ALASKA LEGISLATURE COMMITTEE FILES 1983-1984

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This response confines itself to the Review only of the Acres study and of the data in this study for which Acres was responsible or lent concurrence. It does not respond, for instance, to the comments made in the Review (pages 20 - 25)* on load forecasts since these were developed by Battelle and the Institute of Social and Economic Research, University of Alaska. Acres, acting on direction from the Alaska Power Authority, adopted these energy demand forecasts as a datum base for the Feasibility Study.

The commentary deals with:

o World Oil Prices
  - Long-term future of World Oil Prices

o Alaskan Fossil Fuel Prices
  - Market prices versus opportunity values
  - Linkage between coal and oil prices
  - Linkage between gas and oil prices

o Reliability of Susitna Construction Cost Estimates
  - Construction cost estimates
  - Risk analysis

o Financing Issues
  - Real discount and interest rates

These issues are identified as those requiring further treatment to deal with apparent misunderstandings and need for further comment arising from the Review.

*Bracketed page references throughout this commentary refer to the Review.

1 - WORLD OIL PRICES

1.1 - Long-Term Future of World Oil Prices

The Review asserts oil price forecasts are too high and suggest that real (inflation-adjusted) prices will continue to be below 1982 levels for the remainder of the century (pp 15, 16 and 17).

Comment

The price forecasts were a Battelle responsibility to which Acres lent some degree of concurrence. Our comments, therefore, will be confined to justification for that concurrence.

The forecasts used in the Report are in close agreement with those of all the major forecasting organizations shown in Table 1. The forecasts are all of recent date and take into account all recent trends.

The review offers no new evidence or methodogical grounds for rejecting these forecasts. Instead, it attempts to justify its essentially judgmental position by incomplete reference to recent trends despite the fact that such trends have been taken into account by reputable forecasting agencies to which we have referred.

Thus, one piece of evidence cited is that Data Resources Inc. (DRI) now forecasts a decline in Europe's oil consumption during the rest of this century while today there is an excess oil producing capacity in the world, (p. 17-18). Such partial analysis cannot lead to the conclusion that oil prices will decline over the next 20 years. This requires consideration of the future levels of oil demand outside

Europe; worldwide supply/demand conditions, etc. DRI, itself, taking all such factors into account, supports the position taken in the Report with a forecast 2.8 percent growth in real terms.

A second factor cited by the Review is the scaling down of oil price projections by the Alaska Department of Revenues in its Petroleum Production Revenue Forecast. The State's forecasts made in the spring of 1982 point to declining real oil prices through 1998. Of the numerous eminent authorities engaged in long-term energy forecasting, this alone is cited by the review.

Table 1 below summarizes all the major forecasts for comparison with the Report's base case scenario of 2 percent real escalation, bounded by low and high scenarios of 0 percent and 4 percent respectively. Of the 16 authorities surveyed, only one presented a case with long-term declining real oil prices.

TABLE 1

SUMMARY OF MAJOR FORECASTS OF OIL PRICE TRENDS

Source	Date of Forecast	Forecast Trend (percent)
Data Resources Inc.	Summer 1982	+2.8
International Energy Agency	Spring 1982	
- Low		-0.5
- High		+2.0
US Energy Information Administration	Spring 1982	above +3
Energy Mines and Resources Canada	Summer 1982	+1.7
Ontario Hydro	Spring 1982	+1.8
Energy Modeling Forum, World Oil Report*	February 1982	
- average of 10 models		+3.4
- range of 10 models		+1.9 +5.3
Dr. F. Fesharaki, Resource Systems Institute, East-West Centre, Honolulu	Spring 1982	+1.7

* The 10 models are: Gately-Kyle-Fischer (New York Univ.), IEES - OMS (U.S. Dept. of Energy), IPE (M.I.T.), Salant-ICF (U.S. Federal Trade Commission and ICF, Inc.), ETA-MACRO (Stamford Univ.), WOIL (U.S. Dept. of Energy and Environmental Analysis, Inc), Kennedy-Nehring (Univ. of Texas and the Rand Corp.), OILTANK (Chr. Michelsen Institute), Opeconomics (BP Co. Ltd.), OILMAR (Energy and Power Subcommittee, U.S. House of Representatives).

Although a wide range of oil prices is reflected in these projections, it is clear that with the single qualification already noted they are all calling for positive real growth in world oil prices <u>over the long-term horizon required for power planning studies.</u> The Report did not, however, <u>exclude</u> the possibility of zero real growth in oil prices: it merely assigned it a lower possibility of 25 percent compared with the 50 percent probability assigned to the 2 percent growth case. It is Acres' assessment that the Review does not present a case for rejecting this assessment (and the similar forecasts shown in Table 1) and effectively assigning 100 percent probability to the zero growth scenario.

2 - ALASKAN FOSSIL FUEL PRICES

2.1 - Market Prices Versus Opportunity Values

The review states that "it is amazing that neither Acres nor Battelle has attempted to assess the probable future costs of fossil fuels for generation in the Railbelt from local coal or gas supply conditions", (p. 27-28).

Comment

Both Acres and Battelle reviewed the studies made both of Beluga coal costs and worldwide coal production cost estimates. The use of production costs for natural gas and coal would be wholly appropriate and desirable for the financial analysis of a power project from the narrow perspective of private investors or owners. As a public project, however, Susitna should be, and was, appraised from the point of view of the State as a whole and valued the fossil fuels at their opportunity cost in terms of potential exports.

It is for this reason that Acres supported the net-back approach in which the value of coal and natural gas in Alaska was determined as the c.i.f. (landed) price in the most likely (East Asian) market less the cost of transportation from Alaska to that market.

2.2 - Linkage Between Coal and Oil Prices

The Review is critical of the approach whereby "both contractors have deduced their price assumptions for Railbelt coal and gas wholly from forecasts of oil prices in Japan" (p. 28, 29).

Comment

The statement may be misleading as, in fact, it is the real growth rates in coal and gas export prices that are estimated, in the most likely case, to equal real rates of world oil price escalation. Base period (1982) opportunity values of coal and gas were determined (as shown above) independently of oil prices. The Review calls this linkage among fossil fuel growth rates "mechanistic" and cites a need for forecasting "the change in relative prices" (p. 31). That is precisely what the Susitna study has accomplished: In the most likely (base) case it forecasts that there would be no change in relative prices, that is, the 1982 price ratios among oil, gas and coal would be maintained during the planning period. This estimation is supported by forecasts of coal and natural gas prices provided in the Report. It is also supported by the historical data on coal and residual oil prices presented in the Review itself (p. 34). A moving average of coal/oil price ratios exhibits relatively little fluctuation over the 8-year period. (There is an estimated probability of over 65 percent that the ratio is .42 plus or minus 0.04).

In respect to the Review's assertion that coal prices must reflect production costs (p. 35), we reiterate our study contention that markets are imperfect and that worldwide production cost functions have served poorly in the past as predictors of market prices.

2.3 - Linkage Between Gas and Oil Prices

The emphasis of the criticism of Acres assumptions relating to natural gas is centered on the fact that the current price of Cook Inlet natural gas is significantly below the "opportunity value" suggested in the Report, and that this price is not expected to increase to levels in line with the opportunity value. It is maintained that "Cook Inlet gas prices will be established largely on the basis of factors local to the region", (p. 31) and thus these prices will be insulated from the effects of world price movements.

Further critcism is directed towards the "opportunity value", itself, and the use of the net-back approach. This criticism rests to a great extent on a number of points concerning the "only LNG export scheme to be seriously proposed", and the fact that "there are no other proposals to establish new...Cook Inlet LNG facilities", (p. 41-42).

Comment

Regardless of whether Cook Inlet gas prices do or do not equal opportunity values, the results of the Susitna public benefit-cost anaysis would not be altered. In fact, it is only the opportunity values which are of relevance, and the Cook Inlet domestic gas prices at any point in time should not be an issue of any concern in an analysis of net economic benefits.

This results solely from the fact that, if export markets exist for LNG at the prices which have been determined in the Report, then it must be assumed that any rational gas producer in Alaska would select the opportunity to receive the highest price which is offered for the gas. If the gas producer chooses to sell gas in Alaska at a lower price instead, then should the Susitna project evaluation be based on this economically inefficient price? If this is so, the project evaluation will not reflect the true costs to Alaska of gas-fired generation, and will not be consistent with generally accepted principles of public investment appraisal.

This leads to the second criticism relating to the actual "opportunity value" which was derived and the questionable option of exporting LNG. An attempt has been made to refute the opportunity value approach by suggesting that the export of LNG is not a viable alternative. This criticism is supported by five points which relate to the supposedly negative experience of "the only LNG export scheme to be seriously proposed".

It is indicated that "a major sponsor has withdrawn support" (p. 41) for the proposed LNG project, thus alluding to some dissatisfaction with the project on the part of the sponsor. However, a comment in the footnote reveals that "in fact, (the sponsor) remains a part of the consortium, but has stated that it cannot provide any additional capital for the project", (p.64). It is not made clear why the sponsor cannot provide the additional capital but there may be many reasons.

Another point related to the negative aspects of an LNG export scheme concerns the apparent declining California market for LNG. References do not support this claim. The Point Conception, California terminal is currently being developed with plans to receive LNG from both Alaska and Indonesia.[1] As recently as April 1982, it was reported that "projects to import LNG from Trinidad, Chile, and Colombia are under negotiation".[2]

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[1]Schlesigner, B., Hay, N., & Mitchell, J., "The Potential Role of Natural Gas in a Major Oil Crisis", "The Energy Journal", 1982.

[2]IBID.

In particular, it should be noted that markets other than California have also been identified. For example, three Canadian groups of companies, of which only one will receive final approval for LNG export, have identified specific Japanese and Korean markets. One group, for example, has potential buyers for nearly 200 billion cubic feet per year of natural gas. In addition Korea's Fifth Five Year Plan indicates that the country plans to develop LNG terminals able to receive 3 million tons of LNG per year by 1986. Markets for substantial amounts of LNG exports obviously do exist.

A final criticism of the net-back approach is that there are not any proposals to establish new LNG facilities and that "until serious industry interest appears in some such project, it is unrealistic to assume that Cook Inlet gas prices will be dictated by "net-back" gas values in export markets, (p. 42). Again, it must be stressed that although the current market has not yet adjusted to a more efficient allocation of resources, there is no justification for evaluating far-term projects based on today's conditions.

Finally, in dealing with gas price escalation it appears that the criticism is not directed at the correlation between gas prices and oil prices, but rather at the oil price forecast per se (p. 44). Acres' discussion of this issue has been presented in Section 1 of this commentary.

3 - RELIABILITY OF SUSITNA CONSTRUCTION COSTS ESTIMATES

3.1 - Construction Cost Estimates

The review questions (p. 44-52) the reliability of Acres capital cost estimate. The concern appears to be based on generalizations stemming from the "mega project" experience of the last decade.

Comment

This questioning does not appear to be founded on any detailed data or experience of hydroelectric power development engineering and construction. The only specific mega projects cited to justify allegations of "misplaced specificity, subjectivity and over-optimism, institutional blind spots, and underallowance for non-completion" in the Acres construction cost estimate are the Trans Alaska oil pipe line and the Washington Public Power Supply System nuclear reactor program. It is Acres' view that neither of these projects has any practical bearing on a site specific, basically conventional engineering hydroelectric power development such as Susitna where the project estimate has been as extensive, evaluated and assigned as high a confidence level as in the Susitna case.

Acres places special emphasis on the firm's consulting engineering practice, on recording and analyzing the "outcome versus estimate" of construction costs and, has achieved a high degree of accuracy (i.e., low mean error and variance) on its hydroelectric project estimates. Its record of achievement is, therefore, as a question of fact wholly at variance with the negative generalizations advanced in the Review. In support of this and as a project selected by Professor Tussing as broadly comparable with Susitna we detail in Table 2 a review of Acres Churchill Falls Hydroelectric Power Project estimate versus outcome.

Two estimates of costs are given. The first for 1963 is in the nature of an early stage feasibility estimate while the second, for 1968 is a final pre-contract estimate broadly comparable in confidence level to that produced in the Susitna Reference Report. It is seen that, reduced to comparable purchasing power (1963 dollars), the 1963 estimate is at variance from the final cost by 4.2 percent. This favorable (negative) variance has to be viewed, furthermore, in light of the fact that between 1963 and 1968 there was an increase from 10 to 11 in the number of hydroelectric units and an increase in the rating of all generators from 450 MW to 475 MW.

TABLE 2

COMPARISON OF ACRES ESTIMATE AND ACTUAL COST REDUCED TO COMMON (1963) LEVEL

	$ Millions Current Dollars	1963 Dollars	Percent of 1963 Estimate
1963 Estimate (incl. contingency) (1)	488.2	488.2	100.0
1966 Estimate (incl. contingency) (2)	563.3	489.5	100.3
Completion Cost	665.6	467.8	95.8

Note: (1) 1963 Estimate was for 10 x 450 MW Units; 1966-68 Estimate and Actual was for 11 x 475 MW Units.

(2) The project budget provided for a contingency allowance of $41 million, i.e. approximately 8 percent of the base construction cost estimate and a provision for escalation of $102 million based on a rate of 4.5 percent per annum, constant over the construction period.

As further evidence of the reliability of construction cost estimates, Figure 1 shows graphically the progression of estimates to the actual completed costs for individual elements of the 5,225 MW Churchill Falls Hydroelectric Development. It will be apparent that the level of accuracy was achieved not only in the overall construction cost, but also, to a substantial degree, in each of the major components.

A description of Churchill Falls Power Development is attached as Appendix A. It will be noted that in place of the single large dam which creates the operating head and storage reservoir for Watana, a large number of fill structures were constructed at Churchill Falls with an aggregate length of over 42 miles and volume of more than 40 million cubic yards. Construction work spread out over 2,500 square miles of reservoir area was inherently more difficult to control than a concentrated development area such as Watana.

Other examples of estimate/final cost comparisons uphold Acres' record of performance on major hydroelectric power projects in northern latitudes and at remote sites.

3.2 - Risk Analysis of Construction Cost Estimates

The Review provides a summary of the reasons that "some authorities believe that the kind of risk analysis executed by Acres may not be an appropriate tool ...." (p. 41). Specifically, the following broad areas are cited

- Misplaced Specificity
- Subjectivity and Overoptimism
- Institutional Blind Spots
- Underallowance for Non-completion.

Subsequent to discussion of each of the above areas, the Review raises questions regarding the relevance of data used by Acres for comparisons with the Susitna Project which will

o involve one of the highest dams in the world
o be the largest enterprise anywhere, ever, of its particular type, and
o be the highest-latitude large-scale hydroelectric project in the world and the largest civil works project ever attempted above the 55th parallel (p. 51).

Comment

We have not the slightest doubt that any attempt to quantify future events, even in a probabilistic way, is most certainly fraught with difficulty and is, at best, imperfect. Even so, we are convinced that such an attempt should have been made and that it was clearly in the best interests of the State of Alaska to present the results for Susitna candidly. Each of the above concerns expressed in the Review is valid and all of them deserve the attention of decision makers charged with plotting the future course of Alaskan energy supply. It does appear appropriate, however, to consider certain mitigating aspects which were implicitly or explicitly considered in the Acres study. Succeeding paragraphs briefly address each of the reviewers' concerns and criticisms.

- Misplaced Specificity

It is, of course, almost inevitable that some evolution will (indeed, should) occur between the development of a comprehensive feasibility level conceptual design and commissioning of a completed project. In recognition of this inevitability, we have made a concerted effort to be extremely conservative, assuming a "worst case" for each area where the data base was insufficient to permit a final choice for particular configurations. It was on this basis that we produced a "not to exceed" estimate--one in which we have a high degree of professional confidence that it can be achieved. Specific examples which may very well lead to eventual cost <u>reductions</u> include, but are not limited to

(1) Acres has assumed that extensive concrete lining will be required in underground facilities and water passages. It is likely that ongoing field investigations will demonstrate that rock is highly competent and that reductions are possible.

(2) Acres has placed cofferdams outside the main dam in our conceptual design because we have not yet fully confirmed that riverbed materials will provide favorable foundation conditions. If cofferdams can be incorporated in the main dam, significant savings will accrue both because lesser total volume of fill will be required and because reduced lengths and potential realignments in tunnels and outlet facilities may be possible.

(3) Acres has been conservative in the choice of dam slopes. Identification of better construction materials during continued field investigations and improvements in the seismic data base could lead to significant savings as a result of steepening the slopes and reduction in total volume of fill.

Although we believe that reasonable high probabilities of cost savings during detailed design do exist, we did not factor them into our risk analysis.

Briefly stated, we agree that design changes are likely as the project evolves. We believe, however, that such changes are more likely to lead to cost reductions than to overruns and will be, in any event, within the allowances made for contingency.

- Subjectivity and Overoptimism

To the maximum extent possible, we have sought hard data and external sources as the basis for assigning probabilities. Even so, some subjectivity was necessary and we have explicitly noted where subjective choices were made. While some skepticism on the part of any reviewer is to be expected and challenges to our choices are healthy, we do assert that our subjective data are not "blind guesses", nor are they "inexpert" or "uninformed". Our corporate experience over nearly 60 years in the development of major hydroelectric projects in northern regions and in seismic areas permitted us to make expert and informed judgements.

- Institutional Blind Spots

The Review correctly notes the importance of load and energy demand forecasts in project analysis. Objectivity in this area is extremely important. To avoid even the appearance of a conflict of interest, our intention, even at the proposal stage, was to seek independent analysis of load growth. Thus, we have relied wholly upon the earlier work of ISER and the later analyses by Battelle throughout the study period.

