Economic Feasibility of Coal to Liquids Development in Alaska’s Interior

Preliminary Comments on the Proposed Fairbanks and Healy CTL Projects*

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Prepared for the
Northern Alaska Environmental Center
By John Talberth, Ph.D.†

Center for Sustainable Economy
1704-B Llano Street, Suite 194
Santa Fe, New Mexico 87505
(505) 986-1163
www.sustainable-economy.org

* Given the preliminary nature of these projects and the analyses which accompany them, all cost and benefit estimates presented herein are to be considered rough estimates of potential magnitude subject to significant refinements once more detailed project information is made available.
† President and Senior Economist, Center for Sustainable Economy (jtalberth@sustainable-economy.org).
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The U.S. Congress, Department of Energy, Alaska Legislature, Fairbanks Economic Development Corporation (FEDC), Fairbanks North Star Borough (FNSB) other public entities are actively investigating the economic feasibility of coal to liquids (CTL) development in Alaska's Interior as a way to combat fuel insecurity associated with interruptions of supply from Prudhoe Bay refineries and increasingly scare and expensive foreign oil imports. To this end, there have been two studies issued since 2007 addressing the economic feasibility of CTL development in the Interior. The first, prepared by the Department of Energy’s National Energy Technology Lab concluded that a CTL plant located at the mouth of the Usibelli Mine near Healy would be potentially feasible if wholesale Fischer – Tropsch (F-T) fuel prices remained above $70 per blue barrel (bbl) over the 30 year plant life.\textsuperscript{3} The other, a preliminary feasibility study of a Fairbanks CTL plant prepared by Hatch, Ltd. in October 2008 implied that feasibility could be achieved at F-T product prices of $108 - $138/bbl.\textsuperscript{4}

At the request of the Northern Alaska Environmental Center, Center for Sustainable Economy (CSE) completed a preliminary review of the findings, methods, assumptions, and calculations included in both reports. While these reports suggest that there may be potential for CTL projects to be economically viable from the narrow perspective of plant investors, from the public perspective required by law, all indications are that a proposed CTL plant would be economically infeasible, by a fairly wide margin. In particular:

- Because public funds are being used to subsidize CTL development and public authorizations are required, the feasibility of CTL plant development in Alaska's Interior must be based on benefit-cost analysis and not financial returns to private investors. Net present value and benefit-cost ratios are the primary criteria for evaluating the feasibility of projects wholly or in part financed, authorized, or otherwise facilitated by public entities.

- The Hatch FEL1 study suggests that the Fairbanks CTL plant will be economically infeasible from the public perspective since the net present value for all three alternatives is negative and since all three benefit-cost ratios are well below one. Although NPV and benefit cost ratios were not calculated in the NETL study, the figures that do appear suggest similar results.

- Even from a private perspective, both CTL plants appear to be infeasible as well. This is because the internal rate of return for both falls below the cost of capital of 12%. In general, the internal rate of return must exceed the cost of capital for private investments in power plants to be attractive.

- The Hatch study, and to a lesser extent, the NETL study, omitted a significant range of costs that, if included, would make net present value, benefit-cost ratios, and internal rate of return even less. Many of these costs can be estimated using

information already published by NETL or other sources of publicly available information. These include carbon sequestration costs, transportation costs, natural resource damages, interest during construction, owner costs, and taxpayer costs.

- Both the Hatch and NETL studies fail to demonstrate the existence or magnitude of public benefits. For CTL projects, changes in consumer surplus should be the basis for benefit calculations. Consumer surplus benefits can be approximated by consumer cost savings. Using CTL plant revenues as a basis for benefits rather than cost savings greatly exaggerates project viability. If change in consumer surplus or cost savings are used, benefit estimates would be much less and both net present value and benefit-cost ratios would be significantly less as well.

- There are several questionable assumptions included in both the Hatch and NETL studies that tend to overstate economic viability. These include the price of coal inputs, revenues from generated electricity, plant life, and plant availability.

- If even a handful of these additional costs or questionable assumptions are addressed, the Fairbanks CTL project's benefit-cost ratio will probably be so low as to make the plant infeasible even if the Hatch report overestimated project costs by 40% or more.

- In terms of benefit-cost ratios and Energy Return on Investment (EROI), it appears that CTL development would generate far fewer net public benefits than a similar magnitude of funds invested in renewable energy, energy efficiency, and conservation.

- Although the economic feasibility of CTL plant development along the lines of that suggested by the Hatch and NETL studies cannot be conclusively determined at this point due to the preliminary nature of the studies, it appears evident that CTL development, at least from a public perspective, is a poor use of public funds relative to investments in renewable energy, energy efficiency, or conservation. The basis for these conclusions is set forth below.

Figure 1: Overall CTL Plant Block Flow Diagram from the Hatch Feasibility Report
I. Appropriate Criteria for Evaluating Economic Viability

1.1 Net Present Value is the Appropriate Criteria for Evaluating Economic Viability

It is clear that coal to liquids development in Alaska’s Interior will require considerable involvement by public agencies at the federal, state, and local levels. The Fairbanks CTL project has already received $550,000 in public funds for the feasibility study, with another $6-7 million sought. Both the Alaska Legislature and U.S. Congress are considering legislation to subsidize CTL development and even to mandate production quotas. Public ownership – at least for the Fairbanks CTL plant – is being contemplated at some point in the future. A prominent capital investment firm concluded that public financing would be essential to jumpstart development of the first few CTL plants in the United States. Finally, there are dozens of authorizations required from federal, state, and local public agencies such as the Environmental Protection Agency, U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, Alaska Department of Natural Resources, and Alaska Department of Environmental Conservation. As such, the economic feasibility of CTL development must be analyzed from a net public benefits perspective through benefit-cost analysis and not the perspective of private investors.

The standard criterion for deciding whether a government policy, program, or project can be justified on economic principles is net present value.

Benefit-cost analysis (BCA) compares the present value of the social benefits of a public policy, program, or project against the present value of social costs. There are two fundamental results from performing a benefit-cost analysis: 1) net present value (NPV); and 2) benefit-cost ratio. The “present worth” of a project is commonly referred to as its NPV. The standard criterion for deciding whether a government policy, program, or project can be justified on economic principles is net present value -- the discounted monetized value of expected net benefits (i.e., benefits minus costs). NPV is a measure of the absolute magnitude of the gain or loss to society. As described by the Office of Management and Budget (OMB), net present value is computed by assigning monetary values to all benefits and costs -- regardless of who enjoys or incurs them -- discounting future benefits and costs using an approach.

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5 For example, in Congress, the Coal Liquid Fuel Act (H.R. 2208) will authorize the Secretary of Energy to enter into: (1) standby loan agreements with up to six qualifying CTL projects, at least one of which shall be owned by two or more small coal producers; and (2) a profit-sharing agreement with the project at the time the standby loan agreement is executed. At the state level, a “work draft” of a bill modifying the Renewable Energy Grant Fund (HB 152) to invest nearly $21 billion in coal to liquids and other “alternative energy” projects is being circulated in the 2009 Alaska Legislature’s session.


7 NETL, 2007, Appendix C.


appropriate discount rate, and subtracting the sum total of discounted costs from the sum total of discounted benefits. Discounting benefits and costs transforms gains and losses occurring in different time periods to a common unit of measurement. Importantly, “[p]rograms with positive net present value increase social resources and are generally preferred. Programs with negative net present value should generally be avoided.” Stated more precisely, projects that attain an NPV greater than 0 are worth investing in – the benefits over time outweigh the costs over the life of the project.  

“Programs with positive net present value increase social resources and are generally preferred. Programs with negative net present value should generally be avoided.”

The benefit-cost ratio is simply the present value of benefits divided by the present value of costs. A benefit-cost ratio above 1.0 is indicative of a policy, program, or project that has a NPV > 0 and is economically worthwhile from a public perspective. A benefit-cost ratio of 1.0 represents the lowest value that should be considered for public support as long as the analysis incorporates all significant costs and benefits and if uncertainty is relatively low. A benefit-cost ratio below 1.0 is indicative of a policy, program, or project that has a NPV < 0 and is not economically viable from a public perspective. Benefit-cost analysis (BCA) can be used as a method to rank different projects or different alternatives for a single project all of which may have NPV of greater than zero and, therefore, are theoretically worthwhile. As explained by DOT, “[i]n a capital-constrained situation, it is not possible to invest in every project with a positive NPV, and therefore a way to prioritize is required. The benefit-cost ratio is a measure of return on investment – ‘bang for the buck’.”

The duty to evaluate the economic viability of projects financed or authorized by government entities from a benefit-cost perspective is firmly ensconced in statutes, rules, regulations and guidance manuals for virtually every government agency at the federal, state, and local levels. For example, OMB’s Circular A-94 requirements “apply to any analysis used to support government decisions to initiate, renew, or expand programs or projects which would result in a series of measurable benefits or costs extending for three or more years into the future.” Individual federal agencies have adopted the benefit-cost perspective in their individual regulatory frameworks.

Decisions to fund, authorize, or otherwise facilitate CTL development must consider the public interest through benefit-cost analysis and not narrow assessments of financial viability for potential investors.

For example, benefit-cost analysis and net present values “are key components of EPA’s policy development and evaluation process.” U.S. Army Corps of Engineers (Corps) civil works projects are justified on the basis of their contributions to national economic development (NED). Contributions to NED are “increases in the net value of the national output of goods and services, expressed in monetary units. Contributions to NED are the direct net benefits that accrue in the planning area and the rest of the

10 DOT, 2006, op. cit. note 8, Section 7.2.
11 Ibid.
12 OMB, op. cit. note 8, Section 4(a).
nation.” In Alaska, the benefit-cost perspective was recently mandated in the Alaska Gasline Inducement Act (AGIA). AGIA is designed to expedite construction of a natural gas pipeline that “maximizes benefits to the people of the state.” In support of this purpose, the AGIA requires a strict NPV test for all projects as well as ranking of projects based on NPV.15

Thus, as decision makers in the Alaska Legislature, Fairbanks Economic Development Corporation, and all other federal, state, and local agencies contemplate decisions to fund, authorize, or otherwise facilitate CTL development in Alaska’s Interior those decisions must rest on a determination that CTL development is in the public interest through benefit-cost analysis and not a narrow assessment of financial viability for potential investors.

