FINAL REPORT (Revised)

ASSESSMENT OF TECHNICAL OPTIONS FOR REFINERS TO MEET THE INTERIM-PERIOD REQUIREMENTS OF THE SULPHUR IN GASOLINE REGULATIONS

A study performed for

Environment Canada

under

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by

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L I S T O F E X H I B I T S

L I S T O F A B B R E V I A T I O N S

CPPI	Canadian Petroleum Products Institute
IOL	Imperial Oil Limited
PC	Petro-Canada Products
FCC	Fluid catalytic cracking
FDS	FCC feed hydrotreating
GDS	FCC naphtha hydrotreating
ISBL	Inside battery limits (on-site) investments
OSBL	Outside battery limits (off-site) investments

EXECUTIVE SUMMARY

Environment Canada retained John Clark Consulting (Toronto) Inc. and MathPro Inc. to (1) identify available alternatives for meeting the requirements of the Sulphur in Gasoline Regulations (the Regulations) – particularly during the *interim* period; (2) assess the benefits and costs of these alternatives to certain Canadian refineries; and (3) delineate the advantages conferred to these refineries by the option recently proposed by the Canadian Petroleum Products Institute (CPPI).

Under the Regulations, each refinery's gasoline out-turn must contain ≤ 150 ppm sulphur on average, during the *interim* period: July 1, 2002 through December 31, 2004. The average may be calculated over the entire 2½-year period. (In addition, gasoline sulphur content will be capped at 300 ppm, starting January 1, 2004.) In the *long-term*, starting January 1, 2005, each refinery's gasoline out-turn must contain ≤ 30 ppm sulphur on average, with a cap of 80 ppm.

The CPPI has requested that the Regulations be amended to allow an additional option for refiners. Under the CPPI proposal, a given refinery could choose not to meet the *interim* sulphur requirement and instead meet the *long-term* sulphur requirement starting in January 2004, one year earlier than the Regulations require.

Two companies are pressing for the CPPI proposal: Imperial Oil (IOL) (for its Sarnia, Nanticoke, Dartmouth, and Strathcona refineries) and Petro-Canada (PC) (for its Oakville, Montreal, and Edmonton refineries). This study addresses available alternatives and the potential benefits of the CPPI proposal for only these two companies and these seven refineries.

ANALYTICAL APPROACH

Our approach for analyzing (1) alternatives available for complying with the interim sulphur standard alternatives and (2) the CPPI proposal comprised these steps.

1. Identify a set of prospective *compliance strategies*, each representing a technical approach – likely to be feasible but not necessarily attractive – for compliance with both the interim and the long-term standards, without recourse to the CPPI proposal.

2. Estimate the *compliance month* for each compliance strategy for each refinery of interest.

   The "compliance month" for a given strategy is the latest month that a given refinery could install sulphur control facilities that would enable compliance with both the long-term and the interim sulphur standards. For a given refinery, different strategies would lead to different compliance months. (The compliance month for the CPPI proposal is January 2004, by definition.)

3. Estimate the costs and technical implications of each strategy for each refinery of interest.

4. Estimate the costs and technical implications of the CPPI proposal for each refinery of interest – based on our best judgement regarding the technical approach that the refineries would take to meet the Regulations' long-term sulphur target under the CPPI proposal.

5. Compare the cost estimates developed in Steps 3 and 4, for each refinery of interest.

   This step enables one to estimate the potential benefits to the refining industry of the CPPI proposal, relative to the other compliance strategies considered.

TECHNICAL CONSIDERATIONS

Of the seven refineries of interest, three – PC Oakville, IOL Sarnia, and IOL Nanticoke – produce gasoline pools with especially high average sulphur content. Indeed, they are three of the four highest-sulphur refineries in Canada (Shell Sarnia is the other). These refineries are likely to incur the highest costs in complying with the Regulations.

Each of the IOL and PC refineries has fluid catalytic cracking (FCC) capacity. The FCC unit is the heart of a fuels refinery, converting heavy crude fractions into more valuable refinery streams that are blended into light products, such as gasoline, jet fuel, diesel fuel, and other light products.

FCC naphtha – the gasoline blendstock produced by FCC units – comprises roughly 40% of the gasoline pool, as high as 57% (at IOL Dartmouth) and as low as 32% (at IOL Sarnia).

Achieving the Regulations' sulphur standards requires controlling the sulphur content of FCC naphtha. Absent sulphur control, FCC naphtha contributes about 97% of the sulphur in a typical North American refinery's gasoline pool. In turn, about two-thirds of the sulphur in FCC naphtha is in the heaviest 10% of the stream; most of the balance is in the next heaviest 50%.

We considered the following technical approaches for controlling the sulphur content of FCC naphtha:

- Reducing the average sulphur content of the refinery's crude oil slate
- Rejecting the heaviest fraction of the FCC naphtha – which contains most of the sulphur – to other dispositions
- Employing a special-purpose FCC catalyst that reduces the sulphur content of raw FCC naphtha
- Desulphurizing the raw FCC naphtha, in an FCC naphtha hydrotreater
- Desulphurizing the FCC feed, in an FCC feed hydrotreater
- Shutting down the FCC unit, to eliminate FCC naphtha from the gasoline pool

These approaches may be used singly or in combination. Any or all of the first three could be employed to meet the interim sulphur target, but they are less likely to be employed to meet the long-term sulphur target. On the other hand, either FCC feed hydrotreating or FCC naphtha hydrotreating is capable of meeting the Regulations' long-term sulphur target – and hence the interim target as well.

On the basis of prior studies and information available to us, we conclude that, for most North American refineries, advanced FCC naphtha desulphurization (**GDS**) will be the method of choice for gasoline sulphur control. (Most, if not all, U.S. technology licensors share that view.)

Accordingly, we analyzed the following situation.

- All Canadian refineries – including the IOL and PC refineries – employ GDS to meet the Regulations' *long-term* sulphur standard.
- Each refinery makes its GDS investment in a particular compliance month, as part of a strategy for meeting the *interim* sulphur standard as well.
- Alternatively, under the CPPI proposal, a refinery may bring its GDS unit on line January 1, 2004 and not comply with the interim standard.

ECONOMICS OF FCC NAPHTHA DESULPHURIZATION

Long-term operating experience with GDS processes is limited, because gasoline sulphur standards are new. However, a number of processes, offered by established technology licensors, are available to refiners on commercial terms.

Drawing on information supplied to MathPro Inc. in prior studies, we estimated GDS economics for meeting the Regulations' long-term sulphur standard:

- Capital investment: C$1.7 K–2.6 K/Bbl per day
- Average operating cost: 3¼–4C¢/gal (0.9–1.1C¢/liter)

The *capital investment* range covers both on-site (ISBL) and off-site (OSBL) facilities, for a Canadian location, in 1998 dollars.

The *average operating cost* range covers the additional refining costs incurred in meeting sulphur standards: hydrogen supply, replacement of lost octane-barrels, utilities, catalyst and chemicals, and capital charge (at a 10% after-tax rate of return) on all facilities (ISBL and OSBL).

TIME-TABLE FOR FCC NAPHTHA DESULPHURIZATION

We estimated a representative (non-refinery-specific) schedule for a project to bring a GDS unit on line in a North American refinery. The estimate is based on information and guidance provided by three technology licensors and a large engineering, procurement, and construction (EPC) firm.

The standard elapsed time for a GDS project, from letter of intent to completion of start-up, is about 27-30 months. For this analysis, we used an elapsed time of *30 months*. Given that elapsed time, if a refiner were to issue a letter of intent by July 1, 2000, the GDS unit would be on line by January 1, 2003.

Given their gasoline sulphur positions, six of the seven refineries of interest – all but IOL Sarnia (which has the highest average gasoline sulphur content) – could meet the Regulations' interim sulphur standard by initiating a GDS project by July 1, 2000. IOL Sarnia could meet the interim sulphur standard by starting a starting a GDS project one month sooner – June 1, 2000.

PROSPECTIVE COMPLIANCE STRATEGIES

We defined and analyzed six prospective compliance strategies, or cases, for each IOL refinery and PC refinery.

- Case 1: Install a GDS unit.
- Case 2: Switch to sulphur reducing (SuRCa™) FCC catalyst, then install a GDS unit.
- Case 3: Reject heavy FCC naphtha, then install a GDS unit.
- Case 4: Switch to SuRCa catalyst *and* reject heavy FCC naphtha, then install a GDS unit.
- Case 5: Switch to a low sulphur crude slate, then install a GDS unit.
- Case 6: Shut down the FCC unit, then install a GDS unit.

In all cases, the GDS unit starts up in the compliance month.

For each strategy/refinery combination, we estimated the compliance month, the overall cost during the interim period, and the primary operating and business implications.

SUMMARY OF RESULTS

Exhibit ES-1 shows the estimated compliance month for each strategy/refinery combination.

Exhibit ES-2 shows the estimated total interim period cost for each strategy/refinery combination, as well as for the CPPI proposal. It also shows the total cost for each strategy, summed over all seven refineries.

The costs shown in Exhibit ES-2 include refinery operating costs (hydrogen supply, replacement of lost octane-barrels, utilities, catalyst and chemicals) and capital charge (at a 10% after-tax rate of return) on all facilities (ISBL and OSBL), for the period July 1, 2002 to December 31, 2004.

