ALASKA GASLINE DEVELOPMENT CORP.
GAS FOR ALASKANS

August 12, 2011

Senator Bill Wielechowski
Alaska State Legislature
716 W. 4th Ave., Ste.540
Anchorage, AK 99501

Honorable Senator Wielechowski;

Thank you for your letter August 5th commending the Alaska Stand Alone Gas Pipeline/***ASAP*** project work. It was a privilege to accept the appointment to oversee this group and I am extremely pleased with the facts and findings as reported in the Project Plan.

Attached you will find answers to the fifty-four (54) questions presented in your letter. The questions as presented required extensive work from the team. I am confident you will find the answers beneficial in providing you, your constituents and other Alaskans greater understanding and knowledge on the ASAP project to assist in the selection of the best energy options for Alaska.

Again Senator Wielechowski, thank you for acknowledging the extensive work performed by the ASAP project team to provide the deliverable as mandated in HB369. We appreciate the opportunity to perform and produce this important work for Alaskans.

Sincerely,

Daniel R. Fauske, President
Alaska Gasline Development Corporation

cc: Governor Sean Parnell
Members of the Alaska State Legislature
DNR Commissioner Dan Sullivan
Commissioner of Revenue Bryan Butcher

Responses of the Alaska Gasline Development Corporation to Questions from Alaskans about the July 1, 2011 Alaska Stand Alone Gas Pipeline Report

Note: *For convenience of review, AGDC numbered the questions.*

Large Pipe versus Small Pipe:

1. ***To what extent, if it all, would building a 24-inch-diameter pipeline to the Railbelt encourage new exploration and development on Alaska's North Slope?***

   According to the feasibility studies AGDC commissioned for the ASAP Project Plan, the project should be an incentive to existing producers to sell currently stranded gas and an incentive for those explorers close to the pipeline (North Slope Foothills, Yukon Flats Basin, and Nenana Basin exploration projects) to market their gas if their programs are successful.

2. ***What effect would construction of the 24-inch ASAP have on state revenues? How much revenue would accrue to the state annually and over the foreseeable life of the pipe? How does this compare with the anticipated revenue from a large diameter pipeline?***

   AGDC's Plan of Finance by Citigroup/Ramirez contains an estimate of $3.75 billion to $4.57 billion in direct nominal revenues coming from the State's royalty gas portion, property taxes, and income tax over the first 20 years of the project (see page 33 of *Alaska Gasline Development Corp. Plan of Finance,* prepared by Citigroup Global Markets Inc. & Samuel A Ramirez & Co., Inc. for AGDC, 2011; the report is published on AGDC's website). Production taxes on the upstream were not estimated, as they are dependent on the cost of upstream production.

   It is not within the scope of AGDC's mandate from House Bill 369 to compare the revenues from this project to that of a larger export project. Underlying assumptions should be examined for any project's forecast of revenues in order to make valid comparisons.

3. ***What are the total development (pre-construction) costs of this project that the State is being asked to cover?***

   Based upon the front-end loading (FEL) financial requirements that AGDC has adopted, the total development (pre-construction) cost the State is being asked to cover is approximately $400 million:

   - **FEL Phase 1.** The combined expenditures from the initiation of the project up to July 1, 2011, are approximately $30 million. This amount includes the $15.6 million that was in the Fiscal Note for AGDC for FY2011.

   - **FEL Phase 2.** Expenditures for this phase that will occur from July 1, 2011, up to January 1, 2014, are estimated to total $240 million.

- **FEL Phase 3.** This phase is from January 1, 2014, to January 1, 2015, and is estimated to cost $130 million.

4. ***Can you describe in greater detail the effects building the ASAP would have on the feasibility of constructing a larger diameter pipeline? For example if 500 mmcf/day of North Slope gas were moving down the ASAP, that gas would clearly not be available to be transported in a larger line. In the early years of a large pipeline, this would likely not make much difference as gas reserves would be substantial. But in later years, it could pose challenges. What effects would this loss of gas for a larger line have on the long-term feasibility of building a large diameter pipeline and on pipeline tariffs?***

   The Legislature conceived of ASAP as a project to bring gas to Southcentral assuming the large-diameter project will not be built or will be significantly delayed. It is not within the scope of AGDC's mandate from House Bill 369 to study the effect of ASAP on a large-diameter pipeline, and AGDC did not speculate on such effects. However, the Prudhoe Bay Field currently produces and re-injects about 8 billion cubic feet per day (bcfd) of gas. At full capacity, both projects would take about 5 bcfd. The field could easily source gas for both projects in the initial years. Later, gas will likely be available from multiple sources including but not limited to Point Thomson, the Brooks Range Foothills, and other North Slope fields. Gas from at least one of these other fields is required to source the large-diameter project whether ASAP moves forward or not.

   Over the first 20 years of operation, a 500 MMscfd pipeline will transport about 3.65 trillion cubic feet of gas, which represents about 10% of discovered gas resources on the North Slope. Even without this pipeline, a 4.5 bscfd pipeline cannot be supported by discovered gas in Prudhoe Bay and Point Thomson for the full life of initial contracts. New fields would need to be brought on production to fulfill shipping commitments and enable the large pipeline to recover its investment, with or without ASAP.

