AIR QUALITY MANAGEMENT FOR NATURAL GAS PRODUCTION IN ALBERTA: BACKGROUND TO THE PROBLEM AND AN APPLICATION OF THE PARETIAN DECISION MODEL

by

Drake Hocking

This report is an outcome of the Research Seminar of the Environmental Systems Program of Harvard University.

NORTHERN FOREST RESEARCH CENTRE
INFORMATION REPORT NOR-X-69
MARCH, 1973

CANADIAN FORESTRY SERVICE
ENVIRONMENT CANADA
5320 - 122 STREET
EDMONTON, ALBERTA, CANADA
T6H 3S5

Preface

The atmosphere's ability to absorb wastes is limited. Nevertheless, it has taken a long time for people to realize this, and to begin applying controls on emissions. Now that the shortages of fossil energy supplies are becoming apparent, pressures to relax controls are felt. But we must not neglect the necessity of emission controls for the sake of short term benefits. If we do, the problem can only become worse.

These problems have been studied in Alberta, but much of the data are not readily available. This analysis draws together some of these data. It is intended as an introduction to the problems of air quality management in Alberta.

Acknowledgements

I wish to thank Grant Schaumburg and the participants in the Environmental Economics Research Seminar for discussions and encouragement; Ken Brown for help with notation of the functions; Bob Dunbar and Roger Klemm for permission to quote from their work; the Canadian Forestry Service for leave to conduct the study; and many colleagues for valuable suggestions.

Abstract

Controversy over methods and standards for control of emissions of SO_2 in Alberta centers on the value of benefits derived from the high costs of improving sulfur recovery. A novel system for decision analysis, based upon the judgements of participants, making explicit the judgements of the analysts, is described and applied to the Alberta situation. The present analysis formulates a set of functions expressing the net benefits to each major party affected by a decision on SO_2 standards. Such formulation illustrates the informational gaps for fully rational decision-making on the issue. It also provides a method whereby the sensitivity of the decision, to both the accuracy of data and the political weights of the participants, may be tested.

Contents Page

List of Figures

1. Introduction

Effective decisions on environmental policy are best reached through systematic mathematical and economical analysis. A non-judgemental criterion for evaluating alternative policies was formulated in the late 19th century by Vilfredo Pareto (1848-1923), an Italian political economist born in Paris. He postulated that any change which harms no one and which makes some people think they are better off is an improvement. This postulate, known in economic theory as the "Pareto criterion" and valuable for its social neutrality, was rarely applied, even in the other theoretical constructs of Pareto and his contemporaries. The idea survived, however, and was taken up in a formal decision analysis system.

Paretian Environmental Analysis (PEA), developed by the Harvard Environmental Systems Program, incorporates the interests of the people affected by a decision together with technological and economic data into a set of net benefit functions. Judgements of the analyst are incorporated into the functions by explicitly weighting the net benefits by the estimated political influence of each interest group. Sensitivity of the decision to political influence may be readily tested by solving for different weights. The analysis admits only those potential decisions that cannot be improved in terms of overall net benefits without making at least one participant worse off. Such decisions are defined as Pareto admissible. The model is logical:

"If an environmental control agency can adjust its policy to the benefit of some interested party, and if no one else is disadvantaged by the change, then the adjustment is likely to be made. Put another way, no agency is likely to take a measure that purposefully harms one of its constituents if no others stand to gain by it, and a truly interested party is not likely to let itself be disadvantaged by accident or inadvertence." (Schaumburg, unpub.)

When such judgements are necessary, they must be explicit. The many and diverse elements of complex decisions can be stated concisely in mathematical notation. Systematic analysis reveals informational gaps and provides a way of testing the sensitivity of decisions to error in estimates used to fill these gaps. By programming the functions on a computer, the decision may be easily revised in the light of new data.

The decision to be analyzed is the proposed revision of the ambient air quality standards for sulfur dioxide by the Alberta Department of the Environment. Processing of sour natural gas is the source of nearly all sulfur dioxide emissions in Alberta, in 1973 totalling 500,000 long tons. Subsidiary decisions would necessarily follow as the application of a new ambient standard to each sour gas processing plant is tested. Conversion to individual plant effluent standards by the Energy Resources Conservation Board is likely.

The decision must also include plants processing the Athabasca Tar Sands. This estimated 600 billion barrel reserve has high sulfur content. The production of synthetic crude oil by present technology leaves a petroleum coke (with about 6 percent sulfur) that is burned to generate power for the site. Alternative processes include gasification of residual hydrocarbons, creating a need for sulfur extraction plants similar to those used for sour natural gas. The high rate of production predicted for the future will require efficient sulfur recovery technology to meet even current air quality standards.

Tar Sands processing may succeed the gas industry as Alberta's largest SO_2 emitter. The more stringent SO_2 standards that are under consideration would have to be applied to both. But this analysis deals only with sour natural gas processing because that industry dominates SO_2 emissions at present. Following some background information on natural gas processing, the paper applies PEA to data currently available. Because of the scarcity and generality of information, this paper concentrates on the first three of the six basic steps of PEA. These are:

1. Definition of the decision.
   a. the physical system
   b. indices of environmental quality
   c. policy instruments and control measures
   d. constraints
2. Identification of the interested parties.
3. Determination of the technological relations between a potential decision and resulting environmental quality.
   a. relations between the decision and probable emissions
   b. relations between emissions and ambient concentrations
   c. relations between ambient concentrations and environmental quality
4. Formulation of net benefit functions.
5. Solution for Pareto-admissible decision alternatives.
6. Prediction and prescription.

TABLE 1

Typical analyses of sweet gas
(Mol %)

Component	Medicine Hat (Dry)	Cessford (Lean Sweet)	Pembina (Rich Sweet)
Methane	95.71	86.69	72.58
Ethane	0.15	7.45	13.24
Propane	0.06	3.89	8.89
Isobutane	0.04	0.73	1.03
N-Butane	-	0.72	1.75
Pentanes +	-	0.51	0.57
Nitrogen	3.78	-	1.56
Carbon Dioxide	0.26	-	0.38
Hydrogen Sulphide	0	-	0
C_3+ U.S. Gal/MSCF	0.03	1.710	3.48
C_5+ U.S. Gal/MSCF	0	0.215	0.22

(Source: Berlie 1972)

2. Natural Gas Processing in Alberta

2.1 Background

The conventional 'wisdom' is that natural gas is a clean, non-polluting fuel. As pure methane, so it is. But *natural* natural gas emerges from the ground as a complex and variable mixture (Tables 1 and 2). Gas fields can be described in two ways: dry through lean to rich (depending on the content of condensible longer-chain hydrocarbons); and sweet to sour (depending on the content of hydrogen sulfide (H_2S)). Actual methane content may be as little as 20 percent.

The mixture must be processed extensively to produce the pure methane that is currently in such high demand. The gas is consumed predominantly as a fuel in space and process heating and in electrical power generation. Large quantities are also demanded as a primary raw material in chemical industries. Delivery to markets is primarily by pipelines. All of these functions require essentially sulfur-free gas for health (H_2S is highly toxic) and technical reasons (corrosive sulfur acids greatly shorten pipeline, burner, turbine, and stack life) as well as regulatory ones (emission controls).

2.2 History

Natural gas was an uninteresting, minor by-product of early oil production in Alberta, beginning with discovery of the Turner Valley field in 1914. The main gas reservoir was tapped in 1924 by the Royalite No. 4 well, producing gas with a high percentage of natural gasoline. If it had not been for the gasoline content, that well might have been sealed and forgotten. As it was, the gasoline, a commodity then in high demand, was

TABLE 2

Typical Alberta Sour Gas Analyses

(Mol %)

Component	Waterton*	Okotoks*	Harmattan* Leduc	Panther*** River
	(Rich Sour)	(Lean Sour)	(Lean Sour)	(Lean Sour)
Hydrogen Sulphide	19.24	33.52	53.40	70.00
Carbon Dioxide	4.66	11.53	3.70	8.00
Nitrogen	1.10	2.15	1.0	1.00
Methane	69.05	51.81	42.50	20.00
Ethane	3.74	0.47	0.22	0.05
Propane	0.82	0.09	0.05	0.10
N-Butane	0.48	0.06	0.02	-
Isobutane	0.12	0.08	0.03	-
N-Pentane	0.11	0.04	0.013	-
Isopentane	0.26	0.04	0.015	-
Hexane	0.30	0.03	0.015	-
Heptanes +	0.10	-	0.020	-
Benzene	-	0.015	0.006	-
Toluene	-	0.001	0.004	-
Xylene	-	-	0.001	-
Carbonyl Sulphide	0.020	0.062	0.014	0.14
Carbon Disulphide	0.003	0.013	-	0.14
Mercaptan	0.006**	-	0.0005	-

*Mass Spectrometer Analysis
**Methyl Mercaptan
***Estimated

(Source: Berlie 1972)

condensed out and the gas (containing significant H_2S) was flared off.

The simple, well-site gasoline separators were rather inefficient, leading to the decision to construct a central plant. In 1933, Royalite's Turner Valley plant came into operation to separate the gasoline. This plant also removed the "acid gas" (H_2S), to meet the infant demand for clean methane. No sulfur was recovered at that time; the acid gases were simply vented to the atmosphere. This plant plus two other small similar plants built shortly afterwards constituted the total gas processing industry in Alberta for more than the next decade.

Expanding markets for natural gas in the 1950's and consequent higher prices made feasible the processing of very sour gas. It was also realized that a valuable by-product, elemental sulfur, could readily be added to the process stream. Some reasons for elemental sulfur separation then were: the sulphur's value; the danger and cost of environmental damage and a growing sense of environmental responsibility in the industry's governing body, the (then) Alberta Oil and Gas Conservation Board. It is difficult to rank these reasons.

The Shell Jumping Pound plant came on stream in 1951 producing about 30 long tons per day (LT/D) of elemental sulfur from 35 million cubic feet per day (MMCF/D) of raw, sour gas. It vented large amounts of sulfur dioxide (SO_2) to the atmosphere, as the sulfur recovery process used was only about 60 percent efficient.

As gas demand increased, more processing plants were built (Table 3). Some separate only condensates from the methane of "sweet" gas. Others, whose feed gas contains only small amounts of H_2S, separate out the sour gas and vent it to the atmosphere after incineration to SO_2. Finally, there are the sulfur-producing plants, whose inlet streams are

TABLE 3

Gas Plant Capacities (1956 - 1971)

YEAR-END	RAW GAS GAS MMCF/D	RESIDUE GAS MMCF/D	PENTANES PLUS B/D	PROPANE B/D	BUTANE B/D	SULPHUR LONG TONS/DAY
1971	13,670	11,560	260,100	118,400	72,500	24,750
1970	10,722	9,490	170,823	90,240	52,319	15,256
1969	10,050	8,911	161,747	80,510	47,169	14,330
1968	8,800	7,700	144,300	73,200	43,500	12,170
1967	8,360	7,360	127,500	58,300	39,300	10,600
1966	6,600	5,500	121,000	52,200	33,800	8,135
1965	6,100	5,200	112,000	42,000	30,600	7,100
1960	1,900	1,700	24,500	10,100	7,700	1,800
1956	450	300	5,700	4,300	3,200	127

(*OILWEEK* Jan. 24, 1972, Page 42)

high in H_2S. Industry has gradually been required to improve their sulfur recovery efficiency to an average of 95 percent.

2.3 The Alberta industry in perspective

Alberta is Canada's primary producer of natural gas, accounting for 83 percent of Canadian production in 1971. Total production in 1972 exceeded 5,000 MMCF/D, with almost half of that exported to the U.S. (Figure 1).

Besides methane, the industrial products include other liquifiable petroleum gases and sulfur. Petroleum gases and methane are in high demand, but sulfur is in excess supply. Gas processors, therefore, are reluctant to either expand the capacity or increase the efficiency of their elemental sulfur recovery.