ES-1: Estimated Compliance Months for Compliance Strategies

Case	Description/Cost Categories	Imperial				Petro-Canada		
		Dartmouth	Nanticoke	Sarnia	Strathcona	Edmonton	Montreal	Oakville
CPPI	Install GDS Unit as of January 1, 2004	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04
1	Install a GDS Unit	May-03	Mar-03	Dec-02	Sep-03	May-03	May-03	Feb-03
2	Switch to SuRCa Catalyst, then Install a GDS Unit	Jul-03	May-03	Jan-03	Jan-04	Aug-03	Aug-03	Apr-03
3	Reject Heavy FCC Naphtha, then Install a GDS Unit	Mar-04	Nov-03	May-03	Jan-05	May-04	Apr-04	Oct-03
4	Switch to SuRCa Catalyst and Reject Heavy FCC Naphtha, then Install a GDS Unit	Sep-04	Apr-04	Jul-03	Jan-05	Dec-04	Oct-04	Feb-04
5	Switch to a Low Sulphur Crude Slate, then Install a GDS Unit*	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04
6	Shut Down FCC Unit, then Install a GDS Unit**	Feb-03	Oct-02	Nov-02	Jun-03	Mar-03	Feb-03	Dec-02

* Crude slate switched as of July 2002.
** Indicates FCC shutdown date; GDS installed as of January 2004.

ES-2: Estimated Costs of Compliance Strategies and the CPPI Proposal
(in millions of year 2000 C$)

Case	Description/Cost Categories	Imperial				Petro-Canada			Grand
		Dartmouth	Nanticoke	Sarnia	Strathcona	Edmonton	Montreal	Oakville	Total
CPPI	Install GDS Unit as of January 1, 2004	$17	$27	$24	$40	$38	$22	$21	$188
1	Install a GDS Unit	$28	$50	$49	$52	$60	$36	$39	$315
2	Switch to SuRCa Catalyst, then Install a GDS Unit	$25	$46	$47	$41	$52	$32	$37	$280
3	Reject Heavy FCC Naphtha, then Install a GDS Unit	$24	$34	$23	$64	$45	$29	$24	$243
4	Switch to SuRCa Catalyst and Reject Heavy FCC Naphtha, then Install a GDS Unit	$21	$27	$13	$48	$33	$24	$16	$181
5	Switch to a Low Sulphur Crude Slate, then Install a GDS Unit	$46	$94	$259	$64	$100	$66	$95	$723
6	Shut Down FCC Unit, then Install a GDS Unit	$121	$277	$133	$200	$191	$130	$140	$1,192

ON THE ECONOMIC BENEFITS OF THE CPPI PROPOSAL

The estimated compliance months in Exhibit ES-1 indicate that each IOL and PC refinery could meet the interim standard by building a GDS unit (with or without supporting measures) with a project timetable involving

- Initiation, via letter of intent, on or after July 1, 2000 (after, in most cases), and

- A thirty month project period (consistent with the schedule outlined in Section 5.3).

On the other hand, for a compliance strategy involving GDS, the CPPI proposal implies either (1) project initiation around July 1, 2001 or (2) a project timetable of about 42 months.

The economic benefits of the CPPI proposal to the refining industry would depend on the strategies that the refineries would adopt to meet the Regulations' sulphur standard.

Our analysis suggests that

- Various technically feasible strategies – involving advanced FCC naphtha desulphurization and some additional measures that are not capital intensive – are available to meet the interim sulphur standard.

  Relative to these strategies, the CPPI proposal appears to offer only modest economic benefit.

  Moreover, these strategies involve little or no "stranded" capital. In general, new facilities or modifications that might be installed during the interim period could be employed to meet the long-term standard as well.

- Other, more drastic strategies are available – switching to low-sulphur crudes (Case 5) or shutting down FCC units for a time (Case 6).

  Relative to these two strategies, the CPPI proposal offers large economic benefits, on the order of C$530 million (Case 5) and C$1000 million <u>or more</u> (Case 6).

  On the other hand, these strategies appear to be non-starters. They are far more costly than the other strategies considered here (as well as other, similar strategies that further study could delineate).

  Moreover, unlike the other strategies, Cases 5 and 6 involve complex issues and uncertainties, involving crude oil markets, refined product markets, and logistics. These areas are not subject to control by any refinery or company. Hence, Cases 5 and 6 involve more complexity, uncertainty, economic risk, and business risk than the other, more modest strategies considered here. We did not attempt to quantify these factors.

CONFINES OF THE ANALYSIS

The compliance strategies that we specified might – upon more detailed engineering analysis – prove infeasible or more costly than we estimated. On the other hand, more detailed analysis might delineate more attractive compliance strategies than those considered here.

We did not consider possible approaches involving co-operation between refineries. For example, North Atlantic Refining's Come-by-Chance refinery produces about 33 K Bbl/day of low-sulphur gasoline (50 ppm average). Under the right circumstances, an exchange of some of this gasoline for higher-sulfphur gasoline (or FCC naphtha) produced by, say, the PC Montreal refinery could contribute to an attractive compliance strategy. Similarly, we did not consider the possibility of gasoline or blendstock exchanges between nearby refineries (e.g., IOL Sarnia and IOL Nanticoke).

1. INTRODUCTION

Environment Canada retained John Clark Consulting (Toronto) Inc. and MathPro Inc. to (1) identify available alternatives for meeting the requirements of the Sulphur in Gasoline Regulations (the Regulations) – particularly during the *interim* period; (2) assess the benefits and costs of these alternatives to certain Canadian refineries; and (3) delineate the advantages conferred to these refineries by the option recently proposed by the Canadian Petroleum Products Institute (CPPI).

1.1 BACKGROUND

Under the Regulations, each refinery's gasoline out-turn must contain ≤ 150 ppm sulphur on average, during the *interim* period: July 1, 2002 through December 31, 2004. The average may be calculated over the entire 2½-year period. (In addition, gasoline sulphur content will be capped at 300 ppm, starting January 1, 2004.) In the *long-term*, starting January 1, 2005, each refinery's gasoline out-turn must contain ≤ 30 ppm sulphur on average, with a cap of 80 ppm.

The CPPI has requested that the Regulations be amended to allow an additional option for refiners. Under the CPPI proposal, a given refinery could choose not to meet the *interim* sulphur requirement – 150 ppm average over the Regulations' interim period – and instead meet the *long-term* sulphur requirement – 30 ppm average with an 80 ppm cap – starting in January 2004, one year earlier than the Regulations require.

Two companies are pressing for the CPPI proposal: Imperial Oil (for its Sarnia, Nanticoke, Dartmouth, and Strathcona refineries) and Petro-Canada (for its Oakville, Montreal, and Edmonton refineries). This study addresses the proposal's potential benefits for only these two companies and these seven refineries.

1.2 GENERAL APPROACH

The purpose of this study was to identify and assess feasible alternatives available to Canadian refiners – in particular, to the Imperial Oil (IOL) and Petro-Canada (PC) refineries – for timely compliance with the Regulations, particularly the interim average sulphur standard.

Our approach for achieving this purpose comprised these steps.

1. Identify a set of prospective *compliance strategies*, each representing a technical approach – likely to be feasible but not necessarily attractive – for compliance with the interim and long-term standards, without recourse to the CPPI proposal.

2. Estimate the *compliance month* for each strategy for each refinery of interest.

By "compliance month", we mean the latest month – for a given strategy – that a given refinery could install sulphur control facilities that would enable compliance with both the long-term sulphur target and the interim sulphur target. For a given refinery, different strategies would lead to different compliance months. (The compliance month for the CPPI proposal is January 2004, by definition.)

3. Estimate the costs and technical implications of each strategy for each refinery of interest.

4. Estimate the costs and technical implications of the CPPI proposal for each refinery of interest.

   The CPPI proposal does not indicate the technical approach or approaches that individual refineries would take to meet the Regulations' long-term sulphur target, if the proposal were accepted. Nor did we locate any information on this subject in the public domain. Consequently, we made an assumption regarding the technical approach of choice underlying the CPPI proposal.

5. Compare the cost estimates developed in Steps 3 and 4, for each refinery of interest.

   This step enables one to estimate the potential benefits to the refining industry of the CPPI proposal, relative to each compliance strategy considered.

Consistent with the Terms of Reference, this approach did not involve either specifying the approaches in detail for each refinery of interest or predicting the approach of choice for the IOL and PC refineries.

At the direction of Environment Canada, we conducted this study using only (1) information from public sources and (2) non-confidential information that we already had in hand, as the result of prior engagements and industry contacts. In particular, we did not contact any Canadian refining companies.

1.3 CONTENTS OF THE REPORT

Section 2 summarizes recent data on the average sulphur content of the gasoline produced by the refineries of interest. Section 3 discusses, in general (not refinery-specific) terms, the sources of sulphur in gasoline. Section 4 identifies and discusses the primary technical approaches available to refiners for controlling the sulphur content of gasoline. Section 5 discusses FCC naphtha hydrotreating, the likely method of choice for meeting the Regulations' sulphur targets. Section 6 describes the compliance strategies analyzed in this study. Section 7 presents results of the economic analysis of compliance strategies for each refinery of interest. Section 8 offers comments on the estimated benefits of the CPPI proposal to the refining industry.

