

Plan of Finance

June 20, 2011





New York, NY 10006

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# Appendix:

A: Definition of terms

#### 1. EXECUTIVE SUMMARY

#### A) Introduction

Citi and Ramirez & Co., Inc. ("C&R") were hired by the Alaska Gasline Development Corporation ("AGDC") to develop a comprehensive financing plan for the potential construction of a small diameter in-State natural gas pipeline between Alaska's North Slope and the Cook Inlet Area in South-central Alaska, along with a lateral line to Fairbanks. C&R's finance plan builds upon the substantial body of work that has been assembled to date by AGDC and its consultants, as summarized in AGDC's March 2011 Plan of Development ("POD"). As articulated in this report, AGDC is examining the feasibility of providing a long term, stable supply of up to 500 million standard cubic feet per day ("mmscf/d") of natural gas and natural gas liquids ("NGLs") from North Slope gas fields to markets in the Fairbanks and Cook Inlet areas by 2019.

# B) Scope of Finance Plan

The goal of C&R's plan of finance report is to provide a thorough review of the project delivery and financing structures available for the Alaska Standalone Gas Pipeline Project ("ASAP"), a discussion of the relevant benefits and considerations of each structure, and an analysis of the cost and risk implications for the State of Alaska. The objectives of our finance plan include:

- Determine the available structures for the pipeline entity and evaluate the potential finance plan for each approach, considering the level of cost to consumers and the level of risk to the State
- Determine the appropriate debt/equity ratio
- Identify sources of equity capital and estimate required returns
- Recommend the most appropriate approach for any capital subsidy from the State of Alaska
- Perform a cost/benefit analysis of credit enhancement (including credit provided by the State of Alaska)
- Determine the most efficient debt structure and likely terms
- Determine whether the pipeline should depend on State of Alaska commitments for long term "firm transportation" as part of the 100% firm transportation commitments required or whether the State can take its royalty interest as a direct cash payment
- Determine whether the State of Alaska should create a separate commercial entity to market State of Alaska Royalty Gas in kind, address gas balancing issues and enter into long-term firm transportation commitments

#### C) Overview of Analysis

C&R's analysis is designed to look initially at the three major project delivery alternatives available in the market today:

- 1. Private Ownership (Rate Regulated)
- 2. Public/Private Partnership (Availability Fee)
- 3. State/Public Ownership

These alternatives were selected to bracket the range of ownership structures along the public-private ownership spectrum, while also examining a mid-point option through a public/private partnership ("P3"). The details of each plan of finance are driven to a great degree by the ownership option selected and the corresponding allocation of project-related risks.

Prior to discussing the available financing alternatives in detail, Section 2 of this report discusses the history of the project, the current status of project development, the need for a long-term reliable supply of natural gas within Alaska and the unique aspects of the in-State pipeline project. In C&R's view, any ownership structure, and the related plan of finance, will need to be cognizant of project specific considerations discussed in this section. Section 3 is then dedicated to describing the financing mechanics, associated tariffs, risk allocation and cost/benefit considerations of each ownership structure. This approach is intended to provide a foundation for the reader prior to discussing additional contracting considerations in Section 4 that will impact each of the ownership alternatives.

Given the significant capital cost associated with ASAP, Section 5 of this report is dedicated to discussing the various types of State support and the impact of each approach, evaluating both the cost and the allocation of risk to the State. In Section 6, we explore additional financial considerations as well as certain cost sensitivities and we summarize our findings in Section 7.

In order to develop this report, C&R created a comprehensive cash flow model designed to accommodate various inputs, assumptions, ownership, and financing scenarios. In developing such inputs and assumptions, C&R relied on data provided by AGDC and its tariff consultant, the Black & Veatch Corporation ("B&V"). It is C&R's understanding that B&V has also provided certain tariff projections to AGDC. While we believe our results to be largely consistent with those provided by B&V, no two scenarios are directly comparable across the two models.

## D) Summary of Results

C&R's Base Case analyzes the three ownership structures. The following table lays out the basic financial structuring assumptions among the three cases.

# **Financial Structuring Assumptions**

(Base Case Scenarios)

	Debt to		Debt Service		
	Equity Ratio <sup>1</sup>	Taxes Paid	Coverage	ROE	Tariff Structure
Private Ownership (Rate Regulated)	65:35	Income, Property	Driven by return on equity (ROE)	12.0% after tax	Level annual
Public / Private (Availability Fee)	88:12	Income, Property	Driven by ROE with minimum 1.15x coverage	12.0% pre-tax	Increases by 0.75% annually
State/Public Ownership	100:0	Property Only (Payments-in-lieu-of- taxes)	1.10x debt service coverage		Increases by an average of 0.25% annually

<sup>1</sup> As percentages of construction draws.

In general, the three ownership options presented entail differing degrees of benefit and risk for the State. The Private Ownership and Public/Private Partnership options are meant to transfer ASAP construction and operating risks to private entities, albeit at higher tariffs than the Public Ownership

option. Although the risk of ASAP inoperability due to force majeure would be assigned to private entities in the Private Ownership and Public/Private Partnership options, this risk might in the end largely remain with the State as ASAP inoperability would be a major economic issue for the Railbelt that the State would need to remedy. Further, in the Public Ownership option, the State would expect to receive additional economic value from the free cash flow engendered by the 1.10x debt service coverage assured in that case. All three options may require some level of State support if the pipeline's 500 mmscf/d capacity is not fully subscribed.

At this point, ASAP has not progressed to the point of project definition such that private entities are likely to be willing to step up as sponsors. As a result, only the Public Ownership option has a high degree of execution probability at this time. As the project economics and risk allocation become clearer, the relative merits of the three ownership options may change. In particular, the tradeoff between the degree of project risk that private entities will assume versus the ability to pass through higher tariffs to the Railbelt will become more apparent (see Section 7 for a risk comparison).

C&R have calculated the tariffs for the three financing alternatives and, using the Private Ownership option as the benchmark, have calculated the tariff differential compared to the benchmark for the other options and for the sensitivities. In all cases, the differential is negative, meaning lower tariff levels compared to the benchmark. The resulting estimated transportation tariff differentials for the three financing alternatives are shown in the table on the following page. Throughout this report, the tariff results represent transportation costs over the initial operating term of the project ("Lifecycle Tariff"). The Lifecycle Tariff reflects the aggregate transportation tariff over the initial operating term of the project adjusting for non-level annual cost requirements. The tariff is equal to the present value of all revenue requirements, 2019-2038, over the present value of all units of delivered gas for the same period. This calculation is similar to a levelized tariff calculation in a Private Ownership (Rate Regulated) scenario, with the key difference being that the Lifecycle Tariff calculation is for illustration purposes only and not necessarily reflective of the actual tariff in any one year. Similar to the B&V results, the tariffs indicated within this report reflect future year dollars and are not discounted for assumed inflation. Further, it should be noted that the tariff results relate to gas treatment and transportation costs only. Upstream and downstream costs, including the required net back to Producers, the cost of NGL extraction, and local distribution costs, are not included in the transportation tariff results presented in this report.

Base Case operating and financial assumptions are outlined in Section 3 and assume a 500mmscf/d pipeline with a 20-year contract term. The analysis uses the facilities configuration known as Scenario 4(b) in the pipeline engineering study by the Michael Baker Corporation ("Baker"). The analysis further assumes pipeline throughput is consistent with the ramp-up schedule provided to C&R by AGDC on May 2, 2011. Further, we have assumed that the State continues to fund development costs through 2012.

# Lifecycle Transportation Tariff Differentials (\$/MMBtu)

(Base Case Results - Refer to Section 3 for Assumptions)

Private Ownership Public/Private (Rate Regulated) (Availability Fee) State/Public Ownership

Base Case Benchmark (\$1.38) (\$1.55) (1)

As identified in the table above, there is a significant degree of variation in costs across the ownership options. The State Owned structure is projected to result in the lowest tariff largely because the State is assumed to: (i) finance the project based on its credit, which is highly rated (Aa1/AA); (ii) not be subject to Federal and State income taxes (C&R have assumed that property taxes will be paid), and (iii) not require an equity return component. While the Private Ownership and Public/Private scenarios result in higher projected tariffs, these options also are intended to insulate the State from certain risks that are present in the State Owned scenario. In particular, more construction cost and operating and maintenance risks may be transferred to the private sector in the Private Ownership or Public/Private alternatives, as discussed in greater detail in Section 3 of this report.

A component of both the Private Ownership and Public/Private alternatives is the equity return required by the equity members. This amount represents the payment required for any risk transfer and the earnings necessary to cause the private sector to effect the transaction. Notably, the public ownership option does not require an equity return to the State of Alaska as ASAP is 100% debt financed and provides a public service; however, in C&R's view, a 1.10x debt service coverage ratio is needed to generate adequate ratings on the bonds. In this case, the resulting free cash flow could either be viewed as an equity return to the State of Alaska or used to offset the tariff in future years.

As detailed below, C&R have also looked at certain financing permutations to further reduce the transportation tariff, including: (i) the potential ability to finance ASAP with tax-exempt bonds through the Alaska Railroad Corporation ("ARRC"), subject to IRS approval; (ii) the extension of the contract term from 20 to 30 years; and (iii) the shortening of the construction period by one year.

## Lifecycle Transportation Tariff Differentials (\$/MMBtu)

(Additional Results – Refer to Sections 3 and 6 for Assumptions)

	Private Ownership (Rate Regulated)	Public/Private (Availability Fee)	State/Public Ownership <sup>(1)</sup>
Base Case	Benchmark	(\$1.38)	(\$1.55)
Alaska Railroad (Tax-exempt Financing)	(\$.20)	(\$1.73)	(\$2.16)
30-year Term	(\$.91)	(\$1.80)	(\$1.93)
Shortened Construction	(\$.09)	(\$1.48)	(\$1.60)
Combination: 30-year Term, ARR and Shortened Construction	(\$1.19)	(\$2.20)	(\$2.56)

<sup>(1)</sup> In addition, there is approximately \$0.45/MMBtu in free cash flow to the State as a result of the 1.10x debt service coverage. Could be used to reduce tariff in future years.

<sup>(1)</sup> State/Public Ownership tariff includes \$0.45/MMBtu in free cash flow to the State. Free cash flow could be used to offset tariff in future years. If the State/Public Ownership tariff is calculated net of free cash flow, the differential versus the Private Ownership benchmark is estimated to be \$2.00/MMBtu.

The projections above reflect more attractive outcomes. However, we note that they are also dependent on a number of assumptions, including (i) the use of ARRC to finance the Project with tax-exempt debt in the first case, (ii) the successful negotiation of 30-year contracts with suppliers and gas users in the second case, (iii) the ability to shorten the construction period in the third case, and (iv) the combination of all three in the final case. As discussed in Section 6, each of these possibilities will require additional analysis, negotiations and due diligence.

Further, we note that the results presented in this report assume that the pipeline throughput is consistent with the ramp-up schedule provided by AGDC on May 2, 2011. This assumes that AGDC is successful in identifying anchor industrial users or attracting LNG export demand to provide committed off take for the portion of the pipeline capacity that is in excess of current in-State Railbelt demand. In C&R's view, the Project will need commitments for 100% of pipeline capacity prior to construction under any ownership scenario. This assumption is driven by the fact that, to date, the private sector has been unwilling to accept any demand risk. To the extent ASAP is not fully subscribed, either the transportation tariff per unit of delivered gas would need to be higher or the State of Alaska would need to back stop any unsubscribed capacity with a commitment of its own. This analysis is discussed further within Section 5 of this report.

Finally, we note that all results are preliminary as of June 20, 2011. Results are subject to change based on market conditions, changes in project configuration, capital costs, construction schedules, contracting arrangements and a variety of other factors. The results presented herein represent C&R's best approximation for the transportation tariffs given the current stage of the Project, the assumptions provided by AGDC, and market conditions known as of this date.

#### 2. BACKGROUND DISCUSSION

#### A) Historic Context

In developing our finance plan, C&R have carefully considered the work and efforts to date as well as the Federal and State legislative context. Our finance plan is designed to account for this background, which includes the following:

- Historically, much of south-central Alaska, including Anchorage, Fairbanks and the greater Railbelt region, has sourced natural gas from developed natural gas reserves within the Cook Inlet.
- Future Cook Inlet natural gas production capability is uncertain, as are future initiatives to source new production and/or increase output. Both Petrochemical Resources Alaska and the Alaska Department of Natural Resources project Cook Inlet deliverable reserves from developed fields to fall short of in-State demand for natural gas before pipeline startup.
- It is widely believed that a reliable, long-term alternative to Cook Inlet supplies is needed to supply natural gas to Alaskans for home heating and electric power generation.
- The Alaska Natural Gas Pipeline Act ("ANGPA") was passed by Congress in 2004 in order to
  encourage the construction of an Alaska natural gas pipeline which would transport natural gas
  from producing areas in Alaska to the border between Alaska and Canada.
- The Alaska Gasline Inducement Act ("AGIA") passed by the Alaska Legislature in 2007 allows the State to award an exclusive and enforceable license whereby the AGIA licensee is entitled to matching contributions from the State up to \$500 million to aid in the development of a large diameter pipeline from the North Slope.
- The construction of a large diameter pipeline from the North Slope to the Lower 48 has been a matter of uncertainty for a number of years amid increasing capital cost estimates and depressed domestic natural gas prices. On December 16, 2010, the U.S. Energy Information Administration ("EIA") provided an early overview of its 2011 Annual Energy Outlook ("AEO"), a yearly forecast of domestic energy markets over a 25 year period. Based on the reference case included within the AEO, the EIA excluded a large diameter pipeline from the Alaskan North Slope to account for the rise of North American shale gas resources. In prior AEO projections, the pipeline had been assumed to start production as early as 2020. The EIA noted that the change reflects a possible delay beyond the projection period.
- Lease agreements between the State of Alaska and certain Producers provide the Producers with the right to source, extract, market and sell natural gas from gas reserves on the North Slope. Under these leases, the State has the right to certain royalties, which can be realized either as royalties-in-kind ("RIK") or as royalties-in-value ("RIV").

