Technology Assessment of Alternatives for Handling Associated Gas Produced from Deepwater Oil Developments in the GOM

by

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TABLE OF CONTENTS

LIST OF TABLES AND FIGURES

Tables

Figures

Alternatives for Transporting Associated Gas from Deepwater Gulf of Mexico Developments

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INTRODUCTION

A technical assessment of options for transporting associated gas produced from deepwater oil developments in the Gulf of Mexico has been completed. The options considered included gas pipeline and several processes that convert the gas to another state or product for transport by a vessel to shore. The processes studied included Liquefied Natural Gas (LNG), Compressed Natural Gas (CNG), and Gas-To-Liquid (GTL).

The purpose of this assessment was to:

- To generate consistent or analogous information on the various systems,
- To treat all systems in a uniform and consistent manner, but
- Not to attempt to determine which system is “best”. “Best” in a project sense will depend on project-specific factors and operator-specific drivers and opportunities – both technical and economic.

The results of this study provide information that will be useful to the MMS in assessing gas transportation options that might be proposed for deepwater development projects in the Gulf of Mexico during the next decade. The study also provides information that is useful for studies pertaining to alternative systems for deepwater oil and gas development in the Gulf of Mexico.

This technical assessment of gas transportation options was conducted by the Offshore Technology Research Center (OTRC) for the Minerals Management

Service. The Offshore Operators Committee (OOC) provided assistance through helping to coordinate industry input and participation in this project.

This report describes the study, summarizes the assessment for each gas handling option and presents an overall comparison of the options. Detailed results are presented in the appendices as follows:

Appendix A - Pipelines

Appendix B - Liquefied Natural Gas

Appendix C - Compressed Natural Gas

Appendix D - Gas to Liquids

SCOPE

The technical assessment assumed a deepwater oil development from an FPSO, and considered various alternatives for handling the associated gas as illustrated in Figure 1.

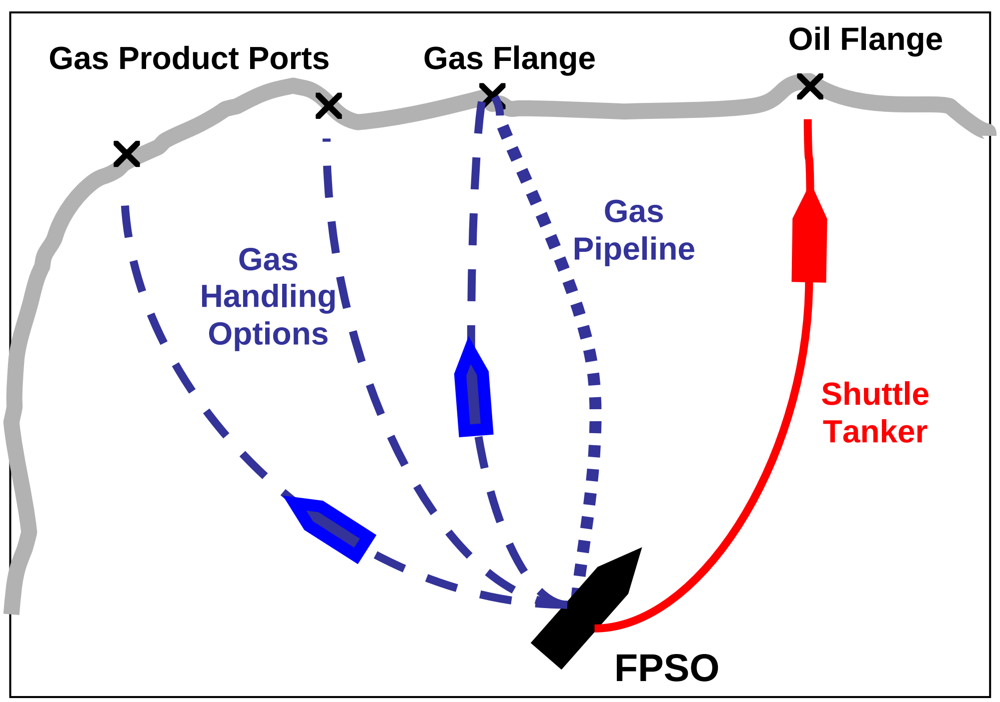

Figure 1 - Study Scope

Gas transportation options included export via pipeline (the base case), and LNG, CNG, and GTL. These processes convert the gas to another state or product for export via a vessel. FPSO production developments in depths of 6,000 ft to 10,000 ft were studied with various export destinations for the gas or gas-product as shown in Figure 2. A range of gas rates and distances were considered for each gas handling technology.

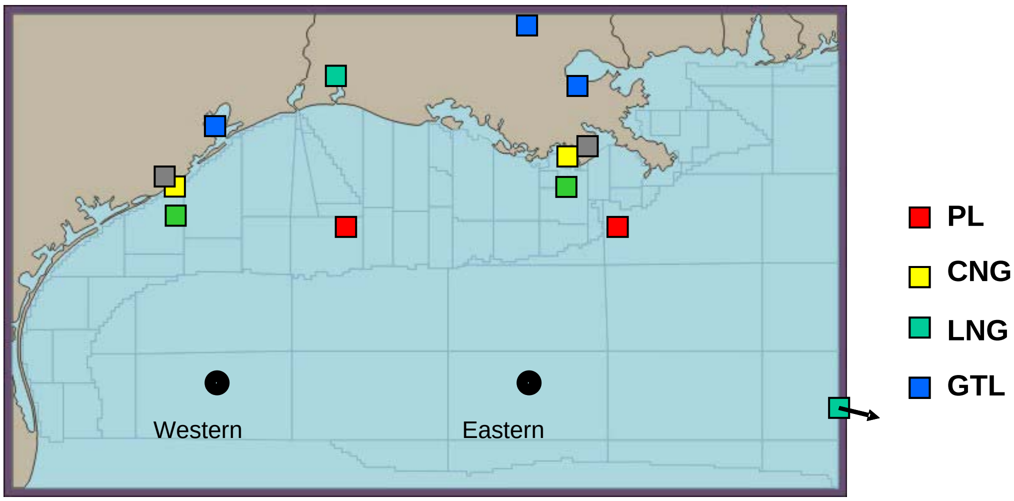

Figure 2 - Deepwater Development & Gas Export Locations

Figure 3 schematically illustrates the FPSO with oil processing and gas processing systems.

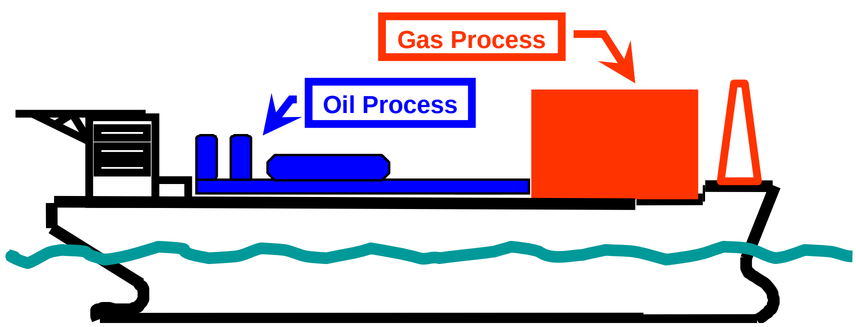

Figure 3 - FPSO with Oil & Gas Processing Systems

The technical assessment addresses the following aspects of the gas transportation options:

- Technical, commercial, and regulatory readiness
- HSE risks and mitigation measures
- Costs (CAPEX, OPEX)
- Process efficiency

A previous study [1, 2] determined that risks for an FPSO development utilizing shuttle tankers to export oil and a pipeline to export gas were similar to the risks of existing deepwater systems in the Gulf of Mexico (TLP's, spars, platforms serving as a hub/host for deepwater production) that use pipelines to export both the oil and gas. Thus the gas pipeline case was considered to represent a baseline for this study. The technical assessment reported on here focused on the incremental or additional risks and issues posed from the different gas handling systems being operated on the FPSO. The notion of the additional or incremental risks is illustrated in Figure 4.

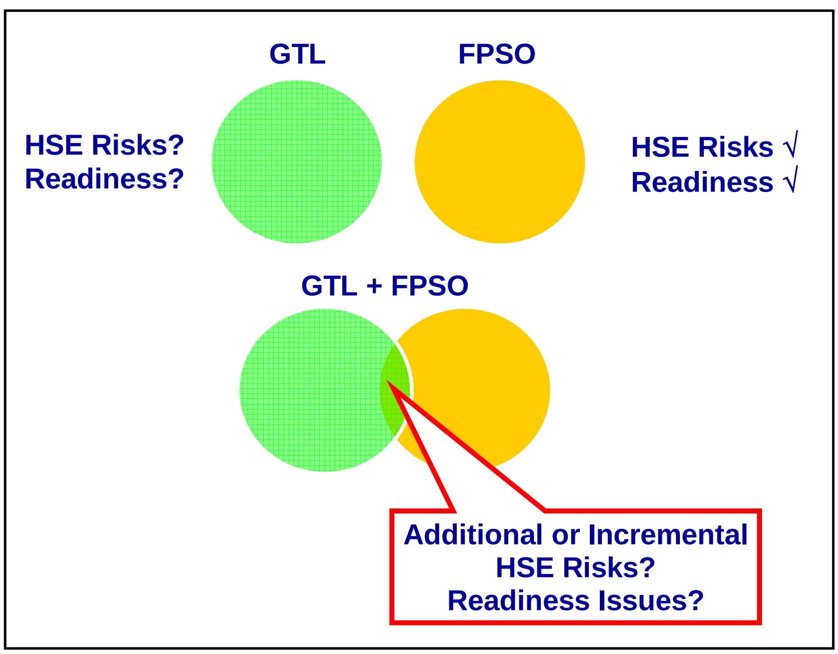

Figure 4 – Focus on Incremental or Additional Risks of a Gas Transportation Alternative (e.g. GTL)

STUDY PROCESS

A steering committee with members from MMS, OTRC and its consultants from AMEC Paragon, and representatives from the OOC developed the assessment metrics and the general work processes to complete the technical assessments. The assessment of each gas handling technology was addressed in a separate workshop. Invited workshop attendees included gas technology and marine experts, representatives from the MMS and industry, members from the steering committee, and representatives from class societies.

The goal of each workshop was to develop a consensus assessment for that gas handling technology. A preliminary assessment for the technology was prepared prior to each workshop. At the workshop, presentations by invited experts provided additional detailed information on the overall process or specific components. The preliminary assessment and presented material were discussed, and used as the basis for completing a consensus assessment for that technology.

The workshops and their results are documented in the Appendices as follows:

Appendix A - Pipelines
Appendix B - Liquefied Natural Gas
Appendix C - Compressed Natural Gas
Appendix D - Gas to Liquids

Each Appendix includes the Workshop Presentations and Workshop Results. Workshop Presentations include all available PowerPoint presentation made at the workshop:

- Workshop Introduction & Objectives
- Agenda and Attendees
- Workshop Presentations - technical presentations on processes & procedures that are important for assessing the particular gas handling process

Workshop Results include the figures and tables that were used to discuss and develop the assessment of the particular gas handling option during the Workshop. These materials were updated following the Workshop to reflect the participants' discussions and the overall concensus of the assessment results.

Material from Appendix B for the LNG option is shown below to illustrate the study process and results.

GAS TRANSPORTATION SYSTEMS

The four gas transportation systems studied are illustrated in Figure 5. Each system layout includes the major components and subsystems required to take the associated gas from the separator on the FPSO and deliver it to shore.

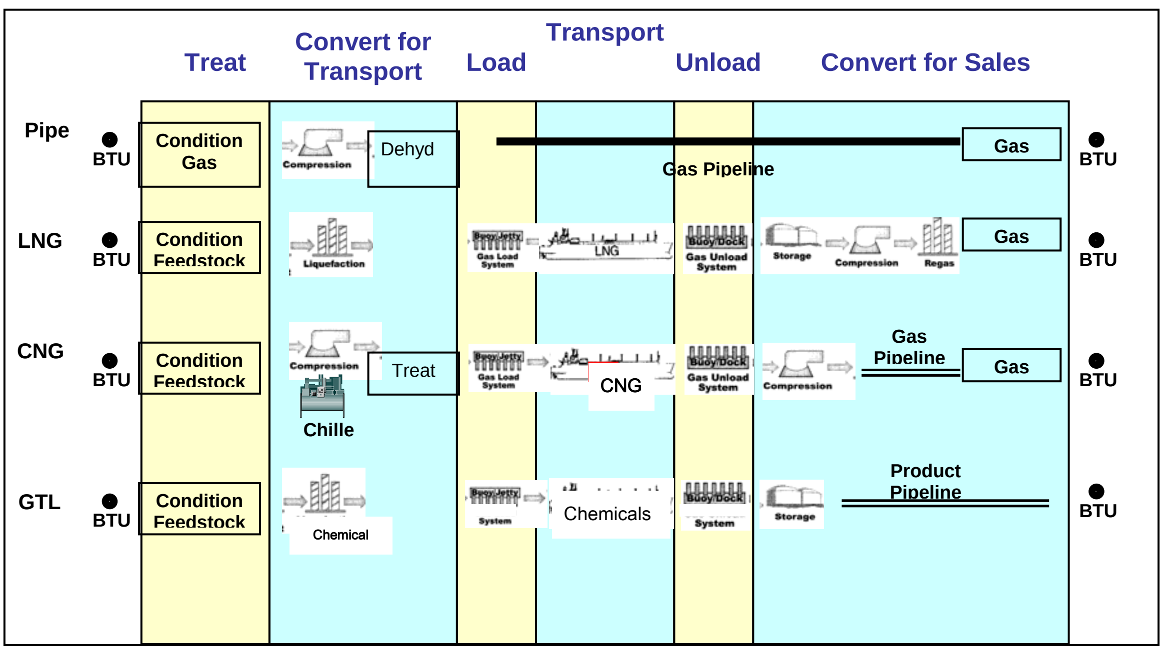

Figure 5 - Gas Transportation Systems (Components & Process Steps)

Figure 5 also indicates how each transportation system was divided into six common Process Steps – Gas Treatment, Conversion to Transport State, Offshore Loading, Transport, Unloading, and Conversion to the Sales State. Each of the Process Steps was addressed when assessing each gas transportation system. This approach has helped ensure a more thorough, consistent, and complete overall assessment, and helped identify the more critical Process Steps for each transportation system. It was also useful for comparing a given Process Step in different alternative systems. These Process Steps formed the basis for organizing the assessment process and presenting results.

We also considered different options for certain Process Steps for some of the transportation systems. For example, options for the LNG system for (1) liquefaction and storage (2) unloading are shown in Figure 6.

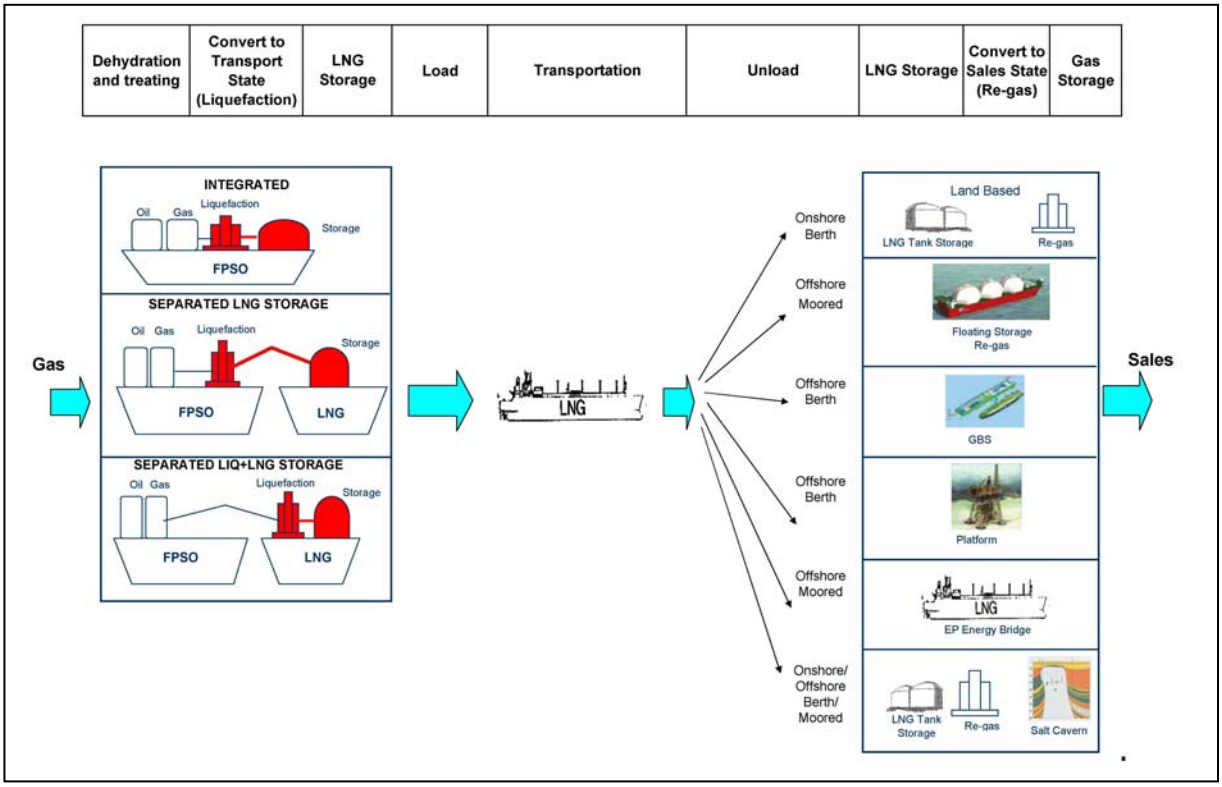

Figure 6 - LNG Gas Transportation System with Options in Various Process Steps

ASSESSMENT PARAMETERS AND METRICS

The technical assessment parameters and metrics are defined and illustrated below.

Technical and Regulatory Readiness Key *readiness challenges* and estimates of the years to "project ready" status for each challenge are identified. *Technical challenges* were identified and discussed for each process step. The following stages of development helped determine the *technical readiness* of the components and/or operations in each process step:

- concept
- bench testing
- pilot test
- field test
- onshore tests or applications of same or similar process
- offshore application of same or similar process

The *regulatory readiness* for each process step was also evaluated based on the similarities between each component and operation with those existing practices, codes, and regulations.

Finally, the years to technical and regulatory readiness were estimated as

- 0 – ready now
- 1 to 3 years
- 3 to 7 years
- 7 to 10 years
- > 10 years

Consensus views of the technical and regulatory readiness were determined in a working session during the Workshop. Examples of some of the challenges and the technical and regulatory readiness for LNG are shown in Table 1.

Table 1 - Technical & Regulatory Challenges and Readiness - LNG Examples

Challenge No.	Challenges	T: Technical R :Regulatory	Years to Resolution
1	Relative motion during load/unload LNG	T	0
2	Motion Effect on LNG production equipment	T	0
3	Metallurgy for cryogenic service	T	0
4	Transfer arm for side-by-side	T	0
5	Transfer arm for tandem for bow loading	T	1 to 3
6	Cryogenic Hoses	T	1 to 3
7	Layout of LNG plant on FPSO	T,R	0 to 3
8	Control and safety systems for combined LNG/FPSO plants	R	0

HSE Risks Key hazards and potential consequences were identified for each process step. These hazards and consequences reflect the HSE risks being considered in this assessment, i.e., risks of fatalities and damage to the environment. Mitigation measures were also identified and discussed. Table 2 shows some of the hazards, consequences, and mitigation options identified for LNG. Note that LNG spills were assumed to cause no environmental damage, but were considered as a possible hazard that could lead to fire or explosion resulting in fatalities and oil spills.

