CA8306612

SP-595

SYSTEM PLANNING DIVISION

COST COMPARISON OF 4 X 500 MW COAL-FUELLED AND 4 X 850 MW CANDU NUCLEAR GENERATING STATIONS

ontario hydro

REPORT NO. 595 SP
JANUARY, 1981

Cost Comparison of 4x500 MW Coal-Fuelled

and

4x850 MW CANDU Nuclear Generating Stations

Report No. 595SP

January 1981

Prepared by: Moti Costa
Planner - Resources

Reviewed by: G. Neil McMahon
Senior Planning Engineer

Approved by:
Manager
Generation Resources Planning

SYNOPSIS

Cost Comparison of 4x500 MW Coal-Fuelled and 4x850 MW CANDU Nuclear Generating Stations

The lifetime costs for a 4x850 MW CANDU generating station are compared to those for 4x500 MW bituminous coal-fuelled generating stations. Two types of coal-fuelled stations are considered; one burning U.S. coal which includes flue gas desulfurization and one burning Western Canadian coal. Current estimates for the capital costs, operation and maintenance costs, fuel costs, decommissioning costs and irradiated fuel management costs are shown on Table 1. A 1995 in-service date is assumed. This report updates Report 584SP issued in January 1979.

The results show:

(1) The accumulated discounted costs of nuclear generation although initially higher, are lower than coal-fuelled generation after two or three years. (Figure 1)

(2) Fuel costs provide the major contribution to the total lifetime costs for coal-fuelled stations whereas capital costs are the major item for the nuclear station. (Figure 2)

(3) The break even lifetime capacity factor between nuclear and U.S. coal-fuelled generation is projected to be 5%; that for nuclear and Canadian coal-fuelled generation is projected to be 9%. (Figure 3)

(4) The effects of varying the parameters are summarized in a sensitivity analysis in Table 2.

(5) The increase required in the various cost elements to make the accumulated discounted costs for coal-fuelled and nuclear generation break even after 30 years is shown in Table 3. Tables 2 and 3 show that large variations in the costs are required before the cost advantage of nuclear generation is lost.

(6) Comparison with previous results (Report 584SP) shows that the nuclear alternative has a greater cost advantage in the current assessment. This is discussed in Section 2.3.

(7) The relative impact on or contribution to the electricity rates charged to the consumer (total unit energy cost) of the construction and operation of the nuclear and coal-fuelled alternatives is shown in Figures 5 and 6.

The total unit energy cost remains approximately constant throughout the station life for nuclear generation while that for coal-fuelled generation increases significantly due to escalating fuel costs. Figure 7 shows the total unit energy costs in 1980 constant dollars.

(8) The 1978 and 1979 actual total unit energy cost to the consumer for several Ontario Hydro stations are detailed in Tables 4-1 and 4-2.

(9) Projected total unit energy costs for several Ontario Hydro stations are shown in Table 5 in terms of escalated dollars. Table 6 shows these costs in 1980 constant dollars.

INDEX

CONTENTS

APPENDICES

LIST OF TABLES

LIST OF FIGURES

Cost Comparison of 4x500 MW Coal-Fuelled and 4x850 MW CANDU Nuclear Generating Stations

1.0 Introduction

This study compares the lifetime costs for a 4x850 MW CANDU nuclear station to those for an equivalent amount of generation from 4x500 MW coal-fuelled stations. These are the sizes of stations which Ontario Hydro would construct to meet requirements following Darlington GS. For study purposes a 1995 in-service date is assumed and the results are appropriate for in-service dates in the 1990's. Since some of the major cost items are sensitive to timing, this work may not be an adequate assessment for in-service dates beyond about 2000.

This report up-dates Report 584SP dated January 1979. In addition to the engineering cost assessment which was covered by 584SP a financial assessment is included to show the relative contributions which the different types of generation make to the rates charged Ontario Hydro's customers.

The engineering assessment is described in two sections. Section 2.0 deals with the basic nuclear/coal-fuelled comparison and Section 3.0 examines the sensitivity of results to variations in parameters.

The financial assessment is described in Section 4.0.

2.0 Basic Nuclear/Coal-Fuelled Engineering Cost Comparison

2.1 Data and Assumptions

The following cost items have been included in the study:

Capital costs
Fuel costs
Operating & Maintenance costs
Heavy Water Inventory costs
Heavy Water Upkeep costs
Net Commissioning costs
Irradiated Fuel Management costs
Decommissioning Costs

The cost and output estimates for the generating stations are given in Appendix 1. Both U.S. bituminous and Western Canadian bituminous coal-fuelled stations are examined.

For the coal-fuelled stations and the conventional parts of the nuclear station it is assumed that the decommissioning costs are equal to the salvage value of the equipment. For the nuclear station an estimate of the decommissioning costs of the nuclear parts of the station is included. No credit or salvage value is given for the heavy water inventory when the station is decommissioned. Its value is difficult to predict and could vary over a wide range.

Incorporating transmission costs are not included because they depend significantly upon the location of the station site and are roughly common to all alternatives.

Flue gas desulfurization (FGD) costs are not included in the Canadian coal-fuelled alternative but are included in the U.S. coal-fuelled alternative. The effects of these costs are shown in the sensitivity analysis in Section 3.0. The sulfur content of U.S. coal is normally 2.0 to 2.5% but can extend from 0.5 to 3.0%. It is estimated that FGD equipment would reduce sulfur emissions by 90%. The sulfur content for Western Canadian bituminous coal is approximately 0.3 to 0.6% for equivalent heat output to the U.S. coal.

The estimated cost of uranium fuel does not include any additional costs which might be incurred in the future to cover the long term environmental aspects of uranium mine tailings disposal. This subject is also discussed in the sensitivity analysis.

The in-service date for the stations is assumed to be April 1, 1995. The period of study covers the assumed 30 year useful life of the facilities. Escalation is based on the October 1980 Economic Forecasting Series and a long-term discount rate of 8.0% per annum is used. Variations in some escalation rates and the use of higher discount rates are considered in the sensitivity analysis.

In Report 584SP the lifetime costs for the alternatives were compared directly on the basis of installed capacity. This was an appropriate basis for comparison because the load meeting capability of the alternatives was essentially the same. This is not the case with the current alternatives.

The smaller 500 MW coal-fuelled units have a higher percent load meeting capability than the 850 MW nuclear units. Fewer installed megawatts of coal-fuelled generation are required to be equivalent to the nuclear generation in terms of reliability of supply to the load. This is a complex issue and involves several things: less reserve generation being necessary to cover the loss of the smaller unit and higher estimated reliability of the smaller unit. In this study it is assumed that flue gas desulfurization will not reduce the coal-fuelled station's reliability. Over the study period it is estimated that 920 MW of coal-fuelled capacity (comprising 4x500 MW units) is equivalent to 1000 MW of nuclear generation (comprising 4x850 MW units).

All costs are expressed in terms of equivalent dollars per kilowatt of installed nuclear generation. For example, the comparable capital cost per kilowatt installed of coal-fuelled generation is reduced by the ratio of 920 to 1000 for the comparison. The annual capacity factors (ACF's) of 80%, 60% and 40% considered in this study are also expressed in terms of the nuclear generation. The energy related costs for the coal-fuelled alternatives are those necessary to produce the same amount of energy from the equivalent coal-fuelled source. The results among the alternatives of the cost assessment expressed in dollars per kilowatt are directly comparable. However, care must be exercised if these results are converted to total dollars.

The capital and first year costs for the U.S. coal-fuelled station, the Canadian coal-fuelled station and the CANDU nuclear station are summarized in Table 1. These costs have not been adjusted for differences in load meeting capability.

2.2 Results of Basic Comparison

Figure 1 shows the costs of a 4x850 MW nuclear station compared to the costs of an equivalent amount of power and energy from the 4x500 MW coal-fuelled alternatives for annual capacity factors of 40%, 60% and 80%. Summarizing these results:

Accumulated Discounted Cash Flow for Nuclear and Coal-Fuelled Stations

ACF	Lifetime Nuclear Cost Advantage* U.S. Coal	Lifetime Nuclear Cost Advantage* Canadian Coal	Years to Break Even** U.S. Coal	Years to Break Even** Canadian Coal
40%	64%	99%	3	3
60%	91%	147%	2	2
80%	114%	187%	2	2

* The nuclear advantage is the amount by which the accumulated discounted cash flow for the coal-fuelled alternatives exceeds that of the nuclear alternative at year 30. It is expressed as a percentage of the nuclear cost.

** The break even year is the time from the 1995 in-service date for the accumulated discounted cash flow of the coal-fuelled alternatives to break even with the nuclear alternative.

While Figure 1 shows the accumulated discounted cash flows for three annual capacity factors, Figure 2 shows the same cash flows for each station type at 40% and 80% ACF. Figure 2 shows that the accumulated total costs for the nuclear station, whose fuelling costs are relatively low, are not very dependent on capacity factor. It also shows that the accumulated total costs for the coal-fuelled stations, which consume a relatively high cost fuel, have a pronounced dependence on ACF.

