6. DISCUSSION, CONCLUSIONS, AND RECOMMENDATIONS

This section contains a discussion of the issues and the economic analysis performed in this study, the conclusions based on the analysis, and recommendations that interested industry, State of Alaska and federal parties may wish to pursue.

6.1 Discussion

Although there has been a high level of interest in developing a capability to bring the huge North Slope natural gas resource to market since the discovery of the giant Prudhoe Bay field, the urgency to develop the capability to sell the large, currently unmarketable, North Slope gas resources has increased in recent years as the steep decline in North Slope oil production has become more evident now that Prudhoe Bay has begun its inevitable decline. As described in **Section 2.2.1**, Prudhoe Bay and Point Thomson (a smaller, undeveloped gas/gas condensate field 50 miles east of Prudhoe Bay) contain about 25 TCF of the 26 TCF of the estimated saleable natural gas discovered on the North Slope. This is a highly significant resource (over 4 billion barrels of oil equivalent) addition to the estimated remaining recoverable reserves of about 6 billion barrels (as of January 1, 1995) from producing North Slope fields. In addition, to the known 26 TCF of saleable gas reserves, there may be twice as much remaining undiscovered recoverable gas in Northern Alaska according to the latest USGS estimate (USGS, 1995).

To date, the only use of the gas that is currently produced at Prudhoe Bay with the crude oil, aside from local ANS use and the extraction of NGLs for sale with the crude oil, has been for reinjection to enhance recovery of crude oil. The use of Prudhoe Bay gas for oil recovery is becoming less important and less valuable with the decline in oil production. Thus, the urgency is increasing to develop the capability to market the gas, and thereby extend the life of North Slope operations and continue the generation of employment and revenue for the State of Alaska and the nation.

The possibility of exporting the gas via a pipeline from the North Slope to a Valdez LNG plant, followed by tanker shipment to Asian buyers, has long been suggested and studied as an ANS gas sales option. This study, however, sought to assess the economic and technical feasibility of a second option, based on newer technology than that well-established for LNG. This option involves the chemical conversion of gas to a distillate-type hydrocarbon liquid (GTL) that could be transported and sold with

continuing ANS crude oil production via the existing TAPS and tanker fleet.

6.1.1 Study Approach

Before the feasibility of the GTL option could be assessed, as well as compared with the LNG option, an updated outlook for prospective oil production from producing ANS reservoirs had to be developed and an assessment of the gas conversion technology that might be deployed under each option also had to be made.

Without the speculative assumption of additional large oil finds, the introduction of unheralded new inexpensive oil extraction technology, or the development of known but marginal ANS oil reservoirs (the currently known reservoirs are not sufficient to offset or reverse the decline in Prudhoe Bay production), it is believed that ANS oil production will continue to decline. ANS oil production peaked in 1988 at 2.0 million barrels per day, declined to 1.4 million barrels per day in 1995, and will continue to decline based on the production outlook for the currently developed and known undeveloped fields. This decline is paced by the Prudhoe Bay field, which has produced almost 9 billion barrels of oil (about 70% of its estimated 13 billion barrels of reserves) since the start of production in 1977 and whose inevitable depletion is now clearly evident. ANS oil production could end abruptly between 2009 and 2016 with a shutdown of TAPS, if TAPS operations becomes prohibitively expensive (or technically impossible) to continue (see **Section 1.4.1** for a discussion of TAPS minimum flow limits).

Prospective gas conversion technology was then examined for both the more established physical conversion to LNG, and the less well established GTL chemical conversion to liquid hydrocarbons. We investigated not only state-of-the-art GTL technology, but also examined the most promising technology advancements known to DOE researchers that conceivably could have application on the North Slope. In spite of proponent optimism that such cost-cutting technology could be ready for application on a large scale by the time of decision making on ANS gas sales, about 4 to 7 years (consistent with investment lead time requirements and gas owner indications that the window of opportunity for major gas sales will be after 2005), a conservative approach to the analysis demanded such advancements not be factored into this assessment. Thus, this assessment assumes that state-of-the-art Fischer-Tropsch GTL technology, reflective of Shell's Middle Distillate Synthesis plant that has been operating in Malaysia since 1993, would be employed in a GTL option for ANS gas sales. Likewise, the LNG option for the gas assumes LNG conversion technology as planned and reported by Yukon Pacific Corporation in 1994.

6.1.2 Gas Sales - Base Economics

Based on the ANS oil and gas production outlook and the conversion technology base, coupled with the assumption that output from either of the options would be marketable at premium prices (a 10% Asian fuel bonus and a $5/BBL premium for clean-burning diesel fuel from GTL conversion liquids), an analytical comparison of the two options was performed. Both options were sized to handle a similar volume of gas on a daily basis beginning in 2005, consistent with the 2.05 BCFPD planned by Yukon Pacific Corporation to handle PBU gas, but adjusted upwards to a capacity of 2.49 BCFPD to accommodate PTU production, which would be completed well before PBU production ends in 2036.

Results of the economic model employed showed (in 1995$) that after all expenses and allowing only a 10% rate of return on the incremental investment for preparing and transporting the gas to market for the respective gas sales options, the LNG option would yield an $11.5 billion net present value (NPV_{10}), while the GTL option could be expected to yield a $10.7 billion NPV_{10}, or about 7% less. The total incremental investments required for these yields, however, would be 24% greater for the LNG option than for the GTL option, $16.9 billion compared to $12.9 billion.

6.1.3 Gas Sales - Economic Variables

These results are a synthesis of the base assumptions developed to complete the assessment. Changes in one or more of these assumptions could significantly alter these financial results.