Table 2 - Hazards & Consequences and Their Severity & Likelihood – LNG Examples

Hazard	Potential Consequences Human Safety (Fatalities)	Potential Consequences Environment (Oil Spill)	Mitigation Options	Severity	Likelihood	Risk
External leaks or failures, potential increase in explosion hazards due to equipment density	Fire/explosion leading to fatalities. Exposure of all POB FPSO or LNG facilities	Fire/explosion leading to a direct breech of oil system containment	Proper layout assessment and design	I	B	3
External leaks/failures	Spilled LNG from loading arms onto deck leading to loss of life.	LNG embrittlement of ship structure leading to oil containment tank failure potential for total loss of vessel	Cambered decks and scuppers Bunded area Leak detection and blowdown Proper drainage design & control	II	D	4
External leaks/failures of liquefaction process equipment or refrigerant storage	Fire/explosion leading to fatalities. Exposure of all POB FPSO or LNG facilities	Fire/explosion leading to a direct breech of FPSO oil system containment	No transfer of LNG to separate storage vessel scenario Nitrogen process eliminates refrigerant leak issue	II	C	5
Start up and Shut Down activities due to well production upsets	Flange leaks leading to localized fire		Safety systems, fire / gas detection	IV	B	4
External/Internal leaks of hull storage tanks	Fire/explosion leading to fatalities. Exposure of all POB FPSO or LNG facilities	Fire/explosion leading to a direct breech of FPSO oil system containment	1. Vessel storage tanks can include a secondary containment system. 2. Proper design, detailed operating procedures, inspection, avoidance of confined spaces, gas monitoring	IV	D	2
External/Internal leaks from piping /equipment	Fire/explosion leading to fatalities. Exposure of all POB FPSO or LNG facilities	Fire/explosion leading to a direct breech of FPSO oil system containment	Proper design, detailed operating procedures, inspection, avoidance of confined spaces, gas monitoring	IV	C	3
Over/under pressurization of LNG storage tanks leading to release within hull or externally		Catastrophic loss of LNG containment or vessel leading to loss of vessel.	Vapor Makeup to avoid vacuums, safety systems, good operations, tank selection, adequate venting and relief systems	I	E	4
Terrorist Attack	Catastrophic loss of LNG containment leading to loss of life.	Catastrophic loss of LNG containment or vessel leading to loss of vessel.	Collision avoidance radar, exclusion areas, standby vessels, safety and security zones, shut down, blowdown, far offshore location is the primary mitigation.	I	E	4

A *risk matrix* was used to rank the *severity* and *likelihood* of consequence and determine a relative risk level. The risk matrix used in this study is shown in Table 3. Rows reflect different levels of severity (I–IV), and columns indicate the likelihood of the consequence (A-E). Note again that the consequences reflect human safety and environmental damage. Consensus views of the severity and likelihood for each hazard and consequence were determined in a working session during the Workshop.   The risk matrix also associates a number from 1 to 8 for each severity/consequence to indicate the relative importance of the risk. Note that high severity/low likelihood consequences can have similar risks to low severity/high consequence events. Each severity/consequence pair is also colored green, yellow, and red to indicate increasing risks and needs for more attention to mitigation measures.

The severity (I–IV), likelihood (A-E), and risk (1-8) as determined from the risk matrix for each of the hazards and consequences are also shown in Table 2.

Table 3 - Risk Matrix

Severity	Consequence		Likelihood				
			A	B	C	D	E
	Safety	Environment	Several occurences possible during facility lifetime.	Occurrence is considered likely: possible during 1 during facility life	Occurrence is considered unlikely: no more than 1 in 10 facility lives	Occurrence is considered highly unlikely: no more than 1 in 100 facility lives	Occurrence is considered practically impossible: no more than 1 in 1000 facility lives
I	Loss of majority of personnel on board	Long term environmental damage affecting extensive area and requiring extensive clean-up, discharge > 10,000 bbl	8	7	6	5	4
II	Single or multiple fatalities	Severe environmental impact, extensive measures requried to restore contaminated environment, discharge > 1000 bbl	7	6	5	4	3
III	Permanent disability or significant irreversable health effects	Significant environmental impact, significant measures required to restore contaminated environment, discharge > 100 bbl	6	5	4	3	2
IV	Minor Injury, lost time incident, reversable health effects incurred	Contamination/discharge affecting immediate surrounding environment, minor response required to restore contaminated area, discharge > 10 bbl	5	4	3	2	1

Costs The incremental CAPEX and OPEX were estimated to illustrate the feasibility of a particular technology for a given production scenario. These costs are over-and-above the costs associated with installing and operating the FPSO, its oil system and the shuttle tankers exporting the oil. The costs included the CAPEX and OPEX for each process step of the alternative.

It proved to be difficult to get information for costs estimated due to several factors:

- Except for pipelines, we were estimating costs for new systems and operations
- Many involve *"marinization"* of onshore processes or equipment (motions, space) that have not yet been done
- Competitive market pressures limit the availability of cost information as some of these competing technologies and components approach the market place

Cost estimates were generally based on a capacity or rate for which some information is available. Much of that information was for land-based or fixed structure applications, and the costs of expanding the FPSO and "marinizing" the components or operation had to be estimated. That information was then scaled to different capacities and rates using project estimating guidelines. It should be recognized that different options available within some Process Steps could significantly impact costs.

The resulting estimates should be used with caution as they could vary significantly from a project-specific and more detailed analysis. The cost data is also circa 2003 – 2004, and costs for oil and gas related facilities and equipments have increased since then. However, it is hoped that the costs estimates presented here will be useful in understanding the economic feasibility and relative costs of the different transportation options and the larger cost components within each option.

Efficiency The overall Process Efficiency is estimated for each alternative. Efficiency is defined as BTU's delivered to sales or transfer point divided by the BTU content of the associated gas produced. The intent was to define a metric that could be useful in considering matters related to the conservation of gas as a resource. However, we note that this metric does not reflect the intrinsic value of gas products such as GTL.

RESULTS

Results are summarized and compared below for the four gas transportation alternatives assessed in this study - Pipelines, LNG, CNG, and GTL. More detailed results for each alternative are given in the Appendices as follows:

Appendix A - Pipelines
Appendix B - Liquefied Natural Gas
Appendix C - Compressed Natural Gas
Appendix D - Gas to Liquids

Technical and Regulatory Readiness Technical and regulatory readiness results are summarized and compared in Table 4 and Figure 7 for each of the gas handling alternatives and process steps. Most of the process steps are "project ready", or have challenges that could likely be resolved within 1-3 years during the execution cycle of a 3-year project through special attention to those issues.

Table 4 - Readiness (years to being project ready)

Process Stage	Pipeline		LNG		CNG		GTL	
	Years	Challenge	Years	Challenge	Years	Challenge	Years	Challenge
FPSO	–		1 to 3	LNG plant layout	–		–	
Dehydration & Treating	0		0		0		0	
Convert to Transport State	0		0		0		~5	Ship-borne capable pilot plant demo Liquid oxygen HTHP vessel fatigue
Offshore Storage	na		0		na		0	
Offshore Loading	0		0	Side-by-Side, others higher	0		0	
Transport	0		4 to 7	Availability of Jones Act LNG shuttles	1 to 3	Availability of Jones Act LNG shuttles	1 to 3	Availability of Jones Act LNG shuttles
Offloading	0		0	Onshore or offshore berth, other schemes longer	0		0	
Storage	0		0	Above ground tanks, underground caverns longer	na		0	
Convert to Sales State	0		0		0		0	
Storage	na		0		na		0	
Other			1 to 3	EA needed? Applicability of existing codes	1 to 3	EA needed? Applicability of existing codes	1 to 3	EA needed? Applicability of existing codes

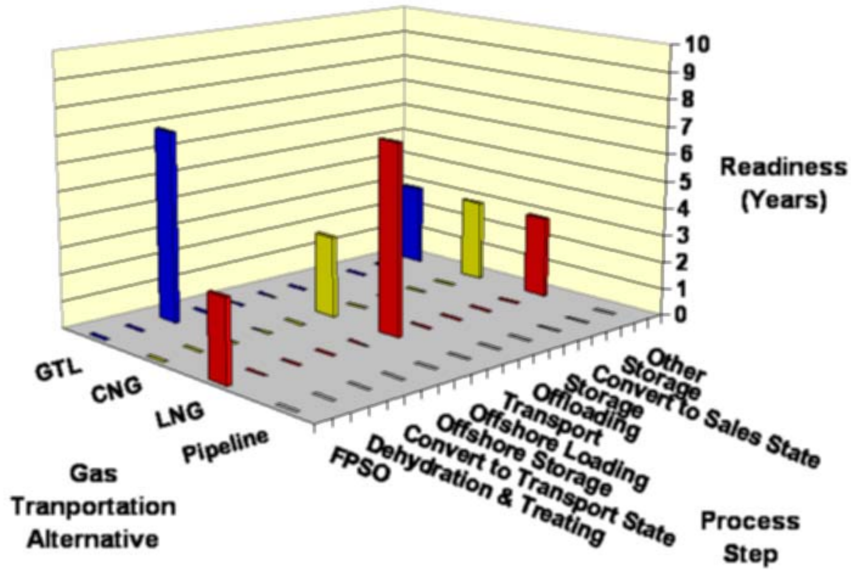

Figure 7 - Technical Readiness

The readiness estimate for LNG FPSO suggested that 1 to 3 years could be needed to plan and design an LNG facility on an FPSO operating in the Gulf of Mexico. The readiness estimate for LNG Transport indicates that 3 to 7 years may be needed to complete Jones Act LNG carriers. Similarly, the readiness estimate for CNG Transport indicates that 1 to 3 years may be required to secure Jones Act CNG carriers. The readiness estimate for the GTL Convert to Transport State suggests that 3 to 7 years may be needed to develop and "marinize" a GTL process to place on an FPSO operating in the Gulf of Mexico. The category "Others" indicates readiness in 1 to 3 years to suggest the time that might be needed to pursue any items such as Environment Assessments or work on codes and standards that might be required.

HSE Risks The Risks for each gas transportation alternative and process step are summarized and compared in Table 5 and Figure 8. Only Risks that are greater than "3" are shown in Figure 8 to focus on those process steps that should be most carefully evaluated for a specific project. These results suggest that all Process Steps for all of the gas transportation alternatives can achieve acceptable risk levels though proper attention to design, operational planning, and mitigation measures.

Table 5 - HSE Risk

	Pipeline		LNG		CNG		GTL	
	Risk	**Consequence**	**Risk**	**Consequence**	**Risk**	**Consequence**	**Risk**	**Consequence**
Dehydration & Treating	3		3		3		3	
Convert to Transport State	3	Fire/explosion due to export riser leak	5	Fire/explosion due to LNG or refrigerant leak	3		4	Fire/explosion due to presence of O_2, H_2 and hi-press CO
Offshore Storage	na		4	Fire/explosion due to LNG leak due to over/under pressure in tank or terrorist attack	3		na	
Offshore Loading	4	Fire/explosion due to onboard piping or export riser	5	Fire/explosion due to LNG spill on deck due to loading system leak due to equipment or mooring failure	4	Fire/explosion due to CNG spill on deck due to loading system leak due to equipment or mooring failure	2	
Transport	1		1		2		1	
Offloading	na		2	offshore terminal	2	Fire/explosion due to CNG spill on deck due to offloading system leak due to equipment or mooring failure	2	
Storage	na		2		na		na	
Convert to Sales State	2		3		2		2	
Onshore Storage	na		2		2		na	

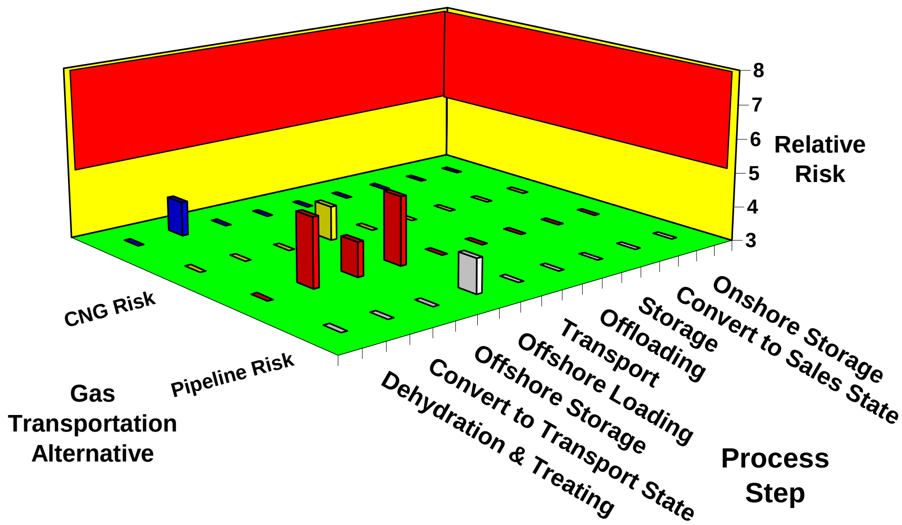

Figure 8 - HSE Risks

The process steps with higher risks are generally those that involve congested equipment layouts, cryogenic temperatures, and offshore loading with "newer" loading systems.

Costs Cost estimates for components of each system are shown in Table 6. A Service Cost which is the cost to take the gas from the separator on the FPSO to the sales point onshore is also estimated. A simple economic model was used to compute the Service Cost from the CAPEX and OPEX using reasonable project parameters (20 year project life, 13 percent pre-tax internal rate of return). Figure 9 illustrates the Service Costs estimated for each alternative as ranges for associated gas production rates of 125 to 500 MMscf/day. Service costs for a Pipeline are lowest, followed by CNG, and then LNG and GTL (which appear to have similar costs).

Table 6 - Comparisons of Estimated Costs ($MM)

	Pipeline		LNG		CNG		GTL		Remarks
Gas Rate	**125**	**500**	**125**	**500**	**125**	**500**	**125**	**500**	
FPSO Modifications	0	0	35	70	0	0	35	70	CNG only need more compressors that can fit in existing FPSO.
Dehydration and Treating	7	13	0	0	0	0	0	0	Dehydration for LNG, CNG and GTL is included in Convert to Transport.
Convert to Transport State	9	26	299	908	4	12	620	1,635	
Offshore Loading	5	7	10	10	40	40	0	0	GTL only needs a hose to offload the liquids
Transport	216	288	110	220	390	1,029	31	67	
Offloading	na	na	20	20	27	34	0	0	GTL only needs a hose to offload the liquids
Convert to Sales State	3	9	160	386	3	8	0	0	
Storage	na	na	0	0	0	0	0	0	No storage for all options
Total CAPEX	239	343	635	1,614	464	1,123	686	1,772	
Total OPEX	4	8	28	76	18	23	55	106	
Service Cost($/MMSCF)	**0.8**	**0.3**	**2.6**	**1.7**	**1.8**	**1.0**	**2.8**	**2.0**	

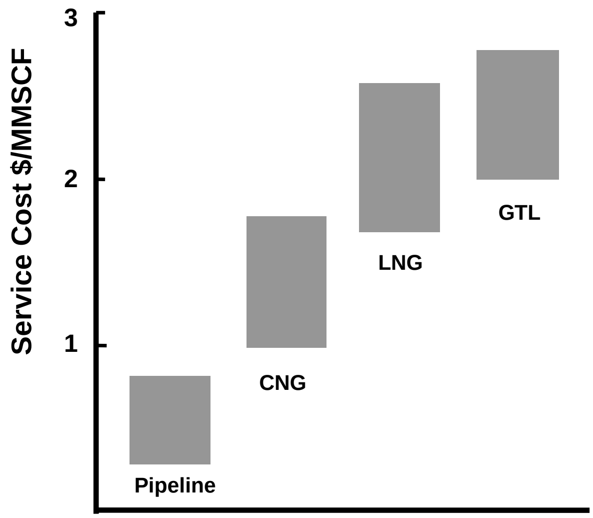

Figure 9 - Service Cost Estimates

Efficiency The process efficiencies based on the ratios of BTU's of gas produced to the BTU's of gas or gas product that is delivered to the sales point are also shown in Table 6. The efficiencies range from 60% to 96%. This may not be a meaningful metric for GTL in that gas products such as chemicals, fuels, or electricity have added or intrinsic value beyond its BTU value.

SUMMARY

An assessment of Pipeline, LNG, CNG, and GTL systems for transporting associated gas from an FPSO at a deepwater location in the Gulf of Mexico has been completed. Results indicate that these systems

- Are now or can be "project ready" in less than 7 years
- Can achieve acceptable levels of HSE risks

Service costs for a Pipeline are lowest, followed by CNG, and then LNG and GTL. The efficiencies of these processes seem acceptable.

ACKNOWLEDGEMENTS

We acknowledge and appreciate the Minerals Management Service sponsorship and participation, the support and participation by the Offshore Operators Committee representatives, and participation by the industry experts and class societies in the Workshops. A list of the organizational affiliations of individuals who have contributed to the Workshops and the study are shown in Table 7. The contributions by the individuals from these organizations added great value and are gratefully acknowledged.

Table 7 – Organizational Affiliation of Contributors to this Study

ABS	Devon Energy Corp.	Marathon
ABSC	DNV	MMS
AJ Wolford+	El Paso	Offshore Operators Committee
Amec	Enersea Transport	OTRC
APCI	ExxonMobil	Paragon
APL Inc.	Fluor	Purvin & Gertz
Black & Veach	FMC	Rentech
Bluewater	Foster Wheeler	SBMI
BP	General Dynamics	Shell
CGI	GulfTerra	SOFEC
ChevronTexaco	Heerema	Synfuels
Conam Inspection & Engr'ng	INTEC	Technip
ConocoPhillips	ITP	Trans Ocean Gas Inc.