1.2 Two Key Considerations for a Benefit-Cost Analysis

Before we proceed, it is important to flag two key considerations in a benefit-cost analysis sufficient for an affirmative public interest determination. First, everyone’s costs and benefits count. To make the process of determining whether or not a policy, program, or project creates net public benefits “all economic benefits and costs must be described and, where possible, quantified.”16 These include costs and benefits that are easy to measure because they have direct effects in the market, as well as costs and benefits that are primarily non-market in nature but may be just as or even more significant economically.

The duty to consider costs and benefits broadly is, again, specified in the regulatory environment. For example, guidelines for analyzing federal infrastructure investments contain the following direction: “all types of benefits and costs, both market and non-market, should be considered. To the extent that environmental and other non-market benefits and costs can be quantified, they shall be given the same weight as quantifiable market benefits and costs.”17 Thus, in making a public interest determination of CTL development in Alaska’s Interior, it is critical to consider all costs and benefits regardless of whether they are easy to measure market effects (i.e. fuel cost savings) or more difficult non-market effects (i.e. health and other socio-economic costs of pollution or carbon emissions) regardless of who enjoys or incurs them.

Secondly, the basis for all benefit estimates should be changes in consumer surplus, and not simple calculations of CTL plant revenues from the sale of its products. Consumer surplus is the excess amount that purchasers are willing to pay for a good or service over and above the market price (i.e., the area under the demand curve but above the price line). Consumer surplus serves as a measure of the social benefits of producing the good.18 Policies that affect market conditions in ways that decrease prices will generally increase consumer surplus. This increase can be used to measure the benefits of the policy. As OMB recognizes, “[c]onsumer surplus provides the best measure of the total benefit to society from a government program or project.”19

15 AS Sec. 43.90.170.
17 Principles for Federal Infrastructure Investments, Executive Order 12893 at Section 2(a)1.
19 OMB, op. cit. note 9, Section 4(a).
II. CTL Development is Economically Infeasible from Public and Private Perspectives

2.1 CTL Development is Economically Infeasible from a Public Perspective Because NPV Estimates are Negative

Both the NETL and Hatch studies were not designed as a basis for a public interest determination. Both are well researched, well written, but narrowly focused assessments of the potential viability of CTL development from the perspective of private investors. As such, they exclude many categories of costs that are essential for determining whether or not CTL development is economically viable from a public investment perspective. Likewise, the basis for benefit calculations are simply revenues, not changes in consumer surplus. The effects of including additional costs and revising benefit calculations to address consumer surplus are discussed below. For now, however, it is important to point out that even at face value, both reports provide clear indication that public investment in CTL development – at least along the lines of what has been proposed for Healy and Fairbanks – is unjustified from an economic perspective. This is because at forecasted average F-T selling prices, NPV calculations for both proposed plants are negative and benefit-cost ratios well below one.

The Hatch report indicates a negative NPV for all three Fairbanks CTL plant scenarios: -$1,872 million for the 20,000 bbl/day plant using coal as a feedstock, -$2,571 million for the 40,000 bbl/day plant using coal as a feedstock, and -$1,493 million for the 40,000 bbl/day plant using coal and natural gas as feedstock. For the Healy analysis, no NPV figures were reported. However, a comparison of the Healy project’s rate of return with current costs of capital reveal that NPV estimates are negative. With carbon capture and sequestration (a project component desired by FEDC) NETL reports that the expected return on investment (ROI) for the Healy project is 9.7%, well below the current estimate (included in the Hatch report) of 12% for cost of capital. When ROI is less than cost of capital, it usually implies IRR is, as well. According to Veilleux and Petro (1988) “[i]f a project’s IRR is equal to its cost of capital, then its NPV equals zero. An IRR greater than the cost of capital implies a positive NPV, and an IRR less than the cost of capital implies a negative NPV.” Thus, we can infer that Healy’s expected NPV is negative as well.

To accurately extract benefit-cost ratios for the Hatch and Healy analyses we would have to have access to precise benefit-cost stream figures modeled over all years of construction and the 30 year plant life

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20 Hatch, 2008, Page 100.
21 NETL, 2007, Page 48. Also, it is important to note the return on investment (ROI) is not identical to IRR. Nonetheless, when either measure is below the cost of capital, net present values are negative.
23 NETL uses a cost of capital of 8%. This is now well below the current 12% estimate. Reapplying a 12% cost of capital and discount rate to the NETL analysis would cause NPV estimates to fall considerably. Alaska CTL Comments, Page 6, 2/12/2009
(2015 to 2044) as well as a list of all assumptions regarding discounting, cost and revenue variability, interest and other factors. Neither report furnished this information in enough detail. Moreover, CSE requested these data from NETL, FEDC, and Hatch. NETL could not retrieve the data due to retirement of project staff. FEDC and Hatch declined to provide the data citing “proprietary information.”

None the less, based on the incomplete information presented, we can make a reasonably accurate reconstruction of the benefit-cost stream, net present value, and from there derive benefit-cost ratios for the proposed Fairbanks CTL plant. Appendix 1 is our best guess of the benefit-cost schedule as explained in the Hatch report for Case 1 and Case 2. Since it appears that using natural gas feedstock is not currently under consideration, we omitted Case 3 for now. And because the Healy CTL project is not being currently pursued, we did not create a similar appendix for that project.

Capital construction costs for years 2011 through 2014 appear in Table 21-5, and total $4,146 million for Case 1, $7,449 million for case two. It appears that no interest during construction was added to these values, so we entered them as is in the Appendix 1 spreadsheet. Annual operating costs, beginning in year 2015, are provided on a per/bbl basis in Table 21-8. These amount to $45.07/bbl for Case 1, $39.74/bbl for Case 2, or roughly $329 million and $580.2 million (undiscounted). Beginning in year 2021 (after a five year “grace” period), both plants incur additional charges associated with annual sustaining capital costs. As set forth in Table 21-6, these are $26.6 million for Case 1, $47.7 million for Case 2, again, undiscounted. All annual cost figures are then discounted at a project discount rate of 12%. The spreadsheet shows discounted values for each year. The resulting present value of costs (i.e. the sum of all discounted year by year values) is roughly $6.9 billion for Case 1, and $12.3 billion for Case 2.

On the revenue side, the Hatch report at Table 21-8 predicts total revenues of $82.18/bbl for Case 1, $82.48/bbl for Case 2 from all sources of revenue, which include diesel, jet fuel, naphtha, sulfur, power generation, and steam for heating. Multiplying these by daily production (20,000 bbl and 40,000 bbl) then by 365 yields an annual revenue estimate of nearly $600 million for Case 1, and over $1.2 billion for Case 2. We model this revenue stream from year 2015 until 2044, discount at 12%, then sum to get a present value for the benefits stream: roughly $4.8 billion for Case 1, and $9.7 billion for Case 2.

With respect to the two metrics of greatest interest from a public perspective – net present value and benefit-cost ratios – public investment in CTL development as proposed in both the NETL and Hatch reports appears unjustified.

Subtracting the present value of costs from the present value of benefits yields a negative net present value estimate of roughly -$2,069 million for Case 1, -$2,612 for Case 2. Appendix 1 also reports associated values for the internal rate of return (IRR): 4.4% for Case 1, 6.9% for Case 2. For Case 2, both NPV and IRR figures are within 1.5% of the Hatch figures. For Case 1, they are within 10% or so. As such, they are reasonably accurate for estimating benefit cost ratios and the effects of additional costs and revised benefit estimates discussed below until we receive the actual figures from Hatch or FEDC. By dividing the present value of benefits by costs we can estimate the benefit-cost ratios: .70 for Case 1, and .79 for Case 2. Both are well below the 1.0 value needed for a public interest determination. Thus, with respect to the two metrics of greatest interest from a public perspective – net present value and benefit-cost
ratios – public investment in CTL development, at least along the lines as what is proposed in both the NETL and Hatch reports, appears unjustified. Of course, this is based on the preliminary findings of these reports, and so cannot be taken as conclusive. However, when we consider additional cost factors not included in these reports and the effects of more appropriate benefit calculations, both metrics are likely to be significantly lower.

2.2 Hatch and NETL Studies Suggest that CTL Development is Economically Infeasible from a Private Perspective Because Expected IRR Falls Below the Cost of Capital

Before we discuss the effects of additional costs and revised benefit estimates, it is important to point out that both the Hatch and NETL studies provide clear indication that economic viability from a private perspective is doubtful, as well, at least at this point in time. This is because the expected internal rate of return (IRR) for all three Fairbanks CTL project configurations falls below the current cost of capital of 12% at expected average F-T selling prices. In the Hatch report, IRR is estimated to be 5.1% for Case 1, 7.0% for Case 2, and 7.4% for case three. As previously discussed, the Healy project’s expected return on investment with carbon capture and sequestration is 9.7%, again, below the current 12% cost of capital.

The internal rate of return is a “cut and dry” method for evaluating the feasibility of a capital investment. IRR is the interest rate that makes net present value equal to zero. A basic decision rule for capital investments is that when IRR is greater than the cost of capital or discount rate, the investment will create value for a firm and is therefore worth considering. Conversely, when IRR is below the cost of capital, an investment will likely lose value for a firm.24 Because IRR estimates under the most likely F-T price scenario for the Fairbanks CTL plant are below the cost of capital, private investment does not appear economically viable.