Other institutional risks were considered explicitly (e.g. regulatory and contractor competence) or implicitly (our "estimating variance" risk was evaluated based on historical data and included such items as design changes and commissions, delays beyond the control of various contractors). It is important to note as well that we assumed an unusually high escalation of construction costs over and above the underlying inflation rate in our base case derivation of net benefits.

- Underallowance for Non-completion

The Review correctly note our analysis found the non-completion risk to be negligible. Note, however, that construction cannot start until a license is issued by FERC. Provided that a license is issued and that the State does decide to proceed with construction of Watana (the first dam), we do anticipate that it will be completed. We have carefully noted throughout our report the implications of building only Watana and not proceeding with Devil Canyon.

- Comparability of Experience

In the interests of objectivity in the development of the risk analysis, we purposely avoided direct introduction of the significant successful project experience enjoyed by Acres in the past. We therefore chose to use an available data base which had been professionally assembled and adjusted for inflation by others. It is relevant to note, however, that Acres has been involved in the design of a fill dam (Mica) nearly as high as the proposed Watana dam; has led the design effort for an even larger hydroelectric enterprise (the 5225 MW Churchill Falls Project); and has significant experience in hydroelectric developments in sub-arctic regions. The attached diagram, Figure 2, provides some perspective in terms of the experience of Acres and PRC (a Joint Venture offering to provide services to the Alaska Power Authority for the design stage of Watana).

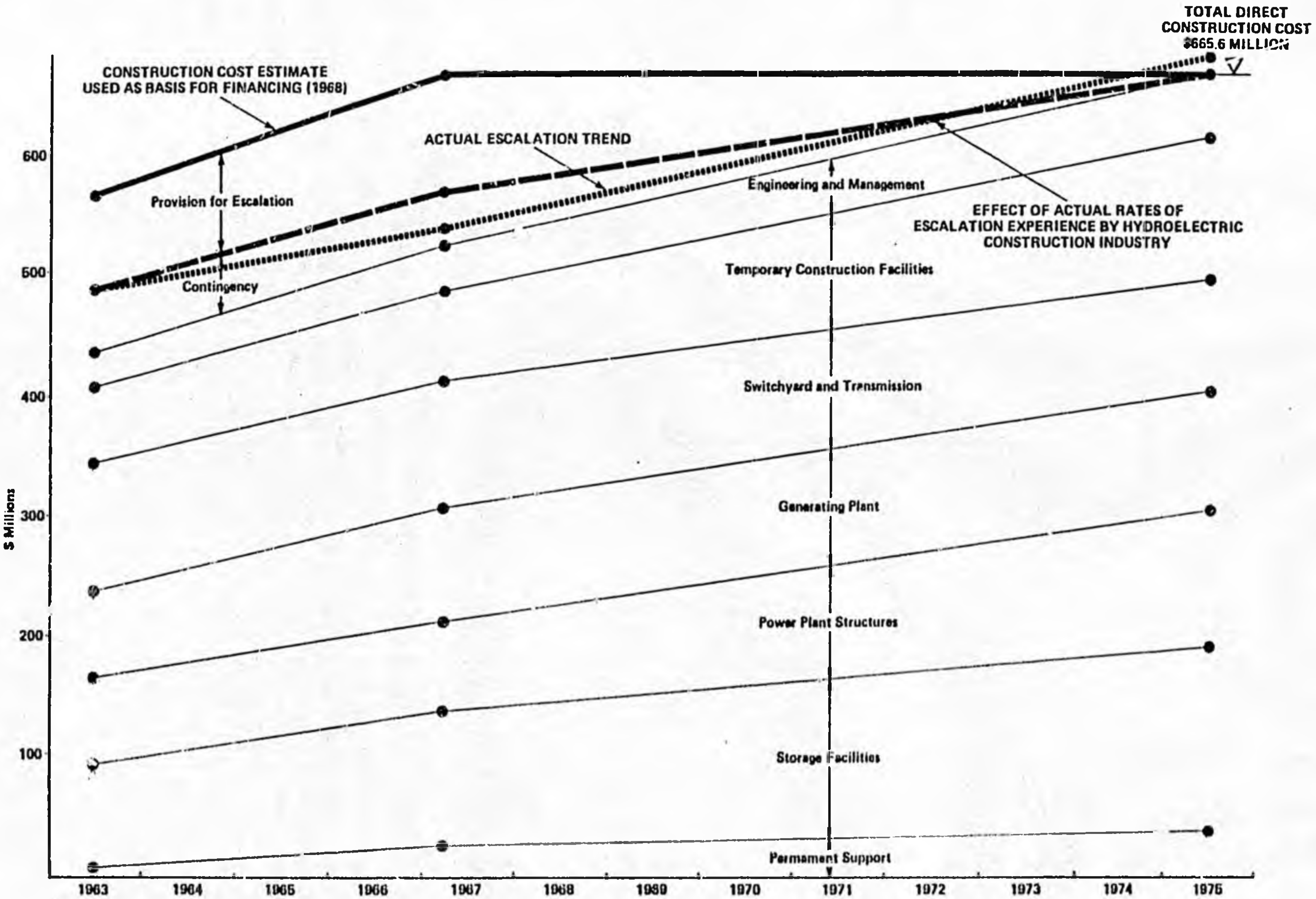

Figure 1

CHURCHILL FALLS HYDROELECTRIC DEVELOPMENT
PROGRESSION OF COST ESTIMATES TO COMPLETED COST

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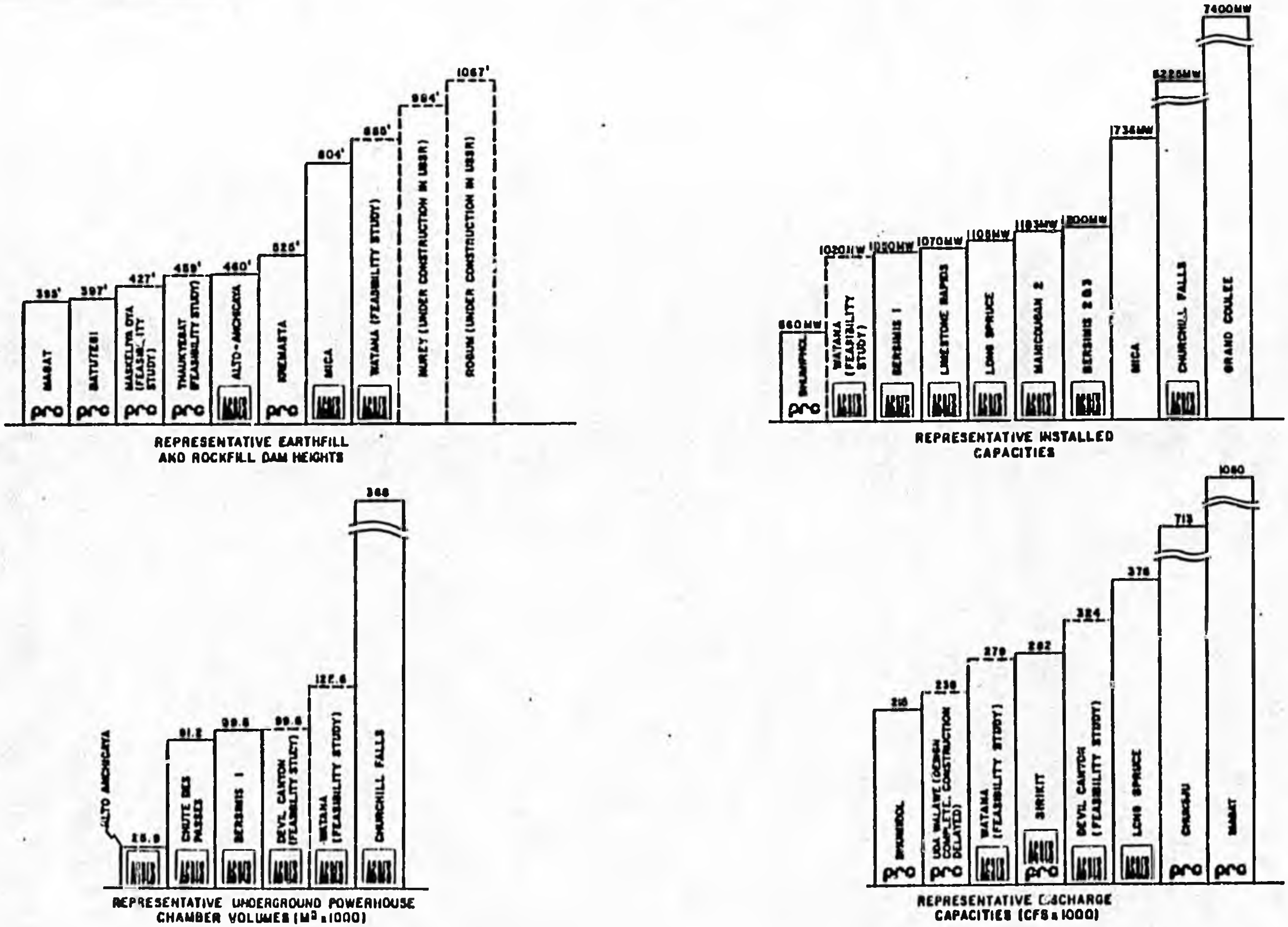

REPRESENTATIVE PROJECT EXPERIENCE (LOGOS REPRESENT INVOLVEMENT BY MEMBER COMPANIES EITHER AS A PART OF A JOINT VENTURE OR AS A SINGLE ENTITY)

FIGURE 2

4 - FINANCING ISSUES

o Real Discount and Interest Rates

The Review objects (p. 52-55) to the standard methodology by which Acres derived the 3 percent real discount rate used in the cost benefit analysis (Reference Report 18.3 to 18.21) and argues for 4.5 percent as the appropriate rate.

Comment

Acres derived the 3 percent discount rate from two sources. First it was given as a guideline for economic evaluation by the Department of Commerce of the State of Alaska. The second source was the generally accepted studies summarized on page 18.4 of the Reference Report.

It is clearly possible to question the standard methodology giving rise to this parameter. Here, as in other parts of the study, however, it was Acres' policy to avoid unnecessary controversy by not questioning accepted methodology or guidelines unless the alternative approaches materially affected our conclusions.

A more precise approach is that of determining the Project Specific Rate (PSR). This is done by first estimating the weighted average interest cost of project borrowing and the opportunity interest cost of any funds provided by State of Alaska, with the weightings being the proportions of these two types of capital. This weighted average is then converted into a real discount rate (approximately) by deducting the relevant rate of inflation. The interest rates used would be those obtained at the time that the capital is to be raised and the rate of inflation the long term rate expected over the life of the borrowing.

On the basis of the DRI forecasts and on the assumption that the opportunity cost of state provided funds is the interest rate forecast for federal government securities while the project borrowing is in the form of tax exempt bonds[1], the weighted averaged interest rate with the state appropriation of $2.3 billion, can be determined. The DRI forecast interest rate on Federal Funds and on Tax Exempt Bonds, both over the relevant capital raising periods and unweighted, are 10.4 percent and 8.1 percent respectively. This gives a weighted average PSR of 9.1 percent in money terms.

The long term forecast rate of CPI inflation from 1985 to 1995 (again as given by DRI) varies between 7.1 (1985-90) and 6.5 percent (1990-95). No forecast is given for the post 1995 period. The implied real rate of interest relevant to the cost benefit at a long term inflation rate of 6.5 percent is therefore approximately 9.1 - 6.5 = 2.6 percent. At these rates of inflation, therefore, this alternative methodology using DRI data, does not support a higher discount rate than the 3 percent discount rate used in cost benefit analysis carried out for the Feasibility Study and dealt with in the Report.

The position taken in the Review is that the discount rate should be that at which the project is financed. This is the PSR approach just described. As such it, as has been seen, produces a lower (not higher) rate than that used in the Acres analysis.

The Review suggests, however, that the appropriate rate is 4.5 percent (p. 56) on the grounds that this is the DRI forecast of real interest rates on <u>corporate bonds</u>[2] in 1992. Since the project is not being financed by corporate

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1 Table 18.4.2 of Reference Report.
2 Using the CPI and not IPD the rate is 4.0 percent.

bonds but by tax exempt bonds and by the State of Alaska, it cannot be argued that this 4.5 percent has any relevance. The relevant tax exempt and federal bond rates consistent with the 4.5 percent corporate bond rate give the result outlined above.

We would also note that the DRI 4.5 percent real interest rate on corporate bonds is very much higher than the Wharton or Chase forecasts or indeed any of the other main forecasting agencies. These are generally in the range of 3-2.4 percent. If these forecasts rather than the DRI forecast used above are accepted then, taking into account the advantages of tax exemption, the 3 percent discount rate used for the Susitna cost benefit analysis is conservative in that the appropriate PSR should be significantly lower. This became apparent in the course of the Acres analysis but was not pursued since it merely had the effect of reinforcing rather than controverting the conclusions reached.

In summary, it appears to us that the Review is mistaken as to the outcome of the methodology which it proposes and that correctly stated, this methodology (which we would stress in itself is only an approximation) gives a result which would argue that the discount rate promulgated by the Alaskan Department of Commerce and used by Acres is too high not too low.

APPENDIX

CHURCHILL FALLS POWER PROJECT: 5,225 MW AND 35.4 BILLION kWh FROM LABRADOR

The Churchill Falls Power Development is located in Labrador, Newfoundland, 54°N by 63°W in a climatic zone similar to that in the region of Susitna (63°N by 148°W). As shown on Figure A, the site is remote being 750 mi (1,210 km) from Montreal and about 1,000 mi (1,610 km) Northeast of New York City.

The Churchill River flows eastward from the Sandgirt and Lobstick Lakes on the Central Labrador Plateau as indicated on Figure B, through a series of rapids and, originally, over a high waterfall, the Churchill Falls, to its lower river gorge, and on to the Atlantic Ocean through Lake Melville, near Goose Bay.

From the Central Labrador Plateau, in a distance of 16 mi (26 km), the Churchill River dropped approximately 1,100 ft (335 m), including the spectacular 245 ft (75 m) high Churchill Falls. At the site selected for power development, a gross head of 1,060 ft (323 m) has been developed.

A storage reservoir was formed by raising the levels of existing large lakes above Churchill Falls on the Central Labrador Plateau. This was accomplished by constructing a series of dikes at low points in the terrain along the rims of the lakes together with dams to divert small rivers.

The storage reservoir now discharges through the Lobstick Control Structure to a continuation of the Churchill River. The regulated flow in the river is diverted some 5 mi (8 km) up-stream from the Falls by the gated Jacopie Spillway Structure into the West Forebay formed by waters retained by a series of dikes and the Whitefish Control Structure. The Whitefish Control Structure discharges to the East Forebay which conveys water to the Power Intake Structure.

The rain and snow melt run-off from 26,744 sq mi (69,265 km^2) of total drainage area flows into the reservoirs.

A gated spillway structure, the Forebay Spillway, is provided in the East Forebay just beyond the Power Intake Structure, which leads to the power installations.

The powerhouse and the gallery accommodating the first stage transformers are situated more than 1,000 ft (305 m) below ground. The switchyard, the second stage transformers and the control building are on the surface above the powerhouse, approximately 1 mi (1.6 km) from the lower Churchill River.

The Churchill Power Development is exceptional in that the gross head of 1,060 ft (323m) is created without a substantial dam; the greatest height of the dikes, 42 mi (68 km) in overall length, is 90 ft (27.4 m). Over 40 million cu yd (30 million m^3) of fill was placed in the diking system which created the main storage reservoir and the forebay systems.

