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THE UNIVERSITY OF ALBERTA

AN INVESTIGATION OF THE ECONOMIC IMPACT OF ENVIRONMENTAL LEGISLATION ON COAL-FIRED ELECTRIC POWER GENERATION IN ALBERTA

BY

L.M. JOHNSTON

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS OF THE DEGREE

OF MASTER OF BUSINESS ADMINISTRATION

FACULTY OF BUSINESS

EDMONTON, ALBERTA

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research for acceptance, a thesis entitled AN INVESTIGATION OF THE ECONOMIC IMPACT OF ENVIRONMENTAL LEGISLATION ON COAL-FIRED ELECTRIC POWER GENERATION IN ALBERTA submitted by L. M. JOHNSTON in partial fulfillment of the requirements for the degree of MASTER OF BUSINESS ADMINISTRATION.

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ABSTRACT

The economic impact of environmental legislation on coal-fired electric power generation in Alberta was investigated by considering a generic 750 MW plant and coal mine model. Only the impact of legislation passed since 1971 was considered because this was the year in which a separate Ministry of the Environment was created in Alberta.

Environmental costs were defined as electric utility private costs incurred primarily for environmental reasons. The types of costs which were considered environmental in nature were specifically defined.

The environmental approval process and operations compliance monitoring process put in place by government since 1971 was investigated in order to establish the basis for the additional regulatory process costs. The impact of the legislation on power plant and mine technology and operations was researched by evaluating the historical experience of existing coal-fired power projects in Alberta.

Generic environmental capital and operating costs were determined based on actual project costs, published studies and the estimates of experts. These costs were applied to a generic project schedule based on the history of recent projects. A simplified generation planning model was used to determine the incremental environmental revenue requirements of the electric utility for a typical case and several special cases. The major factors contributing to the increase in revenue requirements were identified and discussed.

It was found that the increase in revenue requirements is substantial, amounting to typically between $76 million and $94 million or about 4.2 to 5.2% of project revenue requirements on a total present worth basis. This cost is very site-specific and was shown to be more than twice as high in special circumstances. The largest environmental cost is typically for coal mine land reclamation but this is highly dependent on site soil conditions and soil handling technologies. The increased stringency of smoke stack particulate emission standards has also resulted in a major increase in environmental costs.

ACKNOWLEDGEMENTS

The completion of this thesis would not have been possible without the considerable assistance of those in the electric utilities and government who are mentioned in the bibliography. I am especially grateful to Mike and Bill who spent considerable time obtaining data on my behalf, to Dave for his review of the draft from a utility management perspective, to Roger for advising on the research topic and to Jeannie for her many hours of typing.

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1. INTRODUCTION

During the 1970's, the federal and provincial governments of Canada responded to growing public concern about ecological problems by enacting comprehensive environmental protection legislation. This initiative was consistent with government response elsewhere in the western world to a new awareness of mankind's increasing impact on our fragile ecosystem. This was an era of intense government growth as large departments were created to administer a wide range of new social legislation. Prominent amongst these were the Ministries of Environment created by the Canadian federal government and most provinces.

A major feature of the new environmental legislation was the regulation of industrial plant emissions, wastes, water resources and land reclamation by mining companies. In Alberta, comprehensive new legislation dealing with these issues was implemented just in time for the energy boom of the mid 1970s to early 1980s. It was a time of dramatic economic growth which was accompanied by a strong demand for electric power. In Alberta, this electric power demand is most economically satisfied by coal-fired power plants located on dedicated coal strip mines. Over 90% of Alberta's electricity is currently supplied from coal-fired power plants and this is expected to remain the case for many years. The construction and operation of these plants are consequently subject to the full force of Alberta environmental legislation.

The most important of the new legislation is The Clean Air Act, The Clean Water Act, The Water Resources Act, and The Land Surface Conservation and Reclamation Act. Other legislation may also be important where special circumstances exist, such as The Historical Resources Act, in an area with valuable archaeological resources. The Energy Resources Conservation Board plays a major role in coordinating an integrated project approval process under the authority of The Coal Conservation Act and The Hydro and Electric Energy Act.

Seventeen years have passed since the creation of Alberta Environment and the beginning of the new comprehensive environmental regulatory process in 1971. By the late 1970's the approval process which is used today was virtually all in place. Such changes as have occurred since are relatively minor. The Alberta regulatory process for energy projects has become widely recognized across Canada as effective in integrating economic, technical and environmental factors while remaining comparatively streamlined.

This thesis is an examination of the impact of this new environmental regulatory system on recent coal-fired electric power generation projects. The objectives may be summarized as follows:

1) Examine how the environmental regulatory process has changed since the creation of Alberta Environment in 1971.
2) Examine the impact on technology and operations.

3) Discuss the complexities of determining the resultant increase in environmental costs.

4) Estimate the increased environmental costs to electric utilities and the impact on revenue requirements.

5) Discuss the major variables which influence the environmental costs.

This thesis does not question the need for current environmental standards but rather focuses on the economic impact on electric power consumers in Alberta.

2. AN OVERVIEW OF ELECTRIC POWER GENERATION IN ALBERTA

2.1 The Outlook for Coal-fired Electricity Generation

Most of the electricity generated in Alberta is based on coal combustion in large plants located at dedicated strip mines. Since 1970, 90% of the power plant capacity approved for construction by the Alberta Energy Resources Conservation Board was coal-fired.[50] Canadian Electrical Association statistics[35] indicate that in 1986, 77.4% of all the power generating capacity in Alberta was coal-fire.. The coal-fired plants were responsible for generating nearly all of the base load, contributing 91.6% of the electricity in 1986 while hydro and gas/oil-fired power contributed only 5.2 % and 3.2% respectively. This is an increase from 61% in 1976 mainly due to the displacement of gas-fired generation.[50] Although a small transmission line connected the Alberta grid with British Columbia through the Crowsnest Pass, electricity imports and exports were negligible until 1986 when a new 500 kV tie line was commissioned.

Forecasts by the Electric Utility Planning Council in 1985[46] confirm that coal is expected to continue as the major source of Alberta electric power in the forseeable future, even with possible increased imports through the new 500 kV tie line with British Columbia.

Depending on the future scenarios for peaking power gas turbines, coal is expected to contribute between 87.8% and 94.0% of Alberta's power in 2009. Even if the recently-shelved Slave River hydro project were to become a reality, coal is still expected to contribute 76.6% of Alberta's electrical power by 2009.

2.2 The Alberta Electric Power Generating Utilities

Alberta has four electric power generating utilities. Their relative size in terms of generating capacity in operation or under construction is summarized in Table 2.1

Table 2.1

Generating Capacity Installed and Under Construction in 1986[48]

	MegaWatts
TransAlta Utilities Corporation	4727
Alberta Power Limited	1478
Edmonton Power	1850
City of Medicine Hat	164

Note: All capacities specified in this section are Net Peak Continuous Ratings.

Both TransAlta Utilities Corporation and Alberta Power Limited are investor owned while Edmonton Power and the City of Medicine Hat are municipally owned. The Alberta electric power generating utility composition is consequently different from most other Canadian provinces which are dominated by single provincial government utilities. In fact the Alberta situation is more similar to the U.S. utility scene where large investor owned power generating utilities often coexist with substantial municipally owned power utilities (e.g. City of Los Angeles and Southern California Edison).

Both Edmonton Power and the City of Medicine Hat currently operate only gas-fired power plants. The large increase in the price of natural gas in relation to coal during the energy boom of the 1970's and early 1980's resulted in most gas-fired electricity generation in Alberta being displaced by coal. Edmonton Power's two gas-fired plants were relegated to standby and peaking status since the Alberta Interconnected System agreement requires economic dispatch of power units based on variable costs. Edmonton Power will continue to purchase cheaper coal-fired power from the investor owned utilities pending the commissioning of its coal-fired Genesee plant. The City of Medicine Hat was not similarily affected because it owns local gas wells which produce low cost tax-exempt gas.

All electric power generating utilities in Alberta except the City of Medicine Hat are members of the Electric Energy Marketing Agency of Alberta. The member utilities sell their generated power to the Agency and then buy back the power needed to meet the demand of their service areas. Essentially the Agency equalizes the provincial power costs by subsidizing the more remote northern areas at the expense of the populous central and southern regions. The "upstream" power rates at which power is sold to the Agency is regulated by the Public Utilities Board who also regulate customer rates in the TransAlta Utilities and Alberta Power service areas. The municipality electricity rates are regulated by city councils.

It should be noted that until the late 1970s, TransAlta Utilities Corporation was called Calgary Power Limited. Both names will be used in this thesis.

2.3 Coal-fired Generating Stations in Alberta

There are currently seven separate coal-fired power stations operating or under construction in Alberta. These are listed in Table 2.2 below.

All but one of the plants listed in Table 2.2 are fueled by sub bituminous plains coal from dedicated strip mines. The Milner Generating Station uses a high ash low grade coal fraction from the Smoky River Coal mine which exports primarily bituminous coking quality coal.

The newest plants are remarkably similar in overall technology and operation. This is especially true of the three most recent, the Keephills, Sheerness and Genesee plants. Only these plants were subject to the full post 1971 environmental approval process and they form the basis of the generic plant model described in greater detail in Section 6.1. It should be noted that the Keephills power plant was originally called the South Sundance power plant.

Table 2.2

Alberta Coal-fired Generating Stations Operating or Under Construction[48]

Plant Name	Location	Capacity (MW)	Owner/Operator	Mine Name	Owner/Operator
Wabamun	Wabamun	595	TransAlta	Whitewood	TransAlta - Fording Coal mine under contract
Sundance	near Wabamun	2156	TransAlta	Highvale	TransAlta - Manalta Coal mine under contract
Keephills	S.E. Lake Wabamun	798	TransAlta	Highvale	TransAlta - Manalta Coal mine under contract
Battle River	near Forestburg	807	Alberta Power	Vesta Paintearth	Manalta Coal Forestburg Collieries
Milner	near Grande Cache	158	Alberta Power	Smoky River	Smoky River Coal
Sheerness	near Hanna	766*	Alberta Power - TransAlta (jt. venture) operated by Alberta Power	Montgomery Sheerness	Manalta Coal Forestburg Collieries
Genesee	near Thorsby	812**	Edmonton Power	Genesee	Edmonton Power-Fording Coal (joint venture). Fording operate mine.

* Unit 2 under construction
** Plant under construction

3. METHODOLOGY

3.1 Approach

The current environmental regulatory system was examined and compared with what existed before the creation of Alberta Environment. In such a study it is important that not only the legislation, regulations, etc. be referenced but that the actual mode of implementation be interpreted. This was achieved by referring to government guidelines and by interviewing knowledgeable experts on the subject both in government and in the utilities. The author was in a particularly advantageous position to do this as a former employee of Alberta Environment who currently coordinates environmental affairs for an electric utility. The author drew on an intimate knowledge of the workings of the environmental approval process to aid in the interpretation of both current and historical information.

The impact of the regulatory approval process was assessed by examining the important changes to technology and operations at coal-fired power plants since 1971 which could be due to environmental legislation. All requirements in place before this date are considered part of the baseline situation. The reasons were critically assessed to establish whether environmental legislation was the primary factor for the change.

It should be emphasized that this study is of a regulatory system which includes several Acts. Where possible, specific impacts will be attributed to separate Acts but the distinction is not always clearcut. The earlier stages of the approval process fall under the authority of the Energy Resources Conservation Board and issues are assessed by government in an integrated manner.

The next phase of the research was to examine the environmental costs. Even with the benefit of extensive experience in managing environmental affairs, the author was surprised at the problems involved in establishing reasonable estimates. The reasons for this and the nature of the complexities are discussed in Section 3.2. The environmental costs include both the power plant and associated coal mine. Only internalized private utility costs were included.

The impact of the estimated costs on electricity rates was implied by the calculation of the percentage increase in revenue requirements using a modified generation costing model of the type used widely by the utilities for planning purposes. Given the accuracy of the estimates used, such a model is adequate for these calculations.

This evaluation enabled the main variables which influence the environmental costs to be identified. The different circumstances which influence these variables could consequently be discussed based on history or possible future scenarios. It was recognized at an early stage that certain facilities at power plants are environmentally mandated only under site-specific circumstances. These situations were evaluated as special cases to provide a range of possible environmental costs dependent on these circumstances.

3.2 Environmental Costs

One of the main problems in the investigation of regulatory costs of this nature was found to be the lack of definitive data. Firstly there are only three coal-fired power projects which truly reflect the full impact of the regulatory system on a new project. These projects are as follows:

a) Keephills power plant - 798 MW (TransAlta Utilities Corp)

b) Sheerness power plant - 766 MW (TransAlta Utilities Corp and Alberta Power Ltd. - joint venture)

c) Genesee power plant - [illegible]12 MW (Edmonton Power)

All three of these projects are at new sites and may be considered "greenfields" projects. The Keephills plant is however not quite as "greenfields" as the others because it is served by a major mine extension rather than a new mine. The costs incurred when retrofitting improved technology to older plants was not examined. These costs were probably substantial.

It was not possible to obtain complete data from all three projects. This was largely due to the data not being readily accessible since the environmental costs are not accounted for separately in these projects. A great deal of effort is required to extract the costs, often through individual work orders and invoices based on an intimate knowledge of the environmental program. In the case of the most recent projects at Genesee and Sheerness, this difficulty was partly mitigated by the existence of private records kept by environmental personnel. As a result, for approval process costs, good data from only two plant projects and one mine was available. The data base is consequently limited.

Although complete data from one project was available, it was not possible to use it in a specific manner for reasons of confidentiality, except in certain instances. To resolve this problem it was decided to base the evaluation on a generic project model typical of the recent projects.

The use of a generic project model is not an unusual approach in electric utility planning when evaluating the costs of various generation scenarios. The Electric Utility Planning Council often uses generic plant costs based on a 1981 study for such evaluations (40,47). This generic plant data forms the basis for the project model used in this thesis. It should be noted that the use of a generic model has the advantage of allowing informed judgement to be used on whether data is likely to be typical. Each of the three projects previously mentioned include certain characteristics which are non-typical. These include the use of a mine extension rather than a new mine at Keephills, the unit deferrals at S[illegible]s and the high archaeological costs and unit deferrals at Genesee.

Due to the paucity of specific data, it was sometimes necessary to use informed estimating and costs from published studies in order to obtain generic costs. Where possible specific project costs were used as a basis. In some cases the best available expert opinion from those who were intimately involved in the projects of interest was used. Since the data is for a generic project model, it should not matter that the costs are not precise, since precision has no meaning when using such a model. What is important is that the costs represent credible estimates given the assumptions.

A further very real complication when dealing with environmental costs is that these costs may become embedded and cannot be meaningfully separated. This occurs, for example, when the reasons for the improvement of a plant technology include not only environmental constraints but other factors such as efficiency and cost. The improved environmental performance may be simply a necessary by-product of the innovation. An example of an embedded cost is the development of boilers with lower nitrogen oxide emissions. This situation will be discussed in Section 5.1.

All costs estimated in this thesis are incremental since they are due to the new regulatory process introduced after 1970. This is a logical base date because Alberta Environment was created in 1971. It is important to note that there was not total compliance with the pre-1971 requirements (38). In 1988, however, there is essentially total compliance with current requirements. For the purposes of this thesis, the base 1970 costs will assume complete compliance because undoubtedly compliance would have been achieved later if no further regulatory changes had occurred. The incremental costs will, as a result, understate the total investment in environmental protection by the electric utility industry in the 1970's and 1980's.

It is important that the term environmental cost as used in this thesis be adequately defined. Firstly, the costs included are all electric utility private costs or internalized costs. Externalities are not included. A major external cost is the cost of the government regulatory process which is paid for by provincial revenues.

Secondly, environmental costs will not include occupational health and safety costs. These are for the protection and welfare of the electric utilities' own employees. Environmental programs are instead for the protection of those outside the utilities, and the common ecological property on which we all rely.

Thirdly, public relations costs will not be included. It is often difficult to completely separate out all these costs because the regulatory approvals process requires a public participation program which is different from the independent public relations initiatives of the utility. It will be generally assumed that required public participation costs are not true public relations costs but rather environmental costs.

Fourthly, the taxes and settlements paid to local authorities such as counties or displaced individuals are not included. These payments are intended to pay for the infrastructure impacts resulting from the project, the necessary local improvements and to compensate the affected local community.

Finally, environmental costs will include all pollution control costs, regulatory approval and operating compliance costs resulting not only from the environmental protection legislation administered by Alberta Environment, but also by the Energy Resources Conservation Board, and historical resources protection and mitigation costs administered by Alberta Culture. Included in this will be socio-economic impact study costs because these form part of the environmental impact assessment document. They will not include the costs of facilities which are designed to comply with environmental requirements but are not installed primarily for environmental reasons. Mine reclamation costs will be specifically included. Costs of compliance with very recent environmental requirements such as The Hazardous Waste Regulation AR 505/87 or plant decommissioning guidelines are not included because of insufficient experience with these requirements.

4. THE ENVIRONMENTAL REGULATORY SYSTEM

4.1 The Regulatory Approval Process (60)

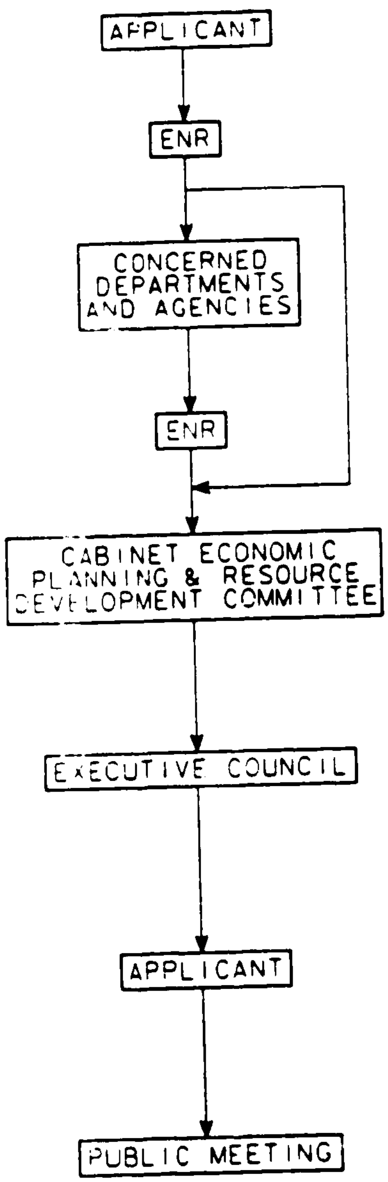
a) Preliminary Disclosure

In recognition of the long lead-time between the birth of a plan to develop a major project and first commercial operation, largely due to the extensive regulatory process, the Alberta government put in place a prescreening procedure for all projects involving coal mining in 1976. This allows the government to indicate at the outset, if it has objections to the plan, it's timing, or any of it's essential features. The procedure is shown on Figure 4.1. As shown, the review is co-ordinated by Alberta Energy and Natural Resources (ENR).

The preliminary disclosure in no way supplants the need for the disclosure to the public or the subsequent formal applications under the controlling legislation. Its purpose is to discover whether, if all departmental and agency requirements were met, the government would give consideration to the project in the general form and at the time proposed.

The preliminary disclosure document is required to include information in brief summary form covering features of the

FIG.4.1 PRELIMINARY DISCLOSURE PROCEDURE



- SUBMITS PRELIMINARY DISCLOSURE OF PROJECT, INDICATING SCOPE, TIMING, OVERVIEW OF ENVIRONMENTAL IMPACT, BENEFIT TO ALBERTA, ETC., TO ENR.
- DISTRIBUTES DISCLOSURES; REQUESTS COMMENTS FROM DEPUTY MINISTERS OF CONCERNED DEPARTMENTS AND AGENCIES ON BROAD FEATURES OF THE PROPOSAL, SUBJECT TO LATER CONSIDERATION IN DETAIL.
- REVIEW PROPOSAL; SUBMIT COMMENTS TO ENR.
- PREPARES AND SUBMITS SUMMARY OF COMMENTS AND RECOMMENDATIONS TO CABINET ECONOMIC PLANNING AND RESOURCE DEVELOPMENT COMMITTEE.
- REVIEWS COMMENTS AND RECOMMENDATIONS; ADVISES EXECUTIVE COUNCIL WHETHER APPROPRIATE FOR APPLICANT (a) NOT TO PROCEED AT ALL, (b) TO DEFER, OR (c) TO PROCEED WITH NECESSARY APPLICATIONS.
- MAKES DECISION; INFORMS APPLICANT AND, IF (a) OR (b), INFORMS PUBLIC.
- MAKES APPROPRIATE BUSINESS DECISION WHETHER AND IF SO WHEN TO PROCEED WITH FORMAL APPLICATION.
- APPLICANT HOLDS A PUBLIC MEETING AT LEAST 45 DAYS BEFORE THE FORMAL ERCB PUBLIC HEARING ON THE DETAILED APPLICATION FOR PROJECT APPROVAL.

proposed project. This includes technical and economic justification, as well as environmental impact information. The environmentai information covers both biophysical and social aspects and consists basically of the following:

- a description of the physical environment in the vicinity of the proposed project (fish and wildlife, soils, vegetation, hydrolo y and landscape characteristics).
- a general statement identifying all significant envir mental impacts associated with the development and operation of the proposed pr
- a summary of environmenta ion and reclamation plans.
- a statement of the significant impacts of the development on the community structure of the region (eg. creation of demand for services and cultural impacts).
- an overview of the costs of the development to the province, weighed against anticipated benefits.

Following government endorsement, the proponent is required to convene a meeting of the general public and provide fairly detailed information about the project. The public meeting must be held at least 45 days before the formal Energy Resources Conservation Board (ERCB) hearing which forms part of the project approval stage and is usually supported by the application documents filed for project approval. No government decisions result from the public disclosure meeting and the main purpose of the meeting is to enable interested parties to be in a position to submit their views to government or intervene at the ERCB hearing.