1. AVERAGE GASOLINE SULPHUR CONTENT

Exhibit 1 shows average gasoline sulphur contents for the Imperial Oil and Petro-Canada refineries, by year, for the period 1994 to 1998. (The data were provided by Environment Canada and are consistent with data recently presented by the companies to the deputy minister of Environment Canada.)

Exhibit 1: Average Gasoline Sulphur Content (ppm), Imperial Oil and Petro-Canada Refineries

		Average Sulphur Content (ppm)					
		1994	1995	1996	1997	1998	Avg.
Imperial	Dartmouth	377	365	419	374	491	405
	Nanticoke	278	340	506	530	528	436
	Sarnia	590	728	787	712	792	722
	Strathcona	223	239	243	346	297	270
Petro-Canada	Montreal	580	472	356	387	318	423
	Oakville	586	528	489	519	520	528
	Edmonton	420	360	380	394	377	386

The shaded cells indicate the lowest yearly average sulphur level for each refinery.

The crude slates of the IOL refineries, except Dartmouth, appear to have become more sour over the five year period. The crude slate of PC's Montreal refinery shows the opposite trend. Only IOL's Strathcona refinery has achieved an average gasoline sulphur level below 300 ppm during the past five years.

2. FCC NAPHTHA: PRIMARY SOURCE OF SULPHUR IN GASOLINE

Each of the IOL and PC refineries has fluid catalytic cracking (FCC) capacity. (Oakville has two FCC units; the others one each.) The FCC unit is the heart of a fuels refinery, converting heavy crude fractions into more valuable refinery streams that are blended into light products, such as gasoline, jet fuel, diesel fuel, and other light products.

Exhibit 2 shows crude running capacity, FCC capacity, gasoline production, and estimated FCC naphtha production for the refineries of interest. (FCC naphtha is the gasoline blendstock produced by the FCC unit.)

Exhibit 2: Capacity Measures for Imperial Oil and Petro-Canada Refineries

		Crude Run	**FCC Capacity**	**Gasoline Make**	**FCC Naphtha**
		(M Bbl/day)	(M Bbl/day)	(M Bbl/day)	(M Bbl/day)
Imperial	Dartmouth	84	29.2	30	Ca.17
	Nanticoke	112	40.9	49.3	23.9
	Sarnia	122	25.6	42.6	13.5
	Strathcona	180	52.3	72.1	31.2
Petro-Canada	Edmonton	120	34.3	67.7	20.8
	Montreal	105	29.7	39.4	16.7
	Oakville	83	25.4	37.6	14.4

As Exhibit 2 indicates, FCC naphtha volume is roughly 40% of gasoline pool volume, ranging as high as 57% (at IOL Dartmouth) and as low as 32% (at IOL Sarnia).

Absent sulphur control, FCC naphtha contributes about 97% of the sulphur in a typical North American refinery's gasoline pool. Hence, achieving the sulphur standards set forth in the Regulations requires controlling the sulphur content of FCC naphtha.

FCC naphtha may be viewed as comprising three boiling range fractions – light (C_5-160^oF), medium (160^o – 300^oF), and heavy (300^o – 430^oF). They constitute, respectively, about ¼, ½, and ¼ of FCC naphtha volume. At least 65% of the sulphur in full range FCC naphtha is in the heavy fraction; most of the rest is in the medium fraction.

Exhibit 3 shows the different gasoline blendstock types that appear (in significant volumes) in the U.S. Summer gasoline pool (conventional and reformulated gasolines), and the average sulphur content (before treatment) of each that is registered in the database of MathPro Inc.'s refinery LP modeling systems (ARMS).

Exhibit 3 also shows our estimates, for each blendstock type, of the average sulphur content required for producing gasoline with average sulphur content ≤ 30 ppm.

EXHIBIT 3: AVERAGE SULPHUR CONTENTS OF GASOLINE BLENDSTOCK CLASSES

		Average Sulphur Content (ppm)	
Blendstock Class	Average Vol% in Gasoline Pool	Untreated	For 30 ppm Sulphur
FCC Naphtha (full range)	35	600-2000	≈ 50
Reformate	25	4	4
Isomerate	6	1	1
Alkylate	12	12	12
Lt. Straight Run Naphtha	7	100–200	15–25
Coker Naphthas	1	3000	1
Natural Gasoline	1	150	150
Hydrocracked Naphthas	4	4	4
Butanes	4	10	10
MTBE – captive	1	200	10
MTBE – merchant	3	10	10
Others	1	10–500	Variable

Clearly, FCC naphtha is the primary stream – in most refineries, the only stream – whose sulphur must be controlled to meet the Regulations' sulphur targets.

4. METHODS FOR REDUCING GASOLINE SULPHUR CONTENT

The technical approaches available for controlling the sulphur content of FCC naphtha include:

- Reducing the average sulphur content of the crude slate
- Rejecting ("under-cutting") the heaviest fraction of the raw FCC naphtha to other dispositions
- Employing a special-purpose FCC catalyst that reduces the sulphur content of raw FCC naphtha
- Desulphurizing the raw FCC naphtha, in an FCC naphtha hydrotreater
- Desulphurizing the FCC feed, in an FCC feed hydrotreater

As a (draconian) alternative to these measures, a refiner could simply eliminate FCC naphtha from the gasoline pool by shutting down the FCC unit. (We understand that CPPI has indicated that some refiners are considering this alternative.)

These approaches may be used singly or in combination. Any or all of the first three could be employed to meet the interim sulphur target, but they are less likely to be employed to meet the long-term sulphur target. On the other hand, either FCC feed hydrotreating or FCC naphtha hydrotreating – suitably practiced – is capable of meeting the Regulations' long-term sulphur target – and hence the interim target.

Following is a brief discussion of the various sulphur control options.

4.1 REDUCING THE AVERAGE SULPHUR CONTENT OF THE CRUDE SLATE

To be feasible for meeting the interim sulphur target, this approach would require moving to a crude slate with very low average sulphur content – in the range of 0.3-0.5 wt.%. Crudes with the requisite sulphur content are in trade (e.g., Brent, Bonny, Syncrude, and others), but may or may not be available in the necessary volumes during the interim period.

The refineries of interest could, in principle, acquire additional volumes of low-sulphur crudes from foreign suppliers or additional volumes of low-sulphur synthetic crude (upgraded heavy oil from oil sands) from Alberta suppliers. Forecasts indicate that the supply of low-sulphur synthetic crude will increase significantly, starting in 2002, by virtue of (1) capacity expansions undertaken by Syncrude, Suncor, and Co-Op and (2) new capacity being developed by Shell and Petro-Canada. At least some of that incremental volume could be available to the refineries of interest.

All else equal, a crude oil's price varies inversely with sulphur content – the lower the sulphur content, the higher the price. Hence, reducing the average sulphur content of a given refinery's crude slate would increase the refinery's operating costs. All else equal, a 1% change in crude oil sulphur content corresponds to (roughly) a US$1.50/Bbl (C$2.25/Bbl) change in price.

In addition, the low-sulphur crudes available to Canadian refineries may or may not be compatible with the refineries' capital stock and product slates.

4.2 Rejecting Heavy FCC Naphtha

As noted in Section 3, a disproportionate fraction of the sulphur in FCC naphtha is in the heaviest fraction (say, the heaviest 10-20 vol%). Consequently, one can achieve significant reductions in gasoline sulphur content (by as much as 60%) by rejecting some or all of the heavy FCC naphtha from the gasoline pool.

Doing so requires certain processing facilities – an FCC naphtha splitter unit or a heavy FCC naphtha draw-off on the main FCC fractionator. We understand that (1) the Nanticoke refinery has an FCC naphtha splitter and (2) the Dartmouth, Montreal, and Strathcona refineries have heavy FCC naphtha draw-offs. Such facilities could be built in other refineries in time for use in the interim period.

Possible dispositions of the rejected heavy FCC naphtha in existing refinery operations include:

- Product sales (as gasoline blendstock or distillate blendstock)
- Distillate product blending
- Resid blending
- Hydrocracking
- Reforming (after naphtha hydrotreating)

Clearly, this approach entails a potential loss in gasoline volume, equal in magnitude to the rejected volume of heavy FCC naphtha. Some or all of the potential loss in gasoline volume could be averted by measures such as reforming the rejected FCC naphtha (i.e., converting it into reformate, a high-octane gasoline blendstock), increasing conversion (i.e., FCC naphtha production) in the FCC unit, or upgrading ("ring-opening") the rejected FCC naphtha in a suitable distillate hydrotreater unit.

Our initial investigations suggest that rejecting heavy FCC naphtha would be an element in certain practical approaches to meeting the interim sulphur target.

4.3 Employing Sulphur-Reducing FCC Catalyst

Grace Davison, an established supplier of FCC catalysts, has developed a catalyst specially tailored to reduce the sulphur content of raw FCC naphtha. The catalyst, called SuRCa™, is available on a commercial basis.