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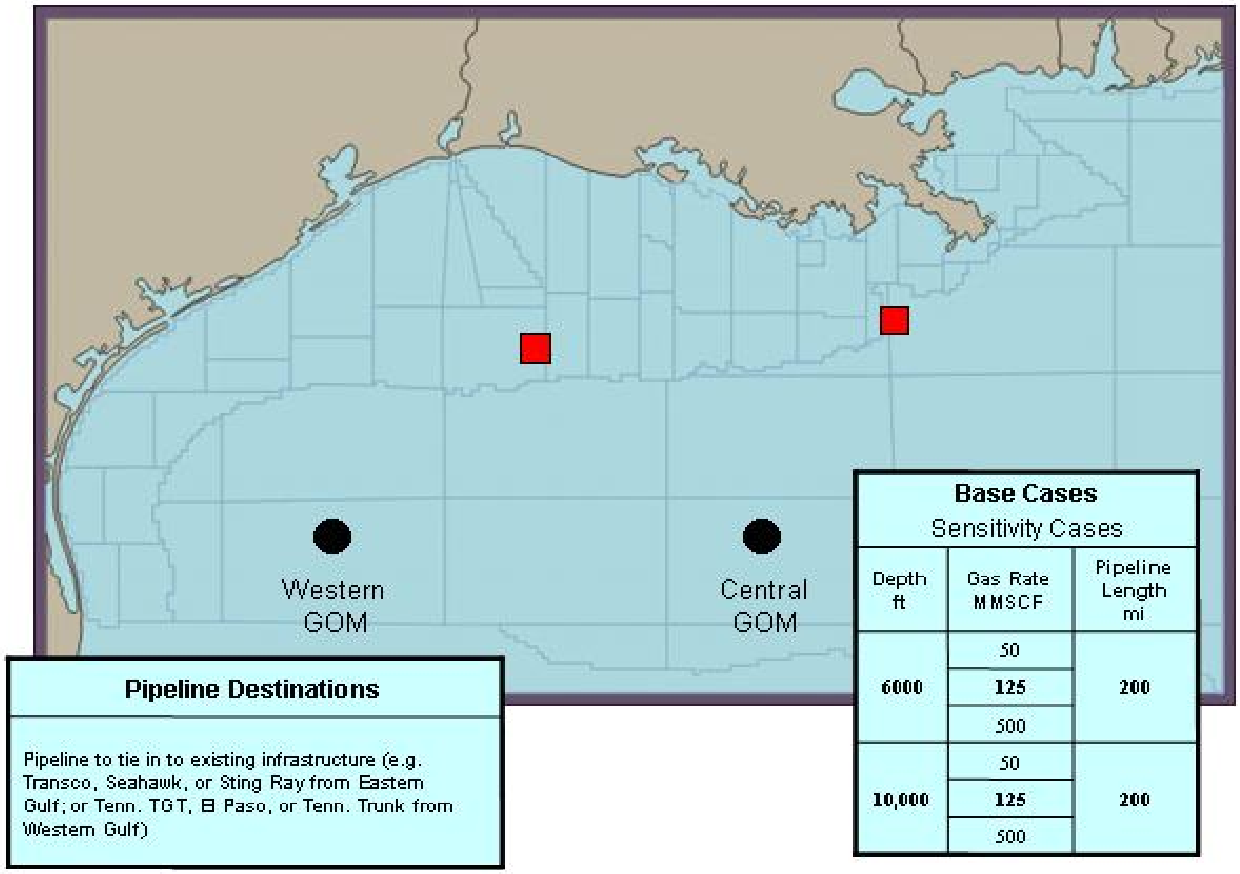
2. Gilbert, R. B., Ward, E. G., and Wolford, A. J. (2001), "Comparative Risk Analysis for Deepwater Production Systems", Final Project Report, Prepared for Minerals Management Service, Washington, D. C.

Appendix A – Pipeline Workshop Results

Pipeline Workshop Results

Figure 1. Pipeline Scenarios



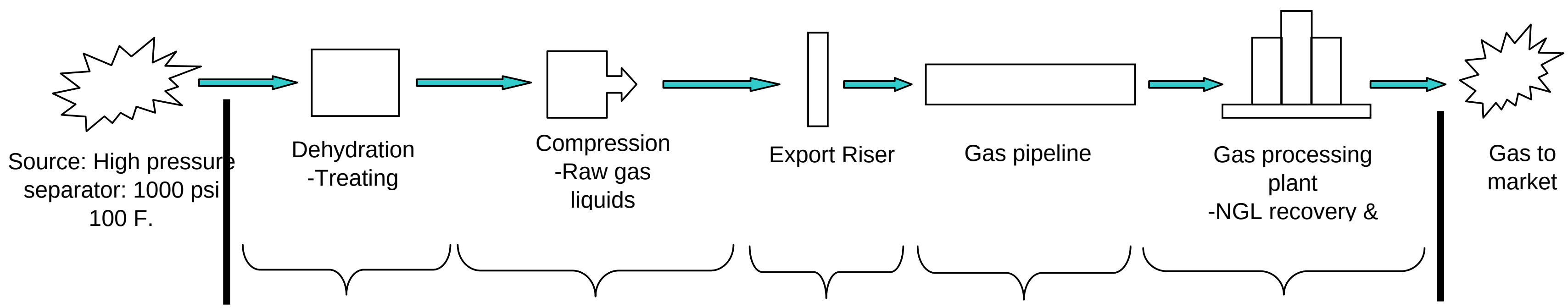
Base Cases
Sensitivity Cases

Depth ft	Gas Rate MMSCF	Pipeline Length mi
6000	50	**200**
	125	
	500	
10,000	50	**200**
	125	
	500	

Figure 2. Process Steps - Pipeline

The pipeline option has been divided into the following steps as illustrated in the sketch below. For the purposes of completing this assessment, please provide the assessment information for each of these steps separately in completing the information on the following pages.
Please feel free to modify the sketch as needed.

Process Steps



Metric	Dehydration and treating	Convert to transport state	Transfer	Transport	Convert to sales state
Technical and Regulatory Readiness					
HSE Risks					
CAPEX/OPEX					
Efficiency					

Table 1. Key Challenges for Technical and Regulatory Readiness - Pipeline

Describe Key Challenges to Technical and Regulatory Readiness in the following Table 1. Readiness is defined as when the technology will be "project ready". Technical Readiness can be assedssed by examining the present stage of development of the technology (e.g., concept, bench test, pilot test, field test, or tests or experience with similar applications of key components) and the barriers that must be overcome to achieve Technical Readiness. Regulatory Readiness refers to the acceptance/approval of the technology by regulatory agencies(MMS, USCG, EPA, others) through the DWOP and other processes. Some potential Challenges to Technical Readiness are listed. Please consider these Challenges as well other technical and regulatory challenges that you see as present barriers for the Base Cases and the Sensitivity Cases. Indicate the number of years you expect will be requred to resolve each challenge.

Challenge No.	Challenges	Technical T Regulatory R	Years to Resolution	Comments
1	Pipeline wall thickness (manufacturability, welding)	T, R	0	
2	Constructability & layability (size, weight, wall thickness, depth)	T, R	0	
3	Export riser (VIV, compression/bucking, plastic deformation, weld corrosion, large vessel motion)	T, R	1-3 (10,000 ft)	Uncertaintity of environmental loading conditions, loop currents, design and effectiveness of VIV suppression. Add erosion as possible detailed description.
4	Pipeline fatigue (bottom spans)	T, R	0	Similar to 3 but a lesser degree.
5	Compression (?)	?	0	Included in 3.
6	Gathering System Pigging Components (Y's, PLETS, Repair Systems)	T	0	
7	Risers for FPSO's (Lazy WaveSCR's, Riser Towers, Dynamic Flexible Pipe Catenary Risers)	T	0	
8	Subsea Production Tie-Back of Smaller Reservoirs	Project Related?	0	Out of scope.
9	Hydrotesting & Drying and Alternatives to Hydrotesting (Pressure Testing & Inspection/Commissioning)	T, R	0	Drying long pipelines and laterals a problem, especially. Glycol only effective solution to date. Opportunity for developing an alternative compliance method during MMS/DOT interface.
10	Leak Detection	T	0	Where should attention be focused, risers or pipelines? Risers? Inspect riser as part of facility inspection. Gas inspection plan a part of DWOP. In 10,000 ft, water leaks into pipe, and can be sensed.
11	Repair Systems	T	0	Existing Shell & bp systems. Deployment based on vessel & ROV capability.
12	Hydrate Blockage Removal Following Wet Pipeline Damage Scenario	T	0	Operational issue. How to locate/charaterize plug and intervene.
13	Design Codes	R	0	Hyrotest req'ts. API 1111. Strain vs stress based… work in progress.
14	Environmental Criteria (Currents)	T	0	
15	Geotechnical Assessment	Project Related?	0	
16	FPSO Turret (Swivel, bearings)	T	1-3	Higher pressure for deeper water. Other FPS's may be better alternative.
17	Natural Gas Liquids			NGL's are a blessing, not an issue. Design for it , ship it with the oil if possible, and sell it.

Table 2. Risk Matrix

Severity	Consequence			Likelihood				
				A	B	C	D	E
	Safety	Environment	Facilities Operations	Several occurences possible during facility lifetime.	Occurrence is considered likely: possible during 1 during facility life	Occurrence is considered unlikely: no more than 1 in 10 facility lives	Occurrence is considered highly unlikely: no more than 1 in 100 facility lives	Occurrence is considered practically impossible: no more than 1 in 1000 facility lives
I	Loss of majority of personnel on board	Long term environmental damage affecting extensive area and requiring extensive clean-up, discharge > 10,000 bbl	Extensive damage to facility and major business interuption, possible total loss of asset	9	8	7	5	5
II	Single or multiple fatalities	Severe environmental impact, extensive measures requried to restore contaminated environment, discharge > 1000 bbl	Partial loss of facility, operations halted for a month, estimated repairs les than $10,000,000	8	7	6	4	3
III	Permanent disability or significant irreversable health effects	Significant environmental impact, significant measures required to restore contaminated environment, discharge > 100 bbl	Operations temporarily halted, can possibly be re-started, estimated cost of repair less than $1,000,000	7	6	4	3	2
IV	Minor Injury, lost time incident, reversable health effects incurred	Contamination/discharge affecting immediate surrounding environment, minor response required to restore contaminated area, discharge > 10 bbl	Possible short disruption of operations, cost of repair less than $100,000	5	4	3	2	1

Note that risks to the facilities are not considered in the scope of the study.

TABLE 3. HSE Risks - Pipeline

Process Steps	Hazard	Potential Consequences Safety (Fatalities)	Potential Consequences Environment (Oil Spill)	Mitigation Options	Severity	Likelihood	Risk	Controlling Consequence Safety/Environment	Comments
Dehydration and treatment	Gas leak from additional gas handling facilities	Fire / explosion, increase in fatality rate	Fire / explosion leading to breech of FPSO oil system containment	Proper design and operation to existing codes (fire and gas detection)	III	D	3	S/E	Similar to CNG
Convert to transport state (Compression)	Gas leak from additional gas facilities and compressors	Fire / explosion, increase in fatality rate	Fire / explosion leading to breech of FPSO oil system containment	Proper design and operation to existing codes (fire and gas detection)	III	D	3	S/E	Similar to CNG
Transfer (Export Riser System)	Gas leak from onboard piping and export risers	Incremental risks introduced by transfer operations - exposure of all POB FPSO	Fire / explosion leading to breech of oil system containment	Proper design and operation to existing codes (fire and gas detection, inspection, VIV monitoring)	II	D	4	S	CRA: 1.00E-3 /riser*yr x 1 riser = 1.0E-3/yr.
Transport (Gas Pipeline)	Pipeline leak due to: Pipeline fatigue (Span), External and Internal Corrosion, Slope Instability, Third Party Construction Damage	No personnel exposure	No oil exposure	1. Proper design and operation to existing codes (SCADA, material selection), monitoring, inspection, routing rectification. [External - coatings, CP, inspection], [Internal - gass process controls, inspection] 2. Route selection, geotechnical assessment. 3. Existing Procedures.	IV	C	3	E	CRA: 4.55E-4 /m*yr x 200m= 9.1E-2 /yr
Convert to sales state	Piping leak from onshore gas plant receiving facilities	Fire / explosion & direct incremental fatality (terminal & neighboring facility personnel)	No oil exposure	Proper design and operation to existing codes (Pressure controls and protection)	IV	D	2	S	Similar to CNG
Gas Storage (Capacity Buffer)	External leaks/failures of gas storage tanks	Fire/explosion leading to fatalities. Exposure of all POB gas storage system	No oil exposure	Standard gas plant design and operating practices	IV	D	2	S	Similar to CNG

Table 4. COSTS & EFFICIENCY - Pipeline

Estimate the ***incremental*** costs over and above the FPSO being installed to produce the oil for the Base Cases in Table 6 below. The costs include the CAPEX and OPEX for the gas pipeline system.

The CAPEX should include process facilities, compression, export risers, utilities, etc., as well as the incremental cost for additions to the FPSO (deck space, buoyancy) needed strictly for the gas pipeline system. The OPEX should include costs to operate and maintain the gas pipeline system for the 20-year operating period, and include labor cost and the value of utilities furnished by the FPSO.
Use P50 estimates. CAPEX in $million. OPEX in $million per year.

We will assume that a transportation tariff may be estimated from this data as:

Tariff ($/1000 scf) = [CAPEX (Annual investment cost) + OPEX] / 1000 scf transported per year

The overall Process Efficiency is defined as BTUs delivered to sales or transfer point divided by BTUs gas produced. The Process Step Efficiency is determined as:

Process Step Efficiency (%) = (Gas into step - Gas Consumed and lost in step) / Gas into step

Then, the overall Process Efficiency is estimated as the product of all Process Step Efficiencies.

Please note in Table 6 below any significant differences in either costs or efficiencies that would be expected for the Sensitivity Cases.

		Base Cases		Sensitivity Cases				
	Depth, ft	6,000	10,000	6000	6000	10000	10000	
	Gas rate, MMSCFD	125	125	50	500	50	500	
	Distance statute, miles	200	200	200	200	200	200	
Floating Production System (FPSO)	**Incremental cost for modification to FPSO for gas pipeline system**							
	CAPEX, MM$	0	0	0	0	0	0	Input assumption.
	OPEX, MM$/yr	0	0	0	0	0	0	Input assumption.
Dehydration and Treating	Dehydration costs, MM$	1	1	0	2	0	2	It is assumed 1MM$ per 250MMSCFD, then escalation factor of 0.7 for other capacities.
	NGL removal costs, MM$	0	0	0	0	0	0	This cost is already considered on the FPSO base case.
	CAPEX, MM$	1	1	0	2	0	2	Sum of "Dehydration cost, MM$" and "NGL removal cost, MM$".
	OPEX, MM$/yr	0	0	0	0	0	0	It is assumed 10% of CAPEX annual
	Efficiency, %	100%	100%	100%	100%	100%	100%	Input assumption.

Table 4. COSTS & EFFICIENCY - Pipeline

Estimate the ***incremental*** costs over and above the FPSO being installed to produce the oil for the Base Cases in Table 6 below. The costs include the CAPEX and OPEX for the gas pipeline system.

The CAPEX should include process facilities, compression, export risers, utilities, etc. as well as the incremental cost for additions to the FPSO (deck space, buoyancy) needed strictly for the gas pipeline system. The OPEX should include costs to operate and maintain the gas pipeline system for the 20-year operating period, and include labor cost and the value of utilities furnished by the FPSO.
Use P50 estimates. CAPEX in $million. OPEX in $million per year.

We will assume that a transportation tariff may be estimated from this data as:

Tariff ($/1000 scf) = [CAPEX (Annual investment cost) + OPEX] / 1000 scf transported per year

The overall Process Efficiency is defined as BTUs delivered to sales or transfer point divided by BTUs gas produced. The Process Step Efficiency is determined as:

Process Step Efficiency (%) = (Gas into step - Gas Consumed and lost in step) / Gas into step

Then, the overall Process Efficiency is estimated as the product of all Process Step Efficiencies.

Please note in Table 6 below any significant differences in either costs or efficiencies that would be expected for the Sensitivity Cases.

		Base Cases		Sensitivity Cases				
	Depth, ft	6,000	10,000	6000	6000	10000	10000	
	Gas rate, MMSCFD	125	125	50	500	50	500	
	Distance statute, miles	200	200	200	200	200	200	
Convert to Transport state (Compression)	Suction pressure, psi	1,000	1,000	1,000	1,000	1,000	1,000	Input assumption.
	Discharge pressure, psi	3,000	3,000	3,000	3,000	3,000	3,000	Input assumption.
	HP needed	8,250	8,250	3,300	33,000	3,300	33,000	Input assumption.
	Cost of compression ($/installed HP)	980	1,020	1,343	673	1,343	673	Input assumption.
	Compression costs, MM$	8	8	4	22	4	22	It is considered 7.2 MM$ per 100 MMSCFD, then escalation factor of 0.7 for other capacities.
	OPEX, MM$/yr	1	1	0	2	0	2	It is assumed 10% of CAPEX annual
	Efficiency, %	97%	97%	97%	97%	97%	97%	Input assumption.
Transfer(Export Riser)	**Export riser**							
	CAPEX, MM$	4.0	5.0	0.0	0.0	0.0	0.0	Input assumption.
	OPEX, MM$/yr	0	0	0	0	0	0	It is assumed 1% of CAPEX annual
	Efficiency, %	0%	0%	0%	0%	0%	0%	Input assumption.
Transport (Gas Pipeline)	**Gas pipeline OD (in)**	18	18	12	24	12	24	
	Cost $ per inch per mile	60,000	60,000	60,000	60,000	60,000	60,000	Input assumption.
	CAPEX, MM$	216	216	144	288	144	288	Product of "Cost $ per inch per mile" times "Gas pipeline OD(in)" times "Distance statute, miles" divided by 10^6.
	OPEX, MM$/yr (@.01xCAPEX)	2.2	2.2	1.4	2.9	1.4	2.9	It is assumed 1% of CAPEX annual
	Efficiency, %	100%	100%	100%	100%	100%	100%	Input assumption.

Table 4. COSTS & EFFICIENCY - Pipeline

Estimate the ***incremental*** costs over and above the FPSO being installed to produce the oil for the Base Cases in Table 6 below. The costs include the CAPEX and OPEX for the gas pipeline system.

The CAPEX should include process facilities, compression, export risers, utilities, etc. as well as the incremental cost for additions to the FPSO (deck space, buoyancy) needed strictly for the gas pipeline system. The OPEX should include costs to operate and maintain the gas pipeline system for the 20-year operating period, and include labor cost and the value of utilities furnished by the FPSO.
Use P50 estimates. CAPEX in $million. OPEX in $million per year.

We will assume that a transportation tariff may be estimated from this data as:

Tariff ($/1000 scf) = [CAPEX (Annual investment cost) + OPEX] / 1000 scf transported per year

The overall Process Efficiency is defined as BTUs delivered to sales or transfer point divided by BTUs gas produced. The Process Step Efficiency is determined as:

Process Step Efficiency (%) = (Gas into step - Gas Consumed and lost in step) / Gas into step

Then, the overall Process Efficiency is estimated as the product of all Process Step Efficiencies.

Please note in Table 6 below any significant differences in either costs or efficiencies that would be expected for the Sensitivity Cases.