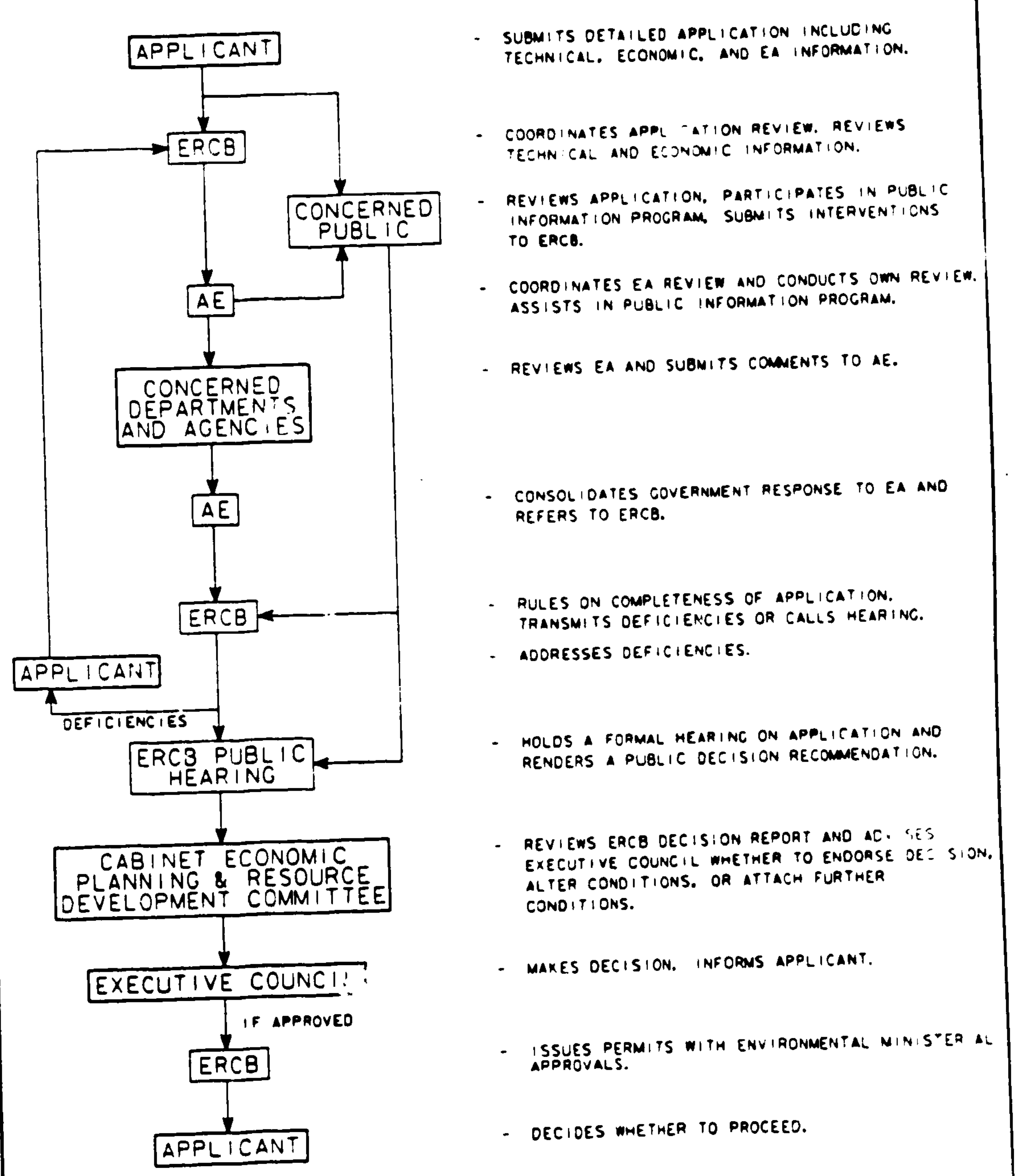
It is normal practice for proponents to initiate their public participation programs before the public disclosure meeting so that it merely becomes part of the ongoing program.

b) Project Approval Stage

This is the major overall approval stage which dictates whether the project may go ahead, and if so, subject to what timing and other general constraints. As stated, environmental considerations submitted in the detailed environmental assessment document form only a part, albeit usually a major part, of the factors weighed in the decision.

The project approval process is outlined in Figure 4.2. The Energy Resources Conservation Board (ERCB) controls the decision-making in this stage and co-ordinates the overall review. The whole process is conducted under the authority of ERCB legislation, The Hydro and Electric Energy Act and The Coal Conservation Act, which requires the ERCB to refer applications to the Minister of Environment and to include any conditions required by the Minister on the ERCB approval, if issued. Alberta Environment is delegated the role of co-

FIG.4.2 PROJECT APPROVAL PROCEDURE



ordinating the environmental assessment review. The ERCB, however, has final say on the completeness of the application.

The ERCB hearing is a formal event held before three sitting Board members. Concerned public and industry are required to submit written interventions well before the hearing. These are circulated to the applicant, concerned government agencies and other intervenors. (Some flexibility is usually accorded the affected community). During the hearing itself,participants are normally supported by lawyers who assist in cross examination and represent clients rights. The proceedings normally follow a pattern of cross examination of the applicant's representatives by the ERCB staff lawyer, Alberta Environment's lawyer and those representing the intervenors. All intervenors are then also subject to cross examination by the applicant's lawyer and other intervenors. The hearing concludes with closing arguments. It is normal for the applicant to be represented by several panels, one of which will deal with environmental and social considerations.

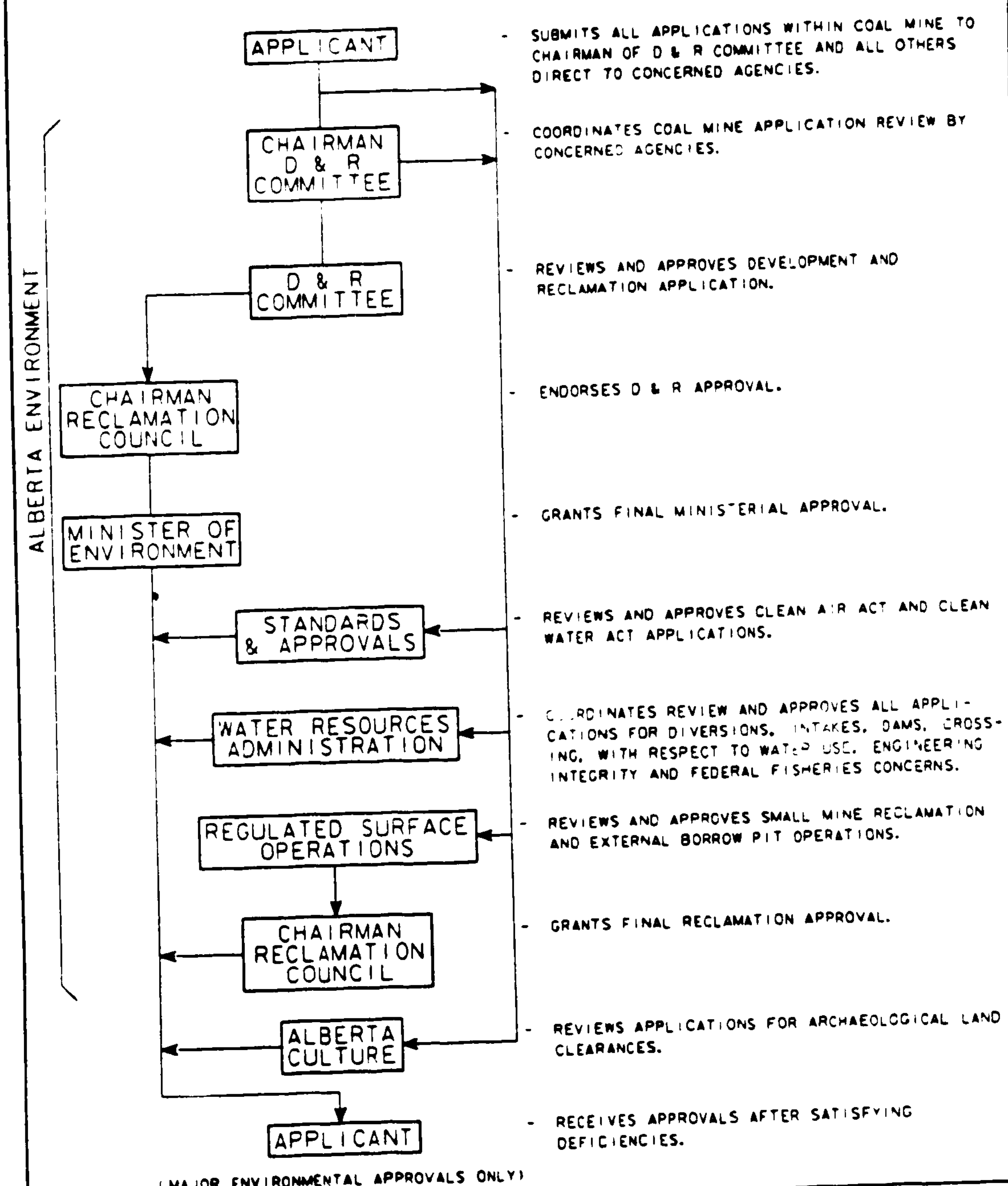
The hearing is usually less than one week long, and environmental and social issues may be major issues. At the Sheerness and Genesee Power Project hearings, approximately 32% and 39% of the time was spend on these issues.[29,79] The government's review of the application and Board decision making is time consuming and usually takes about six months. An ERCB decision for project approval is essentially only a recommendation to cabinet, but is normally endorsed with negligible modification.

c) Detailed Approvals Stage

Following project approval, the applicant is required to obtain the different environmental approvals relevant to the various phases of construction activity and operation. These are numerous and a simplified representation by agency and activity is shown in Figure 4.3.

The largest application by far is usually the Development and Reclamation (D & R) Application. This is essentially an environmental impact assessment type document with a greater level of detail which focuses on the coal mine and emphasizes land use planning and reclamation. The review of this application is co-ordinated by the Chairman of the Development and Reclamation Review Committee. Major applications which include power project mines, are referred to this Committee, which is inter-agency and inter-disciplinary in composition and appointed by cabinet. Since the review of the D & R application is usually initiated before many of the other detailed applications, it can ideally serve as a means of disclosing more detailed features of the project before the actual detailed design work is undertaken, thus ensuring general acceptance by the concerned review agencies.

FIG.4.3 DETAILED APPROVALS STAGE



Normally only coal mine D & R applications over a certain size, or which are considered sensitive, are referred to the D & R committee. These D & R approvals require the endorsement of the Chairman of the Land Conservation and Reclamation Council.

Major approvals require the final approval of the Minister of the Environment and these approvals are normally attached to the ERCB mining license issued pursuant to The Coal Conservation Act as the Ministerial Approval. The ERCB mining license application review normally coincides with the D & R review process. The D & R application consequently must deal with detailed short term plans, as well as a life-of-mine perspective. The D & R approval attached to the mine license may be viewed as analogous to the Ministerial (Environmental) Approval attached to the mine permit which was previously issued as a result of cabinet approval of the project.

All applications not related to the mine are submitted directly to the approving agency concerned, while all those related to the mine are co-ordinated by the Chairman of the D & R Committee and forwarded to the concerned agency. The process shown in Figure 4.3 is highly simplified and certain of the agencies shown require numerous approvals.

4.2 The Environmental Monitoring Process

Environmental monitoring is a requirement of all major and licences issued by Alberta Environment to regulate the operation of a coal-fired power plant. The form of the monitoring process is dependent on the statute. The Clean Air Act and Clean Water Act licences rely heavily on compliance monitoring provisions where emission levels are routinely checked against imposed numerical standards.[11,18] The Water Resources Act similarly requires the routine monitoring of water diversions and returns and may also require the monitoring of the integrity of major dyke works.[12] The Land Conservation and Reclamation Act requires an annual reporting of land disturbance and reclamation activities.[13]

Alberta Environment relies heavily on self monitoring and reporting by industry supplemented by field checks using their own inspectors. Where there is non compliance with standards, Alberta Environment have historically relied on a variety of enforcement measures provided in the legislation.[14] Up until now, most cases of non compliance have been dealt with by consultation with little recourse to offical Control Orders or prosecution unless there was lack of cooperation. Alberta Environment policy on enforcement now, however, appears to be about to become much tougher following a report by a Review Panel on this subject.[74]

The environmental compliance monitoring requirements of Clean Air Act licences are the most sophisticated and costly. Both the emissions from the main plant stacks and the ambient air must be continuously monitored and reported monthly. This requires the installation and operation of sensitive automated analyzers and meters which relay data to computers for evaluation and report preparation. These systems are trouble-prone and require a major maintenance commitment.[2] Routine calibration and quality assurance programs are maintained supplemented by regular stack sampling surveys. Reports tend to be voluminous.

Monitoring requirements in Clean Water Act licences are much simpler and usually require no on-line analysis. Monthly reports are normally fairly brief. Likewise Water Resources Act reports are fairly simple to generate and are brief, unless special consultant studies are required to address certain problems.

Land Surface Conservation and Reclamation Reports are required annually. These are usually fairly lengthy and descriptive[13]. The land disturbance and reclamation activities must be reported in the context of the mine development and future plans discussed. It is not uncommon for the results of ongoing reclamation research programs also to be discussed.

A highly summarized list of the compliance monitoring and reporting requirements for a typical 750 MW coal-fired power plant is given in Table 4.4.

It should be noted that environmental monitoring does not end with compliance monitoring. Alberta Environment may require special

TABLE 4.4

Environmental Monitoring and Reporting Requirements

for a Typical 750 MW Coal-fired Power Plant and Mine

Legislation	Approval	Main Reporting Requirements	
Clean Air Act	Licence (Plant)	Monthly:	Continuous stack emission monitoring results. Continuous ambient air monitoring results. All instrument calibrations. General plant operating data.
		Semi-Annual:	Manual Stack Survey results.
		Annual:	Summary for year.
Clean Water Act	Licence (Plant)	Monthly:	Effluent monitoring results. General plant operating data.
Water Resources Act	Licence (Plant)	Annual:	Report on quantities of water diverted, consumed and released. Diversion rates.
	(Mine)	Annual:	Groundwater and well monitoring.
Land Surface Conservation & Reclamation Act	Development and Reclamation Approval (Mine)	Annual:	Detailed report on land disturbance and reclamation activities in the context of the mine operations. Plans for coming year. Reclamation research test plot results where applicable.
Clean Water Act	Licence (Mine Settling Ponds)		Reporting of any mine drainage analysis depending on the situation.

studies to be carried out to verify environmental assessment predictions. Examples of this include the monitoring of leachates from dry ash disposal sites or local waterwell surveys to assess the impact of mining on drawdown levels and water quality.

A new form of monitoring is becoming widespread partly in response to government pressure but also to demonstrate the environmental integrity of the plant to either the public or an insurer. This is known as environmental auditing. It normally involves an in-depth evaluation of the operation by expert consultants. This usually focuses on only one aspect at a time, for example, waste management or air quality. It differs from other forms of monitoring in that it examines all aspects of the organization of the environmental effort, including staffing, procedures, operator training, emergency response, etc. It is expected that the audit will soon become a normal part of environmental monitoring since it is increasingly favoured by government.[55]

4.3 Standards Setting

When examining how the present regulatory system evolved, it is important to understand what drives the numerical standards setting process. It will be seen that while environmental needs are a basis, the impetus is also political.

ı.. ypes of numerical pollution control standards which are used to regulate all industry - ambient standards and source emission standards. These standards are usually imposed by government after consultation with industry. Government policy is now moving towards greater public consultation when settin standards.(74)

Ambient standards reflect maximum levels of contaminants permissible in either the ambient air or water. In Alberta, regulations have been made for certain ambient air standards only. The Clean Air (Maximum Levels) Regulation 218/75 specifies standards for ambient levels of sulphur dioxide, nitrogen dioxide, ozone, carbon monoxide, suspended particulates, total dustfall, and hydrogen sulphide. Ambient water standards do not appear in Regulations but as objectives. Most of these are to be found in the Alberta Surface Water Quality Criteria (Jan.1977). These standards are, in effect, general objectives for any surface water in Alberta. Other more specific objectives exist for specific end uses such as the Canadian Drinking Water Quality Standards (1978).

All ambient standards or objectives are based on the results of studies which indicate that deleterious health or environmental impacts are possible above certain concentrations of the contaminants. The standards or objectives do not always represent these concentrations but often include a factor of safety. With the recent concerns for toxic contaminants linked to chronic health impacts, the setting of ambient standards has become much more difficult. It is usually impossible to define thresholds below which these contaminants will have zero impact. The probability of impact instead reduces with concentration and it is not possible to define a 100% safe level. The decision on a "safe" level is consequently based on risk assessment and political judgement. This is further complicated by the fact that the data on which the decision is based is often tenuous and an extrapolation of laboratory animal tests. Fortunately, toxic chemicals of this type are not a significant issue at modern coal-fired power plants.(36)

The problem with ambient standards is that they are almost impossible to enforce. There are frequently several emission sources in an area and despite the best continuous monitoring, it is not normally possible to take legal action against a particular source. This fact was recognized in a recent report to the Minister of Environment on environmental law enforcement.(74) The review panel's report recommends that the Clean Air (Maximum Levels) Regulations be amended to repeal the ambient air standards, which should become objectives.

Ambient standards do, however, play an important role in determining the acceptability of plant source emissions. The stack heights of plants are determined by ensuring ground level concentrations of the important flue gas contaminants do not exceed the ambient standards under worst case plant operating conditions and adverse meteorological conditions. Alberta Environment specifies standard plume dispersion models for this determination.[5] In the case of an urban industrial area, the ambient standards can become an important constraint on the amount of emissions permitted from a proposed plant and could even prevent a new plant from being built in the area.

Likewise, the existing water quality in a watershed could become a constraint on the wastewater emissions or siting of a plant. Normally these constraints will become apparent to the proponent of a plant when conducting the necessary environmental assessment studies required by government for all major projects.

It is unusual, however, for ambient standards or objectives to be the determining factor for setting plant source emission standards in Alberta. Ambient ground level concentrations of air contaminants will normally determine minimum stack heights, but airshed or watershed quality in Alberta is usually good and not a restriction. Emission standards are instead set based on a plant installing best practicable, available, or even achievable emission control technology. The meaning of this is not precise but the U.S. Environmental Protection Agency consider best practicable technology to be technology commercially proven on other plants in the same industry sector. If the process is novel, the standards may be based on a technology proven in another industry sector, possibly in another country. This is considered best available technology.[58]

The use of the performance of a technology on which to base emission standards (provided that ambient objectives are not exceeded), is widely practised elsewhere. Both Environment Canada and the U.S. Environmental Protection Agency have long used this basis, as have Ontario and other provinces. It appears that there are four major notions behind the policy. Firstly, it ensures industries are not permitted to use as much of an airshed or watershed as the ambient objectives will allow to absorb their emissions. This minimizes the environmental degradation. Secondly, justifiable provision is made for other industries which may wish to locate in the area. Thirdly, it provides a basis for the equitable treatment of different industries and for different regions. (Environment Canada use it as a means of setting cross-Canada regulations or guidelines to ensure that there are no "pollution havens".) Fourthly, since the technology performance is known and usually proven, industry are not in a good position to oppose the standard unless the cost penalty is prohibitive.

It is important to note that the best practicable technology criterion does not address cost-benefit. It does include a consideration of cost in the sense that the regulator may show moderation in the costs it expects industry to assume when the requirement appears clearly in excess of the environmental need. It is also usually extremely difficult if not impossible, to measure the incremental benefits to the environment accruing from the investment in emissions reductions.

Alberta Environment relies heavily on data from Environment Canada and other jurisdictions such as the U.S. EPA on which to base its interpretation of best practicable or available technology and for the appropriate emission standards. Environment Canada's standards may be in response to international agreements which are of increasing importance for the future of sulphur dioxide and nitrogen oxide regulations. The development of a "best practicable or available technology" is often in response to a situation of perceived need in another jurisdiction where ambient air or watershed contaminant concentrations are excessive. Once proven, this technology may be economically applied elsewhere even when there is not an immediate need. There appears to be a strong political motivation to ensure that emission standards are as stringent as those in other jurisdictions. This was confirmed in a "Role and Mission" document published by Alberta Environment in 1977.[6] With regard to Pollution Prevention and Control it stated, "We would not under any circumstances, sanction standards in Alberta less stringent than those set by EPA in the United States or those set nationally in Canada". This policy appears essentially unchanged.

In the case of coal-fired power plants, the tightening in standards, particularly with respect to stack emissions of particulates and nitrogen oxides, has followed the improvements in the emission control technologies developed but not always proven in other jurisdictions, especially the U.S. It would be simplistic to assume that all technologies are transportable without further development because of site specific differences. In the early 1970s, TransAlta Utilities Corporation and Alberta Power Limited both found the adoption of electrostatic precipitator technology for the removal of particulates from stack gases, involved serious complications. On two plants the results were unsatisfactory and have required costly modifications.[83]

5. IMPACT ON TECHNOLOGY AND OPERATIONS

5.1 The Clean Air Act

(a) Particulate Removal from Flue Gases[38,83]

Prior to the enactment of The Clean Air Act in 1971, power plant air emissions were regulated by The Public Health Act. In 1961 Public Health Act Regulation 252/61 was passed, and it included a limitation on particulates of 0.85 lb/1000 lbs of flue gas at 50% excess air, from combustion, processing or manufacturing. Five years were given for compliance. In 1966 this regulation was amended by Regulation 276/66 which allowed another two years for compliance. (The standard was later finalized in Regulation 375/70.)

At that time particulate removal technology at coal-fired power plants in Alberta was based on multiclone mechanical collectors. These collectors were not capable of more than 85% removal efficiency.[56] In order to comply with the Public Health Act Regulation Standard, an efficiency of about 95% is required based on recent plant data (Appendix I). The electric utilities were consequently unable to comply with the Regulation in 1968 for reasons of technology.

Technology to meet the Regulation standard was available in other parts of the world, namely electrostatic precipitators. This technology was still fairly new and its performance is very dependent on the properties of the coal fly ash. Alberta plains coals usually have high resistivities and low sulphur contents, characteristics which were well known to be very unfavourable to the operation of electrostatic precipitators. This knowledge greatly discouraged the electric utilities from making the costly investment in the technology in the 1960s since the use of electrostatic precipitators to collect high resistivity ash had not yet been proven in North America.

Several factors contributed to the commissioning of the first electrostatic precipitators at Calgary Power's new Sundance power plant at Wabamun in 1973. Electrostatic precipitator technology was developing quickly elsewhere with more efficient and less trouble-prone units becoming available. In addition, experience with the first Sundance Power Plant Unit near Wabamun showed that the fly ash properties were slightly more favourable than those at the Wabamun Plant. Government pressure also increased. Calgary Power Limited conducted intensive studies during this period to successfully pioneer the necessary technology for high resistivity fly ash precipitation which has since been widely adopted in both Alberta and other parts of North America.

