A conceptual cost minimization model for estimating methane hydrate upstream activity in NEA for policy-making

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Abstract: - Methane hydrates are present in substantial quantities in Northeast Asia and have the potential to disrupt global energy markets once economical extraction methods are identified and developed. Any Northeast Asian country that is able to exploit its methane hydrate resources will potentially alter its need for hydrocarbon imports. This would greatly impact future energy trade relations between Northeast Asia and Organization of the Petroleum Exporting Countries participants and could result in a shift from a broader bilateral energy trade relationship into a narrow one. Demand would decrease and hydrocarbon price fluctuations would affect revenue streams as well as international trade partnerships. In this study, we attempt to present a conceptual operational research cost model for methane hydrate integration into the energy mix in the Northeast Asian countries. Our approach takes into account key parameters including the volume of estimated reserves to minimize the cost per unit of methane hydrate in upstream processes while considering natural gas accounting as a reference point, in a reservoir dynamics-based analysis under market constraints. Finally, we propose policy recommendation based on our analysis.

Key-Words: - Gas hydrates, North East Asia, Activity report, Trade partnerships, Price breakdown, Policy recommendations.

1 Introduction

The Northeast Asian (NEA) countries of China, Japan, Korea, and Taiwan rely on the Organization of the Petroleum Exporting Countries (OPEC) participants for hydrocarbon imports [1] - [3]. NEA countries are among the largest importers of energy resources, with main sources being coal, oil, and gas, with coal being the most dominant accounting for 68 percent of the total supply. In the NEA, Japan suffers from limited indigenous hydrocarbon production [4], with 45 percent dependence on oil for primary energy supply. In 2012, about 83 percent of Japan’s crude oil imports came from the Middle East. The main economic sectors that depend on oil are the transport and industrial sectors [5]. As for natural gas, demand is sharply rising is a result of many factors, including the Fukushima disaster that reduced nuclear power production [1]. In 2012, natural gas demand was 124 bcm, compared to 109 bcm in 2010 and 26 bcm in 1980 [2]. The primary energy demand profile is such that the transformation/energy sector is the major consumer at 64 percent, followed by the commercial sector at 16 percent, and then the residential sector at 9 percent [6], [7]. China hydrocarbon resources are comprised of both oil and natural gas, but as a result of its economic and population growth, its demand for energy has significantly exceeded local production [8], [9]. Therefore, to meet this demand deficit, in 2012, China imported 5.4 mb/d of crude oil, which marked 55 percent of its demand and accounted for 50 percent of its crude oil import, from GCC countries such as Saudi Arabia and Oman. In the same year, China imported most of it natural gas (20 bcm), mainly from Turkmenistan, with the figure expected to rise to 122 bcm by 2018. Subsequently, a third of its LNG imports (20 bcm) came from Qatar. In 2012, Korea imported 3.3 mb/d of oil (accounting to 99 percent of its total oil demand) which consisted of 2.5 mb/d of crude oil and 0.8 mb/d of refined products. Oil in Korea accounts for 36 percent of the total primary energy supply. Furthermore, in 2011, Korea imported 46.8 bcm of LNG. [3] - [10]

Methane hydrates are present in substantial quantities, in excess of 12 tcm in the NEA region [2], [11]. The potential emergence of methane hydrates in the NEA, given its probable impact on NEA gas imports as well as the interplay of this discovery in international gas markets, is alarming to OPEC participants [10] - [12]. The US shale gas revolution and growing US energy independence illustrates how important the development of indigenous energy resources can be for a single nation and how disruptive such developments can be for global energy trading partners [13]. Methane hydrates are an emergent unconventional resource with the potential to disturb international energy market dynamics. They have the potential to disrupt global energy markets once economical extraction methods are identified and developed. Any NEA country that is able to overcome the challenges associated with capturing and exploiting its methane hydrate resources will have access to a natural gas resource that can have a substantial effect on hydrocarbon imports.

