas and condensate in place reserves (C1 and C2) are estimated at 3.2 trillion cubic meters and 30 million tons respectively. The share of recoverable condensate reserves amounts to around 80%.

Planned development of the field

More than ten development plans have been studied for the Shtokman field which will be Russia's first gas-condensate offshore deposit to be produced in Arctic environment. This deposit will be developed step by step, optimizing operating conditions, using improved offshore field development technology, with the aim to take the opportunity for potential gas sales "niche".

Until now Russia's gas industry had no significant experience in field construction under such conditions. A number of climatic and technological challenges were encountered when designing the Shtokman field development, including:

- water-depth,
- distance from the shore. Distance between the field and the shore is over 500 km and is considered as an additional obstacle to the field development.
- pipeline transportation security,
- possibility of using large diameter holes.

From economical and technological standpoints, the base-case field development assumes that it would be necessary to drill a total number of 56 to 156 production and observation wells, grouped in six clusters, to produce the field.

SHTOKMANOVSKOYE (CONT.)

E

Total number of wells	156
Production wells	144
Stand-by wells	9
Test wells	3

Table 1. Number of wells necessary for the Shtokman field development (base case)

As it is illustrated below, in this scenario, three platforms are expected to be used to develop the field. Although there is no single opinion with regard to the type of platform (SPAR or TLP), specialists tend to favour the TLP platform.

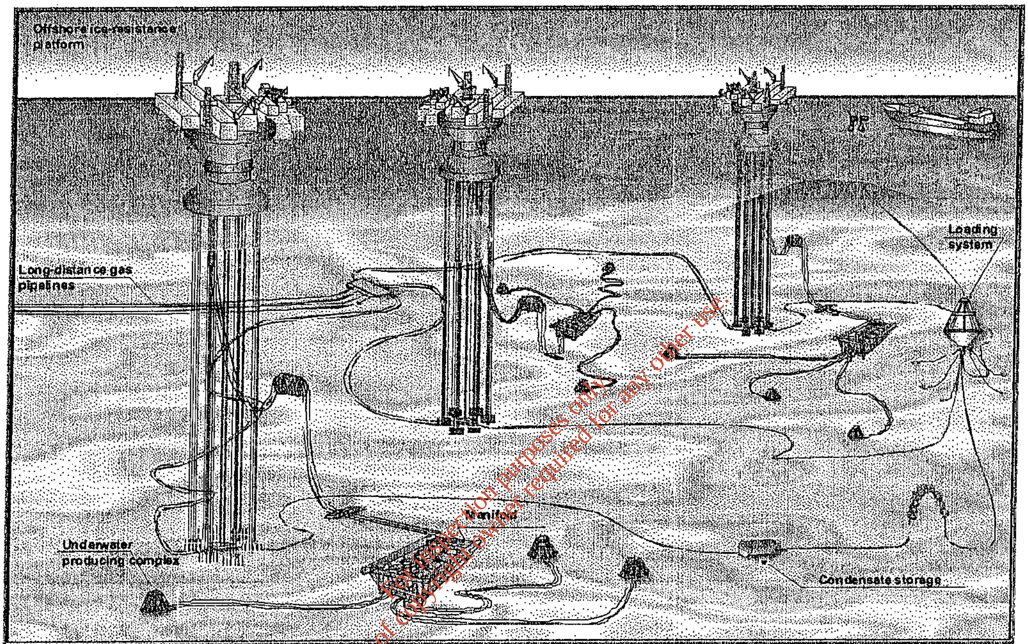


Fig 1. A general layout of the offshore production facilities of the Shtokman field

The use of underwater producing complexes is one of the innovative solutions, which impact on the existing base option of the field development. This solution will allow the platforms not to be brought into operation at the first stage with the subsequent possibility of quicker launch of the project with no reduction in planned production.

Pipeline transportation security over a distance more than 500 kilometers may be provided by a 200 atm working pressure, 30.2 mm average wall thickness long-distance gas pipeline. Throughput capacity of a single line is 22.4 billion cubic meters per annum, which was of aid in determining the base option of field development. Special attention in the project realization will be paid to an automated control system for production and transportation complex and also to an operating parameter control system.

In case of using large diameter holes additional work will be done to make the wells stable under arctic conditions and to protect against external action.

Two options for condensate transportation are under consideration. Produced condensate would be either exported to the onshore terminal by condensate pipeline or pumped into a tanker directly on the field.

Technical Advances (A)

The proved mastery to explore deepwater prospects encouraged others country to explore in off shore. Several fields were discovered in the latest 90's and planned to produce these next years. Krishna / Godavari in India (Mid 2008),) Snovit in Norway (2006), Ormen lange (2007)., Gorgon (2010).

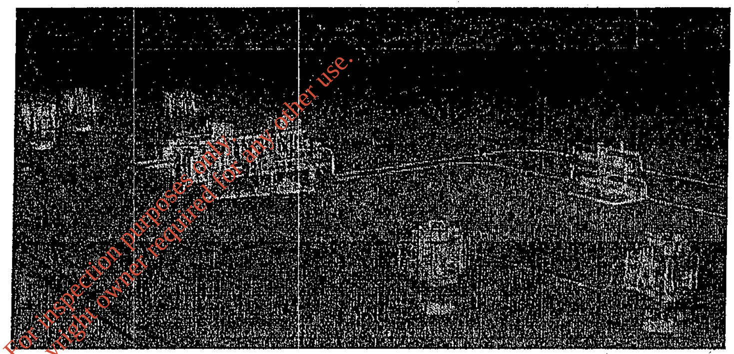
One of the most challenging projects by its difficulties to realize (water depth) is Malampaya deepwater gas field project.

Extracting natural gas deposits in water depths of 820-850 meters and transporting this to its market over 300 kilometers away posed one of the greatest challenges in deep water developments in the world and required the use of the latest in gas technology and skills. The Malampaya field is located 50 kilometers northwest of the Philippines. Discovered in 1992, it is estimated that over 3 trillion cubic feet (Tcf) of gas and 120 million barrels of condensate will be recovered from this resource. The depth of the reservoir is 2,200 meters below the seabed (a total of 3,000 meters from the sea-level). The principal technical challenge is to ensure continuous delivery of sales specification gas throughout the production chain whilst containing costs and maintaining stringent Health, Safety and Environment standards.

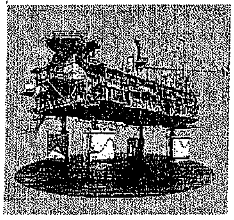
Development Concept

Subsea Facilities

The subsea facilities (water depth: 820 – 850 m) are responsible for controlling the flow from the wells and gathering the gas and liquids. Five christmas trees are installed atop each well which is connected to a subsea manifold. From the manifold, the well fluids are transported to a platform in shallow water (ca. 40 m) via two 30 km flowlines.

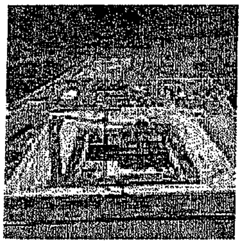


Production platform



The production platform located 30 kilometers away from the subsea system separates the gas, water and condensate. The condensate is temporarily stored at the cells of the platform base called the concrete gravity structure (CGS). The wet gas is dried and transported through the 504-kilometer pipeline.

Concrete gravity structure (CGS)



The CGS was built in Subic Bay and towed to its offshore location in June 2000. The top portion of the platform, the topsides, was built in Singapore and was towed to Palawan where it executed a world record in engineering with the float-over installation method.

suspected sand production, and water influx, the intelligent completions have proven themselves usefull in the management of these assets[10].

Multiphase pipelines

During the past thirty years multiphase flow technology has become increasingly important for the economic transportation of well streams from reservoir to process. In particular, production offshore, where the trend is to develop numerous small fields by transporting untreated fluids via existing infrastructures, imposes high demands on the multiphase science and technology required to ensure economic and safe operation[12].

A number of design and operational difficulties are associated with multiphase flow.

- The prediction of pressure drop-flow rate behaviour is difficult.
- The prediction of the sizes, or even existence, of liquid slugs is even more difficult.
- Plugging due to hydrates may occur, and adequate methods for evaluating transient effects are non-existent[11].
- Their design has been hampered by uncertainties in two-phase pressure drop relations, in flow regime determination, and in liquid slug length prediction.
- This uncertainty makes difficult the choice of pipe size and the design of downstream separation facilities.