Of 152 gas processing plants, 67 process sour gas; of the latter, 42 recover elemental sulfur (Figure 2). Production of sulfur has increased through both higher demand for gas and more stringent pollution control requirements. Total sulfur production in 1972 exceeded 5 million long tons. Figure 3 shows the annual progress of production and the resultant stockpiles and falling prices. Canada (Alberta) is now the world's largest exporter of sulfur.

1.4 The sulfur recovery processes

Plant design for natural gas processing is suited to the mixture of gases to be treated. The most complex series of operations applies to processing rich sour gas, which contains significant amounts of liquifiable hydrocarbons as well as the main acid gases, H_2S and CO_2. Figure 4 shows a diagram of such a plant, and Table 4 illustrates the detailed compositions of gases at each stage.

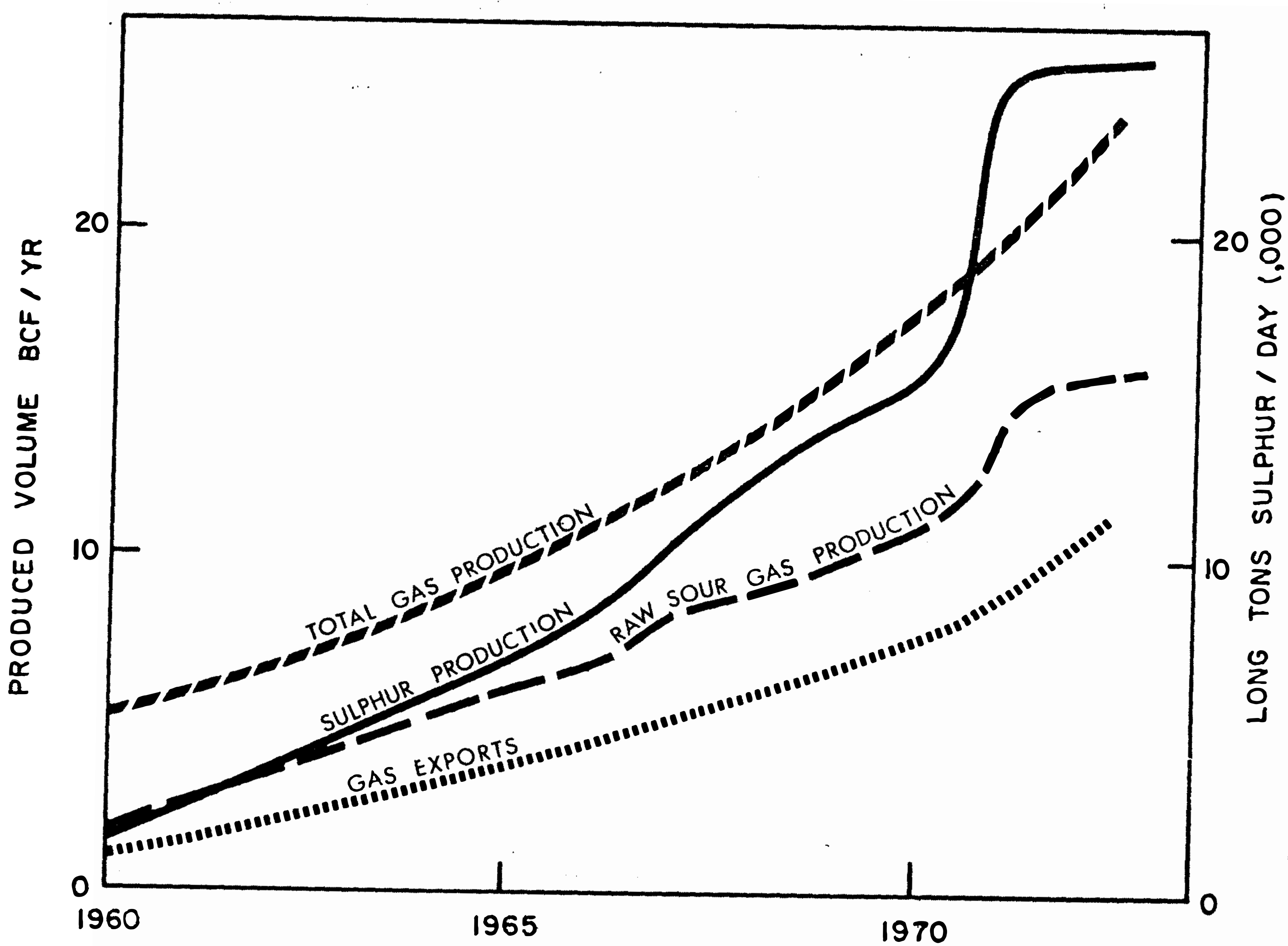


Figure 1. Gas and sulfur production and exports, 1960-72.

(Source: *OILWEEK* 22(49):41)

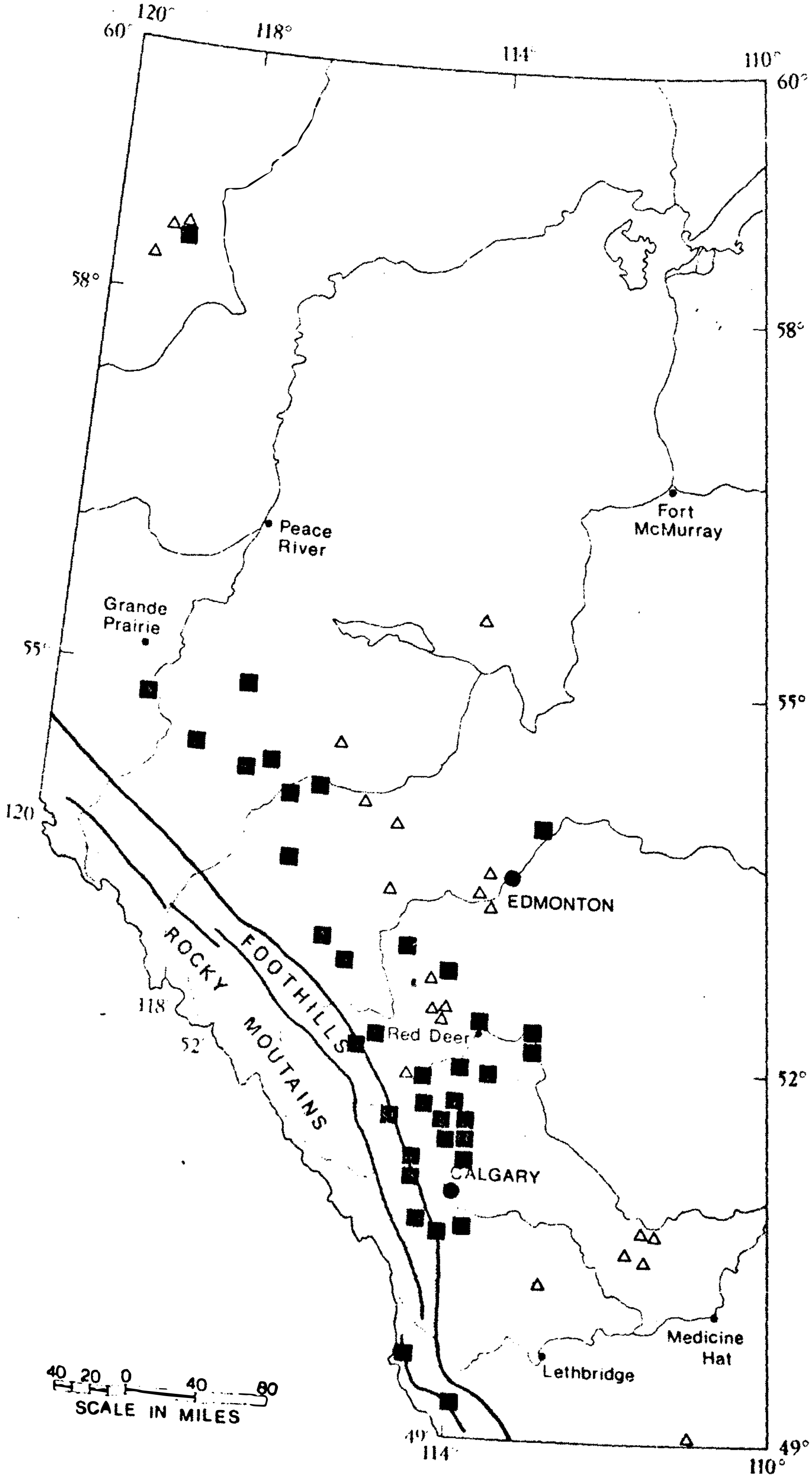
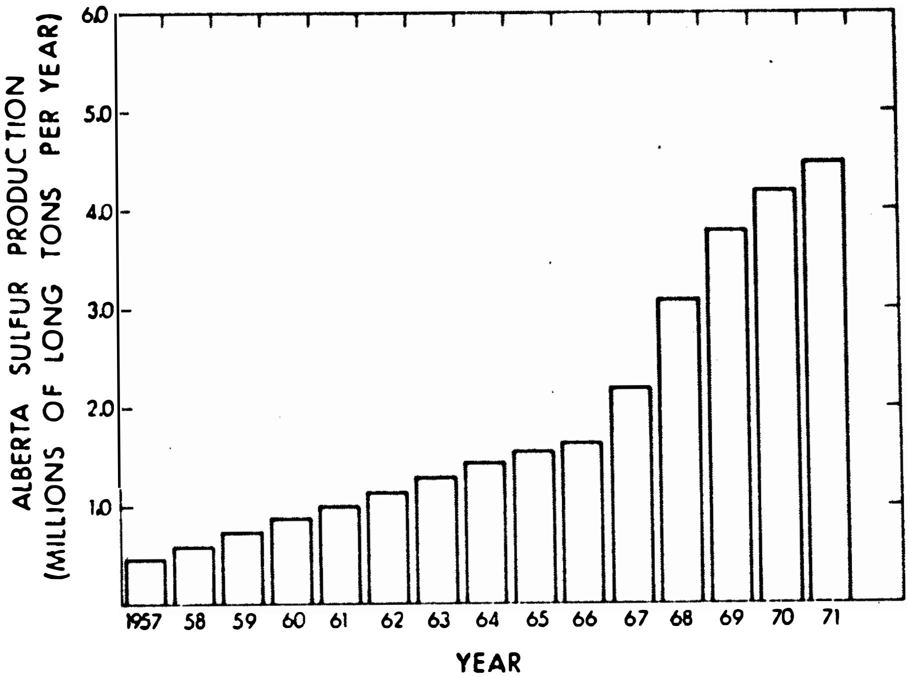


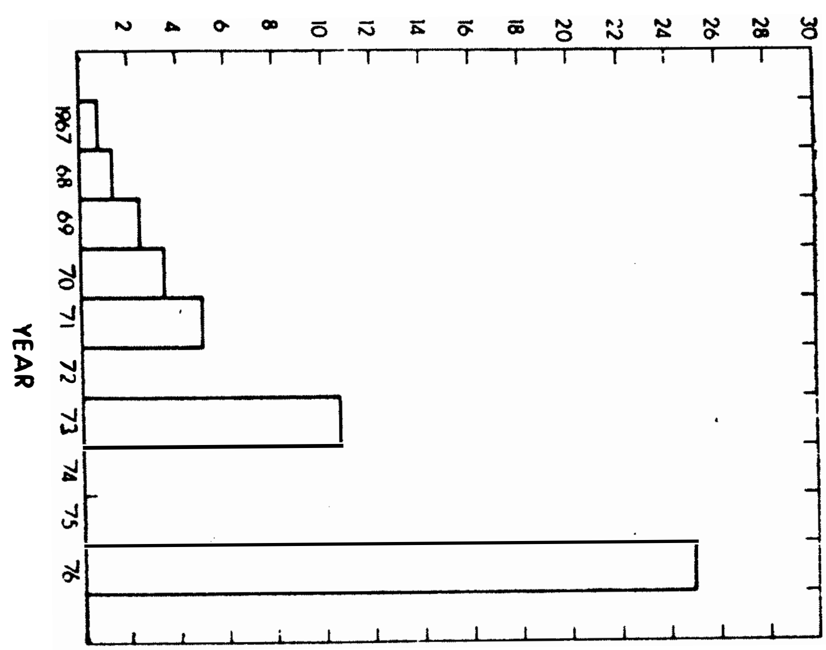
FIGURE 2 - LOCATION OF SULFUR EXTRACTION GAS PLANTS IN ALBERTA.