Because of this, the Hatch report provides the break even product selling prices that would be necessary for IRR and the cost of capital to be equal at 12%. For Case 1, the break even price is $138/bbl, for Case 2, $123/bbl. Of course, if a private firm is willing to gamble on these selling prices in the year 2015 it may decide to proceed with the multi-billion dollar investments needed despite current indications to the contrary. All we can say now is that at least at the most likely price scenario, the Hatch report casts significant doubts as to whether the Fairbanks CTL project would be attractive to investors in the short term. Moreover, a recent study of financial viability of CTL development by Scully Capital suggests that an IRR of at least 19% - not 12%, is needed to attract project participants. If this is true, then it casts even great doubt on whether a Fairbanks CTL plant will be attractive enough even for further study.25

III. Additional Public and Private Costs

When Additional Public and Private Costs are Added, NPV and Benefit Cost Ratios Make CTL Development Appear Even Less Viable

Both Hatch and NETL reports exclude several significant categories of costs important for evaluating the feasibility of CTL development from the public perspective. By including these costs, both CTL projects appear even less viable if F-T product prices are as expected. In terms of cost accounting, the NETL report is far more complete, so in the sections below, we discuss omitted costs mostly with respect to the Fairbanks CTL proposal. Where data exists, we also discuss the potential magnitude of such costs.

3.1 Carbon Capture and Sequestration Costs

Capital or operating costs associated with geological sequestration are explicitly excluded in the Hatch report.\(^{26}\) It also appears that the costs associated with installation and operation of capture technologies are also excluded.

Given the enormous economic, social, and environmental costs of global warming, carbon capture and sequestration technology is an important component of CTL development in Alaska’s Interior. The costs of adding this design component to the proposed Healy plant was discussed by NETL, and also addressed in a 2007 study prepared by DOE’s David Berg and Scully Capital. Although carbon capture and sequestration was discussed in the Hatch report, it appears that the majority of associated costs were excluded from the economic analysis. Capital or operating costs associated with geological sequestration are explicitly excluded.\(^{26}\) It also appears that the costs associated with installation and operation of capture technologies are also excluded. Carbon capture technologies discussed in Section 15 (Page 69) of the report include carbon dioxide compressors and monoethanol amine (MEA) scrubbing, yet neither technology is included in the operating cost schedule in Table 21-8. Nor are carbon capture or sequestration costs discussed in any manner in either the capital or operating cost sections of the report (Sections 19 and 20). Since it is unlikely that a Fairbanks CTL plant will be authorized without carbon capture and sequestration these are critical costs to consider.\(^{27}\) We can use the NETL and Berg (2007) estimates as a basis for estimating the potential magnitude of costs associated with the Fairbanks CTL plant.

According to NETL, “[e]conomically, the cost of capture and sequestration is on the order of magnitude

\(^{26}\) Hatch, 2008, Page 3.

\(^{27}\) Personal Communication with Jomo Stewart, Project Manager, Accelerator Energy Center, Fairbanks Economic Development Corporation, jstewart@investfairbanks.com.
of $0.42/Mscf ($7/ton).” \(^{28}\) Elsewhere in the report, this cost is estimated at $6/ton.\(^{29}\) This is the incremental cost once the technology is in place, and was calculated by NETL by estimating the economic return plant owners would have to receive if the CO2 were marketed in order to cover sequestration costs. For geologic sequestration of carbon dioxide, costs associated with equipment and facilities to compress and transport the gas to the sequestration location and injection wells must be considered.

NETL estimates key capital costs to be $111 million for a CO2 compressor ($69 million), a pipeline to transport CO2 ($10 million), and injection wells at the coal bed site ($32 million) for the 14,640 bbl/day plant considered in their study.\(^{30}\) In addition, the plant design produced 204,000 thousand standard cubic feet (Mscf) per day in carbon dioxide at a projected cost of $31,273,200 per year to sequester. Separately, Berg et al. (2007) estimated an additional capital cost of $130 billion for a plant with carbon sequestration capacity relative to a 30,000 bbl/day baseline plant without, and a 9% or so increase in operating costs.\(^{31}\)

To get a rough sense of anticipated costs for the Fairbanks CTL plant, we can adopt the range bounded by NETL ($111 million) and Berg et al. ($130 million) as a crude estimate of capital costs associated with installation of carbon capture and sequestration technology for Case 1 and Case 2. We can also adopt the lower $6/ton marginal cost figure assuming the plant is designed for sequestration ready specifications. For Case 1, Hatch estimates a plant output of carbon dioxide for sequestration at 598 short tons per hour, 1,194 short tons per hour for Case 2.\(^{32}\) Assuming 24 hour operation all 365 days of the year yields 5,238,480 tons per year for Case 1, 10,459,440 tons per year for Case 2. At $6 per ton, this is an additional $31,430,880 - $62,756,640 cost each year of operation for capture and sequestration in addition to the cost of installing the technology – an increase in operating costs of 9-11%. This is right in line with the Berg et al. (2007) estimate of roughly 9%.

One additional consideration is the amount of energy needed for capture and sequestration. Because greater energy uses on-site means less energy for export and sale, it is an important economic effect that needs to be analyzed. In its economic analysis, it appears that the Hatch report does not account for this. The report does indicate electricity requirements for “difficult to capture” sources of carbon in Table 15-2, yet nowhere in the report is the amount of energy needed to capture and sequester the “easy to capture” carbon dioxide reported or deducted from overall generation. Indeed, there is no mention of it at all in the precise power demand schedule listed in Table 20-4.

NETL relied on a figure of 26 megawatts electricity annually (Mwe) to sequester 5,212,200 tons.\(^{33}\) For the 10,459,440 tons generated by Case 2, this implies a power demand of over 52Mw. Interestingly, this is precisely the amount Berg et al. (2007) predicted for a 30,000 bbl/day capacity plant – so power demand for the 40,000 bbl/day Case 2 plant could certainly be higher.\(^{34}\) For Case 1, we can assume that electricity requirements are roughly equal to the 26Mw estimated by NETL. If these values are even in the ballpark and if the Hatch net power generation estimates do indeed exclude power needed for carbon capture and sequestration it would not only eliminate the entire amount of power Hatch predicts will be available for export (11.9 Mw for Case 1, 36.1 Mw for Case 2), but create internal demands for

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\(^{28}\) NETL, 2007, Page xi. Mscf = thousand standard cubic feet.
\(^{29}\) NETL, 2007, Page 48.
\(^{30}\) NETL, 2007, Page 47.
\(^{32}\) Hatch, 2008, Table 1-1.
\(^{33}\) NETL, 2007, Pages 16-17.
\(^{34}\) Berg et al., 2007, op. cit. note 25, Page 183.
more power than can be generated on-site. At the very least, then, it represents an additional “cost” of roughly $13.1 to $39.8 million per year in lost revenues from power export.35

### 3.2 Transportation Costs

*The costs of transporting coal, F-T liquids, slag, and sulfur represent a significant technical and economic challenge although they are not addressed by the Hatch report.*

The transportation of 6.3 – 12.6 million tons of coal into the proposed Fairbanks CTL plant and 7.3 – 14.6 million barrels of F-T liquids, 660,800 – 1.32 million tons of slag, and 12-24,000 tons of sulfur out represents a significant technical and economic challenge. Despite this, the Hatch report sidesteps the issue of transportation costs by leaving the transportation cost line item in Table 21-4 blank. However, since transportation costs could have a significant bearing on economic feasibility it is important to get a sense of their potential magnitude.

The first challenge is the challenge of transporting coal from the Usibelli Mine to the plant. In their report, Hatch describes 4 potential locations for the Fairbanks CTL plant: Mine Mouth, Ft. Wainwright, North Pole and Eielson AFB. Each location presents pros and cons from the standpoint of 12 location criteria, including rail access, however, the report notes that Eielson AFB is “emerging as a more favorable location.”36 Indeed, as previously noted, a $10 million line item was included in the $488 billion draft defense spending bill for fiscal year 2009 with the support of the U.S. Air Force.37 Thus, it appears that the Fort Eielson location is the leading candidate.

In terms of coal inputs, the Hatch report indicates the challenge at Eielson will be to construct a dedicated rail line providing direct access to the Healy Mine.38 However, Alaska railroad officials dispute whether a new rail line would have to be constructed. Alaska railroad maintains that the existing line to Eielson AFB could accommodate the increased traffic, unless the plan is to build a whole new line over the Tanana River directly to Usibelli.39 If the latter is indeed the plan, then the economic analysis must include new rail line capital construction and operating costs per mile. Such costs were recently estimated by the Alaska Railroad for the Port Mackenzie rail extension project of at least $6,311,111 per mile ($275 million for a maximum 45 mile segment). Alaksa railroad officials put the range at $3‐8 million per mile.40 Operating costs were also estimated of at least $33,333 per mile ($1.5 million per year for a maximum 45 mile segment).41

Since the Hatch report did fold expected marginal transportation costs of coal to the plant it its $25 per ton estimate of input costs, we can take that estimate for granted at this point in time and move

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35 Hatch, 2008, Table 21-3, Page 95 contains estimates of the annual power credit associated with net power generation for each Case.
36 Hatch, 2008, Page 79.
38 Hatch, 2008, Page 78.
39 Personal communication with Tim Thompson, Alaska Railroad, January 23rd, 2009.
40 Ibid.
on to missing costs associated with the second major transportation challenge – moving F-T products to market.