In this work, we provide operational excellence research model for efficient and timely extraction to production of methane hydrate for integration; along the entire energy value chain; into the NEA energy mix. In this work, we attempt to answer the pressing argument regarding the per unit cost of methane hydrate and how that would impact its integration into the energy dynamics of the key energy players in the NEA. This study consists of using a reservoir-dynamics based analysis of using a single well with a single outlet to model the complete reserve pool per country in the NEA. Finally, we use our findings as basis of a regional policy making.

2 Scientific Background on Methane Hydrate

2.1 What is Methane Hydrate?

A clathrate is a chemical compound in which molecules of a particular material (the 'host') form a solid lattice that encloses molecules of another material (the 'guest') under conditions of high pressure and low temperature. Methane hydrate is a naturally-occurring clathrate in which a host lattice of water ice encloses guest molecules of methane [14] - [16]. In methane hydrate, the gas molecules are not chemically bound to the water molecules, but instead are trapped within their crystalline lattice [17]. The resulting substance looks remarkably like white ice [18]. When methane hydrates are exposed to pressure and temperature conditions outside its stable state or 'melted', the solid crystalline lattice turns to liquid water and the enclosed methane molecules are released as gas [19] - [22]. This dissociation can be demonstrated by striking a match next to a piece of methane hydrate; the heat from the match will cause the hydrate to dissociate and the methane molecules will be ignited as they are released, giving the impression of burning ice [22] - [25].

Methane hydrates exist at different depths (reservoirs). Artic and marine sands contain shallow reserves close to the surface, with a higher reservoir quality and estimated percentage of recoverable resource. Current infrastructure can be used for their extraction. Fracture muds, mounds, and undeformed muds are deep reserves with high reserve volume, but extraction is costly. Extraction difficulty is directly proportional to the depth of the reservoir and the deposit volume [22]. However, current oil and gas drilling and mining technologies can be used for extraction, including enhanced oil recovery methods [24] such as carbon dioxide (CO_2) or high pressure steam injection into the well to dissociate the solid. Drilling can be performed using conventional oil and gas methods [25] - [27].

2.2 Natural Gas from Methane Hydrate

Producing natural gas from methane hydrate requires finding economical methods to safely extract gas while minimizing environmental impacts and competing on a cost basis with conventional natural gas. Most natural gas production occurs from conventional gas accumulations by drilling a well into the reservoir rock, casing the well with piping, perforating the piping to allow the gas to flow into the wellbore, placing a string of tubing inside the casing and then extracting the gas up the piping, sometimes with the aid of a pumping system [26]. Production of methane from hydrate deposits in sandstone or sandy reservoirs is likely to be approached in a similar manner [8]. As pressure in the well bore is reduced, free water in the formation moves toward the well, causing a region of reduced pressure, forcing the hydrate to dissociate and release methane [26]. The change in enthalpy (sum of internal energy and a product of pressure and volume) forces the dissociation of hydrate into methane and water. The molecular volume of methane extracted per dissociation chemical reaction depends on the hydrate density within a particular type of hydrate reserve and the reservoir temperature and pressure [27] - [29].

A complication is that hydrate dissociation is endothermic (heat consuming), which results in cooling and potential re-freezing. Therefore, depressurization and, in some cases, local heating are incorporated into production [28]. Methane hydrate wells are more complicated than most gas wells due to technical challenges, such as maintaining commercial gas flow rates with high water production rates, operating at low temperatures and low pressures in the wellbore, controlling formation sand production into the wellbore, and ensuring the structural integrity of the well [14]. Technologies exist to address these issues, but implementation would add to the costs of producing natural gas from hydrate [19], [20]. Production of natural gas from methane hydrate has potential environmental impacts and safety concerns, such as minimizing the release of methane to the atmosphere, as methane has a climate forcing potential 30 times greater than CO_2 [25].

