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FIELD OPERATION
MINERALS MANAGEMENT SERVICE

SUBSEA PRODUCTION FROM KUVLUM:

NEW TECHNOLOGIES, NEW PARADIGMS

Report to:

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SUMMARY

The ideas and engineering developed here started in response to the question "Would subsea processing work for developing Kuvlum?" It became apparent as the thinking developed that: (1) several technologies for multiphase transport were practical candidates, and (2) that shifts in the last two or three years - both in the way technologies are developed and in the way that operators, contractors and vendors work together for offshore developments - might be combined to benefit Union Texas Petroleum at Kuvlum.

This report outlines the choice of technically viable means of subsea production and multiphase transport back to shore, indicating already developed systems which are at the prototype stage or better. It indicates a typical "specification envelope" needed for these facilities.

Recent precedents and technology development programs are identified to demonstrate the extent to which pioneering would be avoided and how the resources and interests of other operators, contractors and vendors might be aligned in a common focus, using new industry paradigms, to mitigate risks to Union Texas Petroleum in applying these new technologies.

Engineering information on the multiphase transport developments discussed here for Kuvlum is assembled in a separate binder for future use which includes OTC papers, technical documentation and proposals from developers and vendors.

TABLE OF CONTENTS

No. Section **page**

1. INTRODUCTION, OBJECTIVES

The report here has its origins in the question from Jim Watt at Union Texas Petroleum: Could Kuvlum be developed using subsea processing, even though that may be a new technology today?

Over approximately a five month period starting in November 1994, a number of discussions, brainstorming sessions and multiphase transport analyses proceeded on the system characteristics needed for a subsea multiphase transport system to produce the Kuvlum reservoir. In parallel, engineering feasibility was evaluated for using one or more of the designs of subsea processing and multiphase pumping systems that had reached the prototype stage or better. As this work progressed, it led into other aspects outside subsea and outside strictly technical issues. For example, ways of first developing and applying new technology, and second in getting facilities built are changing radically in the petroleum industry, and together these paradigm shifts may be particularly advantageous when applied here.

The Cold War ended and coincidentally about the same time a detente has been seen between oil companies, e.g. cooperation in field developments (like in Britannia with Chevron and Conoco as co-operators and a large number of partners), acceptance of the idea of using of third party production facilities, and in the opening up in cooperative technology development like in Deepstar, with what hitherto was operators' jealously guarded information now being exchanged.

The detente spread to contractors and oil companies who are also opening up - even their operating books, like BP/Brown & Root pioneered at Forties - with major shifts to contractors managing operators' facilities. Working relationships emerged that used to be unthinkable (managing our production facilities . . . they'll screw us if we don't watch them like a hawk!) The BP/B&R example required difficult cultures shifts to achieve, was strenuous on people and a few did not adjust and left, and BP had to shed personnel that became surplus in the new working relationships. But the overall results have been reported as highly beneficial in lower operating costs to BP and good business for the contractor. This has gone a stage further: as this work for Kuvlum progressed, oil company/contractor/vendor alliances were being experimented with for major field developments. Whole new ways of working were emerging. These paradigm shifts may now help what is being contemplated for Kuvlum. How can we take advantage of them here?

This thinking leads to the conclusion that what was unthinkable "blue sky" technology a few years ago now looks doable for the planning horizon here. Novel technology and a novel way of applying it and managing the field development via aligning vendors, contractors and oil companies in an alliance now may make it possible to safely and economically developments Kuvlum using some combination of subsea production and a multiphase transport system. These concepts may also work well when production from adjacent fields is linked together - the "string of pearls" idea.

This report therefore pulls together the discussion and work performed during the period from November 1994 through March of 1995. Relevant technical papers, technical brochures and proposals from vendors and contractors on multiphase transport systems of various types suitable for Kuvlum are compiled in a Volume 2 which is separate 4 in. binder.

2. GENERAL TRENDS

This section discusses the state of the art as it might apply to subsea production at Kuvlum: (a) technically, (b) in technology development methods, and © in organizing to build and install offshore production facilities.

From what has been done before - or at least has been prototype tested - components of equipment and technology are selected for Kuvlum as options to consider. The pieces here have all been done or prototype tested individually before, but not in the combination suggested here. Technical and non technical advances are almost all recent, in the last 2-3 years, and open up ways for producing Kuvlum that were unlikely to have been taken seriously before just a few years earlier.

2.1 Subsea and Multi-Phase Pumping Technology:

First, for terms of reference, some definitions:-

Subsea Processing: On an offshore platform it is common for oil production to be processed with separation so that oil and water and gas are separated. Water may be cleaned and discharged, dry gas pumped ashore by pipeline and stabilized crude pumped ashore by pipeline. "Subsea processing" is the same process, except subsea and not on a platform. The theory is that a platform can dispensed with and economies achieved for more remote fields in more inaccessible areas, e.g. some distance from gathering facilities, or in deeper water, or possibly here in arctic conditions. However 3 separate pipelines would be needed for single phase transport of gas, oil and water - or maybe just 2 pipelines if the oil and water are transported in the same pipeline.