The Clean Air Act was passed in 1971 and a new more stringent particulate standard of 0.2 lb/1000 lbs of flue gas at 50% excess air was immediately imposed. This standard was confirmed in the Clean Air (Maximum Levels) Regulation 10/73 passed in 1973. (This subsequently became Regulation 218/75.) The situation that consequently evolved resulted in plants moving from non compliance with the Public Health Act Regulation directly to compliance with the more stringent Clean Air (Maximum Levels) Regulations. New power plant units were all designed to safely meet the 0.2 lb/1000 lb standard and during the 1970's old units were retrofitted with electrostatic precipitators. This was successful in most cases as a result of Calgary Power's development work in this area. (Special problems were encountered at the Wabamun and Milner Generating Stations which required further innovation.)

Although no technology was specifically designed to meet the Public Health Act Regulation particulate standard, this will be used as a base case since the purpose of this thesis is to estimate the impact of the new legislation. Without the Clean Air Act Regulation requirements, it can be assumed that electrostatic precipitators would have been required to meet only the 0.85 lb/1000 lb standard.

During the 1970's, electrostatic precipitator technology continued to improve and successful experience was obtained at most Alberta plants. As a result, Alberta Environment continued to increase the stringency of the particulate standards through the permitting process. The Keephills and Sheerness plants were both required to meet a standard of 0.15 lb/1000 lb of dry flue gas at 50% excess air.[11,19] In the case of the most recent plant at Genesee, the permit required compliance with a standard of 0.09 lb/1000 lb of dry flue gas at 50% excess air.[9] It should be noted that these recent standards are based on dry flue gas whereas the Public Health Standard was based on wet flue gas, which is a slightly less stringent basis.

The Genesee plant standard was based on the Draft Guidelines published by Environment Canada in 1981 which included particulate emission standards of 43 ng/J (or 0.1 lb/million Btu).[57] Compliance with this standard at the Genesee plant requires a particulate removal efficiency of about 99.5% (Appendix 1).

The Genesee standard of 0.09 lb/1000 lb at 50% excess air will be used as the most recent Clean Air Act standard in this thesis. This standard is unlikely to become more stringent in the immediate future since Alberta Environment has now adopted the Environment Canada guideline standards in their own guidelines.[10] The Alberta guidelines for all new plants express the standard in terms of emissions per unit of energy input rather than as a weight fraction of flue gas discharge mass. The intent of this is to provide a more consistent basis across the industry.

It should be noted that despite the imposition of the more stringent particulate standards, the Clean Air (Maximum Levels) Regulation standard of 0.2 lb/1000 lb, has not been amended. It is now only applicable to older plants. It should also be noted that the differential costs estimated in this study for particulate removal greatly understate the expenditure actually made by utilities in the 1970's. The actual investment made was for the conversion from relatively inexpensive mechanical collectors to the large and very costly electrostatic precipitators needed to collect high resistivity fly ash. The costs also do not take into account the expensive retrofit of existing plants and the development of the technology to accommodate Alberta conditions.

b) Visible Emissions

In 1970 the visible emissions or "smoke" from power plant stacks was subject to the standards listed in clause 14-4 of Public Health Act Regulation 375/70. The Clean Air (Maximum Levels) Regulation continues to limit visible emissions but uses different test methods.

It is not possible to draw a meaningful comparison between the standards because these tests are largely subjective. The Public Health Act Regulation designates a measurement procedure based on a Ringelman Chart for judging the density or degree of blackness of the smoke. In 1977 new Visible Emissions Guidelines were published for use in regard to the Clean Air (Maximum Levels) Regulation.[15] In addition, all new coal-fired power plants are now required to be equipped with continuous opacity monitors which infer a visible emission level. Opacity standards are included in the Clean Air (Maximum Levels) Regulation.

There is no evidence that visible emission standards have ever imposed costs on Alberta electric utilities, beyond the cost of providing and operating the opacity monitors and performing the necessary tests. In Air Pollution Approvals issued to Calgary Power Limited in 1968 and 1969 for the Wabamun and Sundance Power plants, there was no direct reference to visible emissions controls.[69,70,71] It has so far been safe to assume that if particulate standards are met, the opacity standards from the Clean Air Act (Maximum Levels) Regulations, now imposed in licences, will generally be met. Further tests may, however, disprove this assumption.

No particulate control costs will consequently be allocated to the control of visible emissions. Only monitoring costs are applicable.

c) Sulph'r Dioxide Emissions

Sulphur dioxide is formed during coal combustion from the sulphur compounds normally present in the coal. All Alberta prairie coals currently mined to fuel electric power generation are low in sulphur content, containing between 0.2 and 0.7%. This is expected to remain the case for decades to come.[73] Sulphur dioxide emissions from coal-fired power plants in Alberta are not consequently considered a significant problem.[1]

In 1970, there were no standards controlling stack emissions of sulphur dioxide from coal-fired power plants. Standards in Board of Health Approvals rather specified a maximum concentration of sulphur dioxide in the ambient air over averaging periods varying from one month to one hour. These standards were used as a basis for designing the heights of the power plant stacks used to disperse the emissions.

Ambient air sulphur dioxide standards (when used as ground level concentrations) are still used to determine the design height of power plant stacks. The current ambient sulphur dioxide standards specified in the Clean Air (Maximum Levels) Regulations are unchanged from the standards included in the 1970 Board of Health Approvals (except for the inclusion of a standard average over half an hour). The only difference between 1988 and 1970 is that the dispersion models used to determine stack heights are more sophisticated.[5] As in 1970, sulphur dioxide rather than nitrogen oxides or particulates remains the pollutant dictating stack heights.[38]

All other things being equal, a power plant approved in 1970 would not have a higher stack height than a similar plant built in 1988.[38] Obviously where coal quality and the surrounding terrain are different, or where the plant design dictates different stack diameters or flue gas exit temperatures, stack heights will vary.

All Clean Air Act licences for coal-fired power plants include limits on the maximum mass emission of sulphur dioxide from the stacks (measured in tonnes/hour). These standards are not set based on any particular environmental need but rather reflect the highest emissions expected. This is considered to be when the 99% highest sulphur content coal is burnt when operating at maximum capacity. This is based on a statistical analysis of coalfield sampling results. The maximum ground level concentrations will not likely be exceeded under these conditions because worst case factors were taken into account in the stack design in addition to assuming adverse meteorological conditions.

Existing mass emission standards are consequently not meaningful since they represent artificial maximums and the plant operators have no way of controlling the emissions with existing technology. This situation will change in the future. Any new power plant units beyond those previously approved in the early 1980s will be required to meet the more stringent sulphur dioxide emission standards in new Alberta guidelines.[10] Because these standards are for future plants, no costs will be allocated to sulphur dioxide emissions except monitoring costs.

d) Nitrogen Oxides

Nitrogen oxides are formed during coal combustion from two sources. Both the nitrogen compounds in the coal and some air nitrogen are partially converted to nitric oxide. The extent of the formation of nitric oxide is very dependent on the combustion conditions. After leaving the plant stack, most of the nitric oxide is usually presumed eventually converted to nitrogen dioxide. Nitrogen oxides are of concern because of their association with smog and ozone formation, vegetation damage and acid deposition.[63]

In 1970 there were no standards for nitrogen oxide emissions from Alberta Power plants. The Clean Air (Maximum Levels) Regulations include ambient standards for nitrogen dioxide but these are not normally determining factors when designing plant stacks. Current standards are reflected in the Clean Air Act Permit to construct the Genesee Power plant, Alberta's newest.(9) This standard of 350 ppm at 50% excess air is based on the Emission Guidelines for Fossil Fuel Fired Thermal Power Generating Plants in Alberta which will be imposed on all future plants.(10)

The technology for reducing nitrogen oxide emissions to this level is based on designing the boiler to minimize those conditions favourable to its formation. There has been a worldwide demand for nitrogen oxide emission reductions in the past fifteen years, especially in those areas with high population densities where smog is a serious problem. Boiler designers have responded to this demand by supplying boilers with increasingly reduced nitrogen oxide emissions. This technology has progressed to the point that the latest Alberta Environment standards can be met with the current standard boilers required to burn Alberta plains coals. In effect this means that irrespective of whether a nitrogen oxide standard was in effect in Alberta or not, the utilities would now purchase the same standard boiler. The old higher emission designs are no longer available as a standard order and would thus now probably cost more than a standard boiler.

No cost can consequently be directly attributed to the current Alberta nitrogen oxide standard as far as emission reduction technology is concerned. There is undoubtedly an embedded cost representing the research, development and design costs which went into the boiler modifications over the years. The Electric Power Research Institute estimates thet these costs are less then $5 U.S./kW in the U.S.[77] These costs were, however, in response to a worldwide market demand of which Alberta was only a small part. Alberta standards did not help to force the technology but really just reflected the best practicable technology already available as result of the demand of other jurisdictions. It consequently would not be reasonable to allocate any of these costs to the Alberta utilities even if the costs could be quantified.

e) Monitoring

In 1970, monitoring of stack emissions was limited to semi-annual analysis using manual "wet test" methods. Ambient air testing in the area of the plants consisted of measuring dustfall using a network of cylinders.[71] The capital cost commitment was negligible and only fairly small operating costs were incurred to hire specialists on contract to perform manual stack tests.

Current monitoring requirements are considerably more detailed. Sophisticated instruments are now required to continuously monitor stack emissions of sulphur dioxide, opacity levels, oxygen, and flue gas flows. All plants are required to have at least one continuous air monitoring and meteorological station for measuring ambient levels of sulphur dioxide, nitrogen oxides, and suspended particulates, and for monitoring wind speed and direction, and ambient temperature. These continuous monitors all interface with computer systems which not only control their operation but generate the detailed reports required by the regulatory authorities. The stack monitoring systems in particular have a history of being notoriously trouble-prone and, as discussed in Section 6, have a record of high maintenance costs.[2] Alberta Environment are imposing ever stricter quality assurance standards and efficiency guidelines for these monitoring systems.[8,20] Alberta Environment is also seriously considering proposals that substandard monitoring performance will in future be considered a prosecutable offense and that the data supplied by these systems be legally valid for prosecutions.[74]

In addition to these new monitoring systems, semi-annual manual stack tests are still required. The dustfall measurement networks are also required to be supplemented with a network of sulphation stations for inferring sulphate deposition. Additional suspended particulate sampling is also required. The increase in capital and operating and maintenance costs as a result of the new legislation is consequently significant.

5.2 The Clean Water Act

a) Ash Disposal

In a modern pulverized coal-fired power plant, between 70 and 80% of the non combustible portion of the coal, or ash, is in the form of flyash while the remainder is bottom ash. Nearly all of the flyash is collected in the electrostatic precipitators while the bottom ash is discharged from the boiler bottom where it is quenched in water and combined with the coal pulverizer rejects.

It was common practice until the mid 1970's to dispose of these ashes by slurrying with water and pumping to large ash lagoons. There the ash would settle out and the water would overflow to a river or lake. When the ash had filled the lagoon, the slurry would be diverted to a new lagoon and the original lagoon left as a permanent ash storage area. This was the practice at all Alberta power plants in the early 1970's except at Battle River where flyash and bottom ash disposal has always been dry.(37)

During the 1970's, Alberta Environment imposed increasingly stringent standards on the effluent quality from ash lagoons and power plants generally. These varied according to the plant location. For instance, at the Battle River and Milner

Generating Stations, the limits on suspended solids discharged from holding ponds were reduced from 100 mg/l to 50 mg/l.[67] At the Wabamun power plant, pressure from Alberta Environment helped prompt a partial conversion to dry disposal of ash.

Dry ash disposal consists of the collection of flyash dry in plant silos, and, after wetting to about 20-30% moisture [illegible] to suppress dusting, trucking the ash for disposal in the nearby mine. The bottom ash is still collected wet since it must be quenched, but is subsequently dewatered to about 30% moisture using settling tanks (hydrobins) or an incline (dragbar) conveyor. The bottom ash is then also trucked to the mine for disposal. As an alternative, the ash is sold if a viable market can be found.

As a condition of the approval to construct Unit 3 and 4 of the Sundance Power plant in 1972, the Energy Resources Conservation Board required that a cooling pond replace the once-through cooling system which used Lake Wabamun.[49] The area previously used for an ash lagoon was expanded and converted into the cooling pond. In order to sever all connection with the lake, the cooling pond makeup and blowdown pipelines were constructed to the North Saskatchewan River. Due to terrain limitations on the construction of a new ash lagoon, the higher pumping cost for ash slurry water, and the government's increasing stringency on ash lagoon effluent quality, Calgary

Power Limited converted to a dry haul system. As a result, the conversion to dry ash disposal at the Sundance power plant was primarily due to the environmental reasons which required the construction of the cooling pond at the site.

During the mid 1970's the Milner Generating Station at Grande Cache also converted to dry ash disposal. Ash disposal here was the responsibility of the mining company, McIntyre Mines. Scaling problems were being experienced with the slurry lines and lagoon capacity was becoming exhausted on the banks of the Smoky River. The mining company was also under increasing pressure to improve the effluent quality from the lagoons. Following negotiations with McIntyre Mines, Alberta Power converted the plant to dry flyash and bottom ash disposal. (37) The reason cannot be considered primarily environmental.

At the Battle River power plant, more stringent effluent quality requirements on the water discharged from the bottom ash slurry settling tanks (hydrobins) resulted in Alberta Power replacing this system on Unit 4 with a dragbar system, which has no effluent discharge. The new Unit 5 was also built with the dragbar system. It is believed that the lower operating and maintenance costs of the Unit 4 dragbar system have paid for the cost of the retrofit.[37]

Of the three most recent coal-fired power projects in Alberta, only the Keephills power plant uses ash lagoons. This ash lagoon operation includes one important difference compared with previous operations. It has a zero effluent discharge. All settled ash slurry water is recycled for reuse in ash slurrying. This innovation effectively addresses any effluent concerns.

The Keephills plant (previously known as the South Sundance plant) was orginally approved by the Energy Resources Conservation Board in 1977 with a dry haul ash system. Calgary Power Limited later applied for an amendment to the approval based on a study which indicated a recirculating ash lagoon system would be significantly less costly while still being environmentally acceptable.[30] The application was discussed at an ERCB public hearing and subsequently granted.[51] Since the start-up of the Keephills power plant in 1982, TransAlta Utilities Corp. have successfully operated the ash lagoons with zero effluent discharge.

The two most recent coal-fired power plants at Sheerness and Genesee are designed to use dry haul ash disposal. Despite the favourable experience at Keephills, the author has been unable to find any evidence that ash lagooning was seriously studied as an option at either plant.

Government requirements regarding ash disposal are flexible at this time. There are no written regulations or guidelines. Each project would be evaluated on a site specific basis with both environmental and economic considerations taken into account. Ash lagooning would be acceptable from the point of view of Alberta Environment provided that there is zero discharge of ash slurry water and there are no other environmental factors which could cause a significant problem.(64) The Energy Resources Conservation Board would likewise evaluate the proposed option on its technical and economic merits while being guided by Alberta Environment on environmental matters.(62) The choice of the ash disposal option is normally approved at the integrated ERCB hearing stage of the approval pr ess.

There appears to be a number of reasons why utilities may prefer dry haul ash disposal to lagooning.

a) Lagoons may be costly to build, particularly if the terrain is unfavourable.
b) Lagoons require considerable space, increasing land costs.
c) Dry systems allow for the ready recovery of ash as a saleable product, markets permitting.
d) Slurry pumping can cause costly scaling and abrasion problems in pipelines and associated equipment.
e) The slurry water chemistry may render total recycle impract and the proponent may be unsure of the possible t of this problem at the design stage. This could resu an effluent problem.

f) There may be uncertainty about the reclamation of the lagoons as required by government.

g) The size of the lagoons may appreciably increase the amount of land out of agricultural production at the project site at any time, even when including the strip mine.

h) There may be groundwater pollution concerns at the only viable lagoon sites.

Only the last four factors are environmental and consequently the primary reasons for the choice of a dry haul system may not be environmental. Even if there was a major environmental concern regarding lagooning, the dry haul option may nevertheless be the least expensive options at the site. The history of power plants in Alberta indicates that it was only at the Sundance plant that the conversion to dry ash disposal was definitely caused by mainly environmental factors. At the other plants the reasons for using dry ash disposal are not clear cut and probably represent a mix of reasons. Consequently, for the purposes of the generic plant used in this thesis, ash disposal costs will be included as a special case only.

b) <u>Recirculating Condenser Cooling</u>

It is not immediately clear whether recirculating cooling systems can be considered a true environmental cost at a typical Alberta coal-fired power plant. In at least one case it definitely is, in others probably not. This issue is resolved by reviewing the history of each power plant before drawing a final conclusion.

With one exception, all Alberta coal-fired utility power plants use recirculating condenser cooling water systems. In conventional once-through systems, water is drawn directly from a water body (e.g. a river or lake) pumped through the plant condensers and discharged back to the water body. All the reject heat from the power plant, representing more than 50% of the total heat input from coal combustion, is as a result, transferred to the water body.

Once-through cooling can have a significant impact on aquatic life. The thermal pollution may be sufficiently serious that the alteration of water temperatures either in the plume or further downstream could kill fish or inhibit spawning activities. Thermal impacts have also been implicated in the extensive growth of problem weeds in Lake Wabamun.(49) The large flows of water diverted through power plant condensers may also kill significant number of organisms carried through the system. For these reasons, Environment Canada Codes recommend power plants use recirculating cooling systems.(54)

Recirculating cooling operates by transferring the condenser reject heat from the cooling water to the air, thus permitting the water to be reused. Only comparatively minor flows of water need to be discharged (blowndown) to a nearby waterbody or river to prevent a buildup in dissolved mineral content from evaporation. The quantity of water that needs to be diverted or made up to a recirculating system is likewise small because only evaporative losses and blowdown need replacement.

The most common form of recirculating cooling system at Alberta power plants are cooling ponds. These are usually off-stream artificial lakes which draw makeup water from the nearest river (e.g. Keephills, Sundance, Sheerness and Genesee plants). The Battle River power plant uses a dammed reach of the Battle River as an "on-stream" cooling pond. The only coal-fired plant not using a cooling pond as a recirculating cooling system is the Milner plant at Grande Cache which uses cooling towers. Cooling towers also supplement the cooling pond at Sundance. The oldest coal-fired plant in Alberta, the Wabamun plant, still uses once-through cooling.

Although recirculating cooling is commonly required for environmental water quality reasons, this is not always the prime reason. Only one cooling pond appears to have been built in Alberta with environmental concerns as the main reason - the Sundance cooling pond beside Lake Wabamun. In 1972 the

Sundance plant operated a once-through cooling water system using Lake Wabamun. Public concern about the proliferation of objectionable weeds (especially Elodea) on the lake, attributed to thermal effects, culminated in the ERCB ordering Calgary Power to install recirculating cooling.(49) A cooling pond was commissioned there in 1975.

With the lower emphasis on environmental affairs in the late 1960's, it is hard to guess what might have been if that status quo had persisted. There is consequently some doubt whether the Keephills plant cooling pond is primarily required for environmental reasons or would have been constructed anyway because another lakeside site was not feasible. The excessive coal haul costs may have discouraged a site on the bank of the North Saskatchewan River. An additional complication of using the river is whether year round flows would have been sufficient to support the ultimate size of the plant, projected in 1977 to be at least six 375 MW units. With winter flows dipping to very low levels at times, despite the flow augmentation of TransAlta Utilities' own dams, it appears unlikely that once-through cooling would have been used. In any event, the Keephills plant may not have been built at all, but rather the proposed Camrose-Ryley plant which was rejected by the Alberta Government in 1976, ostensibly for environmental reasons. The Camrose-Ryley plant would have required a cooling pond, not for environmental reasons, but for off-stream storage due to the limited year round water resources in that area.(32) It could be argued that the increase in power costs resulting from this decision is, in fact, an environmental cost. This type of cost will not be included in this study.

The Battle River power plant definitely requires a cooling pond for water storage purposes due to the low flow of the Battle River. Environmental reasons have not been a factor until recently. Alberta government (Fish & Wildlife Division) concern about the effect of elevated water temperatures on Northern Pike in the river since the startup of Unit 5 is causing Alberta Power to augment the cooling in the on-stream cooling pond using cooling towers.(65)

The Sheerness power plant cooling pond was built because of the need for water storage. The nearest reliable water source is the Red Deer River, about 37 km away.(25) A natural lake, Coleman Lake, exists nearby, but is not suitable for cooling purposes due to its shallow depth and low average flushing rate.(65) The Sheerness cooling pond was consequently not primarily required for environmental reasons.

The Genesee power plant cooling pond is only 6.2 km away from the North Saskatchewan River. The dedicated strip mine is an average of 9 km away from the existing river pumphouse and, if a plant had been located for once-through cooling on the flood plain, coal haul distances would have been increased only about 6 or 7 km.[43] This may have been economically justifiable against a cooling pond capital cost of over $20 million. The key determinant however is the year round adequacy of the river flow. When construction of the Genesee plant started, a fairly rapid expansion to a 4 x 400 MW size was envisaged. As in the case of the Keephills plant it is highly unlikely that a plant of this size could be supported on the North Saskatchewan River at this location using once-through cooling. The Genesee cooling pond is, consequently, probably required for other than environmental reasons.

The Milner Generating Station is located on the upper reaches of the Smokey River. Even though this is a small plant (158 MW), the flow of condenser cooling water required is a significant portion of the river's flow, which cannot be relied upon during the low flow winter months. The makeup water flow to the cooling towers is a small fraction of the condenser cooling water flow and consequently, supportable. Here again environmental constraints were not the determining reason for installing recirculating cooling.[37]

In summary there is one plant in Alberta with a cooling pond installed primarily for environmental reasons (Sundance), two where environmental constraints are unlikely to have been the main reason (Keephills and Genesee), and three where the environment was definitely not the main reason (Sheerness, Battle River and Milner). Consequently the cooling pond cost will not be considered as a typical environmental cost in the generic plant. However, since cooling ponds represent a major cost and could be environmentally mandated in certain plants, this cost will be included as a special case.

c) Power Plant Drainage

Wastewater effluent standards are now more stringent than before 1970. No regulations define effluent standards but the experience of the utilities over the years with increasingly stringent effluent standards in licences and permits reflect this.(67,17,18)

Power plants with off-stream cooling ponds, such as the generic plant model, have the advantage of discharging their effluents to the cooling pond rather than directly to a natural river or lake. Although water is released from the cooling pond to the river to ensure evaporation does not over-concentrate the natural dissolved minerals, the cooling pond acts as a large equilization basis and protects against the adverse impacts of spills. Consequently, cooling ponds have actually reduced the extra investment utilities have had to make in effluent treatment capital. The acid and caustic boiler water demineralizer effluents do not need to be co-neutralized before discharge. The large cooling pond volume easily absorbs and co-neutralizes these effluents. Effluents with excessive inert suspended solids loads from the mine can be safely discharged to cooling ponds without further treatment because the large pond area will be more than adequate for the necessary final sedimentation.