2.3 Potential of Methane Hydrate Capacity in NEA

Countries such as the United States, Japan, China, India, Canada, South Korea, and Russia are in stages of exploring and developing methane hydrates [29]. Global deposits are estimated to be in excess of 187 tcm [10]. For the top players in the NEA region, Japan is in the most advanced stage of exploration. Conservative estimates put the country's gas hydrate reserves at 6 tcm, enough to meet its current natural gas needs for more than 80 years [2] - [6]. Similarly, China consumed 147 bcm of natural gas, 45.8 percent of its total energy use. A conservative estimate of China's hydrate reserves is a relatively modest 5 tcm, though smaller neighbors in East Asia hold another 10.5 tcm [5]. Korea consumed 51 bcm of natural gas in 2012 [3]. The country currently produces around 1 bcm of gas. Korea has confirmed hydrates in the Ulleung Basin, base of its modest traditional natural gas production which has been mapped already [2]. Table I shows the summary of crude oil, natural gas and the methane hydrate activity for the key players specifically in the NEA region. Fig. 1 shows timelines for methane hydrate activity by different countries in different reservoir types around the world [20]. The figure highlights that the first methane hydrate production is expected beyond 2020.

2.4 Price and Cost Evaluation of Methane Hydrates

Without data from a long-term production test, private sector partners are collaborating with government agencies to understand the economics of gas production from gas hydrate deposits. Studies by Howe [30] and Hancock et al. [31] are among the few economic analyses of methane hydrate production to have been completed. These studies use CMG-STARS (STARS) for reservoir simulation

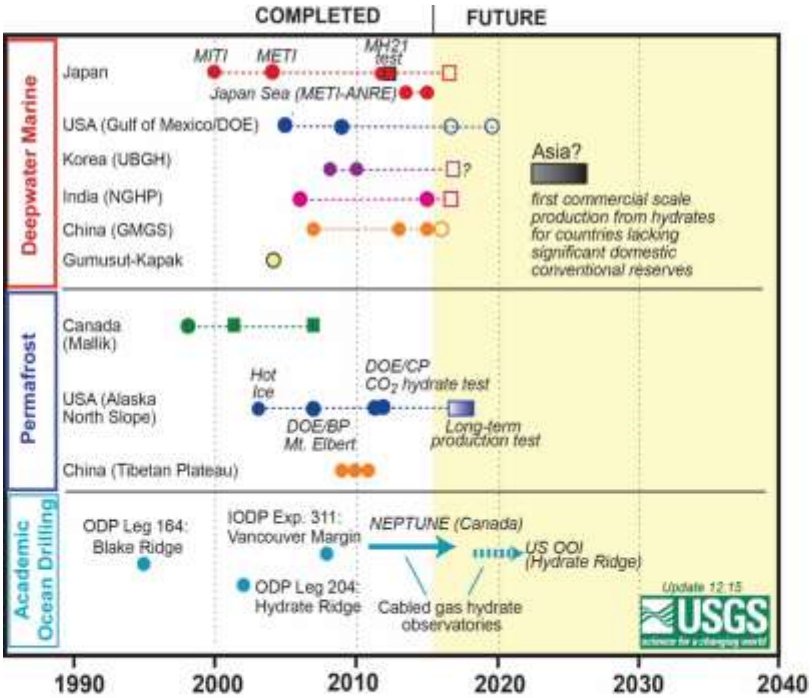

Fig. 1. Timeline chart showing the deep-water marine, Arctic permafrost and academic ocean scientific drilling expeditions dedicated to the research on naturally occurring methane hydrates by different countries around the world. Open symbols are planned/possible programs, circles are primarily 'geologic' programs (characterization) and squares denote production tests. (from ref [20])

Crude Oil imports statistics of NEA countries, 2012						
Country	**Total imports [M barrel day^{-1}]**	**Market price for Brent crude [\$ barrel^{-1}]**	**% of total demand**	**% imported from OPEC**	**Major OPEC contributors to total imports**	**Sector breakdown by consumption**
China	5.5	45.58	55	50	Saudi Arabia (20%) Oman (7%)	Transport (45%) Others (%)
Japan	4.8	45.58	45	83	Saudi Arabia (33%) UAE (23%) Kuwait (8%) Qatar (6%)	Transport (38%) Industrial (30%) Others (%)
South Korea	3.3	45.58	99	87	Saudi Arabia (33%) Kuwait (14%) UAE (10%) Qatar (10%) Iraq (9%)	Industrial (57%) Transport (20%) Others (%)