Figure 2 also shows the component cost breakdown for the total accumulated discounted costs after 30 years for different ACF's. The major contributor to the lifetime cost of the coal-fuelled station is the fuel cost. In contrast, the major contributor to the cost of the nuclear station is the capital cost.

Figure 3 shows the total accumulated discounted costs at the end of thirty years for each station type plotted against annual capacity factor. The nuclear station costs are lower than those for the U.S. coal-fuelled and Canadian coal-fuelled stations for ACF's greater than 5% and 9% (projected) respectively.

2.3 Comparison with the Previous Study (584SP)

A similar cost comparison between 4x750 MW coal-fuelled stations and a 4x850 MW CANDU nuclear station was issued in Report 584SP. A comparison of the basic data used in the two studies is presented in Appendix 2.

The margin by which the accumulated discounted costs of the coal-fuelled alternatives exceeds those of the nuclear alternative at the end of the station's lives (30 years) for the two studies are as follows:

	Report 584SP		Current Study	
ACF	U.S. Coal	Canadian Coal	U.S. Coal	Canadian Coal
40%	16%	25%	64%	99%
60%	39%	53%	91%	147%
80%	60%	78%	114%	187%

The nuclear alternative has improved its cost advantage over the coal-fuelled alternatives under current assumptions.

Earlier it was shown that the major components of the accumulated discounted costs for the coal-fuelled stations are the fuel costs while those for the nuclear station are the capital costs. As described in Appendix 2, the current estimates of higher coal prices and relatively lower nuclear capital costs enhance the cost advantage of the nuclear option. In addition, a lower long-term discount rate favours the nuclear alternative.

3.0 Sensitivity Analysis

3.1 Introduction

The effects of variations in the costs of individual parameters on the overall cost comparison between the nuclear and coal-fuelled alternatives are examined in this section. To simplify the analysis, only the U.S. coal-fuelled station is considered in the comparison with the nuclear alternative in all cases.

The reference case used is the same as that defined in the previous section:

- 4x500 MW U.S. bituminous coal-fuelled station with FGD equipment
- 4x850 MW CANDU nuclear station
- April 1, 1995 in-service date for both stations
- 30 year life
- 8.0% per annum discount rate
- 40%, 60% and 80% ACF's

Results of the sensitivity analysis are summarized in Table 2. For each parameter examined, the effect is measured as follows:

(1) Nuclear Advantage, defined as the margin by which the Accumulated Discounted Cost, in 1995 dollars, of the coal-fuelled alternative is more than that of the nuclear alternative at year 30.

(2) Time to Break Even, defined as the time from the 1995 in-service date at which the Accumulated Discounted Cost of the coal-fuelled and nuclear alternatives are equal.

(3) Lifetime ACF, defined as the annual capacity factor at which the Accumulated Discounted Costs breaks even for the nuclear and coal-fuelled station at year 30.

3.2 Parameters Examined and Results

3.2.1 Discount Rates (Item A on Table 2)

Several discount rates above the 8.0% rate used in the base case are examined. The selection of 13.9% and 20.0% are intended to cover a range of "social" discount rates. The "social" discount rate estimated by Ontario Hydro to be most appropriate is the 13.9% rate.

In terms of the accumulated discounted costs, higher discount rates reduce the economic advantage of the higher capital cost nuclear option. However, even at the high end of the "social" discount rate, 20%, the nuclear alternative retains an economic advantage.

The sensitivity of the results to changes in the long-term discount rate is illustrated in Figure 4 for 40% and 80% ACF.

For an 80% ACF, the nuclear alternative retains an economic advantage over both the U.S. and Canadian coal-fuelled alternatives for discount rates up to 32%, while at 40% ACF, the nuclear alternative retains an advantage for discount rates of up to 24%.

3.2.2 Coal and Nuclear Fuel Price (Items B,C and D on Table 2)

In order to examine the effect of long-term variations in the price of coal and nuclear fuel, escalation rates are varied by $\pm$ 20%. (Items B and C). For example, if the escalation rate between two consecutive years was 5%, a 20% increase in escalation would amount to a 6% rate. For both the higher and lower rates the escalation is assumed to commence in 1980 and is applied throughout the station life.

Because fuel costs constitute a greater component of the accumulated discounted costs for the coal alternative, changes in the fuel price escalation have a greater impact on the costs of that alternative.

The sensitivity analysis (Item D) also shows the effect of a 20% increase in nuclear fuel costs. This is an increase of about $22/kg in the cost of uranium fuel in 1980. The long term disposal of uranium mine tailings has been reviewed by the House Select Committee on Ontario Hydro Affairs. The Committee has recommended that the AECB examine the appropriateness of a long term surety fund for mine tailings disposal to be established from a surcharge on each pound of uranium mined and sold.

In advance of this study, Ontario Hydro is not in a position to estimate this cost. However, it is currently felt that such a surcharge, if imposed, should fall within the range of the 20% price increase considered in the sensitivity analysis.

3.2.3 Capital Costs (Items E and F on Table 2)

Variations of $\pm$20% in the capital costs of each station are investigated.

Construction or capital cost overruns have a more pronounced effect on the nuclear station than on the coal-burning alternative. This is due to the higher capital cost component of the nuclear alternative.

3.2.4 In-service Delays (Item G on Table 2)

One year delays in the in-service date for the coal-fuelled and the nuclear stations are examined separately. The delay is assumed to occur just prior to commissioning; this results in the highest costs for a one year delay since the station is assumed to be built. In each case this delay causes an extra year's carrying charges, assumed penalties by contractors who are required to keep equipment on site, and extra costs to purchase replacement energy. In comparing the costs of a station which is delayed one year to those of one on schedule, credit is taken for the one year residual value of the delayed station.

A one year in-service delay penalizes the nuclear option significantly more than for the coal-burning alternative.

3.2.5 Flue Gas Desulfurization (Item H on Table 2)

Recent concern over "acid rain" has increased the likelihood that flue gas desulfurization equipment will be required on future coal-fuelled generating stations. The reference case for the U.S. coal-burning alternative includes FGD equipment which contributes to higher capital and operating costs.

The sensitivity analysis considers the case with no FGD equipment.

3.2.6 Station Life (Item I on Table 2)

The effect of extending the generating station life to 40 years is analyzed. No allowance is made for additional rehabilitation costs which may be necessary.

3.2.7 Major Variations

The amounts by which some of the individual parameters must be varied in order to eliminate the cost advantage of the nuclear option is shown in Table 3. In each case, only one parameter is varied at a time; all other data corresponds to the reference case.

The results of the sensitivity analysis demonstrates that very large changes in the cost estimates are required before the economic advantage of the nuclear option is lost.

4.0 Contribution to Electricity Rates

The construction and operation of nuclear and coal-fuelled generating stations impact differently on the cost of electricity to the consumer. Costs of generation are not allocated among generating stations for the purpose of setting rates. They are allocated in this study merely to show the relative impacts the particular stations are estimated to have on rates. The costs are determined and allocated by the application of current accounting practices and financial policies.

4.1 Cost of Electricity from the Study Alternatives

Figure 5 shows the estimated cost of electricity for the three alternatives, expressed in terms of energy produced (total unit energy cost in mills per kilowatt hour). The costs are reported for annual capacity factors of 40%, 60% and 80%. The total unit energy costs of the nuclear station are expected to be approximately constant throughout the 30 year period, while those of the coal-fuelled stations are expected to increase steadily.

The total unit energy costs include three components:

(1) Capital Related Costs
- interest*
- depreciation (straight line)
- net income requirement (25% interest cost)
- capital modifications
- decommissioning costs for the nuclear alternative

(2) Other Costs
- operation and maintenance
- heavy water upkeep costs for the nuclear alternative

(3) Fuel Related Costs
- fuel
- irradiated fuel management for the nuclear alternative

*The interest rate assumed for this part of the study is 8.5%. The values and trends shown on the figures are accurate for rates of 8.0 to 9.0%.

Figure 6 shows these three components for the nuclear and coal-fuelled stations based on an 80% ACF. It shows that the increasing total unit energy cost of the U.S. coal-fuelled station is due to the high and increasing cost of fuel. The total unit energy cost of the nuclear station is relatively constant; increasing fuel and operation and maintenance costs are largely offset by declining capital related costs.

Figure 7 shows the total unit energy costs in 1980 constant dollars.

4.2 Cost of Electricity from Existing and Committed Stations

The actual total unit energy cost for major existing stations in the years 1978 and 1979 are shown on Tables 4-1 and 4-2 respectively. The total unit energy costs for the stations are based on the actual energy outputs of the stations in those years. The actual ACF is also shown.

These costs for 1978 and 1979 may be slightly different from other recently published figures because of the inclusion of net income requirement. The current figures more closely represent the cost of electricity from the station as reflected in the rates.

Table 5 shows projected costs for some of the major existing thermal and nuclear stations and those committed for construction. The costs are reported for ACF's of 40% and 80%. Table 6 shows the same costs in constant 1980 dollars. These estimates are based on current accounting practices and the projected cost of borrowings which depend upon future load growth and generation expansion.