Multiphase Pumping: If one could pump all the gas, oil and water down the same line, with a pump at the seabed near the wellhead(s) then that would obviously save the cost of at least one pipeline. However that is often easier said than done because pumping gas absorbs one or two orders of magnitude more power than a single phase transport system, the mixture is not always a smooth composition, i.e. may contain slugs of liquid and then gas only. And the multiphase mixture may tend to separate along the pipeline, causing slugs to arrive at the other end.

Unaided Production: It would be easiest of all if the subsea well produced at a high enough pressure to drive the production through the pipeline back to the sales point. And that can often be the case with subsea production from gas wells. Sometimes it happens with oil wells, particularly with shorter offset distances to the sales point. But in most cases a subsea oil well that is remote from an export point will need some means of assistance to transport the multiphase production. Unaided production could be achieved at Kuvlum in the first few years. But beyond that, particularly if the pipeline distance to the export point was long, some means of boosting was desirable to maximize total recovery.

Exhibit A is a tabulation of development projects completed or underway worldwide done on multiphase transport and equipment - both separation systems and multiphase pumping systems. Most of these developments have been in Europe: 12 out of the total of 16. Hence much of the multiphase transport expertise applicable for Kuvlum is found in Europe and not here in the United States.

The first experiment was on subsea separation by BP in 1970, with substantial broadening in the applications examined and technologies used since these early days. The column on the right of Exhibit A gives the paper numbers and years for the OTC technical papers on these developments - an indication of the industry interest, with 3 or 4 papers given each year for the last 5 years.

As Exhibit A shows, BP, Exxon and Shell have all been pioneers in multiphase transport systems. As they are also owners of neighboring blocks to Kuvlum, it would seem they would be knowledgeable parties to associate with in some form of area wide development. With the combined focus from all of their development work, they could also form a powerful "brains trust" to mitigate the risks of using relatively new technology.

In the first few months of production in early 1995, Shell at Draugen in the North Sea have been producing 30,000 bpd with natural drive, and 35,000 bpd with a multiphase pump. The pump manufacturer told the writer that the payoff for the pump is measured in days and the overall subsea package in weeks! This example is important also because it counters traditional thinking of using boosting only as production declined - Shell now recommends boosting right from the start on the "real barn burners"! This is really what one would expect: if the back pressure on the wells is reduced, then they will produce more. This is also a low risk installation: if the new multiphase pump installation has teething problems, then all is not lost because the wells produce well with natural drive.

The ability to produce under natural drive at Kuvlum is similarly important as at Shell - Draugen, whatever the choice of multiphase transport technology may ultimately be, as production does not come to a standstill if the new multiphase transport equipment were to malfunction for some reason.

One of the drawbacks of using multiphase pumps with well fluids of relatively high GORs (such as the 632 to 1,000 scf/bbl range considered here) is that they may require a lot of power, e.g. 4.5 MW with multiphase pumping estimated by vendors for 18,000 bpd at Kuvlum v. separation and single phase boosting system with say 75 Kw (from 12,000 bpd at 1,000 scf/bbl in the development of GLASS). One may be talking of something like a factor of 40 in power consumption in higher GOR conditions, e.g. about 7.5 MW for 30,000 bpd at Kuvlum v. about 200 kw for separation and boosting of liquids only.

What has led to the confidence in suggesting new directions like these? Subsea separation and was first tried offshore Abu Dhabi by BP and Total in 1970. In the last decade subsea separation and single phase pumping has seen more intense development, along with multiphase pumping systems. Joint oil company and equipment developer projects have included at least 4 multiphase pumping developments and 12 separation developments.

Several trials of multiphase pumps are now underway or planned in the U.S., located onshore and on offshore platforms, but not subsea. Two subsea installations are currently producing: Shell-Draugen (commercial) and Agip-Prezioso (field trials).

In the last several months there has been a shift in the willingness of major operators to seriously look at using subsea boosting of some form (separation and liquids pumping or multiphase). Offshore in December 1994 published the views of BP and Norsk Hydro, identifying field conditions where seabed boosting was attractive, i.e. low reservoir energy and little available infrastructure.

Leofric Studd of BP said they were therefore looking at subsea boosting as a serious option in the Atlantic Frontier, in contrast to most of the North Sea where reservoir energy was high and there was plenty of infrastructure. His criteria for using subsea boosting fit Kuvlum perfectly - low reservoir energy and no infrastructure!

Petrobras' views in Offshore of February 1995 (reference 5 in Volume 2) quoted an economic studies indicating recovery costs in the region of $2.50/bbl with a subsea separation system v. $7.00/bbl typical of their existing semisubmersible based production vessels.