Multiphase pipelines offer the potential for substantial cost savings in the offshore transport of hydrocarbons. Two characteristics of the offshore environment make multiphase pipelines potentially attractive.

- First, pipe laying is expensive. If both liquid and vapor must be transported offshore, their simultaneous transport in a single pipe will save the cost of laying separate liquid and vapor lines.
- Second, offshore processing facilities are exceedingly expensive. Both the facilities themselves and the platform to support the facilities are very high cost items. If offshore vapor-liquid separation can be avoided, considerable facility and platform cost savings may be realized. The avoidance of vapor-liquid separation offshore implies multiphase pipelines to shore.

The gorgon Offshore " Australia" Infrastructure gives a good example of significant gas field using multiphase pipelines : To achieve a competitive "cost of supply" (CoS) the Gorgon gas field will be an all sub sea development with a 70 km pipeline tied back to an LNG plant sited onshore , the development of the field is planned for 2010,

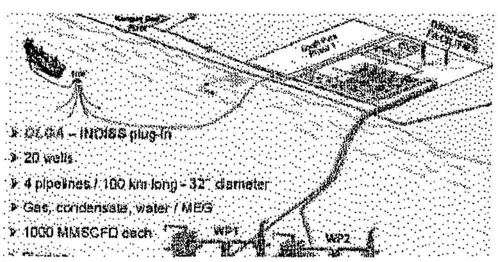


Figure 1: South Pars Gathering System

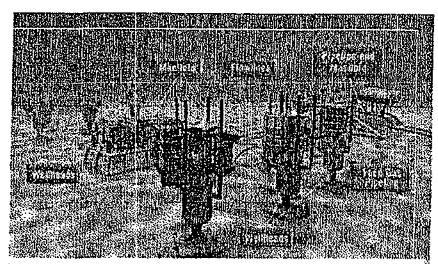


Figure 2: Gorgon Gathering System

But the best example for the multiphase transport of gas is South Pars Giant Gas field "Iran" the volumes in place are 280 TCF , South Pars is the largest project in the world to date using multi-phase transport over such a distance: the transport scheme involves two 32-inch pipelines stretching over 105 kilometers from the field to the onshore facilities(longuest in the world to date) [13]. In the next future Snohvit field "Norwegian Field" situated in Barents Sea is planned to produce from 20 wells and the well stream will be transported to land through a 145-kilometre pipeline " a new record".

Sustainable Development

(A)

- The **Snohvit** project, in the Barents Sea, Norway will also involve CO2 sequestration.

Increasingly CO2 sequestration is becoming the norm, particularly for acid gas reservoirs. But the industry. particularly upstream, has also the issue of methane emissions to tackle, as methane itself is a GHG. Furthermore, the practice of gas flaring has come under increased scrutiny in recent years.

Flaring & venting

Avoiding unnecessary loss of gas is important not just from environmental reasons but also as a matter of simple economics. System designs and maintenance procedures in all parts of the business have aimed to reduce the need for venting of natural gas, but in certain cases, emergency safety considerations mean that the best solution may be to vent natural gas to the atmosphere. A more specific issue for exploration and production activities is gas flaring.

Gas flaring occurs for safety reasons routinely in certain drilling or pre-commissioning hydrocarbon production operations. In many of the gas fields in our examples there is little or no flaring

- **South Morecambe** flaring has been dramatically reduced since startup.
- The environmentally sensitive area around **Loma La Lata** requires constant monitoring and preventative measures; Gas flaring is prohibited.

Gas flaring is used to dispose of waste and non-commercial gases in a safe and reliable manner through combustion in an open flame. On the down side the method generates a greenhouse gas emissions, and is may, at least technically, be wasting gas resources.

Significant flaring of natural gas in the upstream industry occurs primarily where infrastructure for the gas market has not been developed and the gas that is flared is primarily associated gas that is released when crude oil is brought to the surface.

Last year (2005) the World Bank launched a voluntary global standard to provide more incentives particularly in Africa and the Middle East, where most flaring and venting occurs

The World Bank program focuses on ways to commercialise associated gas, including developing domestic markets and access to international markets, creating legal and fiscal regulations for associated gas, and capacity building for the pursuit of carbon credits under the Kyoto clean development mechanism for flaring and venting reduction projects. The aim is to significantly cut venting and flaring in partnership countries over the next 5–10 years.

According to World Bank estimates, eight countries—Algeria, Angola, Indonesia, Iran, Mexico, Nigeria, Russia, and Venezuela— account for 60% of flaring and venting worldwide. Of these, Nigeria (16%), Russia (11%), and Iran (10%) alone are responsible for more than a third of global flaring and venting.

These gas flaring nations are exploring ways to deal with the problem, and Nigeria has said that it plans to eliminate gas flaring altogether by 2008.

Concluding remarks on Sustainable Development Upstream

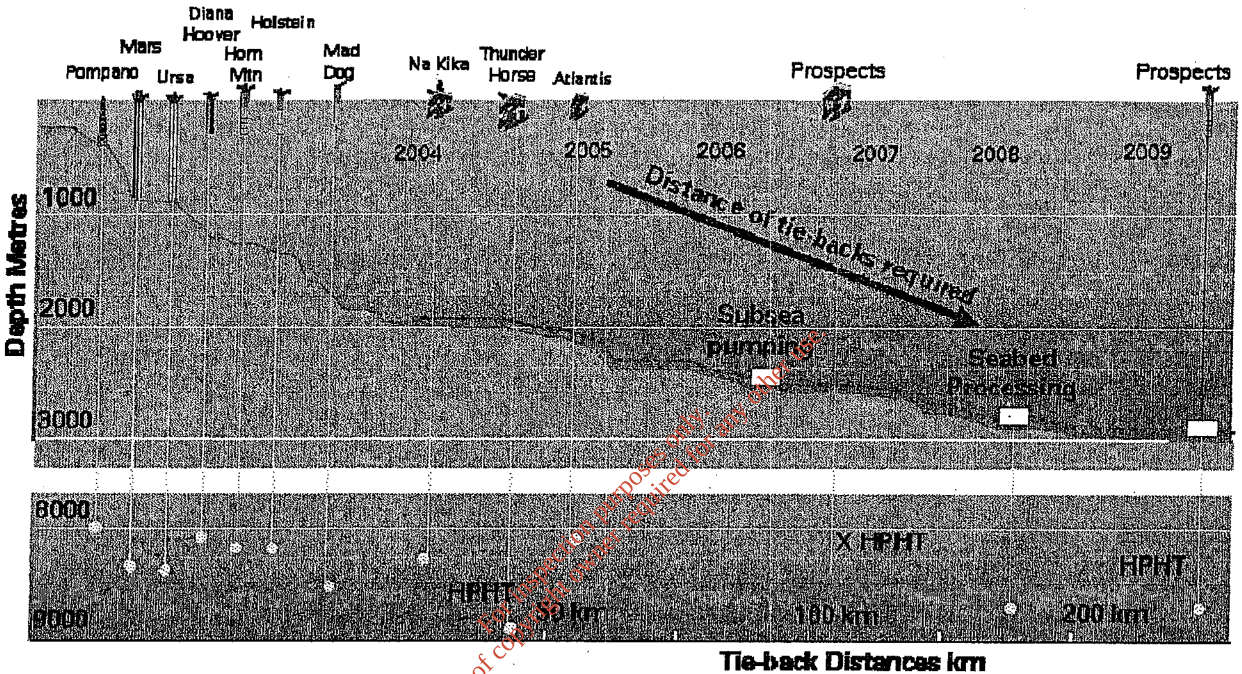
It is necessary that the industry continues to improve its performance by applying adequate management systems, state-of-the-art technology and improving HSE performance. The exploration and production industry has learnt to deal effectively with environmental impact and to take remedial action if damage occurs. As the exploration and production of natural gas now enters its next phase of expansion the challenge will be to continuously aim to minimize the environmental impact so that our earth's heritage is preserved at the same time as we husband its natural resources.

