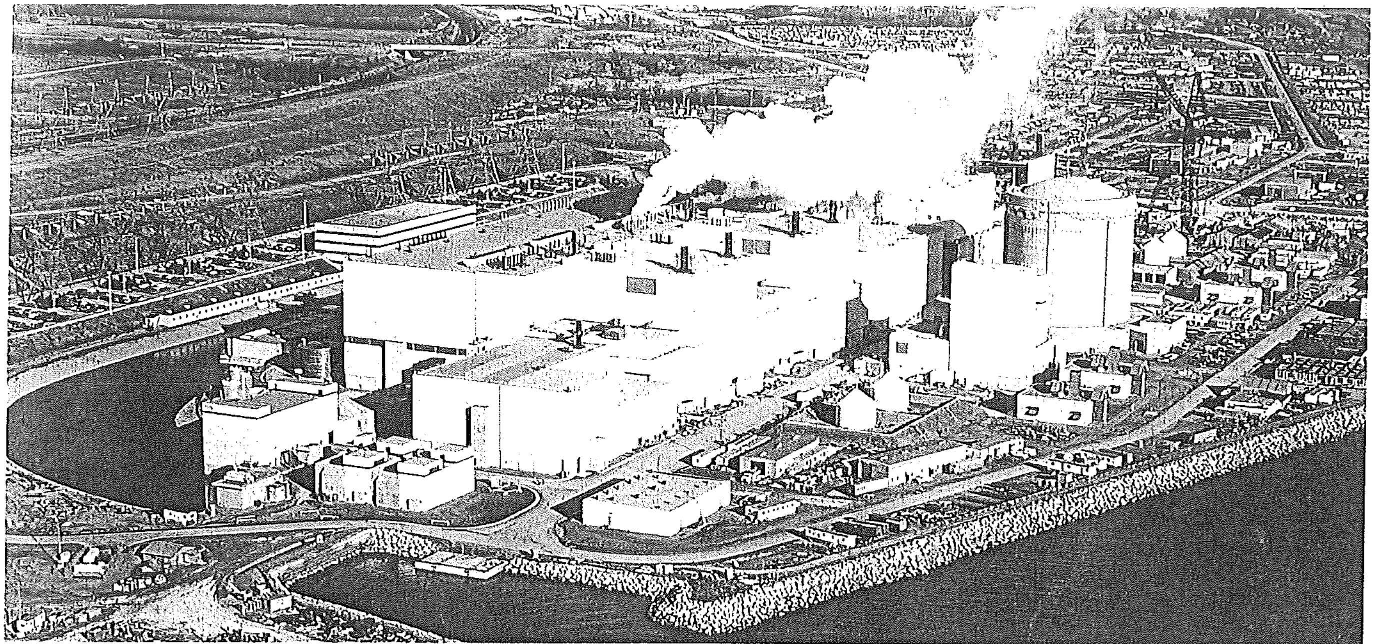
[NUCLEAR CANADA YEARBOOK 1992]

Darlington Cost Increases

CNA Staff Report



Difficulties with fuel damage have forced the shutdown of Unit 2 and a halt in the commissioning of Unit 1.

THERE HAS BEEN CONSIDERABLE CONCERN about the increasing cost of the Darlington Nuclear Generating Station under construction for Ontario Hydro. The current estimate of costs for all four units of the station is $13.5 billion. This includes about $5.5 billion, approximately 40 per cent of the total, in interest charges. In addition to design and construction costs, the project estimate includes costs of commissioning, heavy water, first fuel charge and initial training for a total cost of $2.8 billion.

This would seem to be a considerable amount of money, but this must be seen in context. It must be considered in the light of the fact that Darlington will produce more than 1,300 TWh of electricity across its 40 years of service life, assuming that it averages a capacity factor of 80 per cent. Each year, it will produce enough electricity to supply a city of 2 million people after all four units are in service in 1993. In today's dollars, this electricity will cost about 4 cents/kWh over its lifetime. This compares favourably with other new sources of base-load generation, such as coal-fired generating stations. The types and costs of base-load generation options for Ontario Hydro are shown in Figure 1.

Figure 1

Levelized Unit Energy Cost (LUEC)[1] Comparison

New Fossil Station	IGCC[2]	4.5
New Fossil Station	Conven Coal	4.2
Darlington G.S.[3]	Nuclear	4.0
Manitoba Purchase	Hydraulic	4.0

¢/kWh (in 1991 $)

1. LUEC is an economic measure defined as the unit energy price that has to be charged for each unit of energy generated over the life of the station to recover all capital, operating and fueling costs.
2. Integrated Gasification Combined cycle.
3. For comparison purposes, Darlington G.S. is an incremental LUEC. The accounting LUEC for Darlington is 4.5¢/kWh