# B) Project Status

It is C&R's understanding that ASAP is currently in an early stage of development. In conjunction with its consultants, AGDC has developed a comprehensive assessment of the critical requirements for planning and developing ASAP. This work is in response to the Alaska Legislature's SCS CSHB 369(FIN), which

requires an in-State natural gas pipeline development plan to be delivered to the Alaska Legislature by July 1, 2011. In the course of project development, AGDC has established many parameters, including:

- Proposed pipeline routing;
- Proposed facilities configuration;
- Permitting requirements;
- Preliminary capital cost estimates; and
- Preliminary market demand forecasts.

These assumptions have been included in C&R's financial analysis and are outlined in greater detail in Section 3 of this report. Given the preliminary status of the Project, it is worth noting that there are still a large number of critical assumptions that are undefined, including contract terms, the risk appetite of the State, and the risk appetite of other project participants. As we discuss in this report, there are three basic alternatives to finance ASAP and allocate risk among the parties involved. The optimal approach will be developed through contract negotiations among the parties and, most importantly, will be defined by the general risk appetite of the State. As a result, C&R's approach to the finance plan is to provide the conceptual framework for the financing alternatives available in the market today, while also discussing the risks and advantages of each approach. Given the preliminary status of the Project, our intent is to provide AGDC with the framework of a financing plan that is consistent with the current market environment and the project development work completed to date.

# C) Need for Project

Over the last several years, there have been numerous demand studies commissioned in conjunction with initiatives to commercialize natural gas resources on the Alaskan North Slope. These initiatives have been driven by both the need for a more reliable source of long-term natural gas supply to meet in-State demand and the desire to export natural gas outside of Alaska and generate revenue for the State and Alaskans. It is C&R's understanding that the primary need for ASAP is the looming natural gas supply shortfall in south-central Alaska. While it is envisioned that a component of ASAP may provide natural gas for LNG export to the Pacific Rim markets, the primary driver of the Project is the need to provide the critical resource of natural gas to Alaskans for home heating and electric power generation. As discussed later in this report, any LNG export component of the pipeline is envisioned to provide economies of scale such that the level of transportation tariff is both affordable and below the cost of other natural gas supply alternatives.

Original work on a "bullet" gas pipeline was undertaken by ENSTAR Natural Gas with work finalized and the project put on hold in 2008. A copy of Northern Economics, January 2010 "In-State Gas Demand Study Volume 1: Report" was furnished to C&R in conjunction with our development of the financing plan. Although Northern Economics did not prepare this report on behalf of AGDC or in contemplation of ASAP, the report evaluates potential future in-State demand for natural gas and propane for industrial uses, electric power generation, and heating demand from the residential and commercial sectors, including the military. The report states that Alaska's demand for natural gas historically has been greater for gas-intensive industries than for all other sectors combined (i.e., power, residential, commercial, and other industrial). As a result, future demand for natural gas in the State is substantially affected by the future of Alaskan gas-intensive industries. However, with the shutdown of the Agrium plant and the closure of the ConocoPhillips/Marathon LNG plant, industrial demand has been reduced

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substantially. The Northern Economics study notes that total in-State demand from "no industry" sources is projected to be 260 mmscf/d in years 1-5 of pipeline operation with an 86% likelihood of exceeding 290 mmscf/d in years 10 through 15.

For local utilities, such as ENSTAR, Chugach Electric Association and Anchorage ML&P, Cook Inlet gas currently provides between 88% and 100% of natural gas supply. Current gas supply arrangements are expected to fall short of needs for each of these utilities within the next four years. In March 2010, Petrotechnical Resources of Alaska ("PRA") completed a study commissioned by these utilities with the objectives of: (i) reviewing the deliverability of Cook Inlet gas wells drilled from 2001-2009; (ii) forecasting deliverability of existing and future Cook Inlet gas wells; and (iii) analyzing the timing required for delivery of non-Cook Inlet gas sources. Both PRA and the Alaska Department of Natural Resources ("ADNR") have concluded that the region will face annual supply problems before the commissioning of ASAP if no new wells are drilled and that significant development activity is needed. PRA further concluded that near-term drilling must be successful or gas resources from outside the Cook Inlet could be required as early as 2014.

In sum, there will continue to be critical demand for natural gas throughout south-central Alaska. With the shortfall in natural gas supply from the Cook Inlet region anticipated to occur as early as 2014, there is an essential need for a long-term, cost effective reliable supply of natural gas to the region. As envisioned, ASAP would fulfill this need while also providing revenue to the State of Alaska.

# D) Competitive Position

Given the critical need for a long-term reliable supply of natural gas, support for ASAP relies on its cost-effectiveness relative to other potential alternatives. A key component to securing cost effective financing for ASAP will be the project's ability to secure buyers for the delivered gas. ASAP represents a long-term investment in the State's resources and infrastructure, would create new jobs, and could boost State and local tax revenues. However, ASAP also faces high capital costs and, in turn, would require a substantial transportation tariff. In order to better understand the environment in which an ASAP plan of finance would be cost effective, it is important to also understand the alternative supply proposals. To the extent that Cook Inlet production increases or alternative supplies of gas or electricity become available through other means, these new options could erode ASAP's potential customer base, at least over the short term. To the extent ASAP moves forward, the delivered cost of gas from the line will need to be competitive with other potential alternatives and/or be supported by long-term, credit-worthy offtake contracts.

#### 1) Additional Exploration, Discovery, and Production from the Cook Inlet

Efforts to increase production, including through the use of compressors, the drilling of additional wells in existing fields, and the discovery and development of new reservoirs are ongoing. While these efforts may increase supply in the near to intermediate term, their success is uncertain and future Cook Inlet production is not thought to address long term supply.

#### 2) Construction of a Spur Line off the Large Inter-State Line

This approach would provide for a much shorter line (approximately 300 miles) relative to ASAP (737 miles) and, as a result, could provide a reduction in capital costs. However, the approach is dependent upon the timing and construction of the large diameter line and is not synchronized with the natural gas needs of Alaskans. Given recent shale discoveries in the Lower 48 and

Canada and current forward price projections for natural gas, the Energy Information Administration ("EIA") projects that the domestic market for natural gas will not support the construction of the large diameter line until the 2035 timeframe – well beyond the date at which the Cook Inlet is expected to face a supply shortage.

# 3) Development of LNG Receiving Capabilities

This approach avoids the capital cost of transporting natural gas from the North Slope to south-central Alaska and could potentially be cost competitive with other alternatives, including ASAP. Along with continued production from the Cook Inlet, LNG receipt is thought to provide a viable near term solution to bridge the supply gap. As discussed below, the relative cost of this approach will depend substantially upon its scale. Based on a study completed by SAIC, the projected cost of LNG import and re-gasification is approximately \$14.10/mmbtu to \$19.00/mmbtu. This projection assumes an import volume of 250 mmscf/d, consistent with in-State demand. Further, the projections assume a 10-20 year commitment and utilization of full capacity of the re-gasification facilities. It is C&R's understanding that Enstar recently issued a request for proposals for LNG delivery.

# 4) Development of the Susitna Hydroelectric Project

In 2010, the Alaska State Legislature passed House Bill 306 which directs the State's energy policy. The bill instructs the State to receive 50% of its electrical generation from renewable and alternative energy sources, which can include large hydroelectric, by 2025. There may be concern that, should Susitna or any other large hydroelectric project be developed, the amount of in-state natural gas demand could potentially decline as gas fired electrical generation capacity is replaced with that produced by hydroelectric projects. According to the Preliminary Decision Document prepared by the Alaska Energy Authority dated November 23, 2010, the energy generated by the Susitna project could provide approximately one half of the current Railbelt electrical energy demand.

Of the 240 mmscf/d of projected in-State natural gas demand used in C&R's throughput assumptions, approximately 76 mmscf/d is used as fuel in the generation of electricity in the southern Railbelt from 2019-2024, declining to 57 mmscf/d through 2033 and increasing back to 76 mmscf/d in 2034. These figures were provided by AGDC and are similar to the projected future natural gas demand shown in the Large Hydro/Renewables/DSM/Energy Efficiency Scenario in the In-State Gas Demand study by Northern Economics. The study projects future instate demand for natural gas after taking into account the potential addition of one or more large hydroelectric plants, other renewable resources, and demand side management and energy efficiency programs. The Northern Economics projections show that future electric generating resources added to the region will not greatly diminish the amount of in-state natural gas demand below the levels already assumed in C&R's analysis. In addition, the Susitna project development period is projected to be 11 years, which means that the project would not be completed until 2023 at the earliest.

For the purpose of C&R's analysis, we have made two critical assumptions in consultation with AGDC. The first is that the pipeline remains fully subscribed for the full term of the financing (20 years in the base case), adjusting for 96.5% operating efficiency and seasonal demand, consistent with the ramp-up and operating assumptions illustrated in Section 3(B) herein. Second, we have assumed that in order for

the Project to secure a customer base, it will need to be cost effective relative to competing alternatives. For the purpose of this report and based on guidance from AGDC, we have assumed a LNG transportation tariff of \$12.10. This assumption was supplied by AGDC through its work with SAIC and represents the low end of the estimated price range for LNG delivery to the Cook Inlet. To provide a fair comparison, we have subtracted \$2.00 from the estimated cost of importing LNG, representing the estimated netback that would be required at the wellhead for any gas that is transported on ASAP. This cost would not be required for an LNG import scenario (for which commodity costs are included). Projected commodity costs are outside of C&R's engagement, although we note that in order for ASAP to be commercially viable, the all-in cost of gas will need to be cost effective relative to other available options.

Finally, the relative economics will be driven by the subscription level of the pipeline. While the estimated pipeline tariffs under all three financing options are lower than the estimated cost of importing LNG, the tariffs are also based on a fully subscribed 500 mmscf/d pipeline, while the LNG import figures assume 250 mmscf/d, which is consistent with the level of current in-State demand. In order for ASAP to realize the required economies of scale, it will need to be successful in attracting additional in-State industrial demand or an off take contract with an LNG exporter.

# E) Major Financing Risks

There is a clear correlation between financing cost and risk with respect to the development of ASAP. Further, it is apparent that in the absence of significant inducements, ASAP will not come to fruition on a timetable that meets Alaska's anticipated demand/supply imbalances. AGDC has already committed significant time and resources with respect to planning ASAP and can be viewed as the developer to date. Clearly, these predevelopment activities have significant value and are an incentive in themselves that should encourage private sector participants.

C&R have crafted our financing alternatives while evaluating and balancing various risk and cost tradeoffs. Quite simply, private contractors will offer more favorable terms (and will be more likely to participate) depending on the degree of risk that the State of Alaska will assume. The principal risks of the Project include:

- Gas Supply Risk
- Permitting/Right of Way Risk
- Construction Cost Risk
- Environmental Risk
- Operating and Maintenance Risk
- Demand Risk

While each of the aforementioned risks is critical and will have a direct impact on the Project's cost, there are clearly risks that the State may be able to compartmentalize and for which the State may be compensated in the form of a lower overall project cost. For example, given the work to date, the State may be comfortable assuming the permitting/right of way risk, whereas private contractors may be in a better position to assume construction cost risk.

In crafting various finance alternatives, we have also assumed that the State has a strong desire to quantify its risk exposure. It is unlikely, however, that any private entity will assume the risk of

unsubscribed capacity ("demand risk"). Accordingly, it is vital that the State secure industrial or export demand to anchor pipeline capacity. Likewise, it will be important for certain project participants to sign long-term contracts such that a dependable source of demand can be relied on to finance the pipeline. To the extent that ASAP is not able to secure 100% firm capacity commitments, it could be possible for the State to provide a commitment of its own for any unsubscribed capacity. A discussion of the benefits and considerations of this approach is provided in Section 5.

# F) Unique Aspects of ASAP

Compared to "standard" pipeline projects around the United States, ASAP has three main unique characteristics:

# 1) Single Source for Natural Gas Supply

For ASAP, there is only one source of supply – the North Slope – and the Producers situated there. Compared to other projects, this attribute means ASAP must procure long-term natural gas supply agreements equal to the term of the financing to ensure a viable, cost-effective source of gas. Many other pipeline projects have considerably more sources and therefore have substantially greater contract terms and price flexibility. In addition, it is our understanding that North Slope natural gas producers are viable partners only with the continued operation of the Trans-Alaska Pipeline System ("TAPS"). To the extent oil shipments on TAPS stop or decline significantly, it could create a substantial incremental cost burden on Producers as ASAP would have to bear the full cost of certain North Slope facilities which would benefit both TAPS and ASAP.

#### 2) Defined Service Area

To a great degree, ASAP will have a captive service territory and captive demand. On the other hand, that territory's natural gas demand at this time is only 260 mmscf/d. Absent the location of significant new industry within the Railbelt, ASAP will need to attract an LNG export business to accomplish the preferred economies of scale. In contrast, many other pipeline companies have greater access to multiple customers.