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Figure A

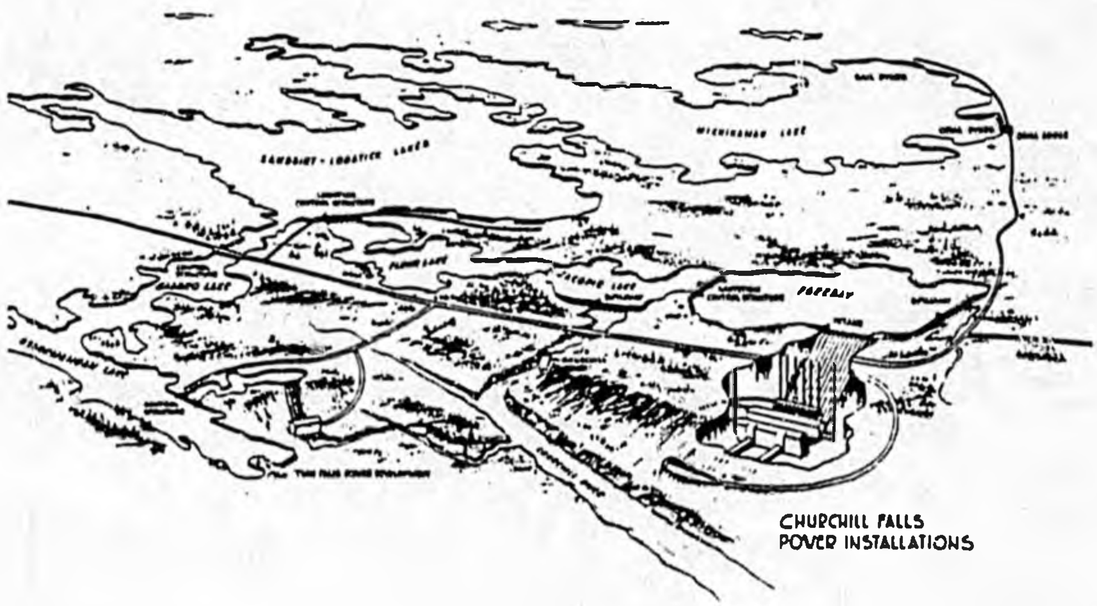
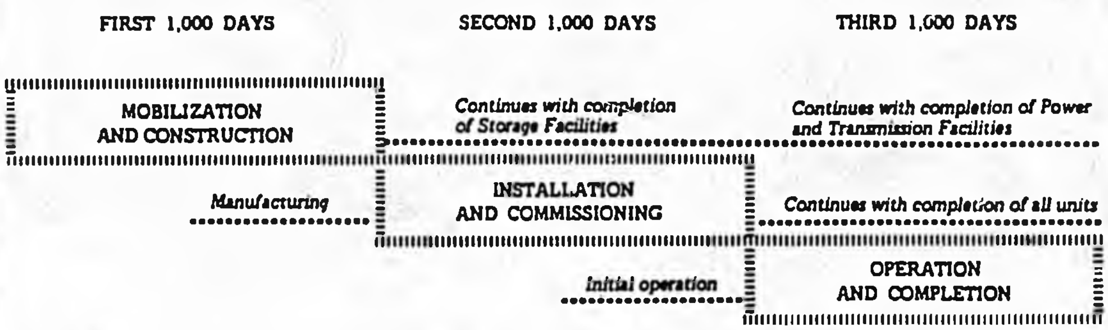


Figure B

3,000 DAYS PROJECT SCHEDULE



Emphasis:

- on mobilization
- on securing materials
- on underground excavation
- on preparation and clearing of sites
- on placing of dykes
- on building of control structures
- on heavy construction

Emphasis:

- on completion of dykes and control structures
- on closure of dykes
- on shipment of permanent equipment
- on installation of equipment
- on power house concreting
- on proving and testing of plant
- on erection of tower steel and stringing conductor
- on commissioning of generating units
- on initial operation and power delivery

Emphasis:

- on completion of works
- on transfer to permanent operation mode
- on introducing water storage control and management
- on establishing permanent community and staffing
- on establishing maintenance and overhaul program
- on fulfilling commitments under power contract

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Figure C

The forebay allows close regulation of water level at the power installations which, within a horizontal distance of about 7,000 ft (2,134 m), accommodate penstocks, powerplant, transformer gallery, surge tank/manifold and tailrace discharge tunnels, just over a mile in length. The facilities are entirely underground and involved substantial excavations, the largest being 972 ft (296 m) by 154 ft (47 m) high by 81 ft (25 m) wide. A total of 2.35 million cu yd (1.80 million m^3) of rock was excavated. Concrete works for power installations and the intake structure required the placement of 340,000 cu yd (260,000 m^3).

Power is transmitted from the generators by three phase bus ducts to the 15-230 kV unit transformers located underground and up through the cable shafts to 230-735 kV auto-transformers on the surface in the switchyard.

From the switchyard, three 735 kV ac transmission circuits carry the power 126 mi (203 km) to the point of delivery to Hydro-Quebec, the electric utility which purchases, under long term contract, the major portion of the energy output from the Churchill Falls Power Development.

The project involved a direct expenditure on construction of $665 million (over the period 1967—1975). The work on the project can be conveniently divided into three principal phases of approximately equal length (as summarized on Figure C) each with its own characteristic emphasis.

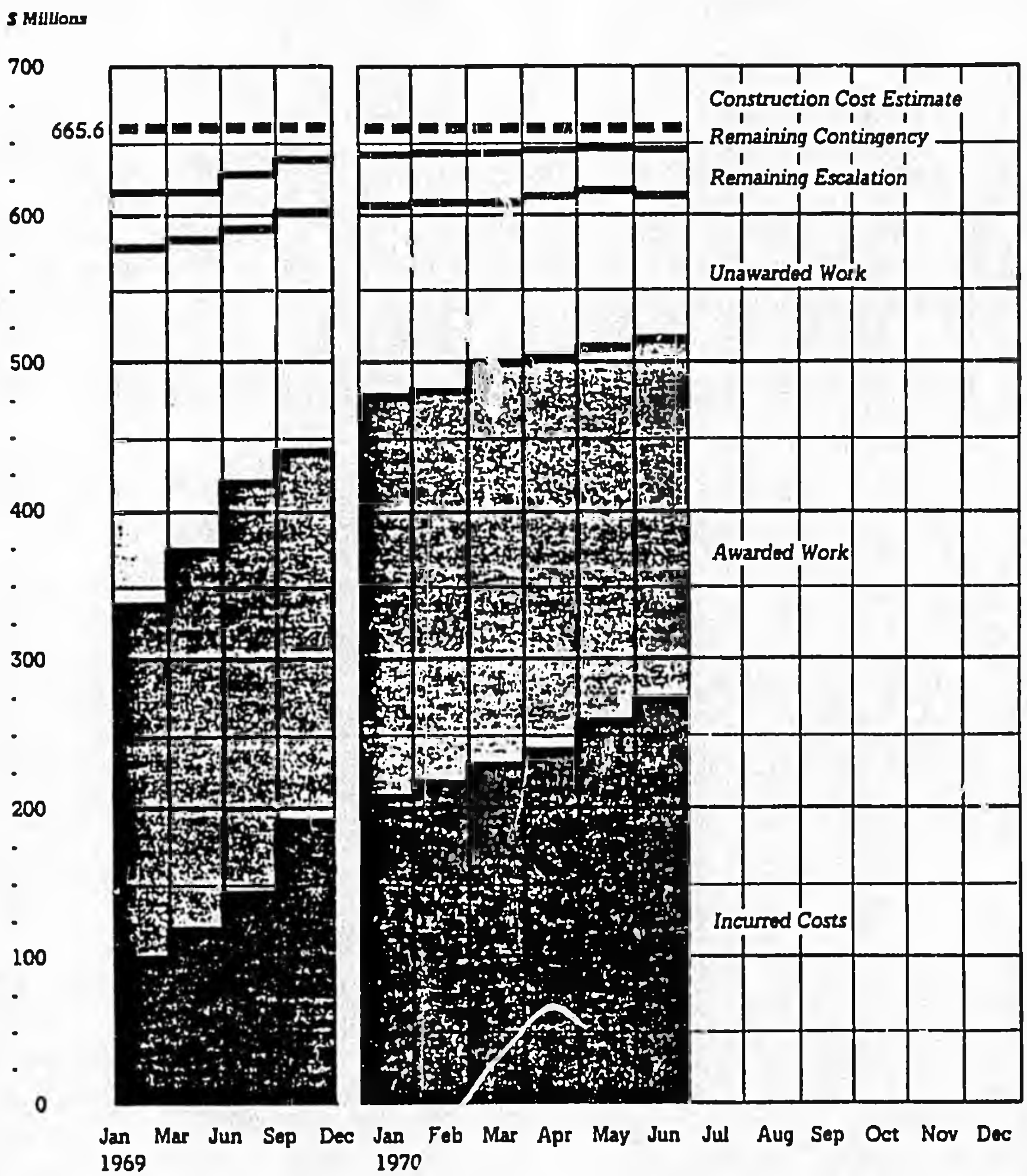
THE FIRST 1,000 DAYS was on mobilization and construction
THE SECOND 1,000 DAYS was on installation and commissioning
THE THIRD 1,000 DAYS was on operation and completion.

During the first 1,000 days, underground excavation was completed and, above ground, dikes and control works were substantially advanced. Transmission line work was begun.

The second phase of 1,000 days was marked by a distinct shift in construction management control from the centralized headquarters of Churchill Falls (Labrador) Corporation and the engineering/construction management joint venture in which Acres was involved, to the field. An increasing volume of major permanent equipment was then being shipped to the Project for final assembly. Attention was focused to an increasing degree on the impoundment of water in the reservoir system and on the first "roll date" for generating equipment. Following the proving periods of hydraulic, mechanical and electrical equipment, the date for the contractual commitment of initial delivery of "commercial" power became of paramount importance.

During the second 1,000 days of the Project Schedule, six machines were installed and commissioned and these began delivering power to Hydro-Quebec under terms of the Power Contract.

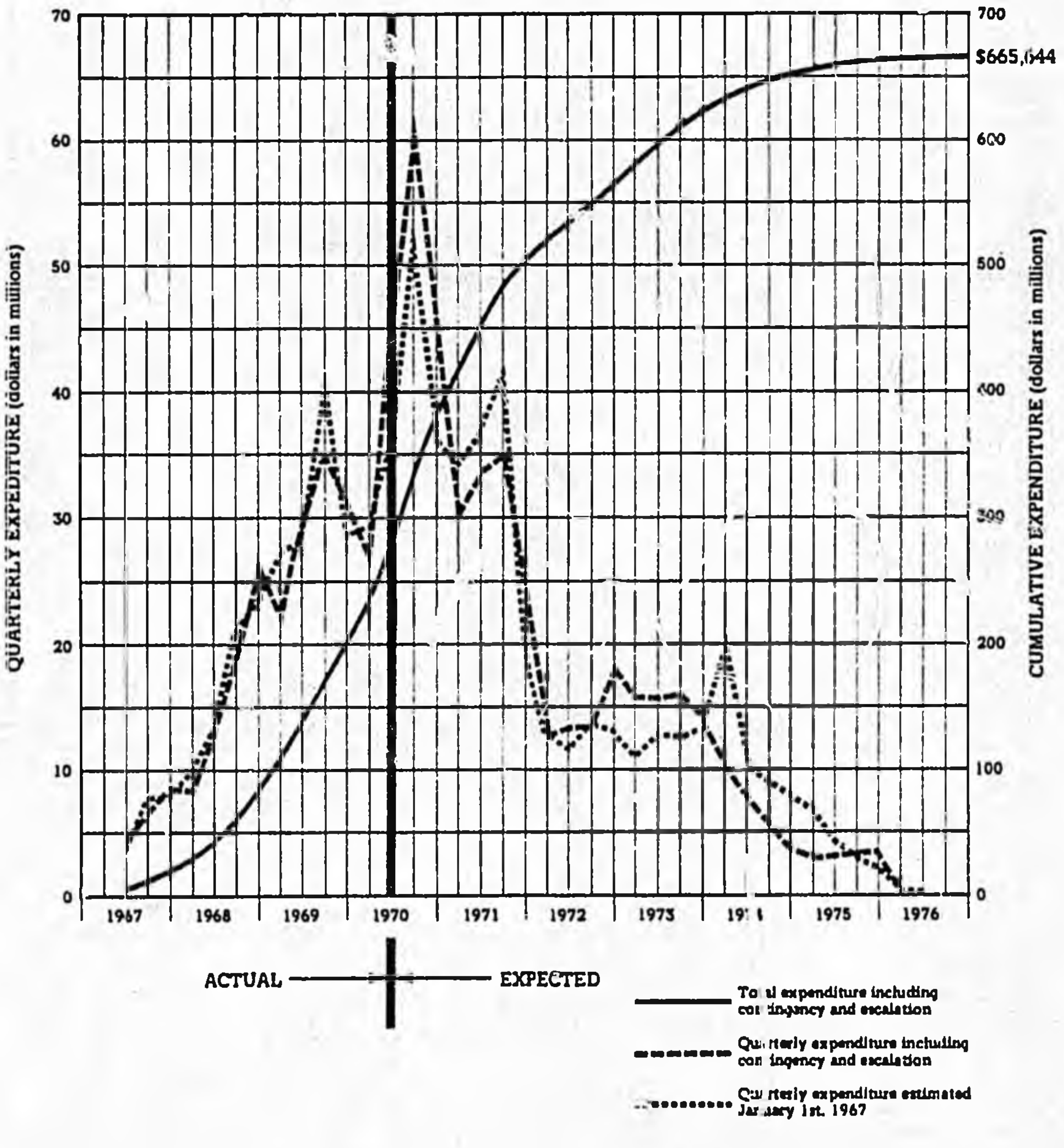
PROJECT STATUS



ACRES

Figure D

PROJECT EXPENDITURE CURVE
Based on:
Schedule: as of June 1970
Estimate: Construction Cost Estimate based on costs
and conditions in effect January 1, 1968
Escalation: 4.5 percent per annum compounded annually



ACRES

Figure E

In the final 1,000 days, the emphasis shifted to the operating phase of the Churchill Falls Power Development. The increasing demands of the Power Contract were met with the installation and commissioning of generating units 7 to 11 with the completion of the project in 1974, some 16 months ahead of schedule and on budget.

The overall period of development of the Churchill Falls Power Project from a firm decision to proceed to completion was 11 years including an enforced delay pending agreement on transmission and sale of power output from the spring of 1964 to the fall of 1966. Engineering of major project features continued during this time and final engineering cost estimates produced in early 1967 were based on a definitive design. At the time of release for construction in April 1967, the estimate of total construction cost was $563,306,000 and an additional provision of $102,338,000 was made for added costs due to inflation and escalation during construction.

By July 1970 at which time 42% of the construction capital outlay had been expanded, incurred costs and the value of awarded work (about 75% of the total) indicated that the remaining contingency and provision for cost increases were still adequate to allow the original estimate to be met. The project status at that time is indicated in Figure D. The variation from plan was minor with quarterly expenditures matching closely the forecasts made in 1967 as shown on Figure E.

Despite a 6 week strike on the Quebec North Shore and Labrador Railroad during the summer construction season which caused deferment of certain non-critical elements of the project and the supply of the remaining construction entirely by air, the schedule was met for impoundment of the reservoirs and for first power generation. Completion of the installation and commissioning of the final, eleventh, 475 MW unit was achieved 16 months ahead of the original program and within budget as shown on Figure F.

Acres was engaged by the project owners, Brinco (and later by the subsidiary company, Churchill Falls (Labrador) Corporation Limited) at the feasibility study stage. Based on a plan developed by Acres at that time, a development concept was adopted, known as the 'Channel Scheme", which conveyed water along the crest of the plateau to the selected power site 16 mi (26 km) downstream, and on a recommendation that full capacity be developed in a single phase, serious plans for construction were initiated. A major U.S. construction management firm, Bechtel, was engaged separately to prepare an independent estimate of construction costs for comparison with Acres' assessment. At the client's request, a joint venture, Acres Canadian Bechtel of Churchill Falls (ACB), was formed to undertake management of engineering and construction. The client retained the responsibility for project management but, in effect, assigned all the major functions to the joint venture.

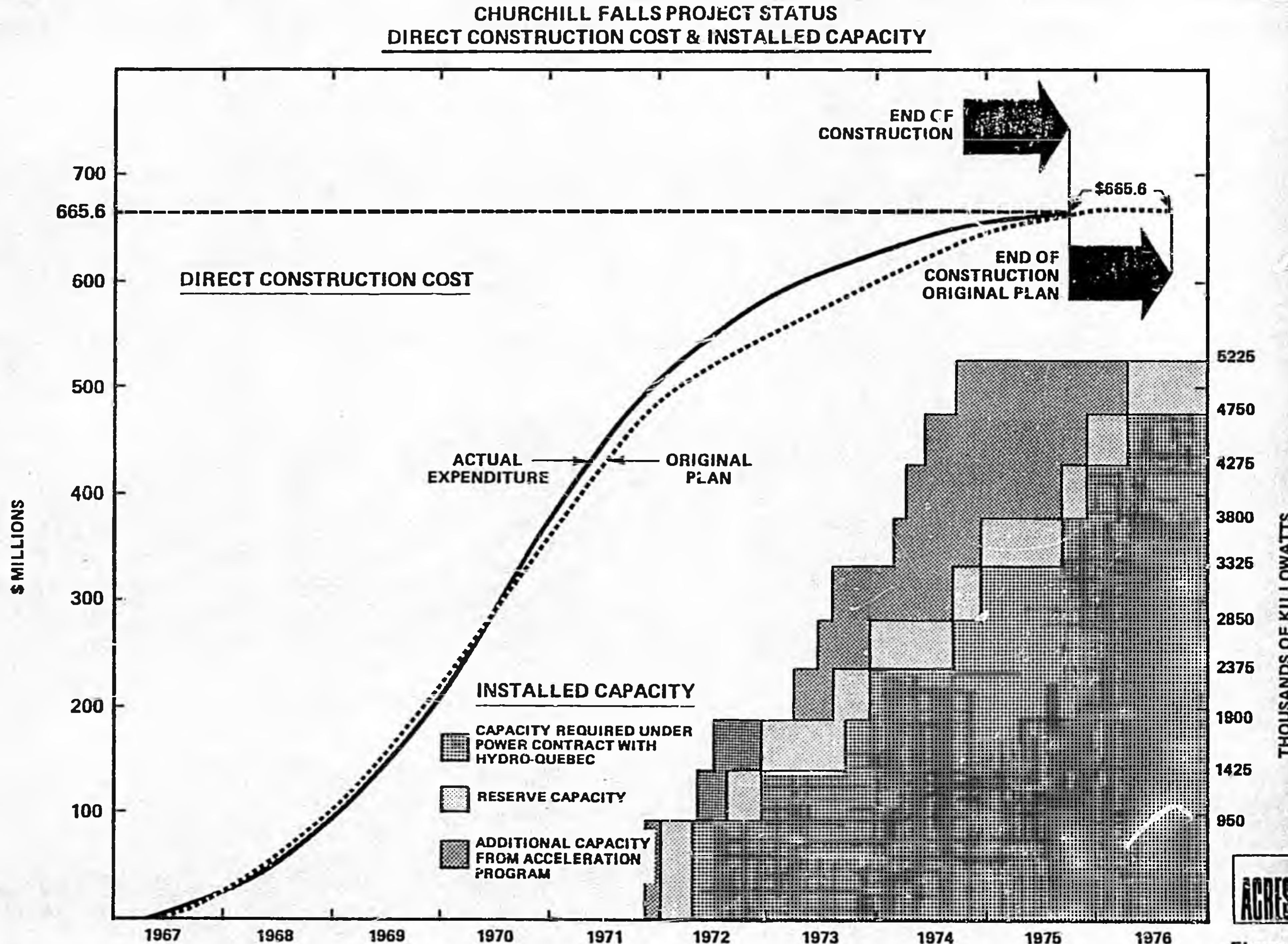

CHURCHILL FALLS PROJECT STATUS
DIRECT CONSTRUCTION COST & INSTALLED CAPACITY
END OF CONSTRUCTION
END OF CONSTRUCTION ORIGINAL PLAN
$665.6
700
665.6
600
500
400
300
200
100
$ MILLIONS
DIRECT CONSTRUCTION COST
ACTUAL EXPENDITURE
ORIGINAL PLAN
INSTALLED CAPACITY
CAPACITY REQUIRED UNDER POWER CONTRACT WITH HYDRO-QUEBEC
RESERVE CAPACITY
ADDITIONAL CAPACITY FROM ACCELERATION PROGRAM
5225
4750
4275
3800
3325
2850
2375
1800
1425
950
THOUSANDS OF KILLOWATTS
1967
1968
1969
1970
1971
1972
1973
1974
1975
1976
ACRES

Figure F

By virtue of past experience and the individual fields of specialization, Acres was predominant in engineering activities and Bechtel in construction management. Both companies provided services in each activity and through a consolidated joint venture office merged management responsibilities. As emphasis changed during the progress of the work and particularly following the tragic loss of seven senior client and ACB executive staff in an air crash in November 1969, functions assigned to the joint venture partners changed. During the mid construction phase, both the manager of engineering and of construction were provided from Acres staff working under the direction of the joint venture general manager appointed by Bechtel.