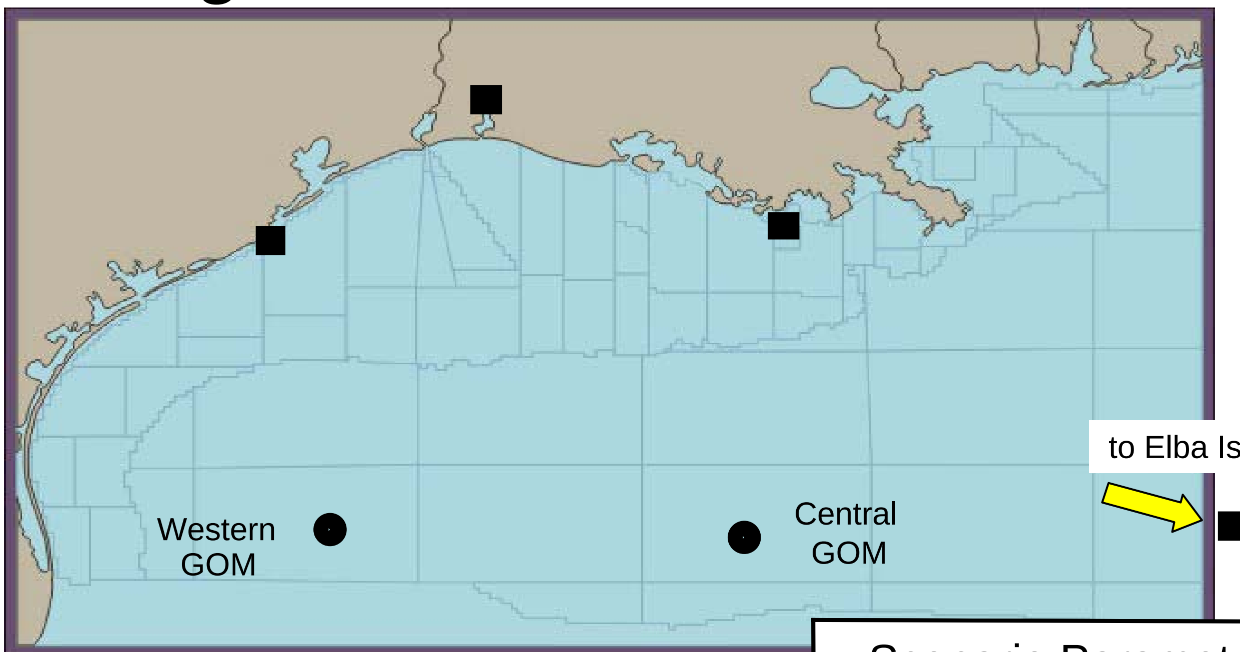
	Base Cases		Sensitivity Cases			
Depth, ft	6,000	10,000	6000	6000	10000	10000
Gas rate, MMSCFD	125	125	50	500	50	500
Distance statute, miles	200	200	200	200	200	200

Convert to Sales State	**Gas process plant (NGL recovery, fractionation products)**							
	CAPEX, MM$	22	22	11	57	11	57	It is assumed 30MM$ per 200MMSCFD, then escalation factor of 0.7 for other facilities.
	OPEX, MM$/yr	2	2	1	6	1	6	It is assumed 10% of CAPEX annual
	Efficiency, %	99%	99%	99%	99%	99%	99%	Input assumption.

Total CAPEX, MM$	**251**	**252**	**160**	**369**	**160**	**369**
Total OPEX, MM$/yr	**5**	**5**	**3**	**11**	**3**	**11**
Overall Efficiency, %	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Amortization per year (13% pre-tax IRR, 20 years)	**41**	**41**	**26**	**63**	**26**	**63**
Cost of service, $/MSCF	**0.9**	**0.9**	**1.4**	**0.3**	**1.4**	**0.3**

Appendix B – LNG Workshop Results

Figure 1. LNG Scenarios



● FPSO Oil & Gas Development

- Oil transported by shuttle tanker
- Associated gas transported by LNG carrier

■ LNG Destinations

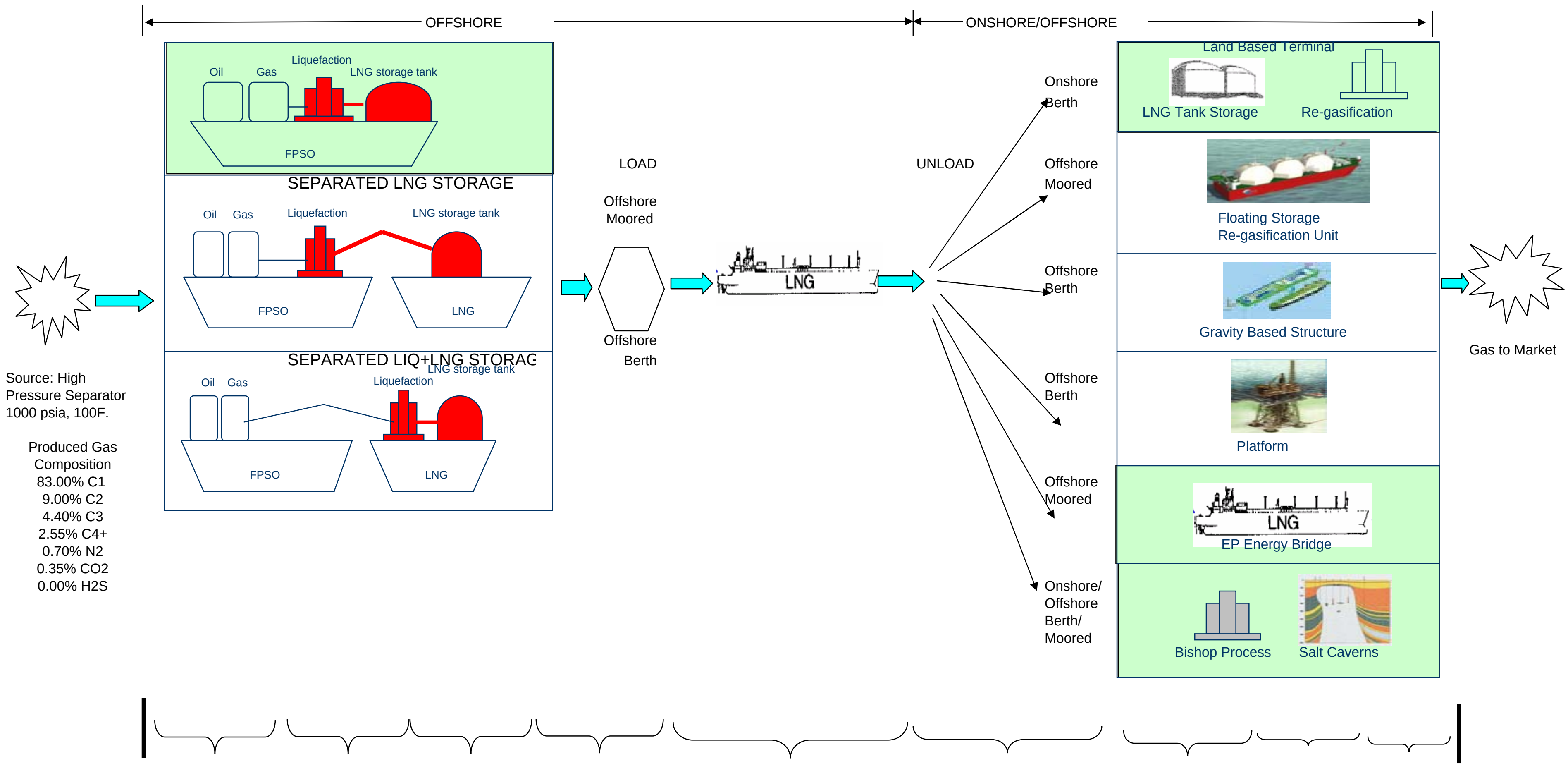
- Existing facilities at Lake Charles, LA or Elba Is, SC
- New facilities along Gulf coast

Scenario Parameters

Depth (ft)	Gas Rate (MMSCF)	Transport Distance (mi)
6000	125	300-1200
	500	
10,000	125	300-1200
	500	

FIGURE 2. PROCESS STEPS & METRICS - LNG

The LNG option has been divided into the following steps as illustrated in the various cases shown below.
Costs are shown in Table 4 for the shaded options.



Metric	Dehydration and treating	Convert to transport state (Liquefaction)	LNG Storage	Load	Transportation	Unload	LNG Storage	Convert to sales state (Re-gasification)	Gas Storage (*)
Technical and Regulatory Readiness									
HSE Risks									
Costs									
Efficiency									

*** If Applicable**

Scenario Parameters:

Depth: 6,000 - 10,000 ft
Gas Rate: 125 - 500 MMSCFD
Transport Distance: 150, 300 - 1200 miles

TABLE 1. KEY TECHNICAL KEY CHALLENGES FOR TECHNICAL & REGULATORY READINESS

Key Challenges to Technical and Regulatory Readiness are described in Table 1. Readiness is defined as when the technology will be "project ready". Technical Readiness can be assessed by examining the present stage of development of the technology (e.g., concept, bench test, pilot test, field test, or tests or experience with similar applications of key components) and the barriers that must be overcome to achieve Technical Readiness. Regulatory Readiness refers to the acceptance/approval of the technology by regulatory agencies(MMS, USCG, EPA, others) through the DWOP and other processes.

Some potential Challenges to Technical Readiness are listed. Please consider these Challenges as well other technical and regulatory challenges that you see as present barriers for the all the Cases. Please, indicate whether the challenge is technical or regulatory issue or both. Also, indicate the years to resolution at water depth of 6000 ft, and 10000 ft in ranges as follows:

Years	Readiness
0	"ready now"
1 - 3	"ready in 1 to 3 years from now"
3 - 7	"ready in 3 to 7 years from now"
7 - 10	"ready in 7 to 10 years from now"
> 10	"ready in more than 10 years from now"

		Consensus		Base Case	Comments
Challenge No.	**Challenges**	**Write T for Technical and/or R for Regulatory**	**Years to Resolution**	✔	
1a	Relative motion during load/unload LNG	T	0	✔	No significant concern
1b	Motion Effect on LNG production Equipment	T	0	✔	Thorough Experience base with oil/gas equipment. No significant difference for LNG equipment. Manufacturers will guarantee performance to a specified design basis.
2	Metallurgy cryogenics	T	0	✔	Significant experience base for materials in LNG service. Operators satisfied that offshore solutions exist.
3	Transfer systems				
3a	Transfer arm for side-by-side	T	0	✔	Technology available for oil. Operating systems for crude oil in service today and are extendable to LNG
3b	Transfer arm for tandem for bow loading	T	1 to 3		20 years experience base in Brunei from fixed structure. Adaptation to floating structures is thought to be a cost issue only.
3c	Cryogenic Hoses	T	1 to 3		Development in progress. Have fatigue issues been addressed?
4a	Layout of LNG plant on FPSO	T,R	0-3	✔	Operator and Class Society input requested. Is this issue significant?
4b	Control and safety systems for combined LNG/FPSO plants	R	0	✔	Uncertainty in how regulators will deal with situation

TABLE 1. KEY TECHNICAL KEY CHALLENGES FOR TECHNICAL & REGULATORY READINESS

Key Challenges to Technical and Regulatory Readiness are described in Table 1. Readiness is defined as when the technology will be "project ready". Technical Readiness can be assessed by examining the present stage of development of the technology (e.g., concept, bench test, pilot test, field test, or tests or experience with similar applications of key components) and the barriers that must be overcome to achieve Technical Readiness. Regulatory Readiness refers to the acceptance/approval of the technology by regulatory agencies(MMS, USCG, EPA, others) through the DWOP and other processes.

Some potential Challenges to Technical Readiness are listed. Please consider these Challenges as well other technical and regulatory challenges that you see as present barriers for the all the Cases. Please, indicate whether the challenge is technical or regulatory issue or both. Also, indicate the years to resolution at water depth of 6000 ft, and 10000 ft in ranges as follows:

Years	Readiness
0	"ready now"
1 - 3	"ready in 1 to 3 years from now"
3 - 7	"ready in 3 to 7 years from now"
7 - 10	"ready in 7 to 10 years from now"
> 10	"ready in more than 10 years from now"

		Consensus		Base Case	Comments
Challenge No.	**Challenges**	**Write T for Technical and/or R for Regulatory**	**Years to Resolution**	✔	
5	Subsea cryogenic pipelines	T	1 to 3		Pipelines do not appear to be an issue. Risers may not be ecomonically feasible for deepwater. Required to have cryogenic flexibles to enable cryogenic pipelines
6a	Underground storage (rights for use of caverns)	R	0-1		Access rights not defined at this time. No federal standard for cavern design and operation (although well-defined by states). Rights not defined at this time for non-leasee parties.
6b	Underground storage (Bishop heat exchanger)	T	1 to 3		DOE-sponsored testing of Bishop Heat Exchanger is in progress
7	Sloshing of partially-filled membrane tanks	T	0-3		Lack of consensus.
8	Small plant capacity	T	0	✔	No identified issues
9	Vapor recovery	T	0	✔	No identified issues
10	C3+ recovery and handling	T	0	✔	No identified issues
11	CO2 Removal and H2S (Acid Gas Removal)	T	0	✔	No identified issues
12	Availability of Jones Act LNG Carriers	R	4-7		Uncertainty about US shipbuilders building affordable LNG carriers?
13	Shipping hazards and route restrictions	R	1-3		Similar siting issues have been faced previously and resolved
14	Tugs and Marine Operations	R	0-3	✔	Part of normal operational planning

TABLE 1. KEY TECHNICAL KEY CHALLENGES FOR TECHNICAL & REGULATORY READINESS

Key Challenges to Technical and Regulatory Readiness are described in Table 1. Readiness is defined as when the technology will be "project ready". Technical Readiness can be assessed by examining the present stage of development of the technology (e.g., concept, bench test, pilot test, field test, or tests or experience with similar applications of key components) and the barriers that must be overcome to achieve Technical Readiness. Regulatory Readiness refers to the acceptance/approval of the technology by regulatory agencies(MMS, USCG, EPA, others) through the DWOP and other processes.

Some potential Challenges to Technical Readiness are listed. Please consider these Challenges as well other technical and regulatory challenges that you see as present barriers for the all the Cases. Please, indicate whether the challenge is technical or regulatory issue or both. Also, indicate the years to resolution at water depth of 6000 ft, and 10000 ft in ranges as follows:

Years	Readiness
0	"ready now"
1 - 3	"ready in 1 to 3 years from now"
3 - 7	"ready in 3 to 7 years from now"
7 - 10	"ready in 7 to 10 years from now"
> 10	"ready in more than 10 years from now"

		Consensus		Base Case	Comments
Challenge No.	**Challenges**	**Write T for Technical and/or R for Regulatory**	**Years to Resolution**	✔	
15	Applicability of existing codes	T, R	0	✔	Elements of codes exist and need to be pieced together from various codes-workable regulatory Risk based approach would be used to supplement existing codes. Code development may be necessary especially on scale-up of size of facilities.
16	Open access to LNG receiving terminals	R	0		Can bid for capacity?
17	Contingencies for delay in gas carrier	T, R	0	✔	Shut in
18	Requirement for new generic EIS for FPSO/LNG system in GOM	R	0	✔	Water flow and air emissions study can be completed within project time frame?

Table 2. Risk Matrix

Severity	Consequence			Likelihood				
				A	B	C	D	E
	Safety	Environment	Facilities Operations	Several occurences possible during facility lifetime.	Occurrence is considered likely: possible during 1 during facility life	Occurrence is considered unlikely: no more than 1 in 10 facility lives	Occurrence is considered highly unlikely: no more than 1 in 100 facility lives	Occurrence is considered practically impossible: no more than 1 in 1000 facility lives
I	Loss of majority of personnel on board	Long term environmental damage affecting extensive area and requiring extensive clean-up, discharge > 10,000 bbl	Extensive damage to facility and major business interuption, possible total loss of asset	9	8	7	5	5
II	Single or multiple fatalities	Severe environmental impact, extensive measures requried to restore contaminated environment, discharge > 1000 bbl	Partial loss of facility, operations halted for a month, estimated repairs les than $10,000,000	8	7	6	4	3
III	Permanent disability or significant irreversable health effects	Significant environmental impact, significant measures required to restore contaminated environment, discharge > 100 bbl	Operations temporarily halted, can possibly be re-started, estimated cost of repair less than $1,000,000	7	6	4	3	2
IV	Minor Injury, lost time incident, reversable health effects incurred	Contamination/discharge affecting immediate surrounding environment, minor response required to restore contaminated area, discharge > 10 bbl	Possible short disruption of operations, cost of repair less than $100,000	5	4	3	2	1

Note that risks to the facilities are not considered in the scope of the study.

TABLE 3. HAZARDS AND CONSEQUENCES - LNG

In this assessment, Risks are determined by Hazards and their resulting Consequences. Key Hazards and their potential Consequences are shown in Table 3 below for each Process Step.

HSE Risks being considered in this assessment include Human Safety and the Environment.

Human Safety Risk is measured as the number of fatalities during a 20 year operational period. Hazards and Consequences that can result in fatalities include LNG or Gas releases that could result in fire and/or explosion.

Environmental Risk is measured as the total volume of oil spilled during a 20 year operational period. Hazards and Consequences that can result in oil spill include LNG or Gas releases that could result in fire and/or explosion leading to a loss of integrity in the oil containment system. It is assumed that if LNG or Gas release (spills) does not lead to a fire and/or explosion, it will disperse and cause no damage to the environment and thus result in no HSE Risk. Spills of the LNG carriers bunker are excluded from this study, but are shown shaded in the table below.

Mitigation options for the various risks are shown. The severity and Likelihood indices from Table 2 (Risk Matrix) are shown along with the resultant Risk index.

Note that damage or loss of facilities is not being considered as a Risk in this assessment.

Process Steps	Hazard	Potential Consequences Human Safety (Fatalities)	Potential Consequences Environment (Oil Spill)	Mitigation Options	Severity	Likelihood	Risk	Controlling Consequence Safety/Environment
Dehydration and treating	External leaks/failures, potential additional increase in explosion hazards due to equipment density	Fire/explosion leading to fatalities. Exposure of all POB FPSO or LNG facilities	Fire/explosion leading to a direct breech of oil system containment	Proper layout assessment and design	I	B	8 3???	E
Convert to transport state (Liquefaction)	External leaks/failures	Spilled LNG from loading arms onto deck leading to loss of life.	LNG embrittlement of ship structure leading to oil containment tank failure potential for total loss of vessel	Cambered decks and scuppers Bunded area Leak detection and blowdown Proper drainage design and control	II	D	4	E
	External leaks/failures of liquefaction process equipment or Refrigerant storage	Fire/explosion leading to fatalities. Exposure of all POB FPSO or LNG facilities	Fire/explosion leading to a direct breech of FPSO oil system containment	No transfer of LNG to separate storage vessel scenario Nitrogen process eliminates refrigerant leak issue	II	C	6	S/E
	Start up and Shut Down activities due to well production upsets	Flange leaks leading to localized fire		Safety systems, fire / gas detection	IV	B	4	S
LNG Storage	External/Internal leaks of hull storage tanks	Fire/explosion leading to fatalities. Exposure of all POB FPSO or LNG facilities	Fire/explosion leading to a direct breech of FPSO oil system containment	1. Vessel storage tanks can include a secondary containment system. 2. Proper design, detailed operating procedures, inspection, avoidance of confined spaces, gas monitoring	IV	D	2	E
LNG Storage	External/Internal leaks from piping /equipment	Fire/explosion leading to fatalities. Exposure of all POB FPSO or LNG facilities	Fire/explosion leading to a direct breech of FPSO oil system containment	1. Proper design, detailed operating procedures, inspection, avoidance of confined spaces, gas monitoring	IV	C	3	S/E
LNG Storage	Over/under pressurization of LNG storage tanks leading to release within hull or externally		Catastrophic loss of LNG containment or vessel leading to loss of vessel.	Vapor Makeup to avoid vacuums, safety systems, good operations, tank selection, adequate venting and relief systems	I	E	5	E
LNG Storage	Terrorist Attack	Catastrophic loss of LNG containment leading to loss of life.	Catastrophic loss of LNG containment or vessel leading to loss of vessel.	Collision avoidance radar, exclusion areas, standby vessels, safety and security zones, shut down, blowdown, far offshore location is the primary mitigation.	I	E	5	S

TABLE 3. HAZARDS AND CONSEQUENCES - LNG

In this assessment, Risks are determined by Hazards and their resulting Consequences. Key Hazards and their potential Consequences are shown in Table 3 below for each Process Step.