5. ***If a big line were built not long after the bullet line, would it render the bullet line obsolete with its higher tariffs? Could this result in significant loss for the state or gas costs for Alaskans that would be higher than running gas through a large diameter line?***

   Once the ASAP transportation contracts are in place, the throughput and tariff for the ASAP line will be set for 20 years. Therefore, since 20 years of capacity is guaranteed, no financial loss is expected.

   The reduction in transportation costs associated with the large-diameter pipeline depends on whether the larger line is ever built, how long it is delayed, the project cost performance and tariff structure of both projects, and the tariff related to the smaller-diameter spur line to Southcentral.

6. ***The report notes that bullet line capacity can be expanded beyond 500 mmcf/day by adding compression. Could this pose any conflict with Alaska Gasline Inducement Act provisions, which require that other state supported pipelines be "designed" to carry no more than 500 mmcf/day? Could this trigger treble damage provisions?***

The AGIA limit applies only to gas sourced from fields north of 68 degrees latitude. The facilities required to expand the throughput beyond 500 MMscfd north of 68 degrees latitude have not been and will not be designed until the AGIA limit is lifted.

7a. ***From an engineering perspective, are there any choke points (e.g., Atigun Pass or the Yukon River crossing) along the proposed routes of the two lines where it would be difficult to fit more than one of the lines?***

There are choke points where design and construction of two lines become more challenging from an engineering perspective and potentially might incur higher costs. However, there are no route proximity issues that would pose significant difficulties for the ASAP and APP lines. The Yukon crossing mode for ASAP is a suspension bridge downstream of the existing E.L. Patton bridge, and the APP crossing mode is a horizontally drilled underground crossing some distance from ASAP. Routing through Atigun Pass will require close coordination with the existing TAPS line and any other buried utility that may exist at the time of construction, but should not pose the need for extraordinary measures.

7b. ***Are there any other circumstances under which construction of a bullet line would increase costs or engineering challenges for a large diameter line?***

No. On the contrary, construction of ASAP some years prior to construction of a larger-diameter pipeline would afford that project insight into ground conditions and logistic issues where the two routes are similar.

8a. ***The estimated in-state tariff for gas transported in a larger pipeline is less than $2.50/mcf in 2020 dollars. This is less than half the estimated tariff for gas transported through the ASAP in 2011 dollars. What do you estimate the tariff for bullet line gas would be in 2020 dollars?***

The full cost of transportation of gas to Southcentral Alaska through the larger pipeline would include a spur line from Delta Junction to the vicinity of Anchorage. The tariff for this approximately 300-mile smaller-diameter line would need to be added to the $2.50 stated above to represent the full cost of gas associated with that project. The ASAP tariff in 2020 dollars (levelized nominal tariff) is $7.75/MMBtu.

8b. ***What is the likelihood the Corporation estimates a large diameter line will be built by 2025? Given the differences in consumer cost, does the Corporation recommend the state proceed with financing of a bullet line if a larger line is likely?***

AGDC cannot speculate about the likelihood of a large-diameter line being built at some time in the future. The AGDC mandate from House Bill 369 was to develop a plan for delivering North Slope gas to Fairbanks and the Southcentral region of the state, and other communities whenever practicable.

Public versus Private Ownership:

9. ***At least one private company (i.e., Enstar Natural Gas Co.) has testified before the legislature that it was interested in building a bullet line without state support. Please describe the Corporation's rationale for recommending state financing and ownership of the ASAP in light of this private corporate interest.***

House Bill 369 mandates that the ASAP Project Plan include recommendations that "make natural gas available to residents at the lowest possible cost." State financing and ownership accomplish that directive.

With regard to private ownership, discussions with potential builder/owner/operators have indicated that once the initial engineering is completed by the State, they would be willing to build, own, and operate the pipeline. When AGDC issues the request for proposals for such services, ENSTAR and all other potential contractors will have the opportunity to express their interest in participating in the construction of ASAP.

10. ***If the private sector is no longer interested in this project or does not believe it is economically feasible, please explain why the Corporation believes is it wise for the state to take on this investment risk.***

The private sector is not interested in funding the feasibility stages of the project. The companies AGDC has had discussions with have indicated they will be willing to participate once a successful open season has been conducted. To date, AGDC has received expressions of interest to participate as an equity partner/owner from no less than four companies at that stage.

Project Costs:

11. ***The current report estimates a $7.5 billion capital cost (plus or minus 30%) based on the assumption that the state will build and own the pipeline. Has the Corporation evaluated the other energy investment opportunities the state would be forced to forego if it covers the full cost of this project and incurs a high debt load?***

AGDC has not evaluated such investment opportunities, since such an evaluation was not part of the mandate of House Bill 369. The only out-of-pocket expenditure by the State that was recommended in the AGDC Project Plan was an additional $340 million to progress the project to full sanction (the total front-end expenditures would be $400 million, including money already spent or appropriated). The capital required to construct ASAP will be financed by the issuance of bonds. The payment of debt service on the bonds will come from tariffs charged for transmission of gas in the pipe.

12. ***If construction costs turn out to be 30% higher than expected, which the report notes could be the case, what would the tariff be and the cost of gas to the consumer?***

Compared to the $5.63/MMBtu tariff to Big Lake without inflation, the tariffs would be $7.14/MMBtu if the capital costs were 30% higher than the base estimate, and $4.11/MMBtu if the capital costs were 30% lower.