■ Sulfur producing plants

△ Sulfur extraction plants which do not recover sulfur

(Source: Klemm 1972)





VALUE OF CANADIAN SULFUR PRODUCTION

Year	Prodn. (LT)	Sales (LT)	$ Sales Value	$ Price/Ton
1971	4.5 million	2.8 million	21 million	7.50
1970	4.2 million	3.1 million	28 million	8.92
1968	3.0 million	3.3 million	78 million	34.53

Fig. 3 Alberta sulfur production, stockpiles and value (Source: Klemm 1972)

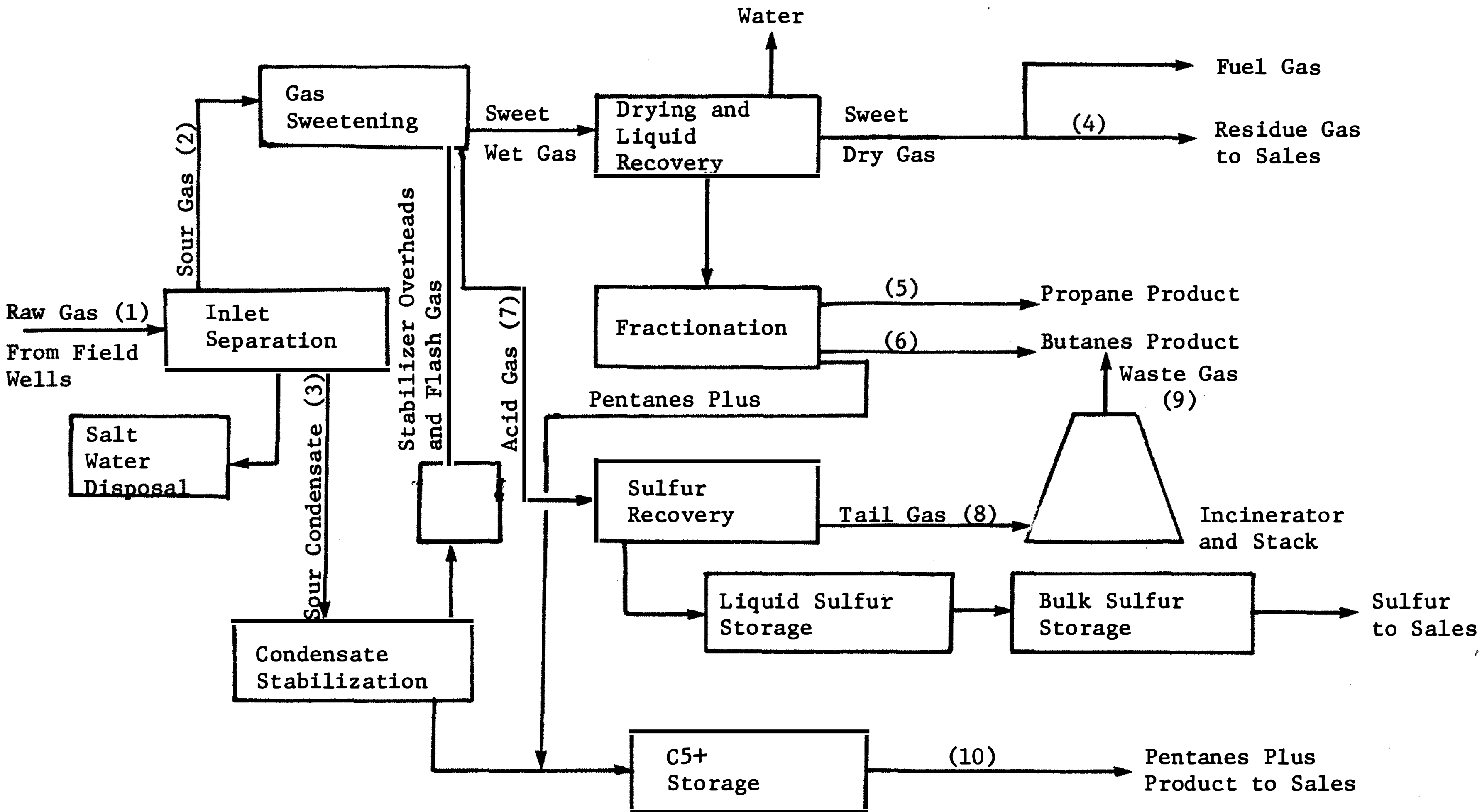


Figure 4. Simplified Flow Diagram, Gas Processing Plant. (Source: Dunbar 1970)

Table 4

Example Gas Compositions at Different Stages of Processing

Mole %

Component	Symbol	1 Raw Gas	2 Sour Gas	3 Sour Condensate	4 Sales Gas	5 Propane Product	6 Butanes Product	7 Acid Gas	8 Tail Gas	9 Stack Gas	10 Pentanes Plus
Nitrogen	N2	0.94	1.08	Tr	1.33	----	---	----	85.52	87.47	----
Methane	C1	65.66	73.78	11.90	92.93	----	---	1.37	---	---	----
Ektane	C2	3.59	3.40	4.62	5.16	2.99	---	0.19	---	---	----
Propane	C3	1.25	0.84	3.71	0.58	96.09	1.05	0.10	---	---	0.05
Isobutane	iC4	0.29	0.14	0.45	----	0.90	32.14	0.06	---	---	0.39
Normal Butane	nC4	0.74	0.28	3.91	----	----	65.76	0.09	---	---	3.29
Pentanes	C5	0.79	0.10	5.66	----	----	1.05	----	---	---	13.31
Hexanes	C6	0.90	Tr	7.20	----	----	---	----	---	---	15.61
Heptanes Plus	C7+	3.88	----	32.96	----	----	---	----	---	---	67.32
Hydrogen Sulfide	H2S	17.66	15.93	27.55	----	----	---	76.94	1.84	---	0.04
Carbon Dioxide	CO2	4.30	4.45	2.04	----	----	---	17.89	10.86	7.30	----
Sulfur Dioxide	SO2	----	----	----	----	----	---	----	0.75	1.73	----
Carbon Disulfide	CS2	----	----	----	----	----	---	----	0.41	---	----
Carbonyl Sulfide	COS	----	----	----	----	----	---	----	0.62	---	----
Sulfur Vapour	Sv	----	----	----	----	----	---	----	Tr	---	----
Sulfur Liquid	S1	----	----	----	----	----	---	----	Tr	---	----
Oxygen	O2	----	----	----	----	----	---	----	---	3.50	----
Total		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Note: 1. Above analysis from Shell Waterton Plant Gas Streams.
2. Analyses are example analyses only and do not represent a material balance about the plant.

(Source: Dunbar 1970)

The first step, after removal of condensed long-chain hydrocarbons and water, is the "sweetening" process; acid gases are removed from the raw gas stream. This step is essentially 100 percent efficient. The next step is conversion of the acid gases into elemental sulfur, and it is here that efficiency is critical. Dunbar (1970a) provides concise descriptions of the processes (See Appendix 1).

Essentially, liquid elemental sulfur is precipitated out of the acid gases stream by means of Claus units, individually capable of removing about 65 percent of the sulfur. A series of 4 Claus units has a maximum theoretical efficiency of about 99 percent, commonly lowered by practicalities to about 95 percent. The tail gas leaving the final stage has an SO_2 content of 1 to 2 percent (Table 4). For very large processing plants, producing in the order of 5,000 tons per day elemental sulfur, 1 to 2 percent is still a large amount. Considerable attention is being paid to improving the operating efficiencies of Claus units.

Much consideration has been given to processes for clean-up of the tail gas (Hyne, 1972). Of about 50 experimental methods, perhaps 20 are feasible. Most involve further reactions between SO_2 and H_2S in the presence of a catalyst, either in the gas phase or in a liquid medium. Two promising new processes (the "I.F.P.-2", and an experimental one developed by Alberta Sulfur Research Ltd.) also convert COS and CS_2 to elemental sulfur.

Only two processes (both patented) have been operationally used in Alberta, both in very large new plants. The "Sulfreen" process has been operating for 2 years in the Aquitaine Ram River Plant with a recovery rate of over 60 percent of the sulfur in tail gas. The "I.F.P.-1" process is in operation at the Chevron Standard plant at Nevis, with a similar sulfur recovery rate.

2.5 Statutory regulation of the industry in Alberta

The oil and gas industry in Alberta was originally regulated by the Oil and Gas Conservation Board, established in 1928 primarily to conserve the petroleum resources. This board has maintained close contact with the industry ever since.

Organized regulation of emissions started in 1960 under the Alberta Department of Health, which passed through several re-organizations during the succeeding decade to accommodate increasing responsibilities in pollution control.

In 1970, through amendments to the Oil and Gas Conservation Act, the Oil and Gas Conservation Board was assigned responsibility to control pollution in oil and gas field operations. During 1971 the legislature of Alberta, by passing the Energy Resources Conservation Act and the Hydro and Electric Energy Act, consolidated energy resource management within the Energy Resources Conservation Board (ERCB). Further, it charged the Board to broadly manage energy matters in balance with other environmental matters.

Also during the 1971 session of the legislature, The Department of The Environment Act was passed; this was complemented with The Clean Air Act and The Clean Water Act. The Department of The Environment Act established the Department and granted the Minister responsibilities and duties in connection with environmental matters. Environmental matters are those legal or economic factors, operations or activities which directly or indirectly affect the quality or quantity of natural resources in any phase of utilization, with emphasis on preventing their degradation or pollution.

Legislative amendments in 1972 confirmed the general role of the ERCB as defined earlier in 1970 but made it clear that regulations and conditions of approvals affecting environmental matters were subject to the approval of the Department of The Environment. Therefore, overall control is the responsibility of the Department.

In oil and gas operations, the ERCB is responsible for devising the conditions of approvals, regulations (subject to the Department's approval), and taking corrective action where required. The Board remains the principal communication link with the industry on pollution control matters.

'Informational Letters' from the ERCB and 'Air Monitoring Directives' issued by The Department of the Environment Pollution Control Division are means of communication with industry. Examples are attached as appendices. The Ambient Air Quality Standards are included in this report as Tables 5 and 6.

Gas processing and sulfur recovery schemes must be approved by the Board prior to any construction. An application for approval must be considered at a public hearing or a notice of the application must be published so that objections may be filed with the Board. The information needed to support an application is detailed and discussed in Section 3.1.3 of this report.

Operators of sour gas processing plants are required to report monthly to the Board operating data including daily amounts of sulfur emitted to the atmosphere as SO_2 (Reimond 1972). Where emissions exceed the quantities approved by the Board, the operator must immediately correct the situation. This places day-to-day responsibility for adherence to *emission* standards directly with the operator of the plant. The sulfur recovery *efficiencies* required of gas processing plants are normally enforced over three month periods and therefore represent three month average recoveries. The sulfur recovery on any one day *may be considerably less* than that required as a three month average. (Much of this section is after Klemm 1972).

3. The basic steps in Paretian analysis

3.1 Definition of the decision

There are alternative types of control, dispersal, definition, measurement and specification of emissions. It is uncertain in many areas the extent to which emissions influence environmental quality. This section attempts to define some of these areas for the purpose of decision.

3.1.1 The physical system

In Canada, management of the natural resources is vested in the provinces. Thus the physical system in this decision is the province of Alberta, at least until the provinces agree to establish common standards. The basic decision on ambient standards must involve the whole province. Subsidiary decisions will be necessary for each gas processing plant currently in operation and for proposed new ones.

As to topography and climate, much of the province is comparatively flat prairie with gentle undulations and river valleys. Most plants are located in this terrain (Figure 2); simple dispersion models can be applied, describing where and how the emission plume mixes with the ambient air. However, hills and valleys do cause complications.