In considering the LNG option, there are a large number of would be LNG suppliers in the world seeking to fill the expected LNG demand growth from gas-short Asian nations. Many of these suppliers are thought to have smaller capital outlays (not having the necessity of building an 800-mi gas pipeline as is required at the start for the Alaskan LNG project), and it is quite possible the LNG project's Asian fuel bonus and its base LNG price will be less than anticipated, thereby reducing the LNG base economics. It is also possible, as more large LNG projects are designed and built around the world, that cost-saving measures will be found that would improve the LNG base economics.

Likewise, for the GTL option, conversion efficiency might prove to be closer to the 57% level of the older South African plants rather than to the plant design level of 63% efficiency for Shell's newer plant, thereby reducing the GTL base economics. In contrast, the target efficiency of 70 to 75% for the advanced

GTL technology under development may prove out in time to be ready for the rapid GTL deployment envisioned (or for major portions of the development, if such GTL development is phased in more slowly), thereby improving the GTL base economics.

Clearly, the base economics of both of the gas sales options could be seriously impacted if, for example: investment cost contingencies associated with Alaska's climate, remoteness, and related factors prove to be underestimated; or such stand-alone projects as LNG and GTL require a greater than 10% rate of return to attract investors; or if world oil prices prove to be substantially lower than the DOE EIA reference oil price forecast (neither LNG nor GTL were found to be financially feasible at an $18/BBL flat oil price in this study's sensitivity analysis).

6.2 Conclusion

At this point in time, if the assumptions for the economic variables are valid -- and, we believe they are valid based on the public information available to us -- both the LNG and the GTL options are economically promising and warrant consideration in the decision making process, *but* it is not possible to conclude that one option is significantly better than the other.

This evaluation, however, does answer the specific question it was directed to address, namely: Is GTL conversion a feasible alternative for bringing ANS natural gas to market? The conclusion from this assessment is that state-of-the-art GTL conversion technology appears to be feasible and could be deployed within a meaningful time frame to sustain ANS and TAPS oil operations for 20 or more years beyond what might be anticipated without GTL.

Placing the issue of GTL feasibility aside, this ANS gas utilization assessment is not expected to be the last of what has been a number of studies focused on the marketing of Alaska's large, and potentially much larger, remote natural gas reserve. Alaskans face difficult gas development and marketing decisions in the near future, and need to develop the most complete understanding of the options possible. This is particularly so with respect to likely requests for State tax incentives and other actions that might be desired to move private commitments forward.

6.3 Recommendations

To assist in responding to such requests and other decisions that must be made to implement the sale of ANS gas, this report concludes with a number of recommended follow-up analyses that interested industry, State and federal parties may wish to pursue in a timely manner:

1. **Existing Infrastructure Savings**--The economics of both of the options could benefit through the utilization of portions of the infrastructure existing at Prudhoe Bay and along the TAPS pipeline. These possibilities should be examined on a site-specific basis, not only for a GTL plant that would be built on the North Slope, but also for the LNG gas pipeline and prospective Valdez liquefaction and shipping facilities. (YPC reports that basic engineering and design have been completed, but it is likely that further engineering and design involving the Prudhoe Bay operators and Alyeska Pipeline Service Company will lead to additional refinements.)

2. **Specific Cost Estimates**--More precise, process- and site-specific cost estimates of the LNG and GTL options should be developed because of the important sensitivity of the economics of both of these options to capital costs in particular. These estimates should incorporate the latest in technologies and designs, attempting also to provide sufficient detail on the cost impact of technology advances possible within a meaningful timeframe.

3. **TAPS Tariff Impact on Future Oil Production**--A more complete assessment is desirable concerning the effect of reduced TAPS tariffs, anticipated from the envisioned GTL product volumes, on future ANS oil production from all existing fields and potential developments. The several dollar per barrel reduction suggested by this study could be important in determining how long selected ANS reservoirs might continue to produce, and could affect whether non-producing reservoirs might be brought on line.

4. **Optimization of GTL Product Composition**--To better refine the operating cost and price estimates of proposed GTL operations, technical assessments should be directed to delineating potential liquid product compositions with respect to: (a) feasible process chemistry, (b) methods of TAPS shipment (mixed with the crude or stored and batched separately, similar to oil product pipelines), (c) crude and GTL product separation and refining process(es) required to obtain to ultimate GTL product value, and (d) other factors as appropriate.

5. **ANS Cost Factors**--A clearer picture should be developed of the cost penalties associated with capital construction and facility operation in the arctic climate and remote location of the ANS. This should be done for both GTL and LNG options and should also examine general Lower 48 and Alaskan capital and operating cost differences to provide the most reliable cost estimates for gas sales decision making.

6. **Gas Sales Benefit to Alaska**--The potential economic benefits of each gas commercialization option on the various regions and overall State should be assessed in detail to aid in decision making. Such examination might include: (a) an analysis of the types and aggregate of manufacturing and labor components for construction and operation of each gas option and the resulting stimulation of State and local economic development, (b) direct and indirect local employment to be generated (and saved or extended, if such be the case), and (c) gross and net revenues to State and local jurisdictions through prevailing or alternative tax schedules, etc.

7. **Alternative GTL Development Schedule**--The GTL option does not have to be developed at the pace required for the LNG project (resulting from the requirement to build the pipeline up front). The development scale was chosen to match the proposed TAGS LNG scale, pace, and scope in an attempt to make the obvious comparisons between the two options as comparable as possible. Hence, it would be useful to consider a slower development of GTL that could take advantage of the learning curve associated with deployment of new technology to lower costs and potentially take advantage of advanced GTL technology in the later modules for improved conversion efficiencies. Slower, incremental development would also reduce the magnitude of the capital outlays required in the early years and allow them to be offset by the increased profits from GTL sales. Such a development scenario increases the possibility of constructing more of the plant modules in Alaska and pacing the development over a long period of time to sustain higher employment and infrastructure levels within the State.