13. ***What assurance do we have that the Internal Revenue Service will allow the Railroad to issue tax-free debt for this project? If the IRS does not allow this, will the tariff and project cost be higher? If so, by how much?***

There is no assurance that the IRS would allow the Railroad to issue tax-free debt for the ASAP Project. As a result, the baseline tariffs presented in the ASAP Project Plan do not contemplate tax-exempt financing.

14. ***If the Railroad cannot issue tax-free debt, the next best alternative identified is for the state to issue revenue bonds. Would this impact the state's bond ratings? If so, what effect would any downgrading of the state's credit rating have on municipal, school district and state corporation borrowing? What other effects could there be on state finances?***

Because rating agencies do not issue prospective ratings, the best that can be done is to speculate on their reaction to a particular course of action. Ratings on revenue bonds are, by definition, based upon revenues of the project pledged, not the State's general obligation. In this case, ASAP will not be built without a successful open season and therefore will have revenues to support the projected debt service, mitigating any negative credit impact upon the State.

15. ***The report indicates that issuing revenue bonds for $7.5 billion would make our debt to GDP ratio three times higher than any other state. Are there financial ramifications because of this and is this of concern to the Corporation?***

This concern was raised by then Deputy Commissioner Burnett in response to questions from AGDC staff. AGDC is concerned about the fiscal health of the State. If the State elects to finance all or some of ASAP, a policy decision must be made by the Governor and Legislature as to whether to use cash or debt to finance the project.

16. ***The report assumes that "half the gas transported will be sold in the Pacific Rim." Will this trigger Federal Energy Regulatory Commission (FERC) jurisdiction because the export component would be essential, substantial and integral to the project? If so, how would this effect project timing and cost?***

Because it is not required for the ASAP Project to proceed, LNG export is not "essential, substantial, and integral to the project." The anchor tenant could be made up of other industries, such as mining. It is AGDC's understanding that the U.S. Army Corps of Engineers (USACE) has received guidance from FERC that only the export facilities would be under FERC jurisdiction, not the ASAP line.

Because AGDC is not proposing export facilities, the FERC licensing of export facilities would be the responsibility of the exporter.

17. What are the estimated project costs in 2015 dollars, when major pipe and equipment orders would be made?

Using a 3% inflation factor from 2011, the project cost estimate in 2015 dollars is about $8.5 billion. The ASAP Project Plan assumed a 3% annual inflation for calculating nominal estimated tariffs.

18a. The report assumes enhanced gas value and reduced tariffs by shipping gas enriched with natural gas liquids (NGLs). However, the capital costs (almost a billion dollars) of adding the NGLs on the North Slope and removing, fractionalizing and transporting them in Cook Inlet are not included in project costs. Has the Corporation assessed the likelihood there will be a market for 35,000 barrels/day of NGLs from Alaska?

AGDC assessed the market for NGLs based on the report *Economic Feasibility Study of the Transportation and Sale of NGLs for the Alaska Gasline Development Corporation* by SAIC, which is published on the AGDC website. There is growing demand for propane and butane in the Pacific Rim markets, and NGLs from Alaska would be competitive.

18b. In 2019 nominal dollars, the tariff for transporting those liquids would be about $13/barrel, which is much higher than typical liquids transportation costs elsewhere. Will that put North Slope NGLs at a competitive disadvantage?

Competitive advantage/disadvantage is determined by total cost of supply, including among other things production and transportation costs. It cannot be determined by looking at only one piece of the value chain (e.g., transportation). As a result, all of AGDC's feasibility studies including NGLs evaluate the North Slope netback value. The netback values expected for North Slope NGLs are presented in the SAIC feasibility study (published on the AGDC website) and are discussed on page 3-15 of the ASAP Project Plan.

18c. Will a private entity be willing to step forward to invest nearly $1 billion in the necessary infrastructure?

The open season results from mid-year 2013 will determine whether there is enough interest in NGLs to support the export infrastructure.

18d. Do you have any assurance that North Slope Producers will be willing to sell these liquids?

NGLs are generally defined as all gas components heavier than methane. There are two sources for NGLs from the Prudhoe Bay Unit (PBU):

- For the approximately 23,000 barrels of NGLs contained in the gas that is sourced from the PBU Central Gas Facility (CGF), there is no economic advantage for either the producers or ASAP to remove those NGLs prior to transportation. About 18,000 barrels are ethane that can be consumed at our burner tips. The other 5,000 barrels would be propane and butane. In the Non-Binding Expression of Interest, producers have indicated a willingness to ship these components.

- The other source of NGLs is the miscible injectant stream, which is the source for further enriching the ASAP gas stream with propane and butane. Whether this enriched stream is added to ASAP will depend on a number of market and cost factors. The open season results from mid-year 2013 will determine whether there is enough interest in NGLs to support the enrichment of the stream and the cost of the export infrastructure.

18e. In light of these concerns, what is the likelihood the transportation of these liquids will bring down the tariff for gas to be used in-state?

The likelihood that NGLs (the fraction from the CGF) will be transported is fairly certain. Whether this enriched stream is added to ASAP will depend on a number of market and cost factors. The open season results from mid-year 2013 will determine whether there is enough interest in NGLs to support the enrichment of the stream and the cost of the export infrastructure.

19. What would the cost be to develop a local gas distribution network in Fairbanks? How much would this add to the Fairbanks consumer cost? How does this cumulative cost compare to the cost of trucked gas?