#### 3) Project Size and Complexity

ASAP is a "mega-project" and represents a large capital commitment and substantial set of risks to the private sector, making it difficult to find an entity willing or able to undertake the Project on its own. Further, given the length of the Project pipeline, the long construction period, and the difficult geographic and weather conditions, substantial risks exist compared to many other pipeline projects across the nation.

#### 3. ANALYSIS

In order to develop this finance plan, C&R have built a comprehensive cash flow model designed to accommodate various inputs, assumptions and scenarios. In developing such inputs and assumptions, C&R relied on data provided by AGDC as well as B&V.

# A) Facilities Configuration

Consistent with AGDC's direction, C&R's analysis assumes the facilities configuration known as Scenario 4(b) in the Baker Study. Scenario 4(b) includes a 24" diameter pipeline from Prudhoe Bay ("PB") to the Big Lake Interconnect ("Big Lake") along the Parks Highway route. The scenario assumes nominal 500 mmscf/d capacity and assumes additional natural gas liquids ("NGLs") are injected into the gas stream for pipeline gas with a higher heating value than in other scenarios. The Project includes a Gas Conditioning Facility ("GCF") at PB with compression into the pipeline, a pipeline to Dunbar, an NGL straddle plant and lateral line to Fairbanks, and a pipeline from Dunbar to Big Lake. This scenario assumes a nominal 50 mmscf/d off take to Fairbanks. There are no facilities included for CO2 disposal at the North Slope. Further, while NGL handling facilities at Big Lake would also be required in this scenario, it is assumed these costs would be borne by an NGL counterparty and not the pipeline entity. As a result, the costs related to an NGL facility at Big Lake are not included in the tariff calculations.

# B) Assumptions

The following financial and operating assumptions were provided to C&R by AGDC and its advisors. These assumptions were used for all base case scenarios analyzed. We note that all construction, operating and maintenance costs are assumed to be identical across the three ownership scenarios. Actual costs will depend on specific contracting arrangements.

#### **Pipeline Operating Assumptions**

Capacity	500.0 mmscf/d
Operating Efficiency	96.5%
Materials & Supplies	1% of gross plant + inflation
Annual Operating Expenses	\$136.0 million (\$2011)
Line Pack	4.0 Bcf
Property Insurance	0.50% of depreciated plant
Annual Cost Escalation	3%
Gas Used for GCF	14.6%
Gas Used for BTU Plant	0.5%
Transportation Losses	0.6%
NGL Composition	11.3%
•	

#### **Taxes**

Federal Income:	35%¹
State Income:	9.4%¹
Property:	2.0%2
Property Tax Basis:	Replacement cost new less depreciation (inclusive of financing costs)
Federal Tax Depreciation:	15-year MACRS (GCF); 20-year MACRS <sup>3</sup>
State Tax Depreciation:	17-year MACRS (Pipeline); 20-year MACRS <sup>3</sup>
Book Depreciation:	Level over full term

- (1) Income taxes included in Rate Regulated and Public/Private cases. Assumed not to apply to State/Public Ownership case.
- (2) Property taxes included in Rate Regulated, Public/Private, and State/Public Ownership cases.
- (3) MACRS Modified Accelerated Cost Recovery System

Billing Determinants – Billing determinants related to the heating value of the delivered gas at the output of the pipeline segment for the base scenarios are provided in the table to the right. Figures are reflective of Scenario 4(b) from the Baker Study.

Capital Costs – Capital costs for the base scenarios are provided in the table to the right. Cost estimates are shown in 2011 dollars and reflective of Scenario 4(b) from the Baker Study.

Gas Demand Schedule – Pipeline throughput is assumed to begin in 2019. The demand profile used in C&R's analysis, inclusive of a 96.5% operating efficiency and seasonal variation, is provided in the table to the right. This schedule was provided by AGDC on May 2, 2011.

Full Load Billing Determinants (000 mmbtu/d)	)
Gas Conditioning Facility	587
Pipeline: GCF to Dunbar	583
Fairbanks Straddle Plant and Pipeline	50
Pipeline: Dunbar to Big Lake Interconnect	531
Projected Capital Costs (2011 \$Million)	
GCF	\$1,839
GCF to Dunbar	3,413
Fairbanks Straddle Plant and Pipeline	278
Pipeline Dunbar to Big Lake Interconnect	1,985
Total	\$7,515
Pipeline Throughput (mmscf/d)	
Year 1 (2019)	437.1
Year 2 (2020)	453.6
Year 3 (2021)	478.2
Year 4 - 20 (2022 – 2038)	482.2

Development Costs / Start-up Capital – C&R have assumed that the State of Alaska will continue to fund project development costs through 2012. In C&R's view, this initial subsidy is necessary to continue the project development work completed to date as no outside entity would be willing to take control of the Project at the current preliminary stage of development. We believe the State is in the best position to continue the development work on ASAP through AGDC. Consistent with the B&V analysis, C&R have assumed that the State will subsidize development costs through 2012, which are projected to be approximately \$292 million.

Similarly, in our analysis, C&R have assumed that the State of Alaska provides the initial project funding post 2012. Although significant in dollar amount, the capital costs prior to heavy construction are small relative to the overall project cost. As a result, we have assumed that the State of Alaska provides the initial funding for project construction, by providing an interest free bridge loan from 1/1/2013 to 1/1/2014 in the amount of \$190 million. This bridge financing would be repaid to the State on 1/1/2014 when the pipeline entity is assumed to have more efficient access to the capital markets.

In C&R's view, the State's funding of the 2013 capital requirements will provide significant cost efficiencies. In the current market, it would be exceedingly difficult for the Project to source outside capital more than one year prior to construction and six years prior to commercial operation.

# C) Financing Alternatives

C&R have looked at three base case financing alternatives in order to bracket the range of project delivery structures along the public-private ownership spectrum and have included a "mid-point" public-private partnership ("P3") alternative. The alternatives analyzed are: (i) Private Ownership (Rate Regulated); (ii) Public/Private Partnership (Availability Fee Concession); and (iii) State of Alaska/Public Ownership. These alternatives are generally outlined below.

# Private Ownership (Availability Fee) (P3) Greatest Public Risk / Reward State/Public Ownership

- Pipeline company builds and operates ASAP and collects revenues from users
- Pipeline company contracts with suppliers
  - Given limited user base, substantially all pipeline capacity must be under contract
  - State may need to be the buyer of last resort
- ASAP is regulated by Regulatory Commission of Alaska and potentially FERC

- State enters into long-term DBFOM concession with private sector consortium
- Private sector receives availability fees, subject to delivery of service (successful construction and operation and maintenance of ASAP)
- Availability fee payment is an obligation of the State, subject to appropriation
- State bears all revenue risk
  - State mitigates revenue risk by entering into supplier contracts
- Asset reverts to the State upon maturity of concession

- State retains 100% ownership of Project
- Contracts with private sector for construction and operating contracts
- State bears all revenue risk
  - Operating and construction risks can be transferred to the private sector
  - State mitigates revenue risk by entering into supplier contracts
- State or AGDC issues debt to fund ASAP construction supported by the State

It is important to note that given (i) the significant size and complexity of the ASAP construction project, (ii) the need to provide a secure revenue source given the limited in-State demand, and (iii) the required tariff levels, the State of Alaska may need to provide some level of support for debt and/or project revenues in all three of the cases analyzed.

Further, it is important to note that there are certain structural and credit considerations which will apply to all these project delivery alternatives, including:

- 1) terms of the natural gas supply agreements with Producers ("Supply Agreements"),
- 2) terms of the pipeline transport agreements with Shippers ("Transport Agreements"),
- 3) terms of the gas purchase agreements with End-users ("Off-take Agreements")
- 4) nature and terms of the construction contracts.
- 5) use of State of Alaska royalty gas,
- 6) shape of the tariff structure,
- 7) length of the financing term,
- 8) sensitivity of the project cost and tariff to changes in interest rates,
- 9) number and timing of financings,
- 10) potential use of ARRC for tax exemption, and
- 11) any alternate project facility configuration under consideration by ASAP.

C&R will analyze the impact of these factors on the financing plan after discussion of the three base ownership structures below.

# 1. Private Ownership (Rate Regulated)

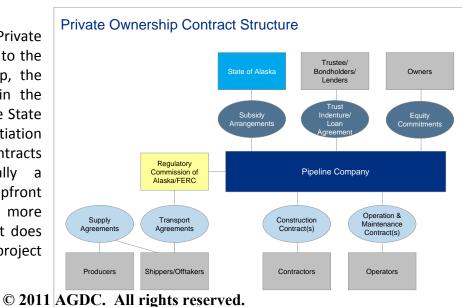
The Private Ownership structure represents the most common approach to financing pipeline projects in the United States. The Private Ownership of a pipeline is commonly structured as a joint venture among equity holders. Often one equity owner who has one of the larger percentage holdings of the equity ownership also holds the role as operator. In the current market, there are a large number of dedicated, competitive participants in all aspects of the pipeline industry (including development, construction, operation, and engineering firms, as well as debt and equity financing providers) who have worked together to finance, build and operate large-scale pipeline projects in the United States and internationally. AGDC is familiar with many of these participants through recent meetings that it has conducted with regard to the Project.

The typical private ownership financing model for precedent projects consists of two stages. In the first stage (the development/initial construction phase), the pipeline project is effectively developed on the balance sheets of the large, creditworthy pipeline owner/operators. Financing comes from two major sources: (1) pipeline owner/operator equity, and (2) credit facilities/commercial paper that are backstopped by corporate guarantees from the pipeline owner/operators. This initial financing is used to fund the engineering and construction of the pipeline project.

Once a large portion of the construction project is complete (the operational phase), the pipeline owner/operators will seek to refinance the credit facilities/commercial paper in the long-term capital markets under a non-recourse structure (in which the long-term debt is solely backed by the project and no longer receives any implicit credit support from the pipeline owner/operators). This can be considered the operational phase of the pipeline project. Access to the public debt capital markets will be dependent on the project's ability to obtain solid investment grade ratings, binding long term agreements with major shippers (who are responsible for making Reservation Demand Charge payments to the pipeline entity sufficient to pay debt service and operating costs), and market conditions. Investors and rating agencies will typically look to the term of the shipping and off take agreements and the credit quality of the parties involved as the key credit considerations.

# **Contract Structure**

The contract structure for the Private Ownership approach is depicted to the right. Under Private Ownership, the private sector takes the lead in the development of the project. The State assists in the facilitation of negotiation and execution of key project contracts (as an agent and potentially counterparty) and provides an upfront or ongoing subsidy to provide more favorable project economics, but does not play the integral project coordinator role.



# **Contract Descriptions**

#### **Corporate Structure**

Under a Private Ownership structure, the joint venture would operate under the terms of a limited liability company agreement. The expectation is that ASAP would be managed by its members through a board and most actions of the board would require an affirmative vote of board members representing at least a majority percentage of membership interests. Experienced parent companies would help manage and drive the project strategy going forward. Often, an experienced pipeline company would serve as operator for the pipeline's daily operations and as an overseer of construction of the pipeline.

# Operations and Maintenance Contract(s)

The Pipeline Company will typically enter into an Operation and Maintenance Contract with an experienced, market-acceptable Operator. This contract typically takes the form of a fixed fee for services and a profit sharing component. The contract term is typically for a longer period (20 years or more is possible) and may be subject to a number of five/ten-year extensions.

#### **Construction Contract(s)**

Although construction obligations are often covered under the Operations and Maintenance Contract(s) in the pipeline sector, it would also be possible for the Pipeline Company to enter into standalone Construction Contract(s) and Operation and Maintenance Contract(s), depending on which structure provided the most cost-effective allocation of risks. Typically, the Construction Contract would provide the Pipeline Company with a fixed price, date certain arrangement with incentives for early completion and penalties for delays in timing or shortfalls in demonstrated performance. Due to the complex nature of ASAP, it may be necessary to use a "modified turnkey" approach as outlined in Section 4(D).

#### **Transport Agreements**

Transport Agreements represent the key revenue contracts for the Pipeline Company. The Pipeline Company will contract with viable transportation shippers, possibly including the State of Alaska, to ship volume through the pipeline. Shippers may pay a reservation demand charge for the maximum daily quantity and possibly a commodity charge based on actual transported volume. Additional commentary related to Shippers is included below.

# Supply and Offtake Agreements

In typical pipeline projects, Supply and Off-take Agreements are considered to be outside the scope of the pipeline financing given that the Transport Agreements are typically recourse to the Shippers (i.e., Shippers are required to pay the reservation demand charge, regardless of whether they have a contract with a buyer for the gas shipped or receive payment for that gas). However, given the nature of the proposed ASAP financing with captive supply on the North Slope and limited in-State natural gas demand, the Supply and Off-take Agreements will factor into the project credit and contract analysis.