An off-stream cooling pond cannot, however, be treated as a dumping point for all untreated water wastes. At Genesee, the cooling pond has a recreational area for swimming and non-power boating which is run by the County of Leduc as part of their development Agreement with Edmonton Power. This is the first time a utility has agreed to allow a cooling pond to have this use but it is important to note that the Development Agreement specifies that the primary use of the pond is for power plant cooling. In addition the Genesee cooling pond is the source of drinking water for both the plant and mine staff. Effluent control measures include a special holding pond for the treatment of boiler cleaning waste, a contaminated water settling pond and a sewage lagoon. Contaminated plant drains and ash plant and coal pile runoff are diverted to the settling pond with provision for both oil and solids removal. Special provision is made to contain switchyard and in-plant oil spills. Sewage is treated in facultative lagoons where there is also considerable evaporation. Basically similar wastewater treatment facilities exist at the Sheerness plant.[25]

Since there were no power plants with off-stream cooling ponds before 1971, there is no true base case with which to compare the generic model. The Battle River power plant with its on-stream cooling impoundment was in existence then but cannot be used for comparison. The authorities have always regulated this impoundment as a part of the river. It is likely that the only difference in costs between the base case and current situation would be for the following:

a) a settling pond for contaminated plant drainage and coal pile runoff,

b) the collection piping and ditching for the above settling pond **and**

c) plant and switchyard oil spill control measures.

Pre-1971 plants nearly all used once-through ash lagoons. The requirement for a separate settling pond for contaminated streams other than boiler cleaning wastes and sewage was consequently unnecessary. There was also negligible regulatory concern about coal pile runoff in those days and this would have been especially true if the wastewaters were discharged to a cooling pond.

d) <u>Coal Mine Drainage</u>

Before 1971 there were no controls on the drainage of surface water and pit dewatering flows from prairie coal strip mines. In 1978 Alberta Environment published Guidelines requiring the control of this drainage and imposed water quality standards.[16] The main reason for these Guidelines was to reduce the impact of mine drainage on mountain and foothills streams and lakes which are sensitive aquatic habitats. Although Alberta coal mine drainage is non acidic, other concerns exist. Excessive loadings of suspended solids in the mine drainage is known to degrade these streams and lakes by siltation, resulting in the loss of the primary food chain organisms, the killing of fish eggs and the disappearance of the fish. Although similar concerns are generally not relevant to intermittent prairie creeks which are often subject to natural high silt loads, Alberta Environment have recently been requiring the control and treatment of drainage from prairie mines serving power plants.[45]

The usual way of managing Alberta coal mine drainage is to collect the runoff from disturbed mining areas and the pit dewatering pump flows in ditches which discharge to settling ponds. The settleable suspended solids are removed in these ponds before the water is released. It is still not clear whether Alberta Environment will impose the same stringent water quality standards in prairie situations where there are not the same environmental concerns. It is however, clear that collection ditching and settling ponds will be required unless the drainage can be released directly to the cooling pond.[45]

For the purposes of this thesis, it will be assumed that two settling ponds will have to be constructed over the life of the mine. This is a reasonable assumption based on the experiences of TransAlta Utilities Corporation at their Highvale Mine, Forestburg Collieries Limited in the Battle River area, and the proposed plans at the Genesee Mine.

5.3 The Land Surface Conservation and Reclamation Act

This legislation was enacted in 1973 to consolidate the environmental regulation of industrial land surface disturbance activities. It also greatly increased the regulation of these activities which include mines, quarries, pipelines, etc. As is evident from Section 4.1, it deals with much more than land reclamation. It requires environmental impact assessments for major surface disturbance developments such as mines and authorizes the creation or continuation of certain regulatory bodies. The most important of these are the Land Conservation and Reclamation Council and the Development and Reclamation Review Committee whose roles were described previously.

This Act and its associated regulations and guidelines introduced the comprehensive requirements for coal mine reclamation which are now standard practice Very basically this requires the replacement of not only topsoil but usually also about 1 metre of suitable subsoil if available, the recontouring of spoil piles, and the establishment of a viable permanent vegetation.[7] The final reclamation is required to meet the following objective in the Alberta Coal Policy.

" The primary objective in land reclamation is to ensure that the mined or disturbed land will be returned to a state which will support plant and animal life or be otherwise productive or useful to man at least to the degree it was before it was disturbed." (4)

In order to provide an added incentive, Alberta Environment requires mine owners to post a security deposit against the successful completion of reclamation. This is usually $25,000 plus 25 cents per tonne of coal for prairie mines dedicated to power plants[7] - the minimum authorized in the Security Deposit Regulations.[21] To help ensure the suitability of reclamation plans, the D & R Approval normally requires a reclamation research program to be undertaken. This involves the establishment and monitoring of test plots over a period which usually lasts 10 years.[7]

Before the application of the provisions of The Land Surface Conservation and Reclamation Act, there were no formal requirements for coal mine reclamation. Such land reclamation concerns as existed in the 1960s were aimed primarily at the oil and gas industry. This was a time of low activity in the coal sector and the major government regulatory concern was mine safety. The Surface Reclamation Act of 1963 and its Surface Reclamation Regulations (AR 457/63) are very brief documents. They authorized the creation of the Surface Reclamation Council in the Department of Energy and Natural Resources which was the forerunner of t · Land Conservation and Reclamation Council today in Alberta Environment. In 1969, the Public Lands Surface Reclamation Regulations (AR 301/69) were enacted under The Public Lands Act. Like the Surface Reclamation Regulations, these brief regulations were primarily administrative in nature and had negligible impact on plains coal reclamation. (82,39)

The impact of The Land Surface Conservation and Reclamation Act on prairie power plant coal mines has consequently been to impose the whole reclamation process in evidence today and the detailed regulatory process described previously. These costs are covered in the mine environmental costs, the regulatory approval costs and the operations phase corporate overhead costs in Section 6.2.

5.4 The Water Resources Act (59)

The licensing of water diversions for consumptive purposes has been required in Alberta since w before 1971. In 1971 the Act was amended and new regulations passed requiring the permitting of non consumptive drainage works. This has resulted in the requirement that all minor drainage works at power plants must be advertised and approved. While this has increased the complexity of the regulatory process for the power plant, it has had a greater impact on the mine.

The plains strip mining process requires a continuing ditching program to divert water away from the pits, for pit dewatering, and to handle the mine drainage requirements of The Clean Water Act. All these drainage works require approval. A greater complication for mining is the application of the requirements for the regulation and permitting of groundwater diversions since 1980. This occurred as a result of increasing complaints about wells near dewatering operations going dry. Before dewatering is permitted, a groundwater monitoring program is required over the permit area. This is considered important because the coal seams to be mined are frequently the favoured aquifer of surrounding farmers or other users. In areas where there are neighbouring groundwater users, it is normal for an aquifer drawdown model to be used to predict the impact of the mine on the surrounding groundwater wells. Alberta Water Resources Administration have also recently been requiring coal operators or utilities to conclude Water Policy Agreements with any surrounding local community.(44)

Another measure introduced under The Water Resources Act in 1978 is the Dam Safety Regulation. This applies to all dykes or dams over metres in elevation and has resulted in a closer scrutiny of major power project dyke works such as those used on cooling ponds. During dyke construction subject to these Regulations, the Interim Water Diversion Licence authorizing the use of cooling water also imposes a schedule of geotechnical monitoring and reporting.(45) The cost of compliance with this Regulation is not included in this the is.

The cost of most of the additional regulation under this Act since 1971 is included in the regulatory approval process a porate overhead discussed in Section 6.2. Nearly all of the remaining costs are attributed the ongoing studies and monitoring of groundwater which are covered in the mine monitoring costs. No actual capital costs for drainage works are included because it can be argued that virtually all of this expenditure would have been necessary before 1971 to design and construct adequate drainage works. The main impact since 1971 is consequently of a regulatory nature.

5.5 Other Legislation

The Historical Resources Act has recently become an important factor in the environmental approval process for a coal-fired power plant and its mine. The Act and its associated regulations empower Alberta Culture to ensure that before earth moving construction activities or mining proceeds, an inventory of archaeological resources has been conducted. In the event archaeological sites are detected, Alberta Culture may require a detailed assessment of the value of the sites be performed. This information must be submitted in a Heritage Resources Impact Assessment and it should include expert recommendations on the need for further studies from archaeologists holding Alberta Culture permits. Following Alberta Culture approval, studies consisting of additional excavation, artifact cataloguing and evaluation may be required. This is known as mitigation since it enables the knowledge and some artifacts to be preserved before the onset of earth moving destroys the resource. It is only after the Heritage Resources Impact Assessment is approved by Alberta Culture and field mitigation studies are complete, that construction or mining in a particular area can proceed.[24,23,3]

In an area with rich archaeological resources, the approval process costs can be high. The Genesee project is in an area with numerous prehistoric Indian camp sites and it eventually cost about one million dollars to obtain all the necessary approvals from Alberta Culture.[45] In contrast, at the Sheerness plant site few archaeological resources were found and approval costs were low.[66]

It is unlikely that the Genesee archaeological approval costs will appear unduly exaggerated in future projects. This is because Alberta Culture have been requiring more detailed inventory surveys of historical resources than is the 1970's. The preliminary archaeological studies required for the Slave River hydroelectric project in 1984-85 indicated costs would be much higher than those at Genesee.[65]

There were no archaeological approval costs at power plants before 1971. In fact, it was not until March 15, 1977 that the Archaeological Survey of Alberta published its "Interim Guidelines, Historical Resources Impact Assessments". All archaeological approval costs are consequently captured in the overall approval process costs. Normally there are no other capital costs although a project could be required to relocate an historical building or monument. There are also no operating or maintenance costs unless the archaeological approval of later mining areas is deferrred.

6. ENVIRONMENTAL COSTS IN A TYPICAL COAL-FIRED GENERATING PROJECT

6.1 Project Description

6.1.1 Power Plant

a) **General Description**

The generic power plant is based on the detailed description of a typical 750 MW Alberta plant in an unpublished study prepared for the Electric Utility Planning Council in 1982.[40] Some of the data in this report was subsequently revised by the EUPC [47] and these changes are assumed for the thesis model. Unless otherwise stated, all the data in this section is drawn from these references.

The EUPC have since used their generic plant data as the basis for many economic evaluations. Although the EUPC generic plant costs are only order of magnitude estimates, they are considered adequate for utility planning purposes and should consequently be adequate as a basis for gauging the relative magnitude of the environmental costs estimated in this thesis.

While the generic plant is basically similar to either the Keephills, Sheerness and Genesee plants , each of these plants does have features which are different. The generic model does, however, incorporate all the typical major features.

The generic plant consists of two 375 MW nominal units at a mine-mouth site which could accommodate two further units at a later date. The cooling water for the condenser and other plant auxiliaries is drawn from an off-stream cooling pond. Make-up to the pond is from a nearby river or lake.

The plant utilizes pulverized coal-fired 2400 psig type boilers and tandem compound 3600 rpm steam turbines. Flue gases to a single stack are treated in high efficiency electrostatic precipitators. Each unit has two precipitators, each of 50% capacity. Coal is supplied from the mine by truck to "run of mine" hoppers. Ash is disposed of dry in the mine using trucks.

The more detailed description of the generic plant included in the report to the EUPC [40] is not of interest here. It is important to note that the plant does include all the major cost environmental features of a power plant design subject to the current Alberta requirements. Such differences as exist are minor and will have little impact on the total plant costs.

For the purposes of this thesis, the first Unit is assumed to start commercial operation on July 1, 1987 and the second on July 1, 1988. This was a typical pattern before the current economic downturn. The Keephills plant was the last to follow this pattern.

b) **Performance Specifications**

Nominal capacity (MW)	2 x 375
Net capacity, maximum continuous rating (MW)	2 x 349
Capacity Factor	80%
Heat Rate (kJ/kWh)	10,500
Coal properties:	
Ash (%)	19
Heating Value (kJ/kG)	17,500
Coal production (tonnes/MWh)	0.60
Unit life	35 yrs

Electricity Output:

	1987	1988	1989	1990	1991 to 2021	2022	2023
% of annual output:*							
Unit 1	38.4	94.7	99.6	99.9	100.0	50.0	0.0
Unit 2	-	37.7	94.6	99.5	100.0	100.0	50.0
Electricity Output (GWh)	939	3238	4750	4877	4892	3669	1223
Coal production (000s tonnes)	563	1943	2850	2926	2935	2201	734
Ash generated (000s tonnes)	107	369	542	556	558	419	140

[* This assumes a base loaded plant[76]]

c) **Capital Costs**

The capital cost cash flows by year are as follows:

(mid-1982 $000s)

Year	Unit 1	Unit 2
1982	10,000	4,000
1983	46,000	16,000
1984	77,000	29,000
1985	122,000	47,000
1986	88,000	48,000
1987	36,000	57,000
1988	1,000	36,000
1989	-	3,000
Total	**380,000**	**240,000**

These cash flows do not include the cost of obtaining regulatory approvals, coal mining costs, substation costs or offsite waste disposal costs. The mining costs are included elsewhere while the substation is not included in the model. The other costs are small and can be neglected.

d) **Operating and Maintenance Costs**

(mid-1982 $000s)

	Unit 1	Unit 2
Fixed (/year)	3,440	3,440
Variable (/GWh)	0.45	0.45
Replacements, Insurance & Property Tax (/year)	5,170	3,200

e) **Financial Parameters**

Real Rate of Return (%) - assumed allowed by the Public Utilities Board 6

Depreciation - Straight line with zero book value at the end of year 30.

Escalation:

Capital	-before 1988	Statscan Composite for power plants
	-1988 and later	Inflation (42)
Operating and Maintenance		Inflation
Replacement, Insurance and Property Tax		Inflation

Interest during construction (%): (26)

1979*	1980	1981	1982	1983	1984	1985	1986	1987	1988
10.6	10.9	10.01	12.48	12.88	12.92	12.72	12.75	12.07	12.00

(* Pre 1979 figures are assumed equal to 1979 figures)

6.1.2 Coal Mine

a) General Description

The generic coal mine model used in this thesis is based on the plan for an actual prairie mine supplying a power plant but numerous modifications were made. These modifications were introduced to ensure the mine is fairly typical of recent operations and to preserve confidentiality. Mines developed in the 1970s will have lower costs. The mine model and associated costs were prepared by a mining engineer with a high degree of expertise in the subject.[75]

The mine is a single pit operation which uses a standard dragline stripping technique to expose the coal seams. Scrapers and dozers are used to prestrip and salvage topsoil and subsoil ahead of the dragline consistent with environmental requirements. Exposed coal is excavated using a mechanical shovel and loaded into coal haul trucks for removal to the power plant.

The dragline casts the overburden into the previous mine cut in piles which are levelled and recontoured by dozers according to the reclamation plan. There is approximately 25% rehandle of the dragline spoil. Subsoil is then replaced to a depth of 1 metre and topsoil to a depth of 0.2 metre as specified in the environmental approval. The reclaimed ground is then cultivated and revegetated.

The thickness of the coal seams allows an average coal yield of 60,000 tonnes per hectare. A life of mine average strip ratio of 5 cubic metres of overburden per tonne of coal is used. It is assumed that levelling occurs in the year of mining with cultivation contracted one year later. (In fact, there is often more delay.)

It is assumed that the mining company operating the mine holds all the coal rights in the coalfield. Consequently royalties are high. In addition, it is assumed that the mining company receives a constant nominal return on its investment averaged over the life of the mine.

b) **Total Mining Costs**

The total mining costs for the 35 year life of the mine are given in Table 6.1 below. The costs include the cost of dry ash disposal. Although the ash disposal costs are based on different assumptions from those given in Section 6.2.1 (c), the error introduced is small because ash disposal costs are very small compared with the total coal mining costs. Because the [illegible]-1971 base case for ash disposal is based on ash lagooning, the total mining cost of dry ash disposal is approximately the same as the difference between dry and wet disposal.

In Table 6.1, the total costs include the return, taxes, depreciation, depletion, indirect operating costs with contingency, override royalties, crown and crown equivalent royalties and direct operating costs. The last three of these items are considered variable costs.

Table 6.1

Generic Total Mining Costs (1986$)

Year	Total Costs ($ 000 s)	Unit Coal Cost ($ / tonne)
1987	8,067	14.33
1988	24,197	12.45
1989	34,652	12.16
1990	35,840	12.25
1991	36,650	12.49
1992	36,788	12.53
1993	36,984	12.60
1994	36,902	12.57
1995	36,783	12.53
1996	37,130	12.65
1997	36,968	12.60
1998	36,888	12.57
1999	36,780	12.53
2000	36,648	12.49
2001	36,883	12.60
2002	36,824	12.55
2003	36,991	12.60
2004	37,004	12.61
2005	37,175	12.67
2006	37,099	12.64
2007	37,069	12.63
2008	36,941	12.59
2009	36,782	12.53

Table 6.1 (Continued)

Year	Total Costs ($ 000 s)	Unit Coal Cost ($ / tonne)
2010	36,659	12.49
2011	38,061	12.97
2012	37,908	12.92
2013	37,853	12.90
2014	37,804	12.88
2015	37,714	12.85
2016	38,263	13.04
2017	38,264	13.04
2018	38,163	13.00
2019	38,021	12.95
2020	37,881	12.91
2021	37,507	12.78
2022	32,796	14.90
2023	13,997	19.08

6.2 Environmental Capital and Operating Costs

6.2.1 Power Plant

(a) Electrostatic Precipitator Costs

(i) General:

Only one power plant unit has so far been constructed with an electrostatic precipitator designed to meet the new Alberta guideline standard of 43 ng/J - the 2 x 400 MW Genesee power plant. This was used to derive the Genesee Clean Air Act permit standard of 0.09 g/kg of dry flue gas at 50% excess air.[[illegible]1] In order to meet this standard, the Genesee electrostatic precipitators are required to remove 99.51% of the flue gas particulates under [illegible]% worst coal conditions. The precipitators do, however have a design capability of over 99.67% efficiency to allow reasonable provision for contingencies. It can be shown that if the Genesee electrostatic precipitator had been designed to comply instead with Public Health Act Regulation 375/70, a particulate removal efficiency of only 95.09% would have been required (Appendix 1).

A 1977 study for the U.S. Environmental Protection Agency[81] provided graphical estimates which related the capital and operatin· and maintenance costs of electrostatic precipitators to particulate removal efficiency for different unit sizes and for different coal types. Figures 6.1 and 6.2 fr·m this study reflect most closely the typical Alberta power plant under consideration - a pulverize·l sub bituminous coal-fired plant with cold-side electrostatic precipitators. The coal sulphur content of 0.6% is on the high side of the typical Alberta coals currently mined (0.2 - 0.6%) and the other properties which affect precipitat.cu. ·s cially resistivity are indeterminate. Howeve U.S lata should be adequate for the purpose it is used i·· ·_ study since only comparative rat uot absolute values are derived.

By t· ıg off the capital cost and operating and maintenance cost values for 400 MW units with electrostatic precipitators of efficiency 99.51% and 95.09%, capital and operating and maintenance cost ratios were calculated. These ratios are used to estimate the cost impact of the Clean Air Act requirements over the Public Health Act Regulations 375/70.