Several plants, including the newest and largest, are in the high foothills of the Rocky Mountains. The terrain is severely undulating with complex intersecting valley and ridge systems. Specific dispersion models have been developed for some situations, but testing has hardly begun.

The province has short hot summers and long very cold winters. Many areas have long periods with very light or no wind. During winter, especially near the foothills, warm high westerly winds (chinooks) often blow steadily for several days. Annual precipitation is low (about 20"). Low atmospheric temperature inversions prevail throughout the winter and for about half the time during the summer.

Relevant to gas plant regulation is the existing or intended land use. Most plants are situated in agricultural land with scattered human residences. Those in the foothills are generally located in forested areas supporting diversified land uses including fibre production and recreation. Frequently, two or more plants are within a few miles of each other; areas affected by effluents tend to overlap.

The time horizon for the decision (how long it will have to be in force) is influenced by other SO_2 emitting processes. Although tar sands oil extraction is likely to dominate total sulfur emissions in the future, for the present these are due almost entirely to gas processing. Thus the important time horizon for the current decision is the best estimate of the life of the gas fields.

The quantity and quality of the reserves in a field directly influence decisions about the processing of gas. The allowable daily production, forming the *design basis* for processing plant capacity, is arrived at by dividing total reserves by 7,300 (the number of days in 20 years). The sulfur content (as H_2S) of that volume provides the design basis for the sulfur recovery technology of the plant.

New gas fields cannot go on being discovered indefinitely. New reserves are not likely to be discovered where existing plants are located. Therefore, 20 years seems to be the effective time horizon for the area of influence of any one gas plant.

Complications arise, however, from a variety of sources. The reserves of the gas field may be larger or smaller than estimated. Rates of sulfur content may change over time as other strata are tapped. And new gas fields may be close enough for the product to be pipelined raw to an existing plant, either increasing its through-put or extending its life, or both. Most complications can be handled, however, through modifications to specific requirements; checking how much exposure the area has already had.

3.1.2 Indices of environmental quality

The primary index directly relevant to the present decision is the ambient concentration of SO_2. A *fluctuating standard* should be seriously considered.

The major source of SO_2 is incinerated tail gas from sulfur recovery. Other sources of SO_2 exist, notably flare stacks. Raw sour gas may be flared during periods of plant turnaround (when catalyst beds are cleaned and regenerated) and during upset emergencies. Details are sketchy about combustion and dispersion from flare stacks. This is doubly a problem, as flare stacks are in *continuous* use at sour gas processing plants where the sulfur content or the volume through-put is small enough to deem a sulfur recovery process unwarranted.

Minor sources of SO_2 include leaks and carryover from various points of operations in the plant. These are controllable through minor technological improvement and general "good housekeeping".

Gas plants have other environmental impacts. Disposal of process wastes and living quarters' sanitary wastes may affect water quality. Elemental sulfur may be lost from stockpiles, making the local soil too acid for plant growth. Soil acidity may be increased over large areas by washout of stack SO_2, if continued over a long enough period. But application of lime can restore the productivity of acid soil.

Visual impact is important, especially for plants located near prime wilderness recreation areas. Even small releases of odourous bases become distasteful if in recreational areas or near human habitations.

For our purposes these other environmental impacts will be shelved. Some are covered in other regulatory decisions; some are left to individual complaint and bargaining; some have been left to legal processes. For this analysis, only atmospheric sulfur dioxide will be considered.

3.1.3 Policy instruments and control measures

The Alberta Department of Environment (ADOE) sets standards for ambient air quality. The Energy Resources Conservation Board (ERCB) enforces these standards in the gas processing industry through approvals (Table 7) and informational letters.

The present ambient standards for SO_2 in Alberta are shown in Tables 5 and 6. These contain a number of deficiencies by present day criteria and are under review. A comprehensive set of new, more stringent standards has been proposed by the ADOE specifically for gas plants.

These, too, lack specific frequencies by which the ambient standard may be exceeded. Improved sulfur recovery *efficiencies* relating to plant size are required by the ERCB (Informational Letter 1L 71-29 Appendix 3). Stack monitoring technology has been highly developed in Alberta by Western Research & Development Ltd., an oil industry consulting firm. Thus stack monitoring and effluent standards are now feasible. The ERCB is about to require installation on a graduated scale according to plant size, before effluent standards become law.

These new "guidelines" issued by the ERCB have been accepted with reluctance, by the gas industry. Remedial facilities are moving ahead slowly (*Oilweek*, 19 Feb. 73). There is provision for certain exemptions after public hearings. Plants exempted may still be required to reduce emissions if the proposed new standards are adopted.

Essentially, the *ambient* air quality standards are still the legal basis for regulation of emissions. But the proposed new standards also contain an *effluent* or stack concentration standard, to be derived for each plant from dispersion models relating to the new ambient standard. An effluent standard would be a more effective regulatory instrument, being much simpler and cheaper to measure than ambient sulfur dioxide levels. However, it does not allow for adverse weather and temperature inversion effects, so more stringent ambient standards also are proposed. An instrument not mentioned in the proposed new standards would modulate the ambient standard according to probable effects upon receptors. A higher ambient concentration could be tolerated during winter months when vegetation is less sensitive *and* gas demand is higher. Short term modulation of the *effluent* standard may also be possible with sophisticated monitoring of dispersal conditions and effective predictive models. A fuller discussion follows in Section 3.

TABLE 5
AMBIENT AIR QUALITY STANDARDS

	POLLUTANT	CONCENTRATION UNIT	AVERAGE CONCENTRATION FOR APPLICABLE TIME PERIOD: 1 HR.	24 HR.		METHOD OF MEASUREMENT
1	FLUORIDES (as HF)	ppm. (vol.)		.0040		Spectrophotometry
		mg./m³		.0033		
	FLUORIDES in forage for livestock (dry wt. as F)	ppm. (wt.)			35.0	Gravimetry
		mg./l			35.0	
2	TOTAL OXIDANTS (as O_3)	ppm (vol.)	.15	.10	90% of readings per month $<$ .07 ppm. (vol.) (.137 mg./m³)	Spectrophotometry
		mg./m³	.29	.20		
3	TOTAL OXIDES OF NITROGEN (as NO_2)	ppm. (vol.)	.30	.10		Spectrophotometry
		mg./m³	.56	.19		
4	CARBON MONOXIDE (CO)	ppm. (vol.)	60.0		8 hour average 15.0 ppm. (vol.) (17.2 mg./m³)	Infrared Spectrophotometry
		mg./m³	68.7			
5	HYDROGEN SULFIDE (H_2S)	ppm. (vol.)	.030	.005		Light transmittance or reflectance
		mg./m³	.042	.007		
6	SULFUR DIOXIDE (SO_2)	ppm. (vol.)	.30	.10		Conductivity
		mg./m³	.79	.26		
7	SOILING INDEX	coh	90% of average readings per month $<$ 1.0		Annual Average $<$ .45	Light transmittance or reflectance

(Source: Alberta DOE)

TABLE 6

MAXIMUM CALCULATED GROUNDLEVEL CONCENTRATION STANDARDS

	POLLUTANT	CONCENTRATION UNIT	MAXIMUM ACCEPTABLE CONCENTRATIONS FOR APPLICABLE TIME PERIOD		LAND USE
			30 MINUTE	OTHER	
1	SULFUR DIOXIDE	ppm. (vol.)	.2		urban and arable agricultural areas
	SULFUR DIOXIDE	ppm. (vol.)	3		all other areas (1)
	SULFUR DIOXIDE	ppm. (vol.)		1.0 (2)	all
2	HYDROGEN SULFIDE	ppm. (vol.)	.01 (3)		all
3	OXIDES OF NITROGEN AS NO_2	ppm. (vol.)	.2		urban
	OXIDES OF NITROGEN AS NO_2	ppm. (vol.)	3		rural
4	FLUORIDES as HF	ppm. (vol.)	01		all
5	AMMONIA	ppm. (vol.)	2.0		all

Footnotes

1 In forested areas due allowance must be made for height of trees for stack height calculations

2 To be utilized for short period emergency flaring only (less than one hour)

3. Where incineration is feasible, the H_2S must be incinerated to SO_2.

(Source: Alberta DOE)

Table 7. Gas Processing Approvals Criteria

Approvals for gas processing operations will normally have the following pollution control requirements:

1. A maximum raw gas inlet rate.

2. A maximum hydrogen sulfide inlet rate.

3. A conservation clause requiring that certain minimum levels of gas, hydrocarbon liquid and sulfur contained in the raw gas be recovered as products.

4. A maximum sulfur dioxide emission rate from the sulfur plant incinerator stack or the acid gas flare stack.

5. A minimum incinerator stack or acid gas flare stack height.

6. A minimum incinerator stack flue gas emission temperature.

7. Clauses restricting the flaring of gaseous hydrocarbons and other gases.

8. A clause requiring that the flare be equipped with a continuously burning pilot and a flame igniter.

9. A clause requiring that in the event of an emergency necessitating the flaring of sour gas, sufficient fuel gas be added to the sour gas prior to flaring to ensure complete combustion and to give sufficient thermal rise to the gas leaving the flare to maintain ground level sulfur dioxide concentrations below acceptable values.

10. A clause requiring that the Operator conduct a minimum number of stack surveys each year.

11. A clause requring that the Operator maintain a minimum network of pollutant measuring detection equipment in the plant vicinity.

12. A clause requiring that the true vapour pressure of the stored pentanes plus product be maintained below a maximum of 12 psia.

13. A clause requiring that the Operator control the release of sulfur dust from the plant to the satisfaction of the Board.

14. A clause requiring that the Operator provide and use facilities for the storage of sulfur and liquid products that, in the opinion of the Board, are adequate and reasonable.

Also several other requirements are specified by the regulations.

(Source: Dunbar 1970)

There is little need for effluent charges or transfer payments to parties adversely affected at currently prevailing standards, although one class action suit in the early 1960's was settled out of court with an *ex gratia* payment of over three quarters of a million dollars. This collective complaint developed well before ambient standards prevailed and when there was only spot check or monthly average monitoring.

Thus it seems likely that the present system of policy instruments works reasonably well and will probably serve for implementation of new standards, if adopted.

Two approaches are possible for control measures: improving sulfur recovery and improving SO_2 dispersion. Dispersal may be improved by increasing stack height or velocity and temperature. The latter can only be slightly adjusted in existing plants.

Measures to improve sulfur recovery range from the addition of one or two Claus units for smaller plants to the installation of expensive tail gas clean-up systems, like the Sulfreen process, for larger plants. Recent work suggests that significantly improved efficiency might be achieved by detail improvements in existing Claus units.

Plants nearing the end of their practical lives, due to either technical obsolescence or exhaustion of reserves, may meet new standards by reducing daily through-flow. Many smaller plants have already opted to do so to meet the ERCB guidelines.

3.1.4 Constraints

A decision may be limited by legal, technological, economic, or political constraints.

For the current decision, the legislative framework does not limit the regulatory powers of the ADOE and the ERCB. The existing set of standards and guidelines in Alberta are already within the broader Canadian "acceptable" range of ambient air quality guidelines. This is necessary to qualify for various federal grants-in-aid.

Technological constraints exist at a level of 99.9% recovery of sulfur. Current economic constraints reduce practical recovery to about 99.4%. But *local* economic constraints are minimal because cost increases might be spread over the large volumes exported. In 1971, 84% of Alberta natural gas was exported from the province, 45% to the United States.

Natural gas is low in price due to institutional restrictions in the face of high demand. The export price is in part politically determined. In Alberta the price is rigidly controlled by the quasi-judicial Public Utilities Board (Nobbs et al, 1971). This Board bases its decisions upon a "reasonable rate of return" to the company on its total investment, or "rate base". All costs, including the more stringent environmental controls, making application for rate increases or representation at public hearings, may be included in the rate base. Thus there is a clear mechanism for plants to pass on additional costs to the customers. While an increase would be detected, costs of a clean product may be absorbed by the export market.