The Churchill Falls Power Development was an undertaking conceived, planned and built by Brinco, an organization ultimately substantially owned in 1967 by Rio Tinto Zinc Corporation and Bethlehem Steel. The Corporate organization was mainly staffed by senior members of RTZ worldwide affiliates. At the crucial time when the President and senior staff of Brinco's subsidiary, Churchill Falls Labrador Corporation Limited, were killed in the air crash, Chief Executive responsibility was assumed by Sir Val Duncan, then Chairman of RTZ. That the project was able to withstand and overcome the impact of the tragic loss within its project management team is testimony to the strength of the overall organization established to bring Churchill Falls Power Development into reality.

Throughout the planning and construction phases, the project manager role was firmly held by the owner CFLCo and certain vital functions were performed throughout by their internal organization (financing, contractual negotiations, insurance, government relations, public relations, project monitoring and direction). The engineering and construction manager (Acres Canadian Bechtel) functioned under the direction and control of the owners' project manager and provided, as requested, individuals and task force groups to operate directly as part of the owners' team. As the project progressed, more and more functions were transferred to CFLCo's organization resulting, on completion of the project, in a smoothly functioning operating organization capable of operating a 5,225,000 kW power utility.

The project was completed within budget, 16 months ahead of schedule and exceeded all performance levels designated in the engineers' opinions. The plant has delivered 5,500,000 kW of capacity and in a single year of relatively high precipitation, has generated over 40 billion kW·h of electrical energy.

Churchill Falls Power Development is now part of the provincial power system of Newfoundland and Labrador and the ownership of CFLCo involves both this Province and the Province of Quebec, to whom the largest proportion of the annual energy output of Churchill Falls is delivered under long-term contract.

Engineering News-Record / The McGraw-Hill Construction Weekly / February 12, 1981 /

ENR

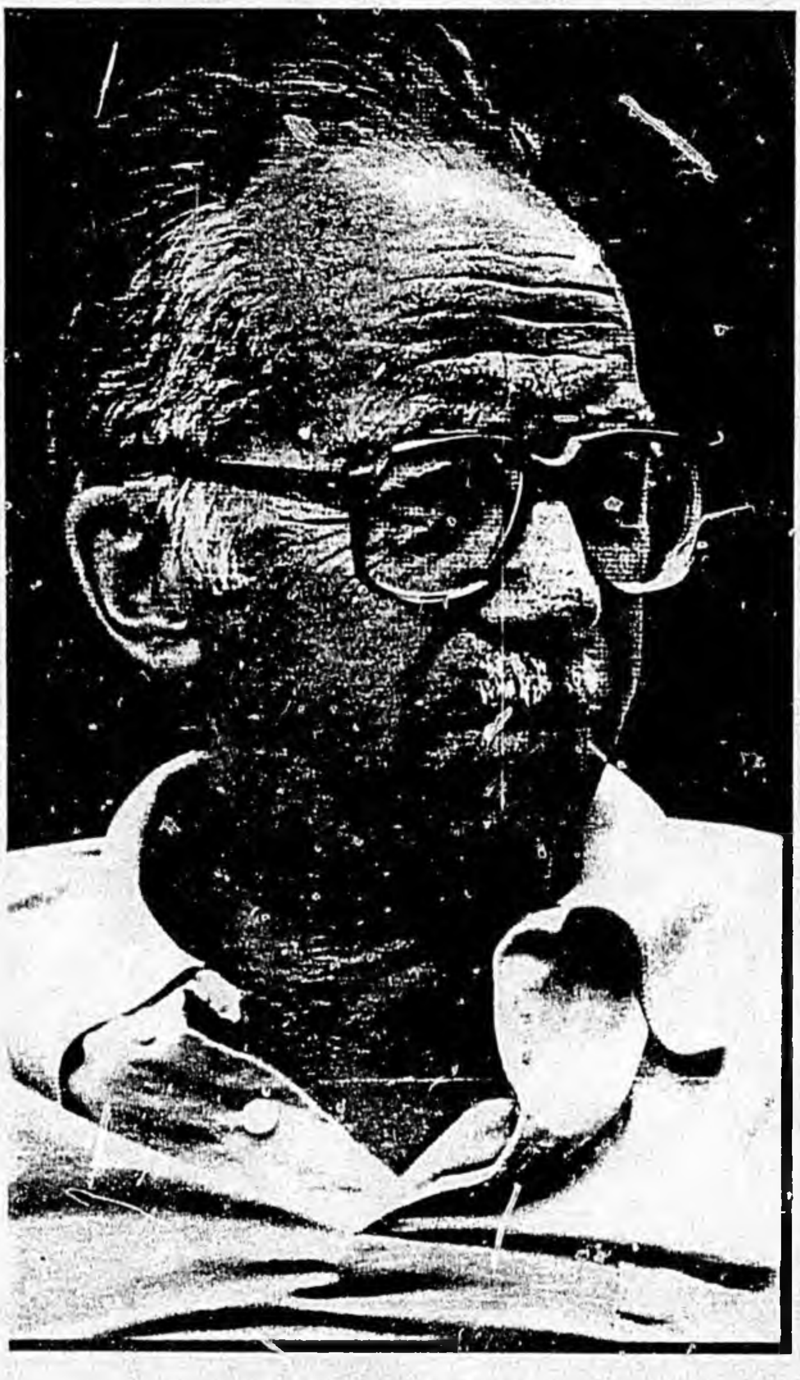
MAN OF THE YEAR

Robert A. Boyd

ENR

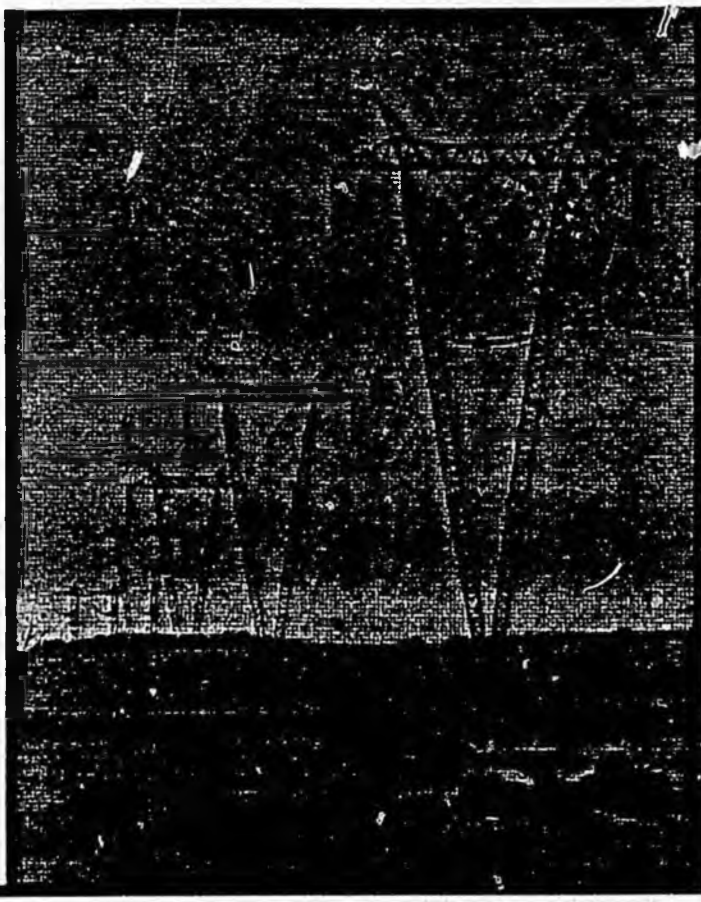
Hydro power-broker Robert Boyd

Quebec's masterbuilder energizes James Bay



ublic hearings are being held throughout Quebec this month to air plans drawn by the provincial utility to spend $55 billion over the next 10 years for energy development. For an economically stagnant province of 6 million persons politically divided on most major issues, that staggering figure is obviously controversial. Its per capita equivalent in the U.S. would be more than $2 trillion. Nevertheless, the ambitious plan is almost assured of widespread support, mainly because of the public's trust in Hydro-Quebec and, implicitly, in its leader, Robert A. Boyd.

The 62-year-old president and chief executive officer of North America's most profitable utility has proven he can



deliver the electricity Quebec needs at prices that are close to being the lowest in the world.

More importantly, Boyd, an electrical and mechanical engineer, has given his fellow French-speaking Canadians a benchmark of engineering and managerial excellence in the 10,269-Mw development of the LaGrande River in the remote, subarctic James Bay region of Quebec.

The enormity of the task, begun in 1972 and well on its way to completion in 1985 ahead of schedule and within budget estimates made six years ago, is unparalleled in North America. The efficiency of its execution is rare in the world.

More than any major engineering feat in recent memory, the $14.5-billion (Canadian) La Grande complex is the product of one man's competence. That man is Robert Albert Boyd, Construction's Man of the Year, 1981, the first selected by ENR editors in 16 years who is not an American.

As the energy policy paralysis in the U.S. seems to indicate, trust in decision-makers—or the lack of it—is a critical element in any society's ability to build constructively for the future. Boyd has that trust; from his fellow Quebecois, from his peers in the engineering and construction fraternity and from the international banking community. It is embedded in the concrete and frozen earth at James Bay.

"The James Bay project is the only area of agreement in Quebec today," says Robert Bourassa, Quebec's Liberal Party

premier from 1970 to 1976 and the original promoter of what he called "the project of the century." Business, labor, language and regional differences have split the province, he says. But as the 15,000 visitors each summer indicate—from students, Rotary Clubs and women's groups to the engineering delegations flown in from around the world—the James Bay project, 650 air miles north of Montreal, has the support of Quebec.

Power and the glory. What Quebec's muscle, managers and money are creating is the firm capacity to produce 62.2 billion kwh of electric energy from 37 turbine-generator sets in three powerhouses spread out along a 288-mile section of the La Grande. Until the late 1980s, when the Itaipu hydropower project is spinning out 73.6 billion kwh a year on the Parana

River between Brazil and Paraguay, the La Grande, a much smaller river, will be the premiere power source in the world.

To assure the economics of opening up the 400,000-sq-mile James Bay territory, flows from two major river basins are being diverted into reservoirs built along the La Grande, increasing its power potential from 8,000 Mw to the 10,269 being developed.

At the southernmost project, water from three rivers has been channeled into the La Grande to feed the sixteen 333-Mw turbine-generators being installed in the LG 2 powerhouse. Blasted 450 ft deep in the Canadian shield, the massive cavern is the largest underground power station in the world. When all units are spinning later this year, it will represent more than half the total capacity of the power complex. Two other powerhouses are being built above ground upstream, the LG 3 station with a rated capacity of 2,304 Mw and LG 4 rated at 2,637 Mw.

Creating the project's reservoirs in the water-logged flatlands of the taiga requires placement of close to 200 million cu yd of precisely engineered moraine and graded rock for a total of 182 dams and dikes. Transporting the electricity produced from the power of that falling water to consumers in the south requires stringing 3,200 miles of new 735-kv dc transmission lines.

From day one, Boyd has had the job of coordinating the thousands of large and small tasks, managing the hundreds of construction contracts and assuring that the detailed drawings are supplied on time for the seemingly endless engineered parts of this massive power machine.

"In recent years we've let management techniques take over for the functions of the chief engineer," says Wallace L. Chadwick, an international consultant on large dams and a member of the board of experts hired to oversee the James Bay work. "On this job, there was a chief engineer who knew what he wanted to achieve and how. And he did it."

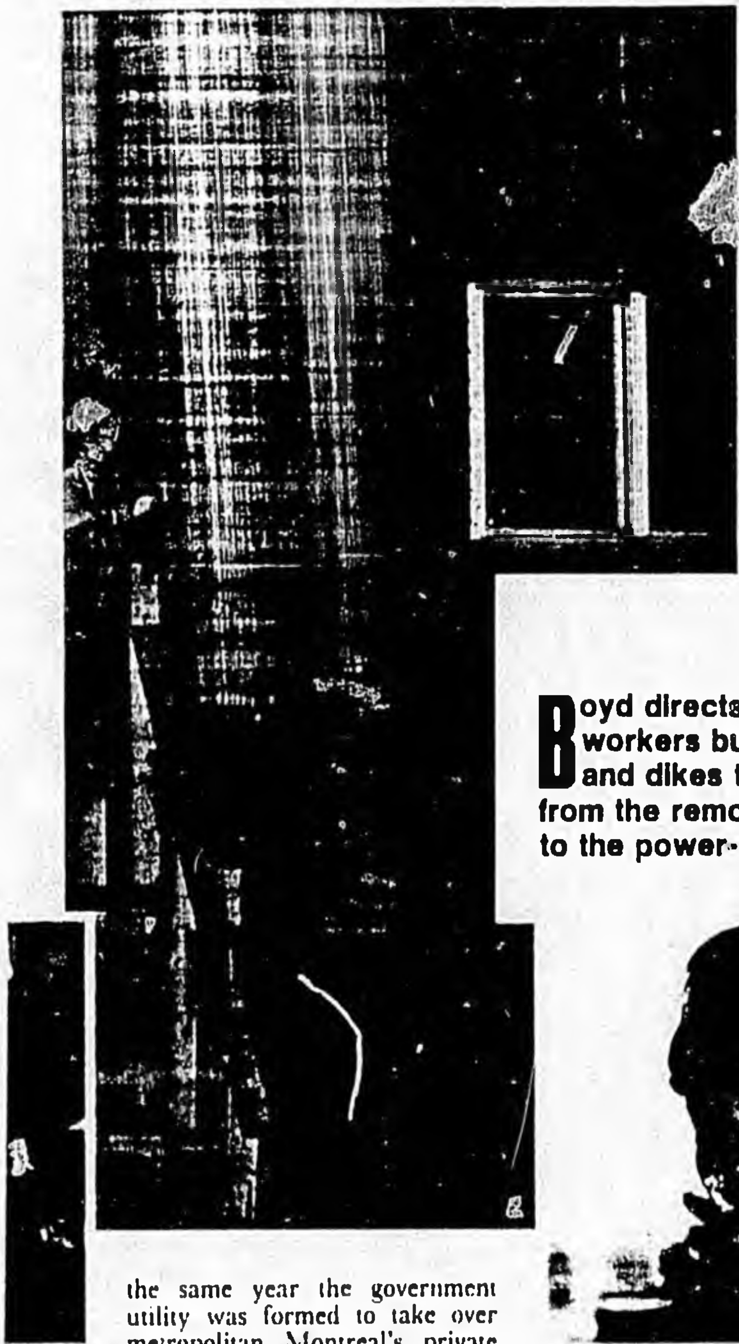
In his 35 tours of the complex since 1972—all of them accompanied by Boyd—Chadwick has come to respect the unassuming engineer-manager and the quality of his work. "He's a remarkably talented man," says Chadwick, adding, "In terms of the engineering excellence of the product, the La Grande complex is the equal of anything we've ever done in the United States."

In the eyes of superbuilder Stephen D. Bechtel, Jr., chairman of Bechtel Group Inc., San Francisco, "The La Grande project is in a class by itself."