It should, however, be noted that the efficiency of an electrostatic precipitator is not a good predictor of its mass emission of particulates. These emissions vary with flue gas flow, temperature, ash properties, dust loading, etc. It is not possible to investigate the sensitivity of the derived cost ratios to all these factors. However another design case

FIGURE 6.1 CAPITAL COST: COLD-SIDE ESP, PULVERIZED SUBBITUMINOUS COAL, 0.6% SULPHUR

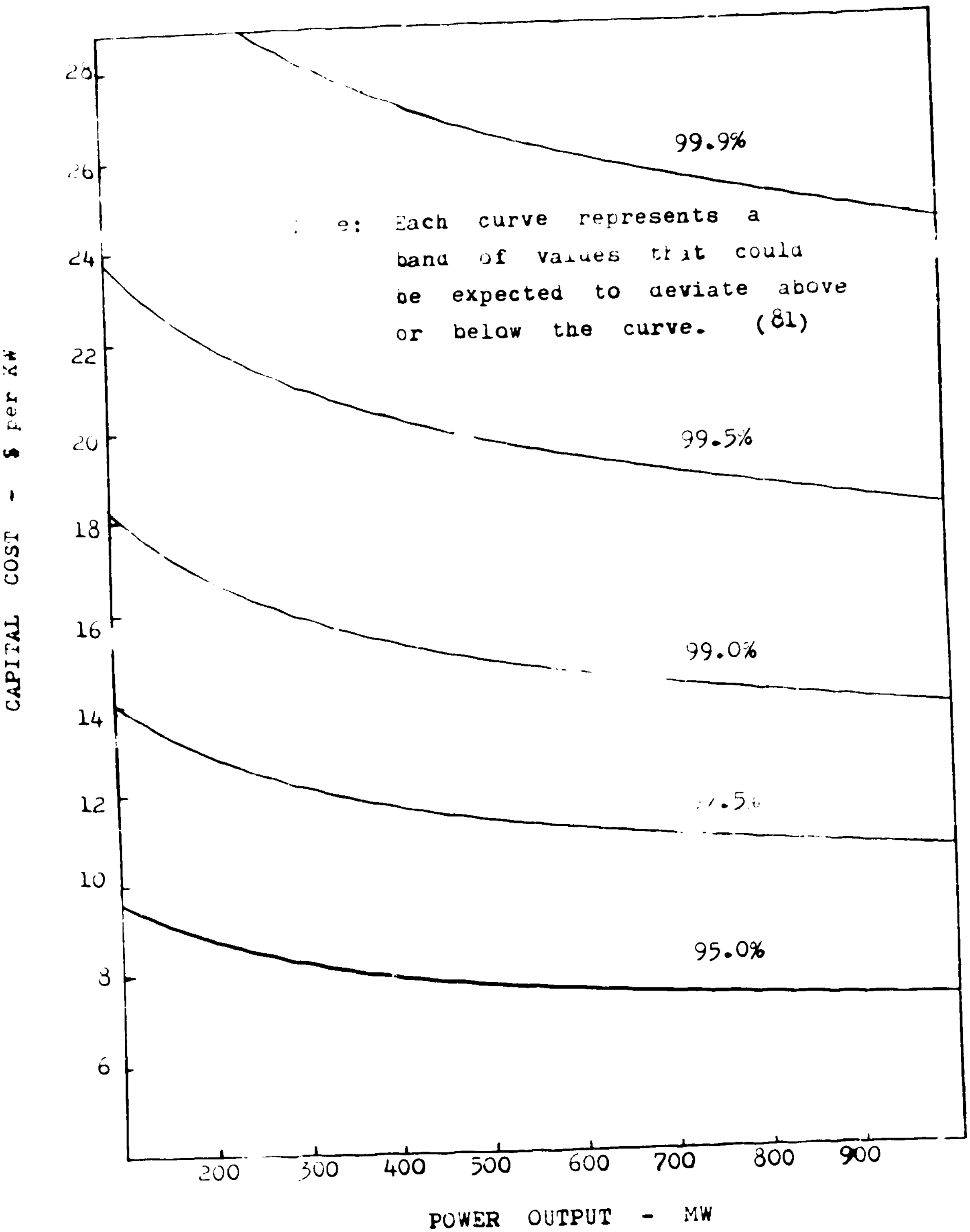
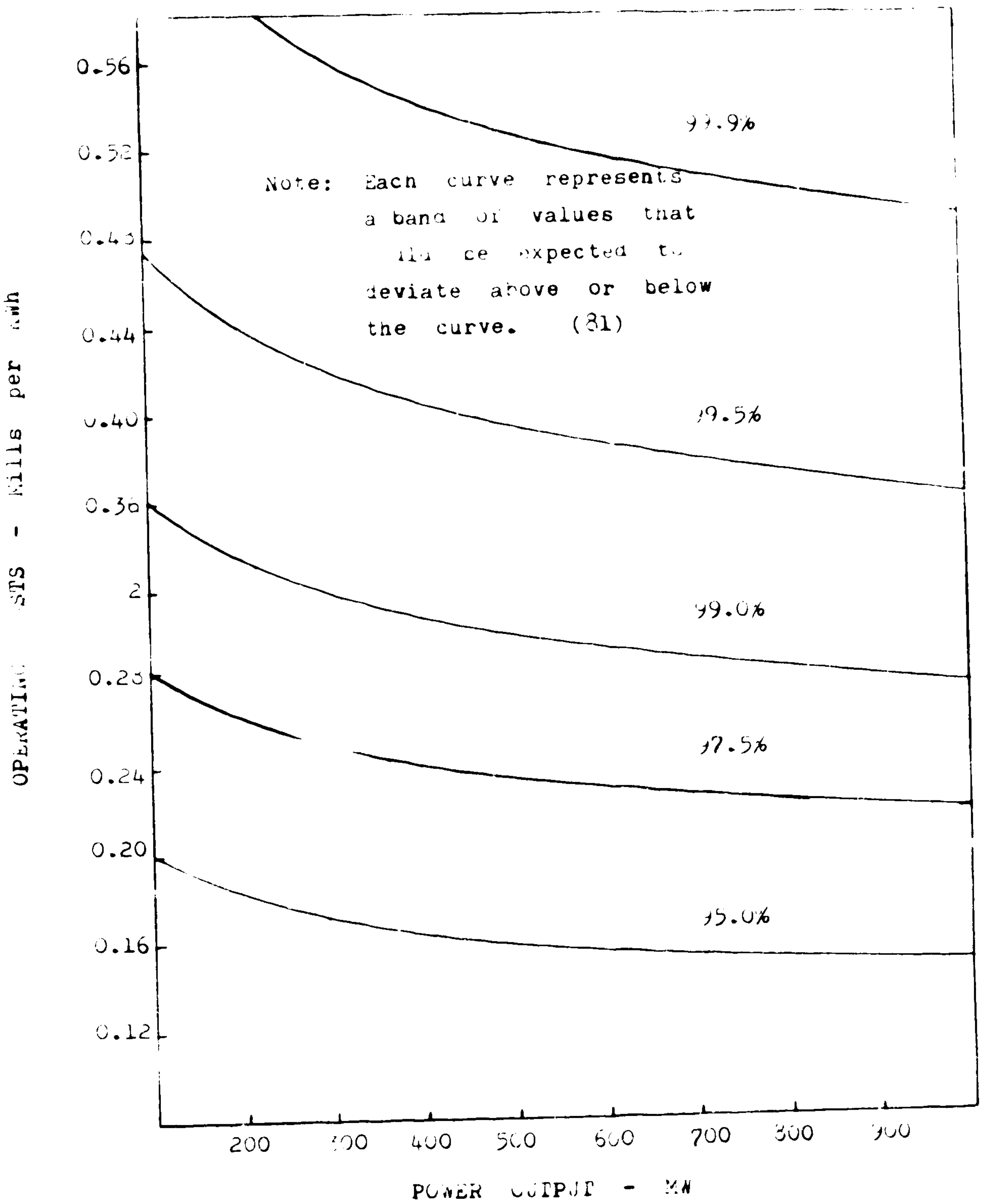


FIGURE 6.2

OPERATING COST: COLD - SIDE ESP, PULVERIZED SUBBITUMINOUS COAL, 0.6% SULPHUR



involving much higher dust loadings and temperatures was examined. When a plant burns coal with a higher dust loading, a higher efficiency is required to comply with the same emission standard. Higher temperatures imply a higher flue gas volume which may also require a higher efficiency.

The design data for this sensitivity case was drawn from the Dynawest Study for the EUPC.[40] The results are tabulated in Table 6.2. As can be seen, despite the much higher dust loading and temperature in the sensitivity case, the cost ratios are only slightly altered. This is not unexpected since the impacts of the higher efficiency are mutually offsetting.

Table 6.2

Impact of Different Dust Loadings on ESP Efficiency and Derived Cost Factors

	Thesis Case	EUPC Study Case
Unit Size (MW)	400	375
1987 Standard Basis (ng/J)	43	43
1987 Licence Standard (g/kg *dry basis)	0.090	0.082
1987 Efficiency (%)	99.51	99.67
1970 Standard (g/kg *wet basis)	0.85	0.85
1970 Efficiency (%)	95.0[illegible]	9[illegible].44
Flue Gas Temperature (°C)	121	163
Dust loading (g/m³) (at 121°C wet)*	16.26	21.17
Flue Gas Flow (m³/s) (at 121°C wet)*	611	619
Coal ash content - 90% worst (%)	19.4	25.1
Fly ash carryover (%)	80	85
Costs based on U.S. study[81]: -		
1987 Capital Cost - (mid 1975 $/kW)**	21.0	23.5
1970 Capital Cost - (mid 1975 $/kW)	8.1	9.8
Capital Cost increase factor	2.60	2.40
1987 O & M Cost - (mid 1975 MILL/kWh)**	0.404	0.45
1970 O & M Cost - (mid 1975 MILL/kWh)	0.165	0.205
O & M Cost increase factor	2.45	2.20

The cost factors consequently show a variation of only about 8% for capital and O & M.

* At 50% excess air

** US $s

It was consequently estimated that the impact of the Clean Air Act has resulted in a 2.6 times increase in capital costs and 2.45 times increase in operating and maintenance costs in real terms compared with the 1970 Public Health Act Standard. It is important to note, as stated previously, that this assumes compliance with the standard. While this is true in 1988, it certainly was not true in 1970 since the technology to meet that standard, the precipitators, had not been introduced into Alberta at that time.

(ii) <u>Capital Costs</u>

The capital cost cash flows for the supply, freight, erection (including foundations) and commissioning of the generic electrostatic precipitators for the two generic 375 MW units are based on actual origin[illegible] costs for the Genesee power project.[45] These costs in no way represent the actual installed capital costs of the Genesee electrostatic precipitator because the project has been subject to two major deferrals during construction, imposed by the Alberta Energy Resources Conservation Board. This has resulted in different escalation impacts from contract re-negotiations and some design changes. The actual cash flows are confidential. However, the cash flows provided (Table 6.3) are realistic, being based on an actual bid, and are modified only to include the foundation costs[45] and escalation factors appropriate to the generic plant construction schedule.

It should be noted that there are differences between the Genesee plant and the generic plant model. Firstly the Genesee units are each nominally 400 MW capacity rather than the 375 MW size. This is not considered a significant factor in the capital cost cash flows provided below - the capacity difference is only 6.6%. Of more importance is the higher ash content of the generic plant coal. The Genesee precipitator assumes an average ash content of 16.6% and a 90% worst case of 19.6% for design purposes. With an average ash content of 19% for the generic plant, the design ash loading would be much higher. Assuming the same level of flyash carryover, this would tend to make the costs in Table 6.3 more conservative. The error should not, however, be excessive in the overall accuracy of the estimates used in this study.

Table 6.3

Electrostatic Precipitator Capital Cost Cash Flows

for 2 x 375 MW Generic Plant

($000s as spent)

Year	1984	1985	1986	1987	1988	1989
Unit 1	2367	5525	2829	1992	105	-
Unit 2	402	5636	3503	1814	105	109

In order to calculate the differential capital cost between 1970 and 1988 legislation, the derived cost ratio is applied. In the absence of better data it is assumed that the factor can be applied evenly to each cash flow. This is obviously an approximation since the cost ratio is based on thirteen year old U.S. data but the error should be well within the estimating range for this study. Since capital costs have increased 2.6 times since 1971, ly 1.6/2.6 or 61.5% of the total capital cost cash flows in Table 6.3 are c d due to the new legislation.

The costs in Table 6.3 do not include the ele utility's engineering, contract administration and com ning sts. These were also not included in the environmental corporate overhead discussed in Section 6.2.4 because it is assumed that these costs would not be significantly different for an electrostatic precipitator meeting the 1970 standard. This is a reasonable assumption since these costs should not vary significantly with the efficiency of the precipitator. If there is any error in this assumption it should be in favour of a higher cost for the more efficient unit due to its greater complexity. (New electrostatic precipitators contain more fields and sophisticated energy conservation systems which may not have been developed for lower efficiency units.) Neglecting differential owner man-hour costs should consequently be an acceptable conservative approach. The costs in Table 6.3 also do not include ash handling and disposal costs. There is only 4.4% difference in the ash weight requiring handling now compared with 1970. Ash disposal costs are assessed later in this section.

(iii)Operating and Maintenance Costs

The largest component of this cost is normally considered to be for energy. The costs used in this study are based on the energy consumpti quoted by the supplier of the Genesee electrostatic precipitator and a capacity cost. This energy consumption is quoted to be 348 kilowatts per pair of 50% capacity precipitators when the units are operating at maximum capacity rating (MCR).(45) This is a total energy consumption including the supply to the transformer rectifier sets, the rappers, insulation heaters, ash hopper heaters and fluidizing air systems. The annual energy consumption costs are calculated based on the annual net power production specified for the generic plant.

Table 6.4

Electrostatic Precipitator Energy Costs for

2 x 375 MW Generic Plant

(1987 $000s)

	1987	1988	1989	1990	1991
Net plant energy generated (GWh)	939	3,238	4,750	4,877	4,892
Equivalent hours at MCR	1,345	4,639	6,805	6,987	7,009
ESP energy consumption (MWh)	2,281	7,868	11,541	11,850	11,887
Cost (Energy at $5.5/MWh)$	266.9	552.1	572.3	574.0	574.2
(Capacity at $300/kW)					

The cost/MWh of $5.50 is based on an inspection of confidential electric utility incremental power costs for coal fired plants in the Alberta Interconnected System in 1987. For some plants, the cost is much lower, for others, much higher. The capacity cost of $300/kW is based on avoided gas turbine capacity costs.[76]

Since operating and maintenance costs have increased 2.4 times since 1971, the energy cost due to new legislation is considered to be 1.4/2.4 or 59.2% of the total energy costs provided in Table 6.4

It should be noted that the costs in Table 6.3 may prove to be slightly lower in the face of recent technical innovations now being applied to new coal-fired power plants in Alberta. Advances in micro-electronics have permitted the development of pulse charging systems and energy control systems. In Alberta these systems have the potential of more than halving the incremental energy consumption costs.[37,68] This is, however, only a small component of the full cost of the energy which includes the $300/kW capacity cost.

The residual operating and maintenance costs for electrostatic precipitators consist of operating and maintenance labour and materials for repairs. These costs are not accounted for separately at Alberta power plants but are estimated to be very much lower than the energy costs, based on discussions with utility personnel.[37,61] An electrostatic precipitator is unlikely to incur significantly different operating and maintenance costs of this category if designed to operate at 95.09% or 99.51% efficiency. These costs can consequently be ignored when comparing the effect of the Clean Air Act on the Public Health Act Standard.

(b) **Stack Emissions and Ambient Air Monitoring Costs**

As described in Section 5.1, all coal-fired power plants are now required to install and operate continuous stack emission monitors as well as a remote ambient air monitoring site, including a met station.

The most up-to-date costs for these systems are available from the Sheerness and Genesee power projects.[66,45] The Sheerness plant equipment has now been in operation for more than two years while the Genesee equipment had just been purchased in January 1988. The costs shown below are an average of the two projects' costs except for the stack elevator which is a Genesee cost. All costs are for supply, installation and commissioning.

Stack monitoring equipment	$260,000
Stack elevator	76,000
Air monitoring and met station	113,380

Since the air monitoring and met station is now required by Alberta Environment to be in operation two years before commercial operation to collect background data,[9] this cost is shown as being incurred in 1985 in the generic model schedule. The stack monitoring equipment and elevator are normally not required until the end of the construction period and the costs are consequently shown as being in 1986.

Discussions with instrument engineers indicate that it will be necessary to replace the monitoring equipment several times during the life of the power plant. An instrument life of 12 years is considered optimistic but will be assumed to ensure costs represent a lower bound estimate. Experience with stack and air monitoring equipment at Edmonton Power's gas fired plants support this assumption. After less than ten years of operation, the entire computer system is now being replaced due to obsolescence and lack of assured spare parts supply. The stack elevator will be considered to last the life of the plant with normal maintenance.

It will be assumed that the replacement cost of the systems will be the same as the original cost expressed in real dollars. The future cost of these systems is unclear. Recently costs of the data systems have declined markedly due to the introduction of new microprocessors. Instrument costs have continued to rise. Unless there are further technological breakthroughs, the overall monitoring system costs can consequently be expected to at least keep pace with future inflation.

c) **Ash Disposal Costs**

As established in Section 5.2, ash disposal costs since 1970 cannot typically be considered to be primarily environmental. The government is flexible on whether a closed circuit lagoon is used or dry disposal in the mine, depending on site specific circumstances. Although once-through lagoon disposal was normal in 1970, no additional cost can be typically associated with a closed circuit operation due to off-setting savings in pumping and pipeline costs.[30] Additional ash disposal costs will consequently be considered as a special case only.

Only one published study is available for Alberta power plant ash disposal costs. This is the study conducted by Montreal Engineering Limited for Calgary Power Limited on the South Sundance power plant (now known as the Keephills power plant).[30,31] This study showed a significant saving in using a closed circuit ash lagoon over a dry disposal system. The study is, of course, highly site specific and completely different conclusions could be reached at another site. However, the costs are considered appropriate for use in assessing a special situation where dry ash disposal is considered environmentally mandated. These costs include the following features:

(i) One of the key costs of dry ash disposal is the haul distance from the plant to the mine or ash dump area. This has a major impact on the capital replacement cost for ash haul trucks and the associated operating and maintenance costs. The Keephills study is based on short haul distances, for the most part only 4 to 6 km.

(ii) The main site specific determinant of ash lagoon costs is the nature of the terrain and the extent of the dyking fill, and excavation required. The sensitivity of the construction cost to terrain considerations is shown in the site selection study for the Keephills lagoon which showed a variation of from $2,955,000 to $7,570,000 (1977$s). Even the most economical option required major dyke works. No information is available as to what lagoons would have cost to build at other power plants now using dry ash disposal. It should, however be noted that at Keephills, the lagoon capital cost was estimated to contribute less than 10% of the levelized cost per tonne of ash disposal.(30)

(iii) A disadvantage of the Keephills study is the assumption that the plant bottom ash system is based on hydrobins for bottom ash slurry settling with a closed recycle water system. This is the technology also assumed in the EUPC generic plant used in this thesis. This is now however, considered by some to be an older and less economical technology compared with the dragbar systems installed at the

Battle River, Sheerness and Genesee plants. Unfortunately no data exists to allow comparison of these two bottom ash systems. The more modern dragbar technology will as a result probably reduce the difference in cost between the dry haul and ash lagoon systems.

(iv) The ash lagoon cost assumes that the lagoons will be reclaimed. This was not a requirement in 1970 and consequently this cost is not included in this thesis.

(v) The Keephills study assumed all ash disposal in either final mine pit cuts or, if room was not available, in the existing nearby ash relief dump. A comparative analysis[31] indicated this to be the most economical and practical way to dispose of the ash in this case. Other options such as ash disposal between the spoil piles or at the pit bottom were shown to be less economical and less workable. Other plants do, in fact, use pit bottom or spoil pile disposal for ash since mine configurations are different.

(vi) A study conducted for Saskatchewan Power's Poplar River plant indicated 30% higher differential costs for dry haul ash disposal over a closed circuit lagoon than the Keephills study even though additional lagoon costs were included in Poplar River study (i.e., compaction of till for lagoon bottom). The Keephills study costs are consequently more conservative.[54]

The net ash disposal costs are given in Table 6.5. These costs are split on the basis of whether they are plant or mine costs. This distinction is important for inclusion in the revenue requirements model used in Section 7. Plant capital costs are depreciated and form part of the net property in service on which the utility calculates its return. The mine costs are included in the coal costs which are added as part of the power plant's revenue requirement.

It is of interest to note that on a levelized cost basis, the difference between the dry haul and ash lagoon costs (Table 6.5) are almost all represented by additional mining costs only, with plant capital being essentially similar and O & M costs greater by only $0.18/tonne of ash.

The mid 1977 $ costs in Table 6.5 are escalated in the revenue requirements model to "as spent" or nominal dollars when considering this special case.

It should be noted that at the Battle River and Wabamun power plants, appreciable quantities of ash are sold for use in construction materials. Markets permitting, the sale of ash is currently only economic if collected dry as is the case with a dry haul ash disposal system. Any savings from the sale of ash are not included in this study because figures are not readily available and only a small proportion of the total ash produced by Alberta power plants is sold.

Table 6.5

Net Ash Disposal Costs - Keephills Study Basis

(mid 1977 $000s)

Year	Net Plant Capital	Net Mine Capital	Net Plant O & M	Net Mine O & M	Total Net Mining Cost ($/tonne coal)
1987	269	299	(96)	102	1.13
1988	1940	599	-	306	0.51
1989	-	598	111	[illegible]	0.39
1990	-	-	111	510	0.18
1991	-	-	110	510	0.18
1992	(92)	-	110	510	0.18
1993	-	-	109	510	0.18
1994	-	247	109	593	0.29
1995	-	74	109	711	0.27
1996	(92)	(44)	109	710	0.23
1997	(138)	254	109	711	0.33
1998	(70)	289	110	608	0.31
1999	-	800	109	609	0.49
2000	(1279)	18	86	608	0.22
2001	-	(11)	86	609	0.21
2002	(92)	(44)	86	608	0.19
2003	211	(45)	85	609	0.19
2004	(2898)	237	83	608	0.29
2005	-	17	80	609	0.22
2006	(92)	(44)	82	608	0.19
2007	(138)	288	81	609	0.31

Table 6.5

(Continued)

Year	Net Plant Capital	Net Mine Capital	Net Plant O & M	Net Mine O & M	Total Net Mining Cost
					($/tonne coal)
2008	(70)	255	82	608	0.30
2009	-	800	80	609	0.49
2010	(68)	52	82	608	0.23
2011	-	(45)	80	609	0.19
2012	(92)	(44)	81	608	0.19
2013	-	(11)	80	609	0.21
2014	(46)	203	81	608	0.28
2015	-	17	80	609	0.22
2016	(92)	(10)	81	608	0.21
2017	(138)	(45)	80	609	0.19
2018-2023	-	(44)	81	608	0.19

Note: In the first two years it was necessary to take into account the difference in commissioning dates between the Keephills study (Oct.1) and the cost/tonne of coal. This was done by dividing the capital by the generic model coal tonnage and the O & M by the Keephills study coal volume and adding. All other year costs were divided by the Keephills coal volume. There is an error of only 7% in the ash volume which is lower in the Keephills case.

Table 6.6

Net Ash Disposal Costs

Levelized (1977 $s per tonne of ash)

		Lagoon	Dry	Net
Capital:	plant	2.81	2.81	nil
	mine	nil	0.39	0.39
O & M	plant	2.05	2.23	0.18
	mine	nil	1.15	1.15

d) **Cooling Pond**

The cost of constructing and operating a cooling pond is included as a special case because it is not normally an environmental cost.

Cooling pond costs vary according to the terrain which determines the amount of excavation and dyking required and the distance from a water source which determines pipeline and pumping costs. An example of a new two-unit cooling pond exists at the Keephills power plant. The following cost estimates for this cooling pond were published by Calgary Power Limited in 1977.(33) The capital costs include not only the cooling pond but the pipelines and pumping equipment. Pipeline and pumping costs should be less than that at the Sheerness plant but more than at the Genesee plant based on the distance of the cooling pond from the river. 1977 dollars are assumed consistent with the date of the study.

Capital Cost	$22,500,000
Power cost present worth *	1,368,000
O & M cost present worth *	3,000,000

* Based on 6% real discount rate over 30 years. In Section 7 this will be used to generate a cash flow stream over the 35 year life of the generic plant.

Although these costs will vary for different sites, they will serve to show the magnitude of the impact of including a cooling pond in the environmental costs.