Darlington has had many hurdles to cross since it was approved by the Provincial Government of Ontario in the late 1970s. Significant schedule delays have occurred on the project, with the average unit delay being about five years. However, 75 per cent of these schedule delays resulted primarily from the decline in the load forecast as well as borrowing restraints imposed on Ontario Hydro in the early stages of the project. This occurred most notably in the period 1978 to 1986. Schedule slippage makes up the other 25 per cent, about one year per unit, and this resulted primarily from design staff shortages, more complex design and construction requirements, more stringent regulatory requirements, operating staff shortages, cracked generator rotors, and more recently fuel failures

Figure 2 shows the schedule changes in greater detail. From a project life cycle viewpoint, Darlington is far from being an ideal model. A complex nuclear power facility such as Darlington with a large capital cost and requiring a long lead time before being placed in service is at risk if major planned schedule changes occur because of the change in the load forecast and the resulting need for the project. As stated, 75 per cent of the delays on Darlington fell into this category. This risk must be realized and kept in mind in deciding to either reschedule or to maintain the existing schedule.

Capital cost will be minimized if a future project is built on the shortest possible schedule with the design fully licenced in advance by AECB. This would result in a lower levelized unit energy cost (LUEC) than that for Darlington. The changes in the project cost estimates are shown in Figures 3 and 4. These are shown in escalated and constant dollars estimates since the Difinitive Estimate in 1981. The most significant single cost increase was in 1983, when the project cost estimate rose by $3.7 billion due to the imposed two-year deferral of Units 3 and 4, Ontario Hydro financial policy changes and worsening economic conditions.

Figure 5 summarizes the major factors contributing to the overall cost increase of $6.1 billion since 1981. Approximately 70 per cent of this increase is primarily interest associated with schedule delays and financial policy changes. The balance represents scope changes, mainly due to more stringent regulatory requirements, and estimate changes resulting from the complexity of the project.

The uncertainty of the Darlington project during the early stages due to declining load forecast and the large capital program underway in other areas such as Bruce and Pickering led to other disruptions, such as:

- difficulties in obtaining trained design staff in the early stages of the project. It is important that design work stay ahead of construction. However, with these staff shortages, it became difficult at times to keep design work sufficiently ahead of construction, resulting in some program disruptions;
- significant changes in regulatory requirements. Regulatory approval of design is normally obtained on an ongoing basis as work progresses. With the on-again/off-again schedule that developed on Darlington from 1987 to 1991, significant regulatory changes developed, which in most cases were more stringent. Costly rework resulted when changes had to be made to accommodate new or revised regulatory requirements; and
- availability of sufficient, trained operating staff. The development of more stringent regulatory requirements cascaded into a requirement for more station operators. Limitations on trained operating staff were a significant problem in the later stages of the project and continued to be a restriction in 1991.

With any major project, problems develop, and Darlington was no exception. However, the two

Figure 2

Darlington G.S. Schedule Changes

Planned Schedule Change; 75% of total

	Unit 1	Unit 2	Unit 3	Unit 4
(a) 1979 delay in months	18	18	30	30
(b) 1980 delay	18	18	12	12
(c) 1981 delay	6	6	12	12
(d) 1982 delay	0	0	24	24
(e-1) 1986 delay	6	6	0	0

Schedule Slippage Change; 25% of total

	Unit 1	Unit 2	Unit 3	Unit 4
(e-2) 1986 delay	0	0	6	6
(f) 1987 delay	0	4	0	0
(g) 1988 delay	8	6	0	0
(h) 1989 delay	8	6	7	10
(i) 1990 delay	4	7	0	0
(j) 1991 delay	8	0	6	3
Net delay	**64**	**59**	**61**	**61**

Reasons For The Schedule Changes:

(a) & (b) Reduced Load Growth Forecast

(c) BILD: Reduction in Acid Gas Emissions and Creation of Jobs in Construction and Electrical Equipment Industries

(d) Reduction in Borrowing and Load Growth Forecast

(e-1) Primarily the Result of 6 month Strike by Electrical Workers at Site

(e-2) Primarily for Site Manpower Leveling and Capital Cost Reduction

(f) Recognition of More Complex Engineering and Construction Workload

(g) Late Turnover of More Complex Systems to Operations and Limited Number of Trained Operating Staff and Cascading Effect from Delays of Units 1 & 2

(i) Contingency for Unforeseen Problems during Commissioning of Units 1 & 2 and Generator Rotor Repairs

(j) Operations Resourcing Difficulties for Units 3 & 4 and Fueling Difficulties

The schedule slippage which makes up only 25% of the total delay, primarily resulted from design staff shortages, more complex design and construction, more stringent regulatory requirements, operating staff shortages, cracked generator rotors and more recently, fuel failures. The present scheduled in-service dates for the four 950 MW Darlington units are as follows:

Unit 2 - October 1990

Unit 1 - December 1991

Unit 3 - June 1992

Unit 4 - March 1993

most significant problems that occurred in 1990 and 1991 were clearly unexpected: generator rotor cracks and fuel damage problems on Unit 2. In the case of the generator rotor cracks, having contracted a reputable, experienced manufacturer to design and manufacture the Darlington generators, this problem was totally unexpected,and it caused a significant, costly disruption to the schedule.