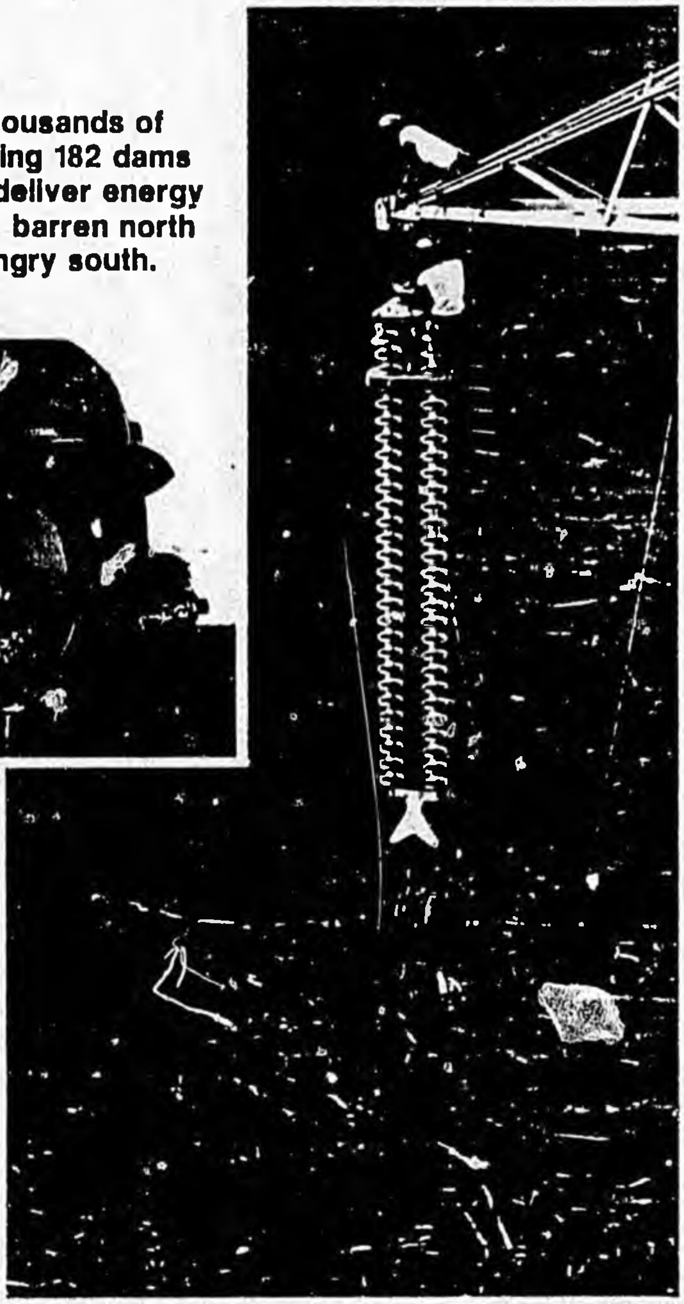
Bechtel's Montreal arm, Bechtel Quebec, Ltee., supplies a number of top managers to the Societe d'energie de la Baie James (SEBJ), the unique construction management organization set up as a Hydro-Quebec subsidiary by Boyd in 1972. And while the well-reported success of the project has generated discussion in some circles about who deserves the accolades, Bechtel says flatly, "Boyd has had the lead role in it all the way through."

The only son of a Quebec Central Railway conductor, Boyd was born in 1918, in Sherbrooke, a conservative bastion east of Montreal that served as a haven for British loyalists escaping across the Vermont border during the American Revolution. It's an area without much imagination but strong on individualism and personal achievement. "My father taught me hard work and respect for other people's opinions," says Boyd.

He had wanted to be a doctor but instead took a railroad scholarship given to prospective engineering students and completed his applied sciences degree in 1943 at Ecole Polytechnique de Montreal. A year later Boyd joined Hydro-Quebec,



Boyd directs thousands of workers building 182 dams and dikes to deliver energy from the remote, barren north to the power-hungry south.



the same year the government utility was formed to take over metropolitan Montreal's private utility. Boyd started writing technical specifications, was soon transferred to the operating division and ran it two years later. He was named chief engineer in 1962 and general manager over all division directors in 1965, a job that was created for the ambitious technocrat.

Up the ladder. He was appointed a commissioner of Hydro-Quebec in 1969, and president of SEBJ in 1972. Five years later, Boyd became the utility's sixth president, the first to rise through the ranks. And in 1978, after Rene Levesque foisted a new 11-member board of directors on Hydro-Quebec to replace the five-member commission of insiders, Boyd became the first president and CEO under the new structure.

Surviving the shifting politics of three different governments on his way to the top has taught Boyd much about the ways of power. First, he says, "If you let yourself get mixed up in politics, someone, somewhere will try to shove you out." The second lesson: "What counts is success."

When the political decision was made in 1963 to nationalize all of Quebec's electric utilities, Boyd was given the job of integrating the 44 systems into one public company. Government experts figured the task would take two decades to complete. By his own reckoning, Boyd did it in five years.

When Quebec City agreed in 1967 to Boyd's plan for an electrical research institute, Boyd and his advisers, who during the previous two years had toured laboratories in seven countries, set out to make their facility the best high-voltage research center in the world. "The French Canadians have done things with high-voltage direct current that have led the world," says Chadwick.

When the power contract was signed between Quebec and Newfoundland in 1969 for output from the 5,200-Mw Churchill Falls hydroelectric project, Boyd, as the province's chief negotiator, made sure that in exchange for financially backing its neighbor's proposal, Hydro-Quebec would get a fair deal. Close to one-third of Quebec's electricity demand today is met by power from Churchill Falls at a price equivalent to $1.80 per bbl of oil.

Applying lessons learned and contacts borrowed from his predecessor, Roland Giroux, a financial wizard credited with opening international money markets for Hydro-Quebec, Boyd and his money team have raised close to $2 billion a year since 1978. For each of the next three years the utility will need an estimated $2.2 billion. Finding it will require fast footwork, however. "They can get done in two days what my other clients get done in a month," says Edward J. Waters, a vice president at investment banker Kidder, Peabody & Co., Inc., New York City. "Hydro-Quebec's finance guys know what's going on better and faster around the world than the people on my foreign desk. They move incredibly fast."

Boyd's role at James Bay started long before any plans were drawn to develop the La Grande. Even before the 1970 elections, a raging debate had been under way over the direction Hydro-Quebec and the province should go in developing new energy sources. The consensus among the Quebec press and a number of political figures, most notably Rene Levesque, was that nuclear power would be the cheapest source of electrical energy for Quebec's future.

Power from LG 2's 5,328-Mw capacity machine hall was delivered early.

They had reason to believe that a string of nuclear plants along the St. Lawrence River would be less costly than remote hydropower projects up north. In negotiations with Newfoundland during the late 1960s over the power contract for output from Churchill Falls, U.S. bankers insisted that Hydro-Quebec sign an ironclad, long-term contract to protect the project from competition from lower-cost nuclear plants.

Before that, in May, 1967, Vermont authorities terminated negotiations with Hydro-Quebec for access to Canadian energy at a price in excess of 4.3 mills per kwh after American reactor manufacturers announced nuclear plants could produce electricity at 4 mills per kwh.

"All the American bankers were reluctant to go hydraulic because they were listening to all that talk about nuclear," says Giroux.

A mistake? When Bourassa finally announced in April, 1971, that his "project of the century" would be one of the most ambitious and expensive hydroelectric projects in the world, Levesque, who a few years before had split from the Liberal Party to form his own separatist Parti Quebecois, was quick to call it "the mistake of the century."

It became Giroux's job to prove that Bourassa was right. And Giroux, a finance man, called on his top engineer. "I was doing the fighting in Parliament because I've got the big mouth," he says. "Boyd was supplying all the answers."

Early on, Hydro-Quebec had focused on a three-river system, the Nottaway, Broadback and Rupert (NBR) south of the La Grande, as the most feasible hydroelectric alternative. Although the geology posed difficult design and construction problems, the NBR basin was the best known and most accessible of Quebec's remote, northern watersheds.

Utility engineers had been studying data developed from tests in the U.S. and Soviet Union on nuclear excavation techniques and figured the deep clay formations along the NBR system could be cleared with a few kilotons. When that idea was dropped, so was the NBR alternative. The La Grande River farther north was the next best source of new power.

While enthusiastic about the huge potential of the James Bay region, Boyd was less than pleased with the organizational structure proposed by Bourassa's government for developing the power there. The government wanted to control the project. Boyd and Giroux wanted it under the wing of Hydro-Quebec.

A battle of wits—and guts—ensued. Boyd was offered the presidency of what would have been a government-controlled James Bay development agency in return for his support. He turned it down cold, insisting that engineering and construction were the sole domain of Hydro-Quebec.

Eventually, with the support of Giroux, construction unions and the people, Boyd won out. In August, 1972, he was appointed to the five-man board of directors of SEBJ. Shortly thereafter, the directors, three of whom were from Hydro-Quebec, elected Boyd president of an organization funded, directed and controlled by Hydro-Quebec.

That power struggle behind him, Boyd began the task of setting up an organization to coordinate design and construction of the hydroelectric complex. He started with seven employees: the same secretary he has today and six loyal aides. Within a month he had an organization chart and began filling in the 2,000 slots with Hydro-Quebec construction experts, engineering managers from a Montreal consultant, Lalonde, Valois, Lamarre, Valois & Associates (LVLV) and top managers from Bechtel Quebec.

"We got the cream of three different organizations, put them together in one building and then worked for two years to make them realize they had become SEBJ," says Boyd. "Each had projects and ideas of his own and thought his method was the best."

Hiring an American firm to help manage what was supposed to be a French-Canadian enterprise had its drawbacks. But Boyd knew he needed Bechtel's expertise in contract and project management and as an added measure of credibility in dealing with the international financial community.

By the luck of the draw, Bechtel's top man on the job in 1972 was Martin Lowenthal, an executive from the company's hotel building business. SEBJ old timers describe him as "an incredibly powerful man." He could roar the troops into submission, a perfect partner for the circumspect, calculating Boyd. A year and a half later, however, Lowenthal died.

Problem-solver. For the next three turbulent years, Boyd's quiet roar could be heard over the screaming diesels at James Bay. "Boyd had to fill a big gap," says Laurent Hamel, Hydro-Quebec project manager at LG 2 and now director of special projects for SEBJ. Boyd regularly visited the sites twice a month in the early years of the project, rarely directing but always listening, assessing and solving problems. "When Boyd says, 'I'll take care of it,'" says Hamel, "the problem gets solved."

At the start of construction in 1974, already a month behind schedule at LG 2 because of an early thaw of the winter road, forest fires and a legal suit the year before, contractors were geared to make up the lost time. Work started early, in January. Two months later, however, rampaging union activists sacked the camp. Boyd's punishment for refusing to negotiate a project agreement that included generous union hiring prerogatives. It was a matter of principle. And Boyd paid the price—$30 million in damages and another five months lost.

Glory of Boyd's James Bay success shines on Premier Levesque.

At the time of the Mar. 21 violence, Boyd was in a wheelchair with a wet cast drying on his leg, broken in a skiing accident. From his office in Montreal, he immediately ordered all Bechtel and LVLV managers off the site—to protect them—and put his French-speaking Hydro-Quebec managers at the front line to deal with the problems at LG 2. For three weeks straight, Boyd was in his office 7 a.m. to 10 p.m., rarely emerging.

Soon after the incident, Boyd called for a national commission to investigate the union violence. It was a brilliant tactical move. On the one hand, it produced a number of recommendations that forced a purging of the disruptive forces in the unions. And it allowed Bourassa's Liberal Party, which had been elected with strong support from the unions, to take a harder line. Most importantly, the James Bay projects moved ahead smoothly from then on.

So smoothly that by the fall of 1977, LG 2, the showcase James Bay project and the proving ground in the public's eye for SEBJ and the project contractors, was back on schedule. Boyd's next decision was his most gutsy—to ask publicly for the extra cash to push the job to an early startup.

It came at a fortuitous time. Two months earlier Boyd was appointed president of Hydro-Quebec, making him the chief of both SEBJ and its parent. His feathers were well-preened when Hamel posed the question, "If we can get the generators on line early, can you be sure of having the power lines completed in time?" Boyd asked his hand-picked construction chief if he could get the job done, was assured and, says Hamel, "Two weeks after that conversation the word came down to push construction, spend the money and get the turbines spinning."

On October 27, 1979, over 100 print, radio and television journalists from around the world joined 175 of Quebec's top personalities, including Parti Quebecois Premiere Levesque and his cabinet ministers, for a huge media event broadcast live from LG 2. The occasion: first power was delivered six months ahead of schedule from the LG 2 generators along 630 miles of new 735-kv lines to the Montreal grid.

Boyd gambled and won. The LG 2 flag flying below the Maple Leaf at his gentleman's farm in the eastern township of Cowansville waves in victory over the physical and human obstacles of the far north. Back at the office, however, things are not going so smoothly.

With the reorganization of the Hydro-Quebec management in 1978, when Boyd was joined by 10 new directors on the board, he was forced to choose between being president of SEBJ and of Hydro-Quebec. He chose the latter and now must cope with the growing independence of the stepchild he created and has nurtured since 1972.

Another threat to his kingdom comes from the east. Brian Peckford, Newfoundland's premier, has introduced a bill in his legislature that, in effect, would nationalize the Churchill Falls project. He has called for a Canadian Supreme Court test of the legislation, which, if it stands, would deprive Hydro-Quebec of a hefty chunk of very low-cost electricity.

As always, Boyd has a number of cards up his sleeve. And one of them is the ace of spades: Until Newfoundland, Canada's poorest province, can finance and build its own $1-billion transmission line, there's no way it can export the 34.5 billion kwh of electricity sold to Hydro-Quebec except to Quebec.

Plucking the plum. Boyd's bargaining chip for reopening the Churchill Falls contract—the point of all the maneuvering by Peckford—is an agreement that would allow Hydro-Quebec to develop five St. Lawrence tributaries with headwaters in Labrador, a Newfoundland protectorate. Their power potential is about 5,000-Mw, a plum that Boyd can hardly ignore.

Whether he can work a deal with Peckford remains to be seen. In the meantime, there's plenty of water left in Boyd's subarctic stomping grounds for close to 15,000 Mw of new power. The mandate for developing that potential—much of it for export to the U.S.—is building across Quebec now.

Boyd, whose term as president expires in 1983, is putting in long hours today to ensure that his plans for the future are put into action, plans that include a place for himself at the top. He intends to remain the power behind the power of Hydro-Quebec. □

POLICY ANALYSIS PAPER NO. 82-13

Alaska Energy Planning Studies
A review of three consultant studies
submitted to Alaska state agencies
in fiscal-year 1982

November 18, 1982

ALASKA ENERGY PLANNING STUDIES
A review of three consultant studies
submitted to Alaska state agencies
in fiscal-year 1982

for Division of Policy Development and Planning
Office of the Governor
State of Alaska

by Arlon R. Tussing

and

Gregg K. Erickson

INSTITUTE OF SOCIAL AND ECONOMIC RESEARCH
UNIVERSITY OF ALASKA

4 November 1982
(supersedes all previously-dated drafts)

APPENDIX

CONTENTS

ALASKA ENERGY PLANNING STUDIES

Introduction and Summary

Introduction. During the first half of 1982, Alaska state agencies received three major energy-policy reports they commissioned in 1980 and 1981. The first of these is the second annual "Long Term Energy Plan" mandated by the Legislature.[1] Two others specifically address issues raised by the proposed Susitna hydropower project (hereinafter the "Acres" and "Battelle" reports).[2,3]

> Unfortunately, these newly-delivered reports are already largely obsolete.

Their critical assumptions regarding price trends for various fossil fuels, the growth of population and economic activity in Alaska, and the resulting growth of energy demand in the state, are based upon a conventional wisdom about future energy prices that subsequent experience has made nearly untenable.

The Division of Policy Development and Planning (DPDP) of the Governor's Office engaged the University of Alaska Institute of Social and Economic Research (ISER)[4] to review the three study reports and to identify and discuss those areas that are central to the reports' conclusions, particularly with regard to investment in new electrical-generation facilities in Alaska's "Railbelt" (roughly the corridor from Fairbanks through Anchorage to the Kenai Peninsula).

Readers should be aware that this paper is only a review and not intended as a successor to or substitute for any of the existing studies. The following pages are intended to cover a few crucial issues in sufficient depth to determine whether or not the reports make a solid case for their findings. In large, the answer is "no", but any new recommendations about an optimum energy-development strategy will have to await a new study or amendment of one of the existing studies.

Summary. Briefly, the findings of this review are that:

1. World Oil Prices and Alaska Energy Demand. The dramatic change in oil-price expectations since 1980 calls for reconsideration of the levels of Alaska economic activity and energy demand assumed in the Acres and Battelle studies, and to a lesser extent in the Long Term Energy Plan.

2. Alaska Coal and Natural-Gas Supply. The assumptions in the Battelle and Acres studies concerning the prices and availability of Alaska coal and natural gas for local electric power generation are not well supported.

3. Capital-Market Conditions. Recent high interest rates and capital-market conditions not dealt with by the contractors cast serious doubt on the Acres and Battelle conclusions regarding the risks, costs, and financing arrangements of the Susitna hydroelectric project, and with respect to capital-intensive energy-supply projects generally.

4. Implications for Susitna. Findings 1-3 imply significantly less favorable conclusions from those of Acres and Battelle regarding the relative economic attractiveness of the Susitna hydroelectric projects for serving electricity demand in the Railbelt region.

5. All of these findings point toward a conclusion that now is not the time for major initiatives in publicly financed power development in Alaska.

Despite the erosion of some of their fundamental assumptions, the analytical framework and much of the data presented in the reports remain useful --- even essential --- to evaluating Alaska's choices with respect to the Susitna project in particular, and energy issues in general.

Background to the Studies

Energy looms bigger in Alaska's public-policy deliberations than in any other state. Elsewhere --- even in states with a history of economic activism, like Wisconsin or California --- no one would consider as even plausible a scheme to invest public funds equivalent to two or three times expected annual state tax revenues (or about $15 thousand per capita) in all energy ventures as a class, let alone to devote such funds to a single electric-power generation project like Susitna.