The costs for Pickering A include the payments to AECL and the Provincial Government according to the Nuclear Payback Agreement. These payments amount to two-thirds the difference in the operating and the capital modification costs between units 1 and 2 at Pickering and Lambton. They contribute significantly to the increase in costs at Pickering A. In addition the Pickering A and Bruce A costs include estimates of capital expenditures for items such as re-tubing and modifications to the emergency cooling injection system. These expenditures are expected to extend the station's life, but in this study they are depreciated to the original 30-year life span. The tabulated costs for both Pickering A and Bruce A are therefore slightly higher than expected ultimately.

Care must be taken when comparing the costs shown on Tables 5 and 6. The most reasonable comparisons should be made between stations with similar in-service dates.

TABLE 1

Capital and First Year (1995) Costs Based on
<u>Straight Line Depreciation</u>

Cost		4x500 MW Fossil (1970 MW)* U.S. Bituminous Coal			4x500 MW Fossil (2000 MW) CDN Bituminous Coal			4x850 MW CANDU (3400 MW) Nuclear Units		
		ACF=40%	ACF=60%	ACF=80%	ACF=40%	ACF=60%	ACF=80%	ACF=40%	ACF=60%	ACF=80%
Capital Cost	$M	3314	3314	3314	3371	3371	3371	7153	7153	7153
	$/KW	1682	1682	1682	1689	1689	1689	2104	2104	2104
D_2O Inventory	$M	-	-	-	-	-	-	248.1	248.1	248.1
	$/KW	-	-	-	-	-	-	73.0	73.0	73.0
FGD Capital	$M	536	536	536	-	-	-	-	-	-
	$/KW	272	272	272	-	-	-	-	-	-
Net Commissioning Cost	$M	51.11	51.11	51.11	81.35	81.35	81.35	-39.11	-39.11	-39.11
	$/KW	25.94	25.94	25.94	40.68	40.68	40.68	-11.61	-11.61	-11.61
Total Capital Cost	$M	3901	3901	3901	3452	3452	3452	7362	7362	7362
	$/KW	1980	1980	1980	1726	1726	1726	2165	2165	2165
Annual Interest and Depreciation (I&D)**	$/KW	224.4	224.4	224.4	195.6	195.6	195.6	245.4	245.4	245.4
	Mills/KWH	64.04	42.69	32.02	55.82	37.21	27.91	70.02	46.68	35.01
Operation and Maintenance (O&M)***	$/KW	75.23	81.02	83.25	40.23	40.91	41.60	51.94	51.94	51.94
	Mills/KWH	21.47	15.41	11.88	11.48	7.78	5.93	14.82	9.88	7.41
I&D + O&M	$/KW	299.6	305.4	307.7	235.8	236.5	237.2	297.3	297.3	297.3
	Mills/KWH	85.51	58.10	43.90	67.30	44.99	33.84	84.84	56.57	42.42
Fuel Cost	Mills/KWH	49.70	49.70	49.70	83.95	83.95	83.95	9.17	9.17	9.17
Irradiated Fuel Care Cost	Mills/KWH	-	-	-	-	-	-	2.34	2.34	2.34
D_2O Upkeep	Mills/KWH	-	-	-	-	-	-	0.53	0.35	0.26
Decommissioning Costs	Mills/KWH	-	-	-	-	-	-	1.44	0.96	0.72
Total Annual Cost	Mills/KWH	135.2	107.83	93.60	151.3	128.9	117.8	98.32	69.39	54.91

*Flue gas desulfurization equipment causes a reduction of 1.5% in the peak output of the station.

**Annual Interest and Depreciation is calculated using straight line depreciation. It is based on an interest rate of 8.0% p.a. and facility life of 30 years.

***Operation and Maintenance includes Labour, Materials and Capital Modifications for the operation of the station and, in the case of the US coal-fuelled station, the FGD equipment.

TABLE 2
Summary of Sensitivity Analysis

Parameter varied from Reference Case (1)		Value of Parameter	at 80% ACF		at 60% ACF		at 40% ACF		Lifetime ACF (4)
			Nuclear Advantage (2)	Time to Break Even (3)	Nuclear Advantage (2)	Time to Break Even (3)	Nuclear Advantage (2)	Time to Break Even (3)	
Annual Discount Rate	(A)	8.0 %	114 %	2 years	91 %	2 years	64 %	3 years	5 %
		9.75 %	100 %	2 years	79 %	3 years	54 %	4 years	6 %
		13.9 %	67 %	3 years	50 %	4 years	31 %	5 years	12 %
		20.0 %	36 %	4 years	23 %	5 years	10 %	10 years	26 %
Coal Fuel Price Escalation	(B)	+ 20 %	181 %	1 year	146 %	2 years	104 %	2 years	3 %
		As Forecast	114 %	2 years	91 %	2 years	64 %	3 years	5 %
		− 20 %	65 %	2 years	51 %	3 years	35 %	4 years	8 %
Nuclear Fuel Price Escalation	(C)	+ 20 %	93 %	2 years	76 %	2 years	54 %	3 years	5 %
		As Forecast	114 %	2 years	91 %	2 years	64 %	3 years	5 %
		− 20 %	132 %	2 years	104 %	2 years	72 %	3 years	4 %
Nuclear Fuel Price	(D)	As Forecast	114 %	2 years	91 %	2 years	64 %	3 years	5 %
		+ 20 %	104 %	2 years	84 %	2 years	59 %	3 years	5 %
Coal Station Capital Cost	(E)	+ 20 %	120 %	1 year	98 %	1 year	71 %	1 year	1 %
		As Forecast	114 %	2 years	91 %	2 years	64 %	3 years	5 %
		− 20%	108 %	2 years	85 %	4 years	57 %	6 years	9 %
Nuclear Capital Cost	(F)	+ 20 %	98 %	3 years	76 %	4 years	50 %	7 years	10 %
		As Forecast	114 %	2 years	91 %	2 years	64 %	3 years	5 %
		− 20 %	133 %	0 years	110 %	0 years	82 %	0 years	−
In-service Date	(G)	Nuclear delayed one year (Coal on schedule)	98 %	4 years	79 %	5 years	56 %	5 years	5 %
		Both Stations on Schedule	114 %	2 years	91 %	2 years	64 %	3 years	5 %
		Coal delayed one year (Nuclear on schedule)	116 %	0 years	93 %	0 years	66 %	1 year	4 %
Flue Gas Desulfurization	(H)	With Equipment	114 %	2 years	91 %	2 years	64 %	3 years	5 %
		Without Equipment	89 %	3 years	67 %	4 years	40 %	7 years	16 %
Station Life	(I)	30 years	114 %	2 years	91 %	2 years	64 %	3 years	5 %
		40 years	124 %	2 years	100 %	2 years	72 %	3 years	4 %

Notes
1. The Reference Case in the Sensitivity Analysis is shown shaded in each of the parametric studies. In each study only one parameter is varied from the Reference Case.
2. "Nuclear Advantage" is the margin by which the Accumulated Present Worth of the coal-fuelled alternatives is more than that of the nuclear alternative at the end of its life.
3. "Time to Break Even" is the time from 1995 in-service for the Accumulated Present Worth for coal and nuclear to break even.
4. "Lifetime ACF" is the Annual Capacity Factor at which the Accumulated Present Worth for coal and nuclear break even. This ACF is the same in each year.

TABLE 3

Variation in Parameters Required so that Accumulated Discounted Costs for U.S. Coal and Nuclear Generation Break Even at Year 30.

Parameter Varied from Reference Case	At 80% ACF	At 60% ACF	At 40% ACF
If the ANNUAL DISCOUNT RATE were to increase, it would have to increase to **** per annum. (1)	32 %	29 %	24 %
If the COAL FUEL PRICE were to decrease, it would have to decrease to **** of the value currently forecasted for year 30. (3)	7%	8%	10%
If the COAL CAPITAL COST were to decrease, it would have to decrease to **** of the current estimate. (2)	<0 %	<0 %	<0 %
If the NUCLEAR FUEL PRICE were to increase, it would have to increase to **** the value currently forecasted for year 30. (3)	16 times	16 times	15 times
If the NUCLEAR CAPITAL COST were to increase, it would have to increase to **** of the current estimate including Heavy Water	371 %	300%	229 %

Notes

(1) Higher discount rates reduce the annual operating component of the Accumulated Discounted Cost for the coal-fuelled station significantly more than that of the nuclear station.

(2) "<" means less than.

(3) In the case of fuel price variations, the fuel price is fixed for 1980 and the escalation rate is varied.