HSE Risks being considered in this assessment include Human Safety and the Environment.

Human Safety Risk is measured as the number of fatalities during a 20 year operational period. Hazards and Consequences that can result in fatalities include LNG or Gas releases that could result in fire and/or explosion.

Environmental Risk is measured as the total volume of oil spilled during a 20 year operational period. Hazards and Consequences that can result in oil spill include LNG or Gas releases that could result in fire and/or explosion leading to a loss of integrity in the oil containment system. It is assumed that if LNG or Gas release (spills) does not lead to a fire and/or explosion, it will disperse and cause no damage to the environment and thus result in no HSE Risk. Spills of the LNG carriers bunker are excluded from this study, but are shown shaded in the table below.

Mitigation options for the various risks are shown. The severity and Likelihood indices from Table 2 (Risk Matrix) are shown along with the resultant Risk index.

Note that damage or loss of facilities is not being considered as a Risk in this assessment.

Process Steps	Hazard	Potential Consequences Human Safety (Fatalities)	Potential Consequences Environment (Oil Spill)	Mitigation Options	Severity	Likelihood	Risk	Controlling Consequence Safety/Environment
Load	Transport vessel collisions with floating storage vessels / regasification vessels / fixed offloading towers during connection and disconnection.	Fire/explosion leading to fatalities. Exposure of all POB FPSO or LNG facilities and LNG carrier	Fire/explosion leading to a direct breech of LNG carrier bunker/diesel containment	Use proven offshore rules, methods and procedures in the approach, hook-up and disconnect of vessel to vessel or vessel to tower operations. Monitor relative position and speed during these operations. Use of DP, thrusters, or support vessels for side by side mooring.	IV	D	2	E
Load	External leaks/structural failure of loading system, or LNG transfer lines from vessel to vessel (relative motion).	Fire/explosion leading to fatalities. Exposure of all POB FPSO or LNG facilities and LNG carrier	Fire/explosion leading to a direct breech of LNG carrier bunker/diesel containment	1. Use dual (primary and secondary) sealing systems on all static and dynamic connections. Monitor all primary sealing systems for leaks. Also monitor all flow functions for abnormal conditions. Link all monitored functions to an ESD system. 2. Ensure the Emergency Release System (ERS) utilized considers an offshore environment. Ensure a regular ERS test program is in place. Have a system to ensure loading/unloading only take place within designed wave conditions. 3. Proper design, detailed operating procedures, inspection.	IV	C	3	S/E
Load	Other vessel collisions with FPSO/LNG vessels (trading vessels, military vessels, cruise ships)	Fire/explosion leading to fatalities. Exposure of all POB on LNG carrier Direct deaths from collisions without fire Damage to topsides and escalation			IV	D	2	S
Load (combine w/above)	Mooring (ship to ship) failures leading to unplanned separation and stroke out. Leading to spill of LNG on deck.	Spilled LNG from loading arms onto deck leading to loss of life.	Spilled LNG from loading arms onto deck leading to cryogenic damage to ship and subsequent escalation to fire or breach of cargo tanks	Automatic tracking and warning systems. Containment systems easily direct spill overboard. ERS Fire protection systems and classified areas, routine inspection and HSE management.	II	D	4	No simops….offloading of LNG and crude oil
Load	Fire aboard LNG carrier	Fire escalation to FPSO leading to fatalities (FPSO shuttle tankers separated by greater distance than LNG carriers)	Fire escalation to FPSO leading to loss of oil containment	Fire safety systems, HSE management, Initiate separation of vessels (effective in tug case, system potentially impaired if DP)	IV	D	2	S

TABLE 3. HAZARDS AND CONSEQUENCES - LNG

In this assessment, Risks are determined by Hazards and their resulting Consequences. Key Hazards and their potential Consequences are shown in Table 3 below for each Process Step.

HSE Risks being considered in this assessment include Human Safety and the Environment.

Human Safety Risk is measured as the number of fatalities during a 20 year operational period. Hazards and Consequences that can result in fatalities include LNG or Gas releases that could result in fire and/or explosion.

Environmental Risk is measured as the total volume of oil spilled during a 20 year operational period. Hazards and Consequences that can result in oil spill include LNG or Gas releases that could result in fire and/or explosion leading to a loss of integrity in the oil containment system. It is assumed that if LNG or Gas release (spills) does not lead to a fire and/or explosion, it will disperse and cause no damage to the environment and thus result in no HSE Risk. Spills of the LNG carriers bunker are excluded from this study, but are shown shaded in the table below.

Mitigation options for the various risks are shown. The severity and Likelihood indices from Table 2 (Risk Matrix) are shown along with the resultant Risk index.

Note that damage or loss of facilities is not being considered as a Risk in this assessment.

Process Steps	Hazard	Potential Consequences Human Safety (Fatalities)	Potential Consequences Environment (Oil Spill)	Mitigation Options	Severity	Likelihood	Risk	Controlling Consequence Safety/Environment
Transportation	In-transit hazards of LNG carriers (no pump room hazards, safer than oil shuttle tankers); external leaks, collision, structural failure, overpressurization, loss of propulsion, steering, foundering from LNG carrier.	Fire/explosion leading to fatalities. Exposure of all POB LNG carrier	Fire/explosion leading to a direct breech of LNG carrier bunker/diesel containment	Proper design, detailed operating procedures, inspection, avoidance of confined spaces, gas monitoring, follow international regulations, traffic management schemes	IV	E	1	S
Unload	Transport vessel collisions with fixed offloading structures during connection and disconnection.	Fire/explosion leading to fatalities. Exposure of all POB LNG carrier and LNG storage/regasification/gas storage system	Fire/explosion leading to a direct breech of LNG carrier bunker/diesel containment	Use proven offshore rules, methods and procedures in the approach, hook-up and disconnect of vessel to vessel or vessel to tower operations. Monitor relative position and speed during these operations.	IV	E	1	S
Unload	External leaks/structural failure of unloading system or LNG transfer lines	Fire/explosion leading to fatalities. Exposure of all POB LNG carrier and LNG storage/regasification/gas storage system	Fire/explosion leading to a direct breech of LNG carrier bunker/diesel containment	1. Use dual (primary and secondary) sealing systems on all static and dynamic connections. Monitor all primary sealing systems for leaks. Also monitor all flow functions for abnormal conditions. Link all monitored functions to an ESD system. 2. Ensure the Emergency Release System (ERS) utilized considers an offshore environment. Ensure a regular ERS test program is in place. Have a system to ensure loading/unloading only take place within designed wave conditions. 3. Proper design, detailed operating procedures, inspection.	IV	D	2	S

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Mitigation options for the various risks are shown. The severity and Likelihood indices from Table 2 (Risk Matrix) are shown along with the resultant Risk index.

Note that damage or loss of facilities is not being considered as a Risk in this assessment.

Process Steps	Hazard	Potential Consequences Human Safety (Fatalities)	Potential Consequences Environment (Oil Spill)	Mitigation Options	Severity	Likelihood	Risk	Controlling Consequence Safety/Environment
Unload	High traffic density/congestion at inshore terminals	Collision of LNG transport vessel with other vessel / fixed objects		Vessel control and increased separation for LNG carriers. Exclusion zones, tug escorts, speed restrictions. (These vary depending on terminal and waterway rules.) Offshore ports Coast Guard mid term inspection increase due to more traffic.	IV	D	2	S
Unload	Offshore terminal	Collision of LNG transport vessel with other vessel / fixed objects		Vessel control and increased separation for LNG carriers. Exclusion zones, tug escorts, speed restrictions. (These vary depending on terminal and waterway rules.) Offshore ports Coast Guard mid term inspection increase due to more traffic.	III	D	3	S
LNG Storage	External/Internal leaks/failures from LNG storage	Fire/explosion leading to fatalities. Exposure of all POB LNG storage system	NA	1. Vessel storage tanks can include a secondary containment system. 2. Proper design, detailed operating procedures, inspection, avoidance of confined spaces, gas monitoring.	IV	D	2	S
LNG Storage	Terrorist Attack	Catastrophic loss of LNG containment leading to loss of life.	Catastrophic loss of LNG containment or vessel leading to loss of vessel.	Exclusion areas, safety and security zones, shut down, blowdown, onshore location provides easier safety/security	IV	D	2	S
Convert to sales state (Re-gasification)	External leaks/failures of regasification system	Fire/explosion leading to fatalities. Exposure of all POB re-gasification system	NA	1. Monitor all flow functions for abnormal conditions. Link all monitored functions to an ESD system. 2. Proper design, detailed operating procedures, inspection, avoidance of enclosed spaces.			3???	
Gas Storage (Capacity Buffer)	External leaks/failures of gas storage caverns	Fire/explosion leading to fatalities. Exposure of all POB gas storage system	NA		IV	D	2	S

TABLE 4. COSTS & EFFICIENCY - LNG

The ***incremental*** costs over and above the FPSO installed to produce the oil is estimated below. The costs include the CAPEX and OPEX .

The CAPEX includes liquefaction, load & unload, storage, regasification facilities, utilities, etc., as well as the incremental cost for additions to the FPSO (deck space, buoyancy) needed strictly for the LNG option.
The OPEX includes costs to operate and maintain the LNG chain for the 20-year operating period, and include labor cost and the value of utilities furnished by the FPSO.

The overall Process Efficiency is defined as BTUs delivered to sales or transfer point divided by BTUs gas produced. The Process Step Efficiency is determined as:

Process Step Efficiency (%) = (Gas into step - Gas Consumed and lost in step) / Gas into step

The overall Process Efficiency is estimated as the product of all Process Step Efficiencies.

		Cases				
	Depth, ft	6,000 - 10,000	6,000 - 10,000	6,000 - 10,000	6,000 - 10,000	
	Gas rate, MMSCFD	50	125	500	500	
	Distance statute, miles	300	300	300	1200	
Floating Production System (FPSO)	**Cost of a separated hull for the liquefaction plant and LNG storage**					
	CAPEX, MM$	10	19	50	50	It is assume 50 MM$ for the additional hull that will aocommodate the liquefaction and LNG storage for the gas rate of 500 MMSCFD , then scaled with 0.7 factor for other capacities.
	OPEX, MM$/yr	0	0	0	0	No operating expense.
Dehydration and Treating	Dehydration costs, MM$	0	0	0	0	It is included in Liquefaction cost
	NGL removal costs, MM$	0	0	0	0	It is included in Liquefaction cost
	CAPEX, MM$	0	0	0	0	It is included in Liquefaction cost
	OPEX, MM$/yr	0	0	0	0	It is included in Liquefaction cost
	Efficiency, %	100%	100%	100%	100%	It is included in Liquefaction efficiency
Convert to Transport State (Liquefaction)	Net MMSCFD liquefacted	44	110	440	440	The product of "Gas Rate, MMSCFD" by "Liquefaction Efficiency,%".
	Million tonne LNG produced per year	0.3	0.9	3.4	3.4	Conversion of "Net MMSCFD liquefacted" to "Million tonne LNG produced per year".
	M3LNG produced per day	2,187	5,469	21,874	21,874	Conversion of "Million tonne LNG produced per year" to "m3LNG produced per day".
	CAPEX, MM$	165	314	828	828	It is assumed 230 MM$ for 4 million tonne LNG produced per year, then scaled with 0.7 factor for other capacities .
	OPEX, MM$/yr	8	16	41	41	It is assumed 5% of CAPEX annual
	Efficiency, %	88%	88%	88%	88%	It is assumed 12% of gas is consumed in the process.
LNG Storage	CAPEX, MM$	0	0	0	0	It is included in Liquefaction Costs.
	OPEX, MM$/yr	0	0	0	0	It is included in Liquefaction Costs.
	Efficiency, %	100%	100%	100%	100%	It is included in Liquefaction Efficiency.
Load	CAPEX, MM$	28	28	28	28	It is the average cost of Option A (30MM$ loading arm) and Option B (25MM$ turret).
	OPEX, MM$/yr	0	0	0	0	Input assumption
	Efficiency, %	100%	100%	100%	100%	Input assumption

TABLE 4. COSTS & EFFICIENCY - LNG

The ***incremental*** costs over and above the FPSO installed to produce the oil is estimated below. The costs include the CAPEX and OPEX .

The CAPEX includes liquefaction, load & unload, storage, regasification facilities, utilities, etc., as well as the incremental cost for additions to the FPSO (deck space, buoyancy) needed strictly for the LNG option.
The OPEX includes costs to operate and maintain the LNG chain for the 20-year operating period, and include labor cost and the value of utilities furnished by the FPSO.

The overall Process Efficiency is defined as BTUs delivered to sales or transfer point divided by BTUs gas produced. The Process Step Efficiency is determined as:

Process Step Efficiency (%) = (Gas into step - Gas Consumed and lost in step) / Gas into step

The overall Process Efficiency is estimated as the product of all Process Step Efficiencies.

		Cases				
	Depth, ft	6,000 - 10,000	6,000 - 10,000	6,000 - 10,000	6,000 - 10,000	
	Gas rate, MMSCFD	50	125	500	500	
	Distance statute, miles	300	300	300	1200	
Transportation	Type of carrier	Ship	Ship	Ship	Ship	Input assumption
	Carrier speed knots	19	19	19	19	Input assumption
	Number of days at sea per trip	1	1	1	5	"Distance,miles" divided by "Carrier speed knots" divided by 24 times 2.
	Loading, days	1	1	1	1	Input assumption
	Port/demurrage, days	1	1	1	1	Input assumption
	Total cycle time, days	3	3	3	7	Sum of "Number of days at sea per trip", "loading,days", and "port/demurrage,days".
	Number of carriers needed	1	1	1	2	Input assumption
	M3 LNG transported per ship	6,876	17,190	68,759	143,790	The product of "m3LNG produced per day" by "Total cycle time, days"
	CAPEX, MM$	27	51	135	453	It is considered a cost of 220MM$ per 138,000 m3 Jones Act LNG carrier and then scale down with 0.7 factor to determine the cost of small capacities.
	OPEX, MM$/yr	1	3	7	23	It is assumed 5% of CAPEX annual. It includes the cost of the fuel.
	Efficiency, %	100%	100%	100%	100%	Input assumption
Unload	Unloading system cost, MM$	28	28	28	28	It is the average cost of Option A (30MM$ unloading arm) and Option B (25MM$ turret).
	Diameter of subsea pipeline, inch	12	12	24	24	Input assumption
	Length of subsea pipeline, miles	2	2	2	2	Input assumption
	Cost $ per inch per mile	60,000	60,000	60,000	60,000	Input assumption
	Subsea pipeline cost, MM$	1	1	3	3	Subsea pipeline cost in case it is needed.
	CAPEX, MM$	29	29	30	30	Sum of "Unloading system cost, MM$" and "Subsea pipeline cost, MM$".
	OPEX, MM$/yr	0	0	0	0	Input assumption
	Efficiency, %	100%	100%	100%	100%	Input assumption

TABLE 4. COSTS & EFFICIENCY - LNG

The ***incremental*** costs over and above the FPSO installed to produce the oil is estimated below. The costs include the CAPEX and OPEX .

The CAPEX includes liquefaction, load & unload, storage, regasification facilities, utilities, etc., as well as the incremental cost for additions to the FPSO (deck space, buoyancy) needed strictly for the LNG option.
The OPEX includes costs to operate and maintain the LNG chain for the 20-year operating period, and include labor cost and the value of utilities furnished by the FPSO.

The overall Process Efficiency is defined as BTUs delivered to sales or transfer point divided by BTUs gas produced. The Process Step Efficiency is determined as:

Process Step Efficiency (%) = (Gas into step - Gas Consumed and lost in step) / Gas into step

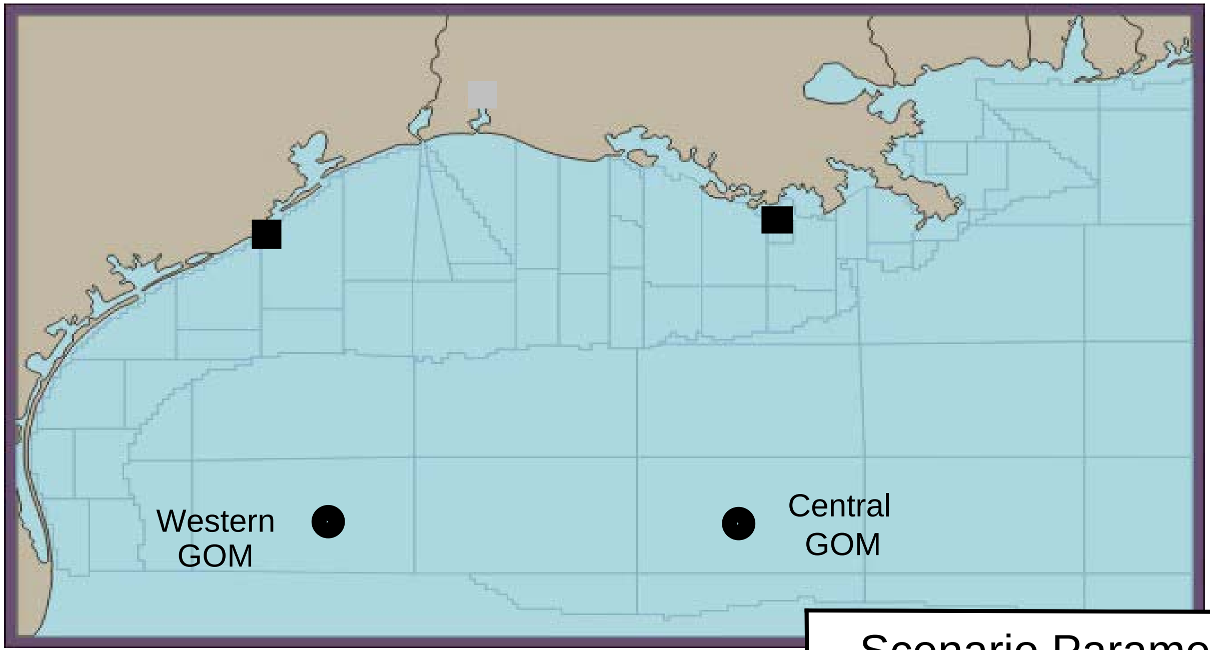
The overall Process Efficiency is estimated as the product of all Process Step Efficiencies.