Gas (natural, other gases and methane hydrate) imports statistics of NEA countries, 2012								
Country	**Gas consumed [BCM]**	**Market price for natural gas [\$ MMBtu^{-1}]**	**Local production [BCM]**	**Gas imports [BCM]**	**Major OPEC contributors to total import**	**Sector breakdown by consumption**	**MH reserves [TCM]**	**Current demand met by MH reserves [yrs]**
China	147	2.73	107	20	Turkmenistan (66%) Qatar (34%)	Energy (36%) Industrial (23%) Residential (23%) Others (%)	5	34
Japan	130	2.73	4.8	124	Qatar (17%) Australia (16%) Indonesia (10%) Russia (9%) Brunei (7%) UAE (7%) Oman (6%)	Transport (64%) Commercial (16%) Residential (9%) Others (%)	4.8	37
South Korea	51	2.73	1	50	Qatar (22%) Indonesia (21%) Oman (12%) Malaysia (11%) Russia (8%)	Power Generation (47%) Residential (23%) Industrial (18%) Transport (3%) Others (%)	Mapped region	-

Table 1. Crude oil and gas statistics for top players in the NEA in 2012. We show the total imports, the volumes imported from the OPEC participants and breakdown of total consumption sectors. *BCM/TCM is billion/trillion cubic meters, 1 billion cubic meters = 36 trillion Btus and market price is subject to daily stock market fluctuations. (from ref [2] - [14])

of permafrost-associated gas hydrate production and Que$tor, an Oil and gas capital and operational cost estimation software [32], for estimation of cost per million British thermal units (MMBtu). The reported cost was $6 per MMBtu for production from permafrost-associated gas hydrates overlying producible free gas. These estimates include pipeline tariffs, but not local taxes and tariffs [21]. To assess the production characteristics and economics of marine gas hydrates, Walsh et al. [33] used the TOUGH+HYDRATE reservoir simulation results published by Moridis and Reagan [34] - [40] and Que$tor for cost analyses comparing gas hydrate production to that from a conventional gas reservoir. The cost estimates included: pipeline, production facility, and subsea development for both conventional and gas hydrate production and the extra costs (e.g., additional wells, artificial lift to manage water production, etc.) associated with gas production from hydrates.

At a 50 percent confidence level, the additional cost associated with production from deep-water gas hydrates as compared to conventional gas deposits is $3.40 to $3.90 per MMBtu [22]. The International Energy Agency has estimated that methane hydrates will be produced by 2025 at a cost of $4.70 to $8.60 per MMBtu [15], [39], [41]. The breakdown of this range is not clearly defined and the evolution of the industry over time (as shown in Fig. 2) will dictate the eventual price per unit. At this point, it is too early to predict. Additionally, transportation issues will likely pose an even greater economic challenge for gas hydrates than for many conventional gas reservoirs or other forms of unconventional gas. The primary reason is geographic: many conventional and unconventional (e.g., shale, coalbed) deposits are closer to production and distribution infrastructure than the deep-water marine and permafrost areas where resource-grade gas hydrates are concentrated [42].

3 Conceptual Upstream Cost Minimization Model Under Constraints

The variations in per MMBtu price and cost of methane hydrate stems from the fact that large-scale productions have not commenced in any of the proven reserve sites globally to date. Although, several reservoir simulations have been conducted but the trade price remains uncertain. Therefore, in this study, we attempt to present an optimized operational cost model for methane hydrates in the North East Asian countries' reserves in a reservoir dynamics-based analysis under economic constraints along the finite planning time horizon of T years. In this paper, the optimization model presented is not aimed to find an exact production policy but to specify the cost factors that must be included in the objective function and the essential constraint conditions which must be included for overall decision making. It should be noted that in comparison to standard oil & gas production, methane hydrate suffers from major differences in practice [6], [7], [31], [37], [42]:

(1) Oil and natural gas simply flow out when a well is drilled, on the other hand, methane hydrate requires an extra step of dissociating in the layers, and this mechanism must be included in the development system.
(2) Oil and natural gas exists in the deep portion 2,000 to 4,000 meters beneath the ground or sea level. On the other hand, methane hydrate is at superficial portion of up to approximately 500 meters below the seafloor.
(3) Therefore, oil and natural gas exist in many cases in already consolidated layers, but many of the methane hydrate layers exist in unconsolidated layers. Unconsolidated layers can induce productivity reduction unique to these layers.
(4) When the depressurization method is employed

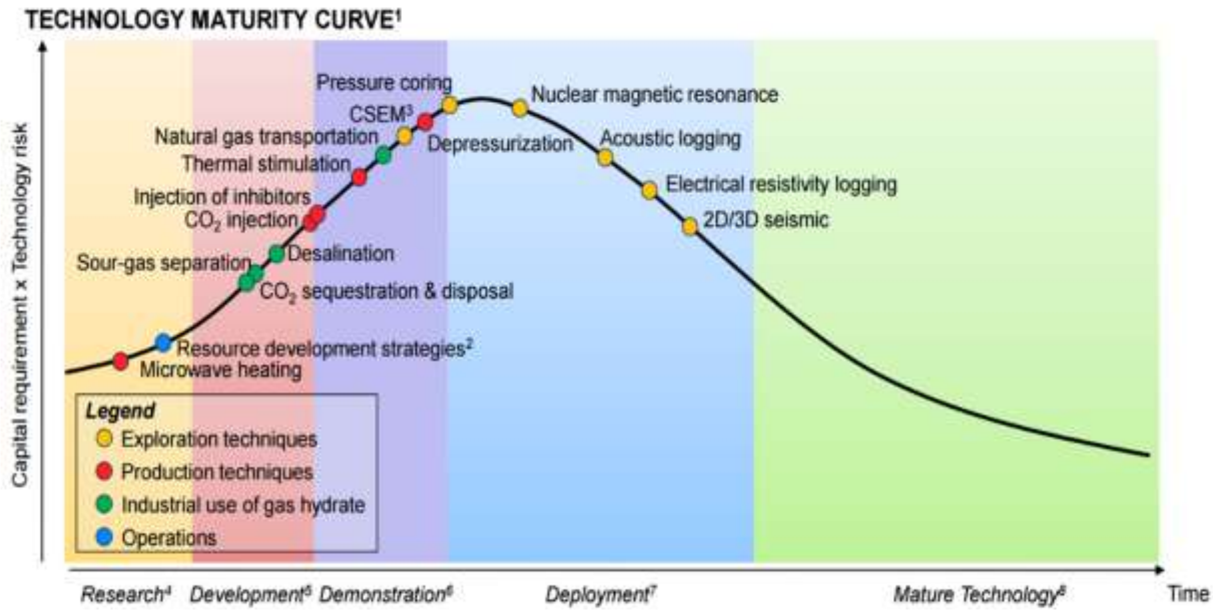

Fig. 2. Gas-hydrate technologies remain at an early stage of development, despite the maturity of many of the individual exploration technologies being used. While some technologies may be widely deployed in the conventional oil and gas industry, most are not mature in the context of gas hydrates. [1]The maturity curve is based on responses from gas-hydrates experts to the Gas Hydrate Survey, in October 2014. Results have been slightly adjusted in light of qualitative interviews conducted by the SBC Energy Institute and academic reviews. While some technologies may be widely deployed in the conventional oil and gas industry, most are not mature in the context of gas hydrates. For example, while core recovery is common practice in the oil and gas industry, coring technologies had to be adapted to enable gas-hydrate coring, and none of the pressure corers have yet reached a commercial scale; [2]Addressing issues relating to operations, e.g. number and type of wells, and size of drilling vessels; [3]Controlled-Source Electromagnetic Methods; [4]Lab work / theoretical research; [5]Bench-scale; [6]Pilot-scale; [7]Proved commercial-scale process, with optimization work in progress; [8]Commercialscale, widely deployed, with limited optimization potential. (from ref [41])

for production purposes, the daily production volume of methane gas will be one digit smaller than that of natural gas (100,000 m³ on an average) (even when the simple depressurization method is employed, the current estimated production volume is around 50,000 m³).