TABLE 4-1
Existing Generating Stations
Total Unit Energy Cost Summary
1978

Station	Lakeview	Lambton	Nanticoke	Thunder Bay	R.L. Hearn	Lennox	Total Fossil	Bruce A	Pickering A	Total Nuclear
Size (MW)	2,296	2,100	4,248	100	1,179	2,232	12,155	2,960	2,060	5,020
In-service Dates	1961 - 1968	1969 - 1970	1972 - 1978	1962	1951 - 1961	1975 - 1977		1976 - 1978	1971 - 1973	
Fuel Type	coal	coal	coal	coal	coal and natural gas	oil		uranium	uranium	
Energy Output (GW·h)	5,930	9,181	11,464	321	2,262	1,724	30,881	12,996	15,834	28,830
Annual Capacity Factor	29.5%	50.0%	30.8%	36.6%	21.9%	8.8%	29.0%	50.1%	87.7%	65.6%
Cost Summary										
— Interest and Depreciation										
Cost (millions $)	29.23	29.41	74.23	2.88	12.67	55.64	204.05	149.72	97.84	247.56
mills/KW·h	4.93	3.20	6.47	8.96	5.60	32.28	6.61	11.52	6.18	8.59
— Net Income										
Cost (millions $)	4.03	4.17	12.09	.35	1.59	9.54	31.76	22.36	6.26	28.62
mills /KW·h	0.68	0.45	1.05	1.08	0.70	5.53	1.03	1.72	0.40	0.99
— Operation and Maintenance										
Cost (millions $)	26.17	14.52	17.57	3.87	12.62	8.25	82.99	44.10	44.88	88.97
mills/KW·h	4.41	1.58	1.53	12.05	5.58	4.78	2.69	3.40	2.83	3.09
— Fuel										
Cost (millions $)	82.09	127.02	159.15	5.58	46.72	34.74	455.31	17.71	22.19	39.89
mills/KW·h	13.85	13.84	13.89	17.38	20.66	20.16	14.74	1.36	1.40	1.38
— Total										
Cost (millions $)	141.52	175.12	263.04	12.67	73.61	108.16	774.11	233.88	171.17	405.05
mills/KW·h	23.87	19.07	22.94	39.47	32.54	62.75	25.07	18.00	10.81	14.05

TABLE 4-2
Existing Generating Stations
Total Unit Energy Cost Summary
1979

Station	Lakeview	Lambton	Nanticoke	Thunder Bay	R.L. Hearn	Lennox	Total Fossil	Bruce A	Pickering A	Total Nuclear
Size (MW)	2,296	2,100	4,248	100	1,179	2,232	12,155	2,960	2,060	5,020
In-service Dates	1961 - 1968	1969 - 1970	1972 - 1978	1962	1951 - 1961	1975 - 1977		1976 - 1978	1971 - 1973	
Fuel Type	coal	coal	coal	coal	coal and natural gas	oil		uranium	uranium	
Energy Output (GW·h)	6,175	10,361	10,871	506	2,114	895	30,922	17,063	15,185	32,248
Annual Capacity Factor	30.7%	56.3%	29.2%	57.8%	20.5%	4.6%	29.0%	65.8%	84.1%	73.3%
Cost Summary										
– Interest and Depreciation										
Cost (millions $)	31.80	30.81	100.10	2.78	12.87	51.32	229.68	204.48	102.82	307.30
mills/KW·h	5.15	2.97	9.21	5.50	6.09	57.35	7.43	11.98	6.77	9.53
– Net Income										
Cost (millions $)	6.32	6.49	26.20	0.55	2.44	15.13	57.13	50.96	9.89	60.85
mills/KW·h	1.02	0.63	2.41	1.10	1.16	16.92	1.85	2.98	0.65	1.88
– Operation and Maintenance										
Cost (millions $)	23.05	16.45	20.91	5.51	12.25	7.25	85.43	61.21	45.42	106.63
mills/KW·h	3.73	1.59	1.92	10.90	5.80	8.11	2.76	3.59	2.99	3.31
– Fuel										
Cost (millions $)	102.35	174.28	180.91	9.38	41.80	19.50	528.22	26.70	26.84	53.55
mills/KW·h	16.58	16.82	16.64	18.55	19.77	21.79	17.08	1.57	1.77	1.66
– Total										
Cost (millions $)	163.52	228.04	328.12	18.23	69.37	93.20	900.47	343.36	184.97	528.33
mills/KW·h	26.48	22.01	30.18	36.05	32.82	104.17	29.12	20.12	12.18	16.38

TABLE 5
Generating Station Cost Summary
Projected Total Unit Energy Costs

Station	Lakeview		Lambton		Nanticoke		Lennox		Pickering A (1)(2)		Bruce A (2)		Pickering B		Bruce B		Darlington	
Size (MW)	2,296		2,100		4,248		2,232		2,060		2,960		2,064		3,024		3,524	
In-service Dates	1961 - 1968		1969 - 1970		1972 - 1978		1975 - 1977		1971 - 1973		1976 - 1978		1982 - 1984		1983 - 1987		1988 - 1991	
Fuel Type	coal		coal		coal		oil		Uranium		Uranium		Uranium		Uranium		Uranium	
Projected Costs (mills/KW-h)																		
Year/ACF	40%	80%	40%	80%	40%	80%	40%	80%	40%	80%	40%	80%	40%	80%	40%	80%	40%	80%
1980	25	22	24	21	29	24	–	–	22	14	32	17	–	–	–	–	–	–
1981	26	22	25	22	31	27	43	35	23	15	32	17	–	–	–	–	–	–
1982	27	23	26	23	33	28	49	41	26	17	32	18	77	40	–	–	–	–
1983	28	25	27	24	35	30	72	65	25	17	33	19	70	37	148	76	–	–
1984	31	27	29	26	38	33			26	18	35	20	70	37	92	48	–	–
1985	34	29	32	28	40	35			26	19	36	21	73	39	85	45	–	–
1986	35	31	34	30	42	37	assumed		30	21	38	22	75	40	81	43	–	–
1987	38	34	36	32	44	40	not to		33	23	38	22	74	40	76	41	–	–
1988	41	36	38	34	45	42	be		34	24	38	23	71	39	73	40	140	73
1989	44	39	41	37	50	45	operating		41	28	41	24	74	40	76	41	121	64
1990	46	41	44	40	53	48			44	30	41	24	73	40	74	41	104	56
1991	49	44	46	42	56	51			45	32	41	25	72	40	73	41	102	55
1992	53	47	49	45	59	54			43	31	40	24	70	39	71	40	97	53
1993	56	50	53	48	63	58			44	32	41	25	69	39	71	40	96	52
1994	60	54	56	51	67	62			46	33	45	27	70	39	71	40	96	52
1995	64	57	59	55	71	66			47	34	48	29	71	40	72	41	96	52
1996	68	61	63	58	75	70			47	35.	52	31	70	40	71	41	95	52
1997	72	65	67	62	79	74			49	37	56	33	71	40	72	41	94	52
1998	77	69	71	66	84	79			52	39	59	35	71	41	72	42	93	52
1999	82	73	76	70	89	83			53	41	59	36	72	41	72	42	93	52
2000	86	77	–	–	94	88			56	43	61	37	72	42	73	43	93	52

(1) Pickering A Costs include Nuclear Payback Agreement payments.

(2) Capital Expenditures for modifications such as re-tubing, which are expected to extend the station's life, are still depreciated to the original 30-year life span.

(3) Projected costs are based on the 1980 System Expansion Program.

TABLE 6
Generating Station Cost Summary
Projected Total Unit Energy Costs
1980 Constant Dollars

Station	Lakeview		Lambton		Nanticoke		Lennox		Pickering A (1) (2)		Bruce A (2)		Pickering B		Bruce B		Darlington	
Size (MW)	2,296		2,100		4,248		2,232		2,060		2,960		2,064		3,024		3,524	
In-service Dates	1961 - 1968		1969 - 1979		1972 - 1978		1975 - 1977		1971 - 1973		1976 - 1978		1982 - 1984		1983 - 1987		1988 - 1991	
Fuel Type	coal		coal		coal		oil		Uranium		Uranium		Uranium		Uranium		Uranium	
Projected Costs (mills/KW·h)																		
Year/ACF	40%	80%	40%	80%	40%	80%	40%	80%	40%	80%	40%	80%	40%	80%	40%	80%	40%	80%
1980	25	22	24	21	29	24	–	–	22	14	32	17	–	–	–	–	–	–
1981	24	20	23	20	28	24	39	32	21	14	29	15	–	–	–	–	–	–
1982	23	20	22	19	27	24	41	34	22	14	27	15	64	33	–	–	–	–
1983	22	19	21	19	27	23	55	50	19	13	25	15	54	28	114	58	–	–
1984	22	19	21	18	26	23			18	13	24	14	49	26	64	33	–	–
1985	21	19	20	18	26	23			17	12	23	13	46	25	54	29	–	–
1986	21	18	20	18	25	22	assumed		18	12	22	13	44	24	48	25	–	–
1987	21	18	20	18	24	22	not to		18	13	21	12	40	22	41	22	–	–
1988	21	18	19	18	24	21	be		17	12	19	12	36	20	37	20	71	37
1989	21	18	19	18	24	21	operating		19	13	19	11	35	19	35	19	57	30
1990	20	18	19	18	23	21			19	13	18	11	32	18	33	18	46	25
1991	20	18	19	17	23	21			18	13	17	10	30	16	30	17	42	23
1992	20	18	19	17	23	21			16	12	15	9	27	15	27	15	37	20
1993	20	18	19	17	23	21			16	11	15	9	25	14	25	14	34	19
1994	20	18	19	17	22	21			15	11	15	9	23	13	24	13	32	17
1995	20	18	19	17	22	21			15	11	16	9	22	13	23	13	30	16
1996	20	18	19	17	22	20			14	10	16	9	21	12	21	12	28	15
1997	20	18	18	17	22	20			13	10	15	9	20	11	20	11	26	14
1998	20	18	18	17	22	20			13	10	15	9	18	11	19	11	24	13
1999	20	18	18	17	22	20			13	10	14	9	17	10	17	10	22	13
2000	20	18	–	–	21	20			13	10	14	8	16	10	17	10	21	12

(1) Pickering A costs include the Nuclear Payback Agreement Payments.
(2) Capital Expenditures for modifications such as re-tubing which are expected to extend the station's life are still depreciated to the original 30-year life span.
(3) Projected costs are based on the 1980 System Expansion Program.