The NETL report provides some figures that can be used as a starting point. In the scenario they considered, raw F-T products would be sold to refineries for further processing into diesel and naphtha, and then distributed wholesale to consumers. In the Hatch report, the F-T liquids would be refined at the plant into diesel, naphtha, and jet fuel, and presumably be shipped to wholesale purchasers (including Eielson AFB) directly from the plant. Another scenario would be to ship F-T liquids, as in the NETL case, to refineries, and leave the final distribution up to them since transportation infrastructure is already in place from those locations. For illustration purposes, we can assume the latter.

In their report, NETL developed two scenarios for purchase of the F-T products by regional refineries: (a) all of the product is shipped to North Pole and is purchased solely by Flint Hills or some combination of Flint Hills and Petro Star, (b) all of the product is purchased by Tesoro and is shipped to Nikiski via Anchorage.42 For the North Pole scenario, the report develops a cost figure of $2.65/bbl, or $2.83 in 2008 dollars. For the Nikiski scenario, the report estimates $5.88/bbl, or $6.29 in 2008 dollars.43 Of course, North Pole is quite a bit closer to Eielson than the Mine Mouth (the basis of the NETL estimates). On the other hand, Mine Mouth is quite a bit closer to Anchorage than Eielson. Since we are just illustrating the potential magnitude of shipping costs, we can assume the marginal effect on cost associated with these different distances offset and develop a range based on the NETL figures: $33,288,000 per year for Case 1 (20,000 bbl/day) and $66,576,000 for Case 2 (40,000 bbl/day).

The third challenge has to do with slag – or the waste products from the coal gasification process. The Hatch report estimates the production of 660,800 tons of slag per year with Case 1, and 1,320,000 tons per year for Case 2 based on 8,000 expected operating hours and slag production rates of 82.6 and 165 tons per hour. According to the Hatch report, "[b]ack-filling the exhausted coal seams is the recommended disposal method for slag and fly ash. Rail cars (or conveyors depending on plant-to-mine distance) transport the solids from plant to mine mouth where it is disposed of."44 While on-site disposal is also an option, it is prudent to consider costs associated with the back-filling option since it is the preferred disposal method. In their report, NETL estimates $7.77 per ton for transport to Anchorage.45 For simplicity’s sake, if we assume that costs are proportional to distance, then transport to the Usibelli mine is likely to be roughly half that amount or $3.89 per ton. Multiplying these figures out implies $2,570,512 in slag disposal transport costs associated with Case 1, and $5,134,800 for Case 2. Since NETL did not address costs associated with fly ash disposal, we leave that potential cost out for now.

The final cost consideration is transport of sulfur to market. The Hatch report assumes production of modest amount of elemental sulfur each year – 12,045 tons for Case 1, 24,090 tons for Case 2. NETL concluded that transport to Anchorage and then shipping overseas was the only feasible option for sale of elemental sulfur. They estimated a cost of $10.00 per ton from Mine Mouth, or $10.69 in 2008 dollars. Again, for simplicity’s sake, if we assume the added distance adds proportionally to this cost, we can assume a ballpark figure of $16.20 per ton from Eielson. This translates into an additional annual transport cost of $195,185 for Case 1 and $390,258 for Case 2.

43 Ibid.
44 Hatch, 2008, Page 33.
45 NETL, 2007, Page 16.
To summarize: transportation costs are a significant factor in the economic feasibility of a coal to liquids plant at Eielson or elsewhere in Alaska’s interior. If previous studies can be used as a guide, then we can expect an additional $3 to $8 million or so in capital costs per mile associated with construction of a dedicated rail line if existing rail lines are not adequate. In addition, annual rail line operating costs, and transportation costs for F-T liquids, slag, and sulfur are likely to add $36,853,689 - $72,901,050 to annual CTL plant costs. This represents 11.2% (Case 1) to 12.6% (Case 2) of the annual operating costs estimated by Hatch. Even if the transportation cost figures presented here are overstated by half, they still represent a significant cost element that should not be overlooked, even at any early phase of project feasibility analysis.

3.3 Natural Resource Damages

As major industrial developments, CTL plants have the potential to cause a wide range of environmental impacts, which will impose economic costs on those who depend on the ecological integrity of natural resources.

As major industrial developments, CTL plants have the potential to cause a wide range of environmental impacts. Such impacts, in turn, impose economic costs on those who depend on the ecological integrity of natural resources for subsistence, recreation, scenery, drinking water and many other products, functions, uses, and values that have economic significance. These economic benefits of natural ecosystems are generally known as “ecosystem services.” Colt (2001) estimated the value of ecosystem services provided by terrestrial ecosystems in Alaska to be roughly $1.2 billion each year, $1.6 billion in 2008 dollars. Lost ecosystem services are a form of natural resource damage that should be accounted for in a social benefit-cost framework. Additional costs are associated with pollution – such as costs associated with increased incidence of asthma and other respiratory problems associated with high concentrations of particulate matter in the air. Such costs are known in the economics literature as “negative externalities,” because they are costs that are externalized onto individuals, businesses, and communities who are not compensated for their losses or even considered in the calculation of project viability.

As configured generally along the lines of what is suggested in both the NETL and Hatch reports, CLT development in the Fairbanks area will both directly and indirectly affect land, water, and air resources and thereby be a source of negative externalities to nearby communities. To be complete, a proper evaluation of net public benefits and net present value must account for these costs using state of the art techniques for valuation of natural resource damages and externalities such as contingent valuation, travel cost, replacement cost, or hedonic pricing models that quantify the loss in property values to nearby homes.

Major impacts to land include the development of the CTL plant site, additional mining at the Usibelli Mine, lands affected by waste disposal, and any land impacted by infrastructure such as rail access or transmission lines not already constructed. Hatch estimates 410 acres of direct land impact for the plant, 505 acres if slag and fly-ash disposal areas are included. At the coal input rates anticipated in

47 Hatch, 2008, Appendix I.
the Hatch report, it is reasonable to expect that Usibelli Mine’s entire 100 million ton Jumbo Dome deposit lease will be depleted for feedstock – or an equivalent land area from several sources.\(^{48}\) Usibelli currently holds 12,500 acres in leases on the Jumbo Dome deposit. According to Usibelli’s Steve Denton, ultimately, this will translate into a mine pit of roughly 3,500 acres in size.\(^{49}\) Applying this land disturbance ratio (3,500 acres for every 100 million tons mined) implies 6,615 and 13,230 acres of disturbance for Cases 1 and 2, respectively. Together with lands needed for the plant and disposal area, this suggests a total land footprint of 7,120 to 13,735 acres. What are the economic costs associated with converting this land from natural habitat to industrial uses?

One way to estimate the damage would be to conduct contingent valuation surveys of regional residents to determine willingness to accept compensation (WTA) for loss of the full range of economic values associated with leaving those lands intact.\(^{50}\) Another method would be to use the “replacement cost” approach, and assume that the magnitude of economic damage is roughly equivalent to the “cost to restore, replace, rehabilitate, and/or acquire the equivalent of the injured natural resources and the services those resources provide.”\(^{51}\) For the mine, reclamation costs are something that is known, however, Usibelli considers this proprietary information, and would not disclose the per acre amount.\(^{52}\)

We do know, however, that in Alaska, the State caps mine reclamation bonding requirements based on a value of $750 per acre. If this value were accurate, it would suggest a replacement cost value of $5.3 to $10.3 million.\(^{53}\) However, the $750 figure is, by all accounts, a gross underestimate. For example, the Center for Science in Public Participation estimated mine reclamation and closure costs to range up to $101,483 per acre for the Greens Creek Mine on Admiralty Island.\(^{54}\) Studies have shown that, on public lands, costs incurred by state and federal agencies can be 10 to 100 times higher than those estimated in reclamation plans and financial assurance calculations.\(^{55}\)

There are few comprehensive studies that report average mine reclamation costs for multiple mines of a particular type. One study for coal mine reclamation in Pennsylvania reported a range of $1,768 to $12,481 per acre across 74 mines, with an average cost per acre of $5,426, or $7,177 in 2008 dollars.\(^{56}\) At this rate, natural resource damage costs associated with the 7,120 to 13,735 of land disturbance would be $51,100,240 for Case 1 and $98,576,095 for Case 2. Moreover, because this represents the cost to

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\(^{48}\) At coal consumption rates of 6.3 (Case 1) and 12.6 (Case 2) million tons per year, this would deplete the 100 million ton deposit in 16 years for Case 1, 8 years for Case 2. The 100 million ton figure is taken from the Usibelli Mine website (www.usibelli.com/Coal_Leases.asp).

\(^{49}\) Personal communication with Steve Denton, Friday, January 23rd.

\(^{50}\) Contingent valuation (CV) is the most widely endorsed method for quantifying willingness to pay for or willingness to accept compensation for environmental improvements or natural resource damages.


\(^{52}\) Personal communication with Steve Denton, Friday, January 23rd.

\(^{53}\) Remediation, restoration, and decommissioning costs for the plant site are likely to be much higher than land reclamation costs for mining. However, to simplify, we just assume costs are comparable.


\(^{56}\) Assessment of Pennsylvania’s Bonding Program for Primacy Coal Mining Permits, Permit Forfeiture and Land Reclamation Status Report (for the period July 31, 1982 to November 30, 1999), Office of Mineral Resources Management, Bureau of Mining and Reclamation. Available at: http://www.dep.state.pa.us/dep/deputate/minres/bmr/bonding/bondinggrpt021000.htm.
restore a functional landscape that confers ecosystem service benefits on an annual basis, at least a part of this cost this could be viewed as an annual cost – i.e. the value of lost ecosystem services that would otherwise be provided by intact landscapes each year.