(A)

OFFSHORE GAS DEVELOPMENT CHALLENGES

INTRODUCTION

In its continued search for new production, the Oil and Gas Industry needs to develop hydrocarbon resources from increasingly challenging reservoirs in ever more demanding environments. For offshore developments, this means deeper water regions of continental shelf in places such as Gulf of Mexico and West Africa, as well as moving into ice infested waters such as around Sakhalin Island and eventually the Arctic. Flow assurance becomes a key issue in these cold environments, whether this is shallow water Arctic or the cold waters at 2000+m in Gulf of Mexico and West Africa. Many of these resources are becoming more complex and aerially dispersed, and may include high pressure/high temperature reservoir fluids. This report will describe some of the engineering challenges of these off-shore gas field developments, focusing on deep or ice prone waters.

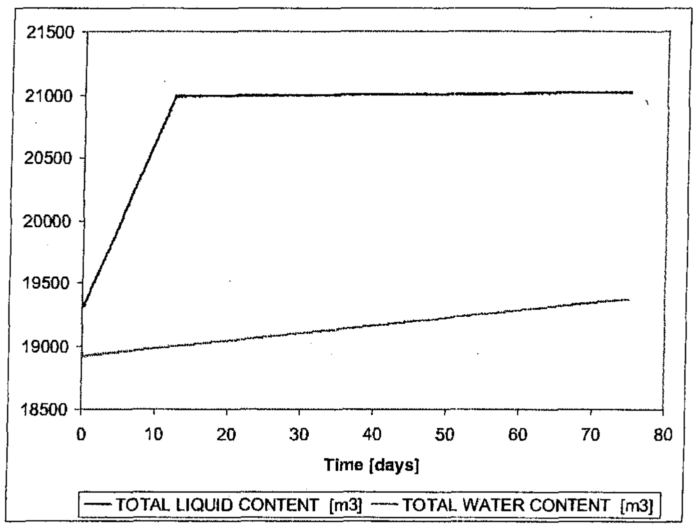


The figure illustrates the evolution of offshore oil and gas developments and concepts deployed as water depth increases, using the Gulf of Mexico as an example. As depth increases beyond 500m, fixed structures are replaced by various floating concepts such as tension leg platforms (TLPs) up to 1000m and Semi-submersibles and Spars (sometimes called Deep Draft Caisson Vessels) beyond. Outside of the Gulf of Mexico, where pipeline infrastructure to shore is less available, ship-shaped FPSOs (Floating Production, Storage and Offloading systems) are more common, for example in deepwater off West Africa. The next generation of developments in these regions will encounter water depths well in excess of 2000m, and in some cases involve tie-backs from subsea wells to floating production hubs of 100 to 200km.

Many of the challenges faced by deepwater offshore gas developments are shared by offshore oil developments; a comprehensive description of these common challenges will not be attempted here. In particular, the extensive engineering and scientific know-how developing around the behaviour, design and installation of floating production systems with their risers and umbilicals and associated moorings is equally important to deepwater oil and gas. This includes riser design and monitoring, and modeling of dynamic effects such as vortex induced vibration, with prediction of fatigue lifetime a key focus area. These are extensively covered in offshore oil and gas Industry reports and conferences. This report will focus only on development challenges that are of particular importance for either non-associated or associated gas.

Offshore oil production systems can either export product via export pipelines or by direct transfer to oil carriers, usually via single point buoy moorings and flexible transfer lines. In contrast, offshore gas developments need an export riser, pipeline manifold and export pipeline – although

OFFSHORE GAS DEVELOPMENT CHALLENGES (B)



The figure illustrates the slow approach to liquid inventory equilibrium in a recently restarted, 60 km, 32" gas condensate line. The true equilibrium between water and hydrocarbon will clearly take many months to establish. As new gas is brought into the system the production of this liquid and its transport to the on-shore facilities (in this case) will present significant challenges, and needs careful modeling to plan operations and design facility modifications.

Tie-back of subsea developments into production hubs raises a further multi-phase flow issue associated with fiscal metering – where more accurate subsea multiphase flow meters are still required by the industry.

Temperature prediction

While the need for accurate temperature predictions in order to support wax and hydrate studies is well understood, there are particular issues with deepwater systems. In long risers, with sophisticated insulation (e.g. pressurised gas in an annulus, or many segments of foam with sea-water penetration), convection cells may be formed that significantly reduce the effectiveness of the insulation, resulting in colder than expected arrival temperatures.

It should also be stressed that in these systems it is essential that simulations are developed with the most precise thermal descriptions of pipeline and riser coatings available. Experience shows that even an anti-corrosion coating of a few mm thickness can significantly alter heat transfer between riser fluids and the surrounding sea, and needs to be taken into account in order to provide a sound design basis for receiving equipment.

Hydrate control

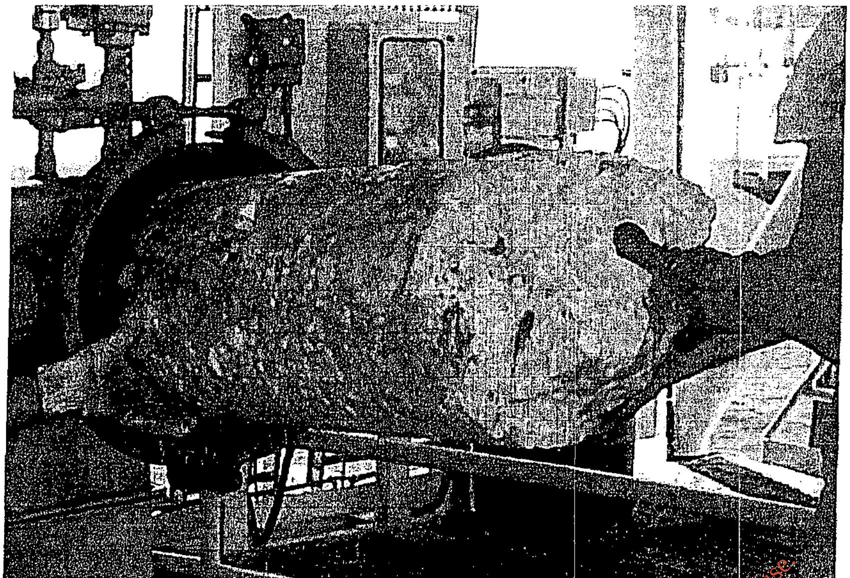
The key flow assurance issue facing gas developments in deepwater environments, which will also be important for Arctic and onshore developments in cold regions, is the control of gas hydrate formation.

Hydrocarbon Gas and liquid water can combine to form crystalline solids which resemble wet snow or ice. These solids are called Gas Hydrates, or more correctly Natural Gas Hydrates (NGH). They are formed by certain low molecular weight hydrocarbons such as methane combining with water under conditions of temperature and pressure commonly found in flow-lines carrying hydrocarbon fluids during normal oil and gas production. These compounds contain gas molecules trapped in a metastable "host" crystal lattice made up of water molecules forming a three-dimensional structure. Gases that form hydrates are light, non-polar, and generally have low solubility in water. They are usually C_1 to C_4 inclusive. Other gases found in oil field fluids such as CO_2 and H_2S will also form hydrates under favourable conditions. Conditions favouring hydrate formation are high pressures (typically >30 bar) and low temperatures (typically <20°C).

OFFSHORE GAS DEVELOPMENT CHALLENGES

C

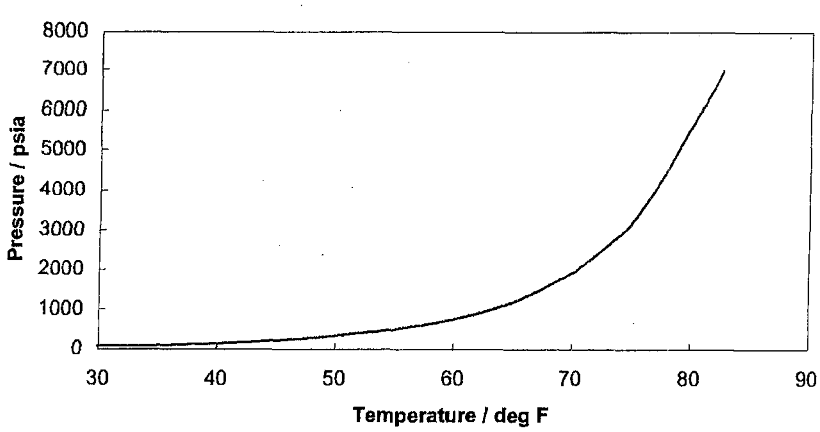
As well as being a natural occurrence in many parts of the world, often below the sea bed in the proximity of natural gas accumulations, hydrates can form in wet gas, condensate or black oil lines. Gas hydrate formation can cause problems during hydrocarbon production by blocking pipelines, valves or other process equipment. It can occur relatively quickly, be difficult to remove and potentially cause serious damage and/or fatalities if not removed with care. The problem is becoming more important as natural gas and gas condensate resources are discovered where operating conditions (deep, cold water and on-shore colder climates) surpass the conditions needed for hydrate formation. Often hydrates will form from gas streams (which are produced saturated with water) in downstream transportation networks once the stream has cooled from reservoir conditions. This can cause large pressure drops throughout the system and reduce or stop the flow of natural gas.