FIGURE 1
ACCUMULATED DISCOUNTED CASH FLOW
VS
YEARS FROM 1995 IN-SERVICE DATE FOR THREE ACF'S
(8,0% DISCOUNT RATE)

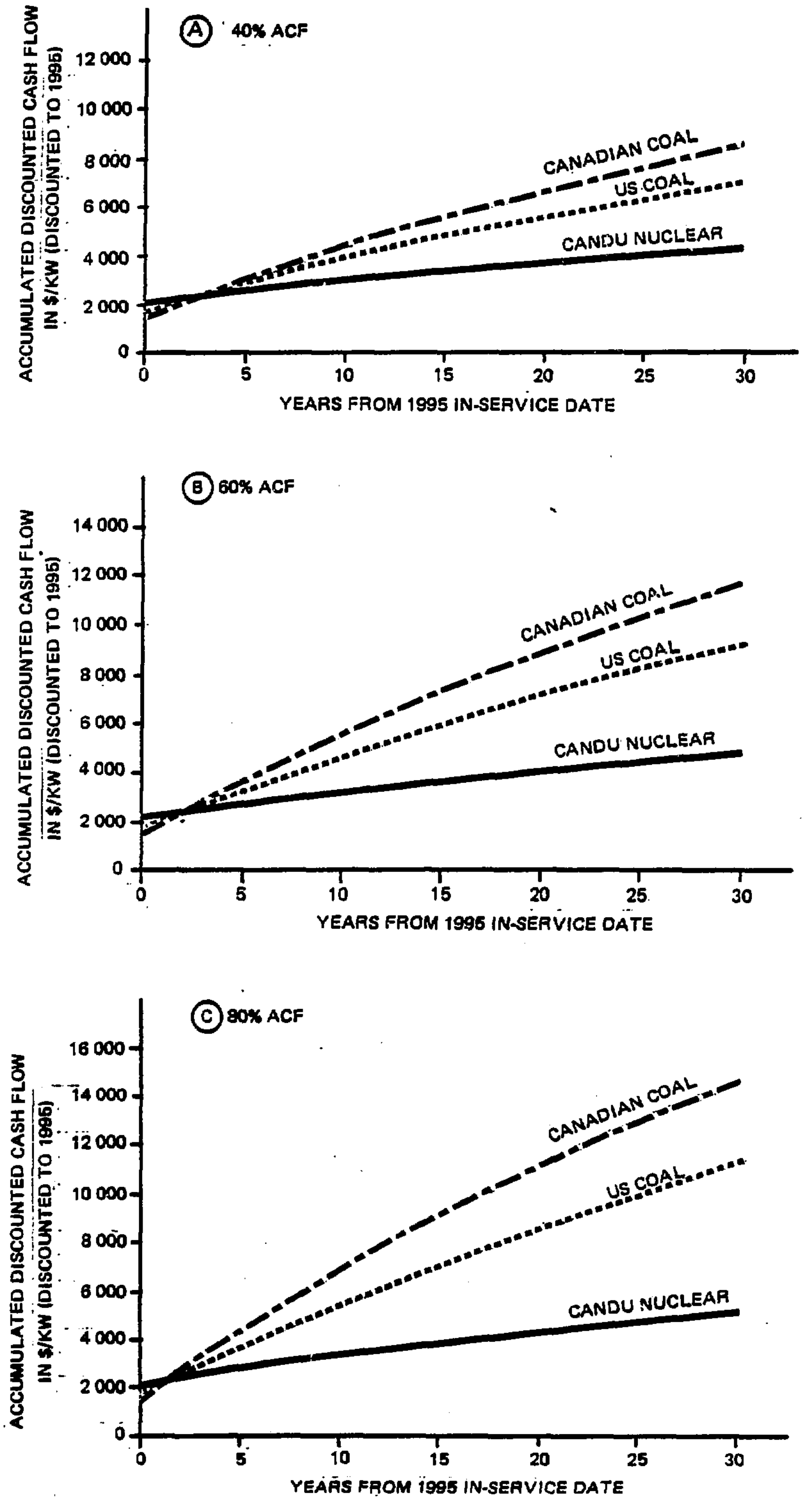


FIGURE 2
BREAKDOWN OF ACCUMULATED COSTS FOR THREE STATION TYPES
VS
YEARS FROM 1995 IN-SERVICE DATE
(8.0% DISCOUNT RATE)

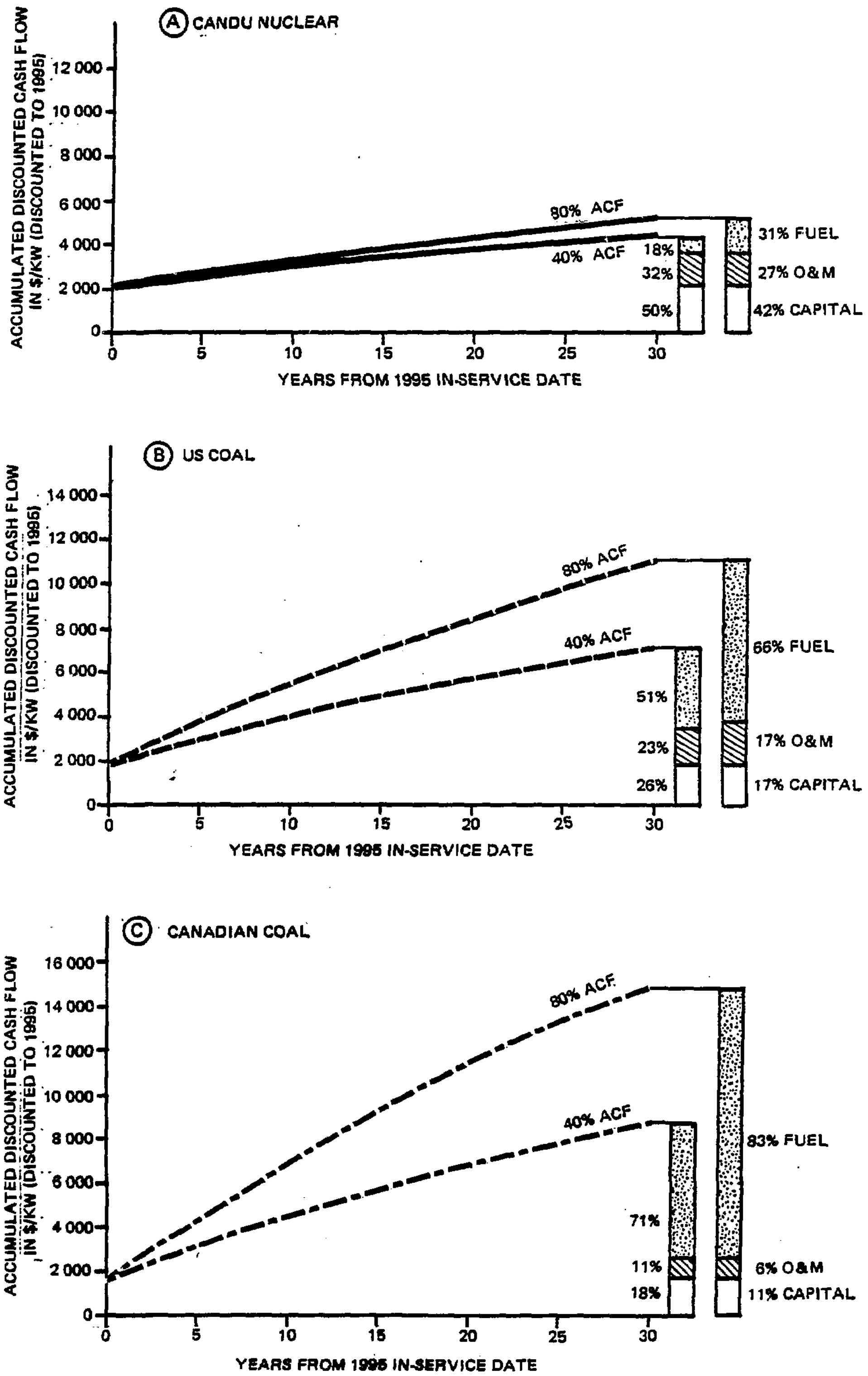


FIGURE 3
TOTAL ACCUMULATED DISCOUNTED COSTS AT THE END OF 30 YEARS VS ACF
(8.0% DISCOUNT RATE)