No cash flow data is available but it is known from the proposed construction schedule in Calgary Power's application to the ERCB that virtually all cooling pond construction is completed early in the construction period.[34] Since in the generic plant case, construction is considered to start in July 1, 1982 (Table 6.9), the following cash flows are assumed, expressed in 1977 dollars:

1982	$2,500,000
1983	20,000,000

It should be noted that the location of the cooling pond is, along with location of the mine, a major determinant of the siting of the plant. This means that while a cooling pond may be more costly than using once-through cooling on a nearby waterbody, there may be some compensating savings due to reductions in coal haul distances or due to other factors. These savings are highly site specific and not taken into account in the above costs. Such savings could be appreciable and greatly reduce the overall cooling pond cost.

e) **Plant Drainage**

As discussed in Section 5.2, the only extra costs since 1971 appear to be for plantsite settling ponds, the associated drainage works, and plant/switchyard spill control measures.

These costs are very difficult to isolate with any accuracy because they normally form small parts of civil and mechanical site contracts. The cost of the generic settling ponds was roughly estimated based on the rates charged for excavation at the plant sites in the early 1980's, and the average settling pond sizes at the Sheerness and Genesee power plants.[45,17] This yielded an average cost of $591,300 which should be conservative because ditching and pump station costs were ignored. Excavation is, however, the largest component by far.

An examination of the works involved in the drainage and spill containment measures indicates that the extra piping and enclosures are not substantial. These additional costs are consequently neglected as being small compared with other environmenta capital such as the electrostatic precipitators.

The settling pond is normally constructed early in the project during the site preparation stage. The $591,300 cash flow will consequently be scheduled in 1983 in the generic plant model (Schedule in Table 6.9).

f) **Compliance Monitoring**

This work is confined to the operating phase and the majority is required for compliance with Clean Air Act licence requirements as discussed in Section 5.1. The work also includes monitoring and reporting costs for the other applicable plant approvals discussed in Section 4.2. It is assumed that the work is nearly all done by utility staff and this labor cost is not included since it becomes part of the corporate overhead estimated in Section 6.2.4 (This is normal in the case of Edmonton Power and Alberta Power Limited. TransAlta Utilities Corporation uses consultants to conduct its air monitoring program.)

Inspection of the budget costs for this activity at the Genesee power plant [45] and actual costs incurred at the Sheerness power plant [80] indicate that on average, an annual cost of

$44,000 is reasonable. This covers routine activities and assumes no special investigations will be required. It is not unusual for special studies to be required every few years to satisfy government licence renewal requirements. Since no data is available for this, it will be ignored for the sake of maintaining a lower bound estimate.

In 1970 it was necessary to retain consultants to conduct stack surveys on a semi-annual basis. Dustfall monitoring and some water sampling was also required. These activities currently cost about $6,000 per year to perform[45] and should be deducted from the $44,000 total cost to obtain the impact of the post 1970 legislation. An annual cost of $38,000 will be used based on 1987 $ and escalated annually for inflation.

6.2.2 Coal Mine

a) Reclamation

As discussed in Section 5, environmental requirements at coal mines since 1970 consist of spoil recontouring, subsoil salvage and replacement to 1 metre depth, topsoil salvage and replacement to 0.2 metre depth, and revegetation.

These costs were based on the generic mine model and calculated by an expert mining engineer.[75] This mine model and the associated environmental costs were in turn based on a modified version of an actual mine plan. The costs are summarized in Table 6.7.

The fixed costs include the return on the investment on capital equipment used in the reclamation, depreciation of the capital, taxes allocated and indirect operating costs. The equipment consists of dozers, scrapers and graders which are used not just for reclamation but for general mining. The reclamation component was estimated on the basis of machine hours.

The variable costs include the direct operating costs and allocated royalties.

The reclamation costs are probably high compared with most prairie strip mines currently in operation. This is because the reclamation plan used in this model assumes the salvage and replacement of 1 metre of subsoil in addition to 0.2 metres of topsoil over the entire mine. None of the currently operational mines are able to salvage as much as 1 metre of subsoil throughout the mine because suitable subsoil is not everywhere available. As a result, Alberta Environment require mine operators to salvage and replace variable amounts depending on what is available.[72,75] Occasionally, recontoured spoil may be suitable for use as subsoil, without special salvage. Since subsoil handling represents nearly 70% of the reclamation costs quoted in Table 6.7, a reduction in subsoil salvage has a major effect on costs.

Table 6.7

Generic Reclamation Costs (1986 $)

Year	Fixed Costs ($000s)			Variable Costs ($000s)			Contract Costs ($000s)	Unit Cost ($/tonne coal)
	Recontouring	Subsoil	Topsoil	Recontouring	Subsoil	Topsoil	Cultivation	
1987	132	111	40	95	78	28	-	0.86
1988	260	823	172	180	432	91	31	1.02
1989	364	1,466	294	256	776	156	58	1.16
1990	365	1,468	294	265	810	162	81	1.18
1991	368	1,483	295	270	826	165	83	1.19
1992	372	1,503	295	273	840	168	83	1.20
1993-2021	381	1,542	299	279	863	172	83	1.23
2022	381	1,542	299	209	647	129	83	1.49
2023	191	771	150	70	216	43	62	2.05
2024	-	-	-	-	-	-	21	NA

Since certain future mines do have sufficient subsoil over the life of the mine to allow a uniform salvage of 1 metre, the Table 6.7 costs are relevant.[75] The effect of lower subsoil salvage requirements will be considered in Section 7 as a sensitivity case.

Although a reclamation cost of $1.20 per tonne of coal may appear high, it is interesting to note that this is only 30% higher than estimates provided at the Sheerness project ERCB hearing in 1978, after allowing for inflation.[29]

b) **Mine Drainage**

It was assumed in Section 5.2 (d) that two settling ponds would be required over the life of the mine to meet Clean Water Act requirements. This will vary greatly from mine to mine, as will the cost of the settling ponds and the water diversion facilities. A cost of $100,000 is assumed based on the cost of constructing a modest waste pond at a power plant.[45] The cost includes capital only and does not include ditching costs. Although ditching costs may approach or exceed the settling pond cost, no data could be obtained to verify this and the costs were neglected.

No operating or maintenance costs were included for the settling ponds. These should be relatively small and consist of dredging every few years, minor structural maintenance as necessary and water sampling activities. The labour component is assumed captured in the estimates for corporate overhead provided in Section 6.2.4.

The construction schedule for the settling ponds is assumed to be at the start of mining and at year 15. This will vary from mine to mine and this schedule is purely generic and not necessarily typical.

Mine drainage is normally the responsibility of the mining company. Although settling ponds represent a capital cost to the mining company, this cost is passed on to the utility as part of the cost of coal. For the sake of simplicity, in the calculations performed in Section 7 it will be assumed that it is part of the utility's capital cost.

c) **Mine Studies and Monitoring**

The environmental costs included here cover those ongoing monitoring and study activities identified in Section 5.3 which are necessary to comply with the Development and Reclamation Approval, the Groundwater Diversion Permit under the Water Resources Act, and any special work in the mine related to the Clean Water Act. All these costs are assumed ongoing for the 35 year life of the mine except the test plot research work.

Test plot work typically lasts about ten years and may be initiated shortly after the ERCB approval. In the case of some projects, test plots may be initiated even before an ERCB hearing to gather data on reclamation which could be used at the hearings. For the purposes of this thesis, the test plot work will be assumed started just after the ERCB approval as was the case at Genesee.[45] In the generic plant schedule, this means a starting date of 1981. The first 6 1/2 years cost of the test plot work to Unit 1 startup will consequently be treated as capital and the last 3 1/2 years as operating costs.

It was not possible to obtain good data on which to base the operational mine studies and monitoring costs. Budget estimates for the Genesee project indicate about $20,000 per year for reclamation quality assurance, soil testing and groundwater work with approximately $25,000 per year to operate test plots in 1987$'s. It is acknowledged that these costs could well be higher depending on government requirements since they assume a routine program with no unforseen problems. The costs do not include in-house labour which is covered by the corporate overhead estimated in Section 6.2.4.

6.2.3 Approval Process Costs

a) General

Regulatory approval costs are very difficult to obtain because electric utility accounting systems are not organized to track these costs separately. In addition costs from only the most recent projects are applicable because only these projects were subject to the full impact of the fully implemented regulatory system under review. These projects at Keephills, Sheerness and Genesee were all planned in the early to mid 1970s and their approval processes covered a period well into the 1980's.

It was possible to obtain costs from only the Sheerness and Genesee projects. While the Genesee costs are comprehensive and well documented from internal Edmonton Power records, the Sheerness costs are more limited since they reflect only Alberta Power's plant approval costs and not those applicable to the mines. Obtaining Sheerness mine approval costs was not possible because two separate mining companies are involved which operate as separate entities to sell coal to Alberta Power. In the case of Genesee, the joint venture agreement between Edmonton Power and Fording Coal Limited as mine operator considerably simplifies the accounting of environmental costs.

The costs used in this section consequently reflect average Genesee and Sheerness plant environmental approval costs and Genesee mine approval costs. The major component of the costs are billings paid to the expert consultants required to generate the diverse studies for environmental approvals.

It is obvious that the data base used in this study is very small because of the few projects involved and the limited data available. In addition, site specific circumstances can significantly affect costs as is shown when comparing Sheerness and Genesee archaeological approval costs. These costs should consequently be seen as a sampling of recent experience but not as good predictors of future costs.

The methodology followed in this section was to take the actual annual cost information and place it on the schedule appropriate to the generic plant model. Since there is not more than two years of timing adjustment, no inflation or deflation was applied to the "as spent" dollar amounts. Considering the other estimating errors involved, this sort of minor adjustment is not meaningful.

b) **Generic Approval Process Schedule**

The time taken to obtain regulatory approvals is based on the time taken in recent projects. These times and milestones are given in Table 6.8.

Based on Table 6.8, the following generic approval process times are appropriate:

ERCB submission to hearing	6 months
ERCB hearing to approval	6 months
Approval to start construction	1 1/2 years

Table 6.8

Approval Process Timing

	Keephills	**Sheerness**	**Genesee**
ERCB submission date	Nov.76 (34)	Aug.77 (25)	Jan.78 (43)
ERCB hearing date	Mar.77 (53)	May 78 (52)	Jul.78 (52)
ERCB approval date	Aug.77 (53)	Jan.79 (52)	Mar.81 (22)
Start Construction date	Sep.78 (72)	Sep.80 (65)	Jul.82 (45)
Time between ERCB submission and hearing	4 months	9 months	6 months
Time between ERCB hearing and approval	5 months	8 months	32 months
Time between ERCB approval and construction start	13 months	20 months	15 months

Note:

(i) The Genesee and Sheerness applications were competing, with the Sheerness project receiving approval first. Hence the delay in the Genesee approval.

(ii) The Keephills project was planned on a fast track to meet an anticipated power shortage due to the cancellation of the Camrose-Ryley project. In addition, the site was not strictly speaking "greenfields" but an extension of an existing mine site.

(iii) Construction here means the start of site clearing. Clean Water and Air Act Permits generally consider the start of construction to be the plant site foundation work which starts later.

The time over which environmental studies were conducted for the Sheerness and Genesee project which culminated in the application to the ERCB was about 3 years.[45,66] This excluded early feasibility studies conducted years previously. Such exploratory studies are not included in this thesis.

The following plant unit commissioning dates were assumed for the generic plant model in Section 6.1

Unit #1	July 1, 19[illegible]
Unit #2	July 1, 1988

A five year construction period to startup of Unit #1 was used consistent with the EUPC generic plant data.[47]

The detailed approvals stage commences directly after the ERCB approval is obtained. While many approvals must be obtained before construction commences, others are dependent on certain stages of the construction and commissioning process schedule.

Table 6.9 summarizes the resulting generic plant project schedule.

Table 6.9

Generic Plant Project Schedule (2 x 375 MW)

Milestone	**Date**
Start Environmental Studies	Jan. 1, 1977
Submit ERCB Application	Jan. 1, 1980
ERCB Hearing	Jul. 1, 1980
ERCB Approval	Jan. 1, 1981
Start Construction	Jul. 1, 1982
Unit #1 Commercial Startup	Jul. 1, 1987
Unit #2 Commercial Startup	Jul. 1, 1988

c) **Approval Costs**

The costs presented in Table 6.10 below include mainly the billing costs of consultants hired to conduct the required environmental studies or to assist in the preparation of applications. The costs represent the average Sheerness and Genesee project approval costs and the Genesee mine approval costs for reasons explained earlier. The costs have also been rescheduled to conform to the generic plant schedule.

The costs do not include utility and mining company staff labour and overhead. These costs are estimated separately in Section 6.2.4.

Table 6.10

Generic Project Approval Costs

($000s as spent)

Year	**Major Activities**	**Cost**
1977	Enviromental Impact Assessment	179
1978	studies and application	94
1979	preparation	218
1980	ERCB Hearing and Decision	75
1981	Detailed Approvals	1105
1982	Start Construction & Detailed Approvals	637
1983	Detailed Approvals	177
1984	Detailed Approvals	81
1985	Detailed Approvals	66
1986	Detailed App. & Preoperational Monitoring	60
1987	Detailed App. & Preoperational Monitoring	34

Notes:

(i) The years 1977 - 1979 involve intensive field studies.

(ii) Most costs in 1980 are for the attendance of consultants at the hearing or at public meetings and for addressing the application review deficiencies communicated by the ERCB and government agency review.

(iii) Costs in 1981 and 1982 are high for two reasons:

- Archaeologic survey costs were very high at Genesee compared with Sheerness since it was found to be rich in prehistoric resources.
- The major Development and Reclamation application is usually prepared at this time, requiring detailed soil surveys and other studies.

(iv) These costs are all assumed incremental since 1971. As discussed in Section 4, there was virtually no environmental approval process before that date.

6.2.4 Corporate Overhead

For the purposes of this study, environmental corporate overhead is defined to mean the cost of all utility and mining company staff labour for environmental work excluding the actual mine reclamation labour. (This is included in the reclamation costs.) The cost includes all benefits and the office overhead allocated to cover such items as accommodation, secretarial support, computing support, vehicle usage, travel expenses, etc.

Since the implementation of the new environmental legislation in the 1970's, electric utilities and coal mining companies involved in major projects have had to commit staff on a full time basis to environmental matters. Either staff specially trained in environmental disciplines were hired or existing staff with previous experience were used. Before 1970, environmental requirements were trivial in comparison and work was usually allocated on a temporary basis to staff engineers and plant technicians

The three generating utilities in Alberta have organized their staffing in different ways according to varying company philosophies, the degree of coal mining involvement and the proximity of head office resources to plants.

TransAlta Utilities Corporation, which is by far Alberta's largest generating utility, operates three large coal-fired plants in the Wabamun area as well as a number of hydro dams. TransAlta is also responsible for the environmental affairs at the two mines serving these plants. All environmental applications are coordinated by staff at the Calgary head office. Until a corporate re-organization late in 198[illegible], the environmental planning department consisting of five professionals was responsible for applications and the organization of any studies. A professional engineer in another department was responsible for plant operations environmental matters, and a reclamation specialist for mine reclamation. Operations personnel at the plants were responsible for compliance with environmental requirements and monitoring equipment maintenance. Ambient air monitoring was done entirely by consultants. Two mine agronomy personnel implemented various reclamation monitoring programs. TransAlta also had an engineer with major involvement in environmental research programs.

Alberta Power Limited operates three coal-fired plants at Battle River, Grande Cache and Sheerness as well as a number of small diesel and gas turbine plants in remote areas. All mine environmental matters are the responsibility of the coal companies which supply the plants, and all mine approvals are in the name of the mining companies. At the Edmonton head office a senior environmental engineer is responsible for environmental planning and an engineer in another department for licence renewals and operational reporting. Environmental monitoring equipment design and acquisition has traditionally been handled by the engineering services. The other operational environmental matters are handled by staff at the plants mostly under the supervision of the laboratory and instrument maintenance sections. Generally plant individuals are not dedicated to environmental work and have other duties.

Edmonton Power operates two gas-fired plants in the City and has the Genesee coal-fired plant under construction nearby. The Genesee mine is a joint venture with Fording Coal Limited. Although the mine environmental programs are mostly handled by

Fording Coal, all mine approvals are in Edmonton Power's name. Edmonton Power must consequently have involvement in mine environmental programs. Virtually all environmental work in Edmonton Power is centralized in one section consisting of two professionals and two technicians. This group is responsible for all planning, approvals, plant and transmission system environmental programs, and monitoring instrument specifications, designs, and maintenance. When the mine becomes operational, an agronomist will be used part time on reclamation activities. Fording Coal hav e full time environmentalist with responsibilities for n ie Genesee Project.

All three of these utilities have been involved in a major project which saw fruition during the 1980s. In addition, all utilities have been involved in planning other projects which have either been temporarily postponed or shelved. There is also some environmental work not related to coal-fired generation. It is consequently difficult to estimate the utility or mine staff time commitment to environmental affairs for a single typical 750 MW power plant and mine project. No detailed time sheets are available to support any assumptions. The problem is further complicated by the fact that not only staff whose main task is environmental work are involved. Many individuals in a utility or mining company spend small amounts of time on environmental matters during the planning, engineering, construction, and operating phases. These small time fragments should also be taken into account because cumulatively, the time involved is likely significant.

The method used to estimate this internal staff time commitment was to average the estimates of an expert from each of the three major generating utilities.[65,72] This included the author's own estimate. The estimates did not segregate the utility and mine staff time because some utilities are more directly involved than others in mine environmental work. The estimates were, however, separated into the approvals phase and the operations phase because the requirements for these two phases are distinctly different.

The man-years of work were assumed spread evenly over the two activity phases in order to simplify the estimates unless stated otherwise. This may be approximately true in the case of the operating phase but not in the case of the approvals phase. The approvals process involves periods of high activity when preparing major applications or attending hearings but periods of low activity during some of the construction phase. Consultants are generally used to not only provide specific expertise but to assist during periods of high activity and these costs are reflected in the approval costs in Section 6.2.3. While there is some variation between the utilities on the extent to which consultants are used for this purpose, the variation does not appear to be large and should not invalidate the man-year estimates due to the averaging process used.

ıe estimates were also categorized into professional and technician manhours. Although this is another simplification, it is a convenient way in which to view the labour involved.

The following estimates were obtained:

Approvals phase until

startup of Unit #1 - 1.75 professional man-years/year
(Range of estimates: 1.25 - 2.5)
- 0.5 technician man-years/year
for last two years.
(Range of estimates: No variation)

Operations phase - 1.5 professional man-years/year
(Range of estimates: 1-2)
- 1.75 technician man-years/year
(Range of estimates: 1.5 - 2)

Professional and technician unit man-year costs are based on salary surveys published by the Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA) in 1987 \$.[27] For the purpose of this thesis, an average professional will be considered to be equivalent to an average Level D engineer (about 9 years experience) and a technician, an average certified engineering technician as listed in these surveys. This is a simplification considering that environmental staff may include a range of scientific disciplines, not just engineering. The figures are, however, used more as an indication of responsibility and expertise.

Conversion of annual salary to total payroll costs assumes a factor of 1.13, a figure considered reasonable for general benefits in the APEGGA publication. In addition, an overhead factor on payroll cost of 1.5 was choosen based on assuming the environmental staff can be roughly compared with engineers in a large consulting company. An APEGGA Guideline[28] estimates an overhead factor of 2.0 for breakeven on billed manhour payroll cost in such a company. This was adjusted downward by 25% to allow for the unbillable time in a consulting com[illegible] which does not apply to corporate staff on salary. This r[illegible]s in a total overhead factor on annual salary of 1.695 and the costs shown in Table 6.11.

Table 6.11

Generic Environmental Staff Labour Costs

(1987 $/man-year)

	Average Salary	**Total Cost**
Professional	54,207	91,881
Technician	34,940	59,223

Before 1971, the only environmental approvals required were Board of Health Air and Water Approvals and a Water Diversion Licence. Approvals consequently required few man-hours of work compared with the involved process currently in existence. Similarly, operational man-hours were negligible compared to today's situation which requires detailed monitoring and reporting. Consequently, the pre 1971 environmental labour costs were neglected as being small compared with the current costs.

7. IMPACT ON REVENUE REQUIREMENTS

7.1 The Revenue Requirements Model

The utility revenue requirements are defined as the sum of the return on capital, the depreciation expense, and the plant operating and maintenance expense (which includes the coal cost). The determination of utility revenue requirements was by a modified generation planning model of the type used by the Electric Utility Planning Council. This model has the following features:

a) Capital cost cash flows for each unit accumulate interest during construction until the units start commercial operation. On that date it is assumed that the accumulated capital enters the rate base and the utility receives a constant real rate of return over the life of the plant.

b) The term "interest during construction" does not refer to project debt interest but to the interest rate approved by the Public Utilities Board based on the utility's corporate debt structure. The correct utility terminology would be "allowance for funds used during construction" (AFUDC). The convention of calculating this based on half the cash flow incurred in any year before commercial startup was followed.

c) All costs are converted to nominal dollars. Cash flow data expressed in constant dollars are escalated at appropriate rates (Appendix II).

d) Once capital costs enter the rate base, they are subject to depreciation. A straight line rate is used with the plant property in service having a zero book value at the end of year 30 for each unit. For the last 5 years of operation, the utility is assumed to obtain no return on capital. All additional capital in years after the year of commercial startup is assumed added in the mid year and depreciated for only six months of the year. Similarily, in the year of U.it startup (in the mid-year), only the remaining six months depreciation are allowed.

e) When calculating the total plant revenue requirements, virtually all capital enters the rate base with the commercial startup of the two units. No replacement capital is included during the life of the plant and virtually all depreciation of capital is consequently spread over 30 years. Replacement costs are included as an annual fixed operating expense.

f) When calculating the revenue requirements of environment components, some capital costs are shown as entering the ra base at different points during the life of the plant. T situation is simplified by continuing to depreciate on a straight line basis to zero book value at the end of year 30. Later capital additions are consequently depreciated at a higher rate. Since nearly all plant environmental capital costs are incurred during the construction phase, this simplification introduces negligible distortion. The only situation when major capital costs are shown entering the rate base throughout the operating period is when considering the special case of net ash disposal costs.

g) All plant environmental capital costs are assumed to be part of the first unit capital except for the electrostatic precipitator costs for the second unit. This is logical because virtually all of these costs would have to be incurred to bring the first unit into commercial operation and to sustain the operation.

h) In the total plant revenue requirements calculation, all the mine capital and operating costs are included in the coal cost.

i) In the environmental revenue requirements calculation, all the mine reclamation costs are expressed as part of the coal cost. Other mine environmental costs are, however, treated in the same way as plant capital or operating and maintenance costs. This simplification was necessary because in the case of the environmental corporate overhead cost, it was not possible to separate the mine operator's component. The other items which include settling pond capital and mine monitoring are relatively small items which are more conveniently handled as plant capital with negligible overall error.

j) Federal and Provincial taxes are ignored in the environmental revenue requirements calculations. These are minor since all provincial and 95% of federal taxes are refunded to the investor owned utilities while the municipally owned utilities are not taxed. Property taxes are included in the operating and maintenance fixed costs.