# **Major Shippers**

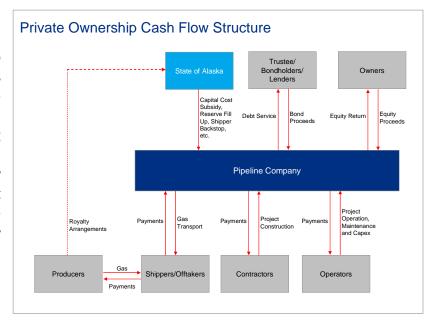
Shippers are often oil and gas producers or marketers with significant balance sheets and financial resources. The agreements with the Shippers to provide major transportation services for the pipeline's capacity will be key to ASAP's ability to source capital in either the public or private capital markets. Most notably, the length of

		Market Cap	
Builder / Owner / Operator	Ticker	(\$bn)	Moody's / S&P
Exxon Mobil Corp	XOM	424.7	Aaa / AAA
BP plc	BP	144.4	A2 / A
ConocoPhillips	COP	114.4	A1 / A
Enterprise Products Operating LLC	EPD	36.2	Baa3 / BBB-
Enbridge Inc	ENB	24.8	Baa1 / A-
Enbridge Energy Partners, L.P.	EEP	8.4	Baa2 / BBB
Kinder Morgan Energy Partners LP	KMP	23.1	Baa2 / BBB
The Williams Companies	WMB	18.6	Baa3 / BB+
Williams Partners LP	WPZ	15.7	Baa3 / BBB-
El Paso Corp	EP	14.6	Ba3 / BB
El Paso Pipeline Partners	EPB	7.6	Ba1 / BB
Plains All American Pipeline, L.P.	PAA	9.5	Baa3 / BBB-

the agreements and the credit ratings of the Shippers will factor into the credit considerations of ASAP, as well as what outs the Shippers may have in the agreements related to their ongoing payment obligations. Binding long-term firm transportation agreements for 100% of the total pipeline capacity will be critical to the Project's success in a Private Ownership approach as we do not believe that a private owner would be willing to take any significant merchant risk associated with unsubscribed pipeline capacity. The Private Ownership option will likely require the State of Alaska to initiate negotiations with potential Shippers (which could also include utilities) and Producers. C&R understands this process is currently underway.

#### **Cash Flow Structure**

flowchart of payment and responsibilities in a private ownership structure is depicted to the right. As illustrated in the graphic, there are essentially three sources of capital: (i) the State of Alaska for start-up funding and any required State contribution; (ii) the capital markets for a bank facility (construction phase) or long-term debt (operating phase); and (iii) the private for owners private equity contributions.



#### **Financing Assumptions**

An overview of financing assumptions is included below. As discussed in the introduction, a Private Ownership financing alternative for ASAP is assumed to be undertaken in two phases: initial construction phase (with pipeline owner/operator credit support) and an operational phase (with debt that is non-recourse<sup>1</sup> to the pipeline owner/operators and solely backed by the project). For the purpose of our analysis, C&R have assumed long term credit ratings of BBB-/Baa3. This assumption is intended to provide a conservative base case for the private ownership approach. As discussed above, the ultimate credit ratings assigned to the project will depend on the credit ratings of the equity participants.

#### **Initial Construction Phase**

Financing Structure	Combination of equity / bank loan
Equity / Debt Ratio	35% / 65%
Construction Draws	Equity and bank loan drawn pro-rata
Bank Loan Interest Cost	Drawn: 1 mo LIBOR + 250 bps* Undrawn: 83 bps
Bank Loan Upfront Fee	1% on committed amount
LIBOR Assumption	2.38% (1 month LIBOR 10-yr average)

#### **Operational Phase**

Financing Structure	Combination of equity / long-term taxable bonds
Equity/Debt Ratio	35% / 65%
Bank Loan Repayment	Bank loan taken out with bonds upon end of construction period
Long Term Debt Service Structure	20 year level debt service, matched to term of initial contracts
Debt Service Reserve Fund	None
Cost of Issuance / Underwriters Discount	1% total
Interest Rate	Treasuries (10-year average) + 275 bps (assumes BBB-/Baa3 ratings)

Assumptions are preliminary based on market conditions as of May 16, 2011.

#### **Capital Structure**

The capital structure in the Private Ownership option should be targeted to meet certain financial ratios that map to the appropriate credit ratings as set out by the credit rating agencies. Each rating agency weighs both qualitative and quantitative variables in its analysis and rating of an issuer. Some of the important financial ratios observed by the rating agencies include:

Moody's	Standard & Poor's
Funds from Operations plus Interest / Debt	Debt to EBITDA
Funds from Operations / Debt	Funds from Operations / Debt
Operating Margin	EBITDA Interest Coverage
Debt / Total Capitalization	Funds from Operations plus Interest / Debt
	Debt / Total Capitalization
	Net cash flow to Capital Expenditures
	Return on Capital

<sup>1</sup> Non-recourse debt is debt secured only by the Project and Project revenues. If there is a payment default, bondholders can only look to the Project and cannot seek out the borrower or State for any further compensation.

<sup>\*</sup> bps = basis points; 100 basis points are equal to 1%.

Debt to capitalization is a traditional measure of leverage and can be a useful way to gauge a pipeline's overall financial flexibility in light of its overall debt load. High debt to capitalization levels are not only an indicator of higher interest obligations, but can also limit the ability of a company to raise additional financing if needed and can lead to leverage covenant violations in bank credit facilities or other financing agreements. In the United States, pipeline leverage is typically managed in the 50% to 60% range. Project-financed pipelines are often about 70% debt financed. However, pipeline capital structures can vary considerably from company to company. Given the specific attributes of ASAP, with an eight year development period and a project environment running the length of Alaska, C&R believe a 65/35 debt to equity ratio to be the most appropriate at this time.

#### **Tariff Structure**

A levelized tariff structure is assumed for the Private Ownership approach. This is consistent with a FERC regulated structure where a rate base tariff calculation is performed based on the pipeline's cost projections, which is then levelized over the term of the rate case. In C&R's analysis, the tariff is assumed to be level over the term of the initial operating contracts (20 years) and is structured to generate a 12% after-tax return on equity. The base case tariff over the initial operating term (lifecycle tariff) for the Private Ownership scenario is used as the benchmark for comparing the three ownership options.

#### **Benefits and Considerations**

The Private Ownership approach provides one template for the financing, construction, and operation of ASAP. There are a number of industry participants with significant experience with similar projects and in Alaska. By transferring the project to a private owner/operator, the State of Alaska can potentially limit its risk profile. However, ASAP is also unique to the industry and brings a set of risks that will require special consideration on the part any private party.

**Benefits** Considerations

- Most common approach to pipeline ownership in the U.S.
- Transfers risks of designing, building, financing, operating and maintaining the Project to private sector participants with significant experience in the industry
- Provides known upfront cap on total public sector obligations (equal to any upfront subsidy payments), unless additional State support is needed
- Competitive bid market incentivizes pipeline developer/manager to quickly and efficiently construct pipeline
- Fully leverages expertise of pipeline owner/operator

- Public sector loses all day-to-day control of the Project
- Requires equity return to private owner (12% ROE equal to approximately \$6.4bn in nominal dollars over the 20 year term)
- Given construction and operating risks and credit quality of contract counterparties, debt backed solely by private sector credit will likely fail to achieve high investment grade ratings, leading to an increased cost of capital
- State takes risk that the Project is not financially viable and private entity shuts down operation
- Unlikely that Shippers will assume all demand risk given limited in-State demand and may require State support for any unsubscribed capacity

# 2. Public Private Partnership (Availability Fee) (P3)

Under an Availability Fee (P3) structure, the State would enter into a long-term design, build, finance, operate and maintain ("DBFOM") concession contract with a private sector consortium of experienced pipeline owner/operators ("Concessionaire"). The Concessionaire would finance, construct and operate ASAP and, in return, receive Availability Fees from the Project's public sector sponsor (the State of Alaska), subject to the delivery of service.

Under the Availability Fee (P3) structure, the primary source of revenue for the Concessionaire would be the Availability Fee that is received from the State of Alaska. The fee is a pre-determined, fixed fee with inflation escalators and is designed to cover the costs required to operate and maintain the pipeline, service the debt, and provide an equity return. The Availability Fee payments are expected to be offset by revenues the State receives from Shippers and/or off take. The Availability Fee payment from the State would be subject to the Concessionaire meeting certain stipulated requirements under the concession contract, typically contains deductions for shortfalls in performance, and would be subject to RCA regulation. As connoted by the name, payment is subject to the asset being "available" for use (i.e., fully constructed and operating within certain thresholds).

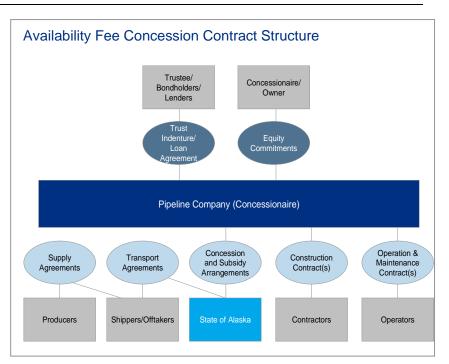
Assuming that the asset is constructed and operating, the Concessionaire receives baseline payments for the life of the concession, beginning with substantial operational completion of the Project. From the private sector's perspective, a primary risk in a project with the complexity and size of ASAP is revenue risk (i.e., generating enough contracted revenue to ensure payment of debt service, O&M expenses and return on equity are met). An Availability Fee from the State can alleviate this concern over contracting enough revenue on an annual basis to support the Project's costs. Through the Availability Fee, the State supplies general revenue to the extent there is a shortfall in in-State demand/sales revenues or in LNG export demand/sales revenues. On the other hand, the Concessionaire bears the risk of project construction and performance. This allocation of risks in turn reassures bondholders by ensuring that both the State and the Concessionaire are able to mitigate project risk and continue to have a stake in the financial health of the Project.

The Availability Fee payment could be structured as an obligation of the State, subject to appropriation. Given that the structure does not provide for the transfer of demand/revenue risk for delivery of service to the private sector Concessionaire, the structure is typically utilized in projects that generate inadequate revenues to cover their full cost of construction and ongoing operation. As a result, the State would bear the demand risk for any unsubscribed pipeline capacity or the future revenue shortfall. The benefit for the State is the ability to shed all or a substantial portion of liability during the construction period and for the operating period of the Project, avoiding the potential for expensive cost overruns. Further, the pipeline asset would revert to the State upon maturity of the Concession.

Availability Fee P3 structures are common financing mechanisms in Europe and have become increasingly common in the United States, particularly in the financing of transportation infrastructure. Many recent P3 financings in the United States have incorporated Availability Fee mechanisms, including the Denver RTD FasTracks transit project (financial close August 2010), I-595 South Florida Express Lanes (financial close March 2009), the Port of Miami Tunnel (financial close October 2009), and the Long Beach Courthouse Project (financial close December 2010).

#### **Contract Structure**

The contract structure for the Availability Fee (P3) option is provided in the graphic to the right. discussed, the Availability Fee (P3) structure will shift the revenue risk associated with the long-term Off-take Transport, Supply and Agreements from the private sector to The Concessionaire will the State. contract with the State through the Concession Agreement to provide turnkey construction, operation and maintenance services, and the Shippers and Producers will contract with the State of Alaska with regard to transport and supply to the pipeline.



#### **Key Contract Descriptions**

#### **Corporate Structure**

In Availability Fee (P3) financings, similar to the Private Ownership structure, an ownership joint venture is formed, which would operate under the terms of a limited liability company agreement. Precedent Availability Fee (P3) financings have seen this joint venture comprised of some combination of construction firms, operating/equipment firms, and financial sponsors. Similar to the Private Ownership option, an experienced pipeline owner/operator would be expected to play a lead role in this structure.

# Operations and Maintenance Contract(s)

Similar to the Private Ownership alternative, the Concessionaire will typically enter into an Operation & Maintenance Contract with an experienced, market-acceptable Operator. Often the Operator will be an equity member of the Concessionaire. This contract typically takes the form of a fixed fee for services and a profit sharing component. The contract term is typically for a longer period (20 years or more is possible) and may be subject to a number of five/ten-year extensions.

#### **Construction Contract(s)**

Under the Concession, the Pipeline Company is responsible for delivering a completed project. Not until then is the State responsible for making the availability fee payments. The Pipeline Company will offload most of the construction risk by entering into one or more construction contracts. The Pipeline Company will attempt to enter into fixed price, date certain, turn-key design-build arrangement for the delivery of ASAP. Due to the complex nature of ASAP, it may be necessary to use a "modified turnkey" approach as outlined in Section 4(D), which will be factored into the Availability Fee proposals made to the State.

#### **Concession Agreement**

The main project agreement in Availability Fee (P3) financing structure will be the Concession Agreement between the Concessionaire and the State. The Concession Agreement will provide for the initial and ongoing construction, operations, and maintenance obligations of the Concessionaire, as well as the formulaic Availability Fee payment from the State that will serve as the sole source of revenue to the Concessionaire.

#### **Transport Agreements**

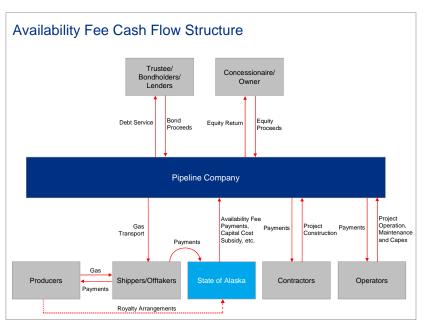
In an Availability Fee financing structure, Transport Agreements will not be an obligation of the Concessionaire. The State of Alaska will contract with Shippers to utilize the project, subject to ASAP availability. In the event that ASAP is not available, the State of Alaska will make liquidated damage payments to the shippers. If the unavailability of ASAP is due to the fault of the Concessionaire, the Concessionaire will make liquidated damage payments to the State to cover these (and possibly additional) payments.

# Supply and Offtake Agreements

Similar to the Transport Agreements, in an Availability Fee Structure, Supply and Off-take Agreements will not be an obligation of the Concessionaire. The State of Alaska will contract with the Producers and Offtakers and bear the associated revenue risk.