(5) Since the dissociation of methane hydrate is an endothermic reaction, continued production reduces the temperature of surrounding layers, leading to a decline in production volume.

Given that the upstream exploration study of methane hydrate reserve in the NEA region [2]; through various seismic studies to locate theoretical reserve capacities and coordinates (z), as shown in country-wise activity report of Fig. 1; have previously been incurred, therefore, we assume the cost affiliated to it as a known characteristic and a fixed cost variable [17]. The missing upstream cost elements are not clear and therefore, in this study, we consider operational research cost minimization mathematics where the production rate $v(t)$ at time t, is the most important control variable, and the policies, $x = \{x_1, \dots x_i, \dots\}$, are selected as decision variables to predict the total cost per MMBtu. Each x_i is the policy associated with the cost component, C_i. As an example, for transportation costs, corresponding policy is logistic strategies to transport productions from the well.

In natural gas extraction, the cost has a fixed and a variable component associated to it, consisting of equipment utilization capex cost (per reserve capacity), labor cost (per manpower hours), license cost (per unit square of drilling area), sunk cost (provision for non-collectability or bad debts), utility (fossil fuel, electricity, water, etc.), cost of rig (rental or purchase), depreciation, maintenance (per extraction rig work hours), administrative & overheads, etc. [12], [22], [35], [36]. Therefore, in this study on methane hydrates, we adopt similar strictures for cost calculations for overall process cost (C) minimization. The overall process costs is sum of the cost functions, C_i, $i = 1,..,5$, which are functions associated to a single reservoir and are time & per methane hydrate reserve activity dependent in the NEA region. These cost components are broken down below along with the variables they depend on and their respective mathematical formulations. Table 2 gives the detailed description, units and dependents for each of the variables.

(1) Selling, general and administrative expenses (C_1): selling, general and administrative expenses (SG&A) per well.

$$C_1(x_1, v) = \sum_{t=0}^{T} SG\&A\ (x_1(t), v(t), t) \tag{1}$$

Assuming that SG&A is directly correlated to selling, general and administrative policy, x_1, and volume, $v(t)$, at time t.

(2) Unproven asset cost (C_2): cost of acquiring unproved property (present value of asset) per well, where $DE\big(x_2(0)\big)$ is defined as direct expenses related to asset acquisition at time $t = 0$; $BP\big(x_2(0)\big)$ is one-time buying price of asset at time $t = 0$; $AM(x_2(t), t)$ is amortization at time t; $DR(x_2(t), t)$ is depreciation at time t; $IC(x_2(t), t)$ refers to impairment costs associated to asset at time t; and $Tax(x_2(t), t)$ denotes Taxes on asset at time t.

$$\begin{aligned} C_2(x_2) = \Big(DE\big(x_2(0)\big) + BP\big(x_2(0)\big)\Big) \\ - \sum_{t=0}^{t-1} [AM(x_2(t), t) + DR(x_2(t), t) \\ + IC(x_2(t), t) + Tax(x_2(t), t)] \end{aligned} \tag{2}$$

(3) Production costs (C_3): also known as lifting costs. These are the sum of costs, $R(x_3(t), v(t), t)$, incurred to operate & maintain wells and related equipment and facilities. Note that $R(x_3(0), v(0), 0) = 0$, because there is no production at the present time.

$$C_3(x_3, v) = \sum_{t=0}^{T} R(x_3(t), v(t), t) \tag{3}$$

(4) Development and Finding costs (C_4): sum of costs of acquiring, constructing, and installing production facilities and drilling development wells, $ED(x_4(t), v(t), t)$, costs of geological and geophysical work, $GG(x_4(t), v(t), t)$, licensing rounds, signature bonuses, costs of drilling exploration wells and proven/unproven property acquisition costs, $PA(x_4(t), v(t), t)$.