Grace Davison claims that, as a total replacement for the incumbent FCC catalyst, SuRCa reduces the sulphur content of FCC naphtha by ~ 25%-30% (all else equal). The sulphur removed from the FCC naphtha leaves the FCC unit as H_2S. Other than that, SuRCa has little effect on FCC yield patterns, according to Grace Davison. We understand that SuRCa catalyst costs about 40% more than conventional FCC catalyst.

The refineries of interest may well find that using SuRCa is not warranted for meeting the Regulations' *long-term* sulphur target. But, if it performs as Grace Davison claims, SuRCa could be useful to the refineries of interest in meeting the Regulations' *interim* sulphur target.

4.4 HYDROTREATING FCC NAPHTHA

For brevity, we use the term **GDS** to denote FCC naphtha hydrotreating.

A GDS unit is a "stay-in-business" investment. It does not offer the operating and economic benefits of an FCC feed hydrotreating unit. But, it entails lower investment and operating costs, and it is sufficient for compliance with the Regulations' long-term sulphur standards.

Advanced GDS processes can achieve up to 99% sulphur removal. Hence, an advanced GDS unit alone can produce FCC naphtha with < 50 ppm sulphur – low enough to meet the Regulations' long-term sulphur target.

Replacing lost octane-barrels is one of the costs associated with GDS. Conventional (obsolete) GDS processes incur significant losses in the octane-barrels that FCC naphtha contributes to the gasoline pool, through olefin saturation and yield loss.

> Octane loss results mainly from the unwanted hydrogenation of olefins (relatively high octane) to paraffins (relatively low octane). Heavy FCC naphtha has a low concentration of olefins (< 10 vol%); medium FCC naphtha has a high concentration (~ 25-35 vol%).

In addition, severe desulphurization tends to reduce the volume of FCC naphtha. That is, fewer barrels come out of a GDS unit than go in.

Advanced GDS processes incur minimal octane losses – less than 1 number for full range FCC naphtha, and they incur little or no yield loss.

The higher the sulphur content of the raw FCC naphtha, the more stringent the gasoline sulphur standard, and the larger the share of total gasoline out-turn that must meet the standard, the more attractive the advanced processes become relative to conventional processes. These factors indicate that Canadian refiners selecting the GDS route for sulphur control would tend to prefer advanced (rather than conventional) GDS processes.

Commercial advanced GDS processes are available from a number of technology providers.

Section 5 discusses the GDS approach in more detail.

4.5 Hydrotreating FCC Feed

For brevity, we use the term **FDS** to denote FCC feed hydrotreating.

An FDS unit is a relatively expensive, but profit-seeking investment. It entails high investment and relatively high operating costs, including the costs of hydrogen generation. In return, it offers operating and economic benefits to the host refinery; it can achieve compliance with the Regulations' long-term gasoline sulphur standards; and it offers a partial capability for meeting more stringent diesel fuel sulphur standards (should they be instituted).

Depending on the crude slate and its operating severity, an FDS unit alone can reduce the sulphur content of FCC naphtha to ~ 50-150 ppm and of light cycle oil (LCO) – a distillate products blendstock – to ~ 500-1500 ppm. For the refineries of interest, high severity FDS processing, using the best contemporary technology, would suffice for meeting the Regulations' long-term sulphur target.

FDS units enable or contribute to meeting applicable sulphur standards, <u>and</u> they can deliver a range of operational and economic benefits by improving FCC performance. The benefits include

- Protecting FCC catalyst from sulphur, nitrogen, and metals poisoning (thereby improving catalyst activity, selectivity, and life);
- Reducing refinery emissions, especially of SOx;
- Increasing yields of FCC naphtha and (perhaps) distillate;
- Increasing the cetane number of the diesel fuel pool;
- Reducing yields of coke, light cycle oil, and other undesirable streams; and
- Permitting increased use of relatively low-cost heavy/sour crude oils.

Capturing these benefits is economic – if price differentials between sweet and sour crudes is sufficient, and refiners have the ability to sell the incremental gasoline and distillate volumes generated by FDS processing.

Commercial FDS processes are available from a number of technology providers.

One Canadian refiner (Co-Op) has an FDS unit.

Some ratios of FDS capacity to FCC capacity in the U.S. may be of interest:

- U.S. as a whole 35%
- California 100%

At present, no FDS units are under construction in the U.S., though a number of potential new units are reportedly under study.

4.6 SHUTTING DOWN THE FCC UNIT

In a conversion refinery – that is, a refinery with an FCC unit – the FCC unit is the primary contributor to the refinery's profit margin. An FCC unit converts each barrel of feed into 0.5–0.6 Bbl of FCC naphtha, 0.2–0.3 Bbl of diesel fuel blendstock, 0.1–0.2 Bbl of feed for alkylate production (alkylate is a high-octane, high-quality gasoline blendstock), and a number of other refinery streams that contribute to other product pools.

Shutting down an FCC unit affects the refinery's profit contribution in a number of ways.

- Producing revenue through the sale of FCC feed (for processing by another refinery).
- Reducing operating costs by eliminating the costs of operating the FCC unit.
- Reducing revenue by reducing the out-turn of gasoline, jet fuel, diesel fuel, heating oil, petrochemical feedstocks, and fuel oil – all of which contain, in part, FCC outputs.

For purposes of this analysis, we assumed that any of the refineries of interest could sell its full volume of FCC feed in the U.S. Gulf Coast market, and that the necessary logistics facilities would be available year-round.

Shutting down an FCC unit would be costly. Shut-down would cost the refinery the value added by the FCC unit plus the cost of moving the FCC feed to the buyer's site. It would reduce the refinery's market share for all affected products, unless the refinery made up the volume short-falls by importing product volumes. Shut-down would, however, enable the refinery to meet the Regulations' interim sulphur target.

5. FCC NAPHTHA DESULPHURIZATION

Over the past four years, MathPro Inc. has conducted numerous studies of the technical requirements and economics of gasoline sulphur control to meet various standards, including the recently-announced U.S. Tier 2 sulphur standard (30 ppm average) and the interim and long-term standards in the Regulations. We have concluded that, for most North American refineries, FCC naphtha desulphurization (GDS) will be the method of choice for gasoline sulphur control. (Most, if not all, U.S. technology licensors share that view.)

Accordingly, for this analysis, we considered the following scenario.

- All Canadian refineries – including the IOL and PC refineries – employ GDS to meet the Regulations' long-term sulphur standard.

- Each refinery makes its GDS investment in a particular compliance month, as part of a strategy for meeting the interim sulphur standard as well.

- Alternatively, under the CPPI proposal, a refinery may bring its GDS unit on-line January 1, 2004 and not comply with the interim standard.

This section presents some of the technical and economic information on GDS processes that we used in the economic analysis of compliance strategies (discussed in the next two sections).

5.1 Advanced GDS Processes

In 1999, the National Petroleum Council (NPC) solicited information on advanced GDS processes from various technology licensors. The NPC solicited this information in its current study of the implications of new environmental regulations on the production capabilities of the U.S. refining industry. The NPC has placed some of this information in the public domain.

Exhibit 4 (pages 12 and 13) lists the advanced GDS processes that either are in commercial use now or are candidates for commercial application by 2004-2005.

Exhibit 5 (pages 14-16) shows representative octane and yield losses for the various GDS processes, for two different FCC naphtha feeds (denoting average and high feed sulphur levels).

Development continues at a rapid pace. Several firms have recently released, or will soon release, new data showing more severe desulphurization capability, improved economics, and more commercial experience.

Exhibit 4: FCC Naphtha Desulphurization (GDS) Processes

Status	Process Licensor	Process	Technology
Proven	Various	Various	Conventional Hydrotreating
Demonstrated	CDTech	CD Hydro	Selective Hydrotreating
	Exxon	SCANfining	Selective Hydrotreating
	IFP	Prime G	Selective Hydrotreating
	Mobil	OCTGAIN 125	Non-selective Hydrotreating + Oct Rec.
Near-Commercial	CDTech	CD HDS	Selective Hydrotreating
	Mobil	OCTGAIN 220	Non-selective Hydrotreating + Oct Rec.
	UOP	ISAL	Non-selective Hydrotreating + Oct Rec.
Developing	Phillips Petroleum	S Zorb	Selective Hydrotreating + Sorption
	Black & Veatch	IRVAD	Adsorption

NOTES:

1. **Status** denotes the state of commercial readiness of the indicated process, as estimated by the Technology Workgroup (Committee on Refining) of the National Petroleum Council (NPC).

    Proven means "in [commercial] use at multiple locations on a variety of feedstocks, at required operating conditions, such that use in another application poses no technology-performance risk."

    Demonstrated means "in commercial use with demonstrated run lengths [of at least] two years. . . such that scale-up of pilot plant results has been demonstrated. Experience is limited, such that extrapolation of pilot plant or commercial results is required for new operating conditions or feed compositions."

    Near-Commercial means "currently in initial phases of commercial demonstration with sufficient pilot plant experience to make scale-up and commercial operating practices the primary technology risk. No commercially demonstrated basis for . . . extrapolation [of pilot plant results] to commercial operation."

    Developing means "new concept with some limited pilot plant results; significant scale-up and commercial operation issues remain."

2. **Technology** denotes the technology category applied in the indicated process

   Conventional Hydrotreating achieves desulphurization with essentially complete olefins saturation (and hence substantial loss of octane in the treated FCC naphtha (10 octane numbers or more)).