Exhibit A lists BP, Exxon and Shell as operators who have been active in multiphase

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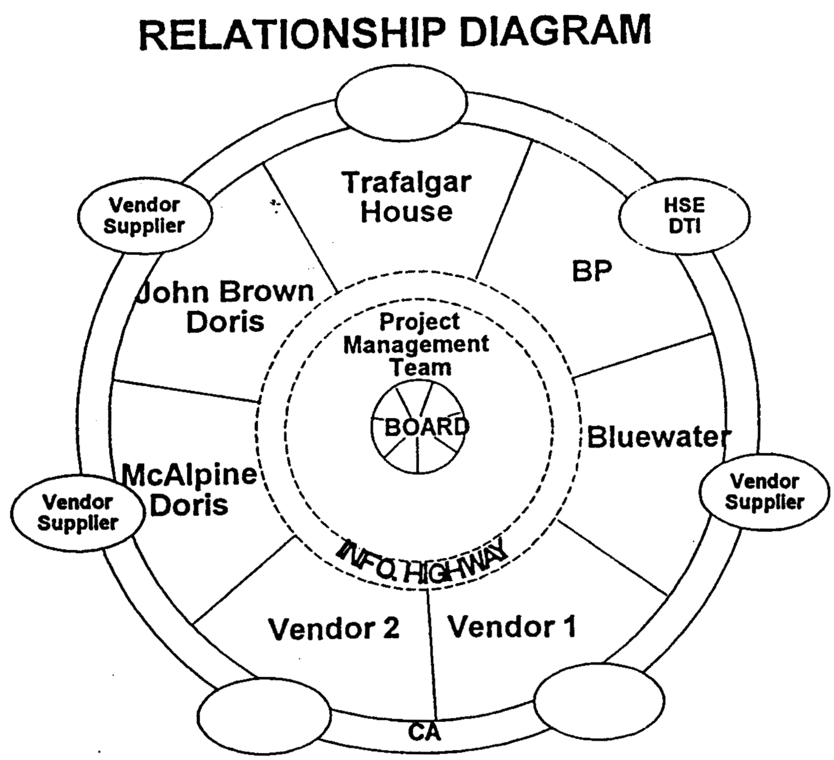

Shetland Deepwater Alliance

Date : 7 April 1995

Exhibit B: Shetlands Development Alliance

2.2.3 Operator / Contractor / Vendor - the Alliance. After getting Phase 1 started of their Foinaven development, BP took an even more novel approach for their larger Phase 2 development, now called Schiehallion, which involved roughly a half billion dollar commitment.

It started in the second half of 1994 with five contractor led groups which proposed different field development solutions. The operators's reservoir data were not yet fully defined and so the FPSO location had not been fixed and ranges of values were specified for water depths and production rates in the design basis. The operator coached the different competing groups as the design development and proposal effort progressed.

Technically viable solutions had to be developed for this precedent breaking project. Target costs had to be developed and an agreed sharing established on project savings and over-runs.

The commercial vehicle for the field development was proposed as an alliance, composed of multiple contractors and vendors with difference capabilities, plus the operator. Exhibit B is a diagram showing how this alliance was structured.

Alliance members were to be jointly and severally liable for the performance of the alliance - so there was no doubt that all members took it all very seriously! A separate organization was set up under the identity of "Shetland Development Alliance", composed of people from all companies in the alliance. Special lines of communication were set up to help make it work without traditional "turfs". Again, a formula has been created that might be of benefit in future development of Kuvlum with its precedent breaking attributes, to help harness the various contractor and vendor capabilities now available.

3. MULTI-PHASE PUMPING

Two competing technologies were considered for Kuvlum: (I) separation and single phase pumping (subsea processing) requiring two pipelines, and (ii) multiphase pumping requiring only one pipeline. Pipelines in the Arctic are very expensive and so the number of pipelines was important: they might be separate lines laid individually, or multiple lines contained inside a larger carrier pipe. This was not a simple comparison because the carrier pipe might also have advantages as a means of heating the separate lines inside it, via heated fluid in the annulus or in some form of heat tracing.

3.1 Background:

3.1.1 Brief History. The development and field testing of multiphase pumps has been underway for the last decade, as Exhibit A demonstrated. The technical papers in the separate volume of supporting information document this work, much of it recent and ongoing. Agip has field tested multiphase pumps onshore and in a subsea installation adjacent to a platform (reference 2). Shell has experimented with their use on a platform offshore Malaysia and on a platform and subsea in the North Sea (reference 4). Petrobras has been testing a multiphase pump onshore in Brasil (references 5 and 6). Mobil in the United States has been testing multiphase pumps on platforms and onshore (reference 4). Texaco has been testing multiphase pumps in their test loop in Humble, north of Houston (reference 1).

Five developers and manufacturers responded to a preliminary enquiry for a multiphase pump for use in Kuvlum, as shown in Exhibit D. Their brochures and technical information are included in the separate volume of supporting information. Thus on the supply side, there are a number of viable sources.