#### **Cash Flow Structure**

flowchart of payment and responsibilities in an Availability Fee payment structure is depicted to the As illustrated in the graphic, there are three sources of capital: (i) the State of Alaska for start up funding and any required State contribution; (ii) the capital markets for a bank facility (construction phase) or long-term debt (operating phase); and (iii) Concessionaire for the private equity contribution.



#### **Availability Fee (P3) Financing Assumptions**

An overview of the financing assumptions is included below. Under the Availability Fee (P3) financing structure, C&R have assumed that the Project would be undertaken in a two-step process (similar to the Private Ownership structure), with the construction financing supported by the credit of the project equity participants and the operational financing solely backed by the Pipeline Company and non-recourse to any of the project equity participants. This structure is achievable due to the credit strength of the Availability Fee financing structure, which is backed by the State of Alaska's payment obligation. From the lender's perspective, there are two primary credit risks: (i) the operation and performance of the Project (which are controlled by the Concessionaire) and (ii) the timing and sufficiency of project-related revenues (which are supported by the State of Alaska).

#### **Initial Construction Phase**

Financing Structure	Combination of equity / bank loan
Equity / Debt Ratio	12% / 88%
Frequency of Construction Draws	Equity and bank loan drawn pro-rata
Bank Loan Interest Cost	Drawn: 1 mo LIBOR + 300 bps Undrawn: 100 bps
Bank Loan Upfront Fee	1% on committed amount
LIBOR Assumption	2.38% (1 month LIBOR 10-yr average)

#### **Operational Phase**

Financing Structure	Combination of equity / long-term taxable bonds
Equity/Debt Ratio	12% / 88%
Bank Loan Repayment	Bank loan taken out with bonds upon end of construction period
Long Term Debt Service Structure	20 year with 1% annual ascending debt service
Debt Service Reserve Fund	6 months of maximum annual debt service
Cost of Issuance / Underwriters Discount	1% total
Interest Rate	Treasuries (10-year average) + 200 bps (assumes A/A ratings)

#### **Capital Structure**

Recent Availability Fee (P3) offerings in the United States have featured debt/equity mixes in the ranges of 10-15% equity and 85-90% debt (net of capital contributions from public sector sponsors, including federal, state, and local grants). The capital structure for the \$1.6 billion Denver RTD FasTracks light rail P3 that reached financial close in August 2010 featured approximately \$400 million of US tax-exempt bonds and \$55 million of cash equity (equating to a debt/equity mix of 88/12%). The remainder of the funding was provided by federal and state grants. Similar profiles were observed in other recent completed Availability Fee (P3) financings, including the Port of Miami Tunnel P3 (90/10%) and the I-595 Corridor Roadway P3 (87/13%).

#### **Tariff Structure**

The tariff is structured to escalate by 0.75% annually over the initial operating term (20 years) and is set to generate a 12% pre-tax return on equity with minimum debt service coverage of 1.15x, after payment of all operating and maintenance expenses. The base case tariff for the Availability Fee scenario is projected to be \$1.38/mmbtu (lifecycle tariff) less than the Private Ownership benchmark.

# **Benefits and Considerations**

An Availability Fee (P3) public private partnership provides a proven approach to large scale infrastructure financing. The P3 approach provides benefits by allocating specific project risks to the parties who find those risks most palatable. Similar to the Private Ownership approach, the private sector will be responsible for the construction and operation of ASAP through experienced construction contractors and operators. Unlike the Private Ownership approach, the State of Alaska will assume all revenue risk subject to the delivery of service. To the extent ASAP is unable to obtain capacity commitments for 100% of the pipeline's throughput, this approach could make the Project more palatable to the private sector, while shifting the demand risk to the State.

Benefits Considerations

- Transfers risks of designing, building, financing, operating and maintaining the Project to private sector concessionaire
- Provides known upfront cap on total State obligations (equal to any upfront subsidy payments plus maximum Availability Fee payments)
- Provides cap on private sector upside
- Competitive bid provides strong incentives for Concessionaires to provide efficiency gains in construction, operation, and maintenance
- Shift of revenue/demand risk to the State of Alaska likely would result in "A" ratings during operational period

- Public sector retains demand risk associated with Project
- Requires equity return to private owner pre-tax (12% ROE equal to approximately \$1.9bn in nominal dollars over the 20 year term)
- Debt backed by the Concession in the construction period will likely be rated no higher than BBB/Baa2, which will result in relatively higher cost debt
- Shifts revenue/demand risk to the State of Alaska

#### 3. State / Public Ownership

The State/Public Ownership alternative represents a public ownership structure where the State receives the greatest benefits and the most direct obligations with respect to ASAP. The underlying public policy rationale is straightforward. Unlike P3 or Private Ownership options in other situations and locales where broader markets exist, the State most likely will bear a significant portion of ASAP project risks in any case. State/AGDC ownership may actually reduce or eliminate the State's potential level of required support, may decrease its net risk versus required guarantees/backup credit on Availability Fee P3 or Private Ownership structures, and should lead to higher credit ratings and significantly lower financing costs.

The Public Ownership Option envisions ownership of ASAP in the hands of AGDC or another State agency. AGDC would contract with experienced private sector entities to construct, operate and maintain ASAP. ASAP would enter into long-term gas supply contracts with North Slope Producers and provide gas and transportation to Fairbanks and the Railbelt. AGDC or another appropriate entity would issue revenue bonds to fund the costs of construction of the Project. The bonds would be "double barreled," secured by revenues received from Off-take Agreements, as described below, and some form of backing by the State. This backing could include issuance of voter-approved General Obligation Bonds ("GOBs"), debt backed by a State appropriation, backing from a funded State guaranty fund, or backing in the form of a State "moral obligation," such as a covenant to replenish the bond reserve account to the extent it is drawn upon, subject to annual appropriation by the State legislature. AGDC would enter into contracts with Railbelt utilities and any industrial customers to provide gas supply at specified points through long-term contracts. Industrial customers could include any LNG export plant(s) with supply contracts to Pacific Rim entities. Revenue bonds issued by AGDC would be backed by the revenues from Railbelt utility contracts and industrial/LNG contracts.

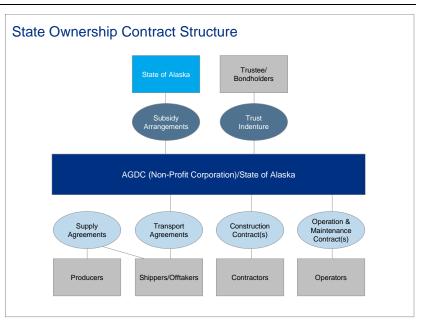
As in the Availability Fee (P3) and Private Ownership cases, the overall financing/operating structure depends on end users paying the all-in delivered cost of gas. The Public Ownership option, however, simplifies the ownership/funding structure. For example, North Slope producers are only responsible for supplying gas under some type of long-term contract and are not needed to own/reserve transportation capacity on ASAP, thereby eliminating the need to assemble some type of consortium of participating producers for pipeline ownership and eliminating a potential weaker credit link. In order for the State to limit the risk of unsubscribed capacity, similar to the Private Ownership and Public/Private Ownership approaches, the State could use an Open Season process to receive supply and demand commitments from both Producers and off take counterparties.

In order to meet required tariff levels, the State would need to back stop any unsubscribed pipeline capacity below the 500 mmscf/d level or guarantee a portion of the ASAP debt. Due to the higher credit ratings expected for the State Owned option, these amounts would be less than for the Availability Fee (P3) and Private Ownership structures, but do present significant costs as discussed within Section 5. Further, to provide the most secure credit, C&R believe that ASAP should pursue an exemption from regulation by the Regulatory Commission of Alaska ("RCA"). Rating agencies place a high value on the ability of a public entity to set rates independently and in a timely manner. Like the other options, secure long-term off take contracts with Railbelt power and gas utilities will be critical, as well as LNG export customers, to round out off take from the 500 mmscf/d pipeline.

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#### **Contract Structure**

The contract structure is depicted to the right. As discussed above, although the State or a State agency would own 100% of the Project, the construction and operations of ASAP would be outsourced to the private sector. In the Public Ownership approach, the assumption is that the State would provide financing and act as owner, while experienced pipeline operators would be contracted to design, build, operate and maintain ASAP.



#### **Key Contract Descriptions**

**Ownership Structure** 

ASAP would be fully owned by the State of Alaska or another non-profit agency of the State such as AGDC.

Operations and Maintenance Contract(s)

Non-Profit Corporation/State of Alaska enters into Operation and Maintenance contract with an experienced pipeline operator. O&M arrangement is very similar to Private Ownership or Availability Fee structures, with key difference consisting of O&M contract not being an integrated financing component under State Ownership structure. Given this, debt financing can be raised to construct ASAP without the O&M Contract in place. The contract can be either a fixed cost arrangement or on a cost plus fee basis.

**Construction Contract(s)** 

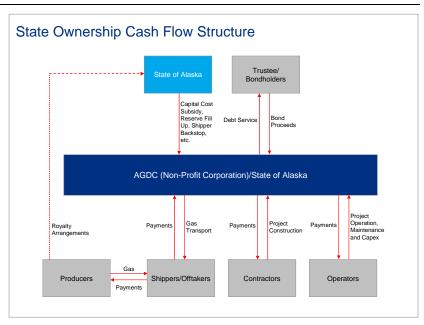
It would be prudent for the State to enter into construction contracts for the bulk of the project prior to financing. While the rating agencies and bond investors will look to the State backstop payment obligation on the project debt, they also want to see that the project is viable on a stand alone basis. The State should offload most of the construction risk by entering into one or more construction contracts. Optimally, these construction contracts would provide the State with a fixed price, date certain, turn-key design-build arrangement for the delivery of ASAP. Due to the complex nature of ASAP, it may be necessary to use a "modified turnkey" approach as outlined in Section 4(D), the risks of which should be factored into financing as additional contingency.

Transport/Supply Agreements

Similar to the Availability Fee financing structure, Transport and Supply Agreements will be separately negotiated with Shippers/Offtakers and Producers.

#### **Cash Flow Structure**

flowchart of payment and responsibilities for the Public Ownership structure is depicted to the As illustrated in the graphic, there are two sources of upfront capital: (i) the State of Alaska; and (ii) the capital markets for long-term debt. Ongoing revenue would be contracted through Off-take Agreements with Railbelt utilities, potential industrial customers and potential LNG exporters, which are intended to be sufficient to cover all project costs and pay the State's debt service obligations.



#### **Public Ownership Financing Assumptions**

Under the Public Ownership approach, C&R have assumed that the Project's capital requirements are satisfied through the issuance of long-term taxable bonds in regular intervals throughout the construction period. Given the credit backstop provided by the State, no interim financing is required prior to commencement of commercial operations.

#### **Overall Financing**

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Financing Structure	Taxable Bonds <sup>1</sup>	
Equity/Debt Ratio	100% debt	
Frequency of Construction Draws	Semi-annual issuance to fund subsequent 6 months of costs	
Financing Structure	Long-term taxable bonds	
Long Term Debt Service Structure	20 year with 1% annual ascending debt service	
Debt Service Reserve Fund ("DSRF")	50% of maximum annual debt service	
Cost of Issuance / Underwriters Discount	1% total	
DSRF Earnings Rate	4.11% (10 year average of 10 year Treasury)	
Capitalized Interest Earnings Rate	2.01% (10 year average of 1 month Treasury) through 1/1/2019	
Interest Rate <sup>(1)</sup>	Treasuries (10-year average) + 150 bps (Assumes Aa/AA ratings)	

<sup>1</sup> It is likely that tax-exempt bonds could be issued for the pro rata share of the Project which serves tax-exempt offtakers such as municipal utilities.

# **Capital Structure**

C&R's analysis has assumed that the Project is 100% debt-financed through "double barreled" bonds that are secured by both the revenue of the project and either (i) bonds backed by some form of State support subject to annual appropriations by the State or (ii) direct State backed bonds (which would require voter approval). The Public Ownership approach would provide the most efficient financing for ASAP and fully leverage the State's access to low cost financing through its high credit ratings.

The State may also be able to consider financing a portion of the pipeline with State equity, such that the pipeline has a similar capital composition as a Private Ownership or Availability Fee structure. This

approach could be used to generate a return for the State over time. To the extent the return on State equity is higher than the State's cost of debt, this approach would increase the tariff above the projected level discussed below.

#### **Tariff Structure**

The tariff is structured to provide 1.10x debt service coverage after payment of all operating and maintenance expenses. Because debt service is structured to adjust for the ramp-up in demand, the resulting tariff increases slightly over time. While the State backstops the debt service payment obligation, the tariff structure is intended to result in a project that "stands on its own" (i.e., generates adequate cash flow to cover O&M and debt service without the State providing funds). The 10% debt service coverage provides a cushion for the State and, if the Project performs as projected, this cushion provides a cash flow that could be returned to the State. The base case tariff for the Public Ownership scenario is projected to be \$1.55/mmbtu (lifecycle tariff) lower than the Private Ownership benchmark. The 110% debt service coverage in this scenario generates excess cash flow equal to \$0.45/mmbtu, which could be returned to the State or used to offset the tariff in future years. The lifecycle tariff net of free cash is estimated to be \$2.00/mmbtu lower than the Private Ownership benchmark.