Nor would the legislature of any other state countenance anything remotely similar to the energy-cost subsidy programs that Alaska now has on its books --- programs which in Fiscal-Year (FY-) 1983 can be expected to account for more than one-sixth of the state budget.[5] The sources of this unique perspective on the state's role in energy policy are not the focus of this review, but they surely include the fact that oil production has --- almost painlessly --- put unprecedented fiscal resources at the command of state policy-makers.

Regardless of its origins, the deep involvement of Alaska state government in energy decisions that would be left to the private sector in any other state has evoked a demand for information and analysis on an awesome range of engineering, economic, and financial topics. Because the responsible state agencies (including the legislature and the governor's office) do not have the experience or staff to assemble this information, evaluate it critically, or assimilate it effectively, they have had to depend on outside consultants to generate and process the relevant data, propose policies and programs, and monitor them.

The legislators and executive-branch officials who promoted and authorized these three studies viewed them as complementary to one another --- overlapping in places so that decision-makers could view certain crucial issues from more than one perspective but, on the whole, dealing with different aspects or segments of an interrelated whole. These officials expected that, together, the various reports would put the decisions they had to make in some kind of rational order, and resolve some of the uncertainties they faced in making these decisions. One hope, for example, was that rigorous engineering and economic analysis by nationally renowned experts would give them objective and politically acceptable answers, for each of the state's regions, about ---

> 1. The amount of electrical-generating capacity Alaska would need over the next two decades;
>
> 2. Which generation technologies and/or specific generating projects would be most cost-effective; and
>
> 3. What was the optimum strategy for financing the chosen investments?

Most of the information sought from these three studies is clearly relevant to the issues the state intended to address. And, although the quality of the three reports varies widely, as a group they present the bulk of the requested information --- in one place or another --- in a professionally competent fashion.

> Nevertheless, these studies, together with the march of events since they were commissioned, have conspired to leave the responsible state officials facing even more uncertain and contradictory signals than when the various studies were commissioned.

The Three Studies

Acres' study of the Susitna hydroelectric project. The Feasibility Study of the Susitna Hydroelectric Project prepared by Acres American Inc. was conceived as a detailed examination of the technical and economic feasibility of the the proposed project. In addition, it was to provide searching analyses of the project's environmental and social impacts. The studies leading up to the report were carried out over a two-year period at a cost to the state of nearly $40 million. The report itself is organized in three hierarchical tiers, a Summary Report of 56 pages, a main report titled Draft Susitna Hydroelectric Project Feasibility Report, consisting of three weighty volumes and four equally weighty appendices, and a multitude of "task reports" which, unlike the others, have not been widely circulated. Our review has focused on the Summary Report, volume 1 of the Feasibility Report, and the the Task 11 Reference Report: Economic, Marketing and Financial Evaluation.

The centerpiece of the Acres study is a "multivariate risk analysis", which uses the probabilities the investigators have attached to different assumptions about the key variables (fuel prices, construction costs, interest rates, etc.) to produce an array of economic judgments (about whether the Susitna projects are the least-cost approach to serving Railbelt electrical demand, for example) ranked by their respective probabilities.

Of the three works reviewed here, the Acres study deserves the greatest praise. Not only is it physically the largest, but it is also --- particularly in the Summary Report --- the most carefully and readably written. In most areas of interest a reader has the option of delving deeply or superficially, and in either case will usually find a clear and appropriately detailed explanation of the assumptions used, the evidence supporting those assumptions, and the methodology by which they were incorporated into the analysis.

The fact that the Acres report is analytically the most interesting of the three studies --- and will clearly be the most influential --- has caused us to devote more attention to it than to the others --- and to emphasize its failings. Readers should not be misled by this concentration. The methodology by which the Acres team evaluated the project's economic feasibility is elegant, and largely sound. While the report's errors come at sufficiently critical points to invalidate Acres' "bottom line", namely the economic ranking of the various electrical generation alternatives for the Railbelt, most of these errors are correctible, and Acres' general approach will survive them.

The Battelle "Alternatives" study. Both authors of the present review were professionally involved in the process that led to the choice of Battelle to conduct a Railbelt generation-alternatives study. This involvement gives them a special insight into what was expected of the study, but it inescapably colors their assessment of the work that resulted. Readers should be aware of this fact, and draw their own conclusions taking it into account.

The Battelle study has generated several documents, but we have reviewed only two of them here: Railbelt Electric Power Alternatives Study: Evaluation of Railbelt Electric Energy Plans (February 1982), and Railbelt Electric Power Alternatives Study: Fossil Fuel Availability and Price Forecasts. Although the former volume is labeled "comment draft", we understand that it is in substance the final report.

Because Acres and the other contractors were directed to use scenarios and vital assumptions from Battelle, we have dealt with the Acres and Battelle analyses of individual issues, like load forecasting and coal prices, in one place.

"The Long Term Energy Plan". In 1978, Alaska adopted legislation requiring the state Department of Commerce and Economic Development, in conjunction with the Alaska Power Authority, to prepare an annual "long-term energy plan". The law (AS 44.83.224) mandates that the plan shall contain: (1) an "end-use" study of Alaska energy consumption, (2) a plan for meeting "projected energy needs", (3) a review of conservation efforts, (4) an emergency energy supply plan, and (5) a review of ongoing energy research. The Division of Energy and Power Development (DEPD) has been responsible for the preparation of both the 1981 and 1982 plans, but in both cases has made extensive use of contractors. The 1982 report was largely written under a $390,000 contract with the national accounting and consulting firm of Booz, Allen & Hamilton. However, the firm's name does not appear on the cover or in the introduction, and we do not know how much of the report's content and format should be attributed to Booz-Allen, and how much to the DEPD staff.

The 1982 report was designed, in its own terms, "to focus existing energy information to support current decision-making needs and to provide a sense of priority across state projects and programs."[6] The report is well written, contains few serious errors of fact or obviously faulty analysis, and provides the mandated "existing energy information" in a convenient format.

The "plan" does not fare well in its attempt "to provide a sense of priorities," however. With respect to the really tough social and political issues raised by Susitna and the state's hydropower program generally it largely leaves the field to Acres and Battelle; the Plan's treatment of the Railbelt hydroelectric construction proposals is confined to less than two pages of text. After urging the state to continue planning for Susitna, the report warns that the project's "impact may be to severely limit the consideration of less costly alternative Alaskan based resources such as coal or residual oil."[7]

In other areas, including the treatment of Alaska's complex system of energy subsidies, the authors develop an extensive and unique data collection, but seem reluctant to draw the prescriptive conclusions that clearly follow from it. Finally, many of the study's featured findings are pedestrian, for example the conclusion that "opportunities exist to increase the completeness and accuracy of Alaska's energy data."[8]

Some of these deficiencies are probably the result of the short time in which the state's contractor was required to produce a draft report. In one of their concluding sections the authors seem to recognize these shortcomings, proposing that next year's energy plan focus on developing a "strategic energy planning process." The discussion of how that might be accomplished is one of the most interesting in the entire report.[9]

The Conceptual Framework for Considering Electrical-Generation Alternatives for the Railbelt

The Acres report sets out most clearly the conceptual framework shared by all three studies. In the Railbelt, the key issue is to identify the combination of electrical generating facilities that is most likely to be the cheapest in the long run. The main choices are: (1) a two-stage strategy involving Susitna River hydroelectric power; (2) continued reliance mainly on gas-fired combustion turbines (either "simple-cycle" or "combined-cycle" plants), or on some combination of gas turbines and coal-fired steam plants; (3) and a combination of smaller hydropower facilities with thermal generation.

> The crux of the economic comparison between Susitna and thermal generation is the comparison, over time, of hydro construction costs and thermal-plant fuel costs.

The chief hydroelectric option, which centers on the Susitna River projects, involves a relatively high front-end capital expense per unit of capacity but very low continuing costs for maintenance and operation. Combustion turbines, on the other hand, are relatively cheap to install per unit of generating capacity, and the cost of the electricity they produce is principally the cost of the natural gas used as fuel. Coal-fired steam turbines would be less capital intensive than hydro, and while they would cost considerably more to build per unit of capacity than gas turbines, they might still provide the cheapest base-load power if the price of coal (per unit of electricity generated) were sufficiently below that of natural gas.

Out of the many issues that are relevant to this choice, the present review focuses on the way the various reports deal with ---

a. Future world oil prices;
b. Future Railbelt electricity demand;
c. Future Railbelt fossil-fuel prices;

d. Construction costs for hydro projects;

e. The appropriate interest or discount rate; and

f. Risk and uncertainty regarding these and other issues.

The six issues fit together as follows:

(a) World oil prices will powerfully influence Alaska economic activity, and through it electricity demand, by determining state revenues from petroleum royalties and taxes, and thus state spending. Oil prices are also a major influence on Alaska economic development and thereby on electricity demand, by way of their impact on energy-related private investment --- in oil and gas exploration, coal export projects, the Alaska Highway gas pipeline (ANGTS), petrochemicals manufacturing, and the like.

World oil prices, moreover, may influence the prices of natural gas and coal for electrical generation in the Railbelt. Indeed, the Acres and Battelle analyses seem to treat world oil prices as the crucial force determining fossil-fuel prices in the region.

(b) Electricity load growth. Susitna generating capacity would be very "lumpy" as well as capital-intensive; additions would come in multi-billion-dollar packages or not at all. Gas-turbine capacity can be added in small increments, however, with coal-fired steam turbines and some smaller hydroelectric options falling between the Susitna projects and gas turbines in "lumpiness".

If projected power demand and demand-growth rates are high, they can be expected to liquidate any excess generating capacity rapidly; high load-growth forecasts therefore improve the prospective economic ranking of the Susitna projects, all other things being equal.

With low or uncertain load growth, however, the larger hydro projects pose a greater risk than do thermal plants that underutilization of capacity would result in high unit costs for electricity. Thus, the risk of temporary or permanent overbuilding would be least in a strategy built around gas-fired combustion turbines, with the risks somewhere in-between for smaller hydroelectric projects and for coal-fired steam generation.

(c) Future fuel costs and (d) expected construction costs. In the framework described here, the comparison of electricity costs must focus most sharply on the cost of fuel for gas-fired combustion turbines, and on the original construction cost for the proposed hydroelectric plants. The relative cost of electricity from coal-fired steam plants will depend more on capital costs than electricity from gas turbines, but more on continuing operating (fuel) expenses than hydroelectric power.

Estimates of construction costs and future fuel costs are both subject to great uncertainty --- and the treatment of this uncertainty (f) below is itself a major issue in any comparison.

(e) Discount rates. Because the Susitna plants would be capital-intensive, long-lived, and take many years to build, the long-term cost of electricity from these projects would be highly sensitive to interest rates. This would be true whether the interest rates in question were the rates the state would have to pay to borrow for Susitna construction, or the rates it could have otherwise earned on money appropriated to build Susitna. The net benefit from the Susitna option is, therefore, most sensitive to the choice of interest rates used to "discount" future costs and benefits.

(f) Treatment of risk and uncertainty. The various factors that influence future Alaska economic activity and thus electricity demand (including but not limited to future world oil prices); Susitna and other generating-plant construction costs; future Alaska fossil-fuel prices (which may or may not be closely linked to world oil prices); and future interest rates are all unknown today. Important assumptions that the analysts plug into their models are thus essentially guesses.

These guesses may be informed or ignorant, and insightful or obtuse, but their impact on the final comparison will reflect both the raw values assumed by the analysts, and the way in which the analysts deal with the risk and uncertainty that surround them. Subsequent sections of this review reveal considerable disagreement with some of the raw values Battelle and Acres have assumed in the studies, and the probabilities they have assigned to these values, but not with Acres' design and execution of the "multivariate risk analysis" used to integrate these assumptions.

Future Oil Prices

World oil prices and Alaska state revenues. From the standpoint of Alaska policy-makers, no aspect of the current scene is more confusing than the recent radical change in the the state's official oil-price forecasts, and the forecasts of state revenues that depend directly on oil prices.

> This change in the oil-price outlook invalidates virtually every important economic and policy conclusion in the studies reviewed here.

Between June 1980 and January 1982, the Alaska Department of Revenue's quarterly Petroleum Production Revenue Forecast predicted that nominal-dollar ("inflated") oil revenues would increase over the four years beginning on the forecast date at a compound annual rate between 12.2 and 25.8 percent. In its March 1982 Forecast, the Department's three-year estimate of the expected annual change in state revenues fell abruptly to a negative 0.8 percent.[10]

Specifically, the "most likely" projection in the March Forecast was that the weighted average wellhead value for Alaska North Slope (ANS) crude oil in fiscal year (FY) 1983 would be 29 percent lower than in FY-1982, and that world prices would then resume their nominal-dollar increase, at a compound annual rate of about 7 percent. Not until the beginning of FY-1987 did the Department expect prices to regain FY-1982 levels. With respect to constant-dollar ("real") oil prices, the March Forecast boldly reported "a consensus that oil prices will continue to fall,"[11] and projected declining real oil prices through 1998.[12]

> The authors of the present review agree that world oil markets cannot sustain the level of prices reached in early 1981, and that prices in any given year during the remainder of the century are likely to be considerably lower in real terms than they are today.

There was, however, no consensus on the long-term oil-price outlook that one could prudently rely upon last March, and none exists today.

What has happened, instead, is that the near-consensus which did exist at the beginning of 1981 has been shattered, namely the assumption that the long-term trend in oil prices was inexorably upward.

Abrupt changes in expectations have not been a problem unique to Alaska's official revenue forecasters; a review of the energy literature generally confirms that a widespread reevaluation began in late 1981 and early 1982. Few authorities any longer confidently assume that the energy-price increases of 1973-1981 will continue unabated through the rest of the Century, and an increasing number are suggesting, as the present reviewers have done since 1980,[13] that the price rises of the 1970's may never resume. The crude-oil price slump of late 1981 and early 1982, which few industry and government forecasters anticipated, drew attention to the difficulties of predicting energy prices, but is also pushing forecasters into a more general reexamination of both the demand and supply of petroleum, and the way in which they determine oil prices in the long run.

As late as September 1980, it was possible for Cambridge economist Nicholas Kaldor to write seriously that, " . . . OPEC changed everything. By cornering oil it managed to increase the price four-fold, then double it again, and presumably it could be doubled again, without any really serious impact on consumption." (emphasis added)[14] It is now clear that the world economy has a much greater capacity and willingness both to substitute other fuels for high-priced petroleum and to economize on energy generally than had been widely supposed. Over the past six months, virtually every published authority in the area of petroleum demand has radically altered its expectations regarding future U.S. and world petroleum demand.[15]

On the supply side, so much excess oil-producing capacity now exists that it is hard to contrive any scenario in which OPEC, Saudi Arabia, or anyone else, can long function as a "price-maker" in world oil markets. To the extent that there is any consensus about world oil markets among the experts today, the managing director of Royal Dutch-Shell summarized it well when he wrote that "we are in for a period of severe and unpredictable discontinuities."[16,17]

An advance draft of Tussing's "Reflections on the End of the OPEC Era", included as an appendix to this review, takes a backward look at the events that led most forecasters in the late 1970s to expect ever-increasing world oil prices, and the reasons such an outlook seems untenable today.

Consequences for Alaska. These changes in outlook have extraordinary significance for Alaska, because its economy, like that of (say) Kuwait, is a net exporter (seller) of energy. Well over half of Alaska economic activity depends directly or indirectly on crude-oil production. The largest such influence operates directly through state oil royalties and production taxes, and if prices continue to fall, resulting reductions in state revenues will make it impossible for state spending to continue its new-found role as the main prop and guarantor of Alaska's economy.

Table 1 below compares the state's June 1981 and June 1982 forecasts.

At the same time the Department of Revenue was reducing its revenue expectations generally, it also decided to emphasize the uncertainty of petroleum-price forecasts, and began highlighting its "30-percent" rather than its "expected value" series. The different percentage figure indicates the Department's judgment about the probability that actual revenues will be less than the figure shown.

Table 1

1982-Dollar Petroleum-Revenue Projections by the Alaska Department of Revenue, June 1982 vs June 1981

Fiscal Year	Oil and Gas Revenue ($ Millions) June 1981 Forecast "Expected Value"	June 1982 Forecast "Expected Value"	June 1982 Forecast "30%" Series
1983	4030	2654	2399
1984	4137	2657	2250
1985	4271	2623	2177
1986	4448	2953	2411
1987	4713	3305	2644
1988	4851	3196	2507
1989	4983	3365	2595
1990	4742	3095	2246
1991	4544	2714	1862
1992	4382	2477	1668
1993	3979	2285	1427
1994	3637	2149	1265
1995	3144	1826	1059
1996	2701	1622	936
1997	2289	1608	908

Alaska Department of Revenue, Petroleum Production Revenue Forecast, Quarterly Report, June 1981, p.13; June 1982, p. 18, Personal Communication, Charles Logsdon to Erickson.

In 1981, state and local government employment directly accounted for 21 percent of Alaska non-agricultural wage and salary employment.[18] State government expenditures, in turn, were 86 percent financed in FY-1982 by oil production revenue,[19] and Alaska local governments received about two-thirds of their revenues from the state government. State aid to the City and Borough of Juneau, for example, will equal 262 percent of local property tax revenues in FY-1983.[20] Much of the revenue received by several other local governments in Alaska, moreover, comes from direct taxes on oil industry activity and property.