Political constraints are also low because of increasing public support for measures to improve environmental quality. Public hearings on the environmental effects of gas plants have been held by the Environment Conservation Authority, an advisory body to the Provincial Cabinet. Their report contains recommendations for more stringent ambient air quality standards and for effluent standards and monitoring, and for further research.

In short, the present decision process has remarkably broad latitude in all of the legal, technological, economic and political contexts.

3.2 Identification of the interested parties

There are several levels of influence on a decision regarding ambient standards for SO_2, and there are several ways of classifying interested parties with direct influence. All participants (actors) probably have interests that are conflicting. They are affected negatively and positively by all degrees or alternatives to a decision.

To identify the principle discrete interests, several levels of disaggregation may be attempted. Re-aggregation of interests assumed to be represented in the actions of the principle actors simplifies the model.

The major participants are:

a. The Canadian Department of Environment (CDOE).

b. The ADOE and the ERCB.

c. Alberta governmental biological management agencies.

d. The general populace and private conservation organizations.

e. The natural gas industry, representing gas producers, processors, distributors, and marketing companies.

f. Gas consumers, including domestic and industrial.

g. Provincial government exploiting and developmental agencies.

Their interests are:

a. The CDOE has an interest through national ambient air quality guidelines established under the Clean Air Act of 1971. Three levels have been proposed: desirable, acceptable, and maximum tolerable. The current Alberta standards match the acceptable level; the proposed new ones match the desirable level. Setting of legal standards is the prerogative of the provinces. To have the *desirable* level of SO_2 the Alberta standard would be an important precedent for the country.

b. The ADOE has an interest through its Air Pollution Control Branch which sets standards. The ERCB enforces the standards and works closely with the ADOE in setting them.

c. The Alberta government also manages the biological resources of the province: agriculture, forests, and wildlife. The agencies responsible clearly have an interest in establishing the best possible standards for their constituents.

d. The general populace has interests and influences the decision mostly through a number of conservation-minded organizations. These include such groups as the Alberta Chapter of the National and Provincial Parks Association, the Alberta Fish and Game Association, the Alberta Wildlife Foundation, the Rocky Mountain Section of the Canadian Institute of Forestry, the Alberta Environmental Coalition, and the many smaller, local groups. There are globalists, who feel that emissions world-wide need to be reduced. They would influence local conservation organizations through common membership in international groups such as the Sierra Club or the International Wildlife Preservation Fund.

e. In Alberta, the 67 sour gas processing plants stand to incur the major costs of more stringent standards. Although only 42 actually extract elemental sulfur, the other plants have at stake their rates of production; excess emissions may be curtailed by lower allowable through-puts.

f. Gas consumers clearly have an interest in the price they pay for their commodity. The interests of major consumers, such as electrical utilities, industries, and foreign customers, are perhaps best represented by the gas utilities who supply them, purchasing directly from the processing companies. High-level political leverage might be employed if there were threats to increase export prices sharply.

Small, domestic consumers feel conflict between their concern for environmental quality and the price they pay for gas. However, because Alberta gas is one of the cheapest fuels in the world, they are not likely to be motivated to action by price increases. Their interests will be manifested through the groups in (d.) above.

g. Provincial government agencies are also responsible for development of industry and resource extraction, e.g. the Departments of Mines and Minerals and of Industry and Tourism.

Government agencies tend to act in their own, rather narrowly defined, interests during a decision-making process. Hence their influences need to be represented separately in the decision analysis. Conflict among government agencies is usually resolved in the Conservation and Utilization Committee, a group of senior officials from all government natural resource agencies. Represented are the Alberta Departments of Agriculture and Lands and Forests (including fish and wildlife). Not represented is the Department of Youth, Culture and Recreation, whose Recreation Branch has considerable interest in the wilderness recreation areas. Its interests, however, tend to be congruent or at least similar to those of sub-agencies of the Department of Lands and Forests.

3.3 Determination of the technological relations between the decision reached and resulting environmental quality

This phase has three parts: the relations between the decision and the probable actual emissions, the relations between those emissions and ambient concentrations, and the impact of those concentrations upon environmental quality (their effects upon receptors). Any new set of ambient air quality standards that is more stringent than the previous standards will probably initiate technological improvements and/or reduced plant throughflows in efforts to meet them. It is crucial to the decision on standards to consider to what extent the industry can and will abide by them.

3.3.1 Relations between the decision and probable emissions

Regular violations of ambient air quality standards occur (Appendix 4). Some regularities are apparent in past violations and these may be traceable to technological deficiencies and to predictable weather influences not taken into account in the dispersion models used to draw up approved emission rates.

Approvals might be revised in these instances towards improved technology for either sulfur recovery or dispersal, or both. But still, many violations will continue to occur.

Past violations have been detected by continuous monitoring stations located some distance from emission sources. Adoption of *emission* standards and in-stack monitoring will mean quicker and more certain detection permitting more rapid corrective action by the plant. This aspect of the new proposals will likely lead to fewer violations of shorter duration; hence closer adherence to the ambient standards.

3.3.2 Relations between emissions and ground level concentrations

Local topography and weather may lead to ground level concentrations exceeding *ambient* standards as frequently as before, despite in-stack monitoring of *emission* rates. And flare stacks can lead to very high concentrations; current regulations *permit* up to 1.0 ppm for periods up to 1 hour.

3.3.3 Relations between ambient concentrations and quality

Definition of the quality index, Q, is best done through examination of the *effects* of the probable ambient concentrations upon receptors. The linkage for SO_2 is extremely complex, owing to a wide range of predispositional and environmental variables.

Considerable data are available for influences upon human beings, especially for individuals with respiratory illness. Levels of SO_2 resulting in measurable adverse effects are in the order of 0.1 ppm (Carnow 1970). A cost has not yet been applied to these adverse effects.

In Alberta, the areas likely to be subject to the highest concentrations of emissions are mostly uninhabited, although farm residences are often influenced. Effects are more likely to be first noticeable on vegetation. Here, costs of an acute fumigation are closely tied to the area of photosynthetic tissue destroyed: a directly measurable quantity, although in practice very difficult, especially in areas of recreational uses.

But the dose-response relation between an ambient concentration of SO_2 and the leaf area destroyed is impossible to predict in a general way. The effect depends on at least 8 environmental variables (Loman, Blauel and Hocking, 1972, for review). Table 8 gives minimum concentrations at which observed damage occurred on several tree species.

Table 8

Minimum average SO_2 concentrations (in ppm) at which injury to trees occurred (Adapted from Dreisinger *et al* 1970). Ground Level Concentration Standards (G.L.C.S.) and Ambient Air Quality Standards (A.A.Q.S.) (Anonymous 1970).

Species	30 min	< 1 hr	1 hr	2 hrs	4 hrs	8 hrs	24 hrs
			ppm				
Trembling aspen			0.42	0.39	0.26	0.13	
Jack Pine			0.52	0.44	0.29	0.20	
White birch			0.46	0.38	0.28	0.21	
Larch			0.41	0.38	0.34	0.26	
Balsam poplar			0.82	0.65	0.45	0.26	
White spruce			0.87	0.79	0.70	0.50	
G.L.C.S.	0.30	1.0					
A.A.Q.S.			0.30				0.10

(Source: Loman et al. 1972)

For forested regions, a further uncertainty lies in the current use of treetop height as effective ground levels for dispersal models and emission rate calculations. Monitoring is carried out at "fence-post" height. Sulfur dioxide is heavier than air and may tend to settle beneath the forest canopy, causing higher local concentrations than predicted. Alternatively, tree foliage may act as a filter or sponge for SO_2 so that tree tops may be exposed to higher concentrations than are detected. Most plant species become less susceptible to acute injury during dormancy (op. cit. 1972). A provision for modulating emissions according to the current sensitivity of surrounding receptor vegetation might be built into the standards. This would be particularly valuable for an industry with seasonally fluctuating volumes like the gas processing plants, since the season of probable lowest receptor sensitivity coincides with the season of highest demand and therefore greatest throughflow and emission rates.

Considerable research is required to establish ranges of sensitivity, under varying environmental conditions, of Alberta receptor species. This will be necessary before potential damage can be accurately costed for any given emission rates.

3.4 Determination of the net benefit functions

Cost data for improved sulfur recovery processes are reasonably accurate; they are related to percentage recovery and to plant design capacity (Berlie 1972, Anon. 1972). The technological requirements of each plant to meet the proposed new ambient standards depend on its particular dispersion pattern relating to local topography and climate. These will be considered by the ERCB during implementation of the decision, when the ambient standards will probably be converted to emission standards for each plant. Although direct costs of controls increase sharply with efficiency of recovery, the total costs are small and decreasing compared to the overall value of product.

In Alberta, the costs lie in the following:

Costs:
1. purchase, installation and operation of additional Claus units.
2. purchase, installation and operation of tail-gas clean-up units.
3. additional monitoring instruments, if necessary, for ambient quality enforcement.
4. in-stack monitoring instruments (these are already being required by the ERCB).
5. reduced production of sales gas in plants whose allowable throughput is curtailed to meet standards.
6. higher prices of gas to consumers.

The benefits are mostly those which are difficult to measure. A start has been made towards estimating their value (Manning 1970) but specific research is needed for Alberta. What proportion of such benefits should be assigned to which participants in the decision is another difficult question.

Benefits:
1. improved human, animal and plant health.
2. reduced material damage (corrosion, etc.).
3. consequent more valuable agricultural and forest harvests.
4. consequent improved recreational opportunities and utilization.
5. vicarious satisfaction of city dwellers knowing that healthy forest are available.
6. reduced risk of long-term land-use degradation.
7. sale value of sulfur recovered.

Development of functions

Despite quantitative deficiencies, net benefit functions can be constructed, indicating important factors and their relations (Schaumburg 1972).

For each of the gas plants (i) there will be associated a particular control method (x_i) with its capital caost ($\Phi_i(x_i)$). From the perspective of the federal government, the capital costs may be discounted by an interest rate (in this example, 7.5%) and the amortization period (20 years).

Using these assumptions, the following federal government (f) cost function (C_{f_i}) applies:

$$C_{f_i}(x_i) = .098\ \Phi_i(x_i) + \Theta_i(x_i) \quad . \tag{1}$$

The first term would be zero for those plants who control emissions through reduction of throughput without installation of recovery equipment. In these cases the second term would represent the annual costs of lost production (Θ_i).

The annual costs perceived by the gas plant owner (h) would require different factors a and b allowing for taxation credits on the control equipment, including rapid depreciation allowances. These may be represented for each gas plant i, as follows:

$$C_{h_i}(x_i) = a\Phi_i(x_i) + b\Theta_i(x_i) \quad . \tag{2}$$

Summing the costs perceived by the federal government:

$$C_f(X) = \sum_{i=1}^{67} C_{f_i}(x_i) \tag{3}$$

and by the industry:

$$C_I(X) = \sum_{i=1}^{67} C_{h_i}(x_i) \quad . \tag{4}$$

Net costs of improved monitoring and enforcement instrumentation should not be included in the net benefit functions associated with the present decision. Many improvements have been already installed or ordered and the costs would be incurred for *any* new decision.

The provincial government probably does not perceive the direct control costs as its own, because much of the total would remain in the province through local supplies of equipment and expertise.

For the Alberta situation, the generalized form of the benefit (B) function for health of living organisms at an environmental quality (Q') is

$$B(Q') = \sum_{j=1}^{3} b_{o_j} q_j R_{o_j} \tag{5}$$

where (q_j) is the improvement in quality in sector (j) (human habitation, agricultural, or forested zones), (b_{o_j}) is a function of the concentration level prevailing and the particular organism concerned (human, plant, or animal and (R_{o_j}) is the number of organisms (o) in sector (j) (for plants, expressed perhaps in acreages). In areas where the soil is sulfur deficient (as in Alberta), some level of emissions (b_{o_j}) above zero will provide positive benefits to plant growth.