Hydrate plug removed from a flow-line

The problems associated with gas hydrates in gas production and transportation were first reported by Hammerschmidt in 1934 where he states 'the presence of water vapour in natural gas has always been a source of trouble to the natural gas industry. The movement of gas through the pipe tends to collect and compress the snow at low spots until the line may become entirely plugged'. As a result of these issues, technology has developed to predict and prevent hydrate formation in gas lines and wells. The technical solutions to prevent hydrate formation include methanol or monoethylene glycol solvents as thermodynamic inhibitors, triethylene glycol contactors to dehydrate gas, and pipeline insulation/heating to keep the system warm and hence outside the hydrate formation region (ie to the right of the red line shown in the graph below).

Hydrate dissociation curve for a GOM fluid with pure water

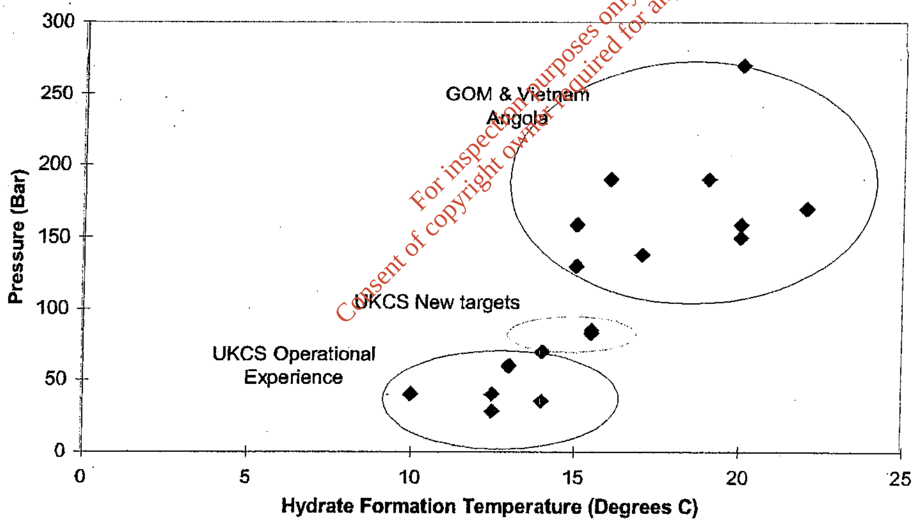


OFFSHORE GAS DEVELOPMENT CHALLENGES

In recent years, new low dose Hydrate Inhibitors have been receiving considerable industry attention. Replacement of the traditional thermodynamic inhibitors methanol and glycol is highly desirable from both commercial and Health & Safety considerations. The operating costs for these solvent based inhibitor treatments are high, and the off-shore facilities for these treatments can be complex and logistically intensive. From a safety perspective, it is becoming increasingly unacceptable to store large inventories of solvent on off-shore platforms. The Industry has been working since the mid 90's to develop robust and cost effective low dose inhibitor technology which can be commercially deployed in oil and gas production operations. This is exemplified in the Ravenspurn Southern North Sea Gas field where Kinetic Hydrate Inhibitors (KHI) have been deployed since 1996 and in the North Sea ETAP field where substantial capital costs were realized through the removal of 'conventional' methanol solutions and replacement with KHI technology in the design and subsequent operation.

The latest development in Low Dosage Hydrate Inhibitor (LDHI) technology centres around the use of Anti Agglomerates (AA). Also known as dispersants, AA's target the hydrate crystal size and morphology. Unlike KHI's, AA's do not try to delay the onset of hydrate growth. The goal is to produce a transportable oil/water/hydrate slurry. This is accomplished by forcing the hydrate crystals to form slushy to fine powdery particles, which do not adhere to surfaces. Recent successes have been reported in Deepwater Gulf of Mexico (GoM) fields especially as a replacement for methanol in cold oil well start-ups. LDHIs are an emerging new technology in offshore oil and gas production. In certain situations, applications of KHI and AA technology are more economical than methanol or other glycols. This is because LDHI dosage levels are an order of magnitude less than the dosage levels of thermodynamic inhibitors. These low KHI and AA dosage levels translate into lower pumping, storage and transportation capital and operating expenditures. LDHIs can also provide an alternative technical solution, e.g. where sufficient volumes of methanol cannot be injected (pumping or umbilical limitations). This technology also overcomes some of the growing concerns about the environmental impact of large volumes of methanol on downstream processing facilities.

METHANOL



In the past few years, the 'challenges' surrounding hydrate management have stretched with increasing water depth and subsea developments meaning much colder environments. The previous graph illustrates the technical challenge the industry faces in deepwater areas such as the Gulf of Mexico and West Africa.

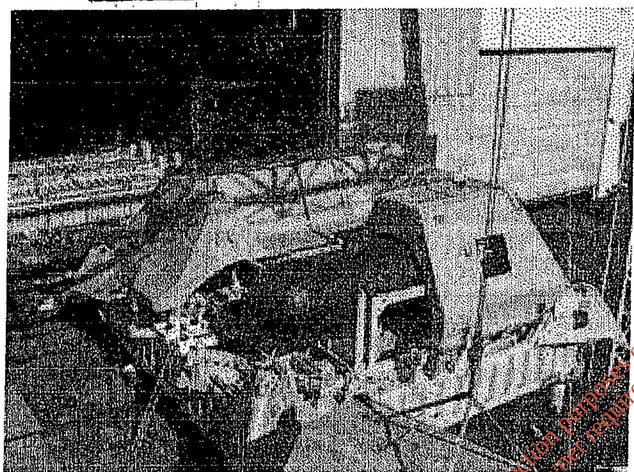
Many of these new provinces are outside the technical limit of KHI, and in some instances current AA technology, which allows scope for improvements in the chemistry by the chemical vendors, amongst others. The industry is also looking toward other solutions such as improved insulation, pipeline heating, and 'step out' technologies such as 'Cold Flow'. One or more of these technologies needs to come to fruition if we are to avoid widespread use of thermodynamic inhibitors as the preferred hydrate management strategy.

2.2.3 SUBSEA GAS PROCESSING CHALLENGES

In addition to the engineering and technical challenges associated with deepwater installation depths and longer distance tie-backs, subsea gas developments also face processing issues specifically linked to gas/condensate fluids properties. Start-up of subsea gas/condensate production wells can result in low temperature conditions for flow-lines and instrumentation systems close to the wellhead that challenge design, material selection and fabrication. In extreme cases the initial start-up conditions can produce temperatures as low as -50°C which create brittle conditions in pipework and out of range parameters for standard temperature instrumentation sensors at the wellhead. This drives material specifications to address not only issues during the start-up of subsea production, but also the associated difficult machining and weldability issues with high specification materials.

In addition, flow-line metallurgy, weldability, and corrosion management issues associated with the fluid properties such as hydrogen sulphide and carbon dioxide in the process gas, and oxygen in any required injected chemicals for flow assurance purposes must also be addressed.

Subsea separation and compression has been the subject of significant effort by the oil & gas industry over the last 10 years or more. Whilst subsea liquid pumping systems (as opposed to electrically submersible pumps, which tend to be platform deployed) have now started to gain acceptance for reliability and are seeing early commercial trials, there has been a slow take-up of separation and gas compression systems (1).



Subsea liquid pumping and separation module

The current state of technology qualification testing would suggest both subsea pumping and the integration of modular separation systems are ready for commercial application. For pumping in particular, there are examples of deployed system for oil developments.

However, the case for gas compression boosting is not as well accepted, predominately from a reliability viewpoint in relation to rotating equipment and associated power delivery, and further development and qualification testing will be required. Gas compression requires considerably more power delivered to the subsea equipment than oil pumping and this lead to a requirement for very high power deliver components such as subsea connectors and variable speed drives. Overall, there seems to be a future requirement for subsea gas compression systems for application to longer distance tie-backs for gas developments. In particular, this will enable full field development of remote, off-shore gas fields using an entirely subsea architecture. This may be important for the development of gas fields in ice infested and Arctic waters.