		Cases				
	Depth, ft	6,000 - 10,000	6,000 - 10,000	6,000 - 10,000	6,000 - 10,000	
	Gas rate, MMSCFD	50	125	500	500	
	Distance statute, miles	300	300	300	1200	
LNG Storage	Gas storage capacity, m3LNG	9,063	22,658	90,633	165,664	1 capacity of ship plus 1 day of production for contingency.
	Gas storage capacity, bcf	0.2	0.5	2.0	3.6	Coversion from "m3LNG" to "bcf".
	Days of gas storage	4	4	4	8	"Gas storage capacity, bcf" divided by "Net MMSCFD liquefacted" and all the efficiencies in the LNG chain to this point.
	CAPEX, MM$	8	14	38	58	In case of it is needed, it is considered a cost of 50M$ per 136,000 m3 (2.9 bcf) LNG tank storage and then scale with 0.7 factor to determine the cost of other capacities.
	OPEX, MM$/yr	0	0	0	0	Input assumption
	Efficiency, %	100%	100%	100%	100%	Input assumption
Convert to Sales State (Re-gasification)	Send out capacity, MMCFD	44	110	440	440	Product of "Net MMSCFD liquefacted" by all efficiencies in the LNG chain to this point divided by 1000.
	CAPEX, MM$	42	79	208	208	It is considered a cost of 120M$ per 200MMSCD sendout capacity and then scale with 0.7 factor to determine the cost of other capacities.
	OPEX, MM$/yr	2	4	10	10	It is assumed 5% of CAPEX annual.
	Efficiency, %	98%	98%	98%	98%	Input assumption
Gas Storage (Salt Cavern)	Gas storage capacity, bcf	0.4	1	3	3	Input assumption
	Days of gas storage	9	9	7	7	"Gas storage capacity, bcf" divided by "Send out capacity, bcfd".
	CAPEX, MM$	6	11	23	23	In case it is needed, it is considered a cost of 60MM$ per 12 bcf storage cavern and then scale with 0.7 factor to determine the cost of other capacities.
	OPEX, MM$/yr	0	0	0	0	Included in Re-gasification cost
	Efficiency, %	100%	100%	100%	100%	Input assumption

Total CAPEX, MM$	**313**	**544**	**1,340**	**1,678**
Total OPEX, MM$/yr	**12**	**22**	**59**	**74**
Overall Efficiency, %	**86%**	**86%**	**86%**	**86%**
Amortization per year (13% pre-tax IRR, 20 years)	**56**	**100**	**249**	**313**
Cost of service, $/MSCF	**3.1**	**2.2**	**1.4**	**1.7**

Appendix C – CNG Workshop Results

Figure 1 CNG Scenarios



● FPSO Oil & Gas Development

- Oil transported by shuttle tanker
- Associated gas transported by CNG carrier

■ CNG Destinations

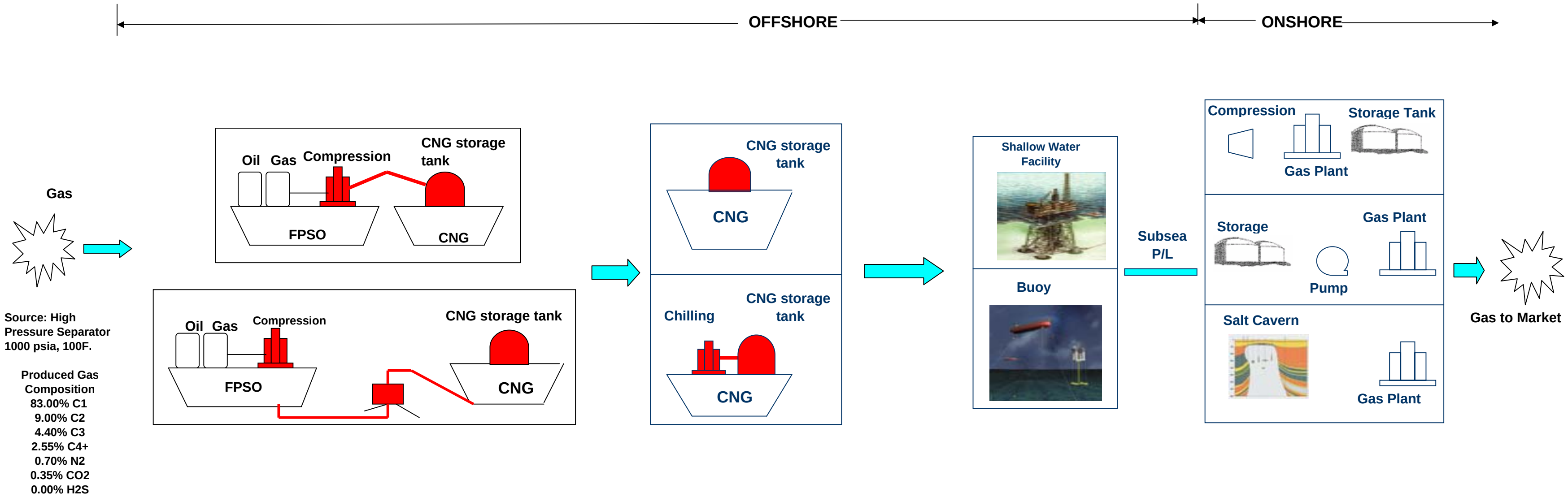
- New build facilities offloading/storage facility in:
- Offshore Grand Isle or Freeport

Scenario Parameters

Depth (ft)	Gas Rate (MMSCF)	Transport Distance (mi)
6,000	125	150-300
	500	
10,000	125	150-300
	500	

Figure 2. PROCESS STEPS & METRICS - CNG

The CNG option has been divided into the following steps as illustrated in the various cases shown below.



Metric	Dehydration and treating	Convert to transport state (Compression & Chilling)	Load	Transportation	Unload	Convert to sales state (Re-compression and Processing)	Gas Storage (*)
Technical and Regulatory Readiness							
HSE Risks							
Costs							
Efficiency							

*** If Applicable**

Table 1. Key Challenges for Technical and Regulatory Readiness - CNG

Instructions:

Describe Key Challenges to Technical and Regulatory Readiness in the following Table 1. Readiness is defined as when the technology will be "project ready." Technical Readiness can be assessed by examining the present stage of development of the technology (e.g., concept, bench test, pilot test, field test, or tests or experience with similar applications of key components) and the barriers that must be overcome to achieve Technical Readiness. Regulatory Readiness refers to the acceptance/approval of the technology by regulatory agencies(MMS, USCG, EPA, others) through the DWOP and other processes.

Some potential Challenges to Technical Readiness are listed. Please consider these Challenges as well other technical and regulatory challenges that you see as present barriers for the all the Cases. Please, indicate whether the challenge is technical or regulatory issue or both. Also, indicate the years to resolution at water depth of 6000 ft. and 10000 ft. in ranges as follows:

Years	Readiness
0	"ready now"
1 - 3	"ready in 1 to 3 years from now"
3 - 7	"ready in 3 to 7 years from now"
7 - 10	"ready in 7 to 10 years from now"
> 10	"ready in more than 10 years from now"

Challenges		Indicate T for Technical and/or R for Regulatory	Years to Resolution	Comments
No.	**Description**			
1	C3+ recovery and handling	T	0	Have to deal with the liquids; project and technology specific problem. Not a technical barrier. NGL separation and storage on board FPSO may add to risks. (Potentially more of an issue for LNG)
2	CO2 Removal and H2S (Acid Gas Removal)	T,R	0	Need to keep the gas dry if CO2 is high. H2S has to be a pipeline spec. Hydrate formation is a possibility. Every technology requires that H2S be removed. Inspection requirments derived for IGC code for metallic containment systems. Container has to be designed to handle H2S. H2S has to be taken out either on shore or offshore.
3	Removal of hydrate and/or wax within the storage units during loading, transportation, and offloading	T	0	Wax is not an issue. Hydrates are the issue. Removal of water to below hydrate level is required. Mitigate hydrates with glycol / methanol.
4	Fatigue loading on storage "pipe" and support steelwork due to repeated pressurization and temperature changes	T, R	0	Local design issue. Fatigue testing is being performed for all technologies. Class Rules (under development) are considering continuous monitoring for fatigue. Other fatigue issues associated with vessel motions.

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Challenges		Indicate T for Technical and/or R for Regulatory	Years to Resolution	Comments
No.	**Description**			
5	Strength of pressure vessels to damage caused by ship impact amidships	R	0	Not an issue. Rules are in place to address side impact. Impacts associated with CNG collisions may not be that much different from collisions associated with Oil tankers or LNG ships. Leak sources within hold are minimized by eliminating all mechanical joints inside containment hold. Strength of pressure vessels: variances between piping code and pressure vessel code and limit state approaches exist. Wing tanks are significantly wider than traditional double hulled vessels, resulting in greater impact resistance to collisions. CNG tankage are more robust than existing ship tankage. Security Vulnerablility Assesment will be required for ports (i.e. CNG terminal) and vessels.
6	Liquids formation during loading	T	0	Refer to item #1.
7	Slugging during unloading	T	0	Affects rate of unloading. When do you remove NGL's onshore or offshore. CNG is a "total system".

Table 1. Key Challenges for Technical and Regulatory Readiness - CNG

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Challenges		Indicate T for Technical and/or R for Regulatory	Years to Resolution	Comments
No.	Description			
8	Materials (Corrosion, stress corrosion cracking, crack propagation and failure)	R	1	High velocity gas. Aga study of cylinders showed no corrosion inside vessel after 15 yrs. Analogies in deepwater pipelines CNG handling will be more benign due to clean gas and ability to treat. Materials are a project specific issue. Test in progress to pre -qualify and pre-select materials. Leak before failure.....thought to be a design issue. Analytically sound, but needs testing to confirm design specifics response. Technology specific. Not thought to be a show stopper, but a design issue.
9	Contingencies in the event of delay of gas carrier, e.g. shut in, flaring	R	0	MMS currently allows 48 hours flaring without approval for small gas volumes under emergency conditons (loss of compressor). Perhaps can reduce production and thereby gas volumes to allow flaring until shuttle tanker arrives. Must also consider dry docking.
10	Relative motion during load/unload CNG	T	0	Technology options exist…. selection is project specific. Consideration needs to be given to the short life of associated gas production
11	Onshore gas storage requirements due to CNG carrier volume versus pipeline capacity	T	0	Not an issue.

Table 1. Key Challenges for Technical and Regulatory Readiness - CNG

Instructions:

Describe Key Challenges to Technical and Regulatory Readiness in the following Table 1. Readiness is defined as when the technology will be "project ready." Technical Readiness can be assessed by examining the present stage of development of the technology (e.g., concept, bench test, pilot test, field test, or tests or experience with similar applications of key components) and the barriers that must be overcome to achieve Technical Readiness. Regulatory Readiness refers to the acceptance/approval of the technology by regulatory agencies(MMS, USCG, EPA, others) through the DWOP and other processes.

Some potential Challenges to Technical Readiness are listed. Please consider these Challenges as well other technical and regulatory challenges that you see as present barriers for the all the Cases. Please, indicate whether the challenge is technical or regulatory issue or both. Also, indicate the years to resolution at water depth of 6000 ft. and 10000 ft. in ranges as follows:

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Challenges		Indicate T for Technical and/or R for Regulatory	Years to Resolution	Comments
No.	**Description**			
12	Gas leak detection and handling; flare or vent	R	0	Regulation not specific. Most contractors pursuing reduntant systems. Acceptance for a proposed project to be derived from risk assesments. (supplement available regulations with risk analysis).
13a	Class approval process	R	0	Class approval process exists and specific rules are being developed. Approval in Principle, plus follow on studies seems to be working.
13b	Port and flag State Approval	R	1-3	See number 15
14	Applicability of existing codes	R	1 - 3	ABS and DNV feel that rules are available to handle all components with exception of gas containment. (IGC rules were written for gas liquids). Safety factors vary with different code approaches (from 1.5 -4.0) however, many other considerations are more important than safety factor on burst. No overall rules exist for CNG offshore systems. Therefore, will have to work by equivalencies. All class approvals can be handled in normal project context.....no show stoppers. USCG will make own decision on assessment on containment systems ...will not rely on class.
15	Will a <u>new generic</u> EA or EIS for CNG carrier system for GOM be required?	R	1 - 3	Uncertain. An EA or an EIS will be required. Some indication that MMS may tier off of FPSO regulations in a EA process. Will be handled within the existing regulatory process.
16	Open access to CNG or LNG receiving terminals	R	0	FERC is considering managed access vs. open access for onshore receiving on case by case basis. Open access is not required if receiving station is offshore.
17	Permitting of an offshore receiving terminal	R	0	Regulatory framework is defined

Table 1. Key Challenges for Technical and Regulatory Readiness - CNG

Instructions:

Describe Key Challenges to Technical and Regulatory Readiness in the following Table 1. Readiness is defined as when the technology will be "project ready." Technical Readiness can be assessed by examining the present stage of development of the technology (e.g., concept, bench test, pilot test, field test, or tests or experience with similar applications of key components) and the barriers that must be overcome to achieve Technical Readiness. Regulatory Readiness refers to the acceptance/approval of the technology by regulatory agencies(MMS, USCG, EPA, others) through the DWOP and other processes.

Some potential Challenges to Technical Readiness are listed. Please consider these Challenges as well other technical and regulatory challenges that you see as present barriers for the all the Cases. Please, indicate whether the challenge is technical or regulatory issue or both. Also, indicate the years to resolution at water depth of 6000 ft. and 10000 ft. in ranges as follows:

Years	Readiness
0	"ready now"
1 - 3	"ready in 1 to 3 years from now"
3 - 7	"ready in 3 to 7 years from now"
7 - 10	"ready in 7 to 10 years from now"
> 10	"ready in more than 10 years from now"

Challenges		Indicate T for Technical and/or R for Regulatory	Years to Resolution	Comments
No.	**Description**			
18a	Availability of Jones Act CNG Ship	R	1 - 3	Economic issue. Korean Shipbuilders have discussed ship builidng techniques with U.S. shipyards and potentially lowered the cost premium for Jones Act ships which used to be between 2 and 3 times Korean ships. It will take significant time to construct a Jones Act ship, even when a specific project initiates.
18b	Availability of Jones Act CNG Slot Barge	R	1 - 3	Ships will not be cost competitive for capacities less than 100 MMSCF. Jones Act barges can be built in the U.S. economically. Not a manning advantage and there may have been some operability issues.
19	Simulatenous Oil & Gas Offloading	R	0	SIMOPS not seen as a technical issue or a regulatory issue. Marine traffic is an issue that needs to be considered for safety and operational planning, ie a congested port.
20	Inspectibility	R	1 - 3	Will non-visual inspection of containment systems be accepted?

Table 2. Risk Matrix

Severity	Consequence			Likelihood				
				A	B	C	D	E
	Safety	Environment	Facilities Operations	Several occurences possible during facility lifetime	Occurrence is considered likely: possible during 1 during facility life	Occurrence is considered unlikely: no more than 1 in 10 facility lives	Occurrence is considered highly unlikely: no more than 1 in 100 facility lives	Occurrence is considered practically impossible: no more than 1 in 1000 facility lives
I	Loss of majority of personnel on board	Long term environmental damage affecting extensive area and requiring extensive clean-up, discharge > 10,000 bbl	Extensive damage to facility and major business interuption, possible total loss of asset	9	8	7	5	5
II	Single or multiple fatalities	Severe environmental impact, extensive measures requried to restore contaminated environment, discharge > 1000 bbl	Partial loss of facility, operations halted for a month, estimated repairs les than $10,000,000	8	7	6	4	3
III	Permanent disability or significant irreversable health effects	Significant environmental impact, significant measures required to restore contaminated environment, discharge > 100 bbl	Operations temporarily halted, can possibly be re-started, estimated cost of repair less than $1,000,000	7	6	4	3	2
IV	Minor Injury, lost time incident, reversable health effects incurred	Contamination/discharge affecting immediate surrounding environment, minor response required to restore contaminated area, discharge > 10 bbl	Possible short disruption of operations, cost of repair less than $100,000	5	4	3	2	1

Note that risks to the facilities are not considered in the scope of the study.

TABLE 3. HAZARDS AND CONSEQUENCES - CNG

In this assessment, Risks are determined by Hazards and their resulting Consequences. Key Hazards and their potential Consequences are shown in Table 3 below for each Process Step.

HSE Risks being considered in this assessment include Human Safety and the Environment.

Human Safety Risk is measured as the number of fatalities during a 20 year operational period. Hazards and Consequences that can result in fatalities include CNG or gas releases that could result in fire and/or explosion.

Environmental Risk is measured as the total volume of oil spilled during a 20 year period. Hazards and Consequences that can result in oil spill include CNG or Gas releases that could result in fire and/or explosion leading to a loss of integrity in the oil containment system. It is assumed that if CNG or Gas release (spills) does not lead to a fire and/or explosion, it will disperse and cause no damage to the environment and thus result in no HSE Risk. Spills of the CNG carriers bunker are excluded from this study, but are shown shaded in the table below.

Mitigation options for the various risks are shown. The severity and likelihood indices from Table 2 (Risk Matrix) are shown with the resultant Risk index.

Note that damage or loss of facilities is not being considered as as Risk in this assessment.

Process Steps	Hazard	Potential Consequences Safety (Fatalities)	Potential Environment (Oil and other liquid - bunker, diesel, displacing fluid spill)	Mitigation Options	Severity	Likelihood	Risk	Controlling Consequence Safety/Environment	Comments
Dehydration and treating	External leaks/failures, potential additional increase in explosion hazards due to equipment density	Fire/explosion leading to fatalities. Exposure of all POB FPSO or CNG facilities.	Fire/explosion leading to a direct breech of oil system containment.	1. Proper layout assessment and design. 2. Limit the need for treating on FPSO.	III	D	3	S	1. Same as P/L risks. 2. These are essentially the same as presently carried out on platforms.
Convert to transport state (Compression)	External leaks/failures	Fire/explosion leading to fatalities. Exposure of all POB on FPSO.	Fire/explosion leading to a direct breech of oil system containment.	1. Proper layout assessment and design.	III	D	3	S	1. Same than P/L risks. 2. These are essentially the same as presently carried out on platforms. 3. Compression requirements vary with CNG concept 4. See Husky Project.
Load	Transport vessel collisions with FPSO	Fire/explosion leading to fatalities. Exposure of all POB FPSO and CNG carrier.	Fire/explosion leading to a direct breech of CNG carrier bunker/diesel containment. Larger oil spill from FPSO.	1. Use proven offshore rules, methods and procedures in the approach, hook-up and disconnect of offload buoy operations. Monitor relative position and speed during these operations. 2. Use of DP, thrusters, or support vessels. 3 Load remote from FPSO. 4. Allow for quick shut off of the gas supply. 5. ESD required both ship and facility side of loading system. 6. Watch circle communication plan.	IV	D	3	S	
Load	Transport vessel collisions / offloading buoys during connection and disconnection. Loss of position (e.g. DP driveoff)	Fire/explosion leading to fatalities. Exposure of all POB CNG carrier.			IV	E	1	S	

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Mitigation options for the various risks are shown. The severity and likelihood indices from Table 2 (Risk Matrix) are shown with the resultant Risk index.

Note that damage or loss of facilities is not being considered as as Risk in this assessment.