7.2 Evaluation Procedure

The impact of environmental costs on power plant revenue requirements is assessed by comparing the total present worth of the revenue requirements. The total present worth of the power plant revenue requirements is used simply as a basis for measuring the relative contribution of the environment component to power consumer costs.

The evaluation includes the consideration of a typical case and several special cases. The typical case includes all those environmental costs usually incurred. Since there is some doubt about typical reclamation costs due to subsoil handling, a second version of the typical case is also considered which halves the salvage requirement for subsoil. Two other special cases are considered - the inclusion of cooling pond costs and the inclusion of net ash disposal costs. Neither of these cases is typical but each could occur at a particular site.

Using the typical case, the contribution of the major components of the environmental costs are calculated. This enables the important factors influencing the environmental costs to be identified. The probable impacts of future changes regulation can consequently be discussed.

Detailed information on the costs used is provided in the spreadsheets in Appendix II. Since the spreadsheets used to calculate the environmental cost components are essentially similar for each case, only the typical case is provided.

The costs included in the various cases are summarized in Table 7.1.

Table 7.1

Environmental Costs Included in Evaluation Cases

Typical Case	Reduced Reclamation Half Subsoil Case	Cooling Pond Case	Net Ash Disposal Case
Capital			
Regulatory Approvals	Same as typical case	Same as typical case	Same as typical case
Electrostatic Precipitators			
Plant Drainage			
Mine Drainage			
Stack & Air Monitoring			
Corporate Overhead			
		$22.5 million cooling pond	Net plant dry ash disposal cost
Operating & Maintenance			
ESP Energy	Same as typical case	Same as typical case	Same as typical case
Compliance Monitoring			
Mine Monitoring			
Reclamation:			
- recontouring			
- 1 metre subsoil	0.5 metre subsoil.		
- 0.2 metre topsoil	Same as typical case		
- cultivation			
Corporate Overhead			
		Cooling pond O & M cost	Net mine and plant dry ash disposal O & M cost

7.3 **Results**

Results are summarized in the tables below. Detailed costs are given in the spreadsheets provided in Appendix II. All total present worth of revenue requirements figures are calculated to the end of 1987.

Table 7.2

Environmental Cost Contribution to Revenue Requirements

Case	Total Present Worth of Revenue Requirements ($000)	Contribution to Total (%)
Total Plant	1,817,940	Reference cost
Typical	93,719	5.2
Half Subsoil	75,672	4.2
Cooling Pond	168,781	9.3
Ash Disposal	120,659	6.6
Cooling Pond & Ash Disposal	195,721	10.8

Table 7.3

Contribution of Capital and Operating and Maintenance Costs to Total Present Worth of Revenue Requirements

Case	Capital (%)	Operating & Maintanance (%)
Total Plant	50.5	49.5
Typical	31.0	69.0

Table 7.4

Contribution of Environmental Components to Total Present Worth of Revenue Requirements Based on Typical Case

Component	TPW Revenue Requirement	Contribution
	($000s)	(%)
Electrostatic Precipitators	24,105	25.7
Regulatory Approvals	5,720	6.1
Regulatory Approvals & Overhead Capital	8,159	8.7
Plant & Mine Monitoring & Overhead Expense	4,955	5.3
Total Overhead	6,196	6.6
Reclamation		
- 1 m subsoil salvage	54,722	58.4
- 0.5 m subsoil salvage	36,659	48.4 *

(* Based on half subsoil case)

7.4 Discussion

As can be seen from Table 7.2, the increased environmental costs since 1971 are substantial, being between 4.2 and 5.2% of the total present worth of revenue reqirements for a typical project. In certain circumstances this cost increase could be as much as 10.8% of revenue requirements, but history so far indicates that such situations are uncommon. This spread of costs emphasises that these environmental costs are highly site specific. Similar plants may use similar cooling and ash disposal options but the environmental costs could be totally different. One site may have allowed the choice of less expensive technologies but the utility may have been unable to adopt these options for environmental reasons.

Table 7.4 indicates that the greatest increase in environmental costs has been due to reclamation. These costs are much larger than for any other environmental component even if lower subsoil salvage requirements are assumed. Reclamation costs are very site specific because they are dependent on the original soil quality and land capability. As the legislation now stands, a poor quality soil with low original capability is generally less costly to reclaim than a good soil of high capability. This is due to the fact that subsoil and topsoil salvage requirements must be lower if this material exists in only limited amounts. This is the case at many existing mines.[72]

While the electrostatic precipitator costs are much lower than the reclamation costs, it must be realized that virtually all the reclamation costs are as a result of regulatory measures since 1971. Only about 60% of the electrostatic precipitator costs were estimated to be as a result of legislation since that date. As a total cost, particulate removal is by far the largest plant environmental cost, excluding reclamation. This cost illustrates a trend commonly exhibited in "add-on" environmental protection technology. The cost of removing an additional 4 1/2 % of the particulates is about 2 1/2 times greater than removing the first 95%.

The total additional cost of obtaining environmental regulatory approvals and the associated monitoring costs, including approval renewal costs and the corporate overhead, are approximately 14% of the total environmental costs or 0.7% of the total present worth of the revenue requirements. The bulk of these costs are for either corporate or consultant labour. The data does not permit a precise estimate of the labour component, but an examination of the work involved in the approvals and monitoring process indicates this should be more than 80% of the cost.[66,45]

The additional utility and mining company overhead is estimated to be only about 6.6% of the total environmental cost. This is not unexpected because the additional environmental costs are dominated by reclamation operating and maintenance costs and plant capital. It is also indicative of the fact that environmental labour requirements are very variable with peak requirements commonly satisfied by consultants. Corporate environmental staffs are normally small.

About 69% of the additional environmental costs are due to operating and maintenance costs. This compares with 50% of the total plant costs. The main reason for this is the reclamation costs. From Table 7.4 it can be seen that without the reclamation costs, the additional environmental costs are mostly from capital.

The generic model assumed for this thesis is for a new plant at a new or "greenfields" site. The doubling of the plant capacity at the site will obviously not double the environmental costs. Environmental costs will not, however, be substantially lower than for the original plant. This can be seen from Tables 7.1 and 7.4. The regulatory approvals and overhead capital can be expected to be substantially lower. Being an expansion at an established site, the regulatory approval process is less detailed because many of the studies will have been completed and the issues resolved when dealing with the first two units. The mine monitoring and plant monitoring activities will also be lower for the same reasons. However, the large cost items, mine reclamation and the electrostatic precipitators, will be essentially duplicated.

In the future, reclamation costs are likely to be increasingly absorbed due to the use of more efficient overburden and subsoils handling technologies. These technologies may not be adopted out of a desire to reduce the reclamation costs but rather the total coal costs by more efficient mining techniques. In effect it may be possible at some mine sites to ensure that at least 1 metre of suitable subsoil is replaced without selectively handling the subsoil. An example of such a technology is the cross-pit conveyor.[75]

The conventional dragline mining technique normally results in the soil profile being inverted with the least suitable materials placed at the surface. Usually this material is not suitable for use as a subsoil. A cross pit conveyor in tandem operation with a dragline normally results in the original more suitable surficial materials being replaced back on the surface. Assuming the typical case generic mine, such an innovation could reduce the environmental costs by as much as 38%. Not all of these savings would necessarily accrue to the cost of coal because of partially offsetting non environmental costs.

The absorption of environmental costs in new technologies is not an uncommon phenomenon with the passage of time. As noted in a recent Electric Power Research Institute publication[77], the first technological response to a new environmental standard is usually some added-on system. This "band aid" approach tends to be expensive because the original plant or mining technology was not developed to include consideration of the en[illegible]nmental constraint. (Consequently the cost of retrofitting an existing plant is virtually always much more expensive than including the technology in a new plant design.) As time passes, new technology is developed which may totally integrate the environmental constraint in the process. The environmental cost may then become embedded and no longer separable as a distinct cost. The new technological design simply integrates the environmental constraint along with many other factors.

Utility boiler design is a good example of this phenomenon. The strict nitrogen oxide standards imposed in some overseas countries (e.g. West Germany and Japan) is resulting in the adoption of a new "add-on" type of technology called selective catalytic reduction. Already new integrated boiler technologies are the subject of intensive research and may achieve comparable results. Where environmental standards for coal combustion are extremely strict, such as California, technology has been developed at a demonstration plant level which radically alters the whole concept of power generation from coal (Cool Water Plant). This technology, known as "integrated gasification combined cycle" is not only very clean but is of interest to many utilities for mainly economic reasons.

Within this context the future of environmental costs in coal-fired power generation will depend mainly on future standards, the cost of the technology and the degree to which these costs can be mitigated by new technologies. Some of these technologies may totally absorb certain costs.

8. CONCLUSIONS

a) Based on total present worth, the environmental regulatory system in Alberta has added approximately 4.2 to 5.2% to the revenue requirements of a typical new 2 x 375 MW coal-fired power plant since 1971.

b) The environmental costs are very site specific. In most cases recirculating cooling water costs and net dry ash disposal costs cannot be considered to be environmental costs. At a site where these facilities and operations are required primarily for environmental reasons, the increase in total present worth of revenue requirements could be as high as 10.8%.

c) At a typical site, reclamation requirements have added the most to environmental costs since 1971. The major component is subsoil handling which is very dependent on soil conditions and this cost is consequently highly variable from site to site.

d) The second largest environmental cost component is particulate removal by electrostatic precipitators. Whereas pre-1971 standards required the removal of about 95% of the smokestack fly ash, the current standards require about 99.5% removal. This additional 4 1/2% removal costs approximately 2 1/2 times more than the first 95%.

e) The environmental costs for a second plant at an existing plant site will not be substantially less than the costs for the original plant, other things being equal. This is because only regulatory approval, corporate overhead, and monitoring costs will be lower and these are only a small part of the environmental costs.

f) New technologies in mining and plants have the potential of significantly reducing the environmental costs of new coal-fired projects by integrating the environmental constraints in the design. Any such savings would be offset by more stringent standards.

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APPENDIX I

Calculation of Electrostatic Precipitator Efficiencies

Calculation of Generic Electrostatic Precipitator Efficiencies for Current Particulate Standards and Pre-1971 Standards

Current particulate standard = 0.09 gm/kg dry flue gas at 50% excess air.

Dry flue gas rate based on 90% worst ash level in coal **(45)** = 8424.8 gm/kg coal at 50% excess air.

Maximum allowable emission $= 0.09 \times 8424.8 \times 10^{-3}$
$= 0.7582$ gm/kg coal

Design worst case flyash loading based on 90% worst ash coal and 80% of ash reporting to ESP $= 0.8 \times 19.4 \times 10$

$= 155.2$ gm/kg coal

$$\text{ESP efficiency} = \frac{(155.2 - 0.7582)100}{155.2}$$

$= \underline{99.51\%}$

Pre-1971 Public Health Regulation Standard = 0.85 lb/1000 lb wet flue gas at 50% excess air.

Wet flue gas rate based on 90% worst ash level in coal **(45)** = 8973.0 gm/kg coal at 50% excess air.

Maximum allowable emission $= 8973 \times 0.85 \times 10^{-3} = 7.6271$ gm/kg coal

$$\text{ESP efficiency} = \frac{(155.2 - 7.6271)100}{155.2}$$

$= \underline{95.09\%}$

APPENDIX II

Revenue Requirements Calculation

Spreadsheets

GENERIC COAL-FIRED POWER PLANT REVENUE REQUIREMENTS

Assumptions:

Plant Capacity	2 x 375 MW Units	
Commissioning Dates	Unit 1	Jul. 1, 1987
	Unit 2	Jul. 1, 1988
Unit Life	35 years	
Depreciation Rate (%)	Straight Line Zero Book Value end year 30	
Taxes	Nil	
Real Rate of Return (%)	6.0	

Escalation:

Capital	(1986-)	Statscan Construction Power Plants
	(1987+)	Inflation Statscan CPI
O & M		Inflation
Replacements		Inflation
Insurance		Inflation
Coal		Inflation

Real Discount Rate (%) 6.0

Operating and Maintenance Costs: (000s mid 1982 $)	Unit 1
Fixed	3440
Variable (/GW-hr)	0.45
Replacements, Insurance, Property Tax	5170

Inflation Rates: (%)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
	9.46	8.36	9.80	11.19	12.10	9.26	4.55	3.76	4.35	4.17	4.40	4.50

Escalators. year end 1976												
Capital	1.079	1.173	1.302	1.453	1.625	1.736	1.800	1.857	1.927	2.020	2.109	2.204
O & M Fixed/Var.	1.095	1.186	1.302	1.448	1.623	1.774	1.854	1.924	2.008	2.091	2.183	2.282
Replacements,	1.095	1.186	1.302	1.448	1.623	1.774	1.854	1.924	2.008	2.091	2.183	2.282
Ins., Taxes												
Coal	1.095	1.186	1.302	1.448	1.623	1.774	1.854	1.924	2.008	2.091	2.183	2.282
IDC Rates. (%)	10.60	10.60	10.60	10.90	11.01	12.48	12.88	12.92	12.72	12.75	12.07	12.00

Capital Cost Cash Flow:
($000s) mid 1982

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Unit 1						10000	46000	77000	122000	88000	36000	1000
Unit 2						4000	16000	29000	47000	48000	57000	36000

($000s) as spent

Unit 1						10000	48395	83781	137354	103343	44225	1283
Unit 2						4000	16833	31554	52915	56369	70023	46193

Interest During
Construction: ($000s) nom.

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Unit 1	0	0	0	0	0	624	4485	13617	29203	48339	30251	
Unit 2	0	0	0	0	0	250	1631	4973	10901	19283	28210	19202

Property in Service:
($000s) nominal

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Unit 1											553617	554900
Unit 2												362338
Total	0	0	0	0	0	0	0	0	0	0	553617	917238

Calculation of Return :
($000s) nominal

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Incremental Depreciation 1									9227	22
Incremental Depreciation 2									0	6039
Depreciation Unit 1									9227	18476
Depreciation Unit 2									0	6039
Accumulated Depreciation 1									[illegible]	[illegible]7703
Accumulated Depreciation 2									0	6039
Net Property in Service									544390	983496
Mid Year Rate Base									[illegible]	713943
Return									[illegible]	[illegible]

Generation: (GW-hrs)

1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
										939	3238

Coal Production: (Ktonnes)

1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
										563	1943

Coal Cost: mid 1986 $/tonne

1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
										14.33	12.45

$/tonne nominal

1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
										14.94	[illegible]

Operating and Maintenance
Costs: ($000s) as spent

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Fixed Plant											2165	6783
Variable Plant											532	1915
Repl., Ins., Tax											3253	8899
Coal											8414	26350
Total	0	0	0	0	0	0	0	0	0	0	14363	43948

Revenue Requirements.
($000s) nominal

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Return	0	0	0	0	0	0	[illegible]	0		0	28308	74964
Depreciation	0	0	0	0	0	0	0	0	0	0	9227	24515
O & M	0	0	0	0	0	0	[illegible]	0	0	0	14363	43948
Total	0	0	0	0	0	0	0	0	0	0	51898	143427

Present Value in 1987:
($000s) nominal

	1987	1988
	51898	129798

Total Present Worth:
($000s, nominal
1917940

Inflation Rates: (%)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
	5.00	4.00	4.30	4.50	4.50	4.80	5.00	3.50	4.50	4.50	4.50	4.50

Escalators: year end - 1976												
Capital	2.314	2.407	2.510	2.623	2.741	2.873	3.016	3.122	3.262	3.409	3.562	3.723
O & M Fixed/Var	2.396	2.492	2.599	2.716	2.838	2.974	3.123	3.232	3.378	3.530	3.688	3.854
Replacements, Ins., Taxes	2.396	2.492	2.599	2.716	2.838	2.974	3.123	3.232	3.378	3.530	3.688	3.8[illegible]
Coal	2.396	2.492	2.599	2.716	2.838	2.974	3.123	3.232	3.378	3.530	3.688	3.854

IDC Rates: (%)

11.80

Capital Cost Cash Flow:
($000s) mid 1982

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Unit 1	0											
Unit 2	3000											

($000s) as spent

Unit 1	0
Unit 2	4033

Interest During
Construction: ($000s) nom.

	1989
Unit 1	
Unit 2	

Property in Service:
($000s) nominal

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Unit 1	554900	554900	554900	554900	554900	554900	554900	554900	554900	554900	554900	554900
Unit 2	366370	366370	366370	366370	366370	366370	366370	366370	366370	366370	366370	366370
Total	921271	921271	921271	921271	921271	921271	921271	921271	921271	921271	921271	921271

Calculation of Return :
($000s) nominal

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Incremental Depreciation 1	22	0	0	0	0	0	0	0	0	0	0	0
Incremental Depreciation 2	70	70	0	0	0	0	0	0	0	0	0	0
Depreciation Unit 1	18498	18498	18498	18498	18498	18498	18498	18498	18498	18498	18498	18498
Depreciation Unit 2	12147	12217	12217	12217	12217	12217	12217	12217	12217	12217	12217	12217
Accumulated Depreciation 1	46201	64699	83197	101696	120194	138692	157190	175688	194186	212684	231183	249681
Accumulated Depreciation 2	18186	30403	42620	54837	67054	79271	91488	103705	115922	128139	140356	152573
Net Property in Service	856883	826168	795453	764738	734023	703307	672592	641877	611162	580447	549732	519017
Mid Year Rate Base	870190	841526	810810	780095	749380	718665	687950	657235	626520	595804	565089	534374
Return	95721	84153	83513	81910	78685	77616	75674	62437	65785	62559	59334	56109

Generation: (GW-hrs)

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
4750	4877	4892	4892	4892	4892	4892	4892	4892	4892	4892	4892

Coal Production: (Ktonnes)

2850	2926	2935	2935	2935	2935	2935	2935	2935	2935	2935	2935

Coal Cost: mid 1986 $/tonne

12.16	12.25	12.49	12.53	12.60	12.57	12.53	12.65	12.60	12.57	12.53	12.49

$/tonne nominal

13.98	14.61	15.51	16.24	17.07	17.82	18.64	19.61	20.32	21.18	22.06	22.98

Operating and Maintenance
Costs: ($000s) as spent

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Fixed Plant	9474	9899	10310	10764	11248	11772	12349	12871	13387	13990	14619	15277
Variable Plant	2943	3158	3299	3444	3599	3767	3951	4118	4284	4476	4678	4888
Repl., Ins., Tax	11526	12043	12543	13095	13684	14321	15023	15659	16287	17019	17785	18586
Coal	39546	42736	45523	47679	50103	52309	54699	57560	59631	62166	64756	67454
Total	63488	67836	71675	74982	78635	82169	86022	90209	93588	97651	101839	106206

. . 1

Revenue Requirements:
($000s) nominal

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Return	95721	84153	83513	81910	78685	77616	75674	62437	65785	62559	59334	56109
Depreciation	30646	30715	30715	30715	30715	30715	30715	30715	30715	30715	30715	30715
O & M	63488	67836	71675	74982	78635	82169	86022	90209	93588	97651	101839	106206
Total	189855	182703	185903	187607	188035	190500	192412	183361	190088	190926	191888	193030
Present Value in 1987: ($000s) nominal	154788	135416	124920	114086	103481	94619	86098	74929	70297	63898	58117	52908

Total Present Worth:
($000s) nominal
1817940

Inflation Rates: (%)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
Escalators. year end - 1976												
Capital	3.890	4.065	4.248	4.439	4.639	4.848	5.066	5.294	5.532	5.781	6.041	6.313
O & M Fixed/Var.	4.028	4.209	4.399	4.596	4.803	5.019	5.245	5.481	5.728	5.986	6.255	6.537
Replacements, Ins., Taxes	4.028	4.209	4.399	4.596	4.803	5.019	5.245	5.481	5.728	5.986	6.255	6.537
Coal	4.028	4.209	4.399	4.596	4.803	5.019	5.245	5.481	5.728	5.986	6.255	6.537

IDC Rates: (%)

Capital Cost Cash Flow:
($000s) mid 1982

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Unit 1												
Unit 2												

($000s) as spent

Unit 1
Unit 2

Interest During
Construction: ($000s) nom.