2.2.4 HIGH PRESSURE HIGH TEMPERATURE RESERVOIR DEVELOPMENTS

Whilst not exclusively an issue with gas developments, high pressure reservoir fluid conditions to 1,000 plus bar are increasingly associated with subsea gas developments, and are being encountered in a number of regions of the world including Gulf of Mexico, North Sea, Offshore Egypt, the Caspian and Trinidad.

Oil and gas fields that have both high pressure and high temperature are typically referred to as HPHT fields by the industry. This combination of conditions is dictated by several factors such as age of oil and gas or geologic and tectonic history of the reservoir; another factor being that pressure and temperature of fluids normally increase with well depth.

The definition of HPHT has changed over the years as the industry has matured and exploration has moved to deeper horizons. Although there is not a universal acceptance of an HPHT definition, it generally refers to fields that have a flowing oil or gas temperature in excess of 100°C and a well shut-in pressure of 700 bar at the wellhead. Thus, the definition is mostly related to the surface

6. Supersonic and other Offshore Processing Technology

MARCH 2004

✓

SUPERSONIC GAS CONDITIONING
FIRST COMMERCIAL OFFSHORE EXPERIENCE

Job M. Brouwer MSc.
Twister BV
Rijswijk, the Netherlands

Gonneke Bakker MSc
Twister BV
Rijswijk, the Netherlands

Huib-Jan Verschoof MSc
Twister BV
Rijswijk, the Netherlands

Hugh D. Epsom BTech FIMechE
Twister BV
Rijswijk, the Netherlands

ABSTRACT

Twister™ is a revolutionary gas conditioning technology which has been under development for natural gas applications since 1997. Condensation and separation at supersonic velocity is the key to some unique benefits. An extremely short residence time prevents hydrate problems, eliminating chemicals and associated regeneration systems. The simplicity and reliability of a static device, with no rotating parts and operating without chemicals, ensures a simple facility with a high availability, suitable for unmanned operation. Full scale test units have been operational since 1998 at five gas plants in the Netherlands, Nigeria and Norway, with varying gas compositions and operating conditions.

The first commercial offshore Twister application successfully started-up in December 2003. Twister has been selected by Petronas and Shell for the gas dehydration process of B11, a large gas processing platform 120 km offshore Malaysia. The B11 field produces 600 MMSCFD of sour non associated gas feeding the Bintulu LNG plant.

The B11 Twister design, including the Twister tubes and Hydrate Separators, and the effects on the overall plant design, will be discussed together with the recent start-up and operating experience of the B11 plant.

Its simplicity makes Twister a key enabling technology for subsea gas processing. An update will be provided on Twister's joint industry project for subsea development and pilot testing.

associated chemical regeneration systems avoids harmful BTX emissions to the environment. The simplicity and reliability of a static device, with no rotating parts and operating without chemicals, ensures a simple facility with a high availability, suitable for unmanned operation in harsh and/or offshore environments. A Twister tube designed for 60 MMscfd at 150 bar is only 2 meters long inside a 6" casing. The compact and low weight facilities can be installed on an unmanned, minimum facilities platform, not much larger than a simple wellhead platform.

Although a relatively new technology, extensive operating experience has been obtained with commercial scale test units in five different gas plants in the Netherlands since 1998, in Nigeria since 2000 and in Norway since 2002. These test units have proved the viability of gas conditioning to typical pipeline specifications as well as the practicality of reliable, safe and unmanned operation.

B11 CONCEPT SELECTION

Petronas and Sarawak Shell Berhad (SSB) successfully started up the first commercial Twister system on December 30th 2003. The two Twister gas dehydration trains have a combined capacity of 600 MMSCFD. Each train comprises six Twisters and one Hydrate Separator.

In 1999 a feasibility study was carried out by the "Twister Venture Team", the predecessor of Twister BV, at the request of Shell Sarawak Berhad (SSB) to evaluate the application of Twister technology in the development of the B11 field Offshore Sarawak, Malaysia.

Originally SSB's "base case" development of the field was based on the concept of wet gas evacuation, corrosion in the carbon steel evacuation system being managed through the injection of corrosion inhibitors. During the study, the "base case" development concept changed in favor of dry gas export using traditional TEG dehydration technology offshore. This decision was driven by the risk of corrosion associated with the high CO_2/H_2S concentration as well as an opportunity to tie-in to an existing dry export line.

The 600 MMSCFD produced and dehydrated on the new B11 platform had to be transferred, combined with dry condensate, through a new 65 km 24" CS pipeline to the already existing E11 riser platform (E11R-B). At E11R-B the gas and condensate was planned to be routed to shore via the existing trunk line network. The gas is feeding the existing Bintulu LNG plant, imposing a contractual system availability of 98%.

MM The feasibility study showed that application of Twister technology compared to a TEG unit, allows the exported gas to be dehydrated with less complex, smaller, lighter, cheaper and emission free facilities. These are mainly resulting from the smaller foot print, reduced utility requirement and reduced or eliminated manning requirements. The high H_2S concentration of 75-3,500 ppm was recognized as a major hazard to personnel and a strong incentive for unmanned operation.

The cost comparisons showed a cost reduction of 24% for the production platform topsides compared to the base case costs. Lifecycle cost reductions of over 40% were identified for an unmanned platform.

The principal disadvantage of Twister was the pressure drop requirement of about 30% which accelerated the need for field depletion compression. This could be mitigated to some extent by retrofitting the newly developed Twister internal design which provides a significantly reduced pressure drop.

As part of the feasibility study, tube tests were executed on a plant scale test facility to verify Twister performance for the B11 application. These tube tests showed that the required Twister performance could indeed be achieved.

B11 TWISTER PERFORMANCE

Plant conditions

The B11 plant started-up on 30 December 2003 and has been running up to now (beginning of March 2004) with just minor incidental shutdowns for concurrent construction and commissioning activities. Plant conditions during this initial period of operation can be summarized as follows:

- The plant design capacity is 600 MMSCFD, this throughput is currently not yet achievable as not all wells are available. Also the downstream LNG processing plant puts some limits on B11 production. The maximum throughput up to now has been 420 MMSCFD with 7 Twister tubes in operation. The minimum stable plant throughput up to now has been 120 MMSCFD with 2 tubes in operation.
- The amount of H_2S and CO_2 contaminants is in the low range of the design, respectively 20 to 75 ppmv H_2S and 7 to 9 mol% CO_2.
- The amount of heavy components in the feed is less than design, however with a longer heavy tail. Current condensate production is about 15 bbl/MMSCF. Water production is at the design limits of 6 bbl/MMSCF.
- The plant inlet pressures vary between 130 and 160 bar, depending on export conditions.

Twister tubes

Twister tube performance closely matches the design:

- the optimum gas slip stream quantity is about 33% of the main stream,
- tube operation is not affected by smooth variation of the inlet pressure and the tubes quickly recover from fast pressure dips and peaks.
- for a Twister inlet temperature of 25C, the mixed gas (secondary plus primary) temperature is about 10C.

The pressure drop over the Twister system is only slightly (2 bar) higher than specified. It is expected that this pressure drop will be reduced as part of the Twister optimization activities.

Hydrate Separator performance

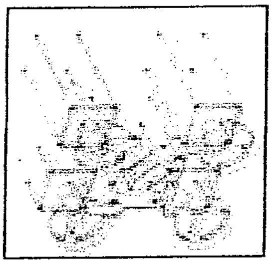
The gas/liquid separation of the secondary LTX type Hydrate Separator is well within the design limits as no hydrate build-up in the separator overhead system has been detected and no negative impact on the water dew point of the dry gas has been observed.

Liquid drainage, liquid/liquid separation efficiency and prevention of hydrate carry-over into the condensate system rely on continuous heat supply. The heat duty required for smooth separator operation is about 300 kW per train (300MMSCFD), which is well below the (conservative) original design. It is likely that further optimization could reduce this figure.