Process Steps	Hazard	Potential Consequences Safety (Fatalities)	Potential Environment (Oil and other liquid - bunker, diesel, displacing fluid spill)	Mitigation Options	Severity	Likelihood	Risk	Controlling Consequence Safety/Environment	Comments
Load	Leaks/structural failure of loading system, including buoy, buoy/ship interface.	Fire/explosion leading to fatalities. Exposure of all POB CNG carrier	Fire/explosion leading to a direct breech of CNG carrier bunker/diesel containment	1. Use dual (primary and secondary) sealing systems on all static and dynamic connections. Monitor all primary sealing systems for leaks. Also monitor all flow functions for abnormal conditions. Link all monitored functions to an ESD system. 2. Ensure the Emergency Release System (ERS) utilized considers an offshore environment. Ensure a regular ERS test program is in place. Have a system to ensure loading/unloading only take place within designed wave conditions. Transfer system equipped with quick disconnect isolation to limit release size. 3. Proper design, detailed operating procedures, inspection. 4. ESD required both ship and facility side of loading system	III	C	4	S	
Load	Other vessel collisions with CNG vessels (trading vessels, military vessels, cruise ships)	Fire/explosion leading to fatalities. Exposure of all POB on CNG carrier Direct deaths from collisions without fire	Fire/explosion leading to a direct breech of CNG carrier bunker/diesel containment	1. Wing tanks are significantly wider than traditional double hulled vessels, resulting in greater impact resistance to collisions. Leak sources within hold are minimized by eliminating all mechanical joints inside containment hold. CNG tankage are more robust than existing ship tankage. 2. Use dual (primary and secondary) sealing systems on all static and dynamic connections. Monitor all primary sealing systems for leaks. Also monitor all flow functions for abnormal conditions. Link all monitored functions to an ESD system. 3. Ensure the Emergency Release System (ERS) utilized considers an offshore environment. Ensure a regular ERS test program is in place. Have a system to ensure loading/unloading only take place within designed wave conditions.Transfer system equipped with quick disconnect isolation to limit release size. 4. Proper design, detailed operating procedures, inspection. 5. ESD required both ship and facility	IV	D	2	S	
Load	Fire aboard CNG carrier	Fire damage to CNG carrier, crew injury / fatality	Fire/explosion leading to a direct breech of CNG carrier bunker/diesel containment	1. Fire safety systems, HSE management, Initiate separation of vessels.	IV	D	2	S	CHECK WITH FPSO WITH EIS

TABLE 3. HAZARDS AND CONSEQUENCES - CNG

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Mitigation options for the various risks are shown. The severity and likelihood indices from Table 2 (Risk Matrix) are shown with the resultant Risk index.

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Process Steps	Hazard	Potential Consequences Safety (Fatalities)	Potential Environment (Oil and other liquid - bunker, diesel, displacing fluid spill)	Mitigation Options	Severity	Likelihood	Risk	Controlling Consequence Safety/Environment	Comments
Transportation	In-transit hazards of CNG carriers (no pump room hazards); external leaks, collision, structural failure, overpressurization, loss of propulsion, steering, foundering from CNG carrier.	Fire/explosion leading to fatalities. Exposure of all POB CNG carrier	Fire/explosion leading to a direct breech of CNG carrier bunker/deisel containment	1. Proper design a) Design according to Class rules, b) failure of a pressure vessel does not endanger the ship, its crew or the surrounding facilities. This requires a choked flow situation and sufficient hold venting to allow gas to be safely vented through the vent stack. It also requires that the vessel or a piece of the vessel cannot be accelerated to the extent that the hull could be breached or other pressure vessels damaged in the event of a failure), detailed operating procedures, inspection, gas monitoring, follow international regulations, traffic management schemes. 2. double hull	IV	E	1	S	
Unload	Transport vessel collisions with fixed offloading structures during connection and disconnection.	Fire/explosion leading to fatalities. Exposure of all POB CNG carrier and LNG storage/regasification/gas storage system	Fire/explosion leading to a direct breech of CNG carrier bunker/diesel containment	1. Use proven offshore rules, methods and procedures in the approach, hook-up and disconnect of vessel to vessel or vessel to tower operations. Monitor relative position and speed during these operations. 2. Offload remote from platform. 3. Allow for quick shut off of the gas supply. 4. ESD required both ship and facility side of loading system	IV	D	2	S	Exposure time is very small. Studies not done.
Unload	External leaks/structural failure of unloading system or CNG transfer lines	Fire/explosion leading to fatalities. Exposure of all POB CNG carrier.	Fire/explosion leading to a direct breech of CNG carrier bunker/diesel containment	1. Use dual (primary and secondary) sealing systems on all static and dynamic connections. Monitor all primary sealing systems for leaks. Also monitor all flow functions for abnormal conditions. Link all monitored functions to an ESD system. 2. Ensure the Emergency Release System (ERS) utilized considers an offshore environment. Ensure a regular ERS test program is in place. Have a system to ensure loading/unloading only take place within designed wave conditions. 3. Proper design, detailed operating procedures, inspection. 4. ESD required both ship and facility side of loading system	III	C	4	S	

TABLE 3. HAZARDS AND CONSEQUENCES - CNG

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Mitigation options for the various risks are shown. The severity and likelihood indices from Table 2 (Risk Matrix) are shown with the resultant Risk index.

Note that damage or loss of facilities is not being considered as as Risk in this assessment.

Process Steps	Hazard	Potential Consequences Safety (Fatalities)	Potential Environment (Oil and other liquid - bunker, diesel, displacing fluid spill)	Mitigation Options	Severity	Likelihood	Risk	Controlling Consequence Safety/Environment	Comments
Unload	High traffic density/congestion at near shore terminals	Collision of CNG transport vessel with other vessel / fixed objects	Fire/explosion leading to a direct breech of CNG carrier bunker/diesel containment	Vessel control and increased separation for CNG carriers? Exclusion zones analogous to LNG carriers, tug escorts, speed restrictions. (These vary depending on terminal and waterway rules).	IV	C	3	S	
Unload	High traffic density/congestion at offshore terminals	Collision of CNG transport vessel with other vessel / fixed objects	Fire/explosion leading to a direct breech of CNG carrier bunker/diesel containment	Vessel control and increased separation for CNG carriers? Exclusion zones analogous to LNG carriers, tug escorts, speed restrictions. (These vary depending on terminal and waterway rules).	IV	D	2	S	
Convert to sales state (Re-compression, pumping, and/or Processing)	External leaks/failures of re-compression and/or processing system	Fire/explosion leading to fatalities. Exposure of shore staff from re-compression and processing system	NA	Standard gas plant design and operating practices.	IV	D	2	S	Negligible (using existing onshore equipment.)
Gas Storage (Capacity Buffer)	External leaks/failures of gas storage facilities (vessels or caverns)	Fire/explosion leading to fatalities. Exposure of all shore staff at gas storage facility	NA	Standard gas plant design and operating practices.	IV	D	2	S	Negligible (using existing onshore equipment.)

TABLE 4. COSTS & EFFICIENCY - CNG

Estimate the ***incremental*** costs over and above the FPSO being installed to produce the oil for all the Cases in Table 4 below. The costs include the CAPEX and OPEX .

The CAPEX should include compression & chilling, load & unload, storage, re-compression & processing facilities, utilities, etc., as well as the incremental cost for additions to the FPSO (deck space, buoyancy) needed strictly for the CNG option.
The OPEX should include costs to operate and maintain the CNG chain for the 20-year operating period, and include labor cost and the value of utilities furnished by the FPSO.
Use P50 estimates. CAPEX in $million. OPEX in $million per year.

The overall Process Efficiency is defined as BTUs delivered to sales or transfer point divided by BTUs gas produced. The Process Step Efficiency is determined as:

Process Step Efficiency (%) = (Gas into step - Gas Consumed and lost in step) / Gas into step

Then, the overall Process Efficiency is estimated as the product of all Process Step Efficiencies.

		Cases					
	Depth, ft	6,000 - 10,000	6000 - 10000	6,000 - 10,000	6,000 - 10,000	6,000 - 10,000	
	Gas rate, MMSCFD	50	62.5	125	250	500	
	Distance statute, miles	150	150	150	150	150	
Floating Production System (FPSO)	**Additions to the FPSO (deck space, buoyancy) needed strictly for the CNG option**						
	CAPEX, MM$	0	0	0	0	0	It is not necessary additional modifications to the FPSO base case.
	OPEX, MM$/yr	0	0	0	0	0	No operating expense.
Dehydration and Treating	Dehydration cost, MM$	0	0	0	0	0	There is no incremental cost in relation to pipeline option.
	NGL removal cost, MM$	0	0	0	0	0	This cost is already considered on the FPSO base case.
	CAPEX, MM$	0	0	0	0	0	Sum of "Dehydration cost, MM$" and "NGL removal cost, MM$".
	OPEX, MM$/yr	0	0	0	0	0	It is assumed 10% of CAPEX annual
	Efficiency, %	100%	100%	100%	100%	100%	Input assumption.
Convert to transport state (Compression & Chilling)	Suction pressure, psi	1,000	1,000	1,000	1,000	1,000	Input assumption.
	Discharge pressure, psi	1,500	1,500	1,500	1,500	1,500	Input assumption.
	HP needed	1,650	2,063	4,125	8,250	16,500	Product of 22 HP by Compression Ratio ("Discharge pressure, psi" divided by " Suction pressure, psi") by "Gas Rate MMSCFD" by "Dehydration efficiency".
	Cost of compression ($/installed HP)	1,000	1,000	900	800	700	Input assumption.
	Compression costs, MM$	2	2	4	7	12	Product of "HP needed" by "Cost of compression ($/installed HP)" divided by 10^6.
	Inlet temperature, F	110	110	110	110	110	Input assumption.
	Storage temperature, F	(20)	(20)	(20)	(20)	(20)	Input assumption.
	HP needed	354	443	885	1,771	3,542	Product of 170 HP per MMBTU/hr by "Gas Rate, MMSCFD" by "Dehydration efficiency" divided by 24
	Cooling/Refrigeration costs, MM$	0	0	0	0	0	Included in Transportation Costs for Company A.
	CAPEX, MM$	2	2	4	7	12	Sum of "Compression costs, MM$" and "Refrigeration costs, MM$"
	OPEX, MM$/yr	0	0	0	1	1	It is assumed 10% of CAPEX annual
	Efficiency, %	98%	98%	98%	98%	98%	Input assumption.

TABLE 4. COSTS & EFFICIENCY - CNG

Estimate the ***incremental*** costs over and above the FPSO being installed to produce the oil for all the Cases in Table 4 below. The costs include the CAPEX and OPEX .

The CAPEX should include compression & chilling, load & unload, storage, re-compression & processing facilities, utilities, etc., as well as the incremental cost for additions to the FPSO (deck space, buoyancy) needed strictly for the CNG option.
The OPEX should include costs to operate and maintain the CNG chain for the 20-year operating period, and include labor cost and the value of utilities furnished by the FPSO.
Use P50 estimates. CAPEX in $million. OPEX in $million per year.

The overall Process Efficiency is defined as BTUs delivered to sales or transfer point divided by BTUs gas produced. The Process Step Efficiency is determined as:

Process Step Efficiency (%) = (Gas into step - Gas Consumed and lost in step) / Gas into step

Then, the overall Process Efficiency is estimated as the product of all Process Step Efficiencies.

		Cases					
	Depth, ft	6,000 - 10,000	6000 - 10000	6,000 - 10,000	6,000 - 10,000	6,000 - 10,000	
	Gas rate, MMSCFD	50	62.5	125	250	500	
	Distance statute, miles	150	150	150	150	150	
Load	Type of unloading system	Turret	Turret	Turret	Turret	Turret	Input assumption.
	CAPEX, MM$	40	40	40	40	40	It represents the cost of the two turrets.
	OPEX, MM$/yr	0	0	0	0	0	Input assumption.
	Efficiency, %	100%	100%	100%	100%	100%	Input assumption.
Transportation	Type of vessel	Barge	Barge	Ship	Ship	Ship	Input assumption.
	Carrier speed, knots	10	10	15	15	18	Input assumption.
	Number of carriers needed	3	3	3	3	3	Input value for Company A. It assures continous loading and unloading.
	MMSCF transported per ship	70	90	150	300	700	Input value for Company A. It gives 94% availability service.
	Cost of each carrier, MM$	60	80	140	270	420	Input assumption. In case of the barge, it inlcudes the cost of the towboats.
	CAPEX, MM$	180	240	420	810	1,260	Product of "Number of carriers needed" multiply by "Cost of each carrier, MM$".
	OPEX, MM$/yr	14	15	17	20	25	Input assumption. The cost of the diesel used as fuel it is considered as OPEX. No gas is used as fuel.
	Efficiency, %	100%	100%	100%	100%	100%	Input assumption.
Unload	Type of unloading system	Turret	Turret	Turret	Turret	Turret	Input assumption.
	Unloading system cost, MM$	25	25	25	25	25	It represents the cost of one turret.
	Diameter of subsea pipeline, inch	8	8	12	16	24	Input assumption.
	Length of subsea pipeline, miles	2	2	2	2	2	Input assumption.
	Cost $ per inch per mile	60,000	60,000	60,000	60,000	60,000	Input assumption.
	Subsea pipeline cost	1	1	1	2	3	Product of "Cost $ per inch per mile" by "Diameter of subsea pipeline, inch" and "Length of subsea pipeline, miles" divided by 10^6.
	CAPEX, MM$	26	26	26	27	28	Sum of "Unloading system cost, MM$" and "Subsea pipeline cost, MM$".
	OPEX, MM$/yr	0	0	0	0	0	Input assumption.
	Efficiency, %	100%	100%	100%	100%	100%	Input assumption.

TABLE 4. COSTS & EFFICIENCY - CNG

Estimate the ***incremental*** costs over and above the FPSO being installed to produce the oil for all the Cases in Table 4 below. The costs include the CAPEX and OPEX .

The CAPEX should include compression & chilling, load & unload, storage, re-compression & processing facilities, utilities, etc., as well as the incremental cost for additions to the FPSO (deck space, buoyancy) needed strictly for the CNG option.
The OPEX should include costs to operate and maintain the CNG chain for the 20-year operating period, and include labor cost and the value of utilities furnished by the FPSO.
Use P50 estimates. CAPEX in $million. OPEX in $million per year.

The overall Process Efficiency is defined as BTUs delivered to sales or transfer point divided by BTUs gas produced. The Process Step Efficiency is determined as:

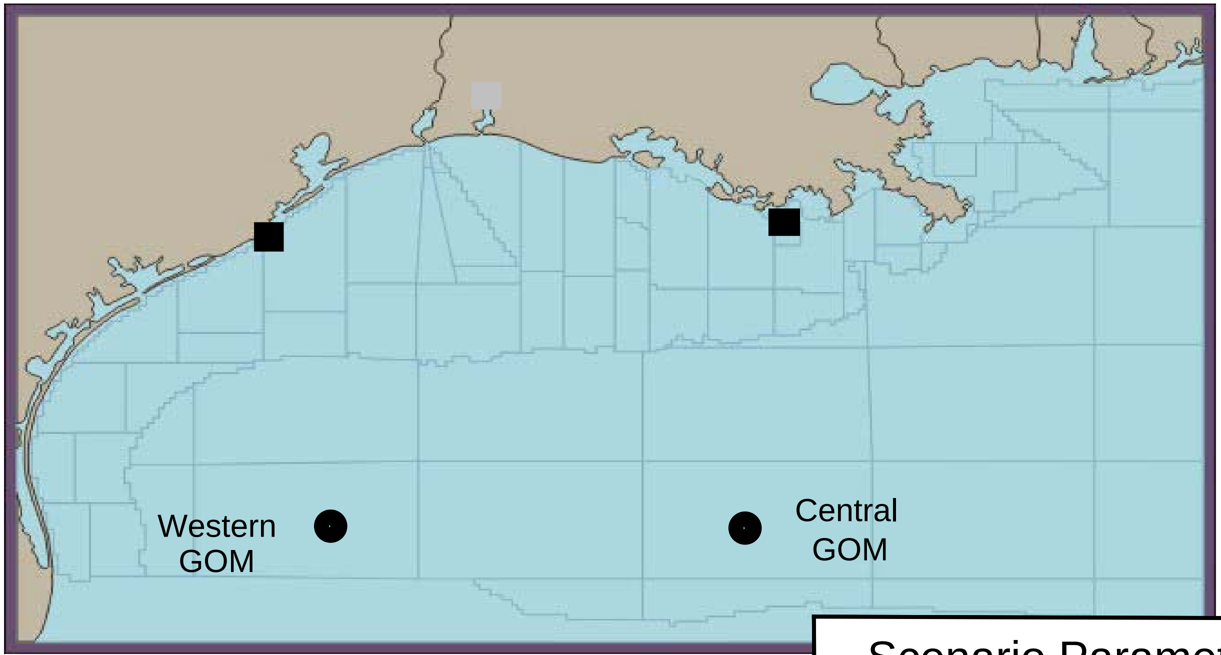
Process Step Efficiency (%) = (Gas into step - Gas Consumed and lost in step) / Gas into step

Then, the overall Process Efficiency is estimated as the product of all Process Step Efficiencies.