According to information supplied to AGDC from the mayors of both the North Star Borough and the City of North Pole, a capital expenditure of approximately $50 million is needed to expand the existing Fairbanks Natural Gas System to create a local distribution network in Fairbanks.

AGDC has not been provided with the tariff rate that would apply to the local distribution network if it were built. Also, AGDC does not have information concerning the cost of installing natural-gas-fired furnaces in households and businesses.

The costs of both the expansion of the Fairbanks local distribution network and the conversion costs need to be added to the costs of trucked gas being delivered into the system.

20. Who is expected to pay for the cost of the estimated $954 million in construction costs to integrate the ASAP into the natural gas system near Big Lake? How much would this add to the price consumers will pay?

The $954 million referenced on the first paragraph on page 3-4 of the ASAP Project Plan is for the cost to fractionate NGLs, transport, and load NGLs downstream of a fractionation plant near Big Lake. This cost would be paid by NGL exporters and is not part of the ASAP Project.

21a. What is the estimated cost to Fairbanks home and business owners and utilities of converting from diesel to gas heating and electrical systems?

AGDC did not investigate this cost since it is not within the scope of House Bill 369.

21b. The report assumes demand of 60 mmcf/day from Fairbanks. What rate of conversion is this estimate based on and is there any data to support this assumption?

To determine the Fairbanks demand, AGDC used the estimate from the Northern Economics In-State Demand Study (Appendix B, page 83, Tables 30 and 31). The demands for Fairbanks (55 MMcfd) and Livengood (8.9 MMcfd) were summed, and the result was rounded down to 60 MMcfd. AGDC did not investigate the conversion rate.

22. What would a private entity charge to operate the line on the state's behalf? Are these costs as well as long-term maintenance costs fully considered in tariff calculations?

The Citigroup/Ramirez analysis of various ownership structures in AGDC's Plan of Finance was conceptual and focused on the large differences that are caused by the financing structure of privately owned vs. state-owned projects. Operating and maintenance (O&M) costs of a gas pipeline system are relatively immaterial in comparison to capital project and financing costs. At this stage of project development, O&M costs are estimated simply as a percentage of capital costs (see ASAP tariff assumptions on page 3-8 of the ASAP Project Plan). In addition, a pipeline operator's fee could vary significantly based on the amount of risk the operator is required to take on in the contract. Therefore, no distinction was made by Citigroup/Ramirez between O&M costs in the case of a privately owned vs. state-owned pipeline.

23. Please list all entities that have expressed interest in acquiring gas or liquids through the ASAP.

The responses to the Non-Binding Expression of Interest were provided under an agreement of confidentiality, and AGDC cannot release the responses or the names of the entities that made them.

Tariff:

The report makes numerous assumptions in estimating the cost (tariff) of shipping gas through the pipeline. If any of these assumptions turns out to be invalid, the cost of gas to the consumer could change significantly.

24a. Is it reasonable to assume that producers will sell North Slope gas for $2/mcf over the life of this project? What evidence does the Corporation have that this is the case?

AGDC does not predict that the price will be $2/mcf over the life of the project. The $2/mcf (2011$) was an assumption used to create a comparison of the current Anchorage/Fairbanks cost at the burner tip to the burner tip cost of ASAP gas in 2011 dollars. The actual price will be determined by the market, and the referenced price is merely an assumption for comparison to the current price. All the ASAP feasibility studies assumed gas product sales prices linked to $80/barrel West Texas Intermediate (WTI) inflated at 3%.

The $2/mcf (2011$) assumption for the burner tip comparison was selected for two reasons:

- First, North Slope gas priced against Henry Hub would likely be discounted for gas treatment costs and a differential equal to the average Gulf of Mexico pipeline cost to Henry Hub. AGDC's estimate for the gas treatment cost is $1.42/MMBtu, and the assumption for the average Gulf of Mexico pipeline cost to the Henry Hub was $0.50/MMBtu. The cost of gas at Henry Hub is $3.92/MMBtu (September NYMEX as reported August 8, 2011). Subtracting $1.42 and $0.50/MMBtu from $3.92/MMBtu yields about $2/MMBtu.

- Second, AGDC looked at the royalty valuation of North Slope royalty gas sales since 2000. AGDC assumed that the producers priced gas at a fair valuation. This is a reasonable assumption since valuing gas over market would violate federal laws requiring arm's length transactions with transportation affiliates. Marketing the gas at less than fair market value would be unfair to the State of Alaska. Since the State of Alaska has not challenged the royalty valuation, AGDC assumed the State of Alaska is satisfied with the current pricing formula. AGDC assumed gas buyers would purchase gas at the lowest average annual posted price for the past 11 years ($1.73) and then rounded that number up to $2 (see page 3-14 of the ASAP Project Plan).

24b. What would consumer costs be over time if this cost rose with inflation or were closer to the price of gas at the Henry Hub?

The price used in all the ASAP feasibility studies assumes 3% inflation. Comparing the inflated burner-tip cost to current 2011 cost is not a meaningful economic comparison, since the only variable is inflation. A comparison to the Henry Hub pricing is provided in the answer to Question 24a above.

24c. It appears that this estimate is based on $80/ barrel oil. What is the estimate at $100 and $150 per barrel?