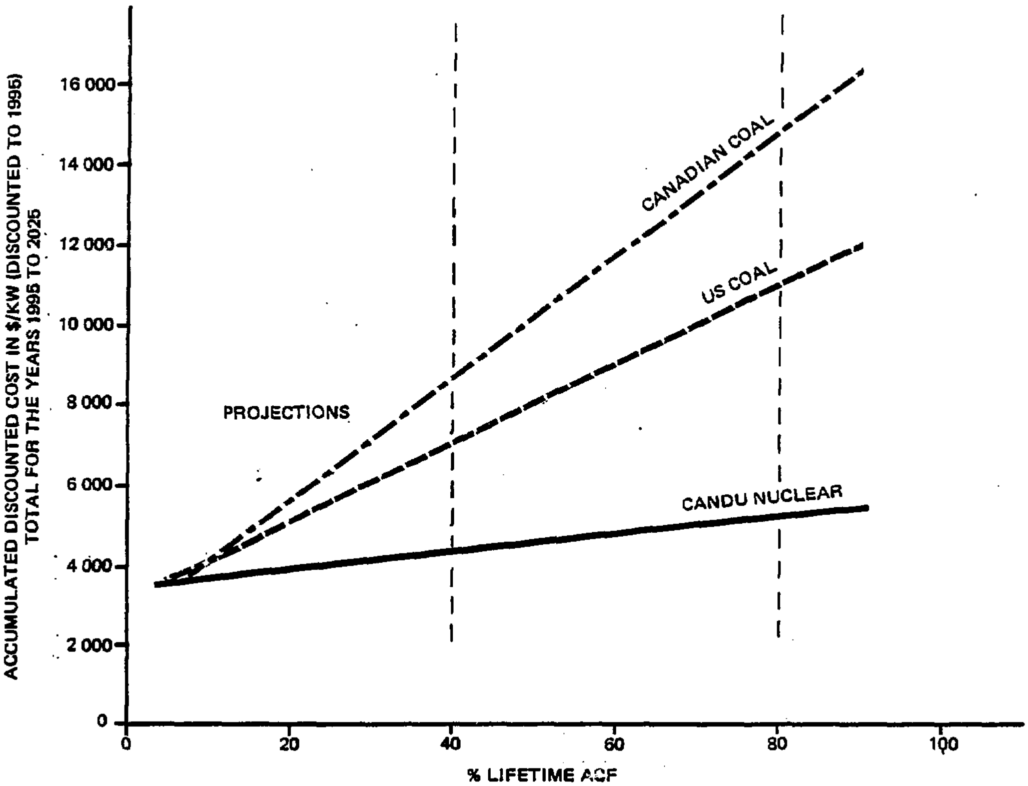
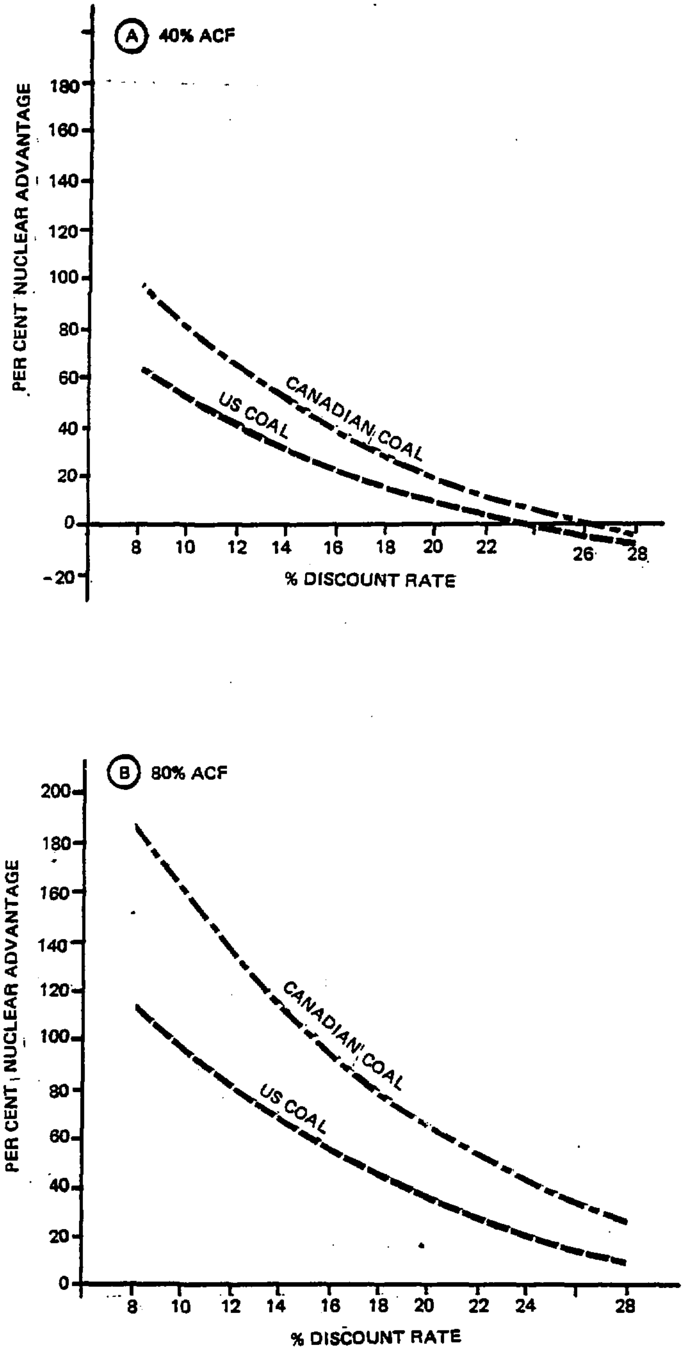


FIGURE 4
NUCLEAR ADVANTAGE* FOR TWO ACF'S
VS
DISCOUNT RATE



*NUCLEAR ADVANTAGE IS THE MARGIN BY WHICH THE ACCUMULATED DISCOUNTED COSTS OF THE COAL-FUELLED ALTERNATIVE IS MORE THAN THAT OF THE NUCLEAR ALTERNATIVE