#### **Benefits and Considerations**

The Public Ownership approach may provide for the greatest cost efficiency, but also may burden the State with the greatest amount of project-related risks. However, unlike Availability Fee (P3) or Private Ownership options in other situations and locales where broader markets exist, it is possible that the State may bear a significant portion of ASAP project risks in any case. Similar to the Availability Fee approach, the construction and operations of ASAP could be outsourced to experienced contractors in the private sector, mitigating a portion of these risks.

Considerations
<ul> <li>State takes risk that end users for full 500 mmscf/d of ASAP are not available over time</li> </ul>
<ul> <li>Direct impact on State debt ratios if voter-</li> </ul>
approved GO bonds are used
<ul> <li>State takes risk if ASAP is inoperable or</li> </ul>
destroyed (force majeure/catastrophic loss)

# 4. CONTRACTING CONSIDERATIONS

PRELIMINARY PLAN OF FINANCE

While the prior discussion describes the fundamental ownership and financing alternatives, there are certain structural requirements and considerations that will be common to any ASAP plan of finance. The purpose of this section is to outline these considerations and discuss their application to ASAP.

# A) Natural Gas Supply Commitments

Given the nature of ASAP, committed natural gas supply will be central to the ability to secure low cost financing. Regardless of whether the Project is privately or publicly-owned, ASAP will ultimately depend on off take contracts with downstream counterparties to provide revenues. Similarly, downstream counterparties will look to the Shippers' supply contracts with Producers to provide certainty of natural gas delivery and cost. Based on discussions with AGDC, it is C&R's understanding that there are sufficient supplies of natural gas in the Prudhoe Bay area to provide firm supply commitments to ASAP. Further, as discussed in Section 4(D), the State is entitled to Royalty Gas from the Prudhoe Field and potentially could use such royalty as one source of supply for ASAP.

#### **Term of Contracts**

To secure the lowest possible cost of financing, ASAP will want to procure supply commitments from North Slope producers for 100% of the pipeline capacity for the full term of the initial financing (20 years in the Base Case). The producers' willingness to provide contracts of this nature will largely depend on their assumption of risk and opportunity cost and could be a limiting factor in the term of the financing.

## **Contract Pricing**

ASAP will also want to consider the pricing of the supply contracts. Market convention dictates that the contracts will provide a floating price indexed to crude. To the extent that the pricing formula differs from the pricing formula used for imported LNG, this could affect the competitive position of ASAP. In consultation with AGDC, we have assumed the Producers will require a \$2.00 netback at the wellhead for the term of the Project.

# B) Offtake Commitments

The question of customers and demand is at the heart of the financing structure. For instance, should ASAP fail to attract enough demand, its structure would need to rely on spot and short-term sales and would be mostly merchant in nature, which would in turn increase risk, and, by extension, costs. Practically, the only merchant option absent mining (from existing and new mines) and new industrial growth in south-central Alaska is LNG export. Alternatively, should the pipeline be significantly or fully subscribed, there is a greater ability to reduce or eliminate merchant risk and lower the cost of the plan of finance. In the case of ASAP, there is a basic conundrum. Existing demand within the Railbelt and south-central Alaska supports a throughput of approximately 260 mmscf/d. At the same time, a 260 mmscf/d pipeline provides little or no capacity to accommodate future growth or industrial demand, no capacity for LNG export, and few economies of scale in terms of capital costs. Given that the relative cost of the Project will be evaluated per delivered unit of gas, ASAP would be much more economic to the extent a larger line could be fully or significantly committed. We also recognize that the AGIA legislation limits the capacity of the line to 500 mmscf/d or less.

# **Capacity Commitment**

With Project throughput of 500 mmscf/d and estimated Railbelt demand of 260 mmscf/d, there is a clear need for incremental demand. To provide for cost effective financing, ASAP will want to secure long-term contracts with as much of the Railbelt demand as possible; however, even with 100% penetration in the Railbelt there will continue to be a significant portion of the line uncommitted.

Unsubscribed capacity after Railbelt use can potentially be dealt with in several ways. It is possible that Shippers/Producers may take an equity interest in the Project based on Project economics and potential Pacific Rim LNG export markets. Secondly, industrial end-users or merchant entities could subscribe for pipeline capacity in the future once ASAP is operating. Both the credit of the off take parties and the nature of any purchase contracts will be critical to the plan of finance. In any event, the State will likely need to backstop any unused capacity either through an Availability Fee in the P3 case or some combination of State support options as described in Section 5 for the Public Ownership and Private Ownership options.

# Ramp-up Schedule

Consistent with the demand discussion, C&R have also assumed that existing Railbelt demand would ramp up over time as existing supply commitments roll off. The ramp-up schedule provided by AGDC and used in our analysis is provided in Section 3(B). As the Project progresses, this assumption will need to be confirmed as lower demand for gas transported in the early years due to existing supply commitments from the Cook Inlet will have an impact on tariff levels.

#### C) Use of State of Alaska Royalty Gas

As noted in Section 4(A), an important consideration in the contracting arrangements is the use of the State's royalty gas. Under the State's lease agreements with the Producers, the State is entitled to certain royalties (typically 12.5%) for natural gas produced on State land. Under the lease agreements, the State can choose to receive this royalty as revenue known as royalty in value ("RIV") or it can choose to receive the royalty as gas, called royalty in kind ("RIK"). Gas taken as RIV could provide significant incremental revenue to the State. If committed to the pipeline, this revenue could be used to offset the tariff by as much as \$0.25 per MMBtu (assuming a \$2 per MMBtu netback at the wellhead). Alternatively, to the extent ASAP does not receive 100% capacity commitments, the State may be able to take its royalty gas as RIK to offset the capacity shortfall and provide for an executable financing structure.

There are several considerations related to the realization of the State's royalty gas as RIK. First, to the extent that a portion of the line is unsubscribed, it is likely that there is no long-term off-take contract for the related RIK gas. As a result, should the State step in, it would be taking merchant risk on the gas resale, both in terms of volume and price. It is possible that additional demand could arise once ASAP is built; however, the State would be at risk for that future demand. Second, the State's leases provide that the State can switch taking RIV and RIK on six months' notice. However, the ability of the State to switch back and forth between RIV and RIK creates a problem for both the Producers and the Shippers as any royalty gas taken as RIV in the future could leave the pipeline's capacity commitments at less than 100% in the absence of any other step-in arrangements. Third, to the extent royalty gas is taken as RIK and is sold into the market in Fairbanks or Anchorage, the gas price would

either need to be fixed via contract with an off take party through a gas sale agreement or floating based on the prevailing market price. It is unclear whether this arrangement would be acceptable to the State, which has sought to maximize the value of its royalty gas in the past.

Finally, to the extent ASAP is undersubscribed by more than the State's 12.5% royalty share, there may be the potential for the State to enter into balancing arrangements with the producers to extract a greater portion of its royalty upfront in exchange for a smaller royalty in the future. While this may be possible, it would depend on the appetite of the Producers. Any balancing arrangement may leave the Producers' share of the natural gas stranded on the North Slope into the future and may be very expensive.

For capacity planning, Producers will want the State to make a long-term decision on whether it will take RIK or RIV. In C&R's view, there are considerable obstacles to the State realizing its royalty gas as RIK. Most notably, the State would be taking merchant risk as to both the volume and the price of the royalty gas on its resale. In the event that the State does elect to take its royalty gas in kind, it would be viewed as a credit positive by the capital markets and may help provide for an executable financing structure in the event the pipeline is undersubscribed. We view these considerations as both public policy in nature (i.e., is the risk acceptable to the State) and legal (i.e., how is the royalty gas integrated into gas sale agreements with off take parties) and believe the use of the State's royalty gas should be revisited following the results of the Open Season.

#### D) Nature of Construction Contracts

Given the significant construction risks, the cost and the possible unwillingness of a private contractor to fully assume the risks through a turn-key construction contract, ASAP may look to a "modified turnkey" approach. Under this approach the more determinable costs are locked in and secured through contracts with credit worthy contractors (possibly pipe, gas conditioning plant, compressor stations), while the remaining balance of plant costs are handled through cost plus fee arrangements with a large project contingency. This form of modified turnkey arrangement is unlikely to achieve a debt rating above triple-B category without additional credit enhancement or a parent guarantee, either through the State of Alaska or a corporate parent guarantee in the case of Private Ownership or Availability Fee (P3) options.

# 5. STATE SUPPORT

PRELIMINARY PLAN OF FINANCE

Given the significant complexities involved in the development of a project of the size and scope currently contemplated, as well as ASAP's overall importance to the State of Alaska and its constituents, it is prudent to provide a discussion of the various support options that are available to the State to enhance the viability of undertaking the Project at the current time.

#### A) Capital Subsidy

The most straightforward enhancement for the State would be a capital subsidy. The State would make a payment (either upfront or as a milestone payment once certain pre-determined construction targets have been achieved) that would reduce the overall financing burden of the private sector. Public sector capital cost contributions have been featured in many greenfield development P3 financing completed in the United States over the past ten years, with contributions ranging from less than 10% to more than 50%. The table below provides select recent public sector sponsor capital contributions on P3 projects.

Project	Total Cost*	Public Contribution ("PC")	PC as Percentage
I-495 Hot Lanes	\$1,937	\$409	21%
North Tarrant Express Lanes	2,047	573	28
Port of Miami Tunnel	973	210	22
I-595	1,824	232	13
LBJ Express Lanes	2,788	512	18

<sup>\*</sup> All \$ in millions

The level of the subsidy provided in each of these projects was driven by the economics of each project (i.e., the amount needed to make the project economically viable and/or incentivize development). In the case of ASAP, the development period is long (eight years) and there are significant development costs involved, where the developer would face substantial stranded costs should the project not come to fruition. To date, these are not costs that the private sector has been willing to accept. In C&R's analysis, we have assumed that the State of Alaska will fund project development through 2012, representing a subsidy of \$292 million or 3.4% of total project costs.

#### B) Backstop for Unsubscribed Capacity

As discussed throughout this report, any financing structure for ASAP will require 100% firm capacity commitments from either shippers or off-takers. Because in-State demand for natural gas is currently 260mmscf/d, a significant portion of the pipeline may not have a committed buyer at the time of ASAP's financing. In this case, a State backstop for unsubscribed capacity, either through a capacity commitment or a guarantee of bonds could provide an executable financing structure.

Similar to the Availability Fee approach, a State backstop for unsubscribed capacity shifts the demand/revenue risk to the State. To the extent the State is able to find buyers for the transported but uncommitted gas, it could be made whole through the gas resale. However, to the extent the State is unable to find buyers, or the market price of gas is below the State's transportation cost, the capacity commitment would represent an expense for the State. Based on C&R's discussions with AGDC, it is our understanding that additional in-State demand may become available upon the commercial operation of

ASAP either through new industrial demand, gas supply contracts with mining companies, or the development of an LNG export market.

Projected growth in demand notwithstanding, the underutilization of ASAP would be the State's risk in both the Public Ownership approach and the Availability Fee approach. While the equity owners would typically bear this risk in the Private Ownership approach, we do not believe that the private sector will be willing to bear demand risk; so it will likely reside with the State in this case as well.

The table below illustrates the potential cost to the State in the event the State provides a backstop for 10% of ASAP's capacity with no resale of the related gas. Alternatively, should the State elect not to provide this type of backstop, the State could instead look to pass the cost of unsubscribed capacity through to consumers in the form of higher tariffs.

#### **Cost of Capacity Backstop**

(Assumes State of Alaska Provides a Capacity Commitment for 10% of ASAP with No Gas Resale)

	Private Ownership	Availability Fee	State Ownership
Nominal Cost of Backstop	\$3.90 bn	\$3.37 bn	\$3.25 bn
Present Value <sup>(1)</sup>	\$1.44 bn	\$1.22 bn	\$1.20 bn
Incremental Tariff to Offset Shortfall	\$1.02/mmbtu	\$0.87/mmbtu	\$0.84/mmbtu

<sup>(1)</sup> Cash flows discounted at 6% to 7/1/2011.

# C) Additional Considerations to Reduce Cost

As an alternative or in addition to a capital subsidy, it may be necessary for the State to provide some form of back-up related to financing ASAP. The chart below outlines certain additional considerations to reduce project financing costs.

<u>Potential Support</u>	Description	<u>Comments</u>
Full State	Under this structure, the State of Alaska would provide a	<ul> <li>Lowest cost of capital</li> </ul>
guarantee of bonds	guarantee of the repayment of debt service on the	Would require public vote
	Bonds by issuing the bonds either as Alaska General	Direct impact on State
	Obligation Bonds ("GOBs") or AGDC debt with full state	debt ratios
	GO backing. This support structure would lead to a	Applies only to Public
	substantial improvement in debt ratings – debt would be	Ownership option
	rated at the State G.O. level (currently Aaa/AA+/AA+).	
	This large improvement in credit quality makes it highly	
	likely that state-guaranteed debt would provide the	
	lowest cost of capital for the Project. The State	
	guarantee could be applied to senior lien and/or	
	subordinate lien debt. One structure that has been	
	utilized for a number of public infrastructure projects in	
	the past is a standalone senior non-recourse revenue	
	bond with significant debt service coverage to garner	
	strong credit ratings and a riskier subordinate bond	
	backed by a State government.	