The sizes of the benefits perceived by each party are represented by a set of weights (λ). Sensitivity of the decision to differing weights will indicate the importance of accurate benefit measures.

Together, these generalized cost and benefit functions contain sufficient data to form net benefit (NB) functions for each interested party, as follows:

a. For the CDOE, the function is derived from (3) and (5):

$$NB_f(x) = \lambda_f B(Q') - C_f(x); \tag{6}$$

b. The ADOE (p) and the ERCB would perceive only benefits:

$$NB_p(x) = \lambda_p B(Q') = \lambda_p \sum_{j=1}^{3} b_{o_j} q_j \, R_{o_j} \tag{7}$$

c. The biological management agencies of the provincial government (p') would also perceive only benefits:

$$NB_{p'}(x) = \lambda_{p'} \, B(Q') = \lambda_{p'} \sum_{j=1}^{2} b_{o_q} q_j \, R_{o_j} \tag{8}$$

where (o) is only plant and animal organisms (excluding direct human health benefits) and (j) is restricted to the agricultural and forested zones.

d. The general populace (g) also perceives only benefits:

$$NB_g(x) = \lambda_g B(Q') = \lambda_g \sum_{j=1}^{3} b_{o_j} \, q_j \, R_{o_j} \tag{9}$$

where the constraints on o and j in (8) above are removed.

e. The industry (I) perceives net benefits only as costs, less the sale value (\$) of recovered sulfur:

$$NB_I(x) = \$_s - C_I(x) = \$_s - \sum_{i=1}^{67} C_{h_i}(x_i) \tag{10}$$

where $\$_s$ is the overall sale value of recovered sulfur. Because most sulfur is unsalable and stockpiled, this term has been relatively small but is dependent on the price of sulfur. For 1973, the value to the industry as a whole has has been estimated at thirty million dollars (*Oilweek*).

f. Gas consumers, when distinguished from their other roles in the general populace, likewise perceive only costs of increased gas prices. Compared to industrial and foreign concerns which consume quantities of gas, small domestic consumers are negligible as an interest group. Their interests are best represented by major consumers (c) who, on the whole, would perceive only the higher prices.

$$NB_c(x) = d(p)V \tag{11}$$

where d(p) is the price increment and (V) is the total volume purchased. Because price is a direct function of the net costs of the gas industry (owing to the pricing methods of the Public Utilities Board), equation (11) becomes

$$NB_c(X) = -\lambda_c C_I(x) \tag{12}$$

g. Similarly, the provincial government agencies responsible for development and resource exploitation (p") would perceive costs to industry due to less new investment and loss of royalties. The tourism branch of the Department of Industry and Tourism would perceive benefits only if it could be shown that present emissions deter tourists. This is unlikely because, except in some small local areas, Alberta's tourist attractions are relatively pollution-free. Therefore,

$$NB_{p''}(x) = -\lambda_{p''} C_I(x) \tag{13}$$

where a part of ($\lambda_{p''}$) could be computed from royalty structures.

3.5 Determination of the Pareto-admissible frontier

This stage solves the maximization problem set by summing the set of net benefit functions weighted by a vector $W = (w_1, \ldots\ldots, w_7)$ that indicates the political influence of each identified party (k):

$$\text{Maximize} \sum_{k=1}^{7} w_k \, NB_k(x) \tag{14}$$

subject to

$$Q \leq Q'$$

for each (W).

Completion of the study will involve the fitting of "best-estimate" data to the functions and solving the maximization problem for differing political weights (w) and benefit weights (λ).

3.6 Prediction and Prescription

Properly, this step should await completion of steps 4 and 5. But some judgements may be made without the quantitative data, aided by the systematic examination of the elements of the decision. The proposed set of new standards is likely to be adopted with little modification. This judgement is based on the array of weights applicable to the participants whose interests lie in more stringent standards.

4. Discussion of Results

An ambient standard is desirable for uniformity, but it is hard to enforce. It is logical, therefore, for the ERCB (the enforcement body) to want to apply emission standards to individual gas plants. Emissions are much easier to measure (and therefore apply standards to) than is environmental quality, the implied aim of ambient air quality standards. But this proposed control route is not necessarily the most cost-efficient. Because of weather, a given emission rate leads to a highly variable SO_2

concentration or *exposure* at the point of a receptor. Furthermore, the effects of any given *exposure* upon *environmental quality* is also dependent on the fluctuating sensitivity or tolerance of the receptors. Emission standards, if constant, must be stringent enough to satisfy the most probable poor-dispersal conditions and the most probable high sensitivity of receptors. Sulfur recovery equipment to meet such standards would be very expensive.

If gas plants were able and willing to modulate SO_2 emissions in immediate response to ambient air monitors, then continuously stringent emission standards might not be necessary. In weather conditions giving good dispersal, higher emission rates might be acceptable. This would be true even if varying receptor sensitivity were not considered.

If sufficient data were available to describe and monitor the factors affecting receptor sensitivity, greater emissions might be acceptable during periods of predictable relatively high tolerance. Intensive biological monitoring (observation of effects on living organisms) might be a method of feedback to plant operators for both variables described above.

Adequate research to satisfy the uncertainties in the foregoing alternatives to emission standards will undoubtedly be very expensive. But it might be more cost-effective in the long run.

Summary and Conclusions

In air quality management for natural gas production in Alberta, scarcity and generality of data make many of the factors in net benefit functions impossible to quantify at this time. Specifically, many benefits of more stringent SO_2 controls are in areas of diffuse information. Data are weak, for example, on recreational benefits, on health benefits of plants and animals, and on valuations of these.

Furthermore, there is some question as to the cost-effectiveness of the control instruments under development or consideration. In particular, the proposed emission standards (as opposed to ambient standards) seem rather rigid in view of the unpredictable variations in dispersal conditions and the predictable (but as yet unknown) fluctuations in sensitivity of receptors. But to allow for these variables the gas processing plants must rapidly modulate emissions in response to physico-chemical and biological monitors.

Solution of net-benefit functions developed for Alberta must follow further research to develop estimates of values presently unknown.

Bibliography

Anon. 1972. Submission to the Environment Conservation Authority on Environmental Effects of the Operation of Sulfur Extraction Gas Plant. Canadian Petroleum Association, Calgary, Alberta.

Berlie, E. M. 1972. Estimating the Capital and Operating Costs of Natural Gas Processing Plants. Paper read at the Sept. 15, 1972, meeting of the Canadian National Gas Processing Assoc. Red Deer, Alberta.

Carnow, B. W. 1970. Relationship of SO_2 Levels to Morbidity and Morbidity and Mortality in "High Risk" Populations. Paper presented to the American Medical Association Air Pollution Medical Research Conference, New Orleans, October 5, 1970.

Dunbar, R. B. 1970a. Natural Gas Processing. Unpublished report, Energy Resources Conservation Board, Calgary, Alberta.

Dunbar, R. B. 1970b. Sources of Pollution from Gas Processing Operations. Unpublished report, Energy Resources Conservation Board, Calgary, Alberta.

Hyne. J. B. 1972. Desulfurization of Effluent Gas Streams - A Review. Presented to NPGA meeting, New Orleans, April 10, 1972.

Klemm, R. F. 1972. Environmental Effects of the Operation of Sulfur Extraction Gas Plants. Report submitted to the Environment Conservation Authority, Edmonton, Alberta

Loman, A. A., R. A. Blauel, and D. Hocking. 1972. Sulfur Dioxide and Forest Vegetation. Inf. Report NOR-X-49; Northern Forest Research Center.

Manning, Glen H. 1970. A Method for Measuring the Value of Forest Recreation. Int. Report E-5, Forest Economic Res. Inst., Ottawa, Canada.

Nobbs, W., W. D. Abercrombie and H. A. Williams. 1971. Decision No. 30253, in the matter of an application by Canadian Western Natural Gas Co., Ltd. for an increase in the rates for gas to be charged by it to its customers. Public Utilities Board, Edmonton, Alberta.

Reimond, R. J. 1972. Sulfur Balance Report. Unpublished report, Energy Resources Conservation Board, Calgary, Alberta.

Schaumburg, G. W. 1972. Application of the Paretian Model to the Syracuse Air Pollution Problem. Paper presented to the Harvard Research Seminar: Economics of Environmental Quality.

APPENDIX 1

The Sulfur Recovery Processes

(after Dunbar, 1970a)

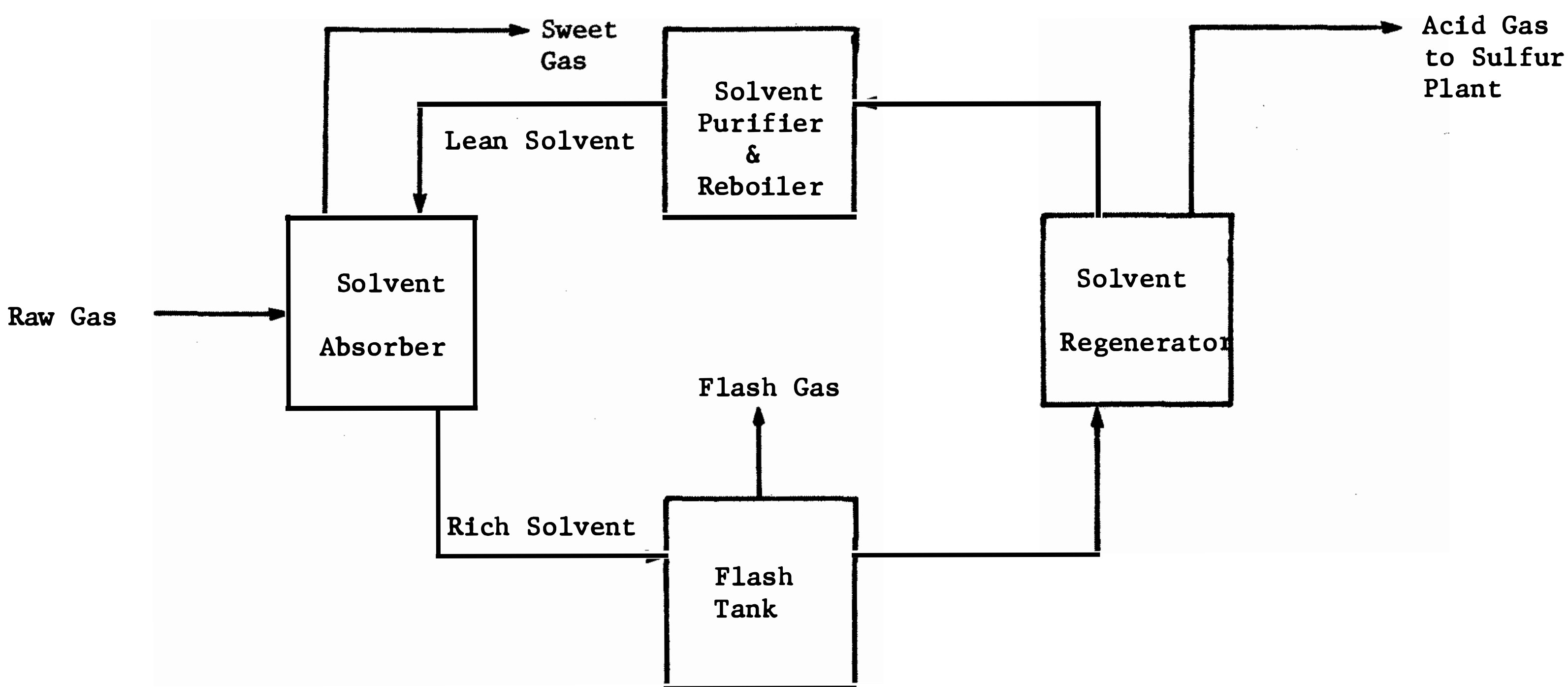


Figure 5. Typical solvent treating system to remove H_2S and CO_2 (acid gas) from natural gas. (Source: Dunbar 1970)

APPENDIX 1: The Sulfur Recovery Processes (after Dunbar 1970a).

a. Gas Sweetening

Absorption in an aqueous solution of an amine is the most common method used in Canada to remove H_2S and carbon dioxide (CO_2 from raw gas streams. Transfer of the acid gases from the raw gas is effected as cool lean amine solution flowing countercurrently downward in a scrubbing tower is contacted with the gas. The H_2S and CO_2 are stripped from the rich amine solution when it is heated. The regenerated amine solution is then ready for another cycle after being cooled.