   Selective Hydrotreating achieves desulphurization with little olefins saturation (and hence little loss of octane).

   Non-selective Hydrotreating + Octane Recovery achieves desulphurization with partial or total olefins saturation (with attendant octane loss), but recovers most of the lost octane by secondary reactions (e.g., isomerization).

   Selective Hydrotreating + Sorption achieves desulphurization with little olefins saturation (and hence little loss of octane) and sequesters the sulphur in a solid sorbent medium.

Exhibit 5: Overview of the Performance of FCC Naphtha Desulphurization (GDS) Processes

		Feed Sulphur: 774 ppm Desulphurization: 95%		Feed Sulphur: 2500 ppm Desulphurization: 99%	
Status	**Process Licensor**	**D Octane No.**	**Yield (Vol%)**	**D Octane No.**	**Yield (Vol%)**
Proven	Various	- 10 or more	100	- 10 or more	100
Demonstrated	CD Hydro (1)				
	SCANfining	-1	100	-4	100
	Prime G	-1.3	99.2	-3.5	99.1
	OCTGAIN 125			-0.5	97.5
Near-Commercial	CD HDS	-1	100	-2.8	100
	OCTGAIN 220	-0.1	99.8		
	ISAL (2)	-5 / 0	100 / 93.6	-6.85 / 0	99.85 / 91.1
Developing	S Zorb	-0.75	100	-1.25	100
	IRVAD	-2	95.3	---	---

NOTES:

1. Estimates for CD Hydro™ are included in those for CD HDS™. CD Hydro and CD HDS would be used together, in one process sequence, for treating full range FCC naphtha.

2. UOP provided data for ISAL™ operating in two distinct modes: "yield neutral" (no yield loss) and "octane neutral" (no octane loss). The first number in each pair applies to the former mode; the second number to the latter mode.

3. The process information shown above was collected by the NPC Technology Workgroup, through a survey of process licensors in June 1999. At least some of the process licensors have announced that they have more recent (and presumably more favorable) data to report.

4. The process information shown above applies to a nominal full-range FCC naphtha feed having the properties shown in the table below. These feed properties (except for the 2500 ppm sulphur value) are average values for refining operations in Summer 1996 in U.S. PADDs 1, 2, and 3 (as reported in the *1997 API/NPRA Survey on Refining*).

Properties of Nominal FCC Naphtha Feed in NPC Survey

Feed Property	Value
Sulphur (ppm)	774 / 2500
Gravity (^{o} API)	55.7
Olefins (Vol%)	33
Aromatics (Vol%)	25.8
ASTM Distillation	
T_{10} (^{o} F)	143
T_{50} (^{o} F)	220
T_{90} (^{o} F)	345

5.2 Estimated GDS Economics

On the basis of confidential information provided by two technology licensors, MathPro Inc. has, in prior studies, estimated the economics of advanced GDS processes. These estimates are incorporated in MathPro Inc.'s modeling database.

The values summarized below are drawn from that database. They are applicable to controlling gasoline sulphur content to meet the Regulations' long-term sulphur standard – 30 ppm average sulphur content.

- Capital investment: C$1.7 K–2.6 K/Bbl per day (US $1K–1.5K/Bbl per day)
- Average operating cost: 3¼–4C¢/gal (0.9–1.1C¢/liter)

The *capital investment* range covers both on-site (ISBL) and off-site (OSBL) facilities, for a Canadian location, in 1998 dollars. The estimate incorporates a location factor to account for differences in investment costs between the U.S. Gulf Coast and Canadian locations.

The *average operating cost* range covers the additional refining costs incurred in meeting sulphur standards: hydrogen supply, replacement of lost octane-barrels, utilities, catalyst and chemicals, and capital charge (at a 10% after-tax rate of return) on all facilities (ISBL and OSBL).

These estimates were developed in the course of modeling aggregate or notional refining operations. They are neither refinery-specific nor process-specific, and they are not intended for project planning. They are intended for policy, planning, and screening studies.

5.3 Estimated Project Schedule for Building a GDS Unit

GDS processes use conventional equipment, established unit operations, mild temperatures and pressures, and well-established chemistry. Moreover, process licensors and EPC firms are already gearing up to meet the demand for new GDS facilities resulting from new sulphur standards in the U.S., Europe, and Canada.

But implementation time is of central importance in assessing the CPPI proposal. Accordingly, we estimated a representative (non-refinery-specific) schedule for a project to bring a GDS unit on line in a North American refinery. The estimate is based on information and guidance provided by three technology licensors and a large engineering, procurement, and construction (EPC) firm.

A GDS project begins with a letter of intent from the refiner to the process licensor and concludes with a successful start-up. A typical project involves four main steps (the first handled by the process licensor, the others mainly by the EPC firm):

- Basic engineering
- Detailed engineering
- Procurement and construction
- Commissioning and start-up

The critical path in the schedule is determined by the lead time for acquiring the hydrogen compressors (relatively small) and the reactor vessels (moderate size and low pressure) in the procurement and construction step.

Exhibit 6, a simple Gantt chart, shows the typical sequencing of these steps.

Exhibit 6: Representative Project Schedule for Building a GDS Unit

Project Task	Task Time	Elapsed Time from Letter of Intent (months)				
		6	12	18	24	30
1. Basic Engineering	6 months					
2. Design Engineering	14 months					
3. Procurement & Construction	18 months					
4. Commissioning & Start-up	2 months					

As Exhibit 6 indicates, the standard elapsed time from letter of intent to completion of start-up is about 27-30 months. With aggressive management (not necessarily warranted in this situation), the schedule could be compressed to about 24 months.

For this analysis, we used an elapsed time of 30 months for a GDS project (which we mean to be conservative.) Given that elapsed time, if a refiner were to issue a letter of intent by *July 1, 2000*, the GDS unit would be on-line by *January 1, 2003*.

Given their gasoline sulphur positions, six of the seven refineries of interest – all but IOL Sarnia (which has the highest average gasoline sulphur content) – could meet the Regulations' interim sulphur standard by initiating a GDS project by July 1, 2000. IOL Sarnia could meet the interim sulphur standard by starting a starting a GDS project one month sooner – June 1, 2000.

6. STRATEGIES FOR COMPLYING WITH THE INTERIM STANDARD

We conducted a brief screening analysis to define possible strategies for complying with the interim sulphur target (as well as the long-term target). Our analysis suggests that feasible compliance strategies can be designed for each refinery of interest – strategies that are not necessarily attractive economically, but are feasible.

We confined our screening analysis to possible compliance strategies involving

1. Applying, if necessary, one or more of the sulphur reduction techniques described in Section 4, starting July 1, 2002, and then

2. Installing a GDS unit – later in the interim period – that would achieve the sulphur control needed to produce gasoline with average sulphur content of 30 ppm.

We chose six prospective compliance strategies (cases) for economic analysis.

- Case 1: Install a GDS unit.
- Case 2: Switch to SuRCa catalyst, then install a GDS unit.
- Case 3: Reject heavy FCC naphtha, then install a GDS unit.
- Case 4: Switch to SuRCa catalyst *and* reject heavy FCC naphtha, then install a GDS unit.
- Case 5: Switch to a low sulphur crude slate, then install a GDS unit.
- Case 6: Shut down the FCC unit, then install a GDS unit.

We defined each strategy such that (1) use of the first measure (e.g., switch to SuRCa catalyst) would begin on or before July 1, 2002 and end when the GDS unit comes on line and (2) the GDS unit would come on line no later than the compliance month.

> Recall that the "compliance month" is the latest month – for a given strategy – that a given refinery could install a long-term GDS unit and still comply with the interim sulphur target. For a given refinery, then, different strategies lead to different compliance months. For example, both switching to SuRCa catalyst (Case 2) and rejecting heavy FCC naphtha (Case 3), starting 1 July 2002, would push back the compliance month in a given refinery, but by different time intervals.

In addition, we specified a strategy for the CPPI proposal: build a GDS unit that comes on line January 1, 2004 and achieves the sulphur control needed to produce gasoline with average sulphur content of 30 ppm.

For purposes of this analysis, we took the baseline gasoline sulphur content for each refinery to be the refinery's average for the five-year period 1995-1999. That is, we assumed no improvement in the coming years in average crude oil quality or refinery upgrading capability (other than what might be called for by the various strategies).

We estimated the volume and sulphur content of FCC naphtha produced in each refinery of interest from public information on the refineries' crude running capacity, FCC capacity, and baseline gasoline sulphur content.

For simplicity, we assumed that all (100%) of the gasoline sulphur content comes from FCC naphtha, instead of the actual proportion, which is about 97% (Exhibit 3).

Following are brief descriptions of the prospective compliance strategies listed above and, for each, our basis for evaluating them.

6.1 Case 1: Install a GDS Unit

This compliance case involves "business-as-usual" from 1 July 2002 to the compliance month, and then bringing a GDS unit on line during the compliance month.

We specified that the GDS unit would desulphurize the heavy and medium FCC naphtha fractions (as defined in Section 3). For some refineries, we also specified mild desulphurization (via Extractive Merox™ treating) of the light FCC naphtha fraction. For each refinery, we estimated a combination of treat volume and sulphur removal rate that would lead to an average sulphur content ≤ 30 ppm for the overall gasoline pool.