Water use is another source of natural resource damage. There are two primary channels – loss of instream flow and water pollution. CTL technology requires rather enormous inputs of fresh water. Hatch estimates raw water demands of 532 tons per hour for Case 1, 1,064 for Case 2, or roughly 4.6 and 3.2 million tons per year. These amounts are equivalent to 1.1 and 2.2 billion gallons per year, or 3,432 and 6,864 acre feet. Regardless of whether raw water is pumped from nearby rivers or streams or groundwater (since groundwater in the area is very near the surface) it is likely to represent a significant diversion from natural uses.

**Water use is another source of natural resource damage. There are two primary channels – loss of instream flow and water pollution. Reductions in instream flow can adversely affect fisheries, wetlands, and associated recreational and subsistence uses. Common water pollutants include salts, minerals, sulfide, chloride, ammonium and cyanide.**

In the Eielson AFB area, there is a rich diversity of aquatic ecosystems supported by surface water flows. Lakes and streams on Eielson contain both native fish and fish stocked by the Alaska Department of Fish and Game. Native fish found in the Tanana River drainage include Chinook salmon, silver salmon, burbot, arctic grayling, northern pike, chub, several species of whitefish, sheefish, rainbow trout, and arctic char. The Alaska Department of Fish and Game stocks five lakes and one stream on Eielson: Grayling Lake, Hidden Lake, Polaris Lake, 28 Mile Pit, Moose Lake, Mullins Pit, and Piledriver Slough. Fish stocked by the Alaska Department of Fish and Game include rainbow trout, arctic grayling, arctic char, silver salmon, and Chinook salmon.57 “The discontinuous permafrost of the Tanana River Valley provides a setting for extensive forested (black spruce) wetlands within Eielson AFB property.”58 The Tanana River, the largest tributary of the Yukon River, hosts large runs of fall chum salmon that support important subsistence, personal use, and commercial fisheries.

Reductions in instream flow can adversely affect fisheries, wetlands, and associated recreational and subsistence uses. To assign a cost to these natural resource damages, a site-specific study of such uses on the lands and waters affected by CTL plant development would need to be completed. One method would be to estimate willingness to pay for water rights needed to replace the expected withdrawals for CTL operation. Costs could be significant. For example, surveying actual water right purchases for conservation Loomis et al. (2003) found an average price of $609 per acre foot, $788 in 2008 dollars.59 If we assume that all CTL water used is taken away from the local aquatic ecosystem (and either discharged elsewhere, discharged in polluted form, or lost to industrial processes) this would imply an annual cost of $2,704,416 (Case 1) to $5,408,832 (Case 2).

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58 Ibid.
The second major channel for natural resource damage costs to water relate to water pollution. Proposed facilities and operations that could result in surface water discharges to be reviewed under National Pollution Discharge Elimination System (NPDES) regulations include “domestic wastewater, storm water runoff, coal, and slag storage facility effluent, cooling blow down, industrial process wastewater, and reverse osmosis brine.” Salts, minerals, sulfide, chloride, ammonium and cyanide are common pollutants in these effluents.\(^6\) In general, wastewater streams would be treated to remove oil and solids prior to discharge, and advanced treatment for some contaminants may be required. In addition, “[s]ome waste streams could be disposed of by underground injection, requiring compliance with EPA’s Underground Injection Control (UIC) regulations.”\(^6\) To the extent that any of these pollution control measures are not implemented on site, but rather passed on to water users downstream, they represent a negative externality that ought to be accounted for in a benefit-cost analysis. If they are implemented on site, the relevant capital and operating costs should be included as well as the damages associated with any unexpected spills, groundwater leaching, or planned discharges.

**CTL plants are also sources of air pollution, discharging emissions that include sulfur dioxide, nitrogen oxide, carbon monoxide, and particulate matter, each of which adversely affects human respiratory function after they are transformed into aerosols.**

CTL plants are also sources of air pollution and related externalities. Airborne emissions from coal and other fossil fuel plants account for most of the externalities which scientific studies have been able to quantify. The primary emissions of concern are sulfur dioxide, nitrogen oxide, carbon monoxide, and particulate matter, each of which adversely affect human respiratory function after they are transformed into aerosols. They also are transformed into acids that damage ecosystems, and ozone, which is a major contributor to haze that reduces visibility in scenic areas.\(^6\) Ozone has also been linked to lower crop productivity. According to NETL, combined emissions associated with operation of a 14,640 bbl/day plant and associated mining at Usibelli would be 474 tons per year for nitrogen oxides, 161 for sulfur dioxide, 82 for particulate matter, 68 for carbon monoxide, and 19 for volatile organic compounds.\(^6\)

As mentioned earlier, there has been quite a bit of scientific research on the magnitude of externalized costs associated with these emissions. In one widely used study of power plants in the European Union, researchers concluded that “if the external cost of producing electricity from coal were to be factored into electricity bills, between 2 and 8 cents per kwh would have to be added to the current price.”\(^6\) Global warming costs were not included. Most published studies are in this range, however, they address coal fired power plants, not CTL plants, which can be expected to emit quite a bit less.

By scaling the NETL figures up to reflect anticipated emissions associated with CTL plant capacities of

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\(^6\) NETL, 2007, Page 55.


\(^6\) NETL, 2007, Page 50.

20,000 and 40,000 bbl/day and then comparing these to typical emissions from a standard 500 MW coal fired power plant, we can get a rough sense of just how much less.\textsuperscript{65} Doing this, it appears that emissions from CTL plants at these capacities would emit roughly 11\% as much as a typical coal fired plant. If we scale down the external cost figures to reflect this, we end up with a range of .22 to .88 cents per kwh instead of 2 to 8 cents. As described in the Hatch report, annual power generation for Case 1 would be 326 megawatts, 654 for Case 2.\textsuperscript{66} These convert to 2.86 billion kilowatt hours for Case 1, 5.73 billion for Case 2. This implies an external cost range of $6.3 to $25.17 million a year for Case 1, $12.60 to $50.42 million for Case 2.

\textbf{Another significant externality associated with air emissions is global warming pollution. Full life cycle accounting of carbon dioxide emissions associated with CTL plants should tabulate emissions associated with mining, transportation, plant operations, and final consumption. Neither the NETL report nor the Hatch report accomplishes this.}

Another significant externality associated with air emissions is global warming pollution. Carbon dioxide is by far the most significant greenhouse gas by volume. Full life cycle accounting of carbon dioxide emissions associated with CTL plants should tabulate emissions associated with mining, transportation, plant operations, and final consumption. Neither the NETL report nor the Hatch report accomplishes this. Carbon dioxide emissions are only reported for plant operations alone. In the Hatch report, hourly emissions range from 728.8 tons per hour under Case 1, to 1,457.6 tons for Case 2. Without sequestration, this represents 6,384,288 to 12,768,576 tons per year. The carbon component of these emissions is 1.74 million tons for Case 1, 3.50 million tons for Case 2.\textsuperscript{67} With carbon capture and sequestration at the 82.1\% efficiency rate estimated by Hatch in Table 15-1, carbon emissions would be 311,460 tons (283,428 metric tons) for Case 1, 626,500 tons (570,115 metric tons) for Case 2.\textsuperscript{68}

Given the enormous costs global warming is expected to have on the world’s economy and the expectation of a carbon tax in the future, there have been hundreds of studies attempting to put a price tag on the marginal social costs of carbon emissions. In one recent meta-analysis, Tol (2005) found a median value of $14 per metric ton carbon (t/c) and a mean of $93t/c over 103 studies.\textsuperscript{69} The range is huge, from as little as $2 to $350 or more. One way to put a price tag on the carbon emissions associated with the Fairbanks CTL plant would be to simply take the median value from Tol, updated to 2008 dollars. This is $15.98t/c, which suggests an annual external cost of $4.53 million for Case 1, $9.11 million for Case 2 with sequestration. Without sequestration, these values would be $25.22 million for Case 1, $50.73 million for Case 2. These figures are conservative because they only

\textsuperscript{65} According to the Union of Concerned Scientists, a typical 500 MW coal fired plant can be expected to generate 10,000 tons of sulfur dioxide, 10,200 tons of nitrogen oxide, 500 tons of particulate matter, and 720 tons of carbon monoxide each year, for a total of 21,40 tons. Based on the NETL figures, we can expect a 40,000 bbl/day CTL plant to emit 2,278 tons, or roughly 11\%. See: \url{http://www.ucsusa.org/clean_energy/technology_and_impacts/energy_technologies/how-coal-works.html}.

\textsuperscript{66} Hatch, 2008, Appendix D.

\textsuperscript{67} To extract the weight of carbon from a given weight of carbon dioxide, we multiply by (12/44), which is the ratio of the carbon atomic mass to the total.

\textsuperscript{68} A short ton is approximately .91 of a metric ton.

consider plant emissions. Also, advocates for carbon taxes suggest a much higher marginal social cost figure closer to $100 per ton.

### 3.4 Interest During Construction

The Hatch analysis excludes all consideration of financing costs.\(^{70}\) While understandable at the preliminary FEL1 stage of analysis such costs, nonetheless, are likely to be a significant cost component and probably should have been considered in a very rough sense, at minimum. The NETL study employed a financial model to get a rough sense of financing costs associated with a 14,640 bbl/day plant at the mouth of the Usibelli Mine. The financial model estimated total financing costs to be just over $258 million for a plant whose capital costs totaled just over $2 billion.\(^{71}\)

The largest component of financing costs is interest during construction (IDC). When major manufacturing or infrastructure projects are built, there is often a considerable period between the start of a project and its completion. Because the cost of an asset should include all costs incurred to prepare it for use or readiness for sale, interest costs related to the construction are generally folded in or capitalized, into the project cost estimates. The amount of interest paid during construction depends on the share of construction costs financed by debt, interest rates, finance fees, loan repayment terms, and other aspects of the specific financing plan. Of course, these variables cannot be known as of yet for the Fairbanks CTL plant, however, the NETL analysis may provide at least a rough sense of IDC magnitude.