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Potential Support	Description	Comments
State appropriation backing	Under this structure, the State of Alaska will provide backing for debt service though a subject-to-appropriation pledge. This structure would likely result in ratings of Aa1 / AA / AA (or one notch below the State's GO ratings due to the need for annual appropriations if the backing is needed) and would also provide a significant improvement in credit quality and lower borrowing costs.	<ul> <li>Low cost of capital</li> <li>Indirect obligation of State</li> <li>Potential annual appropriations</li> <li>Can be applied to all three ownership options</li> </ul>
State guarantee of revenue floor	It is possible for the State to guarantee certain minimum levels of revenue for the Project. Such a guarantee could come in the form of either a minimum capacity guarantee, or a minimum dollar amount guarantee, and could be sized to cover O&M costs, capex, debt service, and potentially a small equity return for the owner, or some combination thereof. Such a structure could also demand a reciprocal obligation on the part of the owner to share revenues beyond a certain threshold, assuming the Project outperforms projections, as a payment for the guarantee.	<ul> <li>Contractual contingent obligation of State</li> <li>Potential for some economic return to State</li> <li>Can be applied to all three ownership options, but is an essential element of the Availability Fee (P3) option</li> </ul>
State guarantee of future construction borrowing interest rate risk	Given the length of the proposed construction schedule, negative arbitrage <sup>2</sup> in the current financing environment, and expected financing size, the Project will likely have to be financed with a bank line and/or in multiple series of debt. The importance of revenue risk to the project means that for structures in which lenders/bond investors are exposed to the Project's revenue risk, future borrowing rates will be factored in to any analysis of ASAP as a credit risk. Lenders/investors will take a cautious view in regard to interest rate risk and demand adequate protections, which will necessarily reduce future borrowing capacity. It is possible for the State to guarantee this risk through a variety of structuring options. Such a guarantee would assuage investor fears and maintain full borrowing capacity for the Project.	<ul> <li>In both the tax-exempt and taxable markets, it is somewhat easy to hedge benchmark indices (i.e., MMD &amp; Treasuries), but considerably more challenging to hedge credit spread risks</li> <li>Can be applied to all three ownership options</li> </ul>

<sup>2</sup> The potential for arbitrage occurs when debt is issued and the proceeds are invested for a period of time until the money is used to fund a project. Negative arbitrage occurs when the money is invested at a rate of return that is lower than the rate on the debt.

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Potential Support	Description	Comments
Reserve fund replenishment obligation	A reserve fund replenishment obligation could secure a series of senior or subordinate bonds. Project financings typically require a debt service reserve fund in order to cover for unexpected shortfalls in revenue. The replenishment obligation would only be triggered in the event the reserve is drawn upon; so a healthy and financially viable project is unlikely to need this debt backstop. However, investors view such an obligation as a backdoor guarantee, as the requirement to continually fill a reserve essentially equates to an obligation by the State to pay debt service. A reserve fund replenishment obligation would likely result in high credit ratings, depending upon the mechanism for re-filling the reserve.	<ul> <li>Essentially the same as subject-to-appropriation pledge</li> <li>Contingent obligation of State and could require annual appropriations</li> <li>Lowers cost of capital significantly</li> <li>Can be applied to Availability Fee (P3) and Public Ownership options</li> </ul>
Tax-exempt funding through ARRC	The ARRC has broad tax-exempt issuance authority that could potentially be employed for ASAP debt. Financing infrastructure projects through the tax-exempt market has historically proven a cheaper, lower cost of financing than the taxable market. All other factors being equal, allowing for the use of tax-exempt debt would lower ASAP's financing costs.	<ul> <li>Letter ruling from IRS likely required</li> <li>Lowers cost of capital versus equivalent taxable financing</li> <li>May need to be coupled with some other form of State backing for credit reasons</li> <li>Can be used with any of the three ownership options</li> </ul>
Shipper of Last Resort	The State could support the Project by acting as a capacity shipper of last resort. Given that a key project risk is contracting enough capacity to pay off O&M, capex and debt service obligations, the State can bridge any potential shortfall by stepping in and filling up pipeline capacity (either up to a certain limit or unlimited) thereby reducing revenue risk without committing to contract for the full capacity of the pipeline. The State can reduce its obligation over time as other Shippers contract for capacity, subject to meeting credit hurdles.	<ul> <li>Contingent obligation of State</li> <li>Fulfills basic State need</li> <li>Ability to guarantee may be dependent on other State shipping contracts</li> <li>Can be used with any of the three ownership options</li> </ul>

#### D. Revenue to the State of Alaska

Finally, in evaluating each of these support alternatives, the State will want to consider its aggregate financial position in relation to the pipeline. First and foremost, ASAP has the capacity to provide a long-term, reliable and cost effective supply of natural gas to Alaskans. This is the greatest benefit and the reason why a traditional cost/benefit analysis may not apply to the State's support of ASAP – the project is vital to the State's interest and overall economy. That said, the State will want to consider the revenues received from the pipeline (the most measurable benefit) versus the cost of any contemplated subsidy. Specifically, the State will receive revenues as a result of: (i) the State's royalty interest in the gas sold (assuming RIV); (ii) the severance tax assessed on the gas extracted from the North Slope; (iii)

the ad valorem property taxes assessed on the project; and (iv) the corporate business taxes assessed on the pipeline entity. The projected State of Alaska revenues under each of the three base case scenarios are provided below on both a nominal and present value basis. For comparison, the projected cost of a 10% capacity commitment is also restated in the table below. The actual amount of State revenue and support could vary significantly from these figures.

### Estimated State of Alaska Revenues<sup>(1)</sup>

(Base Case Scenarios)

· ·	Private Ownership	Availability Fee	State Ownership
Nominal Revenue	\$4.57 bn	\$4.05 bn	\$3.75 bn
PV Revenue <sup>(2)</sup>	\$1.75 bn	\$1.58 bn	\$1.54 bn
Nominal Cost of 10% Capacity Commitment <sup>(3)</sup>	(\$3.90 bn)	(\$3.37 bn)	(\$3.25 bn)
PV Cost of 10% Capacity Commitment <sup>(3)</sup>	(\$1.44 bn)	(\$1.22 bn)	(\$1.20 bn)

<sup>(1)</sup> Assumes revenue to the State of Alaska attributable to: (i) the State's royalty interest (assuming 12.5% royalty taken in value and a \$2.00/mmbtu wellhead netback), (ii) property taxes of 2.0%; and (iii) State of Alaska corporate income taxes of 9.4%.

 $<sup>^{(2)}</sup>$  Cash flows discounted at 6% to 7/1/2011.

<sup>(3)</sup> Represents cost to the State of 10% capacity commitment with no gas resale.

#### **6. Additional Financing Considerations**

In the course of our analysis, we have also looked at certain financing sensitivities. The intent of this section is to provide a discussion of those sensitivities, including the benefits and considerations, such that AGDC is able to forecast the impact to the financing, both in terms of structure and cost. We have analyzed: (i) structural permutations such as an extension of the contract term and the use of a deferred tariff structure; (ii) changes in market conditions through higher interest rates; (iii) changes in project cost and configuration; (iv) the implications of any tax-exempt issuance through ARRC; (v) changes in the level of State subsidy; and (vi) the impact of a shorter construction period. A discussion of each of these sensitivities is provided below.

## A) Term of Financing (20 vs. 30 years)

In our base case, C&R have used a 20-year term, consistent with a 20-year operating period. We have also included an analysis of a 30-year financing. We believe that a 30-year term is financeable in the current market, provided that the initial operating term of the pipeline is also 30 years.

The ability to extend the term of the financing will depend on the useful life of ASAP and the contracts that AGDC (or the Pipeline Company) is able to sign with the upstream and downstream counterparties as well as any Shippers. ASAP is expected to be in operation for the productive life of the natural gas field(s) that supply it. Based on guidance from ADGC, C&R understand that with appropriate maintenance, repair, and refurbishment, the physical life of the ASAP may be indefinite.<sup>3</sup> However, as discussed previously, the ability to extend the term also assumes that the North Slope oil fields continue to produce at a sufficient rate to keep Producers active on the North Slope.

From a cost perspective, extending the term will increase overall financing costs, while reducing the size of annual debt service obligations and in turn, the tariff. By extending further out the yield curve, interest rates will be higher although we note in the current market, the yield curve is relatively flat from 20 to 30 years, with an incremental interest cost of 46 bps in the tax-exempt market and 29 bps in the taxable market. In addition, in a Private Ownership or Availability Fee financing, extending the term will also extend the period over which the equity owner(s) realize their return. If a longer term is pursued and proves feasible, we expect that the longer payback period would require a higher ROE (although we do not model a higher ROE in our sensitivity). With a State Ownership structure, however, the State may have more flexibility in the financing term and could potentially extend the financing to 30 years.

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A summary of the estimated impacts to the transportation tariffs is provided below for each of the three base case scenarios assuming an extension from a 20 year to 30 year term. All assumptions, including owner ROE requirements, are held constant in this analysis. It should be noted that ultimately, the term of the contracts bid during the Open Season will determine the term of the financing.

## Impact of Increase to 30-year Term (\$/MMBtu)

(Lifecycle Tariff)

(\$/MMBtu)	Private Ownership	Availability Fee	State Ownership
Increase /(Benefit) vs.	(\$0.91)	(\$0.42)	(\$0.38)
Respective Base Case	,	, ,	(, ,

#### B) Tariff Structure (Level vs. Deferred)

The shape of the transportation tariff can also impact the affordability of ASAP. By deferring the tariff structure, AGDC could provide for lower tariffs in the initial years of operation with costs increasing over time with inflation. In our base case scenarios, C&R have assumed a level tariff structure (Private Ownership), a tariff structure that escalates at 0.75% per year (Availability Fee), and a tariff structure that escalates at 0.25% per year (Public Ownership). We have also looked at a tariff structure that escalates 3% per year for the Private Ownership case.

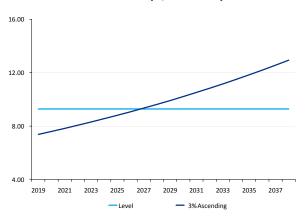
# Impact of Deferred Tariff Structure (\$/MMBtu)

(	Lit	tec	ycl	le	Ţ	a	r	İ	t,	)

(\$/MMBtu)	Private Ownership
Increase /(Benefit) vs.	\$0.11
Base Case	70.11

A tariff structure that ascends at 3% annually results in reduced costs in the initial years of operation, with higher overall costs over the lifecycle of the Project. The graphic to the right illustrates the annual tariffs over the initial operating term (2019 through 2038) assuming the Private Ownership structure.

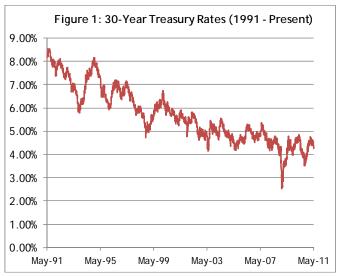
#### Annual Tariff Results (\$/MMBtu)

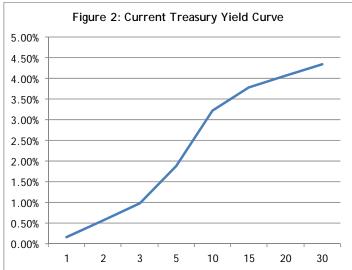


In evaluating a deferred tariff structure, AGDC will want to consider the potential rating implications as well as the likelihood of regulatory approval. In the first case, the rating agencies will view the backloaded revenue and debt structure as a credit negative and AGDC will need to build out a rationale explaining why the tariff structure makes sense. Strong off take contracts with consumers (utilities) who are able to budget and plan for increasing costs over time are essential to the success of this strategy. To the extent the deferred structure negatively impacts the credit of the pipeline company, this approach could have the effect of further increasing the cost of the financing through higher interest rates. In terms of regulatory approval, whether this approach is even feasible will depend on the view of the RCA (for the pipeline) and FERC (for any LNG export component). Typically, FERC regulated structures require a level tariff.

#### C) Sensitivity to Interest Rates

Interest rates are a critical driver of ASAP's economics. As depicted by the graph of long-term Treasury rates below, interest rates are presently very low on a historic basis. Further, as shown in Figure 2, the yield curve, which depicts the borrowing rates for various debt maturities, is generally steep at present (i.e., short term rates are significantly lower than long term rates).





In the Private Ownership and Availability Fee cases, C&R have assumed short term financing of project construction followed by a long-term fixed rate bond issue upon commercial operation of the Project (2019); consequently, ASAP bears significant interest rate risk over the construction period. In the State Ownership Option, C&R have assumed periodic long-term fixed rate bond issues to fund construction. As a result, no interim financing is needed and interest rate risk is ameliorated (compared to the one-time large takeout issue in the Private Ownership and Availability Fee P3 options) by multiple bond issues over time and presumably varying interest rate environments.

C&R have examined the impact of 100 basis point increase in interest rates over our base case analysis. In general, the transaction's economics are interest rate sensitive, with every 100 basis point increase in long-term interest rates increasing the tariff by \$0.47 to \$0.65 per MMBtu as shown in the table below.

# Impact of 100 Basis Point Increase in Long-term Interest Rates (\$/MMBtu) (Lifecycle Tariff)

(\$/MMBtu)	Private Ownership	Availability Fee	State Ownership
Increase /(Benefit) vs. Respective Base Case	\$0.47	\$0.57	\$0.65

In an effort to provide conservative results, C&R have used 10 year average interest rates for our all analyses within this report. 10 year historical averages are higher than current interest rates by as much as 196 basis points (1 year US Treasuries) to 48 bps (20 year US Treasuries).