6.2 Case 2: Switch to SuRCa Catalyst, Then Install a GDS Unit

This case involves (1) replacing a portion of the incumbent (conventional) FCC catalyst with SuRCa FCC catalyst, such that the change-over is complete as of 1 July 2002, and then (2) bringing a GDS unit on line during the compliance month.

We assumed that the SuRCa catalyst would reduce the average sulphur content of the gasoline pool by 20%, relative to each refinery's baseline value. (The assumption of 20% sulphur reduction estimate is intended to be conservative; Grace Davison claims 25%-30%.)

As noted in Section 4, SuRCa catalyst costs about 40% more than conventional FCC catalyst. Accordingly, we set the incremental cost of SuRCa catalyst at US$0.07/Bbl FCC feed.

The use of SuRCA catalyst would reduce the average sulphur content of the gasoline pool in the first phase of the interim period. This would push back the compliance month, allowing deferral of expenditures and more time for installation of the GDS unit. Permanent use of SuRCa catalyst (not considered here) could permit a smaller, less costly GDS unit (relative to Case 1).

6.3 CASE 3: REJECT HEAVY FCC NAPHTHA, THEN INSTALL A GDS UNIT

This case involves (1) rejecting the heaviest 10 vol% of the FCC naphtha from 1 July 2002 up to the compliance month, and then (2) bringing a GDS unit on line during the compliance month.

The 10% rejection rate was based on the premise that this fraction of the FCC naphtha contributes about 50% of the average sulphur content of the gasoline pool. (Information at hand suggests that this premise is reasonable, and indeed conservative.) The target of 50% sulphur removal was arbitrary.

As discussed in Section 4.2, heavy FCC naphtha has a number of possible dispositions. For this strategy, we specified rejecting it to the light cycle oil (LCO) stream, for distillate blending. (This disposition involved fewer technical and assumptions than the others. It offers no benefits other than compliance with the interim sulphur standard.)

Rejecting heavy FCC naphtha to the LCO stream would require an FCC naphtha splitter unit or, preferably, a heavy FCC naphtha draw-off on the main FCC fractionator unit. We understand that the Nanticoke refinery has the former, and the Dartmouth, Strathcona, and Montreal refineries have the latter. The other refineries would have to adapt their FCC main fractionators to reject the heaviest 10% of the FCC naphtha as part of the LCO stream produced by the fractionator. We included capital and operating costs for this item in the economic analysis.

We assumed that this strategy would reduce the refinery's gasoline out-turn and increase distillate out-turn by the volume of rejected FCC naphtha. We incorporated the corresponding revenue changes in the economic analysis. We assumed that the incremental distillate out-turn would be exported, reducing its refinery net-back value by US$4.00/Bbl.

As in Case 2, rejecting heavy FCC naphtha would push back the compliance month, allowing deferral of expenditures and more time for installation of the GDS unit. Permanent use of the technique (not considered here) could permit a smaller, less costly GDS unit (relative to Case 1).

6.4 CASE 4: SWITCH TO SURCA CATALYST *AND* REJECT HEAVY FCC NAPHTHA, THEN INSTALL A GDS UNIT

This case involves (1) switching to SuRCa catalyst *and* rejecting the heaviest 10 vol% of the FCC naphtha from 1 July 2002 up to the compliance month, and then (2) bringing a GDS unit on line during the compliance month.

Combining the approaches used in Cases 2 and 3 would delay the compliance date further than either strategy alone.

All of the technical and economic considerations for Cases 2 and 3, discussed in Sections 6.2 and 6.3, apply here as well.

6.5 CASE 5: SWITCH TO A LOW SULPHUR CRUDE SLATE, THEN INSTALL A GDS UNIT

This case involves (1) changing the refinery crude slate to reduce the average crude sulphur content, and hence, the average FCC naphtha sulphur content, and then (2) bringing a GDS unit on line during the compliance month.

We assumed the compliance month to be January 1, 2004 for each refinery, for alignment with the CPPI proposal. Then, for each refinery, we estimated the average volume fraction of the crude slate that would be replaced by a low sulphur crude during the first phase of the interim period to achieve compliance with the interim sulphur standard.

In analyzing this strategy for each refinery, we assumed that

- The sulphur content of the FCC naphtha would be 10% that of the refinery's FCC feed;
- The sulphur content of the FCC feed would be the same as the average sulphur content of the refinery's crude slate;
- The five eastern refineries would use Brent (≈4000 ppm sulphur) as their low sulphur crude;
- The two Alberta refineries would use Syncrude (≈2000 ppm sulphur) as their low sulphur crude.

In addition, we assumed that

- The cost of crude switching would be US$1.50/Bbl (C$2.25/Bbl) per 1% reduction in average sulphur content of the crude slate;
- Logistics facilities were available for bringing low sulphur crude to each refinery, year round;
- Sufficient volumes of low sulphur crudes were available in national and world oil markets; and
- The properties of the low sulphur crudes acquired were compatible with the given refinery's capital stock and product slate.

6.6 CASE 6: SHUT DOWN THE FCC UNIT, THEN INSTALL A GDS UNIT

This case involves (1) shutting down the FCC unit to eliminate the source of sulphur in gasoline, FCC naphtha, and then (2) bringing a GDS unit on line during the compliance month.

Here again, we assumed the compliance month to be January 1, 2004 for each refinery, for alignment with the CPPI proposal.

One can view this strategy as having three temporal phases in the interim period. First would be a "business-as-usual" phase, in which refinery operations were unchanged. Second would be the FCC shut-down phase. Third, starting (by definition) with the compliance month, would be the long-term, GDS operation phase.

With the FCC unit down, the average sulphur content of the gasoline pool would be $\leq$ 30 ppm (assuming best refinery practice in producing the other gasoline blendstocks). As noted earlier, we assumed that it would be zero for purposes of this analysis. Under this premise, we estimated for each refinery the minimum duration of the FCC shut-down necessary for compliance with the interim sulphur standard.

As discussed in Section 4.6, shutting down an FCC unit affects the refinery's profit contribution in three main ways.

- Producing revenue through the sale of FCC feed (for processing by another refinery).

  We assumed that Canadian refineries could sell all of their FCC feed to U.S. Gulf Coast refineries, at a net-back price equal to the marginal value of FCC feed in the Gulf Coast minus the cost of moving the material to the Gulf Coast.

  We estimated the marginal value of FCC feed in the Gulf Coast from recent refinery modeling studies by MathPro Inc. (which used a weighted average crude price of US$20/Bbl).

  We set the cost of shipping FCC feed to the Gulf Coast at US$6.30/Bbl (C$9.25/Bbl).

- Reducing operating costs by eliminating the costs of operating the FCC unit and (for each refinery that has one) the alkylation unit (which draws feed from the FCC unit).

  We estimated the direct operating costs for FCC units and alkylation units using (mainly) cost elements drawn from MathPro Inc.'s refinery modeling database. These costs cover fuel, power, steam, catalyst and chemicals, and purchased feedstocks.

- Reducing revenue by reducing the out-turn of gasoline, jet fuel, diesel fuel, heating oil, petrochemical feedstocks, and fuel oil – all of which contain, in part, FCC outputs.

  We estimated the losses in product volumes using engineering judgement, published information on the refineries of interest and technical data elements, such as yield coefficients, drawn from MathPro Inc.'s refinery modeling database.

  These estimates do not reflect many refinery-specific considerations, but we consider them accurate enough for the purpose of this study.

We estimated refinery gate prices for these products using results from recent refinery modeling studies by MathPro Inc. These prices reflect an average crude oil price of US$20/Bbl and apply to the U.S. Gulf Coast.

> (Forecasting long-term crude prices is beyond the scope of this analysis, and in general is not a useful undertaking. Price differences between markets on the U.S. Gulf Coast and Canadian refining centers can be significant, but not significant enough to change the order of magnitude of the economic effects of this prospective strategy.)

NOTE: We assumed that, during an FCC shut-down, each refinery of interest could produce a reduced volume of gasoline complying with existing regulations and standards – including, in particular, the cap on benzene content and the Benzene Emissions Number (BEN). In an FCC shut-down, the highest-volume gasoline blendstock remaining would be reformate – a blendstock with very high benzene content (which is controlled) and very high aromatics content (which is not). So, during an FCC shut-down, some or all of the refineries might well not be able to produce significant volumes of gasoline that comply with the BEN requirement. If they could not, gasoline sales volumes would decline more, reformate and straight run naphtha volumes would be sold, and the cost of the FCC shut-down strategy would be higher than we estimate.

6.7 THE CPPI PROPOSAL

In addition to the six prospective compliance strategies, we also specified a strategy corresponding to the CPPI proposal. This case involves building a GDS unit that comes on line January 1, 2004 and achieves the sulphur control needed to produce gasoline with average sulphur content of 30 ppm.

The CPPI Proposal case differs from Case 1 (Build a GDS Unit) only in the date that the GDS unit comes on line. The CPPI proposal case does not lead to uniform compliance with the Regulations' interim sulphur standard.