Using an interest rate of 8%, an assumed debt/equity financing ratio of 70/30, a repayment schedule of 15 years, and finance fees of 3%, NETL concluded that the IDC charge would amount to roughly $211 million. This represents roughly 15% of the debt-financed portion of total capital costs. Assuming a similar debt/equity ratio and applying the 15% figure to the Fairbanks CTL analysis, we can get a ballpark estimate of at least $435 million for Case 1, and $782 million for Case 2. Because IDC is such a significant cost component, it would be advisable to include at least a rough cost estimate in the preliminary consideration of project feasibility.

### 3.5 Owner Costs

Owner’s cost includes separate costs that are directly incurred by the owner of a project. Owner’s costs were excluded from the Hatch analysis.\(^{72}\) “Potential owner’s cost items include labor, land, project permitting, environmental reporting, and facilities.”\(^{73}\) In standard financial modeling of power plants and other industrial facilities, owner’s cost items should be entered as a lump sum amount.

NETL did include owner’s costs, so we can use their assumptions to get a sense of the likely magnitude of owner’s costs associated with the Fairbanks CTL plant. NETL assumed an owner’s cost of 10% of engineering, procurement, and construction costs (EPC). EPC costs were estimated to be $1.43 billion.

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70 Hatch, 2008, Page 84.
71 NETL, 2007, Page 45.
72 Hatch, 2008, Page 85.
making owner’s cost roughly $143 million. Hatch estimates total capital costs of $4.15 billion for Case 1, $7.45 billion for Case 2. If we assume all such costs are EPC related, then this implies an owner’s cost line item of $415 million for Case 1, $745 million for Case 2.

3.6 Taxpayer Costs

It is increasingly clear that CTL development in Alaska’s Interior will not occur without significant taxpayer support. Public agencies have already committed significant funds for initial feasibility studies. As noted earlier, a bill to establish a $21 billion fund to subsidize alternative fuels, including CTL, is working its way through the Alaska legislature. In addition to these direct subsidies, public agencies will incur significant costs to complete all the various regulatory oversight functions related to permitting, environmental analysis, and monitoring. It its report, NETL identified over 34 applicable federal, state, and local permitting activities involving 7 public agencies.74

Recently, Berg et al. (2007) completed a detailed analysis of public subsidies needed to jumpstart CTL co-production (i.e. liquids and electricity) in the United States. They considered a wide range of public finance mechanisms including loan guarantees, investment tax credits, excise tax credits, tax exemptions for debt, purchase agreements and grants. The incentives were analyzed as tools to offset three general categories of risk to private participants: technical risks, policy and regulatory risks, and market risks. Based on interviews with industry experts, it was the conclusion of the report that “government-sponsored incentives would be required to facilitate the development of a co-production facility.”75 In fact, the report found that the only policy or regulatory risk that had both a high probability and a high severity of impact is the risk that national incentives will be insufficient in assuring adequate operating margins for the first co-production plants.76

Given that taxpayer costs are likely to be required and significant for CTL development to occur, they should not be excluded from an evaluation of economic viability from the public perspective. Neither the NETL nor Hatch reports discuss taxpayer liability.

The report estimated taxpayer liability would range between $87 million to $1.5 billion to support a 30,000 bbl/ plant depending on the type of mechanism used. They also modeled two potential incentive package scenarios involving loan guarantees, excise tax credits, and state funded development grants. Taxpayer costs ranged from $383 to $781 million.77 Given that taxpayer costs are likely to be required and significant for CTL development to occur, they should not be excluded from an evaluation of economic viability from the public perspective. Neither the NETL nor Hatch reports discuss taxpayer liability at all.

74 NETL, 2007, Appendix C.
75 Berg et al., 2007, op. cit. note 25, Page 104.
76 Berg et al., 2007, op. cit. note 25, Page 89.
77 Berg, et al., 2007, op. cit. note 25, Page 152.
IV. Consumer Surplus Change

4.1 Consumer Surplus Change Should Be the Basis For Project Benefits

As previously discussed, the basis for all benefit estimates associated with publically supported CTL projects should be changes in consumer surplus, and not simple calculations of revenues from the sale of its products because consumer surplus provides the best measure of the total benefit to society from a government program or project. In general, increases in consumer surplus could be expected if the products sold from the plant generate cost savings for final consumers of diesel fuel, jet fuel, naphtha, sulfur, and electricity. However, because both NETL and Hatch studies consider economic viability from the perspective of private investors, they do not attempt to identify or quantify consumer surplus changes or changes in any other category of public benefits. Instead, plant revenues are the only positive factors considered in the overall evaluation of economic feasibility. Using revenues in this fashion significantly overstates public benefits.

To demonstrate this, a simple example will suffice. Consider a simplified market for diesel in a local community with a downward sloping demand curve (D) and upward sloping supply curve (S0) as shown in the figure below. At equilibrium, consumers purchase 70 million gallons at a price of $3.00 per gallon. Now consider the effects of a project – like a CTL plant – coming on line to deliver diesel at a lower cost at every level of consumption. This represents a shift downward in the supply curve to S1. At the new market equilibrium, consumers purchase 80 million gallons at a price of $2.00 per gallon. The gain in consumer surplus – defined as the area below the demand curve above the price line – increases as shown. In this example, the gain is simply the difference in area between the two triangular regions to the northwest of each equilibrium point. It can be calculated as \( \frac{1}{2} \times 8.00 \times 80 - \frac{1}{2} \times 7.00 \times 70 \), or $75 million. At the new equilibrium, CTL plant revenues are $2.00 * 80 million or $160 million. Thus, using CTL plant revenue as even a crude approximation of public benefits grossly exaggerates their true magnitude.

Completing a market analysis capable of generating accurate consumer surplus estimates for CTL or other infrastructure projects can be a fairly involved task. In lieu of this, public agencies often use a simple cost savings model as a crude proxy. To do this, benefits are estimated as the cost savings to final consumers under existing consumption levels. So in our example, it would simply be the difference between consumer expenditures on 70 million gallons of diesel at the old and new prices: \( 70 \times 3.00 - 70 \times 2.00 \) or $70 million. This approach, however, underestimates project benefits because it ignores additional consumer surplus from new consumption. In this case, consumer surplus is underestimated by $5 million. The more inelastic the demand (i.e. the steeper the demand curve), the better the approximation, so cost savings can certainly be used as a proxy for consumer surplus changes when market demand for a good is somewhat insensitive to price.

78 OMB, op. cit. note 9, Section 4(a).
Neither NETL nor the Hatch report even postulates the level of consumer cost savings associated with CTL plant output. In fact, the basis for revenue calculations is the assumption that F-T liquids will sell at the prevailing market price for crude oil or its distillate products. As such, neither report makes the case for any public benefit whatsoever. This is not really an oversight; it is just a result of the kind of analysis undertaken.

Even if cost savings to consumers were a possibility, they are likely to be far too small to offset the full range of public and private costs associated with CTL development discussed above. For example, according to the latest projections by the Energy Information Agency (EIA), diesel prices are expected to steadily climb from $3.52 per gallon in 2015 to $3.91 in 2030 – an average of $3.72 for the period. In its report, Hatch estimates a breakeven price of F-T products as $138 for Case 1, $123 per barrel for Case 2, $3.29 and $2.93 per gallon, respectively. At best, this would translate into a cost savings (or public benefit) of $362 million per year for the Case 2 plant, far below the $580 million in operating costs estimated by Hatch – a figure that excludes many categories of costs like carbon sequestration, transportation, or natural resource damages.

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V. Additional Realistic Assumptions
Further Erode Project Viability

5.1 Price of Coal Feedstock

The cost of coal feedstock will by far be the largest share of operating costs for the Fairbanks CTL plant so it is critical to have an accurate figure to gauge long term economic viability. Hatch assumes a cost of $25 per ton, which includes a $15 purchase price at mine-mouth and a $10 rail cost. At consumption estimates of 6,278,000 (Case 1) and 12,556,000 (Case 2) tons per year, this amounts to $156,950,000 for Case 1, and $313,899,000 for Case 2 or 48% to 54% of overall operating costs. The Hatch report further assumes that all coal will be supplied from the Usibelli Mine near Healy. The Jumbo Dome deposit is the most likely source.

According to a recent statement by Usibelli Mine Vice President Steve Denton, the $25 figure “seems a little light.” Coal prices are typically expressed in price per million British Thermal Units, or MMBTUs. For the average composition of Jumbo Dome deposits, there are approximately 7,800 BTUs per pound, or 15,600,000 per ton. A purchase price of $15/ton implies a price of $.96 per MMBTU. This value is below the $1.00 MMBTU figure reported in 2006 in the NETL report ($15.60 per ton) and significantly below the $1.50 to $2.00 for average mine mouth prices estimated by Mr. Denton in a September 2008 article published in the Fairbanks Journal of Commerce. This range (in constant dollars) is also predicted in the Energy Information Administration’s most recent estimate of coal prices for 2015 – 2030. Moreover, Jumbo Dome coal mining will cost more because the coal is more distant from the mine’s coal loading facilities and will thus incur higher transportation costs. Thus a figure of $2 per MMBTU is probably the best estimate.

Even if a $1.50 per MMBTU price is more realistic, the impacts on Fairbanks CTL profitability are significant. At $1.50 per MMBTU translates into $23.40 per ton, or $8.40 (56%) over the price assumed in the Hatch report. This represents an additional $52,735,200 in annual operating costs for Case 1, $105,470,400 for Case 2. A price of $2 per MMBTU is equivalent to $31.20 per ton, $16.20 more than the Hatch estimate. Additional costs would then be $101,703,600 for Case 1 and $203,407,200 for Case 2. Thus, a coal price estimate in the $1.50 to $2.00 per MMBTU range represents an operating cost escalation of 17.5 to 35% over the Hatch estimates.