These illustrations do not begin to encompass the indirect effect of expectations regarding future oil prices on the state economy. These expectations largely determine the level of private-sector investment in oil and gas, coal, and other energy-extraction, conversion, and transportation ventures; energy-industry service activity; and have an added "multiplier" impact on the Alaska economy via the income flowing from such investment activity into the trade, finance, and service industries. A large, if not precisely measurable, part of the present boom in the Anchorage area reflects private investment commitments made in 1979-1981 on the basis of a bullish outlook about future oil prices. This boom is unlikely to survive long once those expectations have been shattered or drastically modified.[21]

The situation is quite different for energy-importing states like New York or California, where a radical increase or decrease in energy prices would at the most, over the short run, cause no more than a three or four percent change in the major economic indicators such as employment, gross state product, or disposable income. In these importing regions, the dominant impacts of energy price changes will operate rather diffusely, through the influence of fuel prices on the real incomes of consumers, and through the impact of changed fuel prices on production costs, and thereby on prices, sales, and profits in manufacturing, transportation, and commerce. In Alaska, the potential response is an order of magnitude larger, and is dominated by impacts on employment and population that flow directly from the primary role that petroleum production and state government spending (89 percent supported by petroleum production) play in the regional economy.

Load Forecasts

The studies reviewed here pay close attention to the usual income and price-factors that affect energy demand, and carefully evaluate the impacts of different oil price scenarios on the electrical-power costs implicit in various energy development schemes. But remarkably, they largely ignore the possibility of a major decline in oil revenues, and the direct effects such a decline would have on the Alaska economy. [22]

The Battelle reports base their forecasts of energy demand on scenarios and econometric modeling studies generated by ISER in 1980 and 1981, using its Man-in-the-Arctic (MAP) model. Acres' growth scenarios are, in turn, adapted from those of Battelle, and the Battelle reports provide the clearest explanation of the economic-development and state spending assumptions that went into the forecasts of Alaska Railbelt economic activity. Battelle offers five "scenarios", ranging from "low" to "superhigh", and a sixth scenario (tagged "fiscal-crisis") which shows very high spending in the 1980s, followed by a drastic decline in the 1990s.

The "moderate-growth" case. Battelle's "moderate" case (which the report defines as having a 50-percent probability of being exceeded) shows population in the Railbelt growing at a compound annual rate of 2.15 percent.[23] This scenario is powered by assumptions that state spending will increase from the FY-1981 level (when general-fund appropriations were about eleven thousand dollars per capita) proportionally with per-capita personal income, that the Alaska Highway gas pipeline (ANGTS) will be under construction by 1983,[24] that the PacAlaska LNG project will come on line between 1985 and 1987, that a 100,000-barrel per day refinery will be built in Valdez, and that 7 billion barrels of oil will be discovered and developed on federal outer continental shelf (OCS) acreage leased through 1989.[25]

The Acres study adopts the Battelle load-growth scenarios[26] with some modifications, which are not always described in sufficient detail to allow critical examination. Acres summarizes the outcome, however, as follows:

> *Between 1981 and 2010, the mid-range forecast suggests that electrical and energy demand will grow at an annual rate of about 3.5 percent, with the high and low range limits at about 4.6 percent and 2.8 percent, respectively. . .*
>
> *Under the mid-range forecast, currently scheduled additions are sufficient until 1993 to meet rising demand as well as to replace aging units which must be retired. Between 1993 and 2010, about 1400 megawatts of capacity must be added to the system to meet additional demand as well as to replace aging units.*[27]

The "low-growth" case. The Battelle report states that there is only a 5 to 10-percent chance economic activity will at any point dip below the values projected in the "low-growth" scenario.[28] A review of Battelle's assumptions underlying this boundary case show population increasing at a compound rate of 3.4 percent in the 1980-1985 period,[29] and constant per capita state spending (based on the exceedingly high FY-1981 base) and construction of ANGTS, but with a lower level of offshore oil activity and no Valdez refinery or Cook Inlet LNG plant.

None of Battelle's moderate-case assumptions, as listed above, now appears likely to materialize. The gas pipeline has, for example, been put on indefinite hold; with the most optimistic outlook, construction could not get under way before 1985 at the earliest. The Valdez refinery project was scuttled about a year before the Battelle report was delivered (and never did achieve much credibility among petroleum experts).[30] And Battelle itself has elsewhere virtually written off the LNG project.[31]

The most stunning discrepancy between Battelle's assumptions and what now seems realistic concerns the state government budget. Even in Battelle's low-growth scenario (given the low-case population growth projections), total state spending in FY-1985 would have to be in the neighborhood of $4.3 billion.[32] However, state appropriations for FY-1983 were only $2.7 billion, or $6,590 per capita, a fall of 45 percent from the previous year's peak and about 27 percent less than the low-case figure used by Battelle. The Division of Legislative Budget and Audit expects that even this spending reduction will leave the state budget with a deficit of $400 million relative to projected revenues.[33]

As we noted previously, the state's official March 1982 forecast expected real prices to remain below their FY-1982 levels through FY-1998. Total petroleum-production revenues projected for FY-1985 were $2.8 billion.[34] If non-petroleum revenues add another half billion dollars, the state would have $3.3 billion to spend in FY-1985. The "low-case" population estimate therefore means that $3.3 billion is $6,952 per capita, or only about three-fourths of the figure implied by Battelle's "low-case" assumption that state spending will remain at FY-1981 levels.

In short, the median, "most-likely" revenue projections of the state's Division of Petroleum Revenue imply a level of state spending that is far lower than, and inconsistent and incompatible with, even the "low-case" boundary conditions assumed in the Battelle analysis of electricity demand and the Acres analysis of Susitna feasibility. None of the contractors has used the model to beget a scenario driven by falling real prices for crude oil, but it is clear that oil-price declines of the magnitude implicit in the state's most recent revenue forecasts would, if cranked into the model, result in demand-growth projections below those of the most pessimistic cases considered by either Acres or Battelle.

We have not calculated the quantitative effect on Alaska's economy of these actual and projected changes in state spending, the stalemate and possible demise of ANGTS, or the bleak outlook for other large capital projects (including, by the way, Susitna) whose construction lies explicitly or implicitly behind the load forecasts.

> Clearly, however, a realistic, up-to-date view of state revenues and private-sector investment plans implies a "most-likely" future in which electricity demand will be lower than the lowest case postulated by Acres or Battelle.

Lessons for the future. Predicting future economic activity is and always has been a tricky business, and Alaska's thin, open economy makes it exceptionally so. Recent Alaska electrical load forecasts have consistently overestimated the growth of demand --- even without the kind of downturn in Alaska economic activity that is likely to proceed from the current oil-price slump. In 1977, ISER forecast that state electricity consumption would grow between 1974 and 1980 at an annual rate of nearly 12 percent, with the lowest possible rate 8.7 percent. The actual growth rate was 8.2 percent.[35] The forecasts ISER furnished Acres in 1980 implied a 4.6 percent annual growth of Railbelt electricity consumption in 1978-1981 in the moderate-growth case, and 4.0 percent in the low-growth case. The actual increase was 3.4 percent.[36] It appears, however, that the forecasting performance of other parties has been even less satisfactory.

If there is a lesson to be learned from this experience it is that grave dangers lurk in relying on a single consultant or institution for insights about the future. The purpose of the Battelle Railbelt Alternatives study was (at least originally) to provide a check on the assumptions and analysis used by the Alaska Power Authority and Acres. One reason the governor's office sponsored and the legislature mandated this study was their concern that Acres' stake in Susitna construction might affect the credibility of its load forecasts and other elements of its economic and financial analysis.

Events show that the original purpose of an independent study of Railbelt generation alternatives was frustrated when Acres and Battelle were directed to standardize their assumptions on a number of issues, (e.g., load forecasts) and to rely only on ISER's 1980 economic-development scenarios as the basis for projecting future electricity demand --- probably the most important variable of all in evaluating the wisdom of the massive commitment of present and future resources to a project like Susitna.

Long Term Energy Plan. The Long Term Energy Plan describes its assumptions concerning the variables that drive the Alaska economy as derived from Battelle's work.[37] However, in the case of expected population and employment growth The Long Term Energy Plan respectively assumes compound rates of 1.1 and 0.6 percent through the year 2000, figures that are clearly inconsistent with the Battelle projections.[38] Unaccountably, the authors of the Plan nevertheless adopt Battelle's Railbelt electricity-demand forecast.[39]

Alaska Fossil-Fuel Availability and Cost

The Cook Inlet basin, which contains the bulk of the Railbelt's population and economic activity, is a major natural-gas producing area and contains large deposits of steam coal close to tidewater. Indeed, the bulk of the electricity produced in the Anchorage-Kenai peninsula area today comes from gas-fired combustion turbines, and much of the Interior's electricity comes from a coal-fired steam plant at Healy. Thus, the most obvious alternatives to the Susitna project for new electrical generating capacity in the Railbelt are coal- and gas-fired plants, or a combination of smaller hydro projects with coal-and/or gas-fired plants.

The Acres Summary represents both Acres' and Battelle's position with respect to this choice:

> *. . . If required generation expansion occurs by continued use of the thermal generating plants, a shift toward increased use of coal will be necessary not only because the Cook Inlet gas reserves may be insufficient to sustain long-term reliance upon natural gas in the face of increased demand but also because sharp increases in gas prices will occur in the next decade as old supply contracts expire. The installation of thermal (coal- or gas-fired) plants to meet the demand would offer the consumer no protection against rising costs, since fuel prices will continue to be exposed to inflation and to extraordinary escalation occasioned by world market conditions.*[39]

Despite the central role that fossil-fuel availability and cost must play in comparing generation alternatives, neither Acres nor Battelle has attempted to assess the probable future cost of fossil fuels for generation in the Railbelt from local coal or gas supply conditions. The reports give little if any attention to the incremental cost of gas or coal production in the region, the ownership and regulatory or contractual status of proved and potential reserves, or the other physical, economic, and institutional features of the local supply picture for either fuel. Indeed, the Acres reports and Battelle's Railbelt Alternatives reports do not even cite Battelle's own 1982 forecasts of Alaska oil and gas supply and demand for the Alaska Department of Natural Resources (whose conclusions appear to conflict with the assumptions used in the reports reviewed here), or the coal-supply study conducted by Ebasco Services, Inc., under a subcontract to Battelle for the Railbelt alternatives study.'

Both contractors have, instead, deduced Railbelt coal and natural-gas supply costs from (1) recent LNG and coal import prices in Japan, (2) assumptions about future world oil-price movements, and (3) the relative processing and transport costs between the mine mouth or gas field and markets in Alaska and Japan. The following passage on the relationship between coal prices and the economics of the Susitna project sets out the implicit pricing model Acres shares with Battelle:

> *. . . Coal mining is assumed to occur at Beluga and an export market for Beluga coal is assumed to exist. To recover the investment in these plants and to account for anticipated major increases in gas costs, as well as inflation and fuel price escalation above the underlying inflation rate, the wholesale price per kWh for electricity will have risen by 1994 to 145 mills (+14.5¢) per kWh and will continue to rise thereafter.* ***It is this trend against which any proposed hydroelectric development on the Susitna River must compete.***[40] *(emphasis added)*

The assumption of "fuel price escalation above the underlying inflation rate" stems directly from the proposition Acres shares with Battelle that the price of coal to new electrical generating plants in Alaska's Railbelt will reflect its market value in Japan (less transportation costs between Alaska and Japan) and that this market value is in turn, directly determined by world oil prices. The Acres and Battelle assumptions regarding natural-gas prices follow the same logic: The cost of natural gas to electric utilities in the Railbelt will be the price of LNG landed in Japan (which will move with world oil prices), less liquefaction costs and transportation costs from Alaska.

The relevance of "opportunity cost" to Railbelt natural-gas and coal supp The concept at the heart of Acres' and Battelle's treatment of both coal and gas prices is opportunity cost. The opportunity cost of Alaska-produced natural-gas or coal is the highest price their owners could have got for the fuel, even if they actually made a deal at some lower price. Acres succinctly states the principle as follows:

> *. . . if export markets exist for LNG (or coal) at the prices which have been determined in the Report, then it must be assumed that any rational gas (coal) producer in Alaska would select the opportunity to receive the highest price which is offered for the gas (coal). If the gas (coal) producer chooses to sell gas (coal) in Alaska at a lower price instead, then should the Susitna project evaluation be based on this economically inefficient price? If this is so, the project evaluation will not be consistent with generally accepted principles of public investment appraisal. (parentheses and "coal" added)*[41]

The principle set out in the previous citation is generally a sound one. The cost figure the state ought to use in calculating the net benefits to Alaska of selling royalty oil to an in-state refiner or petrochemical producer is not the actual transaction price (which state officials may decide to discount for the purpose of fostering industrial development) but, rather, the revenue the state would have got by selling its royalty oil to the highest bidder. Likewise, the cost to Alaskans of electricity from the Susitna project includes all interest the state could otherwise have earned on money appropriated to the project, even if the legislature or the Power Authority decides to set electric rates on the basis of a lower (or even zero) rate of return on that money.

Opportunity cost in this sense measures the true cost of state royalty oil sold to an in-state processor and establishes the proper discount rate for evaluating investments of surplus state funds within Alaska, but only because there are ready, and for practical purposes unlimited, export markets for royalty crude oil and surplus state money. Thus, it is reasonable to assume that any royalty oil which is not processed within Alaska can and will be sold at world market prices (as limited, of course, by the federal prohibition on exports of crude oil shipped throught the Trans Alaska pipeline). It is also reasonable to assume that any state money that is not spent or invested within Alaska can and will be invested elsewhere to get the highest available yield (consistent with the degree of security sought by the state's money managers.)

It is not, however, reasonable to suppose that all Alaska gas or coal that is burned in Alaska would otherwise have been exported at the netback prices assumed by Acres or Battelle.

If effective export markets in fact existed for all of Alaska's potential coal and natural gas production at current Japanese import prices less transport costs, export markets would exist at comparable prices for all of the natural gas that is now shut in or being flared (close to tidewater at least) anywhere in the world. Trillions of cubic feet of gas would not be flared each year in the Middle East, for example, and LNG from Cook Inlet would already be flowing into foreign markets to the limit of the region's producing capacity. Likewise, if there were really an effective export market at recent Japanese import prices for any coal that is economically feasible to produce in Alaska's Railbelt, there would be little uncertainty about the future development of Beluga (or Bering River, or other Alaska) coal, while coal prices almost everywhere in the world would have reached levels comparable with the netback "opportunity cost" that the two reports posit for Alaska coal.

What the "opportunity-cost" approach of Acres and Battelle ignores is the fact that the world's known reserves of coal and natural gas, technically capable of development and delivery to Japan at resource costs below that nation's recent import prices, are many times greater than potential Japanese or global markets for coal and LNG at those prices. Since 1974, Japanese consumers (among others) have been willing to pay prices for coal and LNG related to the rising cost of imported oil, but only because the construction of export and import terminals, on-shore transportation facilities, and the specialized bulk carriers could not keep up with the worldwide growth of demand for fuels capable of underpricing OPEC petroleum in the electric-utility and industrial boiler-fuel markets.

In 1981-82, however, a combination of falling oil prices, the economic slump, and completion of the first generation of major LNG and coal-shipment projects initiated after the 1973-74 oil crisis, have (1) marked an end to the period of frantic growth in Japanese and worldwide demand for both coal and LNG, and (2) permitted new supplies to catch up with and perhaps outstrip that demand. Of the more than twenty new coal-export terminal developments that were under active consideration on the West Coast of North America in early 1981, it now appears that the growth of East Asian demand will economically support at most two such projects between now and the year 2000. There is likewise a growing conviction in industry that LNG-export projects already committed to construction will satisfy Japanese demand for the rest of the century, and that even some of these "committed" projects (the British Columbia LNG venture, for example) may yet be scuttled.[42]

<u>Coal prices and oil prices.</u> Acres and Battelle combine (1) the peak 1981 spot prices for coal imported to Japan, (2) the assumption

that world oil prices will continue to escalate in real terms, apparently without limit, and (3) their "opportunity-cost" netback pricing methodology to arrive at the following most-likely constant-dollar price-escalation rates for Beluga Coal (at Anchorage) and Healy coal (at Nenana):[43]

Table 2. Alaska Coal-Price Assumptions

	Coal Source	
	Beluga	Healy
	(01/82 cents per mmbtu)	
Acres	1.43	1.75
Battelle	1.69	2.43
	(annual constant-dollar escalation rate in percent)	
Acres	2.5	2.7
Battelle	2.1	2.0

Two weaknesses in the Acres and Battelle coal-market assumptions compromise the usefulness of their comparisons between Susitna and coal-fired generation costs: Firstly, if constant-dollar oil prices are not likely to increase at the rates that Acres and Battelle assume throughout their studies, the rationale for similarly-increasing coal prices is mortally damaged. Thus, a more realistic, up-to-date oil-price outlook would call for a reevaluation of the probable cost of coal in Alaska, and of electricity generated from coal, just as it calls for reevaluation of most of the important assumptions and conclusions of the two studies.

Secondly, even if Acres and Battelle oil-price scenarios had remained plausible, their supposition that Alaska coal-price movements will be driven by world oil prices in some straightforward and easily predictable way is unwarranted. The effect of this mechanistic assumption is to evade one of the most difficult, yet one of the most crucial, issues in choosing among generation alternatives --- the need to forecast the change in relative prices among various fossil fuels over time.