Unit 1
Unit 2

Property in Service:
($000s) nominal

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Unit 1	554900	554900	554900	554900	554900	554900	554900	554900	554900	554900	554900	554900
Unit 2	366370	366370	366370	366370	366370	366370	366370	366370	366370	366370	366370	366370
Total	921271	921271	921271	921271	921271	921271	921271	921271	921271	921271	921271	921271

Calculation of Return :
($000s) nominal

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Incremental Depreciation 1	0	0	0	0	0	0	0	0	0	0	0	0
Incremental Depreciation 2	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation Unit 1	18498	18498	18498	18498	18498	18498	18498	18498	18498	18498	18498	18498
Depreciation Unit 2	12217	12217	12217	12217	12217	12217	12217	12217	12217	12217	12217	12217
Accumulated Depreciation 1	268179	286677	305175	323673	342172	360670	379168	397666	416164	434662	453160	471659
Accumulated Depreciation 2	164790	177007	189224	201441	213658	225875	238092	250309	262526	274743	286960	299177
Net Property in Service	488302	457586	426871	396156	365441	334726	304011	273296	242580	211865	181150	150435
Mid Year Rate Base	503659	472944	442229	411514	380799	350083	319368	288653	257938	227223	196508	165793
Return	52884	49659	46434	43209	39984	36759	33534	30309	27083	23858	20633	17408

Operation: (GW-hrs)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
4892	4892	4892	4892	4892	4892	4892	4892	4892	4892	4892	4892

Coal Production: (Ktonnes)

2935	2935	2935	2935	2935	2935	2935	2935	2935	2935	2935	2935

Coal Cost: mid 1986 $/tonne

12.60	12.55	12.60	12.61	12.67	12.64	12.63	12.59	12.53	12.49	12.97	12.92

$/tonne nominal

24.23	25.22	26.46	27.67	29.05	30.29	31.63	32.95	34.26	35.69	38.73	40.32

Operating and Maintenance
Costs: ($000s) as spent

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Fixed Plant	15965	16683	17434	18218	19038	19895	20790	21726	22703	23725	24793	25908
Variable Plant	5108	5338	5578	5829	6092	6366	6652	6952	7264	7591	7933	8290
Repl., Ins., Tax	19422	20296	21209	22164	23161	24203	25293	26431	27620	28863	30162	31519
Coal	71111	74016	77655	81214	85272	88898	92825	96695	100565	104755	113676	118333
Total	111606	116333	121876	127425	133563	139362	145560	151803	158153	164934	176563	184050

Revenue Requirements.
($000s) nominal

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Return	52884	49659	46434	43209	39984	36759	33534	30309	27083	23858	20633	17408
Depreciation	30715	30715	30715	30715	30715	30715	30715	30715	30715	30715	30715	30715
O & M	111606	116333	121876	127425	133563	139362	145560	151803	158153	164934	176563	184050
Total	195205	196707	199025	201349	204262	206836	209809	212827	215951	219508	227911	232174
Present Value in 1987: ($000s) nominal	48420	44156	40431	37017	33984	31142	28588	26244	24099	22168	20829	19203

Total Present Worth:
($000s) nominal
1817940

Inflation Rates: (%)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
Escalators: year end - 1976											
Capital	6.597	6.894	7.205	7.529	7.868	8.222	8.592	8.978	9.382	9.804	10.246
O & M Fixed/Var.	6.831	7.138	7.459	7.795	8.146	8.512	8.896	9.296	9.714	10.151	10.608
Replacements,	6.831	7.138	7.459	7.795	8.146	8.512	8.896	9.296	9.714	10.151	10.608
Ins., Taxes											
Coal	6.831	7.138	7.459	7.795	8.146	8.512	8.896	9.296	9.714	10.151	10.608

IDC Rates: (%)

Capital Cost Cash Flow:
($000s) mid 1982

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unit 1											
Unit 2											
($000s) as spent											
Unit 1											
Unit 2											

Interest During
Construction: ($000s) nom.

Unit 1											
Unit 2											

Property in Service:
($000s) nominal

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unit 1	554900	554900	554900	554900	554900	554900	554900	554900	554900	554900	554900
Unit 2	366370	366370	366370	366370	366370	366370	366370	366370	366370	366370	366370
Total	921271	921271	921271	921271	921271	921271	921271	921271	921271	921271	921271

Calculation of Return .
($000s) nominal

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Incremental Depreciation 1	0	0	0	0	0	0	0	0	0	0	0
Incremental Depreciation 2	0	0	0	0	0	0	0	0	0	0	0
Depreciation Unit 1	18498	18498	18498	18498	9249	0	0	0	0	0	0
Depreciation Unit 2	12217	12217	12217	12217	12217	6108	0	0	0	0	0
Accumulated Depreciation 1	490157	508655	527153	545651	554900	554900	554900	554900	554900	554900	554900
Accumulated Depreciation 2	311394	323611	335828	348045	360262	366370	366370	366370	366370	366370	366370
Net Property in Service	119720	89005	58290	27575	6108	0	0	0	0	0	0
Mid Year Rate Base	135078	104362	73647	42932	16842	3054	0	0	0	0	0
Return	14183	10958	7733	4508	1768	321	0	0	0	0	0

Generation: (GW-hrs)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	4892	4892	4892	4892	4892	4892	4892	4892	4892	3669	1223

Coal Production: (Ktonnes)

	2935	2935	2935	2935	2935	2935	2935	2935	2935	2201	734

Coal Cost: mid 1986 $/tonne

	12.90	12.88	12.85	13.04	13.04	13.00	12.95	12.91	12.78	14.90	19.08
$/tonne nominal											
	42.07	43.89	45.76	48.53	50.71	52.83	54.99	57.29	59.27	72.21	96.63

Operating and Maintenance
Costs: ($000s) as spent

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Plant	27074	28292	29566	30896	32286	33739	35257	36844	38502	30176	10511
Variable Plant	8663	9053	9460	9886	10331	10796	11281	11789	12320	9655	3363
Rmpl., Ins., Tax	32938	34420	35969	37587	39279	41046	42893	44823	46840	33831	9778
Coal	123467	128823	134306	142425	148834	155055	161409	168151	173949	158930	70923
Total	192141	200588	209300	220794	230730	240636	250841	251608	271611	232592	94576

Revenue Requirements:
($000s) nominal

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Return	14183	10958	7733	4508	1768	321	0	0	0	0	0
Depreciation	30715	30715	30715	30715	21466	6108	0	0	0	0	0
O & M	192141	200588	209300	220794	230730	240636	250841	261608	271611	232592	94576
Total	237039	242261	247748	256017	253964	247065	250841	261608	271611	232592	94576

Present Value in 1987: ($000s) nominal	17742	16410	[illegible]	14203	12750	11225	10314	9734	9146	7088	2608

Total Present Worth
($000s) nominal
1817940

GENERIC COAL-FIRED POWER PLANT
NET ENVIRONMENTAL REVENUE REQUIREMENTS
TYPICAL CASE

Assumptions:

Plant Capacity	2 x 375 MW Units	
Commissioning Dates	Unit 1 Jul. 1, 1987	
	Unit 2 Jul. 1, 1988	
Unit Life	35 years	
Depreciation Rate	Straight Line Zero Book Value end year 30	
Taxes	Nil	
Real Rate of Return (%)	6.0	
Escalation:		
Capital (1986-)		Statscan Construction Power PI
(1987+)		Inflation Statscan CPI
O & M		Inflation
Studies		Inflation
Corporate Overhead		Inflation
Reclamation		Inflation
Real Discount Rate (%)	6.0	

Inflation Rates: (%)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
	9.46	8.36	9.80	11.19	12.10	9.26	4.55	3.76	4.35	4.17	4.40	4.50

Escalators: year end - 1976												
Capital	1.079	1.173	1.302	1.453	1.625	1.736	1.800	1.857	1.927	2.020	2.109	2.204
O & M	1.095	1.186	1.302	1.448	1.623	1.774	1.854	1.924	2.008	2.091	2.183	2.282
Studies	1.095	1.186	1.302	1.448	1.623	1.774	1.854	1.924	2.008	2.091	2.183	2.282
Corporate Overhead	1.095	1.186	1.302	1.448	1.623	1.774	1.854	1.924	2.008	2.091	2.183	2.282
Reclamation	1.095	1.186	1.302	1.448	1.623	1.774	1.854	1.924	2.008	2.091	2.183	2.282

IDC Rates: (%)												
	10.60	10.60	10.60	10.90	11.01	12.48	12.88	12.92	12.72	12.75	12.07	12.00

Capital Cost Cash Flow:
($000s) as spent

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Unit 1:												
Regulatory Approvals	179	94	218	75	1105	637	177	81	66	60	34	
Electrostatic Precipitators								1458	3398	1740	1225	65
Plant Drainage							591					
Mine Drainage											100	
Stack & Air Monitoring									113	336		
Dry Ash Disposal												
Cooling Pond												
Corporate Overhead	79	86	94	103	116	128	136	142	175	183	95	
Total	258	180	312	178	1221	765	905	1679	3752	2318	1454	65
Unit 2:												
Electrostatic Precipitators								247	3466	2154	1116	65
Total	0	0	0	0	0	0	0	247	3466	2154	1116	65

Interest During
Construction: ($000s) nom.

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Unit 1	14	38	68	105	194	368	535	772	1204	1748	1047	
Unit 2	0	0	0	0	0	0	0	16	254	645	886	529

Property in Service:
($000s) nominal

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Unit 1											19114	19179
Unit 2												9378
Total	0	0	0	0	0	0	0	0	0	0	19114	28557

Calculation of Return :
($000s) nominal

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Incremental Depreciation 1									319	1
Incremental Depreciation 2										156
Depreciation Unit 1									319	638
Depreciation Unit 2									0	156
Accumulated Depreciation 1									319	957
Accumulated Depreciation 2									0	156
Net Property in Service									18796	27444
Mid Year Rate Base									9398	23120
Return									977	2428

Generation: (GW-hrs)

1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
										939	3238

Coal Production: (Ktonnes)

										1987	1988
										563	1943

Reclamation Cost: (mid 1986 $/tonne coal)	0.86	1.02
$/tonne nominal	0.90	1.11

Operating and Maintenance
Costs: ($000s) as spent

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
ESP Energy											158	341
Compliance Monitoring											19	40
Mine Monitoring											23	47
Reclamation											505	2159
Wet Dry Ash Disposal												
Corporate Overhead											121	252
Total	0	0	0	0	0	0	0	0	0	0	825	2839

Revenue Requirements:
($000s) nominal

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Return	0	0	0	0	0	0	0	0	0	0	977	2428
Depreciation	0	0	0	0	0	0	0	0	0	0	319	795
O & M	0	0	0	0	0	0	0	0	0	0	825	2839
Total	0	0	0	0	0	0	0	0	0	0	2121	6061

	1987	1988
Present Value in 1987: ($000s) nominal	2121	5485

Total Present Worth:
($000s) nominal
93719

Inflation Rates: (%)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
	5.00	4.00	4.30	4.50	4.50	4.80	5.00	3.50	4.50	4.50	4.50	4.50

Escalators: year end 1976												
Capital	2.314	2.407	2.510	2.623	2.741	2.873	3.016	3.122	3.262	3.409	3.562	3.723
O & M	2.396	2.492	2.599	2.716	2.838	2.974	3.123	3.232	3.378	3.530	3.688	3.854
Studies	2.396	2.492	2.599	2.716	2.838	2.974	3.123	3.232	3.378	3.530	3.688	3.854
Corporate Overhead	2.396	2.492	2.599	2.716	2.838	2.974	3.123	3.232	3.378	3.530	3.688	3.854
Reclamation	2.396	2.492	2.599	2.716	2.838	2.974	3.123	3.232	3.378	3.530	3.688	3.854

IDC Rates. (%)

Capital Cost Cash Flow:
($000s) as spent

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Unit 1												
Regulatory Approvals												
Electrostatic Precipitators												
Plant Drainage												
Mine Drainage											657	
Stack & Air Monitoring												
Dry Ash Disposal												
Cooling Pond												
Corporate Overhead												
Total	0	0	0	0	0	0	0	0	0	0	657	0
Unit 2:												
Electrostatic Precipitators	67											
Total	67	0	0	0	0	0	0	0	0	0	0	0

Interest During
Construction ($000s) nom.

	1989
Unit 1	
Unit 2	

Property in Service:
($000s) nominal

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Unit 1	19179	19179	19179	19179	19179	19179	19179	19179	19179	19179	19836	19836
Unit 2	9445	9445	9445	9445	9445	9445	9445	9445	9445	9445	9445	9445
Total	28624	28624	28624	28624	28624	28624	28624	28624	28624	28624	29281	29281

Calculation of Return :
($000s) nominal

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Incremental Depreciation 1	1	0	0	0	0	0	0	0	0	0	18	18
Incremental Depreciation 2	1	1	0	0	0	0	0	0	0	0	0	0
Depreciation Unit 1	639	639	639	639	639	639	639	639	639	639	658	676
Depreciation Unit 2	314	315	315	315	315	315	315	315	315	315	315	315
Accumulated Depreciation 1	1596	2236	2875	3514	4154	4793	5432	6072	6711	7350	8008	8684
Accumulated Depreciation 2	470	785	1100	1415	1730	2045	2360	2674	2989	3304	3619	3934
Net Property in Service	26558	25603	24649	23695	22740	21786	20832	19878	18923	17969	17654	16663
Mid Year Rate Base	27001	26080	25126	24172	23218	22263	21309	20355	19400	18446	17812	17159
Return	2970	2608	2588	2538	2438	2404	2344	1934	2037	1937	1870	1802

Generation: (GW-hrs)

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
4750	4877	4892	4892	4892	4892	4892	4892	4892	4892	4892	4892

Coal Production: (Ktonnes)

2850	2926	2935	2935	2935	2935	2935	2935	2935	2935	2935	2935

Reclamation Cost:

(mid 1986 $/tonne coal)	1.16	1.18	1.19	1.20	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23
$/tonne nominal	1.32	1.41	1.48	1.56	1.67	1.74	1.83	1.91	1.98	2.07	2.17	2.26

Operating and Maintenance
Costs. ($000s) as spent

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
ESP Energy	371	388	405	423	442	462	485	505	526	549	574	600
Compliance Monitoring	42	43	45	47	49	52	54	56	59	61	64	67
Mine Monitoring	49	51	24	25	26	27	29	30	31	32	34	35
Reclamation	3772	4117	4337	4566	4891	5119	5370	5597	5821	6083	6357	6643
Net Dry Ash Disposal												
Corporate Overhead	264	276	288	300	314	328	344	359	373	390	408	426
Total	4498	4876	5099	5361	5722	5988	6281	6547	6810	7116	7436	7771

Revenue Requirements:
($000s) nominal

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Return	2970	2608	2580	2538	2438	2404	2344	1934	2037	1937	1870	1802
Depreciation	953	954	954	954	954	954	954	954	954	954	973	991
O & M	4498	4876	5099	5361	5722	5988	6281	6547	6810	7116	7436	7771
Total	8421	8438	9641	8853	9114	9347	9580	9435	9801	10007	10279	10563
Present Value in 1987. ($000s) nominal	6866	6254	5806	5384	5016	4642	4287	3856	3625	3349	3113	2895

Total Present Worth:
($000s) nominal
93719

Inflation Rates: (%)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50

Escalators: year end - 1976												
Capital	3.890	4.065	4.248	4.439	4.639	4.848	5.066	5.294	5.532	5.781	6.041	6.313
O & M	4.028	4.209	4.399	4.596	4.803	5.019	5.245	5.481	5.728	5.986	6.255	6.537
Studies	4.028	4.209	4.399	4.596	4.803	5.019	5.245	5.481	5.728	5.986	6.255	6.537
Corporate Overhead	4.028	4.209	4.399	4.596	4.803	5.019	5.245	5.481	5.728	5.986	6.255	6.537
Reclamation	4.028	4.209	4.399	4.596	4.803	5.019	5.245	5.481	5.728	5.986	6.255	6.537

IDC Rates: (%)

Capital Cost Cash Flow:
($000s) as spent

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Unit 1:												
Regulatory Approvals												
Electrostatic Precipitators												
Plant Drainage												
Mine Drainage		193									1115	
Stack & Air Monitoring												
Dry Ash Disposal												
Cooling Pond												
Corporate Overhead												
Total	0	193	0	0	0	0	0	0	0	0	1115	0
Unit 2:												
Electrostatic Precipitators												
Total	0	0	0	0	0	0	0	0	0	0	0	0

Interest During
Construction: ($000s) nom.

Unit 1
Unit 2

Property in Service.
($000s) nominal

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Unit 1	19836	20029	20029	20029	20029	20029	20029	20029	20029	20029	21144	21144
Unit 2	9445	9445	9445	9445	9445	9445	9445	9445	9445	9445	9445	9445
Total	29281	29474	29474	29474	29474	29474	29474	29474	29474	.3474	30589	30589

Calculation of Return :
($000s) nominal

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Incremental Depreciation 1	0	6	6	0	0	0	0	0	0	0	93	93
Incremental Depreciation 2	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation Unit 1	676	682	689	689	689	689	689	689	689	689	782	875
Depreciation Unit 2	315	315	315	315	315	315	315	315	315	315	315	315
Accumulated Depreciation 1	9360	10042	10731	11420	12108	12797	13486	14175	14863	15552	16334	17208
Accumulated Depreciation 2	4249	4564	4879	5194	5509	5824	6138	6453	6768	7083	7393	7713
Net Property in Service	15672	14868	13864	12861	11857	10853	9850	8846	7842	6839	6857	5668
Mid Year Rate Base	16168	15270	14366	13362	12359	11355	10351	9348	9344	7340	6848	6262
Return	1698	1603	1508	1403	1298	1192	1087	992	876	771	719	658

Generation. (GW-hrs)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
4892	4892	4892	4892	4892	4892	4892	4892	4892	4892	4892	4892

Coal Production. (Ktonnes)

2935	2935	2935	2935	2935	2935	2935	2935	2935	2935	2935	2935

Reclamation Cost:
(mid 1986 $/tonne coal)

1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23

$/tonne nominal

2.37	2.47	2.58	2.70	2.82	2.95	3.08	3.22	3.36	3.51	3.67	3.84

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Operating and Maintenance
Costs: ($000s) as spent

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
ESP Energy	627	655	684	715	747	781	816	853	891	931	973	1017
Compliance Monitoring	70	73	77	80	84	87	91	95	100	104	109	114
Mine Monitoring	37	39	40	42	44	46	48	50	52	55	57	60
Reclamation	6942	7254	7581	7922	8278	8651	9040	9447	9872	10316	10780	11265
Wet Dry Ash Disposal												
Corporate Overhead	445	465	486	508	531	555	580	606	633	662	691	723
Total	8121	8486	8868	9267	9684	10120	10575	11051	11548	12068	12611	13179

Revenue Requirements:
($000s) nominal

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Return	1698	1603	1508	1403	1298	1192	1087	982	876	771	719	658
Depreciation	991	997	1004	1004	1004	1004	1004	1004	1004	1004	1097	1189
O & M	8121	8486	8868	9267	9684	10120	10575	11051	11548	12068	12611	13179
Total	10809	11087	11380	11674	11985	12316	12666	[illegible]	13428	13843	14427	15026
Present Value in 1987: ($000s) nominal	2681	2489	2312	2146	1994	1854	1726	1608	1498	1398	1319	1243

Total Present Worth:
($000s) nominal
93719

Inflation Rates: (%)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50

Escalators, year end 1976

Capital	6.597	6.894	7.205	7.529	7.868	8.222	8.592	8.978	9.382	9.804	10.246
O & M	6.831	7.138	7.459	7.795	8.146	8.512	8.896	9.296	9.714	10.151	10.608
Studies	6.831	7.138	7.459	7.795	8.146	8.512	8.896	9.296	9.714	10.151	10.608
Corporate Overhead	6.831	7.138	7.459	7.795	8.146	8.512	8.896	9.296	9.714	10.151	10.608
Reclamation	6.831	7.138	7.459	7.795	8.146	8.512	8.896	9.296	9.714	10.151	10.608

IDC Rates. (%)

Capital Cost Cash Flow:
($000s) as spent

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Un											
Re ry Approvals											
Electrostatic Precipitators											
Plant Drainage											
Mine Drainage											
Stack & Air Monitoring											
Dry Ash Disposal											
Cooling Pond											
Corporate Overhead											
Total	0	0	0	0	0	0	0	0	0	0	0
Unit 2:											
Electrostatic Precipitators											
Total	0	0	0	0	0	0	0	0	0	0	0

. erest During
Construction. ($000s) nom.

Unit 1
Unit 2

Property in Service:
($000s) nominal

	2013	2014	2015	2016	2017	2018	[illegible]	2020	2021	[illegible]	2023
Unit 1	21144	21144	21144	21144	21144	21144	21144	21144	21144	21144	21144
Unit 2	9445	9445	9445	9445	9445	9445	9445	9445	9445	9445	9445
Total	30589	[illegible]	30589	30589	30589	30589	30589	30589	30589	30589	30589

Calculation of Return :
($000s) nominal

	2013	2014	2015	2016	2017	20[illegible]	[illegible]	[illegible]	2021	2022	2023
Incremental Dep[illegible]iation 1	0	0	0	0	0	0		0	0	0	0
Incremental Depreciation 2	0	0		[illegible]	0	0	[illegible]	0	0	0	0
Depreciation Unit 1	875	875		[illegible]75	437	0	0	0	0	0	0
Depreciation Unit 2	315	315		[illegible]15	315	157	0	0	0	0	[illegible]
Accumulated Depreciation 1	18083	1895[illegible]	[illegible]	[illegible]	21144	21144	21144	21144	21144	21144	21144
Accumulated Depreciation 2	8028	83[illegible]3		8973	9288	9445	9445	9445	9445	9445	9445
Net Property in Service	4478	3289	[illegible]	910	15[illegible]	0	0	0	0	0	0
Mid Year Rate Base	5073	3883	269[illegible]	1504	534	79	0	0	[illegible]	0	0
Re[illegible]rn	533	408	283	158	56	8	0	0	0	0	0

Generation: (GW-hrs)

2013	2014	2015	2016	[illegible]	2018	2019	2020	2021	2022	2023
4892	4892	[illegible]	4892	4892	4892	4892	489[illegible]	4892	3669	1223

Coal Production (Ktonnes)

2935	2935	2935	2935	2935	2935	2935	2935	[illegible]935	2201	[illegible]34

Reclamation Cost:
(mid 1996 $/[illegible] coal)

1.2[illegible]	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.49	[illegible].05

$/tonne nominal

4.01	4.19	4.38	4.58	4.78	5.00	5.22	5.46	5.70	7.22	10.38

Operating and Maintenance
Costs: ($000s) as spent

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ESP Energy	1063	[illegible]	[illegible]	[illegible]	1268	1325	1384	1447	1512	1185	[illegible]
Compliance Monitoring	119	124	130	36	142	148	155	162	169	177	92
Mine Monitoring	63	65	68	71	75	78	81	85	89	93	45
Reclamation	11772	12302	12856	13434	14039	14671	15331	16021	16742	15893	7620
Wet Dry Ash Disposal											
Corporate Overhead	755	789	825	862	900	941	983	1028	1074	1122	586
Total	13772	14391	15039	15716	16423	17162	17934	18741	19585	18469	8760

Revenue Requirements:
($000s) nominal

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Return	533	[illegible]	283	158	[illegible]	8	0	0	0	0	0
Depreciation	1189	1189	1189	1189	752	157	0	0	0	0	0
O & M	13772	14391	15039	15716	16423	17162	17934		19585	18469	8760
Total	15494	15989	[illegible]	17063	17231	17328	17934		19585	18469	8760

Present Value in 1987:
($000s) nominal

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	1160	1083	1012	947	[illegible]	787	737	697	659	563	242

Total Present Worth:
($000s) nominal
93719

I T A

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ar of Birth: 1944

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