(4)

Cost condition	$\sum_{t}^{T} EC_{MH}(x(t), v(t), p(t), t) + PR_{MH}(x(t), v(t), p(t), t) \leq \sum_{t=0}^{T} EC_{NG}(v(t), p(t), t) + PR_{NG}(v(t), p(t), t), \forall t$	(7)
Trade price condition	$MP_{MH}(v(t), t) \leq MP_{NG}(v(t), t)\vert_{per\ MMBtu}, \forall t(\$2.73\ at\ t = 0\ from\ table\ 1)$	(8)
Market penetration condition	$DMD_{MH}(x(t), v(t), p(t), t) \geq DMD_{NG}(x(t), v(t), p(t), t)\vert_{per\ MMBtu}$	(9)
Supply condition	$SUP_{MH}(x(t), v(t), p(t), t) \geq DMD_{MH}(x(t), v(t), p(t), t)$	(10)
Breakeven condition	$EROI_{MH}(t) \geq 1$	(11)
Opportunity cost condition	$OPC_{NG}(x(t), v(t), p(t), t)\vert_{per\ MMBtu} \leq MP_{MH}(x(t), v(t), p(t), t)\vert_{per\ MMBtu}$	(12)
Reserve condition	$\sum_{t=0}^{T-1} v(t) < V\ (Estimated\ total\ reserved\ volume)$	(13)
***$p(t)$**, is market price		

Table 2. Shows the cost factors and constraint variables including parameters, description and units.

$$C_4(x_4, v) = \sum_{t=0}^{T} [ED(x_4(t), v(t), t) + GG(x_4(t), v(t), t) + PA(x_4(t), v(t), t)]$$

(5) Transportation costs (C_5): covers the cost of transporting product to market. Transportation costs, $TR(\cdot)$, is a function of logistic policy x_5 and production rate v.

$$C_5(x_5, v) = \sum_{t=0}^{T} TR(x_5(t), v(t), t) \tag{5}$$

Using the following assumptions, we model the total cost along the planning time horizon (C) using a single well operation:

(1) The reservoir behaves as a tank model with one centrally located production well.
(2) The reservoir behaves as a closed system with no-flow boundaries.
(3) The reservoir is considered as homogenous and isotropic.
(4) Instantaneous equilibrium in terms of pressure and temperature is achieved.

The objective function in equation 6 uses the per unit cost components (C_x, x = 1,..,5) in order to minimize the total cost over the volume provided. It is well known that per unit costs decreases with economies of scale hence the bigger the methane hydrate reserves, the lower the per unit cost. Our formulation accounts for the cost elements associated with a unit production volume and then we integrate over the entire production volume during the horizon.

$$\min_{x=\{x_1,\dots x_5\},v} \frac{\sum_{i=1}^{5} C_i(x_i, v)}{\sum_{t=0}^{T-1} v(t)} \tag{6}$$

The objective function is subject to a series of constraints, therefore, assuming natural gas extraction technology state as a reference and that it is at 100% confidence level, the following constraints limit our cost minimization model. The cost constraint in equation 7 signifies that the methane hydrates costs should be equal or below than that of natural gas. In equation 8, the market price of methane hydrate should equal or below than that to natural gas to make it consumer attractive as substitute to natural gas. Equation 9 gives the condition for the market penetration of methane hydrate where its demand is higher than natural gas. Similarly, the supply of methane hydrate should complement the demand as shown in equation 10. The breakeven investment should at least be unity for economic feasibility and viability of methane hydrate operations in equation 11. The opportunity cost of investing in natural gas should be lower than that of methane hydrate so that more investment in poured into its potential as reflected in equation 12. Finally, the reserve volume aggregate should be lower than the total reserve to ensure supply and future activity growth as shown in equation 13.