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80 Hatch, 2008, Page 86.
82 Hatch, 2008, Page 5.
83 NETL, 2007, Page v.
5.2 Revenue from the Sale of Electricity

The Hatch report assumes a Fairbanks CTL plant will generate enough excess power to export a significant amount for to the Golden Valley Electric Cooperative at a purchase price of $0.1259 per kilowatt hour. Annual exports anticipated for Case 1 are 11.9 Mw, 36.1 Mw for Case 2. These correspond to 104,244,000 kwh for Case 1, 316,236,000 kwh for Case 2. Anticipated revenues, then, are $13.1 million for Case 1, $39.8 million for Case 2.88

However, as noted earlier (Page 10) the Hatch report does not appear to account for the electricity needed to capture and sequester carbon dioxide – a required plant element. Detailed power demands included in the operating cost estimate appear in Table 20-4. Capture and sequestration equipment is absent, as is any mention of capture and sequestration power cost. Nor do the capital or operating cost sections of the report discuss capture and sequestration in any way. Also as previously discussed (Page 10) the amount of electricity needed for capture and sequestration is likely to exceed the export projections by a wide margin. This will likely require use of F-T fuels produced (probably Naptha) to burn for the additional load requirements. Thus, with capture and sequestration in place, a more realistic economic analysis should omit revenue from the sale of power altogether and also include costs associated with any reduction in the sale of F-T liquids needed for on-site power generation.

If the Hatch report does incorporate capture and sequestration power costs in some other way not made explicit, the other issue is the rate at which Golden Valley Electric Cooperative will purchase the excess power. Hatch does not disclose the basis for the $0.1259 estimate. As it turns out, the actual purchase price is highly volatile, and generally tracks the price of oil.89 The $0.1259/ kwh estimate was made when oil prices were at an all time high of nearly $150 per barrel last summer. Now, that price is maintaining steady in the mid $35 - $45 range. At minimum, then, revenue projections (as well as internal cost proxies90) for power generation should be based on expected ranges for GVEC purchase prices given recent and projected oil prices and not assumed to be at the extraordinarily high rate experienced last summer.

5.3 Plant Life

Both NETL and Hatch reports assume a plant life of 30 years. The assumption has a significant effect on economic viability, because with so much capital investment required up front, a long revenue stream is needed to first break even, then assure adequate returns for project investors. Perhaps the most important variable related to CTL plant longevity in Alaska’s Interior is access to economical supplies of coal. Already, as we discussed above, expected coal prices to feed a Fairbanks CTL plant are significantly higher than the assumed price in the Hatch report. As coal reserves are depleted, this price can only be expected to go higher as more distant, more inaccessible, and less productive areas are mined. Reserves then factor into the equation in two ways: (1) regardless of price, they have to be large enough to sustain projected demands for 30 years taking into consideration all demands on the mine, and (2) prices must remain low enough to assure economically profitable plant operation.

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88 Hatch, 2008, Page 95.
90 Hatch assumes a “cost” of power generated and used internally also at the GVEC rate.
Assuming Hatch coal input requirements are accurate, the Case 1 plant would require 6.3 million tons of coal annually, or 189 million over the life of the plant. Case 2 would require 12.6 million tons each year, or 378 million tons over the life of the plant. Usibelli estimates that the Jumbo Dome deposit, the likely source, contains a maximum of 100 million tons.\(^9\) For Case 1, it would be depleted in 16 years, for Case 2, 8 years assuming no other purchasers are competing for this same coal. The looming question, then, is whether coal from additional but as of yet unsecured leases will be of sufficient size, location, and composition to insure economical supplies for the remaining 14 to 22 years of operation.

Unless the answer to this question is definitive, then economic analyses must account for these uncertainties in sensitivity analysis. Neither the NETL nor Hatch sensitivity analyses model a scenario of increasing coal prices after depletion of the Jumbo Dome deposit, or effect on project economics if plant life is less than the 30 year expectation. The effect of shorter plant life can be significant, since each year of operation is expected to generate $271 to $624 million in earnings above costs.\(^9\)

5.4 Plant Availability

Both gas to liquids (GTL) and coal to liquids (CTL) plants are highly complex technologies subject to a wide range of interrelated environmental, mechanical, and economic factors that can lead to unexpected down times and loss of production.

In its economic analysis, Hatch assumes production at full capacity 365 days per year, 24 hour per day – or 100% availability. This can be readily seen from its production estimates for F-T liquids and key bi-products provided in Tables 21-9 and Table 1-1. Case 1 capacity is 20,000 bbl/day, multiplied out by 365 days per year, this is 7.3 million barrels annually, which is what Table 21-9 assumes. Case 2 capacity is 40,000 bbl/day, again, multiplied out by 365 days per year, this is 14.6 million barrels, which again is what Table 21-9 assumes.

These figures serve as the basis for revenue projections found in Tables 21-1, 21-2, and 21.3.\(^9\) Table 1-1 provides hourly production estimates for sulfur, slag, fly ash, and CO2 for sequestration. Of these, only sulfur is considered a bi-product with revenue potential. Table 1-1 estimates the hourly production rate of sulfur to be 1.38 short tons per hour for Case 1, 2.75 for case 2. Multiplying these out by 24 hours, then 365 days yields annual production of 12,045 tons for Case 1, 24,090 tons for Case 2, again, the figures reported in Table 21-9. Clearly, however, the assumption of 100% availability is erroneous, and should not serve as the basis for revenue projections.

Experience shows that both gas to liquids (GTL) and coal to liquids (CTL) plants are highly complex technologies subject to a wide range of interrelated environmental, mechanical, and economic factors that can lead to unexpected down times and loss of production. In its report, Hatch references Sasol’s Oryx demonstration project in Qatar as an indication of the emerging technologies in the field.

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\(^9\) See www.Usibelli.com/Coal_Leases.asp.
\(^9\) For example, Table 21-8 assumes F-T liquids revenue of $70.06/bbl for Case 2. Multiplying this by the 100% reliability production figure of 14,605,000 bbl/ year yields the $1,155,000,000 revenue projection in Table 21-1.
of improved FT synthesis. Yet the Sasol demonstration plant was riddled with problems caused by unexpected accumulations of fine material during the F-T process that caused performance to be substantially less than planned output.

Availability is most vulnerable during the critical (from an economic point of view) first few years of the project. For example, in their study, Berg et al. (2007) assumed availability to be 45-60% in year 1, and 60-85% in year two under pessimistic and optimistic ramp up scenarios. Long term (final) availability assumptions ranged from 85% to 95%. Given Alaska's unique geographic setting and the fact that CTL technology has yet to be used in the State, it would be prudent to expect both ramp-up and final availability to be at the lower end of these ranges for purposes of economic analysis. The importance of reliability to the economic analysis is underscored by Berg et al. (2007): “[e]ven small changes in availability have a large effect on the price of FT fuel.” They found that a 5.56% decrease in final availability for the two plants they considered to require an 8-9% increase in final FT prices to maintain economic viability.

Curiously, elsewhere in its report, Hatch assumes a reliability estimate of 91.32% - or 8000 hours of operation out of a total of 8760 hours per year. But in its economic analysis, availability is assumed to be 100%. Again, for long term reliability, the 91.32% figure may be on the high side due to Alaska's unique setting, but even reducing availability to this level has a significant effect on project economics. An 8.68% reduction (i.e. 100% - 91.32%) in output is equivalent to a reduction in annual revenues of nearly $52.1 million per year for Case 1, and $104.5 million for Case 2.

A more conservative estimate of 85% availability reduces annual revenues by nearly $90 million for Case 1, and $180.6 million for Case 2. Of course, less availability also reduces operating costs, but probably not by the same amount since plant operations would not be completely shut down even if production is. Regardless, it is clear that the expectation of 100% reliability should be dropped and replaced by a more realistic figure that considers difficulties during the first few start-up years, the technological complexities involved, and Alaska's unique setting.

**5.4 Potential Effects on NPV and the Benefit-Cost Ratio**

Assuming the net present value and benefit-cost analysis figures shown in Appendix 1 are roughly equivalent to Hatch's undisclosed analysis, we can demonstrate the effects of the additional cost considerations and alternate assumptions discussed above. Table 1 below shows the incremental effect on net present value and the benefit-cost ratio for the Case 2 (40,000 bbl/day) plant assuming that CO2 capture and sequestration capacity is added, that plant availability is 91.32% and that this reduction affects both revenue and operating costs equally, that no capital costs are incurred for transportation, and that revenues remain at the forecasted level of $82.48/bbl. To be conservative, we use lower bound figures whenever there is a range. The combined impact is shown in Appendix 2.

It must be emphasized that these are not precise figures, only best guesses based on incomplete information. Until Hatch discloses all of the data and assumptions behind its analysis, and until better fig-

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94 Hatch, 2008, Page 44.
95 Berg et al., 2007, op. cit. note 25, Page 190.
96 Ibid.
ures are developed for those estimated by NETL and other sources, this can only be seen as a general assessment of how NPV and the benefit-cost ratio may change if excluded costs are in the ballpark of what is suggested, and if the assumptions made are accurate.

Regardless it seems clear that a Fairbanks CTL plant would have a long way to go in order to break even from a public perspective with NPV of 0 and a benefit-cost ratio of close to 1. In fact, even if cost figures are overestimated by 40% (Hatch’s margin of error) the project, as modeled in Appendix 2, would still reflect a negative net present value and benefit-cost ratio well less than one.