The increase in pricing is about $0.35/mcf for every $10 increase in oil price, assuming pricing linked to WTI and assuming the same formula used by PBU producers for 2000-2010 to price royalty gas.

25. The report states that "the project is likely to be commercially feasible with an un-inflated consumer cost in Anchorage of about $9.63 per million Btu (MMBtu)." What are the inflated consumer costs?

The nominal ASAP tariff that takes inflation into account is $7.75/MMBtu as shown in Figure 3-3 of the ASAP Project Plan. Assuming 3% inflation for the North Slope netback, the cost of gas prior to entering the local distribution system at Big Lake would be $10.28 in 2019. The ultimate cost of gas to consumers would then depend on the prevailing cost of the local distribution system at the time (approximately $2/MMBtu in 2011).

26. The report contrasts these costs with the cost of liquefied natural gas (LNG), which it estimates to be $16-$21/MMBtu. Is this cost estimate for LNG inflated or uninflated? What is it based on? What does the U.S. Energy Information Administration predict will be the spot market prices for

gas in 2019? How does the cost of LNG compare with the inflated consumer cost in Anchorage of gas from the proposed ASAP?

The LNG cost estimate in uninflated, and compares to the \$9.63/MMBtu estimated consumer cost of gas from ASAP. The bottom number of this range is based on the result of the *Greenfield Liquefied Natural Gas Economic Feasibility Study* conducted by SAIC ("LNG Feasibility Study"), which estimated a cost of imported LNG at \$14/MMBtu in 2011 dollars, tied to a WTI price of \$80/barrel, plus \$2/MMBtu for local distribution. In order to compare the price of imported LNG to ASAP, SAIC assumed that the project would supply enough gas to fill the entire Southcentral demand for 20 years. The more realistic case would be imported LNG on a smaller scale, increasing over time as Cook Inlet supply decreased, which would not realize the same economies of scale in re-gasification facilities, shipping, or the LNG market. Hence, the ASAP Project Plan provides a range for the cost of LNG imports.

The Henry Hub spot market price predicted by the U.S. Energy Information Administration for 2019 is \$5/mcf (2009\$). The Energy Information Administration does not issue price predictions for Pacific Rim LNG.

27. ***How does the inflated consumer cost of ASAP-delivered gas from 2019 on compare to the likely cost of gas from Cook Inlet during the same period?***

The Cook Inlet Natural Gas Production Cost Study published by the Department of Natural Resources ("DNR Study") estimated that the expected revenue requirement for Cook Inlet projects necessary to meet demand in 2019 is about \$6/mcf, rising to almost \$9/mcf in 2020 and almost \$11/mcf in 2021 (Figure 12 of the DNR Study). The same section of the DNR Study stated on page 20 that "since this study is unable to address all the risks that producers face, the 90th percentile does not necessarily equate to a risk weighted price required to produce natural gas."

These numbers are comparable to AGDC's estimate of \$10.28/MMBtu in 2019. Since the pipeline tariff is levelized, the only impact after 2019 would be inflation of petroleum product prices through the netback or higher-than-expected inflation of operating costs.

Project Timing:

28. ***The report finds that first gas would not arrive until late 2018 or 2019. This is a delay from what House Bill 369 envisioned (first gas in 2015). Given this, what is the likelihood that Southcentral utilities will already have invested in infrastructure to import LNG? What is the likelihood this will affect their willingness to sign 20-year gas purchase agreements?***

AGDC is committed to progressing the ASAP Project following a stage-gated process that has the best chance of delivering the project on schedule and within budget. The Southcentral utilities will need to assess their investment decisions based upon their own supply requirements. Security of long-term supply is one of the most important criteria that will affect decision making for the utilities.

29. ***The report notes that the project could be delayed past 2019 if the U.S. Pipeline and Hazardous Materials Safety Administration requires it to receive a special permit for "strain-based design," which is the preferred option. How likely is this potential delay? How long could it last and at what cost?***

The potential for delay is low assuming full funding for FEL 2 activities is authorized by 4Q2011, which will allow detailed engineering and steel materials sourcing and testing to occur. Notably, PHMSA has indicated that ASAP will need a special permit because it will be buried in areas susceptible to frost heave loadings on pipe, not because its design will based on a strain model approach. In fact, PHMSA has stated that all buried pipelines in the Arctic will require PHMSA special permits going forward.

Project Need:

30. ***Recent developments in Cook Inlet have potentially changed the supply situation in Southcentral. These developments include the high level of interest in the recent lease sale, the U.S. Geologic Survey revised estimate of gas reserves in the Inlet (19 trillion cubic feet or enough for over 200 years at current consumption levels) and the imminent arrival of two jack-up rigs. The U.S.G.S. survey came out too late for report authors to fully consider. Now that additional time has passed, what are the implications of this new assessment of Cook Inlet's gas potential and these new developments?***

The USGS assessment made no mention of the economic viability of the new resources identified in their latest assessment. They did tell AGDC via e-mail that most of the new resources were in stratigraphic traps, which have a notoriously high exploration risk and correlated high supply cost.

The size of exploration prospects identified in the DNR/AGDC forecast of Cook Inlet production was on the order of 60 to 80 bcf each. Targets of this size are not currently considered economic by DNR as "stand alone" offshore natural gas development prospects.

Based upon historical experience, only a low percentage of exploration prospects ever produce commercially viable developments after conducting exploration drilling and development studies.