Historical evidence. Acres gives a number of good reasons why production costs alone are not sufficient to predict coal prices at any given time and place. For example,

> *. . . "economic rents" (that is, a price that exceeds production costs including a normal return on investment) may be earned by the producers, mine labor and/or governments. For example, in the interests of supply security, a coal importer may be willing to pay a price much higher than actual coal production costs. In addition, oil price increases induce increased demand for coal, thus exerting upward pressure on coal prices.*[45]

The report then remarks that "(h)istorical trends support these observations." "Historically, it has been observed that export prices of coal are highly correlated with oil prices, and that production cost analysis has not predicted accurately the level of coal prices."[46] Acres follows with evidence from a number of sources that real coal prices have increased in recent years, presumably at rates exceeding the increase in production costs, and with citations from a number of other authorities who have also predicted or assumed that coal prices will continue to increase at rates comparable with, or tied to, world oil prices.

The historical data Acres cites do show that rapidly growing coal demand can cause real-price increases, but they do not, in fact, support the notion that coal prices have been tightly linked to oil prices in the recent past. Examine the following three illustrations, for example:

Coal prices (bituminous, export unit value, FOB U.S. ports) grew at real annual rates of 1.5 percent (1950 to 1979) and 2.8 percent (1972 to 1979).[47]

In fact, the constant-dollar price of imported crude oil rose at an average rate of 3.9 percent --- almost 2½ times that of the average FOB export value of coal --- between 1950 to 1979, and at an average rate of 29.2 percent --- almost ten times as rapidly as coal prices --- between 1972 and 1979.[48] The 1.5-percent average coal-price increase cited by Acres for the longer period was actually less than the average increase in hourly compensation of bituminous coal miners in the U.S. over the same period (1.9 percent).[49]

In Alaska, the price of thermal coal sold to the GVEA utility advanced at real rates of 2.2 percent (1950 to 1978) and 2.3 percent (1970 to 1978).[50]

The contrast between Alaska coal and oil-price trends depends wholly on the years chosen. The constant-dollar price of No. 2 fuel oil in Fairbanks actually decreased at an average annual rate of 0.4 percent between 1970 and 1978. Between 1973 and 1981, however, GVEA's real coal price increased at an average rate of 2.1 percent, while No. 2 fuel oil prices were increasing at an average rate of 15.6 percent.[51]

In Japan, the average CIF prices of steam coal experienced real escalation rates of 6.3 percent per year in the period 1977 to 1981.[52]

The constant-dollar price of Japanese crude-oil imports, however, increased at an annual rate of 17.6 percent over the same period --- about three times as rapidly as the country's average coal-import price.[53]

Table 3 compares the cost of coal and oil at electric generating plants in the United States over the last decade, and is further evidence against the direct relationship between coal and oil prices

Table 3. Cost of Fossil Fuels Delivered
To Electrical-Generating Plants in the United States
1973-1981

Year	Current Prices (cents per mmbtu) Coal	Current Prices (cents per mmbtu) Residual Oil	GNP Deflator (1972 = 100)	1981 Prices (cents per mmbtu) Coal	1981 Prices (cents per mmbtu) Residual Oil	Oil-Coal Differential
1973	40.5	78.8	105.8	74.1	144.2	70.1
1974	71.0	191.0	116.0	118.5	318.7	200.2
1975	81.4	201.4	127.2	123.9	306.6	182.7
1976	84.8	195.9	122.7	133.8	309.0	175.3
1977	94.7	220.4	141.7	129.4	301.1	171.7
1978	111.6	212.3	152.1	142.1	270.3	128.2
1979	122.4	299.7	165.5	143.2	350.6	207.4
1980	135.2	427.9	177.4	147.6	467.0	319.5
1981	153.3	529.0	193.6	153.3	529.0	375.7
				Change, 1973-1981		
Absolute				79.2	384.8	305.6
Multiple				2.07	3.67	5.36
Annual rate (%)				9.51	17.64	23.35

Source: Monthly Energy Review

asserted by Acres and Battelle. The real price that utilities paid for coal did indeed more than double between 1973 and 1981, but at the end of the period, the fuel-cost advantage of coal- over oil-fired generation (in constant dollars per million btu) was 5.4 times as high as it was at the beginning.

Whatever limited validity there might be in the model behind the Acres and Battelle coal-price assumptions, it would exist only for spot markets and only for short-term fluctuations. The oil-price surges of the 1970's, without doubt, stimulated increases in the demand for coal that outran the ability of the industry to open new mines. As a result, excess demand did pull up world coal prices dramatically --- particularly the spot prices of steam coal. But Acres ignores the fact that slack demand and overinvestment in coal-producing capacity can just as easily cause reductions as surges of demand can cause increases in spot-market coal prices relative to production costs.

Moreover the Acres report offers the reader no reason to believe that the excess-demand conditions that existed during the 1970's will continue unbroken for the next twenty to forty years. The historical record, which stretches back more than two centuries, shows both cyclical and random fluctuations in coal prices, but no evidence of rising real costs over the long term. It is likely the peak of the most recent cycle was reached in 1981; at any rate, nothing in the world supply-demand picture suggests further real coal-price rises in the foreseeable future.

> In the long-run and on the average, coal prices must reflect the real resource cost of opening and operating new mines.

The real world of coal-purchase contracts. No major coal-fired electrical generating plant will be planned or built by Alaska utilities or the Alaska Power Authority (or financed with revenue bonds) unless it has secured "dedicated" coal reserves and producing capacity sufficient to supply it with fuel over its economic life, or at least over the period of its long-term financing. A prospective mine operator must, in turn, have a long-term coal-purchase contract from the utilities or the Power Authority in order to get financing for mine development and production equipment, and working capital.

That long-term coal-purchase contract will, in every likelihood, be a cost-of-service contract. It will probably provide automatic price adjustments for certain production-cost items, and may allow the return to the mine-owners and/or operators (assuming they are different parties) to increase in proportion to the Anchorage consumer price index (CPI) or the gross national product deflator.

It is almost inconceivable that Chugach Electric Association (CEA) or the Alaska Power Authority would sign long-term contracts containing a floating-price term that was not firmly tied to some element of production cost.

It is even less likely that the Alaska Public Utilities Commission (APUC) or the Legislature (in the case of a facility built by the Power Authority) would approve any coal-or electricity-purchase arrangement that was subject to such a floating-price term. There are two reasons for this judgment:

(1) The cost-of-service arrangement described above is the way that utilities actually purchase coal on long-term contract from dedicated mines.

Indeed, we have not been able to locate any instance in which a state public utilities commission approved a utility's long-term coal-purchase contract whose price was tied to the price of oil. Moreover ---

(2) Mine financing will depend on the existence of long-term coal-purchase contracts. The preponderance of bargaining power in negotiations over such a contract will be on the side of the utilities or the Power Authority, rather than the mine owner.

If CEA, for example, offered one or more of the owners of Beluga coal reserves (or any other coal reserve in the Railbelt) a 20-year cost-of-service take-or-pay contract to provide coal for a 200-megawatt generating plant, with a reasonable rate of return to the operator(s) and a reasonable royalty to the owner(s) of the mineral rights, that offer would be much too good to refuse (assuming, of course, that this production volume is sufficient to cover the mine's startup costs). It would indeed be a more attractive business proposition than anything yet offered by potential customers in East Asia.

Any opportunity the mine owner(s) may have to export coal to the Far East over the same period will, incidentally, make them more, not less eager to deal with an Alaska utility on a long-term cost-of-service basis, because of the ability added sales for export would give them to capture economies of scale by spreading fixed costs over a larger volume of production.

Gas-fired vs Susitna generating costs. The current average cost of Cook Inlet natural gas to Railbelt electric utilities is $0.86 per million btu (mmbtu).[54] Simple-cycle gas turbines that can be bought "off the shelf" would produce electricity at capital costs of about $630 per installed kilowatt.[55] At today's Cook Inlet gas prices, the bus-bar cost (the price at the plant) of power from such a facility will be in the neighborhood of 4.3 cents per kilowatt-hour.[56] The generation cost per kilowatt-hour would presumably be even lower for combined-cycle gas plants, and lower yet for gas-fired steam turbines operated at high plant factors (say, 80 percent) in base-load service. The 4.3-cent estimate, however, contrasts impressively with projected Susitna electricity prices of 1[illegible] cents per kilowatt-hour (assuming the state subsidized the project with a $2.3 billion appropriation) and 30 cents (the full cost of power based upon 100-percent debt financing).[57]

Given these relative costs, it is reasonable to wonder why the Susitna project is even being considered. The Acres Summary gives the answer in brief:

> . . . between 1982 and 1993, many of the long-term contracts now held by utility companies for very favorably priced Cook Inlet gas will expire. Not only will major increases in electric energy costs result from the requirement by local utility companies to purchase gas at market prices, but also known Cook Inlet gas reserves may have been depleted in the early 1990's to the point that reliance upon natural gas as the principal fuel for electrical energy generation would no longer be possible.[58] (emphasis added)

Acres and Battelle have thus assumed that the "market prices" of Alaska natural gas will rise dramatically. Acres' "low" fossil-fuel price case, to which the report assigns a 25-percent probability, projects Cook Inlet natural-gas costs at a constant $3.00 per mmbtu, which is three and one-half times present gas prices. The Acres "medium" ("50-percent probability") fossil-fuel price case assumes that these prices will skyrocket between now and the year 2000 at an average annual real rate of 9 percent, to $4.80 per mmbtu. The "high" case (25-percent probability) projects the trend at 11.2 percent annually, with its end-point at $7.22 per mmbtu, a more than eightfold increase over present gas prices.[59] (All prices are in constant 1982 dollars.)

The weaknesses of Battelle and Acres in their analyses of gas prices closely parallel those that fatally compromise their analysis of coal prices. The assumption of high future prices in both reports flows from two basic postulates, (1) that world oil prices will keep increasing in real terms, apparently without limit, and (2) that Cook Inlet natural-gas and Railbelt coal prices are, or at any rate presently will be, tightly coupled to these rising world oil prices.

<u>The Cook Inlet gas-price/world oil-price nexus</u>. Acres assumes that the "opportunity value" of Cook Inlet gas is now $3.00 per mmbtu, 2.5 times more than prices currently paid by Anchorage utilities. This assumption is based on the contractor's analysis of LNG export opportunities, LNG processing and transportation costs, and the btu relationship between gas and oil. Since the assumption applies to all three cases --- "low", "medium", and "high" --- it is an essential element in the analytical process by which Acres discards natural-gas-fired plants as an economical long-term generation option, and by which the report finds Susitna to be the preferred option.[60]

More importantly, there is enough evidence to make at least a plausible case that Cook Inlet gas prices will be established largely on the basis of factors local to the region. Proved gas reserves, for example, are far in excess of current demand, sufficient to supply the local utilities for roughly 75 years at present rates of consumption.[61] If the full capacity of the existing LNG and ammonia-urea plants is regarded as part of regional demand, the same proved reserves are good for about 23 years at existing production rates.[62] In other regions of North America (Alberta, for example), similar reserve-to-production (r/p) ratios are considered evidence of a gas glut.[63]

Even these measures tend to understate the potential gas supply in Cook Inlet. "Proved" reserves (or "identified economically recoverable reserves", in the terminology of Alaska's Oil and Gas Conservation Commission) constitute only that fraction of the resource base which producers have had a commercial incentive to explore to the point at which the producible volumes are a near certainty. This kind of exploration is expensive and, absent credible near-term market prospects, there is no reason for the lease owners to spend the money.

The known reservoirs of the Cook Inlet basin contain considerably more unproved gas (or "indicated" reserves) than the 3.9 trillion cubic feet (tcf) reported as proved at the end of 1981. Nobody knows the volume of indicated gas in these reservoirs with much confidence (otherwise they would be counted in the "proved" column), but unpublished estimates in the industry tend to be in the 5 to 10 tcf range.[64] Acres and Battelle disregard the high r/p ratios and the region's additional gas-development potential, on the ground that new demands will arise for Cook Inlet gas in the form of additional LNG exports to Japan or California. This may indeed turn out to be the case, but it is a proposition not very well supported by the experience of the only new LNG export scheme to be seriously proposed --- the PacAlaska project, whose sponsors in September 1982 announced the project's indefinite postponement.[65]

Most importantly, overwhelming evidence has accumulated in the last few months that the final-market value of natural gas is considerably lower, and total demand in either the Lower-48 or Japan much more limited, than the industry believed during the 1970's. The new gas-market outlook has cast a serious cloud over all "supplemental-gas" projects --- ANGTS and synthetics --- as well as LNG.[67] At any rate, there are no other proposals to establish new Cook Inlet LNG facilities (or increase the capacity of existing facilities).[68] Until serious industry interest appears in some such project, it is unrealistic to assume that Cook Inlet gas prices will be dictated by "netback" gas values in export markets.[69]

<u>The world oil-price assumption once again.</u> Acres' and Battelle's Alaska gas-price model, in which Cook Inlet gas prices reflect world oil prices, is driven by the contractors' assumption of continuously rising real prices for crude-oil. In Acres' "most-likely case" the rate is 2.0 or 2.6 percent, depending on which of the Acres reports one reads.[71] The report states that its scenarios for gas-price escalation are expected to "follow closely the crude oil-price scenarios."[72]

For the years through 1998, however, the Department of Revenue assumes that the real price of Saudi "marker crude" (which underlies and drives the state's official revenue forecasts) will decrease at a compound annual rate of almost one percent. At least for the period through FY-98, the state's recent oil-price forecasts are as incompatible with the Acres and Battelle assumptions regarding gas-price escalation in the Railbelt as they are with the consultants' forecasts of economic activity and energy demand.

Susitna Construction Costs

The Acres base-case estimate for the original cost of the Watana unit is $5,081 per kilowatt, and for the Devil Canyon unit $2,265 per kilowatt. (Several other figures appear for the two units in the Battelle and Acres reports, but the distinctions among them are not crucial here.) These figures contrast with an estimate of only $636 per kilowatt for a 70-megawatt simple-cycle gas turbine. Costs per kilowatt of capacity for combined-cycle plants, coal-fired steam plants, and some smaller hydroelectric projects considered for the Railbelt fall between these two extremes. Thus, the Susitna project is by far the most capital-intensive of the major electrical-generation options considered by Acres and Battelle, and this capital-intensiveness means that the unit cost of Susitna power is much more vulnerable to capital-cost overruns than power from combustion or steam-turbine plants.

The authors of this review are not in a position to scrutinize the Acres estimates of Susitna construction costs as such; the way in which Acres deals with cost-overrun and related risks is within the scope of this review, however. Large construction projects have become notorious in recent years for costs running far above and sometimes many times higher than the cost estimates on which the owners --- private corporations and public agencies alike --- based their decision to go ahead. The TAPS and ANGTS experiences, among others, have made Alaskans particularly sensitive to the cost-overrun issue.

One obvious question in evaluating and comparing any large project proposal like Susitna is how much credibility anyone can place in the cost estimates and budgets. Public officials and the general public have become increasingly sophisticated about the tendency of project sponsors, their engineers, and their consultants to underestimate costs, and to downplay the risk of delay, false starts, and other causes of overruns. They have become increasingly skeptical about the figures offered by project promoters.

Overruns and other cost-estimation errors are not a new phenomenon,[73] however, and there are a few generalizations that the research literature supports with a good deal of confidence.[74] Errors in construction-cost estimates can be separated, at least conceptually, into two components: variance and bias. Variance is a measure of the expected departure of the actual cost either up or down from the estimated cost, and bias is the expected departure in one consistent direction (usually upward) from the estimated cost. These measures of error depend in different degrees on (1) the specific features of the project, (2) the general economic environment, and (2) the institutional framework in which the project is carried out.

Character of the project. Cost-estimation variance clearly tends to increase with the size of project; novelty in design, location, or construction technique; the time required for conception, authorization, design, construction and shakedown; and the number of licenses, permits, and degree of regulatory surveillance. Both measures of estimation error decline with the amount of experience in similar or related construction on the part of the owners, designers, and contractors. Many of these features are intercorrelated: larger projects tend to be custom-designed, more complex, take longer to complete, and involve a greater number of regulations and regulatory entities. The larger the project, moreover, the fewer similar projects the owners, designers, and contractors are likely to have had experience with. Because of these intercorrelations, the effects of the various factors are nearly impossible to distinguish in practice, but ---

On their face, the specific features of the Susitna project suggest a high risk of cost-estimation error.

Among other things, Susitna would be (a) one of the highest dams in the world, (b) the largest enterprise anywhere, ever, of its particular type, (c) the highest-latitude large-scale hydroelectric project in the world and, so far as we can find, the largest civil works project ever attempted above 55th parallel.

The Acres study has attacked these project-specific features of the cost-estimation risk from two angles; at the core of the whole Sustina feasibility study is an impressively designed, comprehensive engineering-type "multivariate" risk analysis. Acres then checked the findings of this analysis against a comparison of cost-estimates and actual costs on a large sample of completed federal water projects.

In the core analysis, Acres has created a model of the construction process in which the study team has identified each major uncertainty, including everything the designers think might go wrong, in the following areas:

8 categories of natural risks (flood, ice, etc.),
2 categories of design-controlled risks (seepage, etc.),
6 categories of construction risks (equipment availability, labor disputes, etc.),
4 categories of human risks (including contractor capability and quality control), and
2 categories of special risks (including regulatory delay)

The Acres team assigned probabilities to the various contingencies in each category and then combined these probabilities mathematically, to create a schedule that shows the probabilities of various levels of total cost (and a number of other outcomes of the construction process).

With the availability of computers capable of manipulating huge arrays of variables each of which is paired to a probability coefficient, this kind of risk analysis has become common in the engineering of