The treating solutions most commonly used are mono-ethanolamine (MEA), di-ethanolamine (DEA) and sulfinol, a mixture of di-isopropanolamine (DIPA) and solfolane. These are circulated in a water solution. In an MEA treating plant the treating solution is normally from 15% to 20% MEA and from 80% to 85% water. In a DEA treating plant the treating solution is normally from 25% to 30% DEA with the remainder water. In a sulfinol plant the treating solution is normally 45% DIPA, 35% sulfolane and 20% water.

Figure 5 is a simplified flow diagram of a gas sweetening plant. Sour gas enters the bottom of a solvent contactor (absorber) where it flows upward through trays and is contacted with a countercurrent downward flow of the treating solution (MEA, DEA, sulfinol). The treating solution removes the acid gases (H_2S and CO_2) from the sour gas by chemical reaction, in which heat-unstable soluble salts are formed between the amine in the treating solution and the acid gases. In a sulfinol plant some acid gases are also physically absorbed. The gas leaving the top of the contactor is sweet and water saturated. The "rich" treating solution leaving the bottom of the contactor contains the H_2S and CO_2 removed from the sour gas. The rich solution is regenerated (the acid

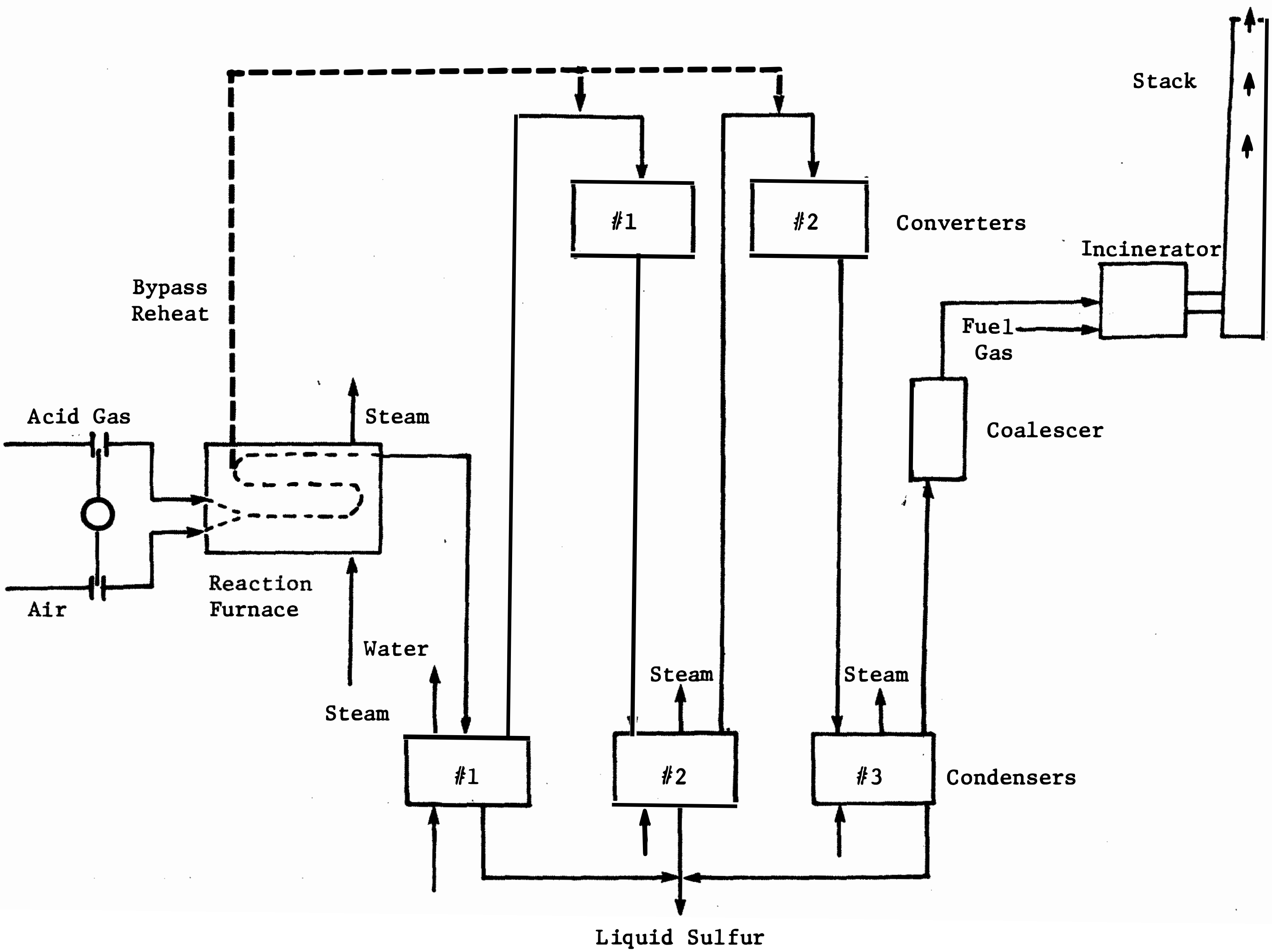


Figure 6. Process Flow Diagram - Sulfur Recovery Plant (Source: Dunbar 1970a)

gases are "stripped" from the solution) using a combination of heat and low pressure in the solvent regenerator (still). The rich solution is preheated in a series of heat exchangers and fed into the top of the regenerator. The acid gas stripped from the rich solution is removed from the top of the column and the "lean" solution is withdrawn from the bottom. The acid gases are cooled, condensed water is separated in a reflux accumulator and pumped back into the regenerator, and the acid gas is directed to the sulfur plant at low pressure (5 - 10 psig). The lean solution leaving the column is further purified in the solvent reboiler, the means of adding heat to the column, then cooled and pumped back to the solvent contactor.

A filter is normally required to remove corrosion products and other impurities from the treating solution. A solvent purifier (reclaimer) is also normally required to remove a buildup of non-regenerable degradation products from the system. A rich solution flash tank is also used to remove absorbed hydrocarbons from the rich solution, in a MEA or DEA system, or to assist in the regeneration of the rich solution in a sulfinol system.

b. <u>The Claus Process</u>

The acid gas (H_2S and CO_2) from the gas sweetening plant is directed to the sulfur recovery plant where elemental sulfur is recovered from the H_2S contained in the gas using the Claus process (named after its inventor). The process has been modified from time to time and from plant to plant, but it is basically as outlined in Figure 6. The acid gas enters the reaction furnace where it is burned with a deficiency of oxygen (air). The air flow is controlled so that only one third of the H_2S is burned to form sulfur dioxide according to reaction (1).

$$H_2S + 3/2\ O_2 \rightarrow SO_2 + H_2O \qquad (1)$$

Some SO_2 formed in the furnace reacts with unburned H_2S to form sulfur vapour:

$$SO_2 + 2H_2S \rightarrow 3S + 2H_2O \qquad (2)$$

[Other authors state that the chemistry and stoichiometry is considerably more complex, with substantial side reactions occurring.]

The hot gas stream leaving the reaction furnace is then cooled in the first sulfur condenser to condense most of the vapour. To promote further reaction between SO_2 and H_2S to form sulfur, the gas stream leaving the first condenser enters the first catalyst converter after being preheated with either hot gas from the reaction furnace or an inline burner. A catalyst of natural aluminum oxide (bauxite) catalyzes the sulfur production reaction (reaction (2) above). The sulfur vapour formed is condensed in the second condenser and removed from the gas stream. This cycle is repeated for up to a total of four stages of catalyst conversion. The gas leaving the last condenser flows through a coalescer which removes fine droplets of liquid sulfur entrained in the gas stream. The gas stream then flows to the incinerator. In the incinerator, sufficient fuel gas and air are added to completely oxidize any unrecovered sulfur (as H_2S entrained sulfur liquid, sulfur vapour, COS or CS_2 may be formed in the reaction furnace due to the presence of CO_2 and trace amounts hydrocarbons in the acid gas stream), to SO_2. The gas stream leaving the incinerator then flows to the stack for disposal to the atmosphere.

Sulfur in the acid gas recovered as elemental sulfur in the Claus plant ranges from 80 to 97 percent (sulfur recovery efficiency). The unrecovered sulfur is discharged to the atmosphere as SO_2. The sulfur recovery efficiency attainable in the plant depends on the following factors:

1. acid gas feed quality (percent H_2S, CO_2, CS_2, H_2O and hydrocarbons),
2. number of reaction stages,
3. plant mechanical design,
4. formation and conversion of COS and CS_2,
5. process design,
6. catalyst condition,
7. ration control, and
8. plant feed rate as a percent of design feed rate.

APPENDIX 2

New gas processing plant standards

AIR POLLUTION CONTROL AND EMISSION STANDARDS FOR NEW AND EXISTING PLANTS

Proposed by the Alberta Department of the Environment
December 21, 1972

ENVIRONMENTAL STANDARDS FOR GAS PROCESSING PLANTS

1. Ambient Air Quality Standards

The Department of the Environment is proposing the following maximum sulfur dioxide and hydrogen sulfide concentrations as acceptable levels in ambient air quality:

Time Period	Current Level		Proposed Levels	
	ppm	$\mu g/m^3$ (Approx.)	$\mu g/m^3$	ppm (Approx.)
Sulfur Dioxide				
1/2 hour	---	----	525	0.20
1 hour	0.30	785	450	0.17
24 hour	0.10	262	150	0.06
1 year	---	----	30	0.01
Hydrogen Sulfide				
1/2 hour	---	----	17	0.012
1 hour	0.03	42	14	0.010
24 hour	0.005	7	4	0.003

2. Ambient Monitoring Requirements

All sour gas processing plants shall be required to implement both continuous and static monitoring programs for the determination of sulfur dioxide and hydrogen sulfide according to the following schedule:

Maximum Allowable Sulfur Emission Rate - LTS/D	Continuous No. of Stations	Mo./Yr.	Static No. of Stations
120 - 149	5	12	40
90 - 119	4	12	35
60 - 89	3	12	30
30 - 59	2	12	25
15 - 29	1	12	20
10 - 14.9	1	9	16
5 - 9.9	1	6	12
3 - 4.9	1	3	8
1 - 2.9	1	2	4
Less than 1	As required	As required	2

All sour gas processing plants producing elemental sulfur shall establish a sulfur dustfall exposure cylinder network for the measurement of elemental sulfur according to the following schedule:

Sulfur Production LTS/D	No. of Sulfur Dustfall Exposure Cylinders
Greater than 1000	12
100 - 1000	8
Less than 100	4

Variations to the schedule will be applied when sulfur is produced but not shipped and also no monitoring for sulfur dust is required where the total shipment is in liquid form.

3. Source Requirements

3.1 Emission Standards

3.1.1 Total Tonnage Released - Total tonnage of sulfur released by existing plants must not exceed that quantity corresponding to the sulfur recovery guidelines as indicated in the Board's IL 71-29 effective December 31, 1974 or sooner. The total tonnage emission from new plants is equivalent to that amount which corresponds to a maximum 1/2 hour sulfur dioxide concentration of 1600 ppm in the stack gases, at a minimum stack gas temperature of 1000°F and an oxygen content of between 2.5 and 7.5 percent. However, under no circumstances shall the total tonnage exceed that amount which is dictated by the E.R.C.B. sulfur recovery guidelines.

3.1.2 Height of Stack Discharge - Stack design heights utilizing acceptable dispersion principles must be adequate to give a 1/2 hour calculated ground level concentration of not more than 0.2 ppm sulfur dioxide. Existing plants having stacks designed to give a calculated ground level concentration of sulfur dioxide in excess of 0.2 ppm will be required to modify their process and/or facilities to achieve a sulfur dioxide calculated ground level concentration of 0.2 ppm no later than December 31, 1974. The more stringent condition will apply to all new plants.