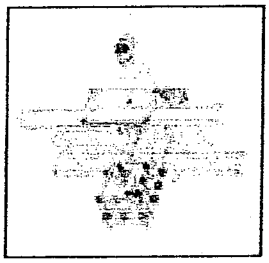
Product quality

Karl Fisher type dew point spot checks indicate a water content of the product gas of 150 ppmv (115 mg/Sm3), which ensures a water dew point of 2 to 5C (depending on which equation of state used), well below the specification of 7C. The on-line (continuous) Hygrophil dew point meter indicates that this value is not exceeded, even during incidental process upsets. Incidental dew point verification with Shaw and Panametric probes showed the same results.

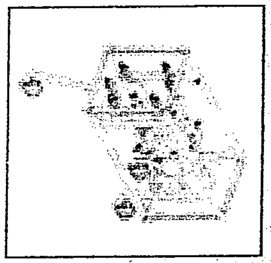
Although the condensate dehydration is not part of the Twister system, its performance affects the performance of the overall plant. Spot check measurements indicate a water in condensate fraction within the design range (275 ppmv). However, as condensate properties are different from design, this subject needs further investigation.



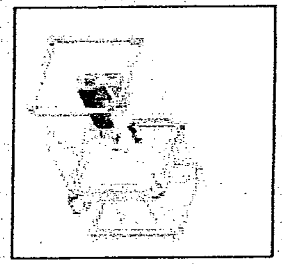
1. Template with four suction anchors, supporting and registering the interfaces for the manifold module and the other retrievable modules.



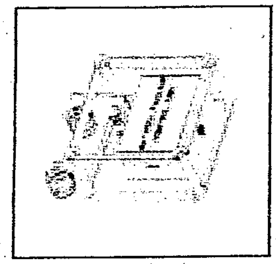
2. Manifold structure including the manifold piping with tie-ins, the Inlet Cooler and the Inlet Separator.



3. Twister unit with the Low Temperature Separator including electric heater, 6 off Twister tubes and related piping and valves.



4. Seawater cooling pump unit with electric motor, installed on top of a transformer unit.



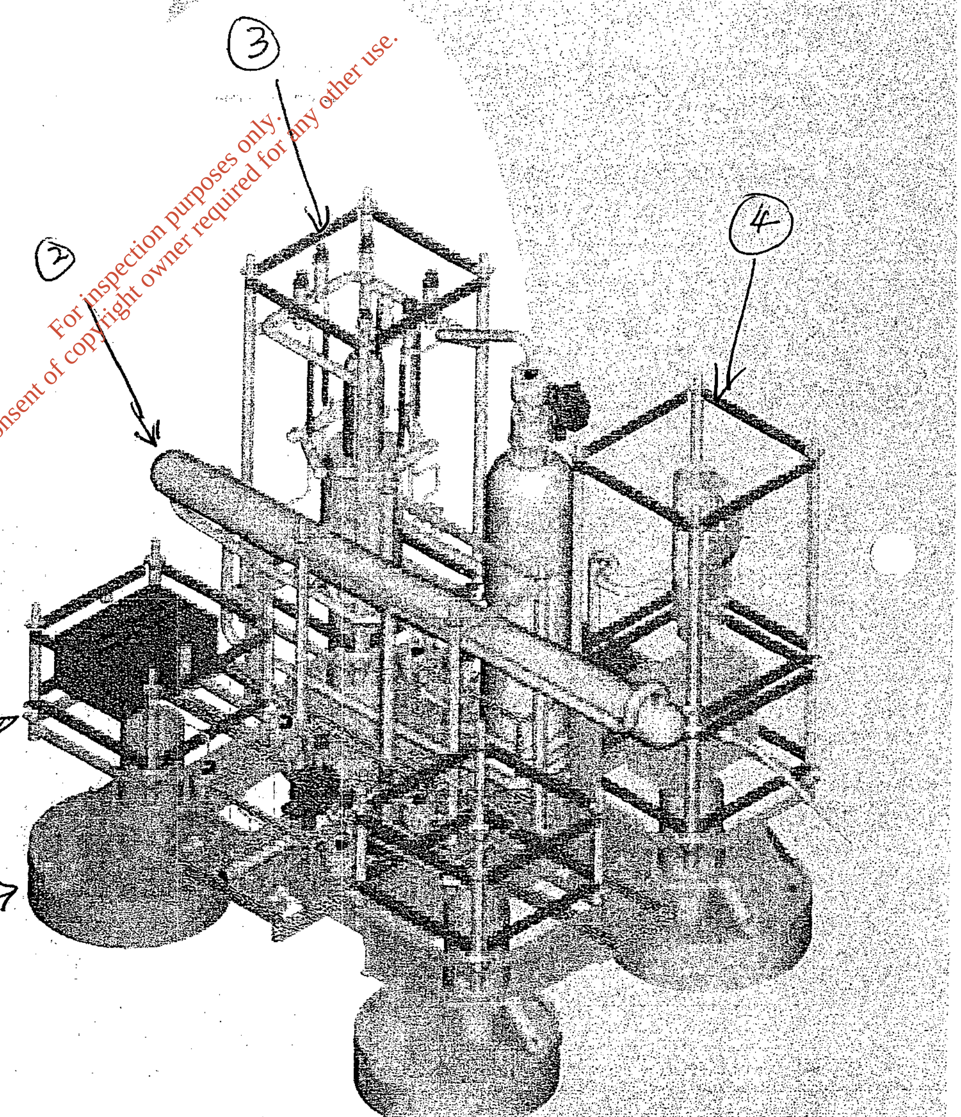
5. Control valve unit with control system and battery back up.

slug-catchers may be avoided. Routine pigging for liquid hold-up management, a costly and inherently hazardous operation, can be avoided. Multi-phase export also limits both pipeline turndown flexibility and maximum pipeline size, sometimes necessitating multiple smaller diameter pipelines and often eliminating the flexibility to tie-in future developments.

- ***Hydrate prevention:*** MEG supply lines and regeneration facilities can be eliminated. The chemistry of the produced, saline formation water in combination with the hydrate inhibition chemicals may result in operational problems like chemical degradation & scale depositions. Costly vacuum glycol desalination facilities may be required to manage glycol salt contamination and its associated operational and corrosion issues.

- ***Corrosion prevention:*** Twister will be a particularly attractive option for corrosive service, which may necessitate a CRA export line, i.e. for gas compositions with a CO_2 fraction in excess of some 4 mol%. Effective corrosion management for wet gas CS pipelines will normally require routine pigging to maintain a protective chemical film on the inside wall of the pipeline, which will be particularly costly and cumbersome for subsea developments.

- Opportunities for pipeline savings where ***tie-in to an existing export pipeline*** is possible (e.g. hot tapping).
- Opportunities to ***de-bottlenecking offshore/onshore processing facilities*** by subsea gas conditioning.



"Modular subsea gas processing system including a Twister dehydration unit"

G-40202/04-03

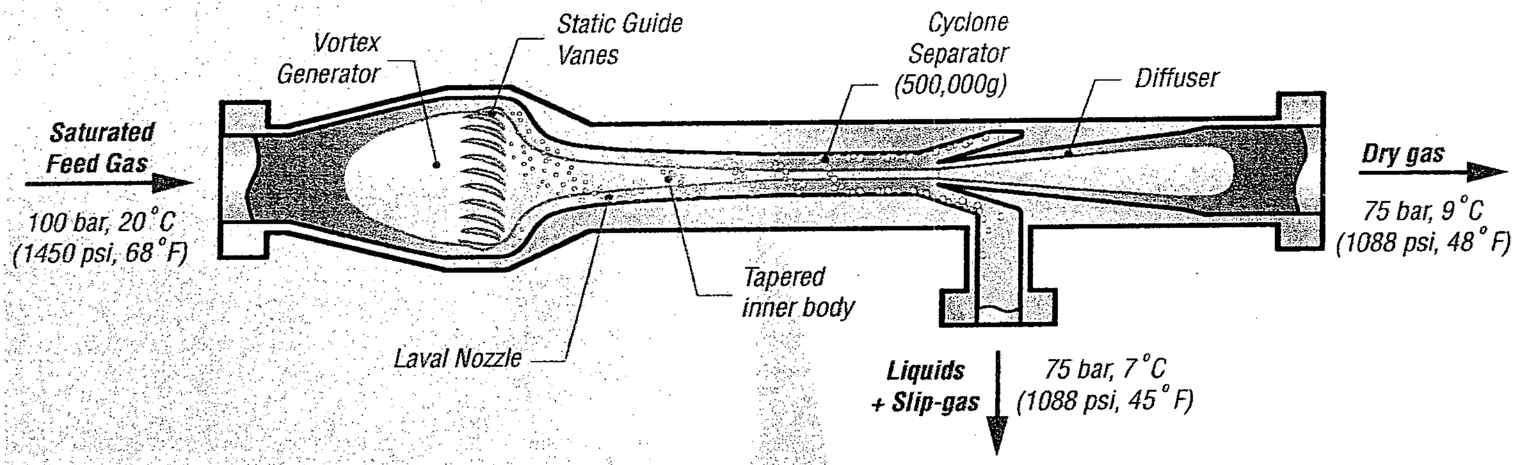


Figure 1 shows a cross-section of a Twister tube with typical process conditions.