3.2 Kuvlum Case Study:

The "envelope" for the production facilities will need a larger silo than used before for subsea completions alone. This was arrived at from consideration of the size and weight of a subsea BOP stack which might be handled by a drilling vessel. That weight and size enveloped had been used to design a subsea separation and pumping package and was felt to be a reasonable size and weight to use as an "envelope" for multiphase pump packages. Space for inspection and

ROV operation around subsea wells was also necessary. This implied a larger space than that currently excavated for Glory Holes, e.g. something like 60 ft. dia. and 50 ft. deep would be necessary to accommodate both the christmas trees, manifolding, controls and the multiphase pumping equipment. But contractors (HAM of Holland and CANMAR of Canada) tell us they could readily build and install this, i.e. it looks doable.

The most recent calculations showed that Kuvlum can produce under natural drive, back to an onshore export point 15-20 miles away. But boosting may increase recovery say 10-25%. Boosting could also allow export in a pipeline about 45 miles back to BP-Badami - or a similar distance away.

Power to drive the pump can come from the water injection supply that is needed for Kuvlum, run first through a turbine to drive the pumps. Again, this would be like Shell - Draugen. The same principle has been considered by certain GOM operators in studies during the last year for their deepwater prospects.

Much of that multiphase pumping power is absorbed in the produced fluid in the form of heat, with the multiphase pump in effect compressing gas in a spongy gas laden liquid mixture, as opposed to pumping just liquid in "single phase" pumping.

3.2.1 Reservoir Suitability. The system requirements for multiphase transport here are defined in Exhibit C. The reservoir characteristics were being developed as this study progressed and so the assessment of suitability of the reservoir for pressure boosting was an iterative process. In addition various options were being considered as the export point, i.e. production from Kuvlum might be delivered to Flaxman Island which is the nearest landfall at about 14.9 miles, or to Point Thomson at about 19.4 miles, or even on to Badami at 43.4 miles. The first analyses were made for the Kuvlum to Flaxman transport, from a set of subsea wellheads in a silo located at Kuvlum, to a shore station on Flaxman Island. Then as it became apparent that it might be feasible to pump a longer distance, trials were made in what it took to pump to Point Thomson (where Exxon might have operations), and then on to Badami where BP was contemplating a connection to the TAPS.

The approach in the analyses was to define the pipeline profile and set some values for the flowing wellhead pressures (FWHP) which might exist for natural drive and for boosted production. Productivity of the well is naturally better the lower the back pressure on the well. If the well had to drive the production over the transport distance, then it had to be higher to achieve that and the production is less than if boosting is employed. A relatively large pipeline - 12 in. diameter - was chosen to minimize the pressure drop to the export point.

File: *PIPESIM4.WK1*
Prepared: *10-Mar-95*
Printed: *11-Mar-95*
Page No.: *1*

Update after 10 Mar 95 discussion

1. Pipeline Characteristics :

Location	Node No.	Elevation, feet	Section, miles	Length, miles	Int. dia., inches	Fluid Temp., deg., F.	.... Comments ....
Wellhead	1	−145.0		0.0		45	
			0.0		12.00		Assume all liquids+ga
Manifold & Pump	2	−118.0		0.0		155	production are in a
			7.0		12.00		single insulated line
Pipeline offshore	3	−103.5		7.0		? ?	soil temperature
			6.3		12.00		28 deg. F.
Pipeline offshore	4	−53.5		13.3		? ?	
			1.6		12.00		ditto
Pipeline offshore	5	−13.5		14.9		? ?	
			4.5		12.00		ditto
Pipeline offshore	6	11.5		19.4		? ?	
			0.0		12.00		ditto
Export point A	7	11.5		19.4		? ?	
			8.0		12.00		ditto
Pipeline onshore	8	11.5		27.4		? ?	
			8.0		12.00		ditto
Pipeline onshore	9	11.5		35.4		? ?	
			8.0		12.00		ditto
Export point B	10	30.0		43.4		? ?	

2. Fluid Characteristics :

Oil Gravity, API:	34.2	Composition:	Use PIPESIM
Gas Gravity:	0.67	Undetermined	simulation to suit
Water Gravity:	1.06		physical properties

3. Analysis Requested :

Description	Ref.	FWHP psi	Total Prod. bpd	GOR, scf/bbl	Water cut, percent	... Comments .... Pump Performance ...
TO EXPORT POINT A:						(Delta P = 500 psi,
Multiphase pump :	SOF	100	15000	632	2	(Delta T = 110 degrees F.
TO EXPORT POINT B:						(Increase to correspond to about (100 psi at Export point B

Exhibit C: System Design Conditions

Update after 10 Mar 95 discussion

File:	*PIPESIM4.WK1*
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Page No.:	*2*