4 Conclusion and Policy Implications

Methane hydrate resources have the potential to be disruptive to the global energy system if developed to even a fraction of their full potential. NEA countries that are heavily reliant on imported fossil fuels, particularly LNG, to meet energy demand and that have significant methane hydrate reserves are likely to pursue aggressive development of these resources. Current barriers to fully developing NEA hydrate resources are certainly not insurmountable and the establishment of an indigenous energy resource that is compatible with current infrastructure is very attractive. Therefore, regardless of the future costs of LNG and coal imports and indigenous renewable energy production, domestically produced natural gas provides energy security in a reliable and low carbon format that is indeed compatible with current energy infrastructure. This paper has therefore addressed the possibility that NEA methane hydrate development could impact natural gas trade significantly in terms of a change in NEA demand volume. NEA methane hydrate development therefore has the potential to become a "black swan" event for OPEC countries. That is, an unprecedented and unexpected event in the future that ultimately will be viewed in retrospect as an event bound to happened based on the NEA context. For the OPEC participants, the lack of demand for conventional gas and downward pressure on its commodity prices would result in lower government revenues in the medium to long-term. Reduced government receipts would bring about reduced government spending and decrease economic growth below its present rate of four percent. Furthermore, slower economic growth in the market would result in decreased consumer spending and decreased investment that would negatively affect the gross domestic product of the OPEC region. Our conceptual model takes into accounts for cost minimization over the volume of reserves in a reservoir dynamics-based analysis under market constraints. Finally, we propose policy recommendation based on our analysis.

Gas hydrate large-scale production and integration into the NEA energy mix depends on a multitude of tangible and intangible factors including [9], [12], [31], [42]:

(1) Energy portfolio diversification.
(2) Desperation for cheaper alternatives.
(3) Price point matching to natural gas, coalbed, shale gas and any other alternatives.
(4) Proven reserves & capacities.
(5) Economic viability of extraction methods.
(6) Extraction technology evolution.
(7) Access to capital.
(8) Political will & regional harmony.
(9) International energy trade dynamics.

In this study, our focus centered on upstream operational cost of methane hydrate extraction as this very cost element has not been thoroughly understood due to lack of large-scale production of the resource to date. An in-depth theoretical economic assessment (without data availability) allows for a basis for policy-making which could potentially impact the trade dynamic and bi-lateral relations between the NEA countries and the OPEC participants, in years to follow. Therefore, based on our findings and the methane hydrate activity reports in NEA, the following key factors must be considered for regional economic prosperity, resource development and geopolitical harmony of all the stakeholder countries:

(1) Hydrates are largely offshore and often far from traditional gas sources, which will slow initial development, limit it to areas with government support, and create larger logistical hurdles than, for example, onshore shale gas production. On the other hand, once infrastructure is in place in these fields, operators should be able to ramp up production, with more predictable long-term production than shale gas enjoys.
(2) The technical hurdles are different and nontrivial for hydrates. The time that industry will need to overcome these hurdles is reflected in the timeline, which uses current projects and progress as a guide for how quickly individual countries will build production on a large scale. Once these technical barriers have been overcome, we expect hydrates to be a viable resource much in demand in the relevant markets, which are largely areas where traditional gas resources are limited.
(3) Early gas production from shale gas occurred at a time of high gas prices worldwide. Gas demand is still relatively high in Japan, which is driving continued activity on hydrates. There is currently little appetite for gas hydrate development in the Gulf of Mexico, though the Gulf does have excellent infrastructure and would be a better target than the undeveloped Japanese fields if the economic drivers were similar. An unexpected spike in local gas prices could drive faster growth in areas outside Asia.
(4) The NEA countries face a political dilemma. For example, Japan has a very high quantity of methane hydrate reserves in the Sea of Japan, which is a disputed territory among Japan, China, and South Korea, disrupting development of an alternative fuel resource. These issues restrict governmental policy

making, investment, and interest in this field of study. Only the development of indigenous energy resources, such as hydrates, will offer the energy security that all countries aspire to achieve.

(5) Japan is leading methane hydrate development in the region as its dependence on natural gas imports is unable to meet increasing demand. Whereas, China, the second largest coal reserve holder in the world, can afford to pace its activity at a much slower rate due to alternatives being present locally and in abundance. Korea is currently in the mapping phase and would follow Japan as a model example due to its soaring demand and high imports. Therefore, it is critical that a regional diplomatic action plan be formulated from "research to market of methane hydrates" with economic theory for long-term sustainability, resource sharing and meeting demand locally than via imports. The price and cost variations are a result of the "state of current technology" being used for extraction and the lack of large-scale production (economies of scale), therefore, an optimized model, would provide strategic directives of focus for cheaper methods and technical alternatives.

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