Twister Factsheet 1

How does Twister work?

The Twister™ Supersonic Separator is a unique combination of known physical processes, combining aero-dynamics, thermodynamics and fluid-dynamics to produce an innovative gas conditioning process. Condensation and separation at supersonic velocity is the key to achieving a significant reduction in both capital and operating cost.

The Twister™ Supersonic Separator has thermodynamics similar to a turbo-expander and combines the following process steps into a compact, tubular device:

- *expansion*
- *cyclonic gas/liquid separation*
- *re-compression*

Whereas a turbo-expander transforms pressure to shaft power, Twister achieves a similar temperature drop by transforming pressure to kinetic energy (i.e. supersonic velocity).

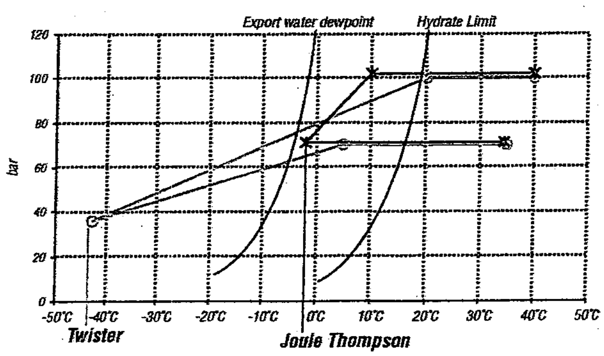
***Figure 1** shows the basic concepts:*

- *Multiple inlet guide vanes generate a high vorticity, concentric swirl*
- *A Laval nozzle is used to expand the saturated feed gas to supersonic velocity, which results in a low temperature and pressure and high centrifugal forces (over 500,000g)*
- *This results in the formation of a mist of water and hydrocarbon condensation droplets.*
- *The high vorticity swirl centrifuges the droplets to the wall.*
- *The liquids are split from the gas using a cyclonic separator.*
- *The separated streams are slowed down in separate diffusers, typically recovering 70 - 75% of the initial pressure.*
- *The liquid stream contains slip-gas, which will be removed in a compact liquid de-gassing vessel and recombined with the dry gas stream.*

Comparison

***Figure 2** compares the thermodynamics of Twister with conventional Joule-Thompson expansion. In this example, the same feed conditions (100 bar/1450 psi, 40°C/104°F) and the same pressure drop (30%) has been assumed for both processes.*

- *Twister is a highly efficient, near isentropic expansion process, achieving more than 60°C (110°F) cooling with the 30 bar pressure drop available.*



Twister
Supersonic Gas Solutions

Subsea

Simplicity and reliability are critical success factors in subsea applications. Twister is currently the only gas-conditioning technology in the market that scores high on both counts by eliminating both chemicals and rotating parts. Twister subsea gas processing is therefore a potential key enabling technology for the development of currently uneconomical subsea reserves.

Twister BV and FMC Kongsberg Subsea have completed a joint study to investigate the introduction of the Twister into the subsea market. Based on the positive results from this study the EU has granted a subsidy to an international consortium to design and build a pilot of a Twister subsea gas processing system.

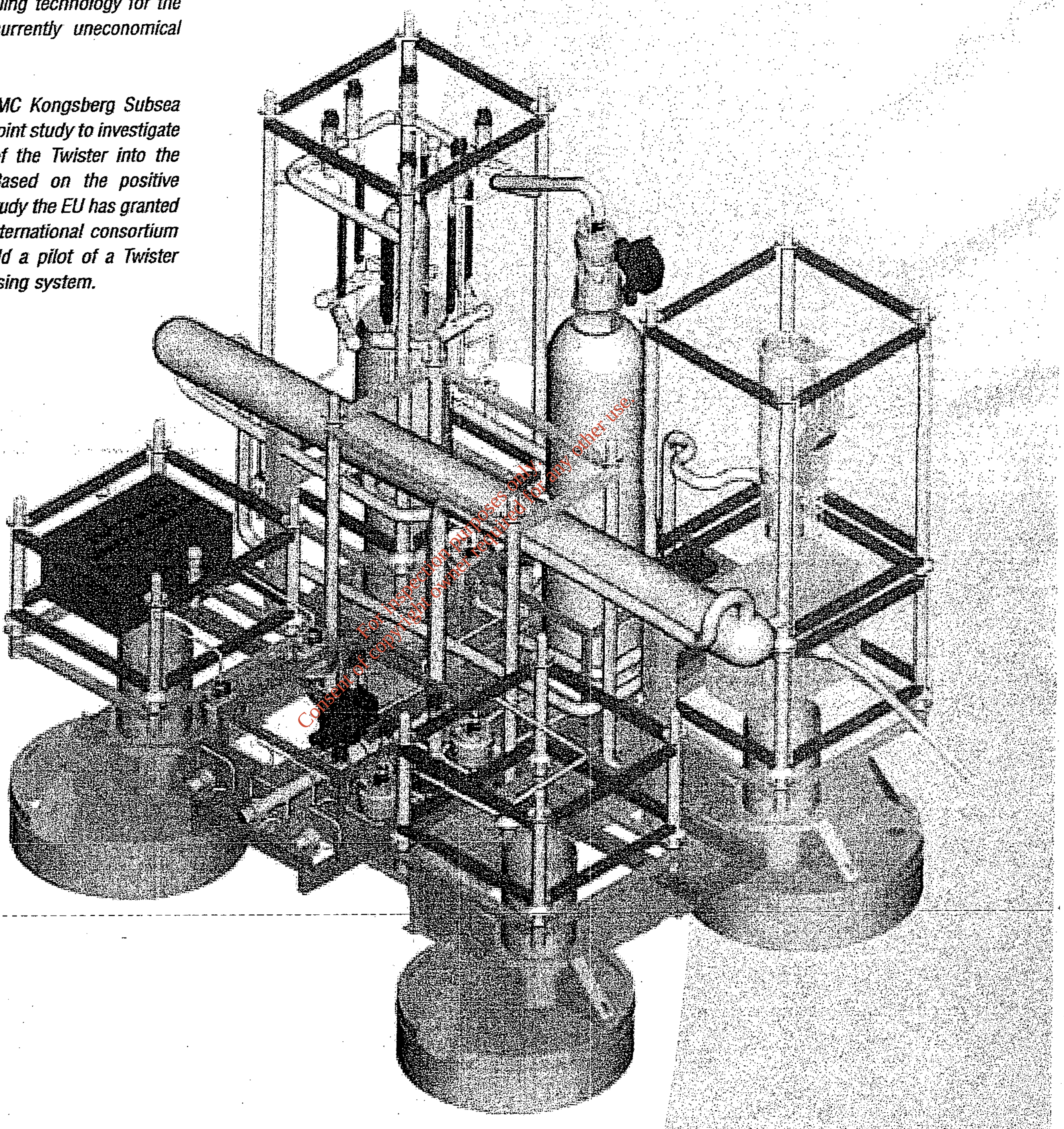


***Figure 7** shows FMC Kongsberg's Modular Subsea Gas Processing System including a Twister dehydration unit.*

For further information and contact details visit our website: www.TwisterBV.com or email: office@TwisterBV.com

Subsea production systems progressing quickly

The quest to move the processing facility to the seafloor - including virtually everything except the crane and the living quarters - is getting close to becoming a reality.

Perry A. Fischer, Editor

The advantages that dry trees and the accompanying surface processing facilities have over subsea systems are substantial. Some of these are monitoring, maintenance, easy access, adjustment and optimization of production. These, along with pressure issues of just getting the oil and gas to the surface, are widely regarded as the biggest reasons that subsea production falls short in terms of ultimate reservoir recovery. The full range of options that exist in very shallow water and land are not yet available for producing from deeper waters. However, the difference in recovery factors, as well as the simple economics of not having to invest in surface real estate, is driving a change.