3.1.3 Temperature of Stack Gas Outlet - A minimum stack gas exit temperature of 1000°F is required for all incinerators.

3.1.4 Source Emission Concentrations

Existing Plants - Sulfur dioxide concentrations in the stack gases must not exceed the levels which would result from meeting the E.R.C.B. guidelines.

New Plants - Sulfur dioxide concentration in the stack gases must not exceed 1600 ppm average for 1/2 hour period and a maximum instantaneous concentration of 2000 ppm.

3.2 Source Monitoring

3.2.1 Continuous - All sour gas processing plants producing more then 50 long tons of sulfur per day or emitting more than 5 long tons of sulfur per day shall continuously monitor stack gases for sulfur dioxide concentration, volume flowrate, temperature and oxygen content.

3.2.2 Periodic - All sour gas processing plants utilizing incineration of sulfurous gases shall be periodically sampled and measurements made for:

1. Concentration of sulfur dioxide, oxygen, carbon dioxide and water vapor.
2. Volume flowrate.
3. Temperature.

Stack surveys shall be conducted according to the following frequency:

Maximum Allowable Sulfur Emission Rate LTS/D	No. of Stack Surveys Per Year
120 - 149	8
90 - 119	7
60 - 89	6
30 - 59	5
15 - 29	4
10 - 14.9	3
5 - 9.9	2
1 - 4.9	1
Less than 1	As required

4. <u>Renewal of Approvals or New Approvals</u>

Generally, approvals to operate are being issued for a period which is not to exceed 5 years. All current approvals being issued are in effect until December 31, 1974 to correspond with the requirements of the E.R.C.B. guidelines as noted in IL 71-29.

5. <u>New Plants</u>

<u>Source Emission Standards</u>

Sulfur dioxide concentrations must not exceed 1600 ppm in stack gases as an average over a one-half hour period. Maximum instantaneous sulfur dioxide concentrations must not exceed 2000 ppm. Stack gases must be maintained at a minimum of 1000^{o}F at the stack exit with an oxygen content of between 2.5 and 7.5 percent.

APPENDIX 3

Province of Alberta

Energy Resources Conservation Board

Informational Letter

No. 1L 71-29

APPENDIX 3

PROVINCE OF ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

Informational Letter
No. IL 71-29

TO: All Operators

Sulphur Recovery Requirements
Gas Processing Operations

The Board has indicated in Information Letter No. IL 70-73, dated July 24, 1970, in meetings with operators of gas processing plants, and through the issuance of certain recent processing plant approvals, that an increase in sulphur recovery efficiency would be required within two or three years. Indications were also given that the requirements would be more stringent but would be consistent with current trends in technology.

The Board has considered the matter of appropriate sulphur conservation requirements on the bases of current technology and the economics of sulphur recovery and, bearing in mind its responsibilities respecting pollution control and the impact on the environment of the total sulphur dioxide emissions in the Province, has developed certain minimum sulphur recovery efficiency guidelines. The guidelines are set out in Attachment I and are related to plant size and various acid gas qualities. The plant size categories were determined, having regard for relative economics, practicality and operating flexibility.

Effective immediately, the Board requests that the requirements set out in Attachment No. 1 be used as a guide in the planning of new gas processing plants and major expansions to existing plants. Where in the opinion of an applicant for the approval of a new plant or a major extension special circumstances warrant a deviation from the guidelines, the Board will consider an application for approval of a lower recovery and will decide the matter on its individual merits.

With regard to existing processing plants, the Board believes that such plants should be upgraded in accordance with the guidelines wherever practicable and that all plants should meet the standards as soon as possible but not later than December 31, 1974. In order to facilitate the achievement of this goal applications for approval of proposed modifications, in accordance with section 9.020 of the Oil and Gas Conservation Regulations, should be made not later than May 31, 1973, with construction to begin as soon as possible thereafter. The

Board appreciates that upgrading may not be justified for certain older plants and is prepared to accept applications for exemption from the prescribed recovery levels, or for lesser adjustments, where exceptional circumstances exist. Applications for such exemptions should be made to the Board not later than May 31, 1972.

ISSUED at the City of Calgary, in the Province of Alberta, this 9th day of November, A. D. 1971.

ENERGY RESOURCES CONSERVATION BOARD

Signed "G. W. Govier"

G. W. Govier
Chairman

Attachment 1
IL 71-29

Minimum Sulphur Recovery Efficiency Guidelines

(Inlet rate LT/day)	Process Requirements	Required Recovery Efficiency for Various Acid Gas Qualities		
		Favourable	Average	Unfavourable
100 to 4000	Stack clean-up required	98-99	98-99	97-99
400 to 1000	Minimal stack clean-up or equivalent process	96-98	95-98	94-97
100 to 400	Minimum of 3 stage Claus plant or equivalent process	94-96	93-95	92-94
10 to 100	Minimum of 2 stage Claus Plant or equivalent process	93-94	92-93	90-92

November 9, 1971 Energy Resources Conservation Board

APPENDIX 4

Air monitoring data submitted to the Alberta Department Environment by sour gas processing plants that are in excess of the ambient air quality standards.

APPENDIX 4

1971

AIR MONITORING DATA SUBMITTED BY THE PLANTS IN EXCESS OF THE AMBIENT AIR QUALITY STANDARDS

BALZAC	Petrogas	October	SO_2
E. CROSSFIELD	Amoco	May, July, Sept. October	H_2S
FT. McMURRAY	Great Canadian Oil Sands	April, May, June, July, Aug., Oct., November	H_2S & SO_2
LONE PINE CREEK	Hudson's Bay Oil and Gas	Sept. - Oct.	H_2S
SIMONETTE	Shell	December	H_2S
STURGEON LK. SOUTH (Valleyview)	Hudson's Bay Oil and Gas	April	H_2S
WATERTON	Shell	April, May, June	SO_2
W. WHITECOURT (Windfall)	Amoco	May, December	SO_2
WIMBORNE	Amoco	June- July	SO_2

1971

DEPARTMENT OF THE ENVIRONMENT MOBILE LABORATORY MONITORING IN EXCESS OF AMBIENT AIR QUALITY STANDARDS

Ft. McMurray	Great Canadian Oil Sands	November	SO_2

EXPLANATORY NOTES:

Since the spring of 1972, the plant showing monitoring results in excess of the Alberta Ambient Air Quality Standards have been required to notify this office as soon as possible after the occurrence and give such details as the time of the occurrence the duration of the reading, and the reading itself. This information is recorded on cards, whose format was suggested by the Deputy Minister's Office. The 1972 readings in excess of the

Alberta Ambient Air Quality Standards are further summarized in the attached tables. For the period of April, 1971 to approximately April, 1972, the list of the plants which exceeded the H_2S and SO_2 standards is on the previous page. This list refers to the month only, and does not give the detail of the reading itself or the duration. At the present time, the Energy Resources Conservation Board is notified of these high readings and further investigation is conducted by the Energy Resources Conservation Board field staff. Any corrections warranted by the findings of these investigations are then implemented through the requirement of the Energy Resources Conservation Board. On occasional cases, the source of the high reading is of an accidental nature (such as fire) and therefore can be remedied almost immediately by the plant itself. Should further detail be necessary for the 1971 data, we could make copies of the actual monthly reports or pertinent data thereof.

Plant Operator	Plant Location	Pollutant Standard Exceeded (H_2S or SO_2)	Peak Value (ppm)	Duration Hourly Standard Exceeded (hours)	Peak Hourly Average (ppm)	Duration and Peak Daily Standard Exceeded Days (ppm)	Date	
Canadian Superior	Harmattan	H_2S	1.0	9			Aug.6/72 Aug. 20-29 1972	Tape monitoring capability exceeded
Shell	Waterton	SO_2		6	.45		Nov. 12 & 13	
Chevron	Kaybob South #3	SO_2	.35	1	.30		Nov. 14/72	
Texaco Exploration	Bonnie Glen	H_2S		5	.039	1	Oct. 31/72	
Shell	Waterton	SO_2				1 (.108)	Nov. 16/72	
Texaco Exploration	Bonnie Glen	H_2S		1	.035		Nov. 25/72	
Shell	Jumping Pound	SO_2		1			Nov. 11/72	
Shell	Waterton	SO_2				1 (.117)	Nov. 23/72	
Hudson's Bay Oil and Gas	Sturgeon Lake	H_2S SO_2 H_2S		1 1 1 2	.048 .052 .355 .054	 1	Nov. 14/72 Nov. 17/72 Nov. 24/72 Dec. 5/72	
Petrogas	Balzac	H_2S		1 1	.037 .035		Dec. 2/72 Dec. 3/72	Faulty valve at nearby well site.

1972 - AIR MONITORING IN EXCESS OF THE AMBIENT AIR QUALITY STANDARDS

Plant Operator	Plant Location	Pollutant Standard Exceeded (H_2S or SO_2)	Peak Value (ppm)	Duration Hourly Standard Exceeded (hours)	Peak Hourly Average (ppm)	Duration and Peak Daily Standard Exceeded Days (ppm)	Date	
Amoco	West Whitecourt	SO_2	.85 .88	9 7	.4 .4	1 1	Feb. 23/72 Feb. 24/72	
Anerada	Olds	H_2S	.032	3	.032		Feb. 17/72	
Canadian Superior	Harmattan	H_2S	.075 .0345	1 1	.075 .035		Feb. 8/72 Feb. 14/72	
Amoco	West Whitecourt	SO_2		2	.70 .35		Mar. 1/72 Mar. 14/72	
Chevron	Kaybob South #3	H_2S	.160	2	.160		Mar. 19/72	
Texaco Exploration	Bonnie Glen	H_2S SO_2	.044	1	.044	 1 (.115)	May 5/72 Apr. 22/72	
Amoco	West Whitecourt	SO_2		1	.355		Apr. 10/72	
Great Canadian Oil Sands	Fort McMurray	SO_2		1 2	.317 .790		Apr. 23/72 Apr. 24/72	
Hudson's Bay Oil and Gas	Kaybob South #1 & 2	SO_2		2	.4		May 20/72	Fire in was sulphur pil

NOTE: H_2S Standard = .005 for 24 hour period
.030 for 1 hour period

SO_2 Standard = .100 for 24 hour period
.300 for 1 hour period

Generally H_2S readings are associated with field rather than plant operations.

Plant Operator	Plant Location	Pollutant Standard Exceeded (H_2S or SO_2)	Peak Value (ppm)	Duration Hourly Standard Exceeded (hours)	Peak Hourly Average (ppm)	Duration and peak Daily Standard Exceeded Days (ppm)	Date	
Great Canadian Oil Sands	Fort McMurray	SO_2		1	.325		May 16/72	#2 Monitoring site.
				2	.500		May 24/72	#2 Monitoring site.
				1	.40		May 31/72	#2 Monitoring site.
				1	.36		May 29/72	#1 Monitoring site.
			3.25	1	.96		May 30/72	#1 Monitoring site.
			1.30	1	.80		Jun. 22/72	
Amoco	West Whitecourt	H_2S		2	.068		Jun. 14/72	
Shell	Waterton	H_2S				1 (.0098)	May 13/72	
						1 (.0119)	May 19/72	
Great Canadian Oil Sands	Fort McMurray	SO_2		1	)		Mar. 4/72	
				2	).30		Mar. 22/72	
				5	)		Mar. 25/72	
Amoco	East Crossfield	SO_2		1	.5		Aug. 2/72	Well testing in area 200' from trailer.
		H_2S		1	.06		Aug. 2/72	
		H_2S		11	.076	1	Aug. 6/72	H_2S from tank vapors.
		SO_2		7	.80	1		SO_2 from flare.
Petrogas	Balzac	SO_2		1	.35			
Texaco Exploration	Bonnie Glen	H_2S		1	.035		Oct. 12/72	