#### D) Benefit of ARRC Tax-exempt Issuance

C&R also analyzed the opportunity to issue tax-exempt debt to finance ASAP. While private use pipelines are not generally an acceptable use of proceeds for tax-exempt debt, ARRC appears to have unique tax-exempt issuance authority. Through Congressional action, ARRC has been given the authority to issue tax-exempt debt, which certain bond counsels believe can be used "for any purpose." In 2003, the Alaska Legislature gave ARRC the explicit authorization to issue up to \$17 billion of tax-exempt bonds for the *inter-state* pipeline (§5, ch. 71, SLA 2003). While ASAP is an *intra-state* pipeline, it is C&R's understanding that the State Legislature may be willing to utilize ARRC's unique authority to finance ASAP.

For a project of this size and profile, C&R believes it would be necessary to seek a private letter ruling from the IRS affirming the tax-exempt status of a tax-exempt ARRC borrowing for ASAP. Any financing of ASAP will be extremely high profile and the tax-exempt status of the offering would be a focus of all market participants (investors, rating agencies, underwriters, and attorneys). The need to point to a letter ruling to eliminate any ambiguity or concern is critical.

The benefit of tax-exempt issuance using a 20-year structure results in tariff decreases ranging from \$0.20 to \$0.61 per MMBtu as shown in the table below. The projected benefit is greater for the State Ownership and Availability Fee scenarios as these structures utilize a greater degree of debt financing.

# Impact of Tax-exempt Borrowing through ARRC (\$/MMBtu)

(Lifecycle Tariff)

Increase /(Benefit) vs. Respective Base Case	(\$0.20)	(\$0.35)	(\$0.61)

#### E) Length of Construction Period/Negative Arbitrage during Construction

Consideration should also be given to the length of the construction period. With AGDC's guidance, C&R have assumed project development through 2013, with construction starting in 2014 and running through 2018, for a five year construction period.

The length of the construction period creates financial complexity and cost. From the lender's standpoint, a long construction period introduces risk of project delays and cost overruns, diminishing the likelihood of repayment and pushing requisite borrowing costs higher. This of course is the reasoning for an interim financing during construction, which could then be refinanced with long-term debt once the Project is operating and investor concerns have been addressed. On the other hand, a finance plan which uses interim construction financing exposes the Project to the risk of higher interest rates in the future. In short, there are three primary financing options:

- 1. Single large upfront financing in 2014
- 2. Bank loan construction financing with refinancing to long-term debt at COD
- 3. Multiple long-term issues every 6 months throughout the construction period

The trade-off between one large upfront financing (thereby eliminating interest rate risk) or multiple debt issuances is the amount of negative arbitrage. Negative arbitrage occurs when long term debt is sold and the proceeds are not immediately spent. While construction funds can be invested, short-term investment rates are generally far lower than the long-term cost of debt in the current market (1-year investment rates are currently 0.30% to 0.50%, while long-term borrowing costs are in the 7.25% range for 20-year taxable issuance). Given the size of the anticipated financing and current market conditions, negative arbitrage can be significant and, for this reason, pre-funding the Project in 2015 is not believed to be economically viable.

Both the Private Ownership and Availability Fee options assume construction is funded from a bank loan to be taken out upon commercial operation with long-term fixed rate bonds. This eliminates negative arbitrage, but will require some form of corporate guarantee (assumption of construction risk by the private owners) or State support (assumption of construction risk by the State). For the State Owned option, C&R have assumed multiple series of long-term fixed rate bonds issued every six months to fund construction.

In all cases, the amount of interest accrued during construction is significant. It is C&R's understanding that the construction schedule for ASAP will be determined by the project manager and the project's engineers and will be based on the amount of time needed to properly build the Project. For illustration purposes, we have estimated the impact to the transportation tariff of a change from a 5 year construction schedule (base case) to a 4 year construction schedule in the table below.

#### Impact of Construction Schedule (\$/MMBtu)

(Lifecycle Tariff)

(\$/MMBtu)	Private Ownership	Availability Fee	State Ownership
Increase /(Benefit) vs.	(\$0.09)	(\$0.10)	(\$0.05)
Respective Base Case	(\$0.09)	(\$0.10)	(50.03)

PRELIMINARY PLAN OF FINANCE

#### F) Sensitivity to State Subsidy

As discussed, multiple forms of State support can be melded into a plan to finance the Project. For example, the State could subsidize a portion of the Project's capital cost through a direct upfront subsidy. In our analysis, we have assumed that the State will continue to carry all project development costs through December 31, 2012. This results in a state subsidy in the amount of \$292 million.

The State could further choose to buy down the capital cost of the Project to reduce the tariff paid by consumers. The table below illustrates the impact to the transportation tariff assuming the State buys down the capital cost by an incremental \$1 billion. This analysis assumes that the buy down is treated as a capital subsidy and there is no direct repayment from ASAP to the State.

# Impact of State Capital Cost Buy Down of \$1 billion (\$/MMBtu)

(Lifecycle Tariff)

(\$/MMBtu)	Private Ownership	Availability Fee	State Ownership
Increase /(Benefit) vs.	(\$0.45)	(¢0 E1)	(\$0.57)
Respective Base Case	(50.45)	(\$0.51)	(\$0.57)

#### **G)** Alternate Facilities Configuration

Thus far, our analysis has focused on the project configuration known as Scenario 4(b) in the Baker Study, which contemplates a 24-inch-diameter natural gas pipeline with a throughput of 500 mmscf/d. AGDC has also asked C&R to analyze the economic impact of an alternative larger diameter (48") pipeline from the North Slope to Dunbar as a means of creating future development and revenue opportunities for the State. Based on AGDC's guidance, assumptions for this scenario include an incremental capital cost of \$2.5 billion over the capital costs assumed for Scenario 4(b).

Based on our understanding of the facility configuration, the 48" segment to Dunbar would represent an overbuild of project capacity. Contracted natural gas capacity would be unchanged from the 24" scenario and significant additional capacity would be available to meet future natural gas demand in-State and abroad. This raises a few significant considerations. First, the project would violate the existing AGIA license, which would need to be restructured. Second, while the Project provides for significant future capacity, it does so only to Dunbar. An overbuild, however, raises the issue of whether the Project should be overbuilt for its full length today, or if a smaller pipeline should be built from Dunbar to Cook Inlet today, with a second line and increased capacity to be built from Dunbar in the future. Third and most importantly, because there is no existing demand for the incremental capacity, the incremental capital cost would likely not be a recoverable item in the tariff for any scenario regulated by the RCA or FERC. As a result, any incremental capital costs would likely need to be funded directly by the State.

We believe this is an interesting development opportunity. Unfortunately, it is not easily financed in the capital markets due to the pre-build of what is initially unneeded capacity. Further, we believe that the State is the only party with the financial resources to consider this project and it is not something that the private market would currently pursue. As a result, the decision to proceed is a policy decision of the State. Additional natural gas extraction could provide increased revenue to the State provided there is demand for the incremental gas. In a pre-build scenario, the question is when that demand will materialize and how long will it take for the State to be repaid for any upfront capital contribution.

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#### H) Construction Cost

Finally, other than demand, the largest single risk to ASAP is the overall level of construction costs. C&R's analyses have been based on preliminary construction cost estimates provided by AGDC with a range of uncertainty of 30%. Although the State may be able to transfer significant construction cost risk once firm construction cost estimates have been established in the project definition stage, there remains substantial uncertainty as to tariff levels until that time. As a result, C&R have analyzed tariff sensitivity to construction costs. The table below looks at the impact to the tariff assuming capital costs are 10% higher than current estimates (representing an increase of \$920 million in nominal dollars).

## Impact of Increased Capital Cost (\$/MMBtu)

(Lifecycle Tariff)

(\$/MMBtu)	Private Ownership	Availability Fee	State Ownership
Increase /(Benefit) vs. Respective Base Case	\$0.41	\$0.46	\$0.51

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#### 7. CONCLUSION

C&R have investigated numerous options and sensitivities to finance ASAP. The following comparative matrix addresses the important issues and considerations related to the three basic financing options and is intended to reflect the current state of ASAP's development. As ASAP reaches further stages of definition and development, the evaluations in this matrix may change significantly. For example, further competitive definition of ASAP and any resulting firming up of industrial anchor tenants and/or LNG export will enhance the likelihood of successful execution of the Private Ownership and Availability Fee (P3) options relative to the State Ownership Option (which already has a high probability of successful execution).

It is important to note that all three options must work through the environmental impact process and depend upon long-term natural gas supply contracts with North Slope Producers, which in turn are economically dependent upon the continuing operation of the Trans-Alaska Pipeline. Finally, relative risk-benefit tradeoffs in this matrix may change if the State is required to backstop essentially the same level of expected risk in each option after negotiations with the interested parties. In the end, it is expected that the Private Ownership and Availability Fee (P3) options will allow a substantial transfer of construction and operating risk to private entities. To the extent these risks and the unlikely risk of ASAP inoperability due to force majeure ultimately reside in some fashion with the State, then the State Ownership option should provide a lower cost tariff and a more favorable economic return to the State in the form of excess debt service coverage.

# State Project Risk Profile

	Private Ownership (Rate Regulated)	Public/Private Partnership (Availability Fee) (P3)	State/Public Ownership
Base Case Tariff Level (\$/MMBtu)	Benchmark	Benchmark less \$1.38/MMBtu	Benchmark less \$1.55/MMBtu  • Approximately \$0.45/MMBtu in additional free cash flow to the State as a result of the 1.10x debt service coverage
Cost of Project Development	Companies likely unwilling to fund development until after open season process, or later	High to Very High  Companies likely unwilling to fund development until shortly before commercial/financial close	Very High  • State responsible for all project development
Construction Cost	Low  Companies may require State to assume limited construction risk for highly variable components where construction wrap is unavailable	Low to Moderate  Companies may require State to assume construction risk for highly variable components where construction wrap is unavailable	Moderate  State assumes all construction risk for components where construction wrap is unavailable
O&M	None Private party responsible for O&M and Capex	None Private party responsible for O&M and Capex	Moderate  • State is unlikely to get 20 year or longer fixed price O&M contract
Capital Expenditures	None Private party responsible for O&M and Capex	None • Private party responsible for O&M and Capex	High  • State is unlikely to get O&M contract to fully cover capital expenditures
Revenue	High     State will have to cover capacity not contracted during open season     Company may be willing to accept contract renewal risk for some shorter term contacts	High to Very High  • State covers all revenue risk, except due to unavailability of the pipeline  • Risk can be mitigated through shipper / off-taker contracts	Very High  • State covers all revenue risk  • Risk can be mitigated through shipper / off-taker contracts
Construction Rate Risk	None	High • State responsible for higher or lower interest rates during construction	Moderate  State responsible for interest rate risk, which is mitigated by long term bonds issued every six months during construction
Refinancing Risk	None to Moderate  State may have to provide some form of backup on portion of takeout financing  Execution risk of very large takeout financing	High     State responsible for availability fee adjustment when permanent financing completed at commercial operation     Execution risk of very large takeout financing	None
Force Majeure / Catastrophic Loss	High  Obligation of private companies, but State may bear substantial parts of risk  ASAP operability is key to Railbelt gas/power supply and economy	High     Obligation of private companies, but State may bear substantial parts of risk     ASAP operability is key to Railbelt gas/power supply and economy	Very High • State bears all risk
Execution Risk (Failure to reach commercial operation)	Very High  • At this point in ASAP development, unlikely that private entities will commit	High     Similar to rate regulated, additional development/State backing is needed to commit	Low  Less complicated structure is within State's control

#### **APPENDIX A: Definition of Terms**

**AGDC** = Alaska Gasline Development Corporation

AGIA = Alaska Gasline Inducement Act

**ARRC** = Alaska Railroad Corporation

**ASAP/Pipeline/Project** = Alaska Standalone Gas Pipeline Project

**Availability Fee** = baseline fee paid to Concessionaire in P3 structure to pay fixed costs subject to Concessionaire's successful completion, operation and maintenance of Project

Basis Points (bps) = 100 basis points equal 1%

**B&V** = Black & Veatch Corporation

Concessionaire = DBFOM private sector consortium in P3 structure which receives Availability Fee

**C&R** = Citigroup Global Markets, Inc. and Ramirez & Co., Inc.

**DBFOM Contract** = Contract with private sector to design, build, finance, operate and maintain Pipeline and associated facilities.

**EBITDA** = Earnings before interest, taxes, depreciation and amortization

**Equity Commitment** = Cash ownership investment by private sector subject to agreed upon return. State may also make equity investment.

**FERC** = Federal Energy Regulatory Commission

**GCF** = Gas Conditioning Facility

Investment Grade Rating = BBB- or higher by S&P; Baa3 or higher by Moody's

**LNG** = Liquefied natural gas

mmscf/d = million standard cubic feet per day

**NGLs** = natural gas liquids

**O&M** = Operations and maintenance

**Offtakers** = Railbelt electric and gas utilities, potential industrial anchor tenants, and potential LNG exporters

P3 = Public Private Partnership (Availability Fee) Option

**PB** = Prudhoe Bay

**Producers** = North Slope gas production companies

**RCA** = Regulatory Commission of Alaska

**RIK** = royalty-in-kind

**RIV** = royalty-in-value

**ROE** = return on equity

**SAIC** = Science Applications International Corporation

**Shippers** = entities purchasing Pipeline capacity to transport natural gas; may include power utilities, gas utilities, producers, off-takers including merchant entities.

**Tariff** = charge necessary to pay fixed costs and operating costs of Pipeline, including debt service on bonds and return on equity. Does not include cost of gas or local distribution costs.

Turnkey Construction Contract = guaranteed maximum price contract