FIGURE 5
TOTAL UNIT ENERGY COST
VS
YEARS FROM 1995 IN-SERVICE DATE FOR THREE ACF'S

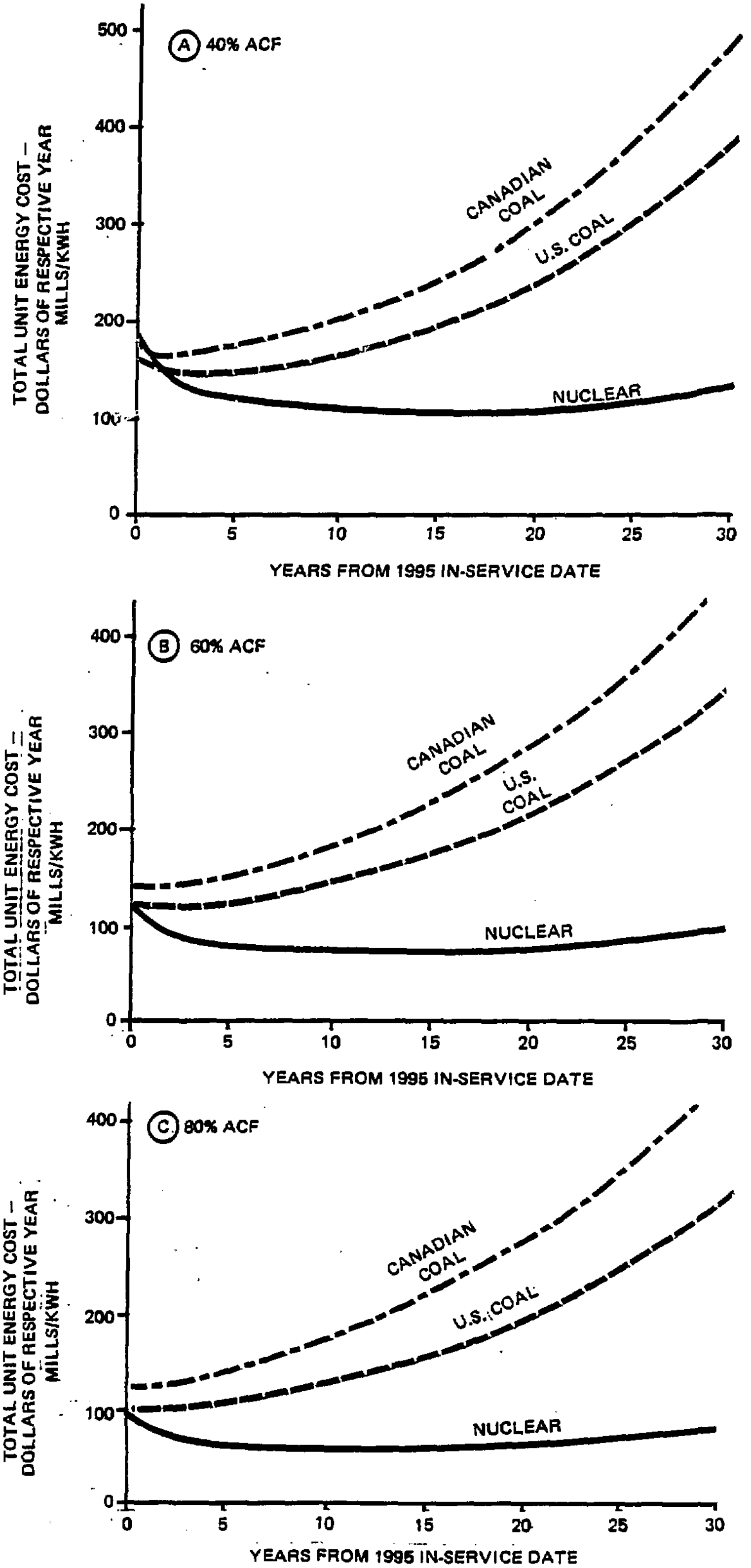
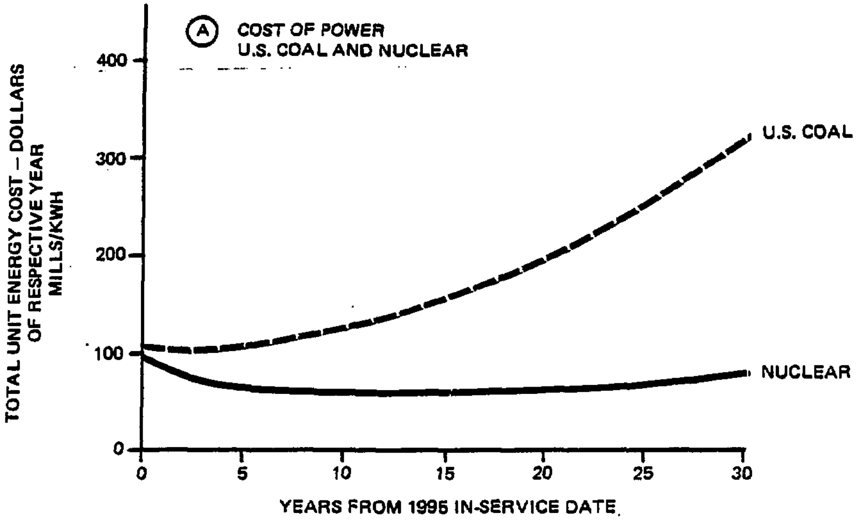
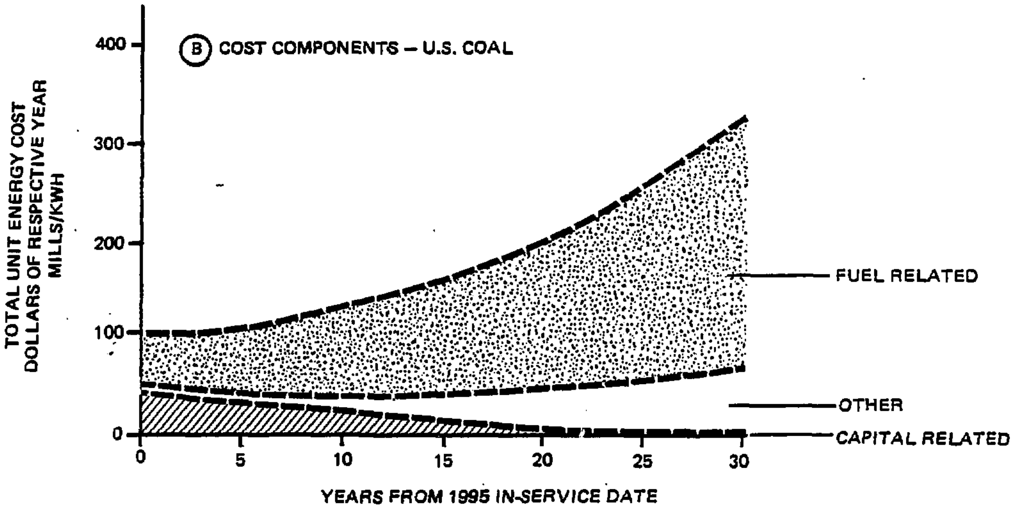


FIGURE 6
BREAKDOWN OF THE TOTAL UNIT ENERGY COST
VS
YEARS FROM 1995 IN-SERVICE DATE
FOR TWO STATION TYPES
(80% ACF)





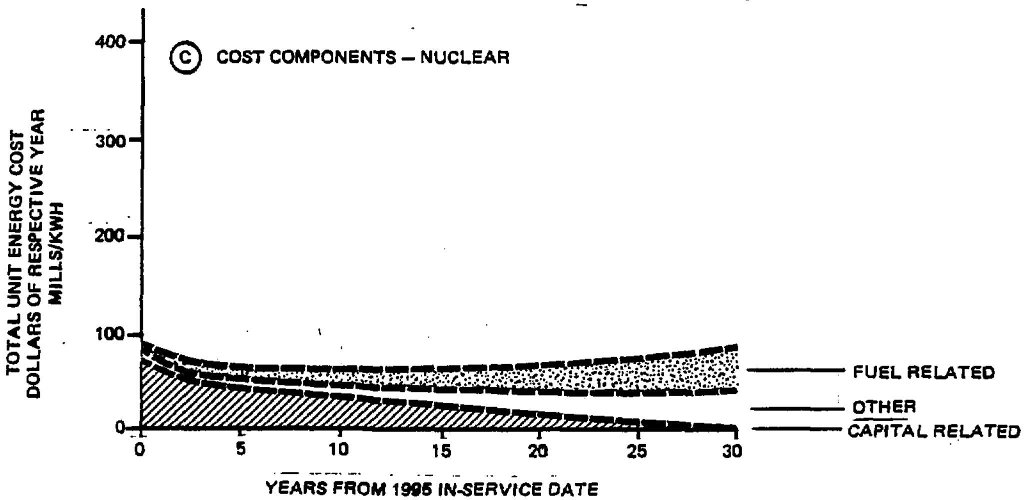
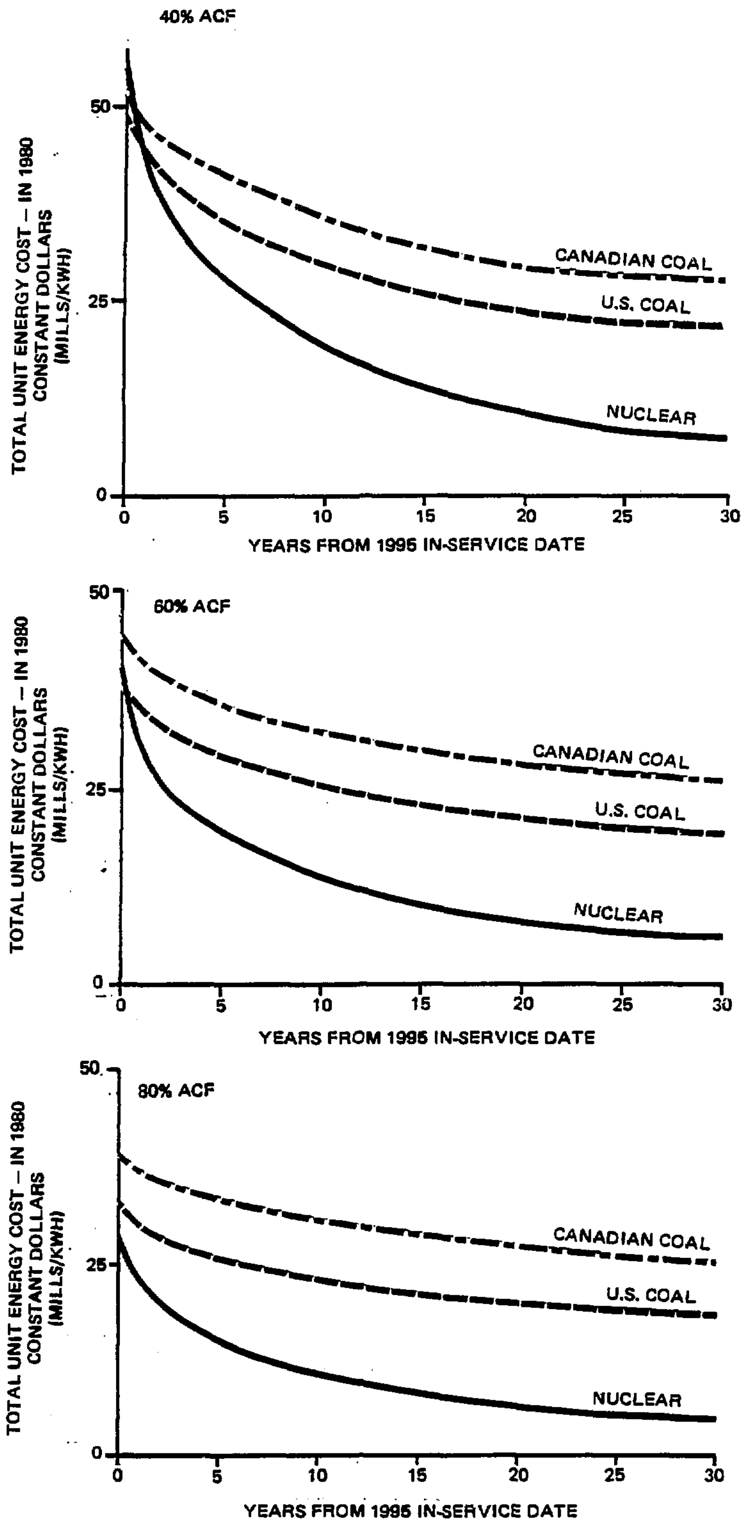


FIGURE 7
TOTAL UNIT ENERGY COST IN 1980 CONSTANT DOLLARS
VS
YEARS FROM 1995 IN-SERVICE DATE FOR THREE ACF'S



Appendix 1

Cost and Output Estimates for the Generating Stations

This study is based on the most up to date consistent set of station cost estimates available. They were obtained in early 1980 from Central Thermal Service, Central Nuclear Service and Generation Planning and Development. They have been adjusted to account for the October 1980 escalation series. Most of the cost estimates used are shown in Table A1.