4. Production Rates :
(basis of one 12 in. pipeline with production from 1–1/2 wells)

Status	Time, years	Total prod., bpd	FWHP, psi	Water cut, percent	Oil prod., bpd	Water, bpd	GOR, scf/bbl	Gas prod. MMSCFD
Primary:								
SOF, natural drive	0	12500	450	2	12250	250	632	7.742
SOF, pump	0	15000	100	2	14700	300	632	9.290
Natural drive	2	4500	300	2	4410	90	1000	4.410
Pump	2	4650	100	2	4557	93	1000	4.557
Production could continue to decline but it is assumed that water injection takes over to give production as calculated for water injection at the 3 year point:								
Secondary, water injection:								
Natural drive	4	9000	300	10	8100	900	1000	8.100
Pump	4	9900	100	10	8910	990	1000	8.910
Natural drive	6	7500	300	30	5250	2250	1000	5.250
Pump	6	8250	100	30	5775	2475	1000	5.775
EOF, natural drive	9	4500	200	50	2250	2250	1000	2.250
EOF, pump	9	4650	100	50	2325	2325	1000	2.325

Note: Flow rates with pump for years 4–9 are probably low

5. Comparison of Recovery, Natural Drive v. Pump:
(basis of one 12 in. pipeline with production from 1–1/2 wells)

	Time, Years	– Average daily production – Oil, bopd	Gas, boe/d	Total, boe/d	Approx. Total Recovery, MMBOE	Water production, bpd
Natural drive :						
Start of field	0	12250	1290	13540		250
	2	4410	735	5145		90
	4	8100	1350	9450		900
	6	5250	875	6125		2250
End of field	9	2250	375	2625		2250
					22.8	
With pump :						
Start of field	0	14700	1548	16248		300
	2	4557	760	5317		93
	4	8910	1485	10395		990
	6	5775	963	6738		2475
End of field	9	2325	388	2713		2325
					25.3	

Hence the potential improvement in recovery is about : 2.5 MMBOE

Roughly : 10.9 percent

Exhibit C: System Design Conditions (continued)

Update after 10 Mar 95 discussion

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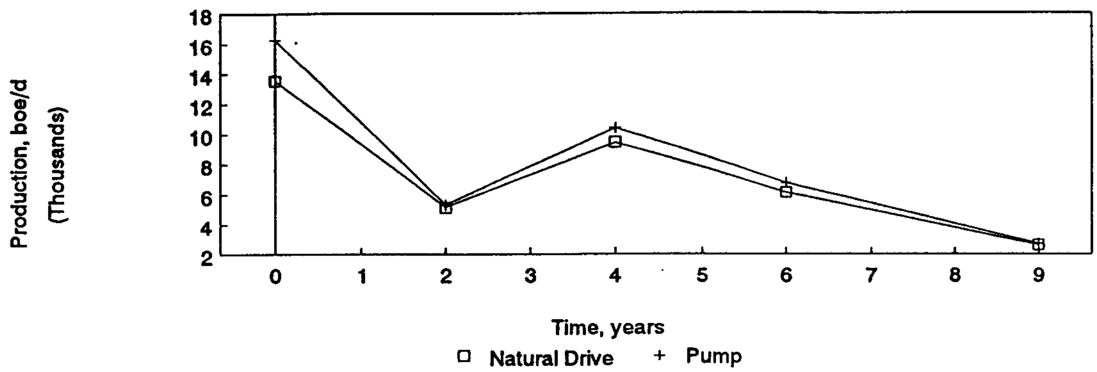
Printed:	*11-Mar-95*
Page No.:	*3*

Production with Natural Drive v. Pump



Liquids speed in line and suitability for pigging :

Field Status	Time, years	Pipe i.d., inches	Total liquids, bpd	Liquids speed, mph	Suitability for pigging
Natural drive :	0	12	12500	10.4	High
	2	12	4500	3.8	Low
	4	12	9000	3.8	Low
	6	12	7500	6.3	OK
	9	12	4500	3.8	Low
					prefer range of 4 to 10 m
With pump :	0	12	15000	12.5	High
	2	12	4650	3.9	Low
	4	12	9900	8.3	OK
	6	12	8250	6.9	OK
	9	12	4650	3.9	Low

Pipeline Bundle Profile
Badami/Pt. Thomson/Flaxman/Kuvlum

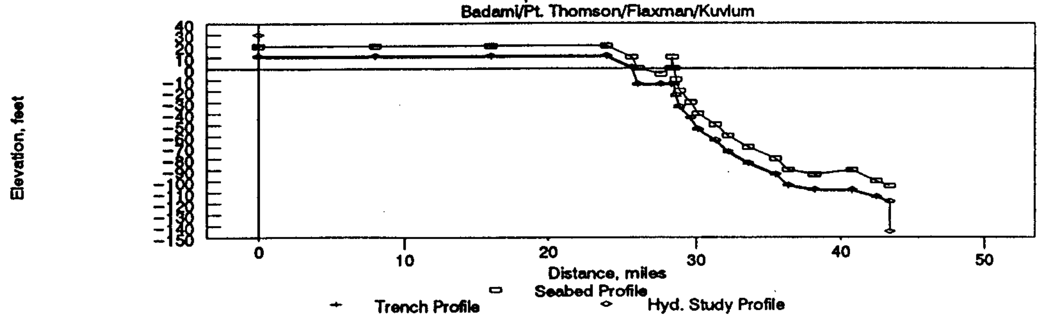


Exhibit C: System Design Conditions (continued)