7. ECONOMIC ASSESSMENT OF THE COMPLIANCE STRATEGIES

This section deals with the methodology and results of our economic analysis of the compliance strategy cases and the CPPI proposal case. The results indicate the economic benefits to the IOL and PC refineries of the CPPI proposal, relative to the various compliance strategies considered.

7.1 ELEMENTS OF THE METHODOLOGY

For each strategy/refinery combination, we estimated the total cost (in 2000 $C) incurred in the entire, 2½-year interim period (July 1, 2002 to December 31, 2004).

> We did not consider costs that would be incurred thereafter, because (1) compliance with the long-term standard is not at issue and (2) we assumed that all refineries would use GDS to comply with the long-term standard in the compliance strategies and under the CPPI proposal.
>
> We did not express the various cost streams as net present values, because the calculation would have involved numerous economic assumptions and (in our view) did not offer any added insight into the economic implications of the various strategies.

The cost estimates for each strategy/refinery combination comprise five aggregate cost (or revenue) elements:

- GDS operations

  This cost item includes hydrogen supply, replacement of lost octane-barrels, utilities, catalyst and chemicals, and capital charge (at a 10% after-tax rate of return) on all facilities (ISBL and OSBL).

- Other unit operations (where applicable)

  This cost item applies to existing FCC, alkylation, and distillate desulphurization units, for cases in which these units change operations (Cases 3 and 4) or shut down (Case 6).

- Sulphur-reducing catalyst (SuRCa)

  This item is the total additional cost of adding SuRCa catalyst to the FCC catalyst charge.

- Change in product revenues

  Revenue additions arise from (1) incremental sales of distillate products in Cases 3 and 4 and (2) sales of FCC feed and alkylate feed in Case 6.

Revenue reductions arise from (1) reduced sales of gasoline in Cases 3 and 4 and (2) reduced sales of gasoline, distillate products, fuel oil, and other products in Case 6.

- Low sulphur crude oil acquisition

  This cost item arises, in Case 5 only, from replacing a portion of the refinery's crude slate with low-sulphur crude oils – whose prices are higher than the average crude price that the refinery now faces.

As noted in Section 6, revenue estimates for refinery sales reflect U.S. Gulf Coast prices with an average crude oil acquisition cost of US$20/Bbl.

The Appendix (the very last page of the report) gives a concise summary of the technical and economic parameters used in the economic analysis.

7.2 Estimated Economics of the Compliance Strategies and the CPPI Proposal

Exhibits 7, 8, and 9 summarize the results of our analysis.

Exhibit 7 shows the estimated compliance month for each strategy/refinery combination.

Exhibit 8 shows the estimated total interim period cost for each strategy/refinery combination, the corresponding breakdown by cost category, and the total cost for each strategy, summed over all seven refineries.

Exhibit 9 shows the estimated changes in refinery out-turns of gasoline, distillates, other refined products, and FCC feed for each relevant refinery/strategy combination (Cases 3, 4, and 6).

7.2.1 Compliance Month (Exhibit 7)

Cases 1, 2, 3, and 4 have estimated compliance months of January 2003 or later for each refinery of interest, with only exception. Case 1 (Build a GDS Unit) at Sarnia has a compliance month of December 2002.

In Cases 3 and 4, Strathcona – the refinery with the most favorable sulphur position – has a compliance month of January 2005. Under these strategies, Strathcona would not have to invest at all to meet the interim sulphur standard.

Collectively, the estimated compliance months indicate that each IOL and PC refinery could meet the interim standard by building a GDS unit (with or without supporting measures, such as using SuRCa catalyst) with a project timetable involving

- Initiation, via letter of intent, on or after July 1, 2000 (after, in most cases), and

- A thirty month project period (consistent with the schedule outlined in Section 5.3).

On the other hand, for any compliance strategy involving GDS, the CPPI proposal implies either (1) project initiation around July 1, 2001 or (2) a project timetable of about 42 months.

7.2.2 Cost (Exhibit 8)

From a cost standpoint, the cases are in two categories.

Cases 1, 2, 3, and 4 are (relatively) low-cost strategies – especially Case 4. Cases 5 and 6 are high-cost strategies.

Cases 1, 2, and 3 have higher estimated costs than the CPPI proposal case, because the former (in general) call for earlier operation of the GDS unit (with its attendant costs) than the CPPI proposal does. Estimated total costs (covering all refineries of interest) for these cases are about C$55–125 million above than the estimated total cost for the CPPI proposal.

The estimated costs for Case 4 (refinery-by-refinery and total) are essentially the same as for the CPPI proposal. This result suggests that compliance strategies – involving GDS and additional operations that don't require much capital – can be fashioned to meet the interim sulphur standard with essentially no economic penalty relative to the CPPI proposal.

Cases 5 and 6 appear to be non-starters from an economic standpoint. Both are much more costly than the other four strategies. Estimated total costs for Cases 5 and 6 are, respectively, about C$530 million and C$1000 million higher than the total for the CPPI proposal.

As noted in Section 6.6, in an FCC shut-down, the refineries of interest might not be able to produce gasoline complying with the benzene cap and BEN requirements. If they could not, gasoline sales volumes would decline more, reformate and straight run naphtha volumes would be sold, and the cost of the FCC shut-down strategy would be higher than the estimate shown in Exhibit 8. We estimate that these effects could increase the total cost of the FCC shut-down strategy by about C$ 500 million.

7.2.3 Changes In Refinery Out-turns (Exhibit 9)

Cases 1, 2, and 5 involve no changes in product out-turns. (For Case 5 (crude switching), we assumed that the refineries could acquire low-sulphur crudes that would allow them to maintain their current product slates.)

Cases 3 and 4 involve small changes in gasoline and distillate out-turns.

Rejecting 10 vol% of the FCC naphtha to the distillate pool, as we assumed here, would (without countervailing measures) reduce aggregate gasoline out-turn in the refineries of interest by about 14 K Bbl/day, about 4% of current aggregate production.

Exhibit 7 indicates that the 10% rejection rate would lead to a compliance month later than January 2004 for four of the refineries of interest (IOL Dartmouth, IOL Strathcona, PC Edmonton, PC Montreal). This result suggests that these refineries could reject less than 10% of their FCC naphtha and still comply with the interim sulphur standard by bringing a GDS unit on line by January 1, 2004.

Only Case 6 (FCC shut-down) involves large-scale changes in product out-turns.

For Case 6, the volume changes shown in Exhibit 9 would apply only during the duration of the indicated refinery's shut-down (also shown in Exhibit 9). The indicated peak (or cumulative) effect would apply to those months (if any) in which *all* the refineries of interest had shut down their FCC units.

We assumed that the indicated shortfalls in product out-turn would be made up by imports, and that markets would exist for the requisite volumes of FCC feed.

8. ON THE BENEFITS OF THE CPPI PROPOSAL

8.1 PRIMARY FINDING

The economic benefits of the CPPI proposal to the refining industry would depend on the strategies that the refineries would adopt to meet the Regulations' sulfphur standard (1) if the proposal were accepted and (2) if it were not.

Our analysis suggests that

- Various strategies – involving advanced FCC naphtha desulphurization and some additional measures that are not capital intensive – are likely to be available to meet the interim sulphur standard. Such strategies are technically feasible.

  Relative to these strategies, the CPPI proposal appears to offer only modest economic benefit.

- Other, more drastic strategies are available – switching to low-sulphur crudes (Case 5) or shutting down FCC units for a time (Case 6).

  Relative to these two strategies, the CPPI proposal offers large economic benefits, on the order of C$530 million (Case 5) and C$1000 million or more (Case 6).

  On the other hand, these strategies appear to be non-starters. They are far more costly than the other four strategies considered here (as well as still other strategies that further study could delineate).

Moreover, unlike the other strategies, Cases 5 and 6 involve complex issues and uncertainties, involving crude oil markets, refined product markets, and logistics. These areas are not subject to control by any refinery or company. Hence, Cases 5 and 6 involve more complexity, uncertainty, economic risk, and business risk than the other, more modest strategies considered here. We did not attempt to quantify these factors.

8.2 CONFINES OF THE ANALYSIS

Only a limited time was available for this analysis, and we conducted it without access to detailed, refinery-specific information. Accordingly, the compliance strategies that we specified might – upon more detailed engineering analysis – prove infeasible or more costly than we estimated.

On the other hand, more detailed analysis might delineate more attractive compliance strategies than those considered here.

We did not consider possible approaches involving co-operation between refineries. For example, North Atlantic Refining's Come-by-Chance refinery produces about 33 K Bbl/day of low-sulphur gasoline (50 ppm average). Under the right circumstances, an exchange of some of this gasoline for higher-sulfphur gasoline (or FCC naphtha) produced by, say, the PC Montreal refinery could contribute to an attractive compliance strategy. Similarly, we did not consider the possibility of gasoline or blendstock exchanges between near-by refineries (e.g., IOL Sarnia and IOL Nanticoke).

Finally, we did not consider the effects of the FCC shut-down strategy on the economics of the Canadian refining sector as a whole. The reduction in gasoline out-turn indicated in Exhibit 9 would promote imports of refined products and would likely lead to increases in the prices of gasoline and other refined products. Such price increases would benefit the IOL and PC refineries to the extent of their remaining production capacity. They would benefit the rest of the Canadian refining sector to a greater extent.