<table>
<thead>
<tr>
<th>Modification</th>
<th>NPV ($ Million)</th>
<th>BCR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case</td>
<td>-2,612</td>
<td>0.79</td>
</tr>
<tr>
<td>Carbon capture and sequestration – additional capital costs</td>
<td>-2,742</td>
<td>0.78</td>
</tr>
<tr>
<td>Carbon capture and sequestration – additional operating costs</td>
<td>-3,247</td>
<td>0.75</td>
</tr>
<tr>
<td>Transportation of products to market</td>
<td>-3,834</td>
<td>0.72</td>
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<tr>
<td>Natural resource damages</td>
<td>-4,151</td>
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</tr>
<tr>
<td>Interest during construction</td>
<td>-4,933</td>
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</tr>
<tr>
<td>Owner costs</td>
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<td>0.63</td>
</tr>
<tr>
<td>Taxpayer costs</td>
<td>-6,061</td>
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</tr>
<tr>
<td>Coal feedstock at $1.50 per BTU</td>
<td>-6,911</td>
<td>0.58</td>
</tr>
<tr>
<td>No electricity export</td>
<td>-7,321</td>
<td>0.56</td>
</tr>
<tr>
<td>25 year plant life rather than 30</td>
<td>-7,288</td>
<td>0.56</td>
</tr>
<tr>
<td>Plant availability at 91.32% rather than 100%</td>
<td>-7,530</td>
<td>0.52</td>
</tr>
</tbody>
</table>

Table 1. Potential Impact on Net Present Value (NPV) and the Benefit Cost Ratio (BCR) from Additional Cost Considerations and Alternate Assumptions, Case 2: 40,000/bbl/day
VI. Conservation and Renewables Are More Viable Options

6.1 Energy Return on Investment (EROI) Analysis Suggests Conservation and Renewables Are More Viable Options.

A final consideration in evaluating overall feasibility is to compare the energy required to build, supply, operate the plant, and deliver its products to market compared with the energy embodied in its final outputs. This kind of analysis is known as an Energy Return on Investment (EROI) analysis, and is useful for determining whether developing a new source of energy is viable from an energy balance perspective and how it stacks up to other investments. In the 1930s, the EROI for oil was nearly 100:1. Crude oil now has an EROI of roughly 20:1. An alarming global trend is the steady decline in EROI for almost all energy sources, implying an accelerating draw down of energy supplies as more and more energy is required to produce the energy we consume. A significant reduction in demand through conservation and energy efficiency is seen as the best alternative for extending supplies of fuels with high EROIs while we develop long term solutions.

While it is not possible to calculate an accurate EROI for the Fairbanks CTL plant with existing data – since it excludes energy use associated with several major activities like construction and transportation – a crude approximation can be made by calculating the energy produced and used by the plant per ton of F-T liquids. Assuming the energy content of a ton of F-T diesel is similar to conventional oil, each ton embodies roughly 42,700,000 BTUs. The Hatch report, Appendix E, estimates total energy consumption as 2,570.4 million BTUs per hour, however, it is unclear whether this represents total energy consumption for all plant processes. Production is estimated at 252.14 tons per hour. This equals 10,194,336 BTUs per ton. To this we add the energy used to extract, process, and transport coal to the plant. DOE estimates these costs to be roughly 2-4% of the energy content of coal. According to NETL, Jumbo Dome deposits average 7,800 BTU/lb, or 15,600,000 BTU/ton. Multiplying this figure by 4% yields 624,000 BTU/ton. Thus, an estimate of energy used per ton (excluding construction and transportation) is approximately 10,818,336 BTUs/ton. Dividing the energy content of F-T liquids per ton by this amount yields an approximate EROI of 3.95. This is almost exactly the 4.0 EROI figure for coal liquefaction reported by Wilshire et al. (2008), and so is probably a reasonable estimate.

An average EROI for crude oil currently stands at about 20:1. Thus, using CTL liquids rather than crude is far more inefficient, implying a faster drawdown of scarce energy supplies relative to what we can

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achieve by greatly improving the energy efficiency of transport, power production, and heating and thereby extending the life of crude oil supplies until we can develop long term renewable solutions. One such solution – hydropower provided by the Susitna dam – is the kind of alternative that should receive careful consideration as an alternative use of public funds for energy infrastructure.

Hydropower has a much higher EROI than CTL, in the order of 14:1, and has virtually no CO2 emissions. Power from this dam would replace power now generated by diesel, likely at a significantly lower cost, and obviate the need for new diesel sources. If such a dam could be constructed in a way that preserved fish passage and minimizes ecological impacts to aquatic ecosystems, it may be a far better investment for Alaska’s energy future than CTL. If not, then replacing diesel based electricity generation with wind and solar should receive similar scrutiny. These renewable also have relatively higher EROIs – 18 for wind, 8 for solar photovoltaic, and are truly sustainable in the long run.

Public investment in a carefully designed package of conservation, subsidies for fuel and energy efficiency and retrofits for wind and solar may prove to be a far better investment than either hydropower or CTL, and would have a significant beneficial effect on the State’s economy.

Public investment in a carefully designed package of conservation, subsidies for fuel and energy efficiency and retrofits for wind and solar may prove to be a far better investment than either hydropower or CTL, and would have a significant beneficial effect on the State’s economy. One recent study suggests that even a relatively modest investment of $275 million in green economic recovery that includes retrofits, wind and solar could lower the State’s unemployment rate by 1.4% in two years and create thousands of new jobs in diverse, highly skilled sectors.103 Energy efficiency investments have been shown to have benefit-cost ratios of 2:1 or better.104 At any rate, this kind of analysis – i.e. careful consideration of renewable alternatives – should be part of the economic debate as CTL proposals advance through the public decision making processes.

VII.
Conclusions

Any decision to further subsidize CTL development in Alaska’s Interior should be based on an analysis of net public benefits.

Net present value and benefit-cost ratios are the primary metrics used to evaluate net public benefits, not financial returns to private investors. The two CTL economic analyses completed to date demonstrate that it is highly unlikely that CTL development is viable from the public perspective because net present values are likely to be negative and benefit-cost ratios well below one, implying that CTL development will probably cause more economic harm than good. In addition, the Hatch report indicates that even from the private perspective, CTL development is unlikely to be attractive to investors because expected internal rates of return (IRR) are less than the cost of capital. NPV, benefit-cost ratios, and IRR would be far less when significant omitted costs are included and unrealistic assumptions corrected. Moreover, neither study even alleges, much less estimates, public economic benefits from CTL development.

If decision makers continue to consider public subsidies for CTL development, subsequent economic analyses, on the benefits side, should address any potential increase in consumer surplus associated with reduced costs for diesel, jet fuel and other Fischer–Tropsch products relative to expected prices for the same products derived from crude oil. On the cost side, the costs of carbon capture and sequestration, transportation and natural resource damages, financing costs, owner costs, and taxpayer costs as well as other private and public costs omitted from the Hatch and NETL analyses should be addressed.

In addition, subsequent analyses should include more accurate and current estimates of coal costs, revenues from power sales, plant availability, and plant life. Finally, such analyses should compare NPV and benefit-cost ratios expected from CTL development with anticipated returns from a similar magnitude of investment in renewable alternatives including hydropower, wind, solar, fuel and energy efficiency, and conservation. These alternatives appear to be superior to CTL because they use far less energy to make energy, enjoy high benefit-cost ratios, and minimize carbon emissions and other natural resource damages.
## Appendix 1

### Approximated Benefit-Cost Analysis of the Fairbanks CTL Plant Cases 1 and 2

<table>
<thead>
<tr>
<th>Year</th>
<th>Case 1: 20,000 bbl/day</th>
<th>Case 2: 40,000 bbl/day</th>
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<tbody>
<tr>
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<td>Project Revenue Stream</td>
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</tr>
<tr>
<td></td>
<td>Annual: $599,914,000.00</td>
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<td>2012</td>
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<td>2043</td>
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<td>2044</td>
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## Appendix 2

### Approximated Benefit-Cost Analysis of the Fairbanks CTL Plant Case 2, With Additional Costs and Changed Assumptions

Discount rate: 0.12
Discount factor: 0.892857

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<td>$0.00</td>
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<td>2010</td>
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<td>$0.00</td>
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<td>2013</td>
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<table>
<thead>
<tr>
<th>Year</th>
<th>Case 2: 40,000 bbl/day</th>
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</thead>
<tbody>
<tr>
<td>2009</td>
<td>$1,059,908,000.00</td>
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<tr>
<td>2010</td>
<td>$8,313,005,889.99</td>
</tr>
<tr>
<td>2011</td>
<td>(7,530,480,206.89)</td>
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<tr>
<td>2012</td>
<td>(5,369,827,378.38)</td>
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<tr>
<td>2013</td>
<td>(3,722,590,695.45)</td>
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<tr>
<td>2014</td>
<td>(1,923,421,578.90)</td>
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<table>
<thead>
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<th>Year</th>
<th>Case 2: 40,000 bbl/day (Costs Decreased by 40%)</th>
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<tr>
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<tr>
<td>2010</td>
<td>$8,313,005,889.99</td>
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<td>2011</td>
<td>(7,530,480,206.89)</td>
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<td>(3,722,590,695.45)</td>
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<td>(1,923,421,578.90)</td>
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<table>
<thead>
<tr>
<th>Year</th>
<th>IRR</th>
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### Case 2: 40,000 bbl/day

- **Project Revenue Stream**: $1,059,908,000.00
- **Project Cost Stream**: $774,805,381.97

### Case 2: 40,000 bbl/day (Costs Decreased by 40%)

- **Project Revenue Stream**: $1,059,908,000.00
- **Project Cost Stream**: $774,805,381.97

The analysis shows a clear benefit-cost ratio with significant changes in the revenue and cost streams due to the increased costs and changed assumptions.