It was eventually assumed that water injection would be employed, probably starting at the 3 year point. Production was assumed to continue over a 9 year period. FWHP pressures pf 450 pis at start of field down to 200 psi at the end of the field were assumed in the calculations. For the pressure boost scenarios, the FWHP. was taken as 100 psi throughout field life, i.e. the "delta P" and "delta T" applied by the use of a multiphase pump was calculated in the multiphase flow analyses. Preliminary multiphase analyses were made using the PIPESIM software.

It became apparent in the multiphase flow analyses that use of a multiphase pump was feasible but that there was some risk of hydrate formation. This meant further consideration of insulation strategies, of the distances that multiphase pumping should be attempted, and the pressure to be used in the pipelines. Further work on these issues was not done, and would be necessary before finalizing a design.

The information of Exhibit C was used as a basis to go out to potential suppliers of a multiphase pump for preliminary proposals, resulting in five proposal which are summarized in Exhibit D.

Exhibit D: Summary of Multiphase Pump Proposals Received

Basis of flow through one 12 in. pipeline

Requirements: SOF: 18,000 bpd; GOR 632 scf/bbl; Water cut 2%; Oil 34.2°API gravity.

Data as at: 8 March 1995

Pump Developer /Manufacturer, Country	No. Red. N	Type	Power, each, P (MW)	Total Power N x P	Max. Speed, rpm	Suction, Discharge psi	Total cost, $million	Delivery, months	Notes, Pumps Operating, . . . Comments . . . .
Cotap - Neptunia France	3	Roto-dynamic	1.5	4.5	6,000	150 500	? ? ?	? ? ?	(a)(d) Prototype tested
IFP/NOMAD France	2	Roto-dynamic	2.0	4.0	? ?	100 500	9.0	14	(a)(d) Prototype tested
IMO USA	3	Twin screw	0.746	2.238	? ?	100 500	1.84	? ? ?	(a)(b)(c)(d) Several operating on platforms & onshore
Leistritz USA	2	Twin screw	1.022	2.044	1,750	100 500	1.46	? ? ?	(a)(b)(c)(d) Several operating onshore
Multiphase Pumping Systems UK	2	Twin screw	1.484	2.968	1,549	100 500	9.6	12	(a)(d) Several operating on on platforms & onshore

Notes:

(a) No spares are included, e.g. with 2 pumps, each handles 50% of production;

(b) Where a driver was not included in the proposal, it was assumed to cost $0.7 million/pump and was added to the pump quotation;

(c) Packaging and controls for subsea operation not included;

(d) No allowance is included here for extended trials and Factory Acceptance Testing.

3.2.2 Hydrate Issues. Low temperatures of both the environment and well fluids (e.g. 45°F. at Kuvlum) mean that hydrate formation in the pipeline might become a problem, particularly as field life progresses. So the 100-120°F increase in temperature at the discharge from the multiphase pump is welcome in inhibiting hydrate formation! A quick simulation showed that this effect may be good for about the first 7-10 miles of an insulated line, i.e. additional heat input may be needed after this distance, or addition of inhibitors to counter the risks of hydrate blockage. In this instance the additional energy consumed in multiphase pumping has a beneficial effect, but there are limits to it.

The risks of hydrate formation might be reduced by use of a separation and single phase boosting system, instead of using a multiphase pump.

Heating via trace lines such as was done in a gas line by Panarctic (reference 15) may be a solution to the hydrate prevention issue, or possibly transmission of a heating fluid in a carrier pipe annulus. Kuvlum is expected to require water injection and so the unconventional step of heating that water injection supply might be worth looking at, assuming that it comes from shore.

3.2.3 Power Source for Pumping. As a multiphase pump can consume considerable power, e.g. megawatts, the source of this power and the transmission and the control of it over several miles can become a serious issue. At Shell Draugen this is taken care of by using the water injection supply to drive the multiphase pump, and this would be a possibility here. This means that the water injection plant would need to be located say on Flaxman Island in order to supply a subsea installation at Kuvlum. Alteratively an electrical supply would be required, with controls. The power source was not investigated here, beyond saying that technically feasible solutions exist.

If the multiphase pump can be located on a bottom founded vessel at Kuvlum, then power from the vessel becomes feasible. However then the options of separation on the vessel becomes an obvious solution, and the potential then emerges for pumping all the way to Badami, about 43.4 miles from Kuvlum. Some separation and slugging might occur over that distance but the economy of avoiding intermediate pumping, perhaps with a higher initial pressure, could be worth considering.