Exhibit 7: Estimated Compliance Months for Compliance Strategies (1)

Case	Description/Cost Categories	Imperial				Petro-Canada		
		Dartmouth	Nanticoke	Sarnia	Strathcona	Edmonton	Montreal	Oakville
CPPI	Install GDS Unit as of January 1, 2004	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04
1	Install a GDS Unit	May-03	Mar-03	Dec-02	Sep-03	May-03	May-03	Feb-03
2	Switch to SuRCa Catalyst, then Install a GDS Unit	Jul-03	May-03	Jan-03	Jan-04	Aug-03	Aug-03	Apr-03
3	Reject Heavy FCC Naphtha, then Install a GDS Unit	Mar-04	Nov-03	May-03	Jan-05	May-04	Apr-04	Oct-03
4	Switch to SuRCa Catalyst and Reject Heavy FCC Naphtha, then Install a GDS Unit	Sep-04	Apr-04	Jul-03	Jan-05	Dec-04	Oct-04	Feb-04
5	Switch to a Low Sulphur Crude Slate, then Install a GDS Unit (2)	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04	Jan-04
6	Shut Down FCC Unit, then Install a GDS Unit (3)	Feb-03	Oct-02	Nov-02	Jun-03	Mar-03	Feb-03	Dec-02

(1) The compliance month for a given strategy is the latest month that a given refinery could install GDS facilities that would enable compliance with both the long-term and the interim sulphur standards.
(2) Crude slate switched as of July 2002.
(3) Indicates FCC shutdown date; GDS installed as of January 2004.

Exhibit 8: Estimated Costs of Compliance Strategies and the CPPI Proposal

(in millions of year 2000 C$)

Case	Description/Cost Categories	Imperial				Petro-Canada			Grand
		Dartmouth	Nanticoke	Sarnia	Strathcona	Edmonton	Montreal	Oakville	Total
CPPI	**Install GDS Unit as of January 1, 2004**	**$17**	**$27**	**$24**	**$40**	**$38**	**$22**	**$21**	**$188**
1	**Install a GDS Unit**	**$28**	**$50**	**$49**	**$52**	**$60**	**$36**	**$39**	**$315**
	GDS Operating Cost	27.9	49.9	49.2	51.9	60.3	36.0	39.4	
2	**Switch to SuRCa Catalyst, then Install a GDS Unit**	**$25**	**$46**	**$47**	**$41**	**$52**	**$32**	**$37**	**$280**
	GDS Operating Cost	24.0	44.8	46.6	38.0	50.9	30.8	35.9	
	SuRCa Catalyst Cost	1.2	1.3	0.5	3.0	1.5	1.2	0.7	
3	**Reject Heavy FCC Naphtha, then Install a GDS Unit**	**$24**	**$34**	**$23**	**$64**	**$45**	**$29**	**$24**	**$243**
	GDS Operating Cost	13.3	21.8	18.9	31.9	30.0	17.5	16.7	
	Revenue Loss from Rejected Heavy FCC Naphtha	9.1	10.8	3.8	27.2	13.0	9.8	6.0	
	Debottlenecking Cost for Rej. Hvy FCC Naphtha	1.5	1.7	0.6	4.4	2.1	1.6	1.0	
4	**Switch to SuRCa Catalyst and Reject Heavy FCC Naphtha, then Install a GDS Unit**	**$21**	**$27**	**$13**	**$48**	**$33**	**$24**	**$16**	**$181**
	GDS Operating Cost	4.6	7.6	6.6	11.1	10.4	6.1	5.8	
	Revenue Loss from Rejected Heavy FCC Naphtha	11.9	14.0	4.8	27.2	17.0	12.8	7.7	
	SuRCa Catalyst Cost	2.4	2.7	1.0	5.0	3.2	2.6	1.5	
	Debottlenecking Cost for Rej. Hvy FCC Naphtha	1.9	2.3	0.8	4.4	2.7	2.1	1.2	
5	**Switch to a Low Sulphur Crude Slate, then Install a GDS Unit**	**$46**	**$94**	**$259**	**$64**	**$100**	**$66**	**$95**	**$723**
	GDS Operating Cost	16.7	27.4	23.7	40.1	37.6	21.9	20.9	
	Incremental Crude Oil Acquisition Costs	29.6	66.3	235.2	23.6	62.3	44.0	73.8	
6	**Shut Down FCC Unit, then Install a GDS Unit**	**$121**	**$277**	**$133**	**$200**	**$191**	**$130**	**$140**	**$1,192**
	GDS Operating Cost	16.7	27.4	23.7	40.1	37.6	21.9	20.9	
	Revenues from FCC Feed Sales (-)	-229.0	-433.7	-240.9	-278.7	-254.9	-219.4	-234.3	
	Lost Revenues from Lost Product Sales (+)	344.1	823.9	362.0	527.5	506.2	357.7	394.8	
	Reductions in Operating and Input Costs (-)	-11.0	-140.8	-11.5	-89.1	-98.1	-30.1	-41.1	

Exhibit 9: Estimated Changes in Product Volumes: Compliance Strategies 3, 4, and 6 (1)

Case	Description	Imperial				Petro-Canada			Peak
		Dartmouth	Nanticoke	Sarnia	Strathcona	Edmonton	Montreal	Oakville	Effect
3	**Reject 10% Heavy FCC Naphtha, then Install a GDS Unit**								
	Duration of Volume Change (months)	20	17	10	31	23	21	15	
	Change in Refinery Output (K bbl/d)								
	Gasoline	(1.6)	(2.4)	(1.4)	(3.2)	(2.1)	(1.7)	(1.4)	(13.8)
	Distillate	1.6	2.4	1.4	3.2	2.1	1.7	1.4	13.8
4	**Switch to SuRCa Catalyst and Reject 10% Heavy FCC Naphtha, then Install a GDS Unit**								
	Duration of Volume Change (months)	27	21	13	31	30	28	19	
	Change in Refinery Output (K bbl/d)								
	Gasoline	(1.6)	(2.4)	(1.4)	(3.2)	(2.1)	(1.7)	(1.4)	(13.8)
	Distillate	1.6	2.4	1.4	3.2	2.1	1.7	1.4	13.8
6	**Shut Down FCC Unit, then Install a GDS Unit**								
	Duration of Volume Change (months)	11	14	14	7	9	10	13	
	Change in Refinery Output (K bbl/d)								
	Gasoline	(16.3)	(34.6)	(13.5)	(46.2)	(32.1)	(19.2)	(17.4)	(179.4)
	Distillate	(3.9)	(5.7)	(3.2)	(7.7)	(5.0)	(4.0)	(3.4)	(32.9)
	Other Refined Products	(10.9)	(9.9)	(9.1)	(13.4)	(7.4)	(9.9)	(8.0)	(68.6)
	FCC Feed (Gas Oil)	28.6	42.0	23.7	56.4	36.6	29.5	25.3	242.2

(1) Cases 1, 2, and 5 entail no changes in product out-turns.

Appendix: Assumptions and Values Used in Economic Analysis

Description	Value
Sulphur in Non-FCC Blendstocks	0
FCC Naphtha Sulfur Reduction from SuRCa Catalyst	20%
Averaging Period (months)	30
Averaging Sulphur Target (ppm)	150
Sulphur Level with GDS (ppm)	30
Reduction in FCC Sulfur from Rejecting Heavy Naphtha	50%
Heavy FCC Naphtha Rejected as % of Total FCC Naphtha	10%
Length of Period Refinery Buys Low Sulphur Crude (months)	18
Averaging Period for FCC Shutdown Case (months)	18
Gasoil Sulfur Content as % of Crude Oil Sulphur	100%
FCC Naphtha Sulphur Content as % of Gasoil Sulphur	10%
Cost Differential on Crude Oil ($/bbl/1% delta sulfur)	$1.50
Alkylate Capacity Utilization	90%
FCC Yield Coefficients	
FCC Naphtha	0.569
Light Cycle Oil	0.136
Clarified Oil	0.064
Alkylate Feed (olefins)	0.147
Other gases	0.171
Alkylation Input Coefficients	
Butylenes	0.575
Isobutane	0.8
Operating Cost of GDS Unit ($/bbl)	$1.05
Canadian Currency Exchange Rate	0.68
Incremental Cost of SuRCa Catalyst ($/bbl of FCC feed)	$0.07
Prices for Products and Blendstocks ($US/bbl)	
Gasoil (adjusted for $6.30 transport & handling)	$16.70
Gasoline	$26.00
Distillate	$25.00
Fuel Oil	$17.00
Light Gases	$18.00
Aklyate Feeds	$18.60
Isobutane	$18.60
FCC Operating Costs ($US/bbl)	$0.80
Alkylation Operating Costs ($US/bbl)	$3.25
Extra Processing Cost or Lost Revenue on Light Cycle Oil	$1.00
Cost of Debottlenecking for Heavy FCC Naphtha Rejection ($/bbl)	$1.00
Cost of FCC Naphtha Splitter ($/bbl of rejected heavy FCC naphtha.)	$4.00
Discount on Exported Distillate in FCC Naphtha Rejection Strategies	$4.20
Discount on Exported Gasoline in FCC Shutdown Strategy	$6.30