The conventional subsea solution is to move the wellstream, intact, to a dry environment - either a topsides-offshore or shore-based facility. But why not move most of those surface components to the seafloor? That question is being addressed by several companies and consortia, each with its own contribution, from the component level to complete modular systems. Discussed here are advances in subsea technology for wellheads, multiphase pumping/boosting/ metering, flow assurance, control systems, separation, compression and complete modular systems.

MULTIPHASE PUMPING

Multiphase pumping is relatively new, even at the surface. The first subsea multiphase pump was installed in 1993, followed by an electric-driven version in 2000. At this juncture, it is essentially a proven technology and is becoming the conventional method for increasing recovery in subsea wells. Several pumps are now capable of delivering wellstreams with gas-volume fractions of 95%, sometimes higher. However, improvements are still coming. For example, there are situations where multiphase pumps need to handle gas-volume fractions close to 100%, and these are still a challenge. Also, when the power source is far away, electrical losses become excessive, and they need to be reduced or the power created locally, such as from a fuel cell or water-driven turbine.

The technology can allow marginal fields to become economic, and field life can be extended. The decision as to whether to use a multiphase pump is complex. The expected boost in production must be weighed against the cost of the pump, its maintenance and the power to operate it.

When dealing with fields remote from infrastructure, long multiphase flowlines have some inherent drawbacks. First, they create increased backpressure, which can lower ultimate recovery. With surface systems, wells can flow unassisted into a system, whose pressure is typically in the 800- to 1,000-psi range. With compression or boosting added, wells can flow down to 100 psi or less before abandonment becomes necessary. However, very long flowlines can add 1,000 to 2,000 psi to the abandonment threshold.[1] Also, flow assurance issues are exacerbated with long flowlines.

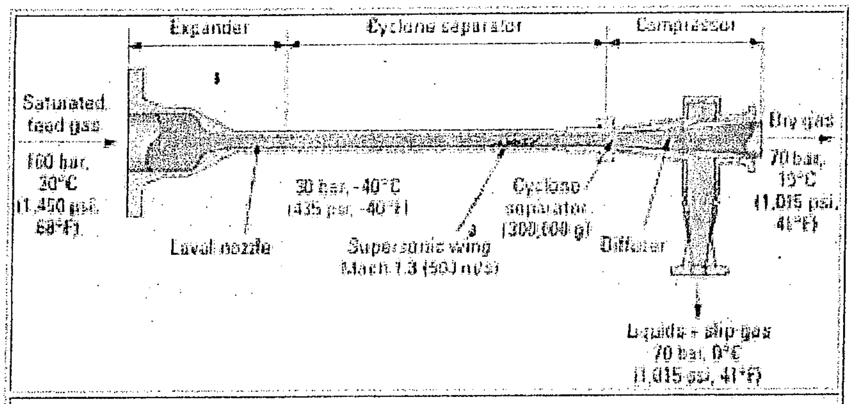


Fig. 6. Operating principle of the Twister.

The device requires a gas reservoir that has the right characteristics to allow its use. When these are present, the benefits are a simple, robust, no-moving-parts dewpointer that can save money. A topsides version, the first ever, became operational less than a year ago on Shell's B11 PA development project offshore Sarawak, East Malaysia, with a design capacity to dehydrate 600 MMcfd of non-associated gas (see *World Oil,* August 2002 and April 2004 issues).

Twister BV and FMC completed a feasibility study of the technology for subsea applications. No fundamental problems were identified, although several components will need further development and qualification prior to installation and operation on the seabed. The companies and various other partners have secured an EU subsidy for a four-year development program. This should result in the design, construction, installation and testing of the first pilot, subsea gas processing installation by 2007.

Complete modular systems. AlphaPRIME is approaching the end of a long road. After nearly 15 years, the Shell/ Alpha Thames consortium probably has the most complete of the all-in-one subsea production systems now brewing. It is a modular system approach that contains all of the seabed installation's operating parts, Fig. 7.

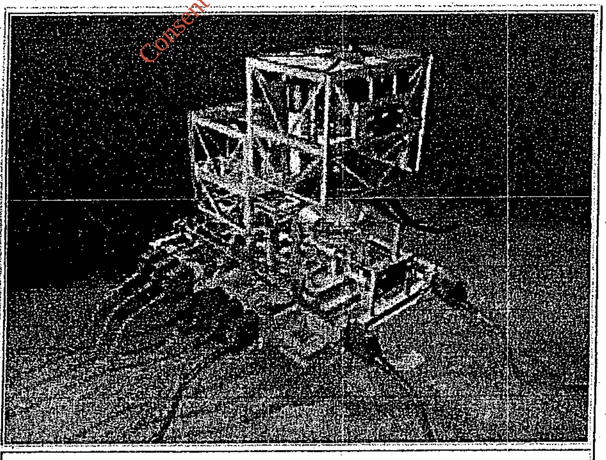


Fig. 7. AlphaPRIME complete subsea system for Shell.

The first stage was the completion of a preliminary, 15-month qualifying program.

3.

program is developing and testing additional components, and further enhancing some existing Shell-specified components. The new electric valve actuators have been qualified through the program, and the entire system has been verified by DNV to agreed standards and established as "catalogue ready" for use in Shell Operating Units worldwide.

A field using the system will deploy an all-electric System-Modular installation known as an AlphaCPU (Central Processing Unit). Located close to the wells on the seabed, each installation comprises at least two operating System-Modules of a size appropriate to the field throughput requirements. They are mounted on a KeyMAN manifold that has no active components or controls. Each compact System-Module contains all of the pumping/ boosting, processing, power and control equipment needed for efficient operation of the field.

"We are going down the path of further component development and testing, and now want Alpha Thames to work on the next generation of these products," explained Ricardo Rodriguez, director of investments for Shell Technology Ventures. "This will include further testing of the high-voltage, wet mateable connector, the AlphaCPU control system and the CPU power distribution unit. The units are working beautifully, but we now want some of them tested to 3,000-m water depth equivalent and others to destruction," he explained. "Shell and Marco Fabbri, one of the industry's foremost experts, are working with their partner to prepare the AlphaPRIME technology for near-term deployment on a producing field."

Because they are modular, self-contained units, the field operator can quickly recover an entire System-Module whenever necessary, whether to add equipment to accommodate changing field conditions, to introduce new technology, or to overhaul existing components. Since the units are typically installed in pairs, one entire System-Module may be recovered, leaving the other on the seabed to maintain production.

Each slot on the KeyMAN uses an identical interface, so different or identical System-Modules can be fitted next to each other, in any order, regardless of function.

Because many fields do not see increased gas or watercut until later in their lives, using System-Modules enables the field operator to control initial capital expenditure, eventually installing boost, separation or injection capabilities when they are needed. This flexibility is not as readily available with other seabed technologies.

Ian Ball, head of Shell's Subsea - to-Beach, subsea processing technology maturation program (S2B), said, "We have been very pleased with the way the component qualification program has gone. Shell specialists believe that the greater water depths, from which hydrocarbons are now being recovered, have accelerated the need for this technology. By enabling oil and any produced gas or water to be separated and/or boosted on the seabed, productivity of certain reservoirs can be significantly increased.

"We now also have the technology to separate the water phase near the subsea wellheads and typically re-inject it back below the reservoir from which it came. It is thus possible to ensure that risers and export pipelines work at their full capacity, carrying only oil, gas or condensate. Boosting these fluids back to the host facility can also be provided in either multiphase pump, or in combined separation and single-phase liquid pump System-Modules, and reconfigured to whatever the field conditions require at any time during the field depletion life."

The present design is being rated to a 10,000-ft water depth. The weight of the System-Modules and other components makes them straightforward to install using vessels of opportunity, supported by one or more ROVs.

Fig. 8. The 850-kW subsea compressor module prototype.

CONCLUSION

Recovery factors need improvement in subsea, particularly deepwater fields. Considering that subsea fields keep aging, and technology keeps advancing, there will continue to be investment in technologies that essentially put the processing platform on the seafloor. The near future should see increased use of multiphase pumps, including some downhole versions, and subsea separation and compression. WO

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