		Cases					
	Depth, ft	6,000 - 10,000	6000 - 10000	6,000 - 10,000	6,000 - 10,000	6,000 - 10,000	
	Gas rate, MMSCFD	50	62.5	125	250	500	
	Distance statute, miles	150	150	150	150	150	
Convert to sales state (Re-compression, pumping, processing)	Compression costs, MM$	0	0	0	0	0	Included in transportation costs for Company A.
	Gpm delivered	1,180	1,475	2,949	5,898	11,796	Product of "Gas Rate MMSCFD" by all efficiencies up to this point divided by 379.49 SCF/mole by 16 mole weight divided by 9 lb/ft3 lean gas divided by 1440 conversion factor and multiplied by 7.4 lb/ft3 pumping liquid density.
	Pressure delivered, psi	1,800	1,800	1,800	1,800	1,800	Input assumption.
	HP needed	1,652	2,065	4,129	8,259	16,517	Input assumption. Assuming 75% pump efficiency.
	Pumping costs, MM$	0	0	0	0	0	Included in transportation costs for Company A.
	Processing costs, MM$	2	2	3	5	8	It is assumed 3MM$ per 125MMSCFD, then escalation factor of 0.7 for other facilities.
	CAPEX, MM$	2	2	3	5	8	Sum of "Compression costs, MM$" and "Pumping Costs", and "Processing costs, MM$".
	OPEX, MM$/yr	0	0	0	0	1	It is assumed 10% of CAPEX annual
	Efficiency, %	99%	99%	99%	99%	99%	Input assumption.
Gas Storage (If applicable)	CAPEX, MM$	0	0	0	0	0	Input assumption.
	OPEX, MM$/yr	0	0	0	0	0	Input assumption.
	Efficiency, %	100%	100%	100%	100%	100%	Input assumption.
	Total CAPEX, MM$	**249**	**310**	**493**	**888**	**1,347**	
	Total OPEX, MM$/yr	**14**	**15**	**18**	**21**	**27**	
	Overall Efficiency, %	**97%**	**97%**	**97%**	**97%**	**97%**	
	Amortization per year (13% pre-tax IRR, 20 years)	**50**	**60**	**88**	**148**	**219**	
	Cost of service, $/MSCF	**2.7**	**2.6**	**1.9**	**1.6**	**1.2**	

Appendix D – GTL Workshop Results

Figure 1. GTL Scenarios



● FPSO Oil & Gas Development

- Oil transported by shuttle tanker
- Associated gas transported by GTL carrier

■ GTL Destinations

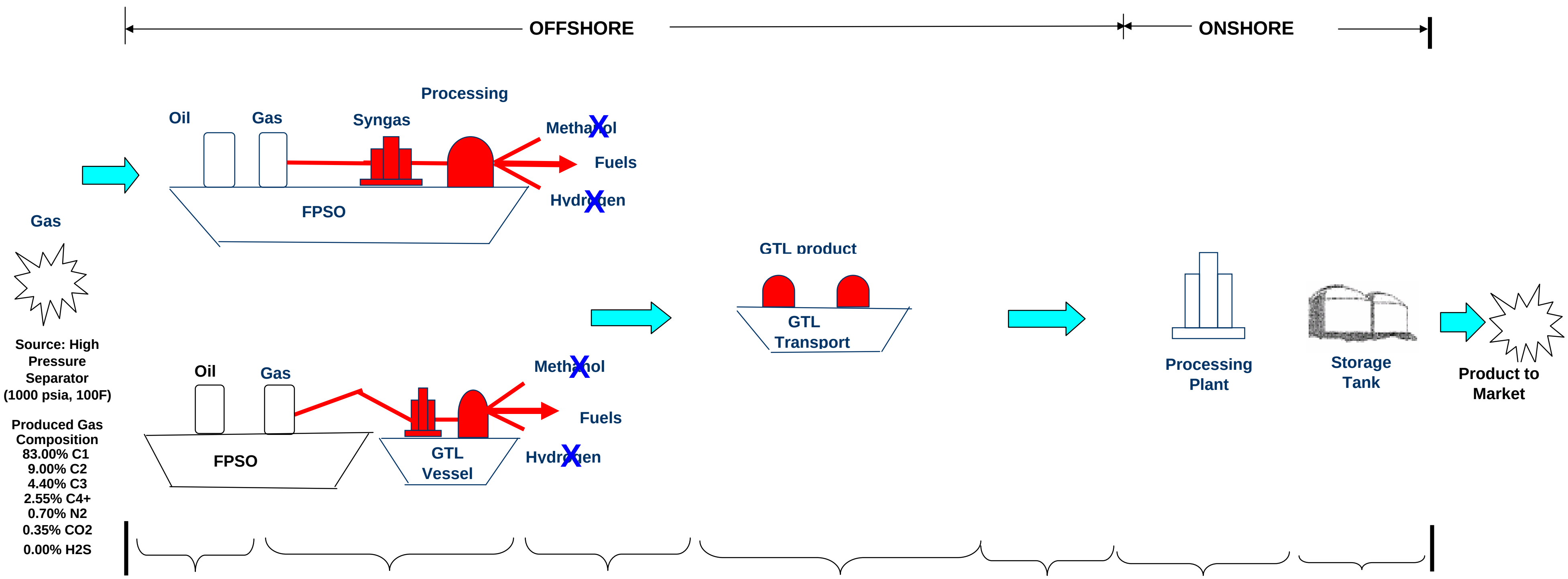
Refinary facilities near Houston/Galveston or New Orleans

Scenario Parameters

Depth (ft)	Gas Rate (MMSCF)	Transport Distance (mi)
6,000	50	300
	125	
	250	
10,000	50	300
	125	
	250	

Figure 2. PROCESS STEPS & METRICS - GTL

The GTL option has been divided into the following steps as illustrated in the various cases shown below.



Metric	Dehydration and treating	Convert to transport state (Chemical Conversion)	Load	Transportation	Unload	Convert to sales state (Processing)	Gas Storage (*)
Technical and Regulatory Readiness							
HSE Risks							
Costs							
Efficiency							

*** If Applicable**

Table 1. Key Challenges for Technical and Regulatory Readiness - GTL

Instructions:

Describe Key Challenges to Technical and Regulatory Readiness in the following Table 1. Readiness is defined as when the technology will be "project ready." Technical Readiness can be assessed by examining the present stage of development of the technology (e.g., concept, bench test, pilot test, field test, or tests or experience with similar applications of key components) and the barriers that must be overcome to achieve Technical Readiness. Regulatory Readiness refers to the acceptance/approval of the technology by regulatory agencies(MMS, USCG, EPA, others) through the DWOP and other processes.

Some potential Challenges to Technical Readiness are listed. Please consider these Challenges as well other technical and regulatory challenges that you see as present barriers for the all the Cases. Please, indicate whether the challenge is technical or regulatory issue or both. Also, indicate the years to resolution at water depth of 6000 ft. and 10000 ft. in ranges as follows:

Years	Readiness
0	"ready now"
1 - 3	"ready in 1 to 3 years from now"
3 - 7	"ready in 3 to 7 years from now"
7 - 10	"ready in 7 to 10 years from now"
> 10	"ready in more than 10 years from now"

Challenges		Indicate T for Technical and/or R for Regulatory	Years to Resolution	Comments
No.	**Description**			
1	C3+ recovery and handling	T	0	
	First application will likely require offshore demonstation plant	T	~5	Timing could be less than 5 yrs, depending on alternatives gas handling options, operator's perception of risk, and needs for specific projects. Methanol process may be considered to be smaller technical risk.
2	H2S and CO2 Removal	T	0	Same issues as other options.
3	Strength of GTL hull vessel to damage caused by ship impact amidships	R, T	0	Same as FPSO. Class rules exist.
	Turnaround maintenance - no.of manhours in offshore environment	T, R	0	Maintenance? Vs. Replacement? Manhour issue. Concern over time to change out catalysts. Approximately every 2-5 years. Involve about one hundred people. Mitigate somewhat by design and/or sparing philosophy.
	Inventory of Liquid Oxygen	T, R	1-3	Present additional hazards that must be addressed.
	Fatigue of high temperature high pressure vessels	T, R	1-3	

Table 1. Key Challenges for Technical and Regulatory Readiness - GTL

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Some potential Challenges to Technical Readiness are listed. Please consider these Challenges as well other technical and regulatory challenges that you see as present barriers for the all the Cases. Please, indicate whether the challenge is technical or regulatory issue or both. Also, indicate the years to resolution at water depth of 6000 ft, and 10000 ft in ranges as follows:

Years	Readiness
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Challenges		Indicate T for Technical and/or R for Regulatory	Years to Resolution	Comments
No.	**Description**			
4	Materials [Corrosion, stress corrosion cracking(SCC), thermal]	T,R	1	Thermal Issues The cooling down of HT equipment during unmanned conditions. The need to inspect and detect damage before startup. (More piping and vessels, less robust equipment (refractory materials) and insulation) Waste heat in boilers pose materials issues. Accomodate HPHT vessel and piping expansions(see also imact of vessel motion). Salt air issues HTHP vessels in salt air offshore air corrosion. The impact of salt air on furnace tubes. Internal & external SCC. If not properly controlled, aluminum can burn in oxygen-rich environments, e.g., ASU Hydrogen, CO and CO2 presence can cause dusting in process vessels and pipes. Presence of liquid oxygen needs to be considered; design to avoid cryogenic fluids from contacting mild steel. Many of these issues could be resolved by demonstration (offshore?) and design studies

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No.	**Description**			
5	**Contingencies in the event of delay of GTL carrier, e.g., shut in, flaring**			**Compared to other options, GTL can better tolerate carrier delays. Worst case, inject GTL in crude. Incremental storage. Temporary flare.Considered not to be an issue due to large storage available.**
	The impact of ship motions on HT piping			**Expansion fatigue issue on piping and on pipe supports. Incorporoate with fatigue above.**
6	**Impact of ship motion on GTL processing facilities**	**T, R**	**1-3**	**Slurry reactor perfomance affected by ship motions (not an issue for calm envvironments, may be GOM issue). Impact of ship motions on the hydrodynamics of slurry reactors needs to understood. Motion compensations systems on passenger ships maybe useful to stabilize ship for GTL processes. Refractory materials may be damaged due to ship motions. Refractory arch vulnerablity to motion/vibration.**
7	**Gas leak detection and handling; flare or vent**	**T, R**	**0**	**CO monitors needed. H2 monitors needed. Class societies will need to determine regulations that are applicable.**

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Challenges		Indicate T for Technical and/or R for Regulatory	Years to Resolution	Comments
No.	**Description**			
8	Risk of presence of hydrogen and oxygen and potential for leaks	R	0	Additional risks for hydrogen and oxygen need to be addressed. Blast protection to isolate oxygen areas from process equipment (Some applicable experience may exist, e.g., SEALAUNCH semi submursible to launch rockets that has hydrogen and oxygen onboard.)
	Layout Issues to arrive at appropriate separation of H2, O2, and process equipment and HTHP equipment.	T, R	0	Congestion needs to be considered when placing large amounts of GTL equipment on FPSO. Studies show feasibile layouts for 100 MM scf/day.
	Adequate training of offshore personnel for chemical processes & equipment	R	0	Training needs to recognize that operations different from standard offshore production systems.
9	Class approval process for GTL vessel hull	R	0	Existing rules should handle.
10	Applicability of existing codes for HPHT GTL equipment	R	0	ASME boiler code should handle.
11	Will a new generic EA or EIS for GTL system for GOM be required?	R	1-3	Would likely have to do an EA (one year) The use of large amounts of sea water for cooling and discharge of large amounts of synthesis water.
	Requirement for an NPDES permit	R	1-3	Could be a lengthy process if a permit is required. Risk perception by operator.

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Challenges		Indicate T for Technical and/or R for Regulatory	Years to Resolution	Comments
No.	**Description**			
12a	**Availability of Jones Act GTL Transport Vessels**	**R**	**0**	
12b	**Availability of Jones Act GTL ATB Barge**	**R**	**1-3**	**Regulatory issues need to be addressed. How will existing regulations be compared by the coast guard? USCG has not addressed manning and equipment issues for ATB's in offshore trade.**
13	**Simulatenous Oil & GTL liquid offloading form FPSO**	**R**	**0**	**No technical problem preceived. Could use single carrier with segregated tanks.**
	GTL plant operating factor(up-time) vs production up-time requirements and expectations			**GTL plant operatiing factors are estimated at 90-95%. Based on experience with other type facilities. Try to benchmark.** **Higher operating factors possible (more equipment redundacy, holding vessels, design)** **Emergency flaring allowed (48 hrs continuous, 144 hrs/month, can request more in emergency)**

Table 2. Risk Matrix

Severity	Consequence			Likelihood				
				A	B	C	D	E
	Safety	Environment	Facilities Operations	Several occurences possible during facility lifetime.	Occurrence is considered likely: possible during 1 during facility life	Occurrence is considered unlikely: no more than 1 in 10 facility lives	Occurrence is considered highly unlikely: no more than 1 in 100 facility lives	Occurrence is considered practically impossible: no more than 1 in 1000 facility lives
I	Loss of majority of personnel on board	Long term environmental damage affecting extensive area and requiring extensive clean-up, discharge > 10,000 bbl	Extensive damage to facility and major business interuption, possible total loss of asset	9	8	7	5	5
II	Single or multiple fatalities	Severe environmental impact, extensive measures requried to restore contaminated environment, discharge > 1000 bbl	Partial loss of facility, operations halted for a month, estimated repairs les than $10,000,000	8	7	6	4	3
III	Permanent disability or significant irreversable health effects	Significant environmental impact, significant measures required to restore contaminated environment, discharge > 100 bbl	Operations temporarily halted, can possibly be re-started, estimated cost of repair less than $1,000,000	7	6	4	3	2
IV	Minor Injury, lost time incident, reversable health effects incurred	Contamination/discharge affecting immediate surrounding environment, minor response required to restore contaminated area, discharge > 10 bbl	Possible short disruption of operations, cost of repair less than $100,000	5	4	3	2	1

Note that risks to the facilities are not considered in the scope of the study.

TABLE 3. Hazards & Consequences - GTL

Process Steps	Hazard	Potential Consequences		Mitigation Options	Severity	Likelihood	Risk	Controlling Consequence Safety or Environment	Comments
		Safety (Fatalities)	Environment (Oil, GTL product, bunker, diesel, chemicals)						
Dehydration and treating	External leaks/failures, potential additional increase in explosion hazards due to equipment density	Fire/explosion leading to fatalities. Exposure of all POB FPSO & GTL vessel (if present)	Fire/explosion leading to a direct breech of oil containment system		III	D	3		Similar to LNG and CNG ranking Same for treaters. No dehydration needed.
Convert to transport state (Syngas generation)	Presence of hydrogen and oxygen and potential for leaks. CO high temperatures, Refractory line vessels, pure oxygen environment. Oxygen generation plant. Mechanical integrity failures.	Fire/explosion leading to fatalities. Exposure of all POB on FPSO and GTL vessel (if present)	Fire/explosion leading to a direct breech of oil containment system	Avoid oxygen unit H2 and O2 CO leak detection Blow down system, water deluge system, limited personnel access, pressure relief of all syngas equipment, and separate release downsteam, flare during startup. Highest explosion risks should be separated from other high risk equipment and oil storage.	II	D	4		Inherent hazard for Syngas is lower than for CNG
Convert to transport state (Syngas conversion)	Presence of hydrogen and oxygen and potential for leaks. Cryogenic liquid spills. HT/HP gas. Oxygen Production & Storage.	Fire/explosion leading to fatalities. Exposure of all POB on FPSO and GTL vessel (if present)	Fire/explosion leading to a direct breech of oil containment system		III	D	3		
Convert to transport state (Product upgrade)	Presence of hydrogen and oxygen and potential for leaks. Cryogenic liquid spills. HT/HP gas. Oxygen Production & Storage.	Fire/explosion leading to fatalities. Exposure of all POB on FPSO and GTL vessel (if present) SIMOP associated with turnaround/maintenance work on multiple decks.	Fire/explosion leading to a direct breech of oil containment system		III	D	3		Methanol distillation is lower risk.
Load	GTL carrier collision with FPSO. Collision by other non-related vessel, act of terrorism, fire.	Fire/explosion leading to fatalities. Exposure of all POB FPSO and GTL carrier	Fire/explosion leading to a direct breech of GTL carrier bunker/diesel containment. Larger oil spill from FPSO.				2		Same as oil shuttle tanker
Transportation	In-transit GTL carrier hazards (external leaks; fire; structural failure; loss of propulsion, steering, floundering). Collision with non related vessel. Act of terrorism.	Fire/explosion leading to fatalities. Exposure of all POB GTL carrier	Fire/explosion leading to a direct breech of GTL carrier bunker/diesel containment				1		Same as oil shuttle tanker
Unload	GTL carrier collision with fixed offloading structures during docking Collision by other non-related vessel Act of terrorism	Fire/explosion leading to fatalities. Exposure of all POB GTL carrier and GTL receiving terminal	Fire/explosion leading to a direct breech of GTL carrier bunker/diesel containment				2		Same as oil shuttle tanker
Convert to sales state (Processing)	External leaks/failures of processing system	Fire/explosion leading to fatalities. Exposure of shore staff at processing facility	NA		IV	D	2		
GTL Storage (Capacity Buffer)	External leaks/failures of GTL storage facilities	Fire/explosion leading to fatalities. Exposure of all shore staff at GTL storage facility	NA		IV	D	2		

TABLE 4. COSTS & EFFICIENCY - GTL

The ***incremental*** costs over and above the FPSO installed to produce the oil is estimated below. The costs include the CAPEX and OPEX .

The CAPEX includes gas conversion, load & unload, storage, processing facilities, utilities, etc., as well as the incremental cost for additions to the FPSO (deck space, buoyancy) needed strictly for the GTL option.
The OPEX includes costs to operate and maintain the GTL chain for the 20-year operating period, and include labor cost and the value of utilities furnished by the FPSO.

The overall Process Efficiency is defined as BTUs delivered to sales or transfer point divided by BTUs gas produced. The Process Step Efficiency is determined as:

Process Step Efficiency (%) = (Gas into step - Gas consumed and lost in step) / Gas into step

Overall Process Efficiency is estimated as the product of all Process Step Efficiencies.

Process Step		Cases				
	Depth, ft	**6,000 - 10,000**	**6,000 - 10,000**	**6,000 - 10,000**	**6,000 - 10,000**	
	Gas rate, MMSCFD	**50**	**125**	**250**	**500**	
	Distance statute, miles	**300**	**300**	**300**	**300**	
Floating Production System (FPSO)	**FPSO upgrade for GTL Conversion and/or Storage**					
	CAPEX, MM$	35	50	80	120	Input assumption
	OPEX, MM$/yr	0	0	0	0	Input assumption
Dehydration and Treating	CAPEX, MM$	0	0	0	0	Input assumption
	OPEX, MM$/yr	0	0	0	0	Input assumption
	Efficiency, %	100%	100%	100%	100%	Input assumption
Convert to Transport State (Chemical Conversion)	Yield, scf/bbl	10,000	10,000	10,000	10,000	Input assumption
	Daily liquid production, bbl/d	5,000	12,500	25,000	50,000	"Gas rate" times 10^6 divided by "yield"
	Cost per daily liquid production, $/bbl/d	70,000	48,000	37,000	28,000	Input assumption
	Process	Fix	Fix	Fix	Fix	Input assumption
	Catalyst	Cobalt	Cobalt	Cobalt	Cobalt	Input assumption
	CAPEX, MM$	350	600	925	1,400	It is assumed 530MM$ for 10,000 bpd liquids, then escalation factor of 0.6.
	Operating Cost, $/bbl	5	5	5	5	Input assumption
	OPEX, MM$/yr	9	23	46	91	"Cost per daily liquid production" times "operating cost" times 365 divided by 10^6.
	Efficiency, %	60%	60%	60%	60%	Input assumption
Load	CAPEX, MM$	5	5	5	5	Input assumption
	OPEX, MM$/yr	0	0	0	0	Input assumption
	Efficiency, %	100%	100%	100%	100%	Input assumption
Transportation	CAPEX, MM$	15	25	35	55	Input assumption
	Operating Cost Transportation, $/bbl	1.5	1.25	1	0.8	Input assumption
	OPEX, MM$/yr	3	6	9	15	"Cost per daily liquid production" times "operating cost transportation" times 365 divided by 10^6.
	Efficiency, %	100%	100%	100%	100%	Input assumption
Unload	CAPEX, MM$	5	5	5	5	Input assumption
	OPEX, MM$/yr	0	0	0	0	Input assumption
	Efficiency, %	100%	100%	100%	100%	Input assumption
Convert to Sales State (Processing)	CAPEX, MM$	25	25	25	25	Input assumption
	OPEX, MM$/yr	0	0	0	0	Input assumption
	Efficiency, %	100%	100%	100%	100%	Input assumption
Liquid Storage	CAPEX, MM$	0	0	0	0	Input assumption
	OPEX, MM$/yr	0	0	0	0	Input assumption
	Efficiency, %	100%	100%	100%	100%	Input assumption
	Total CAPEX, MM$	**435**	**710**	**1,075**	**1,610**	
	Total OPEX, MM$/yr	**12**	**29**	**55**	**106**	
	Overall Efficiency, %	**60%**	**60%**	**60%**	**60%**	
	Amortization per year (13% pre-tax IRR, 20 years)	**74**	**130**	**208**	**335**	
	Cost of service, $/MSCF	**4.0**	**2.8**	**2.3**	**1.8**	

Need for larger vessel due to GTL equipment. Included in 580 below. Increased from 125 DWT to 215 DWT

Producing FT fluids is 50-55%
Produciing Mehtanol is 65-74%

Thermal efficiency is not appropriate for GTL products

Should reflect up-time in comparison

There is no excess power generation.-GTL;s plants energy self-sufficient.

5% or 5$/barrel

20-30 for methanol upgrade and storage