31. ***If substantial new gas is developed in Cook Inlet, what is the likelihood Southcentral consumers will be locked into 20 years of more expensive North Slope gas?***

The newly discovered gas could have supply costs either above or below the cost of supply for North Slope ASAP gas depending on exploration costs and development costs for each individual field discovered.

32. What effect does the recent closure of the LNG export plant have on gas supplies for Southcentral Alaska?

The Cook Inlet supply forecast used by AGDC in the ASAP Project Plan (see Figure 3-1 on page 3-6) assumes no future Kenai LNG production sourced from the Cook Inlet. Therefore, the closure has no impact on AGDC's supply/demand forecasts.

Gas Demand:

33. The report assumes that there will be demand for 500 mmcf of gas a day. Given that the level of demand today is far less than this, what is the Corporation's rationale for building this much higher level of demand into the base case? Is this prudent?

There is currently a demand for about 500 MMcfd if the LNG plant at Nikiski is included. The Cook Inlet produced 600 MMcfd from 1996 through 2006.

34a. If this level of demand is not realized, who will cover the cost of shipping much lower volumes of gas down the pipe?

The risk of demand shortfall is normally allocated between the shippers and the pipeline owners through the open season process.

34b. How high could the tariff rise if existing demand does not increase significantly by 2019 with the addition of new industrial users?

Figure 3-5 on page 3-11 of the ASAP Project Plan shows the estimated tariffs for throughputs of 250 and 500 MMscfd.

34c. What is the state's total risk? Has a risk assessment been performed to quantify the extent and likelihood of this risk?

The State's risk in building the project can be limited to the cash it uses to finance the feasibility stage of the project (approximately $400 million; see response to Question 3) and any risk it chooses to accept during the open season process (as a shipper, owner, or debt underwriter of the project). At the current level of engineering, there is a ±30% project cost uncertainty, which will be reduced to ±10% by the time ASAP is sanctioned.

The Plan of Finance provided to AGDC by Citigroup/Ramirez contains a detailed quantitative and qualitative assessment of risks to the State under different pipeline ownership scenarios. The State has a choice of accepting or not accepting certain risks through the ownership structure of the project up until project sanction (after open season).

35. The project will require long-term (20 year) commitments from Railbelt utilities. What assurances does the Corporation have that the utilities will be willing to do this by the proposed open season in 2013?

Assurances will be sought at the open season. Few pipeline projects at the ASAP current stage of development have contractual assurances of capacity.

36. Is it reasonable to assume that an LNG industrial anchor tenant will materialize when the current owners of the LNG plant plan to shut down next month because of an alleged lack of market for Alaska's gas?

The sanctioning of ASAP will only occur after a successful open season is conducted. AGDC was encouraged by the breadth of non-binding expressions of interest it received. AGDC intends to progress the relationships with all potential anchor tenants, focusing on providing the lowest possible tariffs to assure a successful outcome during a binding open season.

37. To what extent would the Kenai LNG plant need to be retrofitted to continue and expand export of LNG? What would the capital cost of these retrofits and expansions be? Have the owners indicated any willingness to make these investments?

The SAIC *Greenfield Liquefied Natural Gas (LNG) Economic Feasibility Study*, prepared for AGDC and published on the AGDC website, states: "Brownfield LNG export and import facilities were calculated as 30% of Greenfield capital costs of similar facilities." Please see Sections 3.2.2 and 4.1.6 of the study for the complete analysis regarding the use of the existing Nikiski LNG facility for export.

38. In order to make the sale of North Slope gas as LNG economically feasible, the LNG would likely have to sell for more than $12/mcf (This assumes a tariff of $5.63/mcf, a wellhead gas price of $2/mcf, transportation charges to the Kenai LNG plant of $1-2/mcf, and $1-2/mcf tanker charges for liquefaction, re-gasification and to get to Asia, before any profit is taken.) What assumptions did the Corporation make about Pacific Rim LNG prices starting in 2019? What have LNG prices in the region averaged over the past year and what does Energy Information Administration predict for 2019 and beyond? Will gas from the North Slope be competitive with gas from other regions?

AGDC relied on the analysis of long-term price correlation of Pacific Rim LNG to oil prices (WTI) contained in the SAIC LNG feasibility study (Section 2.5.3). As a base-case product-price assumption, AGDC used the oil price of $80/barrel in 2010 with 3% per year inflation, which correlates to a starting LNG market price of $12.79/MMBtu. SAIC used AGDC's nominal levelized tariff of $7.75/MMBtu over the time period that the LNG would be sold (2019-2038) as a cost input to the LNG project, along with costs of liquefaction and shipping and an assumption of 12% return on equity to the LNG project owner. The evaluation of LNG economic feasibility by SAIC focused on the project's ability to deliver a positive upstream netback, using the above-stated LNG price assumptions and project costs and returns. The resulting range of LNG netbacks in 2011 dollars is presented on page 4-13 of the SAIC LNG feasibility study (published on AGDC's website).

Figure 9 of the LNG Feasibility Study shows the historical range of LNG prices in Japan, and Figure 10 shows similar data for South Korea, both averaging at about $10/MMBtu in June of 2010. These averages are comprised of a multiple number of contracts made at different times.

The Energy Information Administration does not issue price predictions for Pacific Rim LNG.