3.2.4 Reliability. Experience with the multiphase pumps at Shell-Draugen and at Agip-Prezioso has been good on reliability. Mean times between failure for pumps of the order of 3-5 years are talked of as practical by pump manufacturers, if one is willing to pay a modest premium on initial cost - which is a worthwhile proposition in light of the costs of service here.

3.3 Subsea Application:

A subsea multiphase pumping system at Kuvlum would need protection from ice scour, just like the wellheads, and it becomes logical to locate this equipment inside the same silo as the wellheads, along the lines of the arrangement shown in Exhibit E.

Space has to be included for initial installation and subsequent retrieval of the multiphase pump package for service. The size of this unit is taken to be 49 ft. high and 13 x 16 ft. in plan - the same subsea BOP "envelope" used in the design of the Kvaerner Booster Station using subsea separation and boosting. It is also assumed that there are 6 subsea completed wells in a template in the base of the silo. Space has to be provided for ROV inspection and service of both the multiphase pump package and the subsea production equipment (valves, controls). These size considerations lead to the minimum clear height inside the silo of 50 ft. and an inside diameter of about 50 ft., as shown in Exhibit E.

The top of the silo has a sacrificial 12 ft. high skirt which can be replaced after iceberg damage or scouring. Hinged doors at the top of the silo provide protection of the silo's contents from drifting bottom material. The arrangement assumes use of a culvert through which pipeline bundle(s) are pulled in at a later date and are connected at a porch in the silo via spool pieces or flexibles. The culverts are shown as having a 12 ft. cover, meaning that they are laid first, before the silo is installed, and provide the necessary cover from iceberg scour in areas adjacent to the berm that is later built up over the silo.

The seabed at Kuvlum is believed to be at about -104.5 ft., meaning that a berm has to be constructed over the silo in order to bring the effective water depth down to where the preferred bottom founded drilling vessel can locate, i.e. about a 80 ft. water depth. The bottom of the silo is then at about -142.0 ft., as shown in Exhibit E.

3.4 Bottom-Founded Vessel Applications:

The use of multiphase pumping need not necessarily by subsea - it could be on board a platform or bottom founded vessel. Maintenance becomes easier and the risks of using a relatively new technology and relatively untried equipment are reduced.