The capital costs, commissioning costs and heavy water inventory costs are fully escalated for a first unit in-service date of April 1995, with subsequent in-service dates at nine month intervals for the nuclear station and six month intervals for the coal-fuelled stations.

The annual mature operation and maintenance costs are given in unescalated 1979 dollars. The annual heavy water upkeep costs are based on marginal production costs and are quoted in 1990 dollars. The heavy water costs are assumed to escalate at 6% per annum.

Fuel costs are those provided by the Fuels Division in October 1980. The 1980 costs are as follows:

Type	Costs	Normal Sulfur Content
U.S. Bituminous Coal	189 cents/10^6 BTU	2.0-2.5%
Canadian Bituminous Coal	275 cents/10^6 BTU	0.3-0.6%*
37 element Nuclear Fuel	117 $/kg	-

*For equivalent heat output to U.S. coal.

The heat contents of the coal fuels shown in Table A1.1 are based on information provided by the Fuels Division. The heat rates at maximum continuous rating were provided by Generation Planning and Development.

The estimates are based on:

(1) Economic Forecasting Series dated October 1980.

(2) Interest rates for capitalization of 8.0% per annum.

(3) Nuclear and coal-fuelled station consisting of four units.

(4) Capital costs of the nuclear station which includes one half of the initial charge of fuel.

(5) Generation developments which employ once through cooling and which are assumed to be located on the shores of one of the Great Lakes.

(6) Net energy credits for energy sent out during the commissioning of the station are consistent with those used in the 1980 system expansion program.

The load meeting capabilities used in this study are:

4x850 MW CANDU Nuclear station	84.5%
4x500 MW coal-fuelled station	91.8%

TABLE A1.1

COST ESTIMATES

Station Type		CANDU NUCLEAR
TECHNICAL DATA		
Station Size (Net Sent Out)	MW	4x850
In-Service Interval	Months	9/9/9
Burnup at MCR	MWh/kg U.	165
Net Sent Out Efficiency at MCR	%	30.4
D_2O Inventory Requirements	Mg/MW	0.9
COST DATA		
Generating Station Capital		
Equip. Mat. & Lab.	1st Unit	5366
Interest @ 8.0%	I/S	1446
Contingency	Apr.1995	341
Total	escalated millions $	7153
Heavy Water Inventory Costs (excluding interest)		248.1
Commissioning Capital		
Labour	1st Unit	214544
Material & Other Costs	I/S	43287
D20 Upkeep	April 1995	1308
Fuelling	escalated	81435
Interest @ 8.0%	thousands	29720
O/H & Contingency	$	5110
Credit for Energy		(439560)
D_2O Inventory Interest @ 8.0%		25044
Net Total Costs		(39112)
Annual Mature Operation and Maintenance Costs		
Labour & Purchased Services	Average	28764
Material & Other Costs	1979	8728
Capital Modifications	thousands $	860
D_2O Upkeep	1990 thousands $	4699
Decommissioning Costs	1995 thousands $	17176
Fuel	1980 $/kg U	117

Station Type		UNITED STATES BITUMINOUS	WESTERN CANADIAN BITUMINOUS
TECHNICAL DATA			
Station Size (Net Sent Out)	MW	4x500	4x500
In-Service Intervals	Months	6/6/6	6/6/6
Heat Content	kJ/kg	30200	25600
Net Sent Out Heat Rate at MCR	kJ/kW.h	9355	9444
COST DATA			
Generating Station Capital			
Equip. Mat. & Lab.	1st Unit	2699	2746
Interest @ 8.0%	I/S	457	465
Contingency	Apr.1995	159	160
Total	escalated millions $	3314	3371
FGD Capital	1980 millions $	186	
Commissioning Capital			
Labour	1st Unit	36790	37079
Material & Other Costs	I/S	2153	2172
Fuelling	April 1995	83144	108167
Credit for Energy	escalated	(76340)	(73020)
O/H and Contingency	thousands	2367	3429
Interest @ 8.0%	$	2997	3518
Net Total Costs		51111	81345
Annual Mature Operation and Maintenance Costs.			
Labour	Average	11452	11739
Material & Other Costs	1979	3444	3616
Capital Modifications	thousands $	3277	3378
FGD Labour & Materials	1980 thousands $	25649	
Fuel	1980 ¢/GJ	179	261

Footnotes to Table A1.1

1) The Credit for Energy produced during the commissioning of the stations is consistent with the October 1980 forecast fuel prices.

2) The administrative overheads are assumed to equal 38% of the Operation and Maintenance labour costs, including purchased services, for both coal-fuelled and nuclear alternatives.

3) Operation and maintenance costs for the coal-fuelled alternatives are based on a 60% annual capacity factor. A $\pm$10% variation in ACF results in a $\pm$3.5% change in material and other costs.

4) Escalated Heavy Water Inventory Costs are based on marginal costs which assume two heavy water plants are in operation and are operated for a range in annual production from 336 to 1160 megagrams.

5) Current practice is to include interest on the Heavy Water Inventory Costs with Commissioning Capital rather than with the inventory costs.

6) Annual heavy water upkeep costs are based on marginal production costs.

7) Capital modification costs are assumed to escalate at the appropriate Generation Construction rate.

8) The annual Mature Operation and Maintenance Costs of the nuclear development do not include irradiated fuel management costs. They are included separately and are 0.74 mills/kWh in 1979 dollars. This includes the cost of auxilliary storage, transportation, immobilization and long-term storage of irradiated fuel.

9) The following flue gas desulfurization costs are based on a 4x500 MW station using 2.5% sulfur content bituminous coal. The estimates assume a 90% SO_2 removal efficiency and that a sludge disposal site is located within a mile of the station.

The costs in 1980 dollars are:

Capital Costs - 93$/kW
Annual Costs -

ACF (%)	Operating and Maintenance Costs (Mills/kWh)
40	3.20
50	2.81
60	2.44
70	2.22
80	2.06

The use of module redundancy and bypassing is expected not to reduce the station reliability significantly and at the same time attain 94 to 99% scrubbing of the flue gas.

10) Nuclear decommissioning costs are based on preliminary results of a study currently underway. These estimates could change significantly if the decommissioning approach is modified. For an 8% discount rate, the annual cost for a 4x850 MW station is estimated to be $17.2 million with a 1995 in-service date. This annual cost would begin in 1995 and remain constant each year over the station's life.

Appendix 2
Cost Comparison Between Current Estimates and Those Used in Report 584SP

The following table provides a rough comparison of the changes in costs between the current study and one issued in Report 584SP dated January 1979.

Ratio of Nuclear Station Costs to U.S. Coal-fuelled Station Costs

	584SP	Current Study	Relative Change
Capital	1.91	1.09	-43%
O&M*	1.57	0.73	-53%
Fuel*	0.242	0.232	-4%

* First Year Annual Costs

The ratios shown under the heading 584SP are not the same as recorded in that report. The O&M and Fuel items have been increased to include heavy water upkeep costs and irradiated fuel management costs respectively. These costs were included in Report 584SP but not identified as O&M and Fuel items. The adjustment has been made to make them comparable with the treatment of those items in the current study. No adjustment was made to the ratios under heading 584SP to account for flue gas desulfurization or nuclear station decommissioning since those were not considered in the base case of that report. The current study includes both flue gas desulfurization and decommissioning costs and they contribute to the changes in the ratios.

The major differences between this report and Report 584SP are:

(a) The current long-term discount rate, as issued by the Corporate Comptroller (December 1980) is 8.0%; the value used in Report 584SP was 9.75%.

(b) The reference design for a coal-fuelled station is changed from a 4x750 MW to a 4x500 MW development. This results in an increase in total lifetime cost of about 1 to 4% after accounting for differences in load meeting capability.

(c) The heavy water inventories and upkeep costs are based on marginal production costs for the engineering assessment. Report 584SP used the overall production costs for estimating the heavy water inventory charge which is considerably higher.

(d) The in-service date used in this study is 1995 whereas 1987 was used in Report 584SP. The effect of this on the cost trends is small.

(e) The costs for long term storage and disposal of irradiated fuel have been revised upwards by about 145%.

(f) Decommission Costs for the nuclear station have been included in this study.

The use of the lower incremental cost of heavy water and increases in the relative costs of the coal-fuelled station (including flue gas desulfurization) have led to a considerable reduction in the capital cost ratio. The use of load meeting capability factors has only partially offset the change. In contrast, the fuel cost ratio has not changed significantly; increases in the coal fuel costs have been essentially offset by higher irradiated fuel management costs.