39. ***What evidence do we have that the Department of Energy would approve expanded exports of Alaska gas? The report bases its tariff estimate of $5.63/mcf in 2011 dollars on the assumption that 240 mmcf/day will be exported.***

The existing Nikiski LNG facility holds a valid export license that has not reached its expiration date (March of 2013) or its maximum volume. Under the current license, about 60% of the authorized 100 TBtu limit has been exported. In the past, the Department of Energy has approved license extensions for Alaska LNG.

40. ***Will the industrial consumers that are assumed to need 250-300 mmcf/day of gas in 2019 likely be willing to sign firm transportation commitments in 2013, during the proposed open season for the ASAP project? If not, what are the implications for the ASAP project?***

Assurances will be sought at the open season. Few pipeline projects at the ASAP current stage of development have contractual assurances of capacity. A failed open season generally means that a project is delayed, re-designed to meet demand, or cancelled. The project owner(s) are in control of this decision.

41. ***What is the estimated amount of gas needed by the Donlin Creek Mine need and in what timeframe? Would this gas be affordable for the mine given that they would have to build an additional 300-mile-long pipe from the bullet line to the mine site? What evidence does the Corporation have that there will be 30 mmcf/day of demand from mines by 2019?***

The demand build-up in the ASAP Project Plan was not dependent on any single mining project, but assumed that one would draw capacity beginning in 2019. There are a number of large mining projects in development in the state that have publicly stated interest in access to power or gas to produce power. Donlin Creek Mine has stated interest through its participation in the consortium of utilities that made the June, 2011 presentation on the need for imported LNG in front of the RCA.

42. ***How does the projected in-state demand for gas in this report compare with the recent demand forecast by Northern Economics for the Alaska Pipeline Project? If there are discrepancies, what accounts for them?***

The Northern Economics In-State Gas Demand Study presents a series of forecasts for instate demand. AGDC assumed the most comparable case for ASAP was their Current Industry Demand Case in which they forecasted in-state demand to be 490 MMcfd in Years 1-5 for the APP project (Page ES-3 of Appendix B). The AGDC forecast demand in Years 1-5 of the ASAP Project is slightly over 500 MMcfd (average annual daily demand; see Figure 3-2 on page 3-7 of the ASAP

Project Plan). The primary difference is that the ASAP Project includes pipeline compressor station gas and some NGLs.

In Years 10-15 using the same forecast case (Page ES-3 of Appendix B), the Northern Economics study projects in-state demand to be about 520 MMcfd for the APP project. In 2030, the last year of the AGDC forecast, the demand for ASAP gas is estimated to be about 530 MMcfd (see Figure 3-2 on page 3-7 of the ASAP Project Plan).

There are minor differences in the components of demand, but the forecasts are very close.

43. The report references the possibility of the state establishing a gas marketing affiliate. This would require the state to negotiate gas purchase contracts with North Slope producers and gas off-take contracts with consumers. Would this result in creation of new state bureaucracies? What are the estimated annual costs of such an endeavor?

Additional personnel would be necessary to establish a gas marketing affiliate. Due to the sensitive nature of the gas purchase contracts, these personnel would probably be employed by the State of Alaska. Determining the number of personnel required and calculating the annual costs would occur during the FEL 2 phase of the project.

44. Currently North Slope gas is being used for enhanced oil recovery. Has the Corporation consulted with the Alaska Oil and Gas Conservation Commission about whether an off-take of 500 mmcf/day would be acceptable in 2018?

This is well below what is presently allowable (2.7Bscf/d) by AOGCC for gas off-take from PBU. This off-take rate was confirmed in a letter from the AOGCC to AGDC on June 27, 2011.

Watana Dam and ASAP:

45. Has the Corporation evaluated the economic feasibility of building both the Watana (Susitna) Dam and a bullet line? If so, what did this evaluation conclude about the financial likelihood of constructing both projects?

It was not in the scope of the work defined under House Bill 369 to evaluate the economic feasibility of other projects.

46a. Is there sufficient demand for both the Watana Dam and the ASAP project?

Yes. Refer to the ASAP Project Plan, Section 3.1.4.5 (page 3-13) and Figure 3-2 (page 3-7).

46b. How much demand is there in the Railbelt for natural gas without industrial anchors, and how much would be offset by the Watana Dam?

Figure 3-2 on page 3-7 of the ASAP Project Plan shows the AGDC forecast of Cook Inlet demand for ASAP gas over time from 2019 to 2030.

46c. How long would Cook Inlet natural gas production be able to make up the difference?

It depends on the level of re-investment in Cook Inlet fields, as discussed in the ASAP Project Plan (page 3-1). AGDC assumes investment at a 50% level.

47a. What does the ASAP report assume about the amount of power the dam will produce that is currently produced with gas? 50 mmcf?

AGDC used the figures from the Northern Economics study for gas demand associated with power generation (about 100 MMcfd) and then assumed 50% of the power generated by natural gas would be supplied by Watana. AGDC assumed it would account for a reduction in demand of 50 MMcfd.

47b. Is this assumption consistent with assumptions used by Alaska Energy Authority consultants?

AGDC assumptions are consistent with AEA energy consultants.

48. Do consultants working on the Watana project assume the same anchor tenants will buy power from them as the ASAP report assumes will buy bullet line gas?