Unit 2 was delayed about three months in 1990 because of this problem. With regard to the fuel damage problems on Unit 2, the investigation is not yet complete. However, significant data has been compiled to satisfy the regulatory authority to allow the startup of Unit 1. This startup occurred on August 30, 1991, and this unit ran at full power by the end of the year. During the investigation into the fuel bundle problem, it was necessary to shut down Unit 2 for modifications and refuelling, and to delay the startup of Unit 1 by about eight months. Units 3 and 4 are currently on schedule for commissioning in June, 1992 and March, 1993 respectively

Figure 2

Darlington NGS Capital Cost Estimate History — Escalated $

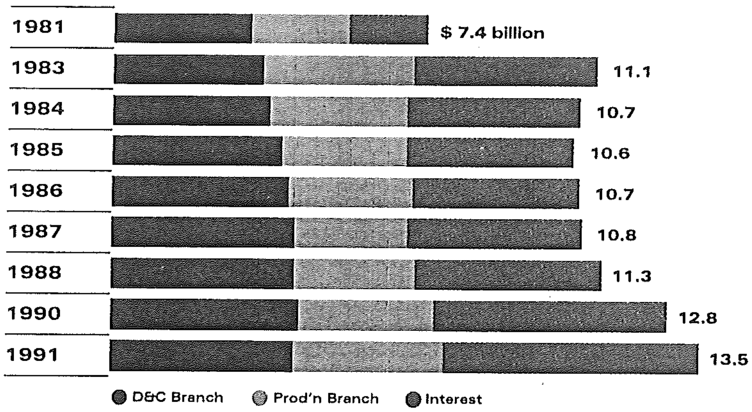


Figure 4

Darlington NGS Capital Cost Estimate History — Constant 1981 $

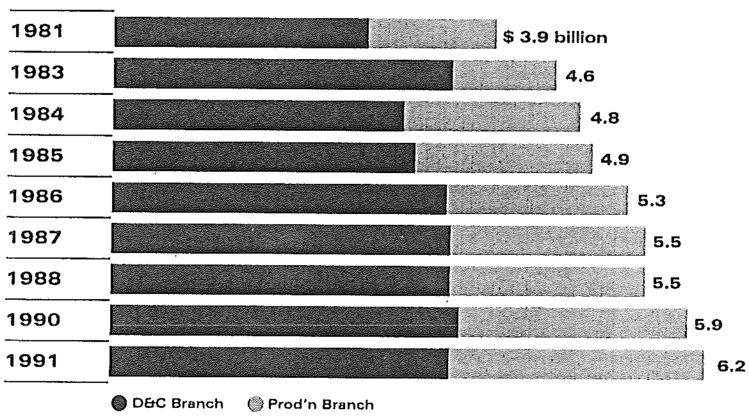
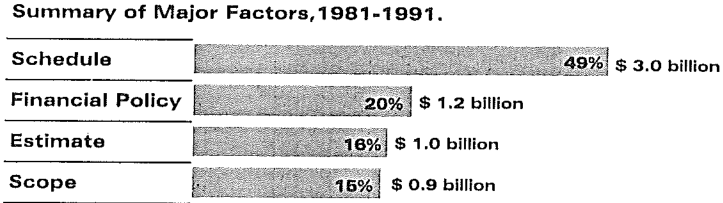


Figure 5

Darlington NGS Hisorical Cost Increases; Summary of Major Factors,1981-1991.



A SECOND DARLINGTON UNIT SHUT DOWN BY FUEL BUNDLE CRACKS

Darlington Unit 1 has been forced to shut down with the discovery of cracks in fuel bundle endplates similar to those which forced the shutdown of Unit 2 in early 1991. The commissioning procedure for Unit 1 which was restarted in mid-December, but the unit was forced to suspend operations before the end of January, 1992. The unit might not be restarted until after new pumps and modified heat transport piping are installed and testing in Darlington Unit 3 this summer.

The reason for the fuel bundle failures in Units 1 and 2 is that vibrations from impeller pumps in the heat transport system damaged fuel bundles within a critical area of the core. The problem was first detected in Darlington Unit 1 when the level of Iodine 131 in the heavy water coolant indicated a pinhole leak in fuel bundle sheathing. Upon subsequent inspection, Ontario Hydro workers found an endplate crack in one bundle from fuel channel M-13 and some bearing pad wear. This bundle was located in the first upstream position in the fuel channel were heavy water enters.

Based on this discovery, fuel bundles from the first upstream position in 36 of the 480 fuel channels have been removed for inspection. These are the channels and locations that appeared to be subject to vibration in Darlington Unit 2. Changing the pump impellers is a task of short duration, but the Atomic Energy Control Board (AECB) is not expected to permit fuel loading into Unit 3 until March, 1992. Several months of testing could be required to demonstrate the reliable operation of the new pumps. At worst, neither Units 1 or 2 would be returned to service until Unit 3 modifications had been thoroughly tested.