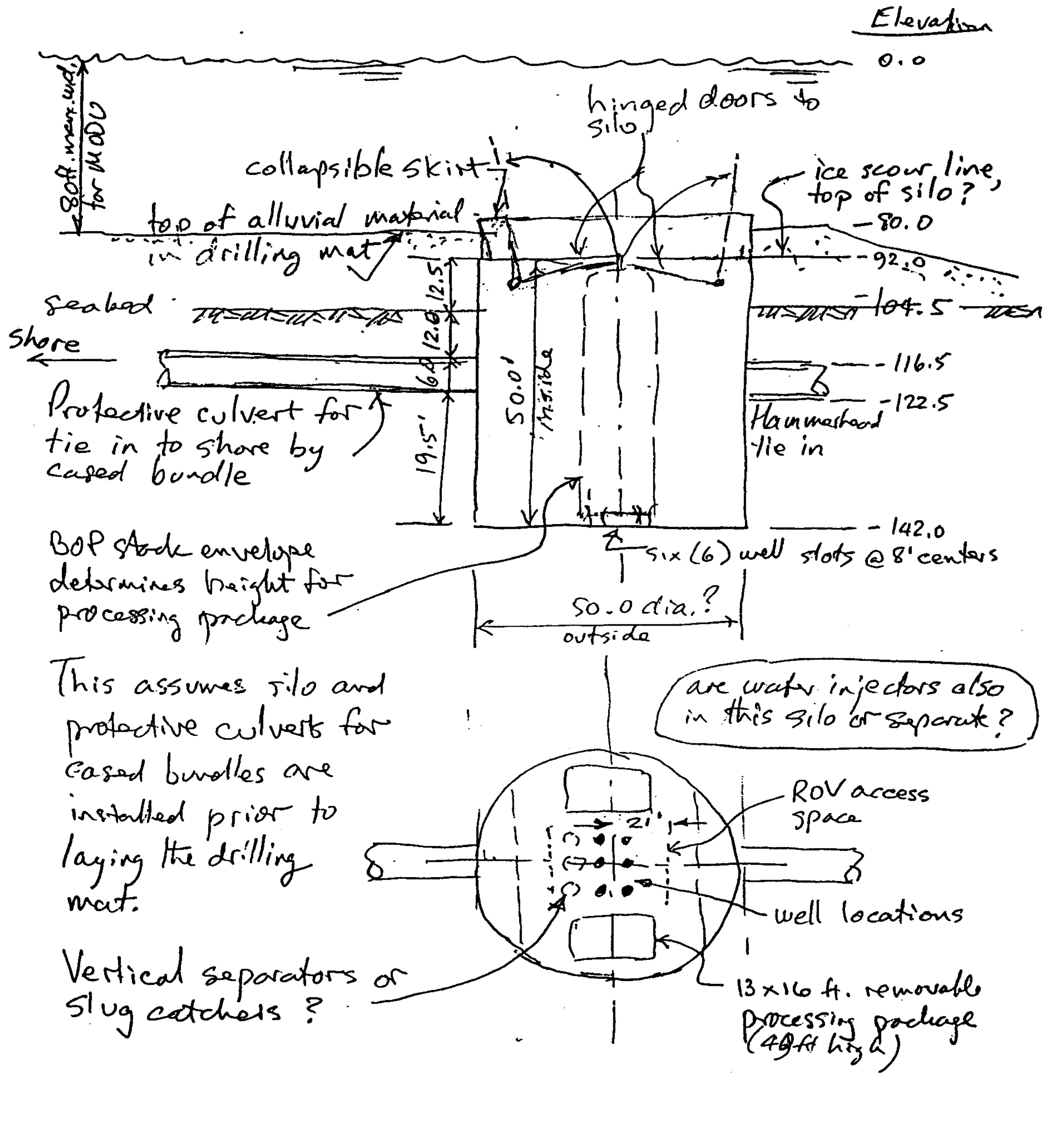


Exhibit E: A Possible Silo Arrangement at Kuvlum

4. SUBSEA PROCESSING

While multiphase pumping appears to be a viable solution at Kuvlum, subsea processing also appears viable, and it was the first technology to be investigated here. Exhibit A showed how a number of subsea processing systems had been developed over the last decade - at least 10.

The decision was made to limit the choice here was by two constraints: (1) the need to have a system which would fit inside the limited space of a subsea silo, and (2) use a system which has reached a prototype stage and which might be supplied by a major contractor to mitigate the technology risks and have some assurance of persistent attention to making it work in the event of debugging new equipment. Thus systems such as GLASS, developed by the writer, are not candidates since they take up horizontal space on the seabed and were developed by a consulting company and not available from a major contractor who might be able to take turnkey responsibility for supply and successful performance.

4.1 Background:

The choice of subsea processing systems came down to two: the Kvaerner Booster Station ("KBS") and the Vertical Annulus Separation System ("VASPS"). Additional detailed information on each of these is contained in the separate volume of supporting information. McDermott through its Babcock & Wilcox affiliate is additionally offering an oilfield version of the technology it has successfully used for steam/water separation, and that might be a third alternative worth consideration as hardware experience exists.

4.1.1 Current Prototypes. Both KBS and VASPS have reached the prototype testing stage and have been the subject of support by oil companies: Saga and Esso for KBS, Agip, BP, Conoco and Petrobras for VASPS. KBS is available from Kvaerner and a VASPS system could be obtained through McDermott, i.e. both have substantial organizations behind them.

Both have been the subject of numerous industry papers, e.g. most recently for KBS in references 5 and 8, and VASPS in reference 10.

The silo arrangement shown in Exhibit E could be used for either system. KBS is a single package, designed to fit in the "envelope" of a subsea BOP stack and hence is of a size that was felt reasonable to be installed in the silo. VASPS requires the drilling of a vertical shaft to serve as a separator, and this is of a size that could be drilled by the vessel drilling the wells, e.g. 30 or 36 in. diameter.

4.1.2 Trends. Kvaerner spent considerable effort during 1992-1994 to market the KBS but has now decided to "put it on the shelf" as it found little serious oil company interest to justify continuing. VASPS is in the process of field trials but no pans are known for any field development using it.

This pattern has been seen by other developers of both subsea processing systems and multiphase pumps: while there was initial industry interest and some funding, when it got down to spending on a real installation, little has been forthcoming. The trend may be now being reversed with the success of Shell and Agip in subsea multiphase pump operation in field trials, but still no field developments based on subsea multiphase transport have been announced.

4.2 Silo Configuration Options:

The idea of a subsea silo for subsea wells has been used before at Hibernia offshore eastern Canada several years ago and at Tordis offshore Norway more recently (reference 9).

Steel construction is favored although concrete segments like in civil engineering might also be workable.

The concept considered here is a silo with doors which can be opened for service but normally are closed and which are located below the iceberg scour line, i.e. about 12 ft. below the seabed. A sacrificial skirt is suggested for uppermost 12 ft. of the silo, such that iceberg scour could shear it off and the silo below would remain essentially intact.

Excavation for the silo in could be accomplished by conventional dredging. Unfortunately the U.S. dredging industry does not have the most competitive equipment for this and the Dutch vessels which are well suited to the task are not U.S. flag, hence may be prevented from operation in the U.S. waters of the Beaufort Sea. Drilling a "glory hole" of this size may also be possible, using a drilling vessel and possibly making four adjacent and smaller holes. Apart from establishing that viable means of excavation were available, further planning and estimates were not worked through.

Some means of tie-in to the pipeline(s) is required, shown here as a porch, with provision for spool pieces or flexibles as final connection to equipment in the silo.

Houston,

5 March 1996

By: ________________
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