AGDC has conducted a Non-Binding Expression of Interest to solicit interested from potential anchor tenants. The results from the EOI remain confidential at this time. AGDC cannot speak for the consultants working on the Watana project.

Special Exemptions for ASAP:

49. The report recommends that the ASAP be exempted from Alaska's pipeline contract law. What are the possible impacts of this for other developers? For instance, if Doyon discovered gas in Minto Flats and wanted to get it to market using the state's pipeline, would they be allowed to? If the pipeline were a common carrier line, which it would be under existing law, would Doyon be guaranteed access?

New prospective pipeline connectors are not guaranteed a connection in either operating state. Both are subject to connection agreements that generally allocate all the costs of the connection to the user.

The difference is how capacity is allocated. Common carrier pipelines allocate their capacity based on monthly requests (called nominations) subject to proration if the nominations exceed capacity, and contract carriers allow shippers to reserve "firm transportation capacity" not subject to proration under long-term contracts. These contracts for firm transportation capacity are necessary in most gas pipelines since the shippers are required to backstop their firm transportation agreements with deliver-or-pay off-take agreements.

If Doyon had a connection but no available capacity, ASAP would add compression to move the gas, subject to an agreement on allocating the cost of the expansion. Gas from the Nenana Basin or from the Fort Yukon Basin is not subject to the AGIA limitation and therefore proration would not be an issue. Gas from Doyon would likely serve to lower the tariff for all shippers.

50. Would the pipeline be economically viable without this special exemption?

No. That is why most FERC gas pipelines in the Lower 48 are contract carriers and not common carriers.

51. The report also recommends that the pipeline be exempt from oversight by the Regulatory Commission of Alaska (RCA), which seeks to ensure that consumer costs are fair and reasonable. What are the potential implications of this proposed exemption? What protections for consumers are built into the project?

Generally, the RCA has authority to regulate natural gas pipeline carriers and utilities pursuant to two statutory chapters: the Pipeline Act (AS 42.06) and the Alaska Public Utilities Regulatory Act (AS 42.05). Under the current provisions in those statutes, a North Slope natural gas pipeline such as ASAP is subject to the Pipeline Act [*see* AS 42.06.630(13)] and expressly exempted from the Utilities Act [*see* AS 42.05.711(n)], except that its rates must be designed as if it were a public utility regulated under the provisions of AS 42.05. [*See* AS 42.06.370(c)]. AGDC recommends that any modifications to the RCA's jurisdiction adopted by the Legislature be specifically limited to AGDC and ASAP to eliminate any unforeseen implications that could arise from more general exemptions.

The ASAP Project Plan's recommendations related to the RCA and statutory common carriage requirements are intended to eliminate provisions that may jeopardize the project's viability or add provisions necessary to ensure the recovery of any state investment. Thus, the appropriate level of RCA oversight of the project depends on the form of ownership and financing the Legislature selects for ASAP. If the Alaska Legislature elects to proceed with ASAP with the goal of transferring ASAP to a private builder/owner/operator and without providing any form of state financing, regulation by the RCA is appropriate, although under the Utilities Act rather than the Pipeline Act. If the Legislature intends to have ASAP built, owned, and operated by a private company, but authorizes state financing to lower the cost of the project, then it should consider limiting RCA jurisdiction during the financing period in a form similar to that found in AS 42.05.431(c) and (e), which exempts certain contracts executed by the Alaska Energy Authority from the RCA's review or approval "until all long-term debt incurred for the project is retired[.]" If the State intends to own all or a portion of ASAP and provide financing to lower the cost of the project, then it should consider subjecting ASAP and AGDC to the Utilities Act, and allowing it to take advantage of the current exemption for political subdivisions found in AS 42.05.711(b). AGDC's statutory duties in AS 38.34, including the duty to make natural gas available to residents at the lowest possible cost, and the oversight provided by the Legislature in making the decision whether to proceed after open season, ensure that ASAP will be pursued only if it has been found to be in the public interest to do so.

52. The report recommends that property taxes for the pipeline be waived during construction and fixed for 20 years following the onset of operations. What are the potential revenue impacts to the

State of the proposed waiver and fixing of tax rates for 20 years? Do other projects have such a guarantee?

The revenue impact of fixing fees cannot be determined, as it is dependent upon how much the fees are projected to increase—information that is unavailable to AGDC. AGDC is not privy to agreements relating to other projects, although a degree of fiscal certainty has been stated as a requirement for most major investments in gas infrastructure in the state.

53. The report also recommends that the state waive rental feels for the right-of-way granted to the ASAP. What is the cumulative effect of this and the other exemptions on state revenues?

The annual right-of-way lease is $188,600, or $3,772,000 for the initial 20 years of the project (subject to periodic appraisals that may change the annual lease amount.)

54a. The report mentions the need for the state to commit "royalty in kind" gas to the line. Does this assume the state will market its own gas?

This was a desire expressed by builder/owner/operators and is not a project requirement. See ASAP Project Plan, page 3-18, paragraphs 2 through 4.

54b. Under existing contracts with the producers, can the state legally take royalty gas from Prudhoe Bay and other fields beyond its share of produced gas?

The Prudhoe Bay Unit Agreement specifically does not allow the State of Alaska to take RIK at a percentage greater than the royalty percentage of the total gas leaving the unit. See the discussion in the ASAP Project Plan, page 3-18, paragraph 3.